

## ADMINISTRATIVE RECORD

Par Hawaii Refining, LLC

Minor Modification Application No. 0088-32  
Application for Renewal Nos. 0088-07 and 0088-17  
Application for Renewal No. 0088-19  
Application for Renewal No. 0088-31

Par West Refinery

Located At: 91-480 Makakole Street CCB, Kapolei, Oahu

**CSP No. 0088-01-C**

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# **Public Notice**



**REQUEST FOR PUBLIC COMMENTS  
ON DRAFT AIR PERMIT  
REGULATING THE EMISSIONS OF AIR POLLUTANTS**

**(Docket No. 20-CA-PA-09)**

Pursuant to Hawaii Revised Statutes (HRS), Chapter 342B-13 and Hawaii Administrative Rules (HAR), Chapter 11-60.1, the Department of Health, State of Hawaii (DOH), is requesting public comments on the following **DRAFT PERMIT** presently under review for:

**Covered Source Permit (CSP) No. 0088-01-C**

Application for a Minor Modification No. 0088-32

Application for Renewal Nos. 0088-07, 0088-17, 0088-19, and 0088-31

Par Hawaii Refinery, LLC

Par West Refinery

Located At: 91-480 Malakole Street, Kapolei, Oahu

The **DRAFT PERMIT** is described as follows:

CSP No. 0088-01-C would grant conditional approval for the continued operation of the existing petroleum refinery. This facility is subject to the following Federal Requirements:

40 Code of Federal Regulations (CFR) Part 60 - Standards of Performance for New Stationary Sources (NSPS)

- Subpart A: General Provisions
- Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (applies to Boilers)
- Subpart J: Standards of Performance for Petroleum Refineries (applies to the Flares, Atmospheric and Vacuum Furnaces F-5103 and F-5153, Process Unit Furnaces F-5600, F-5700, F-5930, and F-5950, Acid Plant Preheater, Gas Turbines with HRSGs in the Cogeneration Plant, Cogeneration Unit K-6704, and Boilers)
- Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (applies to the Catalytic Oxidation Unit and Flares)
- Subpart GG: Standards of Performance for Stationary Gas Turbines (applies to the Gas Turbines with HRSGs in the Cogeneration Plant)
- Subpart GGG: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and On or Before November 7, 2006 (applies to Process Units, Flares, and Flare Vapor Recovery Unit)
- Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (applies to Process Units, Flares, and Flare Vapor Recovery Unit)
- Subpart QQQ: Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (applies to Cogeneration Units, Crude Unit, Vacuum Unit, Crude Desalter, Boiler Plant, Flare Vapor Recovery Unit, API Separators, and Catalytic Oxidation Unit)

- Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (applies to black start DEG and diesel engine pumps)
- Subpart KKKK: Standards of Performance for Stationary Combustion Turbines (applies to Cogeneration Unit K-6704)
- 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Subpart A: General Provisions
- Subpart FF: National Emission Standard for Benzene Waste Operations (applies to the API Separators, Benzene Recovery Unit, Recovered Oil Sump, Skim Oil Tank, Wastewater Surge Tank, Recovered Oil Tank, Foul Water Treatment Plant, and Catalytic Oxidation Unit)
- 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)
- Subpart A: General Provisions
- Subpart CC: National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (applies to Process Units, Flares, and Flare Vapor Recovery Unit, except for the Boiler Plant; Foul Water Treatment Plant, and Catalytic Oxidation Unit)
- Subpart YYYY: National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (applies to the Combustion Turbine in Cogeneration Unit K-6704)
- Subpart ZZZZ: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (applies to black start DEG and diesel engine pumps)
- Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters (applies to Atmospheric and Vacuum Furnaces F-5103 and F-5153, Process Unit Furnaces F-5600, F-5700, F-5930, and F-5950, Acid Plant Preheater, and Boilers)
- 40 CFR Part 68 - Chemical Accident Prevention Provisions (applies to the storage and use of flammable substances in the refinery)
- 40 CFR Part 98 – Mandatory Greenhouse Gas Reporting

These are existing units with no proposed modifications and no proposed emission increases. The total potential emissions from the Par West Refinery are as follows:

<u>Pollutant</u>	<u>Emissions (tpy)</u>
NO <sub>x</sub>	1,008.8
CO	367.8
SO <sub>2</sub>	2,482.5
PM/PM <sub>10</sub> /PM <sub>2.5</sub>	92.9
VOC	399.2
HAPS	22.059
CO <sub>2</sub> e	545,299.77

The **ADMINISTRATIVE RECORD**, consisting of the **APPLICATION** and non-confidential supporting materials from the applicant, the permit review summary, and the **DRAFT PERMIT**, is available online at: <http://health.hawaii.gov/cab/public-notices/> and for public inspection during regular office hours, Monday through Friday, 7:45 a.m. to 4:15 p.m., at the following location:

State of Hawaii  
Clean Air Branch  
2827 Waimano Home Road, #130  
Pearl City, Hawaii 96782

All comments on the draft permit and any request for a public hearing must be in writing, addressed to the Clean Air Branch at the above address on Oahu and must be postmarked or received by **October 16, 2020**.

Any person may request a public hearing by submitting a written request that explains the party's interest and the reasons why a hearing is warranted. The DOH may hold a public hearing if a hearing would aid in DOH's decision. If a public hearing is warranted, a public notice for the hearing will be published at least thirty days in advance of the hearing.

Interested persons may obtain copies of the administrative record or parts thereof by paying **five (5) cents per page copying costs**. Please send written requests to the Clean Air Branch listed above or call Mr. Darin Lum at the Clean Air Branch at (808) 586-4200.

Comments on the draft permit should address, but need not be limited to, the permit conditions and the facility's compliance with federal and state air pollution laws, including: (1) the National and State Ambient Air Quality Standards; and (2) HRS, Chapter 342B and HAR, Chapter 11-60.1.

DOH will make a final decision on the permit after considering all comments and will send notice of the final decision to each person who has submitted comments or requested such notice.

Elizabeth A. Char, M.D.  
Interim Director of Health

# Draft Permit

Issuance Date

**CERTIFIED MAIL**  
**RETURN RECEIPT REQUESTED**  
(xxxx xxxx xxxx xxxx xxxx)

20-xxxE CAB  
File No. 0088

Mr. Richard L. Creamer  
Vice President and General Manager  
Par Hawaii Refining, LLC  
91-325 Komohana Street  
Kapolei, Hawaii 96707-1713

Dear Mr. Creamer:

**SUBJECT: Covered Source Permit (CSP) No. 0088-01-C  
Minor Modification Application No. 0088-32  
Application for Renewal Nos. 0088-07 and 0088-17  
Application for Renewal No. 0088-19  
Application for Renewal No. 0088-31  
Par Hawaii Refining, LLC  
Par West Refinery  
Located At: 91-480 Malakole Street CCB, Kapolei, Oahu  
Date of Expiration: DATE**

The subject CSP is issued in accordance with Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1. The issuance of this permit is based on your minor modification application for CSP No. 0088-01-C dated December 14, 2018, and renewal applications for CSP No. 0088-01-C dated August 1, 2003, and December 22, 2010, with updated information dated March 2, 2016; renewal application for CSP No. 0088-02-C dated November 22, 2011, and renewal application for CSP No. 0088-03-C dated September 6, 2018. This permit consolidates CSP No. 0088-01-C with CSP Nos. 0088-02-C and 0088-03-C and supersedes CSP No. 0088-01-C issued on November 16, 2018, CSP No. 0088-02-C issued on May 23, 2007, and CSP No. 0088-03-C issued on November 15, 2016, in their entireties.

The CSP is issued subject to the conditions/requirements set forth in the following attachments:

- Attachment I: Standard Conditions
- Attachment II(A): Special Conditions - Miscellaneous Process Units and Auxiliary Equipment
- Attachment II(B): Special Conditions - Cooling Tower
- Attachment II(C): Special Conditions - Flares
- Attachment II(D): Special Conditions - Effluent Treatment Plant
- Attachment II(E): Special Conditions - Atmospheric and Vacuum Furnaces
- Attachment II(F): Special Conditions - Process Unit Furnaces
- Attachment II(G): Special Conditions - Acid Plant
- Attachment II(H): Special Conditions - Cogeneration Plant

Mr. Richard L. Creamer  
DATE  
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Attachment II(I): Special Conditions - Cogeneration Unit  
Attachment II(J): Special Conditions - Boilers  
Attachment II(K): Special Conditions - Black Start Diesel Engine Generator and Diesel Engine Pumps  
Attachment II(L): Foul Water Treatment Plant and Catalytic Oxidation Unit  
Attachment II - INSIG: Special Conditions - Insignificant Activities  
Attachment III: Annual Fee Requirements  
Attachment IV: Annual Emissions Reporting Requirements

The following forms are enclosed for your use and submittal as required:

Compliance Certification Form  
Annual Emissions Report Form: Refinery Equipment - Fuel Consumption  
Annual Emissions Report Form: Refinery Equipment - Process Rate  
Annual Emissions Report Form: Acid Plant Preheater - Operating Hours  
Monitoring Report Form: Fuel Consumption  
Monitoring Report Form: Fuel Certification  
Monitoring Report Form: Black Start Diesel Engine Generator Hours of Operation  
Monitoring Report Form: Opacity Exceedances  
Excess Emission and Monitoring System Performance Summary Report

The following are enclosed for your use in monitoring visible emissions (VE):

Visible Emissions Form Requirements, State of Hawaii  
Visible Emissions Form

This permit: (a) shall not in any manner affect the title of the premises upon which the equipment is to be located; (b) does not release the permittee from any liability for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment; and (c) in no manner implies or suggests that the Department of Health, Clean Air Branch (herein after referred to as Department), or its officers, agents, or employees, assumes any liability, directly or indirectly, for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment.

If you have any questions regarding this matter, please contact Mr. Darin Lum of the Clean Air Branch at (808) 586-4200.

Sincerely,

\_\_\_\_\_, P.E., ACTING CHIEF  
Environmental Management Division

DL:tkg  
Enclosures

**ATTACHMENT I: STANDARD CONDITIONS  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

This permit is granted in accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, and is subject to the following standard conditions:

1. Unless specifically identified, the terms and conditions contained in this permit are consistent with the applicable requirement, including form, on which each term or condition is based.  
  
(Auth.: HAR §11-60.1-90)
2. This permit, or a copy thereof, shall be maintained at or near the source and shall be made available for inspection upon request. The permit shall not be willfully defaced, altered, forged, counterfeited, or falsified.  
  
(Auth.: HAR §11-60.1-6; SIP §11-60-11)<sup>2</sup>
3. This permit is not transferable whether by operation of law or otherwise, from person to person, from place to place, or from one piece of equipment to another without the approval of the Department, except as provided in HAR, Section 11-60.1-91.  
  
(Auth.: HAR §11-60.1-7; SIP §11-60-9)<sup>2</sup>
4. A request for transfer from person to person shall be made on forms furnished by the Department.  
  
(Auth.: HAR §11-60.1-7)
5. In the event of any changes in control or ownership of the facilities to be constructed or modified, this permit shall be binding on all subsequent owners and operators. The permittee shall notify the succeeding owner and operator of the existence of this permit and its conditions by letter, copies of which will be forwarded to the Department and the U.S. Environmental Protection Agency (EPA), Region 9.  
  
(Auth.: HAR §11-60.1-5, §11-60.1-7, §11-60.1-94)
6. The facility covered by this permit shall be constructed and operated in accordance with the application, and any information submitted as part of the application, for CSP. There shall be no deviation unless additional or revised plans are submitted to and approved by the Department, and the permit is amended to allow such deviation.  
  
(Auth.: HAR §11-60.1-2, §11-60.1-4, §11-60.1-82, §11-60.1-84, §11-60.1-90)

7. This permit (a) does not release the permittee from compliance with other applicable statutes of the State of Hawaii, or with applicable local laws, regulations, or ordinances, and (b) shall not constitute, nor be construed to be an approval of the design of the covered source.

(Auth.: HAR §11-60.1-5, §11-60.1-82)

8. The permittee shall comply with all the terms and conditions of this permit. Any permit noncompliance constitutes a violation of HAR, Chapter 11-60.1, and the Clean Air Act and is grounds for enforcement action; for permit termination, suspension, reopening, or amendment; or for denial of a permit renewal application.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-19, §11-60.1-90)

9. If any term or condition of this permit becomes invalid as a result of a challenge to a portion of this permit, the other terms and conditions of this permit shall not be affected and shall remain valid.

(Auth.: HAR §11-60.1-90)

10. The permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the terms and conditions of this permit.

(Auth.: HAR §11-60.1-90)

11. This permit may be terminated, suspended, reopened, or amended for cause pursuant to HAR, Sections, 11-60.1-10 and 11-60.1-98, and Hawaii Revised Statutes (HRS), Chapter 342B-27, after affording the permittee an opportunity for a hearing in accordance with HRS, Chapter 91.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90, §11-60.1-98)

12. The filing of a request by the permittee for the termination, suspension, reopening, or amendment of this permit, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

(Auth.: HAR §11-60.1-90)

13. This permit does not convey any property rights of any sort, or any exclusive privilege.

(Auth.: HAR §11-60.1-90)



14. The permittee shall notify the Department and U.S. EPA, Region 9, in writing of the following dates:
- a. The **anticipated date of initial start-up** for each emission unit of a new source or significant modification not more than sixty (60) days or less than thirty (30) days prior to such date;
  - b. The **actual date of construction commencement** within fifteen (15) days after such date; and
  - c. The **actual date of start-up** within fifteen (15) days after such date.

(Auth.: HAR §11-60.1-90)

15. The permittee shall furnish, in a timely manner, any information or records requested in writing by the Department to determine whether cause exists for terminating, suspending, reopening, or amending this permit, or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Department copies of records required to be kept by the permittee. For information claimed to be confidential, the Director of Health (Director) may require the permittee to furnish such records not only to the Department but also directly to the U.S. EPA, Region 9, along with a claim of confidentiality.

(Auth.: HAR §11-60.1-14, §11-60.1-90)

16. The permittee shall notify the Department in writing of the **intent to shut down air pollution control equipment for necessary scheduled maintenance** at least twenty-four (24) hours prior to the planned shutdown. The submittal of this notice shall not be a defense to an enforcement action. The notice shall include the following:
- a. Identification of the specific equipment to be taken out of service, as well as its location and permit number;
  - b. The expected length of time that the air pollution control equipment will be out of service;
  - c. The nature and quantity of emissions of air pollutants likely to be emitted during the shutdown period;
  - d. Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period; and
  - e. The reasons why it would be impossible or impractical to shut down the source operation during the maintenance period.

(Auth.: HAR §11-60.1-15; SIP §11-60-16)<sup>2</sup>

17. **Except for emergencies which result in noncompliance with any technology-based emission limitation in accordance with HAR, Section 11-60.1-16.5, in the event any emission unit, air pollution control equipment, or related equipment malfunctions or breaks down in such a manner as to cause the emission of air pollutants in violation of HAR, Chapter 11-60.1 or this permit, the permittee shall immediately notify the Department of the malfunction or breakdown, unless the protection of personnel or public health or safety demands immediate attention to the malfunction or breakdown and makes such notification infeasible. In the latter case, the notice shall be provided as soon as practicable. Within five (5) working days of this initial notification, the permittee shall also submit, in writing, the following information:**
- a. Identification of each affected emission point and each emission limit exceeded;
  - b. Magnitude of each excess emission;
  - c. Time and duration of each excess emission;
  - d. Identity of the process or control equipment causing the excess emission;
  - e. Cause and nature of each excess emission;
  - f. Description of the steps taken to remedy the situation, prevent a recurrence, limit the excessive emissions, and assure that the malfunction or breakdown does not interfere with the attainment and maintenance of the National Ambient Air Quality Standards and state ambient air quality standards;
  - g. Documentation that the equipment or process was at all times maintained and operated in a manner consistent with good practice for minimizing emissions; and
  - h. A statement that the excess emissions are not part of a recurring pattern indicative of inadequate design, operation, or maintenance.

The submittal of these notices shall not be a defense to an enforcement action.

(Auth.: HAR §11-60.1-16; SIP §11-60-16)<sup>2</sup>

18. The permittee may request confidential treatment of any records in accordance with HAR, Section 11-60.1-14.

(Auth.: HAR §11-60.1-14, §11-60.1-90)

19. This permit shall become invalid with respect to the authorized construction if construction is not commenced as follows:

- a. Within eighteen (18) months after the permit takes effect, is discontinued for a period of eighteen (18) months or more, or is not completed within a reasonable time.
- b. For phased construction projects, each phase shall commence construction within eighteen (18) months of the projected and approved commencement dates in the permit. This provision shall be applicable only if the projected and approved commencement dates of each construction phase are defined in Attachment II, Special Conditions of this permit.

(Auth.: HAR §11-60.1-9, §11-60.1-90)

20. The Department may extend the time periods specified in Standard Condition No. 19 upon a satisfactory showing that an extension is justified. Requests for an extension shall be submitted in writing to the Department.

(Auth.: HAR §11-60.1-9, §11-60.1-90)

21. The permittee shall submit fees in accordance with HAR, Chapter 11-60.1, Subchapter 6.

(Auth.: HAR §11-60.1-90)

22. All certifications shall be in accordance with HAR, Section 11-60.1-4.

(Auth.: HAR §11-60.1-4, HAR §11-60.1-90)

23. The permittee shall allow the Director, the Regional Administrator for the U.S. EPA, and/or an authorized representative, upon presentation of credentials or other documents required by law:

- a. To enter the premises where a source is located or emission-related activity is conducted, or where records must be kept under the conditions of this permit and inspect at reasonable times all facilities, equipment, including monitoring and air pollution control equipment, practices, operations, or records covered under the terms and conditions of this permit and request copies of records or copy records required by this permit; and
- b. To sample or monitor at reasonable times substances or parameters to ensure compliance with this permit or applicable requirements of HAR, Chapter 11-60.1.

(Auth.: HAR §11-60.1-11, §11-60.1-90)

24. Within thirty (30) days of **permanent discontinuance of the construction, modification, relocation, or operation of a covered source covered by this permit**, the discontinuance shall be reported in writing to the Department by a responsible official of the source.

(Auth.: HAR §11-60.1-8; SIP §11-60-10)<sup>2</sup>

25. Each permit renewal application shall be submitted to the Department and the U.S. EPA, Region 9, no less than twelve (12) months and no more than eighteen (18) months prior to the permit expiration date. The Director may allow a permit renewal application to be submitted no less than six (6) months prior to the permit expiration date, if the Director determines that there is reasonable justification.

(Auth.: HAR §11-60.1-101; 40 CFR §70.5(a)(1)(iii))<sup>1</sup>

26. The terms and conditions included in this permit, including any provision designed to limit a source's potential to emit, are federally enforceable unless such terms, conditions, or requirements are specifically designated as not federally enforceable.

(Auth.: HAR §11-60.1-93)

27. The compliance plan and compliance certification submittal requirements shall be in accordance with HAR, Sections 11-60.1-85 and 11-60.1-86. As specified in HAR, Section 11-60.1-86, the compliance certification shall be submitted to the Department and the U.S. EPA, Region 9, once per year, or more frequently as set by any applicable requirement.

(Auth.: HAR §11-60.1-90)

28. **Any document (including reports) required to be submitted by this permit shall be certified as being true, accurate, and complete by a responsible official in accordance with HAR, Sections 11-60.1-1 and 11-60.1-4, and shall be mailed to the following address:**

**State of Hawaii  
Clean Air Branch  
2827 Waimano Home Road #130  
Pearl City, HI 96782**

**Upon request and as required by this permit, all correspondence to the State of Hawaii Department associated with this CSP shall have duplicate copies forwarded to:**

**Manager  
Enforcement Division, Air Section  
U.S. Environmental Protection Agency, Region 9  
75 Hawthorne Street, ENF-2-1  
San Francisco, CA 94105**

(Auth.: HAR §11-60.1-4, §11-60.1-90)

29. To determine compliance with submittal deadlines for time-sensitive documents, the postmark date of the document shall be used. If the document was hand-delivered, the date received ("stamped") at the Clean Air Branch shall be used to determine the submittal date.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II(A): SPECIAL CONDITIONS  
MISCELLANEOUS PROCESS UNITS AND AUXILIARY EQUIPMENT  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

This portion of the CSP encompasses widely applicable requirements, principally rules designed to prevent fugitive emissions that apply to process units, flares, and/or compressors not included with the Special Conditions of Attachments II(B) through II(L).

1. Process Units, Flare Vapor Recovery Unit, and Flares

- a. Crude Unit;
- b. Vacuum Unit;
- c. Hydrogenation Unit;
- d. Hydrogen Unit;
- e. Isomerization Unit;
- f. Cogeneration Units;
- g. Boiler Plant;
- h. Flare Vapor Recovery Unit;
- i. Flares (and Flare Gas Header System);
- j. Deisobutanizer; and
- k. Depropanizer.

2. Compressors

- a. Two (2) Flare Vapor Recovery Unit Compressors, identified as K-5604 and K-5604A;
- b. Two (2) Hydrogenation Hydrogen Makeup Compressors, identified as K-5601 and K-5602;
- c. One (1) Isomerization Hydrogen Recycle Compressor, identified as K-5961;
- d. One (1) Isomerization Hydrogen Gas Recycle Compressor, identified as K-5962; and
- e. One (1) Cogeneration Plant Fuel Gas Compressor, identified as K-6704.

(Auth.: HAR §11-60.1-3)

**Section B. Applicable Federal Regulations**

1. The Process Units, Flares, and Flare Vapor Recovery Unit are subject to the provisions of the following federal regulations:

40 Code of Federal Regulations (CFR) Part 60, Standards of Performance for New Stationary Sources (NSPS):

- a. Subpart A, General Provisions;
- b. Subpart GGG, Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and On or Before November 7, 2006; and
- c. Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.590, §60.590a)<sup>1</sup>

2. The Cogeneration Units, Crude Unit, Vacuum Unit, Crude Desalter, Boiler Plant, and Flare Vapor Recovery Unit are subject to the provisions of the following federal regulations:

40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

- a. Subpart A, General Provisions; and
- b. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.690)<sup>1</sup>

3. Except for the Boiler Plant, the Process Units, Flares, and Flare Vapor Recovery Unit are subject to the provisions of the following federal regulations:

- a. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT):
  - i. Subpart A, General Provisions; and
  - ii. Subpart CC, National Emission Standards for Hazardous Air Pollutants (HAP) from Petroleum Refineries.

- b. The above regulations are not applicable to any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system that is intended to operate in organic HAP service, as defined in 40 CFR §63.641, for less than 300 hours during the calendar year.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11.60.1-174; 40 CFR §63.640)<sup>1</sup>

4. The storage and use of flammable substances in this facility is subject to the provisions of 40 CFR Part 68, Chemical Accident Prevention Provisions. The permittee shall comply with all applicable requirements, including the submittal of:
  - a. A compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR §68.10(a); or
  - b. As part of the compliance certification submitted pursuant to Attachment I, Standard Condition No. 27, a certification statement that the facility is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of the Risk Management Plan.

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §68)<sup>1</sup>

### **Section C. Operational and Emission Limitations**

1. All pumps and compressors handling VOC having a Reid Vapor Pressure (RVP) of 1.5 pounds per square inch (psi) or greater which can be fitted with mechanical seals shall have mechanical seals or other equipment of equal efficiency for purposes of air pollution control as may be approved by the Department. Pumps and compressors not capable of being fitted with mechanical seals, such as reciprocating pumps, shall be fitted with the best sealing system available for air pollution control given the particular design of pump or compressor as may be approved by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-41, §11-60.1-90)

2. The permittee shall not cause or allow the emissions of gas streams containing VOC from a vapor blowdown system unless these gases are burned by smokeless flares, or abated by an equally effective control device as approved by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-42, §11-60.1-90)

3. Compressor

- a. The compressors identified as K-5604, K-5604A, and K-6704 shall be equipped and operated with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in 40 CFR §60.482-1a(c), 40 CFR §60.482-3a(h), and 40 CFR §60.482-3a(i).
- b. Each compressor seal system as required in Special Condition No. C.3.a of this attachment shall be as follows:
  - i. Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or
  - ii. Equipped with a barrier fluid system that is connected by a closed vent system to a control device that complies with the requirements of 40 CFR §60.482-10a; or
  - iii. Equipped with a system that purges the barrier fluid into a process stream with zero (0) VOC emissions to the atmosphere.
- c. The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.
- d. A compressor is exempt from the requirements of Special Condition Nos. C.3.a and C.3.b of this attachment if it is equipped with a closed vent system capable of capturing and transporting any leakage from the seal to a control device that complies with the requirements of 40 CFR §60.482-10a, except as provided in Special Condition No. C.3.e of this attachment.
- e. Any compressor that is designated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by methods specified in 40 CFR §60.485a(c) and is tested for compliance initially upon designation, annually, and at other times requested by the Department is exempt from the requirements of Special Condition Nos. C.3.a through C.3.d, D.3.a, and D.3.b of this attachment.
- f. Compressors K-5601, K-5602, K-5961, and K-5962 are exempt from the requirements above because the permittee has demonstrated that they are in at least fifty (50) percent hydrogen service pursuant to the methods specified by 40 CFR §60.593a.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a)<sup>1</sup>

4. Pressure Relief Devices in Gas/Vapor Service

- a. Except during pressure releases, each pressure relief device in gas/vapor service located at the Crude Unit, Vacuum Unit, Cogeneration Unit, Boiler Plant, and Flare Vapor Recovery Unit shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR §60.485a(c).
- b. *After each pressure release*, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, **as soon as practicable**, but no later than five (5) calendar days *after the pressure release*, except as provided in Special Condition No. C.8 of this attachment.



- c. Any pressure relief device is exempt from the requirements of Special Condition Nos. C.4.a and C.4.b of this attachment if it is equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device that complies with the requirements of 40 CFR §60.482-10a.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a)<sup>1</sup>

#### 5. Open Ended Valves/Lines

- a. Each open-ended valve or line at the Crude Unit, Vacuum Unit, Cogeneration Unit, Boiler Plant, and Flare Vapor Recovery Unit shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR §60.482-1a(c). The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.
- b. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.
- c. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with Special Condition No. C.5.a of this attachment at all other times.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.592a, §63.648)<sup>1</sup>

#### 6. Sampling Connection Systems

- a. Each sampling connection system at the Crude Unit, Vacuum Unit, Cogeneration Unit, Boiler Plant, and Flare Vapor Recovery Unit shall be equipped with a closed-purged, closed-loop, or closed-vent system, except as provided in 40 CFR §60.482-1a(c) or Special Condition No. C.6.c of this attachment.
- b. Each closed-purged, closed-loop, or closed-vent system shall comply with the following requirements:
  - i. Return the purged process fluid directly to the process line; or
  - ii. Collect and recycle the purged process fluid to a process; or
  - iii. Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of 40 CFR §60.482-10a.
- c. In-situ sampling systems and sampling systems without purges are exempt from the requirements of Special Condition Nos. C.6.a and C.6.b of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.592a, §63.648)<sup>1</sup>

#### 7. Pressure Relief Devices in Organic HAP Gas/Vapor Service (including atmospheric pressure relief devices PRD 51-3, PRD 51-4, PRD 51-5, and PRD 51-12)

The permittee shall comply with the requirements specified in 40 CFR §63.648(j) including the requirements for *Pressure release management* specified in 40 CFR §63.648(j)(3) and *Root cause analysis and corrective action analysis* specified in 40 CFR §63.648(j)(6). The requirements of 40 CFR §63.648(j)(3) consists of the following:

*Pressure release management.* Except as specified in 40 CFR §63.648(j)(4) and 40 CFR §63.648(j)(5), the permittee shall comply with the requirements specified in 40 CFR §63.648(j)(3)(i) through 40 CFR §63.648(j)(3)(v) for all pressure relief devices in organic HAP service no later than January 30, 2019. The requirements of 40 CFR §63.648(j)(3)(i) consists of the following:

The permittee must equip each affected pressure relief device with a device(s) or use a monitoring system that is capable of:

- a. Identifying the pressure release;
- b. Recording the time and duration of each pressure release; and
- c. Notifying operators immediately that a pressure release is occurring. The device or monitoring system may be either specific to the pressure relief device itself or may be associated with the process system or piping, sufficient to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.648)<sup>1</sup>

#### 8. Delay of Repair

- a. Delay of repair of equipment for which leaks have been detected will be allowed if the repair is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.
- b. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.
- c. Delay of repair for valves will be allowed if:
  - i. The permittee demonstrates that emissions of purged material resulting from the immediate repair are greater than the fugitive emissions likely to result from the delay of repair; and
  - ii. When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with the requirements of 40 CFR §60.482-10.
- d. Delay of repair for pumps will be allowed if:
  - i. Repair requires the use of a dual mechanical seal system that includes a barrier fluid system; and

- ii. Repair is completed as soon as practicable, but not later than six (6) months after the leak was detected.
- e. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than six (6) months after the first process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.592a, §63.648)<sup>1</sup>

#### 9. Individual Drain Systems

- a. Sewer drains located at the Cogeneration Unit, Crude Unit, Vacuum Unit, Crude Desalter, Boiler Plant, and Flare Vapor Recovery Unit shall be equipped with water seal controls.
- b. Junction boxes located at the Cogeneration Unit and Boiler Plant shall be equipped with a cover and may have an open vent pipe at least three (3) feet (90 cm) in length and shall not exceed four (4) inches (10.2 cm) in diameter.
- c. Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.
- d. Sewer lines located at the Cogeneration Unit, Crude Unit, Vacuum Unit, Crude Desalter, Boiler Plant, and Flare Vapor Recovery Unit shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.
- e. Refinery wastewater routed through new process drains and a new first common downstream junction box at the Cogeneration Unit and Boiler Plant, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-2)<sup>1</sup>

#### **Section D. Monitoring and Recordkeeping Requirements**

- 1. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

## 2. Pumps in Light Liquid Service

- a. Each pump in light liquid service at the Crude Unit, Vacuum Unit, Cogeneration Unit, Boiler Plant, and Flare Vapor Recovery Unit shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §60.485a(b), except as provided in 40 CFR §60.482-1a(c) and 40 CFR §60.482-2a(d), (e), and (f).
- b. Each pump in light liquid service at the Crude Unit, Vacuum Unit, Cogeneration Unit, Boiler Plant, and Flare Vapor Recovery Unit shall be checked by visual inspection **each calendar week** for indications of liquids dripping from the pump seal.
- c. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.
- d. If there are indications of liquids dripping from the pump seal, a leak is detected.
- e. When a leak is detected, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected**.
- f. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of Special Condition No. D.2.a of this attachment provided the requirements of 40 CFR §60.482-2a(d)(1) through (6) are met.
- g. Any pump that is designated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of Special Condition Nos. D.2.a, D.2.b, D.2.e, and D.2.f of this attachment if the pump:
  - i. Has no externally actuated shaft penetrating the pump housing;
  - ii. Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in 40 CFR §60.485a(c); and
  - iii. Is tested for compliance with Special Condition No. D.2.g.ii of this attachment initially upon designation, annually, and at other times requested by the Department.
- h. If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a control device that complies with the requirements of 40 CFR §60.482-10a, it is exempt from the requirements of Special Condition Nos. D.2.a through D.2.g of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a, §63.648)<sup>1</sup>

## 3. Compressors

- a. Each compressor barrier fluid system shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both. Each sensor shall be checked **daily** or shall be equipped with an audible alarm. If the sensor indicates failure of the seal system, the barrier system, or both, a leak is detected.

- b. When a leak is detected, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected**.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a)<sup>1</sup>

4. Pressure Relief Devices in Gas/Vapor Service

**No later than five (5) calendar days after a pressure release**, the pressure relief device subject to the requirements of 40 CFR Part 60, Subparts GGG and GGGa, shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR §60.485a(c).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a)<sup>1</sup>

5. Valves in Light Liquid Service and in Gas/Vapor Service

- a. Each valve in light liquid service at the Crude Unit, Vacuum Unit, Cogeneration Unit, Boiler Plant, and Flare Vapor Recovery Unit shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §60.485a(b).
- b. If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- c. Any valve for which a leak is *not detected for two (2) successive months* may be monitored the **first month of every quarter**, beginning with the next quarter, *until a leak is detected*. *If a leak is detected*, the valve shall be monitored **monthly** until a leak is *not detected for two (2) successive months*.
- d. *When a leak is detected*, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected**.
- e. First attempts at repair include, but are not limited to, the following best practices where practicable:
  - i. Tightening of bonnet bolts;
  - ii. Replacement of bonnet bolts;
  - iii. Tightening of packing gland nuts; and
  - iv. Injection of lubricant into lubricated packing.
- f. Any valve that is designated, as described in 40 CFR §60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of Special Condition No. D.5.a of this attachment if the valve:
  - i. Has no external actuating mechanism in contact with the process fluid;
  - ii. Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR §60.485a(c); and

iii. Is tested for compliance with the Special Condition No. D.5.f.ii of this attachment initially upon designation, annually, and at other times requested by the Department.

- g. Any valve that is designated, as described in 40 CFR §60.486a(f)(1), as unsafe-to-monitor valve and satisfies the criteria outlined in 40 CFR §60.482-7a(g) is exempt from the requirements of Special Condition No. D.5.a of this attachment.
- h. Any valve that is designated, as described in 40 CFR §60.486a(f)(2), as difficult-to-monitor valve and satisfies the criteria outlined in 40 CFR §60.482-7a(h) is exempt from the requirements of Special Condition No. D.5.a of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a, §63.648)<sup>1</sup>

6. Pumps, Valves, and Connectors in Heavy Liquid Service and Pressure Relief Devices in Light Liquid or Heavy Liquid Service, and Connectors in Gas/Vapor Service and Light Liquid Service

- a. Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, and connectors in gas/vapor service and light liquid service at the Crude Unit, Vacuum Unit, Cogeneration Unit, Boiler Plant, and Flare Vapor Recovery Unit shall be monitored **within five (5) days** by the method specified in 40 CFR §60.485a(b) *if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method.*
- b. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
- c. *When a leak is detected*, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8 of this attachment. The first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected.**
- d. First attempts at repair include, but are not limited to, the best practices described in Special Condition No. D.5.e of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a, §63.648)<sup>1</sup>

7. When each leak is detected as specified in 40 CFR §60.482-2a, §60.482-3a, §60.482-7a, §60.482-8a, and §60.483-2a, the following requirements apply:

- a. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
- b. The identification on a valve may be removed after it has been monitored for two (2) successive months as specified in Special Condition No. D.5.c of this attachment and no leak has been detected during those two (2) months.
- c. The identification on equipment, except a valve or connector, may be removed after it has been repaired.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a, §63.648)<sup>1</sup>

8. *When each leak is detected*, the following information shall be recorded in a log and shall be kept for two (2) years in a readily accessible location:
- a. The instrument and operator identification numbers and the equipment identification number;
  - b. The date the leak was detected and the dates of each attempt to repair the leak;
  - c. Repair methods applied in each attempt to repair the leak;
  - d. "Above 10,000" if the maximum instrument reading measured by the methods specified in 40 CFR §60.485(a) after each repair attempt is equal to or greater than 10,000 ppm;
  - e. "Repair delayed" and the reason for the delay if a leak is not repaired within fifteen (15) calendar days after discovery of the leak;
  - f. The signature of the permittee whose decision it was that repair could not be effected without a process shutdown;
  - g. The expected date of successful repair of the leak if a leak is not repaired within fifteen (15) days;
  - h. Dates of process unit shutdown that occur while the equipment is unrepaired; and
  - i. The date of successful repair of the leak.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a, §63.648)<sup>1</sup>

9. The following information pertaining to all equipment subject to the requirements of 40 CFR Part 60, Subpart GGGa, or 40 CFR Part 63, Subpart CC, shall be recorded in a log that is kept in a readily accessible location:
- a. A list of identification numbers for all equipment;
  - b. A list of identification numbers for equipment that are designated for no detectable emissions which is signed by the permittee;
  - c. A list of equipment identification numbers for pressure relief devices required to comply with the requirements of Special Condition No. C.4 of this attachment;
  - d. The dates of each compliance test used to determine no detectable emissions:
    - i. The background level measured during each compliance test; and
    - ii. The maximum instrument reading measured at the equipment during each compliance test.
  - e. A list of identification numbers for equipment in vacuum service.
  - f. A list of identification numbers for equipment that the permittee designates as operating in VOC service less than 300 hr/yr in accordance with §60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
  - g. The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.
  - h. Records of the information specified in Paragraphs (e)(8)(i) through (iv) of this section for monitoring instrument calibrations conducted according to Sections 8.1.2 and 10 of Method 21 of Appendix A-7 of this part and §60.485a(b).

- i. Records of each release from a pressure relief device subject to §60.482-4a.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a, §63.648)<sup>1</sup>

10. The following information pertaining to all valves subject to the requirements of 40 CFR Part 60, Subpart GGGa, or 40 CFR Part 63, Subpart CC, shall be recorded in a log that is kept in a readily accessible location:

- a. A list of identification numbers for valves that are designated as unsafe-to-monitor, an explanation for each valve stating why the valve is unsafe-to-monitor, and the plan for monitoring each valve; and
- b. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.
- c. A schedule of monitoring for valves complying with §60.483-2a.
- d. The percent of valves found leaking during each monitoring period for valves complying with §60.483-2a.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a, §63.648)<sup>1</sup>

11. The following information shall be recorded in a log that is kept in a readily accessible location:

- a. Design criterion based on design considerations and operating experience indicating the failure of the seal system, barrier fluid system, or both of each affected pump or compressor.
- b. Any changes to this criterion and the reasons for the changes.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a, §63.648)<sup>1</sup>

12. Each drain in active service at the Cogeneration Unit, Boiler Plant, Crude Unit, Vacuum Unit, Crude Desalter, and Flare Vapor Recovery Unit shall be checked by visual inspection or physical inspection **initially and monthly** thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-2)<sup>1</sup>

13. Except for out of service drains where a tightly sealed cap or plug is installed, each drain out of active service shall be checked by visual or physical inspection **initially and weekly** thereafter for indications of low water levels or other problems that could result in VOC emissions. Drains having tightly sealed caps or plugs shall be inspected initially and semi-annually to ensure caps or plugs are in place and properly installed.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-2)<sup>1</sup>



14. *Whenever low water levels or missing or improperly installed caps or plugs are identified*, water shall be added or first efforts at repair shall be made **as soon as practicable**, but not later than twenty-four (24) hours after detection unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

15. Junction boxes located at the Cogeneration Unit and Boiler Plant shall be visually inspected **initially and semi-annually** thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-2)<sup>1</sup>

16. *If a broken seal or gap is identified*, first effort at repair shall be made **as soon as practicable, but not later than fifteen (15) calendar days** after the broken seal or gap is identified unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

17. The portion of each unburied sewer line located at the Cogeneration Unit, Boiler Plant, Crude Unit, Vacuum Unit, and Crude Desalter shall be visually inspected **initially and semi-annually** for indication of cracks, gaps, or other problems that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-2)<sup>1</sup>

18. *Wherever cracks, gaps, or other problems are detected*, repairs shall be made **as soon as practicable, but not later than fifteen (15) calendar days** after identification unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

19. Before using any individual drain system installed in compliance with 40 CFR §60.692-2, the permittee shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of 40 CFR Part 60, Subpart QQQ, not to be met. Points of inspection include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.696)<sup>1</sup>

20. For each individual drain systems subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions during the initial and periodic visual or physical inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.697)<sup>1</sup>

21. For junction boxes subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for each inspection when a broken seal, gap, or other problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.697)<sup>1</sup>

22. For each sewer line subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for inspections when a problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.697)<sup>1</sup>

23. Fenceline Monitoring for Benzene

- a. The permittee shall conduct sampling along the facility property boundary and analyze the samples in accordance with 40 CFR Part 63, Appendix A, Methods 325A and 325B and 40 CFR §63.658(b) through (k).
- b. The target analyte is benzene.
- c. The permittee shall determine passive monitor locations in accordance with 40 CFR Part 63, Appendix A, Method 325A, Section 8.2.
- d. The permittee shall collect and record meteorological data according to the applicable requirements in 40 CFR §63.658(d)(1) through (3).
- e. The permittee shall use a sampling period and sampling frequency as specified in 40 CFR §63.658(e)(1) through (3).
- f. Within forty-five (45) days of completion of each sampling period, the permittee shall determine whether the results are above or below the action level using the procedures in 40 CFR §63.658(f)(1) through (3).
- g. Within five (5) days of determining that the action level has been exceeded for any annual average  $\Delta c$  and no longer than fifty (50) days after completion of the sampling period, the permittee shall initiate a root cause analysis to determine the cause of such exceedance and to determine appropriate corrective action. The root cause analysis and initial corrective action analysis shall be completed and initial corrective actions taken no later than forty-five (45) days after determining there is an exceedance. Root cause analysis and corrective action may include, but is not limited to:
  - i. Leak inspection using 40 CFR Part 60, Appendix A-7, Method 21, and repairing any leaks found.
  - ii. Leak inspection using optical gas imaging and repairing any leaks found.

- iii. Visual inspection to determine the cause of the high benzene emissions and implementing repairs to reduce the level of emissions.
- iv. Employing progressively more frequent sampling, analysis and meteorology (e.g. using shorter sampling periods for 40 CFR Part 63, Appendix A, Methods 325A and 325B, or using active sampling techniques).
  
- h. If, upon completion of the corrective action analysis and corrective actions such as those described in Special Condition No. D.23.g of this attachment, the  $\Delta c$  value for the next fourteen (14) day sampling period for which the sampling start time begins after the completion of the corrective actions is greater than nine (9)  $\mu\text{g}/\text{m}^3$  or if all corrective action measures identified require more than forty-five (45) days to implement, the permittee shall develop a corrective action plan that describes the corrective action(s) completed to date, additional measures that the permittee proposes to employ to reduce fence-line concentrations below the action level, and a schedule for completion of these measures. The permittee shall submit the corrective action plan to the Department within sixty (60) days after receiving the analytical results indicating that the  $\Delta c$  value for the fourteen (14) day sampling period following completion of the initial corrective action is greater than nine (9)  $\mu\text{g}/\text{m}^3$  or, if no initial corrective actions were identified, no later than sixty (60) days following the completion of the corrective action analysis required in Special Condition No. D.23.g of this attachment.
- i. The permittee may request approval from the Department for a site-specific monitoring plan to account for offsite upwind sources or onsite sources excluded under 40 CFR §63.640(g) according to the requirements in 40 CFR §63.658(i)(1) through (4).
- j. The permittee shall comply with the recordkeeping and reporting requirements in 40 CFR §63.655(h) and (i).
- k. As outlined in 40 CFR §63.7(f), the permittee may submit a request for an alternative test method. At a minimum, the request must follow the requirements outlined in 40 CFR §63.658(k)(1) through (7).
- l. The permittee must achieve compliance on or before January 30, 2018.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.640, §63.655(i)(8), §63.658, Table 11(4))<sup>1</sup>

## **Section E. Notification and Reporting Requirements**

### 1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate** or equivalent form, shall be used in reporting fugitive emissions.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively. These notifications shall include, but not be limited to:
  - a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report **within five (5) working days** any *deviations from permit requirements*, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and

vii. Any additional information as required by the Department including information to determine compliance.

- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. For valves, pumps, and compressors subject to the requirements of 40 CFR Part 60, Subpart GGG and GGGa, or 40 CFR Part 63, Subpart CC, the permittee shall submit **semi-annual** reports to the Department. 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)**. The **initial** semi-annual report shall include the following information:
- a. Process unit identification;
  - b. Number of valves subject to the requirements of Special Condition No. D.5 of this attachment, excluding those valves designated for no detectable emissions under the provisions of Special Condition No. D.5.f of this attachment;
  - c. Number of pumps subject to the requirements of Special Condition No. D.2 of this attachment, excluding those pumps designated for no detectable emissions under the provisions of Special Condition No. D.2.g of this attachment and those pumps complying with Special Condition No. D.2.h of this attachment; and
  - d. Number of compressors subject to the requirements of Special Condition No. C.3 of this attachment, excluding those compressors designated for no detectable emissions under the provisions of Special Condition No. C.3.e of this attachment and those compressors complying with Special Condition No. C.3.d of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592a, §63.648)<sup>1</sup>

6. All semi-annual reports, required in Special Condition No. E.5 of this attachment, shall include the following information:
- a. Process unit identification;
  - b. For each month during the semi-annual reporting period:
    - i. Number of valves for which leaks were detected;
    - ii. Number of valves for which leaks were not repaired;
    - iii. Number of pumps for which leaks were detected;
    - iv. Number of pumps for which leaks were not repaired;
    - v. Number of compressors for which leaks were detected;
    - vi. Number of compressors for which leaks were not repaired;
    - vii. Number of connectors for which leaks were detected;
    - viii. Number of connectors for which leaks were not repaired; and

ix. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

- c. Dates of process unit shutdowns which occurred within the semi-annual reporting period; and
- d. Revisions to items reported in the initial semi-annual report if changes have occurred since the initial report or subsequent revisions to the initial report.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.592, §63.648)<sup>1</sup>

7. The permittee shall submit to the Department within **sixty (60) days** after initial startup a certification that the equipment necessary to comply with 40 CFR Part 60, Subpart QQQ, has been installed and that the required initial inspections or tests of process drains, sewer lines and junction boxes have been carried out in accordance with 40 CFR Part 60, Subpart QQQ. Thereafter, the permittee shall submit **semi-annually** a certification that all of the required inspections have been carried out in accordance with 40 CFR Part 60, Subpart QQQ.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.698)<sup>1</sup>

8. A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted **initially and semi-annually** thereafter to the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.698)<sup>1</sup>

9. If compliance with the provisions of 40 CFR Part 60, Subpart QQQ, is delayed pursuant to 40 CFR §60.692-7, the notification required under 40 CFR §60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standard is technically impossible without a refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.698)<sup>1</sup>

10. Fenceline Monitoring for Benzene

The permittee shall submit within forty-five (45) calendar days after the end of each quarterly reporting period covered by the periodic report, the following information to the EPA's Compliance and Emissions Data Reporting Interface (CEDRI). CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>). The permittee need not transmit this data prior to obtaining twelve (12) months of data.

- a. Facility name and address.
- b. Year and reporting quarter (i.e., Quarter 1, Quarter 2, Quarter 3, or Quarter 4).

- c. For the first reporting period and for any reporting period in which a passive monitor is added or moved, for each passive monitor: the latitude and longitude location coordinates; the sampler name; and identification of the type of sampler (i.e., regular monitor, extra monitor, duplicate, field blank, inactive). The permittee shall determine the coordinates using an instrument with an accuracy of at least three (3) meters. Coordinates shall be in decimal degrees with at least five (5) decimal places.
- d. The beginning and ending dates for each sampling period.
- e. Individual sample results for benzene reported in units of  $\mu\text{g}/\text{m}^3$  for each monitor for each sampling period that ends during the reporting period. Results below the method detection limit shall be flagged as below the detection limit and reported at the method detection limit.
- f. Data flags that indicate each monitor that was skipped for the sampling period, if the permittee uses an alternative sampling frequency under 40 CFR §63.658(e)(3).
- g. Data flags for each outlier determined in accordance with Section 9.2 of Method 325A of Appendix A of 40 CFR Part 63. For each outlier, the permittee must submit the individual sample result of the outlier, as well as the evidence used to conclude that the result is an outlier.
- h. The biweekly concentration difference ( $\Delta c$ ) for benzene for each sampling period and the annual average  $\Delta c$  for benzene for each sampling period.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.655(h)(8))<sup>1</sup>

#### **Section F. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II(B): SPECIAL CONDITIONS  
COOLING TOWER  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:

One (1) Ten-Cell Induced Draft Cooling Tower

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Operational and Emission Limitations**

1. Chromium-containing water treatment chemicals shall not be used in the cooling tower.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-174; 40 CFR §63.402)<sup>1</sup>

2. The design circulating rate of the cooling tower shall not exceed 50,000 gallons per minute.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section C. Monitoring and Recordkeeping Requirements**

1. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; SIP §11-60-15)<sup>2</sup>



2. Manufacturer's data on the design maximum design circulating flow rate of the cooling tower shall be kept on file at the facility for the life of the equipment.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

3. Records shall be maintained on the type and quantities of water treatment chemicals used in the cooling tower on an annual basis. All Material Safety Data Sheets (MSDSs) associated with each chemical shall be maintained on site and made available for the Department's inspection upon request.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

4. The Department may at any time require the permittee to conduct water sample analysis for chromium based water treatment chemicals.

(Auth.: HAR §11-60.1-5, §11-60.1-90, §11-60.1-174; 40 CFR §63.404)<sup>1</sup>

#### **Section D. Notification and Reporting Requirements**

1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate** or an equivalent form, shall be used in reporting cooling water usage.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively. These notifications shall include, but not be limited to:
  - a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report **within five (5) working days** *any deviations from permit requirements*, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

**Section E. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II(C): SPECIAL CONDITIONS  
FLARES  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:
  - a. One (1) 20" diameter Flare (steam-assisted), identified as F-2301; and
  - b. One (1) 42" diameter Flare (steam-assisted); identified as F-2302.

(Auth.: HAR §11-60.1-3)
2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The Flares are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):
    - i. Subpart A, General Provisions;
    - ii. Subpart J, Standards of Performance for Petroleum Refineries;
    - iii. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007;
    - iv. Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and On or Before November 7, 2006; and
    - v. Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.
  - b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT):
    - i. Subpart A, General Provisions; and
    - ii. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.1, §60.100, §60.590, §63.1, §63.640)<sup>1</sup>

2. The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

### **Section C. Operational and Emissions Limitations**

1. The Flares shall be designed for and operated with no VE except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours, when regulated material is routed to the flare and the flare vent gas flow rate is less than the smokeless design capacity of the flare.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.670)<sup>1</sup>

2. The Flares shall be operated with a pilot flame present at all times when regulated material is routed to the flare. Each fifteen (15) minute block during which there is at least one (1) minute where no pilot flame is present when regulated material is routed to the flare is a deviation of the standard. Deviations in different fifteen (15) minute blocks from the same event are considered separate deviations.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.670)<sup>1</sup>

3. Flare Tip Velocity

For the Flares, the permittee shall comply with either 40 CFR §63.670(d)(1) or (2), provided the appropriate monitoring systems are in-place, whenever regulated material is routed to the flare for at least fifteen (15) minutes and the flare vent gas flow rate is less than the smokeless design capacity of the flare.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.670)<sup>1</sup>

4. Combustion Zone Operating Limits

For the Flares, the permittee shall operate each flare to maintain the net heating value of flare combustion zone gas (NHV<sub>cz</sub>) at or above 270 Btu/scf determined on a fifteen (15) minute block period basis when regulated material is routed to the flare for at least fifteen (15) minutes.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.670)<sup>1</sup>

5. The permittee shall not burn in the Flares any fuel gas that contains hydrogen sulfide (H<sub>2</sub>S) in excess of 230 mg/dscm (0.10 gr/dscf) and 162 ppmv determined hourly on a three (3) hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit. Process upset gases means any gas generated by a petroleum refinery process unit or by ancillary equipment as a result of startup, shutdown, upset or malfunction.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.104(a)(1), §60.103a(h))<sup>1</sup>

6. The permittee shall conduct a root cause analysis and a corrective action analysis for the Flares for each of the following conditions:
  - a. Any time the sulfur dioxide (SO<sub>2</sub>) emissions exceed 227 kilograms (kg) (500 lb) in any twenty-four (24) hour period; or
  - b. Any discharge to the flare in excess of 14,160 standard cubic meters (m<sup>3</sup>) (500,000 standard cubic feet (scf)) above the baseline, determined in 40 CFR §60.103a(a)(4), in any twenty-four (24) hour period.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.103a)<sup>1</sup>

7. The permittee shall develop and implement a written flare management plan (FMP) no later than November 11, 2015, that includes the information described in 40 CFR §60.103a(a)(1) through (a)(7) for the Flares. The FMP shall be submitted to the U.S. EPA as described in 40 CFR §60.103a(b)(1) through (b)(3).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.103a)<sup>1</sup>

#### **Section D. Monitoring and Recordkeeping Requirements**

##### 1. Visible Emissions Monitoring

The permittee shall monitor the Flares for VE using either of the methods shown below:

- a. At least once per day for each day regulated material is routed to the flare, the permittee shall conduct VE observations using an observation period of five (5) minutes using Method 22 at 40 CFR Part 60, Appendix A-7. If at any time the permittee sees VE while regulated material is routed to the flare, even if the minimum required daily VE monitoring has already been performed, the permittee shall immediately begin an observation period of five (5) minutes using Method 22 at 40 CFR Part 60, Appendix A-7. If VE are observed for more than one (1) continuous minute during any five (5) minute observation period, the observation period using Method 22 at 40 CFR Part 60, Appendix A-7 must be extended to two (2) hours or until five (5) minutes of VE are observed. Daily five (5) minute Method 22 observations are not required to be conducted for days the flare does not receive any regulated material.
- b. Use a video surveillance camera to continuously record (at least one (1) frame every fifteen (15) seconds with time and date stamps) images of the flare flame and a reasonable distance above the flare flame at an angle suitable for visual emissions observations. The permittee must provide real-time video surveillance camera output to the control room or other continuously manned location where the camera images may be view at any time.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.670)<sup>1</sup>

2. The presence of a flare pilot flame(s) shall be monitored using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present. The thermocouple, ultraviolet beam sensor, infrared sensor or other equivalent device shall be periodically maintained to ensure continued operation.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.670)<sup>1</sup>

3. Continuous Monitoring System (CMS) for H<sub>2</sub>S

- a. The permittee shall operate, calibrate, and maintain a CMS for continuously monitoring and recording the concentration by volume (dry basis) of H<sub>2</sub>S in routinely-generated refinery fuel gases before being burned in the Flares.
- b. The CMS shall meet the following requirements:
  - i. The span value for the CMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
  - ii. Performance evaluations for the H<sub>2</sub>S CMS shall be in accordance with 40 CFR §60.13(c). The H<sub>2</sub>S CMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 7, Specifications and Test Procedures for H<sub>2</sub>S Continuous Emissions Monitoring Systems (CEMS) in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A-5, Method 11, 15, or 15a shall be used in conducting any relative accuracy test audit (RATA). The alternative relative accuracy procedures described in 40 CFR Part 60, Appendix B, Performance Specification 2, Specifications and Test Procedures for SO<sub>2</sub> and nitrogen oxide (NO<sub>x</sub>) Continuous Monitoring Emission Monitoring Systems in Stationary Sources, Section 16.0, Alternative Procedures (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.
  - iii. Cylinder Gas Audits (CGA) shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.
  - iv. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.
- c. The permittee may apply for an exemption from the H<sub>2</sub>S monitoring requirements described above for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the H<sub>2</sub>S monitoring requirements described above until there are changes in operating conditions or stream composition.
  - i. The permittee shall submit to the Department and U.S. EPA, Region 9, a written application for an exemption from monitoring. The application must contain the following information:
    - (1) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;
    - (2) A statement that there are no crossover or entry points for sour gas (high H<sub>2</sub>S content) to be introduced into the fuel gas stream/system;
    - (3) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;
    - (4) The supporting test results from sampling the fuel gas stream/system demonstrating that the sulfur content is less than five (5) ppm H<sub>2</sub>S; and
    - (5) A description of how the two (2) weeks of monitoring results compares to the typical range of H<sub>2</sub>S concentration expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare.

- ii. The effective date of the exemption is the date of submission of the information required above.
- iii. No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the permittee shall follow the procedures in 40 CFR §60.107a(b)(3).
- d. The permittee shall keep records of the specific exemption determined to apply for each fuel stream that is exempted. The permittee shall keep a copy of the application as well as the letter from the Department and U.S. EPA, Region 9, granting approval of the application.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, §60.107a(a)(2), §60.107a(b), §60.108a(c)(5))<sup>1</sup>

4. Continuous Monitoring System for Total Sulfur (TS)

- a. The permittee shall operate, calibrate, and maintain a CMS for continuously monitoring and recording the concentration of TS in routinely-generated refinery fuel gases before being burned in the Flares.
- b. The CMS shall meet the following requirements:
  - i. The span value for the CMS is 200,000 ppmv.
  - ii. Performance evaluations for the TS CMS shall be in accordance with 40 CFR §60.13(c). The TS CMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 5, Specifications and Test Procedures for TRS CEMS in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A-5, Method 15a, shall be used in conducting any RATA. The alternative relative accuracy procedures described in 40 CFR Part 60, Appendix B, Performance Specification 2, Specifications and Test Procedures for SO<sub>2</sub> and NO<sub>x</sub> Continuous Monitoring Emission Monitoring Systems in Stationary Sources, Section 16.0, Alternative Procedures (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.
  - iii. CGA shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.
  - iv. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.107a(e)(1))<sup>1</sup>

5. The permittee shall install, operate, calibrate, and maintain, in accordance with the specifications in 40 CFR §60.107a(f)(1), a Continuous Parametric Monitoring System (CPMS) to measure and record the flow rate of gas discharged to each of the Flares.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.107a(f))<sup>1</sup>



6. Flare Vent Gas Composition Monitoring

The permittee shall determine the concentration of individual components in the flare vent gas using either the methods provided in Special Condition No. D.6.a or b of this attachment, to assess compliance with the operating limits in Special Condition No. C.4 of this attachment and, if applicable, Special Condition No. C.3 of this attachment and 40 CFR §63.670(f). Alternatively, the permittee may elect to directly monitor the net heating value of the flare vent gas following the methods provided in 40 CFR §63.670(j)(3) and, if desired, may directly measure the hydrogen concentration in the flare vent gas following the methods provided in 40 CFR §63.670(j)(4). The permittee may elect to use different monitoring methods for different gaseous streams that make up the flare vent gas using different methods provided the composition or net heating value of all gas streams that contribute to the flare vent gas are determined.

- a. Except as provided in 40 CFR §63.670(j)(5) and (6), the permittee shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring (*i.e.*, at least once every fifteen (15) minutes), calculating, and recording the individual component concentrations present in the flare vent gas.
- b. Except as provided in 40 CFR §63.670(j)(5) and (6), the permittee shall install, operate, and maintain a grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight (8) hours while there is flow of regulated material to the flare. Subsequent compositional analysis of the samples must be performed according to Method 18 of 40 CFR Part 60, Appendix A-6, American Society for Testing and Materials (ASTM) D6420-99 (Reapproved 2010), ASTM D1945-03 (Reapproved 2010), ASTM D1945-14, or ASTM UOP539-12 (all incorporated by reference—see §63.14).

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.670)<sup>1</sup>

7. The permittee shall comply with the flare monitoring systems requirements in 40 CFR §63.671 for the Flares.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.671)<sup>1</sup>

8. The permittee shall maintain a copy of the FMP.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.108a(c)(1))<sup>1</sup>

9. Flare Recordkeeping Requirements

For each flare subject to 40 CFR §63.670, the permittee shall keep records specified below up-to-date and readily accessible, as applicable.

- a. Retain records of the output of the monitoring device used to detect the presence of a pilot flame as required in 40 CFR §63.670(b), i.e., Special Condition No. C.2 of this attachment, for a minimum of two (2) years. Retain records of each fifteen (15) minute block during which there was at least one (1) minute that no pilot flame is present when regulated material is routed to a flare for a minimum of five (5) years.
- b. Retain records of daily VE observations or video surveillance images required in 40 CFR §63.670(h), i.e., Special Condition No. D.1 of this attachment, as specified below, as applicable, for a minimum of three (3) years.
  - i. If VE observations are performed using Method 22 at 40 CFR Part 60, Appendix A-7, the record must identify whether the VE observation was performed, the results of each observation, total duration of observed VE, and whether it was a five (5) minute or two (2) hour observation. If the permittee performs VE observations more than one (1) time during the day, the record must also identify the date and time of day each VE observation was performed.
  - ii. If video surveillance camera is used, the record must include all video surveillance images recorded, with time and date stamps.
  - iii. For each two (2) hour period for which VE are observed for more than five (5) minutes in two (2) consecutive hours, the record must include the date and time of the two (2) hour period and an estimate of the cumulative number of minutes in the two (2) hour period for which emissions were visible.
- c. The fifteen (15) minute block average cumulative flows for flare vent gas and, if applicable, total steam, perimeter assist air, and premix assist air specified to be monitored under 40 CFR §63.670(i), along with the date and time interval for the fifteen (15) minute block. If multiple monitoring locations are used to determine cumulative vent gas flow, total steam, perimeter assist air, and premix assist air, retain records of the fifteen (15) minute block average flows for each monitoring location for a minimum of two (2) years, and retain the fifteen (15) minute block average cumulative flows that are used in subsequent calculations for a minimum of five (5) years. If pressure and temperature monitoring is used, retain records of the fifteen (15) minute block average temperature, pressure and molecular weight of the flare vent gas or assist gas stream for each measurement location used to determine the fifteen (15) minute block average cumulative flows for a minimum of two (2) years, and retain the fifteen (15) minute block average cumulative flows that are used in subsequent calculations for a minimum of five (5) years.
- d. The flare vent gas compositions specified to be monitored under 40 CFR §63.670(j). Retain records of individual component concentrations from each compositional analyses for a minimum of two (2) years. If NHVvg analyzer is used, retain records of the fifteen (15) minute block average values for a minimum of five (5) years.
- e. Each fifteen (15) minute block average operating parameter calculated following the methods specified in 40 CFR §63.670(k) through (n), as applicable.
- f. All periods during which operating values are outside of the applicable operating limits specified in 40 CFR §63.670(d) through (f) when regulated material is being routed to the flare.

- g. All periods during which the permittee does not perform flare monitoring according to the procedures in 40 CFR §63.670(g) through (j).
- h. Records of periods when there is flow of vent gas to the flare, but when there is no flow of regulated material to the flare, including the start and stop time and dates of periods of no regulated material flow.
- i. Records when the flow of vent gas exceeds the smokeless capacity of the flare, including start and stop time and dates of the flaring event.
- j. Records of the root cause analysis and corrective action analysis conducted as required in 40 CFR §63.670(o)(3), including an identification of the affected facility, the date and duration of the event, a statement noting whether the event resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under 40 CFR §63.670(o)(5)(i).
- k. For any corrective action analysis for which implementation of corrective actions are required in 40 CFR §63.670(o)(5), a description of the corrective action(s) completed within the first forty-five (45) days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.655)<sup>1</sup>

- 10. The permittee shall maintain a file of all measurements and monitoring data, including the CMS performance evaluations; CMS calibration checks; adjustments and maintenance performed on the monitoring system or devices; and all other information required to be recorded by 40 CFR §60.13 in a permanent form suitable for inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7)<sup>1</sup>

- 11. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.655)<sup>1</sup>

## **Section E. Notification and Reporting Requirements**

### 1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate** or an equivalent form shall be used in reporting flare emissions.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively. These notifications shall include, but not be limited to:
  - a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report **within five (5) working days** *any deviations from permit requirements*, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

#### 4. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.

- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

- 5. The permittee shall submit **semi-annually** written reports to the Department for monitoring purposes. The report 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. Results of any Method 22 VE test performed. Include the time and date of test and the corrective actions taken.
  - b. Any deviations from permit requirements shall be clearly identified.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.655)<sup>1</sup>

6. Excess Emissions

- a. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department and the U.S. EPA, Region 9 for every **semi-annual calendar period**. The report shall include the following information:
  - i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period;
  - ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the Flares. The nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted;
  - iii. The date and time identifying each period during which the CMS and the Net Heating Value Analyzer was inoperative except for zero (0) and span checks. The nature of each system repair or adjustment shall be described; and
  - iv. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the CMS operated properly during the period and was not subject to any repairs or adjustments except for zero (0) and span checks.
- b. All reports shall be postmarked by the **thirtieth (30<sup>th</sup>) day following the end of each semi-annual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form shall also be submitted in addition to the excess emissions and monitoring systems performance report.
- c. Excess emission shall be defined as any rolling three (3) hour period during which the average concentration of H<sub>2</sub>S in routinely-generated refinery fuel gases, as measured by the H<sub>2</sub>S CMS, exceeds 230 mg/dscm (0.10 gr/dscf) or 162 ppmv.

- d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission and concentration limits for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7, §60.105, §60.107a(i)(1)(ii))<sup>1</sup>

## 7. Flare Reporting Requirements

The permittee shall submit Periodic Reports no later than sixty (60) days after the end of each six (6) month period when any of the information specified in the paragraph below is collected. The first six (6) month period shall begin on the date the Notification of Compliance Status report is required to be submitted. A Periodic Report is not required if none of the events identified in the paragraph below occurred during the six (6) month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emission averages. The permittee may submit reports required by other regulations in place of or as part of the Periodic Report if the reports contain the same information.

For flares subject to 40 CFR §63.670, Periodic Reports must include the following information:

- a. Records as specified in Special Condition No. D.7.a of this attachment for each fifteen (15) minute block during which there was at least one (1) minute when regulated material is routed to a flare and no pilot flame is present.
- b. VE records as specified in Special Condition No. D.7.b.iii of this attachment for each period of two (2) consecutive hours during which VE exceeded a total of five (5) minutes.
- c. The fifteen (15) minute block periods for which the applicable operating limits specified in 40 CFR §63.670(d) through (f) are not met. Indicate the date and time for the period, the net heating value operating parameter(s) determined following the methods in 40 CFR §63.670(k) through (n) as applicable.
- d. For flaring events meeting the criteria in 40 CFR §63.670(o)(3):
  - i. The start and stop time and date of the flaring event.
  - ii. The length of time for which emissions were visible from the flare during the event.
  - iii. The periods of time that the flare tip velocity exceeds the maximum flare tip velocity determined using the methods in 40 CFR §63.670(d)(2) and the maximum fifteen (15) minute block average flare tip velocity recorded during the event.
  - iv. Results of the root cause and corrective actions analysis completed during the reporting period, including the corrective actions implemented during the reporting period and, if applicable, the implementation schedule for planned corrective actions to be implemented subsequent to the reporting period.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.655)<sup>1</sup>

**Section F. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP..

**ATTACHMENT II(D): SPECIAL CONDITIONS  
EFFLUENT TREATMENT PLANT  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:
  - a. Two (2) Covered API Separators, ID. Nos. D-3617 and D-3618  
Control Devices - Two (2) Carbon Adsorption Canisters (Primary and Secondary);
  - b. Benzene Recovery Unit (BRU) consisting of two (2) Nitrogen Gas Strippers and two (2) Carbon Adsorber Towers  
Control Devices -Two (2) Carbon Adsorption Canisters (Primary and Secondary);
  - c. Recovered Oil Sump  
Control Devices - Two (2) Carbon Adsorption Canisters (Primary and Secondary);
  - d. Skim Oil Tank identified as Storage Tank T-3619;
  - e. Wastewater Surge Tank identified as Storage Tank T-301; and
  - f. Recovered Oil Tank identified as Storage Tank T-302.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The API Separators are subject to the provisions of the following federal regulations:  
40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):
  - a. Subpart A, General Provisions; and



- b. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.690)<sup>1</sup>

2. The API Separators, BRU, Recovered Oil Sump, Skim Oil Tank, Wastewater Surge Tank, and Recovered Oil Tank are subject to the following federal requirements:

40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP):

- a. Subpart A, General Provisions; and
- b. Subpart FF, National Emission Standard for Benzene Waste Operations.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.180; 40 CFR §61.01, §61.340)<sup>1</sup>

### **Section C. Operational and Emissions Limitations**

1. All gauging and sampling devices for the closed vent systems and carbon adsorption canisters for the API Separators, BRU, and Recovered Oil Sump shall be gas-tight except when gauging or sampling is taking place.

(Auth.: HAR §11-60.1-3, §11-60.1-40, §11-60.1-90, §11-60.1-161, §11-60.1-180; 40 CFR §60.692-5, §61.349)<sup>1</sup>

2. The API Separators shall be equipped and operated with a fixed roof, closed vent system, and carbon adsorption canisters.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-180; 40 CFR §60.692-3, §61.347)<sup>1</sup>

3. The fixed roof of the API Separators shall be installed to completely cover the separator tank with no separation between the roof and the wall.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-3)<sup>1</sup>

4. The vapor space under the fixed roof of the API Separators shall not be purged unless the vapor is directed to the carbon adsorption canisters.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-3)<sup>1</sup>

5. Roof access doors or openings of the API Separators shall be gasketed, latched, and kept closed at all times during operation, except during inspection and maintenance.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161; 40 CFR §60.692-3)<sup>1</sup>

6. The closed vent system and carbon adsorption canisters of the API Separators shall be in operation at all times when emissions may be vented to them.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161; 40 CFR §60.692-5)<sup>1</sup>

7. Closed vent systems of the API Separators shall be purged to direct vapor to the carbon adsorption canisters.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161; 40 CFR §60.692-5)<sup>1</sup>

8. A flow indicator shall be installed on the vent stream to the carbon adsorption canisters of the API Separators to ensure that the vapors are being routed to the carbon adsorption canisters.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161; 40 CFR §60.692-5)<sup>1</sup>

9. The BRU must be operated to *treat* benzene from all waste streams containing benzene to the following levels:

- a. Removes benzene from the waste stream to a level less than ten (10) parts per million by weight (ppmw) on a flow-weighted annual average basis; or
- b. Removes benzene from the waste stream by ninety-nine (99) percent or more on a mass basis.

The permittee may also elect to comply with the above requirements by treating the facility's process wastewater containing benzene to achieve a total annual benzene quantity of less than one (1) Mg/yr based on a rolling twelve (12) month period. Total annual benzene from the facility process wastewater shall be determined by adding together the annual benzene quantity at the point of waste generation for each *untreated* process wastewater stream plus the annual benzene quantity exiting the treatment process for each *treated* process wastewater stream.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.342(d), §61.348)<sup>1</sup>

10. The Skim Oil Tank shall be equipped with a fixed roof meeting the following requirements:
- a. The cover and all openings, hatches, and sampling ports shall be designed and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in Special Condition No. F.1 of this attachment.
  - b. Each opening shall be maintained in a closed and sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the tank except when necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance or repair.
  - c. One (1) or more devices which vent directly to the atmosphere may be used on the tank provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the tank or cover resulting from filling or emptying the tank, diurnal temperature changes, atmospheric pressure changes or malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.343)<sup>1</sup>

11. The Wastewater Surge Tank and Recovered Oil Tank shall be equipped with an external floating roof meeting the requirements of 40 CFR §60.112b(a)(2).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.351)<sup>1</sup>

12. The API Separators shall be equipped with a fixed roof and closed vent system that routes all organic vapors vented from the API Separators to the carbon adsorption canisters. The fixed roof shall meet the following requirements:

- a. The cover and all openings, hatches, and sampling ports shall be designed and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in Special Condition No. F.1 of this attachment.
- b. Each opening shall be maintained in a closed and sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the API Separators except when necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance or repair.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.347)<sup>1</sup>

13. Closed vent systems of the API Separators, BRU, and Recovered Oil Sump shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in Special Condition No. F.1 of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-180; 40 CFR §60.692-5, §61.349)<sup>1</sup>

14. The carbon adsorption canisters of the API Separators, BRU, and Recovered Oil Sump shall be capable of recovering VOC emissions with an efficiency of ninety-five (95) percent or greater, or shall receive or control benzene emissions vented to it with an efficiency of ninety-eight (98) weight percent or greater.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-180; 40 CFR §60.692-5, §61.349)<sup>1</sup>

15. The closed vent system and carbon adsorption canisters for the API Separators, BRU, and Recovered Oil Sump shall be operated at all times except when maintenance or repair of the API Separators, BRU, or Recovered Oil Sump cannot be completed without a shutdown of the carbon adsorption canisters.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.349)<sup>1</sup>

16. The permittee shall demonstrate that the carbon adsorption canisters of the API Separators, BRU, and Recovered Oil Sump complies with Special Condition No. C.14 of this attachment by using one of the following methods:

- a. Engineering calculations in accordance with the requirements specified in Special Condition No. D.18 of this attachment; or
- b. Performance tests conducted using the test methods and procedures that meet the requirements specified in 40 CFR §61.355.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.349)<sup>1</sup>

17. Delay of Repair

- a. Delay of repair of facilities that are subject to the provisions of 40 CFR Part 60, Subpart QQQ, or 40 CFR Part 61, Subpart FF, will be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown.
- b. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

(Auth.: HAR §11-60.13, §11-60.1-90, §11-60.1-161, §11-60.1-180; 40 CFR §60.692-6, §61.350)<sup>1</sup>

**Section D. Monitoring and Recordkeeping Requirements**

1. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; SIP §11-60-15)<sup>2</sup>

2. For the Skim Oil Tank, each fixed-roof, seal, access door, and all other openings shall be checked by visual inspection **initially and quarterly thereafter** to ensure that no cracks or gaps occur and that access doors and other openings are closed and gasketed properly.

(Auth.: HAR §11-60.1-3, 11-60.1-90, 11-60.1-180; 40 CFR §61.343)<sup>1</sup>

3. When a broken seal or gasket or other problem of the Skim Oil Tank is identified, or when detectable emissions are measured, first efforts at repair shall be made **as soon as practicable**, but not later than **forty-five (45) calendar days** after it is identified, except as provided in Special Condition No. C.17 of this attachment.

(Auth.: HAR §11-60.1-3, 11-60.1-90, 11-60.1-180; 40 CFR §61.343)<sup>1</sup>

4. Roof seals, access doors, and other openings of the API Separators shall be checked by visual inspection **initially and quarterly thereafter** to ensure that no cracks or gaps occur between the roof and API Separator wall and that access doors and other openings are closed and gasketed properly.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161, 11-60.1-180; 40 CFR §60.692-3, §61.347)<sup>1</sup>

5. When a broken seal or gasket or other problem of the API Separator is identified, or when detectable emissions are measured, first efforts at repair shall be made **as soon as practicable**, but not later than **fifteen (15) calendar days** after it is identified, except as provided in Special Condition No. C.17 of this attachment.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161, §11-60.1-180; 40 CFR §60.692-3, §61.347)<sup>1</sup>

6. Before using the API Separators with a closed vent system and carbon adsorption canister installed in compliance with 40 CFR Part 60, Subpart QQQ, the permittee shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of 40 CFR Part 60, Subpart QQQ, not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161; 40 CFR §60.696)<sup>1</sup>

7. The API Separators with a closed vent system and carbon adsorption canisters shall use the methods specified Special Condition No. F.1 of this attachment to measure the emission concentrations, using 500 ppm as the no detectable emission limit.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161; 40 CFR §60.696)<sup>1</sup>

8. For the API Separators, the location, date, and corrective action shall be recorded for inspections required by Special Condition No. D.4 of this attachment when a problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161; 40 CFR §60.697)<sup>1</sup>

9. For closed vent systems of the API Separators, the location, date, and corrective action shall be recorded for inspections required by Special Condition No. C.13 of this attachment during which detectable emissions are measured or a problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161; 40 CFR §60.697)<sup>1</sup>

10. If an emission point cannot be repaired or corrected without a process unit shutdown, the following information shall be recorded:

- a. The expected date of a successful repair shall be recorded.
- b. The reason for the delay of repair, as specified in Special Condition No. C.17 of this attachment, shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.
- c. The signature of the permittee whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.
- d. The date of successful repair or corrective action shall also be recorded.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161; 40 CFR §60.697)<sup>1</sup>

11. The closed vent systems and carbon adsorption canisters of the API Separators, BRU, and Recovered Oil Sump shall be inspected **initially and quarterly thereafter**. The visual inspection shall include inspections of ductwork and piping and connections to covers and the carbon adsorption canisters for evidence of visible defects such as holes in ductwork or piping and loose connections.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.349)<sup>1</sup>

12. Except as provided in Special Condition No. C.17 of this attachment, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed vent system and carbon adsorption canisters of the API Separators, BRU, and Recovered Oil Sump shall be made **as soon as practicable** but no later than **five (5) calendar days** after detection. Repair shall be completed no later than **fifteen (15) calendar days** after the emissions are detected or the visible defect is observed.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161, §11-60.1-180; 40 CFR §60.692-5, §61.349)<sup>1</sup>

13. The permittee shall monitor the BRU to ensure the unit is properly operated and maintained by one of the following monitoring procedures:
- Measure the benzene concentration of the waste stream exiting the BRU complying with Special Condition No. C.9.a of this attachment at least once per month by collecting and analyzing one (1) or more samples using the procedures specified in 40 CFR §61.355(c)(3).
  - Install, calibrate, operate, and maintain according to manufacturer's specifications equipment to continuously record a process parameter (or parameters) for the BRU that indicates proper system operation. The permittee shall inspect at least once each operating day the data recorded by the monitoring equipment to ensure that the unit is operating properly.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.354)<sup>1</sup>

14. For the carbon adsorption canisters of the API Separators, BRU, and Recovered Oil Sump, the permittee shall monitor either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the carbon adsorption canister on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a **daily basis** or at intervals no greater than twenty (20) percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, the permittee may replace the carbon in the carbon adsorption canister with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption canisters.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-161, §11-60.1-180; 40 CFR §60.695, §61.354)<sup>1</sup>

15. The permittee shall maintain records that identify each waste stream at the Kapolei Refinery subject to 40 CFR Part 61, Subpart FF, and indicate whether or not the waste stream is controlled for benzene emissions in accordance with 40 CFR Part 61, Subpart FF. In addition, the permittee shall maintain the following records:

- a. For each waste stream not controlled for benzene emissions in accordance with 40 CFR Part 61, Subpart FF, the records shall include all tests results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is process waste stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.
- b. For each waste stream exempt from 40 CFR §61.342(c)(1) in accordance with 40 CFR §61.342(c)(3), the records shall include:
  - i. All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters per minute or the annual waste quantity of process wastewater is less than ten (10) Mg/yr in accordance with 40 CFR §61.342(c)(3)(i), or
  - ii. All measurements, calculations and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr in accordance with 40 CFR §61.342(c)(3)(ii).
- c. For each facility where process wastewater streams are controlled for benzene emissions in accordance with 40 CFR §61.342(d), the records shall include for each treated process wastewater stream all measurements, calculations, and other documentation used to determine the annual benzene quantity in the process wastewater stream exiting the treatment process.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.356)<sup>1</sup>

16. The permittee shall maintain engineering design documentation for all control equipment used in accordance with 40 CFR §61.343 through §61.347. The documentation shall be retained for the life of the control equipment.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.356)<sup>1</sup>

17. The permittee shall maintain the following records for the BRU. The documentation shall be retained for the life of the unit.
  - a. A statement signed and dated by the permittee certifying that the unit is designed to operate at the documented performance level when the waste stream entering the unit is at the highest waste stream flow rate and benzene content expected to occur.
  - b. If engineering calculations are used to determine treatment process or wastewater treatment system unit performance, then the permittee shall maintain the complete design analysis for the unit. The design analysis shall include for example the following information: Design specifications, drawings, schematics, piping and instrumentation diagrams, and other documentation necessary to demonstrate the unit performance.
  - c. If performance tests are used to determine treatment process or wastewater treatment system unit performance, then the permittee shall maintain all test information necessary to demonstrate the unit performance.



- i. A description of the unit including the following information: type of treatment process; manufacturer name and model number; and for each waste stream entering and exiting the unit, the waste stream type (e.g., process wastewater, sludge, slurry, etc), and the design flow rate and benzene content.
- ii. Documentation describing the test protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the unit performance. The description of the test protocol shall include the following information: sampling locations, sampling method, sampling frequency, and analytical procedures used for sample analysis.
- iii. Records of unit operating conditions during each test run including all key process parameters.
- iv. All test results.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.356)<sup>1</sup>

18. The following documentation for the carbon adsorption canisters of the API Separators, BRU, and Recovered Oil Sump shall be retained for the life of the equipment.
  - a. A statement signed and dated by the permittee certifying that the closed vent system and carbon adsorption canisters are designed to operate at the documented performance level when the waste management unit vented to the carbon adsorption canisters is or would be operating at the highest load or capacity expected to occur.
  - b. If engineering calculations are used to determine the carbon adsorption canister performance, then a design analysis for the carbon adsorption canisters that includes for example:

Specifications, drawings, schematics, and piping and instrumentation diagrams prepared by the permittee, or the carbon adsorption canister manufacturer or vendor that describe the design based on acceptable engineering texts. The design analysis shall address the following vent stream characteristics and operating parameter:

For the carbon adsorption canisters, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the carbon adsorption canisters and source operating schedule.

- c. If performance tests are used to determine the carbon adsorption canister performance, then:
  - i. A description of how it is determined that the test is conducted when the waste management unit or treatment process is operating at the highest load or capacity level. This description shall include the estimated or design flow rate and organic content of each vent stream and definition of the acceptable operating ranges of key process and control parameters during the test program.

- ii. A description of the carbon adsorption canister including the manufacturer's name and model number, dimensions, capacity, and construction materials.
- iii. A detailed description of sampling and monitoring procedures, including sampling and monitoring locations in the system, the equipment to be used, sampling and monitoring frequency, and planned analytical procedures for sample analysis.
- iv. All test results.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.356)<sup>1</sup>

19. The permittee shall maintain a record for each visual inspection required by Special Conditions Nos. D.2 and D.4 of this attachment that identifies a problem (such as a broken seal, gap or other problem) which could result in benzene emissions. The record shall include the date of the inspection, waste management unit and control equipment location where the problem is identified, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.356)<sup>1</sup>

20. The permittee shall maintain a record for each test of no detectable emissions required by Special Conditions Nos. C.10, C.12, and C.13 of this attachment. The record shall include the following information: date the test is performed, background level measured during the test, and maximum concentration indicated by the instrument reading measured for each potential leak interface. If detectable emissions are measured at a leak interface, then the record shall also include the waste management unit, control equipment, and leak interface location where detectable emissions are measured, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.356)<sup>1</sup>

21. For the Benzene Recovery Unit, the permittee shall maintain documentation that includes the following information regarding the unit operation:
  - a. Dates of startup and shutdown.
  - b. If measurements of waste stream benzene concentration are performed in accordance with Special Condition No. D.13.a of this attachment, the permittee shall maintain records that include date each test is performed and all test results.
  - c. If a process parameter is continuously monitored in accordance with Special Condition No. D.13.b of this attachment, the permittee shall maintain records that include a description of the operating parameter (or parameters) to be monitored to ensure that the unit will be operated in conformance with these standards and the unit's design specifications, and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the unit.
  - d. Periods when the unit is not operated as designed.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.356)<sup>1</sup>

22. For the carbon absorber canisters, the permittee shall maintain documentation that includes the following information:
- a. Dates of startup and shutdown of the closed vent system and carbon adsorber canisters.
  - b. A description of the operating parameters (or parameter) to be monitored to ensure that the carbon adsorption canisters will be operated in conformance with these standards and the design specifications and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the carbon adsorption canisters.
  - c. Periods when the closed vent system and carbon adsorption canisters are not operated as designed.
  - d. Dates and times when the carbon adsorption canister is monitored, when breakthrough is measured, and the date and time when the existing carbon in the canister is replaced with fresh carbon.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.356)<sup>1</sup>

23. For the Wastewater Surge Tank and Recovered Oil Tank, the permittee shall comply with the recordkeeping requirements in 40 CFR §60.115b.

(Auth.: HAR §11-60.1-3, 11-60.1-90, §11-60.1-180; 40 CFR §61.356)<sup>1</sup>

### **Section E. Notification and Reporting Requirements**

#### 1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate**, or an equivalent form, shall be used in reporting wastewater process rate.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively. These notifications shall include, but not be limited to:
- a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;

- b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- c. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

- 3. The permittee shall report **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

#### 4. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

- i. The identification of each term or condition of the permit that is the basis of the certification;
- ii. The compliance status;
- iii. Whether compliance was continuous or intermittent;
- iv. The methods used for determining the compliance status of the source currently and over the reporting period;
- v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
- vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
- vii. Any additional information as required by the Department including information to determine compliance.

- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. The permittee shall submit to the Department within **sixty (60) days** after initial startup a certification that the equipment necessary to comply with 40 CFR Part 60, Subpart QQQ, has been installed and that the required initial inspections or tests of the API Separators, closed vent systems and carbon adsorption canisters have been carried out in accordance with 40 CFR Part 60 Subpart QQQ. Thereafter, the permittee shall submit **semi-annually** a certification that all of the required inspections have been carried out in accordance with 40 CFR Part 60, Subpart QQQ.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.698)<sup>1</sup>

6. For the API Separators, a report that summarizes all inspections when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted **initially and semi-annually** thereafter to the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.698)<sup>1</sup>

7. As applicable, a report shall be submitted **semi-annually** to the Department that indicates each three (3) hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from the carbon adsorption canisters of the API Separators is more than twenty (20) percent greater than the design exhaust gas concentration level or reading.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.698)<sup>1</sup>

8. If compliance with the provisions of 40 CFR Part 60, Subpart QQQ, is delayed pursuant to 40 CFR §60.692-7, the notification required under 40 CFR §60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standard is technically impossible without a refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.698)<sup>1</sup>

9. The permittee shall submit to the Department the following report within ninety (90) days after January 7, 1993, a report that summarizes the regulatory status of each waste stream at the Kapolei Refinery subject to 40 CFR §61.342 and is determined by the procedures specified in 40 CFR §61.355(c) to contain benzene. The report shall include the following information:

- a. Total annual benzene quantity from the Kapolei Refinery waste determined in accordance with 40 CFR §61.355(a);
- b. A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of 40 CFR Part 61, Subpart FF.
- c. For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of 40 CFR Part 61, Subpart FF, the following information shall be added to the table:

- i. Whether or not the water content of the waste stream is greater than ten (10) percent;
  - ii. Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;
  - iii. Annual waste quantity for the waste stream;
  - iv. Range of benzene concentrations for the waste stream;
  - v. Annual average flow-weighted benzene concentration for the waste stream; and
  - vi. Annual benzene quantity for the waste stream.
- d. The information required in Special Conditions Nos. E.9.a, E.9.b, and E.9.c of this attachment should represent the waste stream characteristics based on current configuration and operating conditions. The permittee only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in 40 CFR §61.10(a).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.357)<sup>1</sup>

10. If the total annual benzene quantity from the Kapolei Refinery waste is equal to or greater than ten (10) Mg/yr, then the permittee shall submit to the Department the following reports:
- a. Within ninety (90) days after January 7, 1993, a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests have been carried out in accordance with 40 CFR Part 61, Subpart FF.
  - b. Beginning on the date that the equipment necessary to comply with these standards have been certified in accordance with Special Condition No. E.10.a of this attachment, the permittee shall submit **annually** to the Department a report that updates the information listed in Special Condition Nos. E.9.a, E.9.b, and E.9.c of this attachment. If the information in the annual report is not changed in the following year, the permittee may submit a statement to that effect.
  - c. Beginning three (3) months after the date that the equipment necessary to comply with these standards has been certified in accordance with Special Condition No. E.10.a of this attachment, the permittee shall submit **quarterly** to the Department a certification that all of the required inspections have been carried out in accordance with the requirements of 40 CFR Part 61, Subpart FF.
  - d. Beginning three (3) months after the date that the equipment necessary to comply with these standards has been certified in accordance with Special Condition No. E.10.a of this attachment, the permittee shall submit a report **quarterly** to the Department that includes:
    - i. If the BRU is monitored in accordance with Special Condition No. D.13.a of this attachment, then each period of operation during which the concentration of benzene in the monitored waste stream exiting the unit is equal to or greater than ten (10) ppmw.

ii. If the BRU is monitored in accordance with Special Condition No. D.13.b of this attachment, then each three (3) hour period of operation during which the average value of the monitored parameter is outside the range of acceptable values or during which the unit is not operating as designed.

e. Beginning one (1) year after the date that the equipment necessary to comply with these standards has been certified in accordance with Special Condition No. E.10.a of this attachment, the permittee shall submit **annually** to the Department a report that summarizes all inspections required by 40 CFR Part 61, Subpart FF, during which detectable emissions are measured or a problem (such as a broken seal, gap, or other problem) that could result in benzene emissions is identified, including information about the repairs or corrective action taken.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.357)<sup>1</sup>

11. For the Wastewater Surge Tank and Recovered Oil Tank, the permittee shall comply with the reporting requirements in 40 CFR §60.115b.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.357)<sup>1</sup>

#### **Section F. Test Methods and Procedures**

1. The permittee shall test equipment for compliance with no detectable emissions in accordance with the following requirements:
  - a. Monitoring shall comply with Method 21 from Appendix A of 40 CFR Part 60.
  - b. The detection instrument shall meet the performance criteria of Method 21.
  - c. The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21.
  - d. Calibration gases shall be:
    - i. Zero (0) air (less than ten (10) ppm of hydrocarbon in air); and
    - ii. A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.
  - e. The background level shall be determined as set forth in Method 21.
  - f. The instrument probe shall be traversed around all potential leak interfaces as close as possible to the interface described in Method 21.
  - g. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared to 500 ppm for determining compliance.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-180; 40 CFR §60.696, §61.355)<sup>1</sup>

**Section G. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.



**ATTACHMENT II(E): SPECIAL CONDITIONS  
ATMOSPHERIC AND VACUUM FURNACES  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:
  - a. One (1) - 151.5 MMBtu/hr (LHV) Atmospheric Furnace identified as F-5103 with Low NO<sub>x</sub> burners;
  - b. One (1) - 62.5 MMBtu/hr (LHV) Vacuum Furnace identified as F-5153 with Low NO<sub>x</sub> burners; and
  - c. Equipped with a common air preheater for both furnaces identified as E-5104.
  
2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-3)

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The Atmospheric and Vacuum Furnaces F-5103 and F-5153 are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):
    - i. Subpart A, General Provisions; and
    - ii. Subpart J, Standards of Performance for Petroleum Refineries.
  
  - b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),
    - i. Subpart A, General Provisions; and
    - ii. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.1, §60.100, §63.1, §63.7480, §63.7485, §63.7490)<sup>1</sup>

- The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

**Section C. Operational and Emissions Limitations**

- The atmospheric and vacuum furnaces shall be fired only on liquid fuel with a maximum sulfur content not to exceed 0.5% by weight or refinery fuel gas (RFG) with a H<sub>2</sub>S content not to exceed 230 mg/dscm (162 ppmv). The burner pilots for these furnaces shall be fired only on RFG with a H<sub>2</sub>S content not to exceed 230 mg/dscm (162 ppmv).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR 60.104)<sup>1</sup>

- The permittee shall not discharge or cause the discharge into the atmosphere from the atmospheric and vacuum furnaces' stack SO<sub>2</sub>, NO<sub>x</sub> as nitrogen dioxide (NO<sub>2</sub>), carbon monoxide (CO), and total particulate matter (PM) in excess of the following specified emission limits:

Maximum Emission Limits (if both atmospheric and vacuum furnaces are operating)

<u>Compound</u>	<u>lb/MMBtu</u>	<u>lb/hr (3-hour Average)</u>
SO <sub>2</sub>	0.590	126.0
NO <sub>x</sub> (as NO <sub>2</sub> )	0.327	70.0
CO	n/a	9.0

<u>Compound</u>	<u>gr/dscf @ 12% CO<sub>2</sub></u>	<u>lb/hr (6-hour Average)</u>
Total PM	601.0	32.0

Maximum Emission Limits (if only atmospheric furnace is operating)

<u>Compound</u>	<u>lb/MMBtu</u>	<u>lb/hr (3-hour Average)</u>
SO <sub>2</sub>	0.590	89.2
NO <sub>x</sub> (as NO <sub>2</sub> )	0.327	49.5
CO	n/a	6.4

<u>Compound</u>	<u>gr/dscf @ 12% CO<sub>2</sub></u>	<u>lb/hr (6-hour Average)</u>
Total PM	601.0	22.6

(Auth.: HAR §11-60.1-3, §11-60.1-90)

3. MACT Subpart DDDDD Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the atmospheric and vacuum furnaces' stack, CO, filterable PM, hydrogen chloride (HCl), and mercury emissions in excess of the limits specified below while fired on liquid fuel, or a combination of liquid fuel and RFG, except during periods of startup and shutdown.

Pollutant	MACT Subpart DDDDD Maximum Emission Limits
CO	130 ppmvd @ 3% O <sub>2</sub>
Filterable PM	0.27 lb/MMBtu
Hydrogen Chloride	1.1E-03 lb/MMBtu
Mercury	2.0E-06 lb/MMBtu

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7500)<sup>1</sup>

4. The permittee shall burn only RFG on a maximum twelve (12) of the thirty-six (36) atmospheric and vacuum crude furnaces' burners. The low NO<sub>x</sub> burners shall be installed prior to burning RFG.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

5. Visible Emissions

For any six (6) minute averaging period, the atmospheric and vacuum furnaces shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment breakdown, the atmospheric and vacuum furnaces may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

6. Tune-ups

The permittee shall conduct initial tune-ups of the atmospheric and vacuum furnaces no later than January 31, 2016, and shall conduct tune-ups of the atmospheric and vacuum furnaces annually to demonstrate continuous compliance. The tune-up shall be conducted while burning the type of fuel (or fuels in the case of units that routinely burn a mixture) that provide the majority of the heat input to the unit over the twelve (12) months prior to the tune-up. Each annual tune-up shall be conducted no more than thirteen (13) months after the previous tune-up. The tune-up shall be conducted as follows:

- a. As applicable, inspect the burner and clean or replace any components of the burner as necessary (the burner inspection may be performed at any time prior to the tune-up or the burner inspection may be delayed until the next scheduled unit shutdown). At units where entry into a piece of process equipment is required to complete the tune-up inspections, inspections are required only during planned entries in the process equipment;
- b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;
- c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the burner inspection may be delayed until the next scheduled unit shutdown);
- d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject;
- e. Measure the concentrations in the effluent stream of CO in parts per million (ppm) by volume and oxygen in volume percent before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer;
- f. Maintain a report on-site containing the following information:
  - i. The concentrations of CO in the effluent stream in ppm by volume and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the unit;
  - ii. A description of any corrective actions taken as part of the tune-up of the unit; and
  - iii. The type and amount of fuel used over the twelve (12) months prior to the tune-up of the unit, but only if the unit was physically and legally capable of using more than one (1) type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.
- g. If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within thirty (30) days of startup.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7495, §63.7500, §63.7510, §63.7540)<sup>1</sup>)

## 7. Energy Assessment

The permittee shall have a one-time energy assessment performed for the atmospheric and vacuum furnaces by a qualified energy assessor not later than January 31, 2016. The energy assessment must include the elements listed in 40 CFR Part 63, Subpart DDDDD, Table 3, Item No. 4.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7510)<sup>1</sup>)

## **Section D. Monitoring and Recordkeeping Requirements**

### 1. Continuous Monitoring System for H<sub>2</sub>S

- a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned in the furnaces and burner pilots.
- b. The CMS shall meet the following requirements:
  - i. The span value for the CMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
  - ii. All fuel gas combustion devices, including the furnaces and burner pilots, having a common source of fuel gas may be monitored at one (1) location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.
  - iii. Performance evaluations for the H<sub>2</sub>S CMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 7, Specifications and Test Procedures for H<sub>2</sub>S CEMS in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11, shall be used in conducting any RATA.
  - iv. Cylinder Gas Audits (CGA) shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2. Since performance specification test procedures are only intended for the initial test of the H<sub>2</sub>S CMS, RATA's need not be performed on an annual basis, unless requested by the Department; or there is a significant change or performance deficiency of the CMS.
  - v. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, PS-7)<sup>1</sup>

### 2. Liquid Fuel Sulfur Content Monitoring

The sulfur content of the liquid fuel to be fired in the atmospheric and vacuum furnaces shall be tested in accordance with the most current ASTM methods. ASTM Method D4294-83 is a suitable alternative to Method D129-64 for determining the sulfur content. The liquid fuel sulfur content shall be verified by having a representative sample of each batch of liquid fuel analyzed for sulfur content by weight at least once a **month**. Records of the sulfur content of the liquid fuel shall be maintained on a **monthly** basis.

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

### 3. Liquid Fuel Chlorine and Mercury Monitoring

The permittee shall demonstrate compliance with the mercury or HCl emission limits in Special Condition No. C.3 of this attachment for the atmospheric and vacuum furnaces based on fuel analysis, and shall conduct a monthly fuel analysis according to 40 CFR §63.7521 and Table 6 of 40 CFR Part 63, Subpart DDDDD for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 of 40 CFR Part 63, Subpart DDDDD. The permittee may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least fourteen (14) calendar days. If the permittee burns a new type of fuel, a fuel analysis shall be conducted before burning the new type of fuel in the atmospheric and vacuum furnaces. The permittee shall still meet all applicable continuous compliance requirements in 40 CFR §63.7540. If each of twelve (12) consecutive monthly fuel analyses demonstrates seventy-five (75) percent or less of the compliance level, the permittee may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds seventy-five (75) percent of the compliance level or the permittee begins burning a new type of fuel, the permittee shall return to monitoring for that fuel, until twelve (12) months of fuel analyses are again less than seventy-five (75) percent of the compliance level. If sampling is conducted on one day per month, samples should be no less than fourteen (14) days apart, but if multiple samples are taken per month, the fourteen (14) day restriction does not apply.

- a. The chlorine content of the liquid fuel for the atmospheric and vacuum furnaces shall be sampled at least once a month and tested in accordance with the EPA Methods SW-846-9056 or SW-846-9076, or equivalent.
- b. The mercury content of the liquid fuel for the atmospheric and vacuum furnaces shall be sampled at least once a month and tested in accordance with EPA Methods SW-846-7470A or SW-846-7471B, or equivalent.
- c. The permittee shall submit a fuel analysis plan per 40 CFR §63.7521(b).
- d. The permittee shall keep records per 40 CFR §63.7555(d).

Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7510, §63.7515, §63.7521, §63.7530, §63.7540, §63.7555)<sup>1</sup>

### 4. Visible Emissions

The permittee shall conduct **monthly** (calendar month) VE observations for each equipment subject to opacity limitations by a certified reader in accordance 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

5. The permittee shall maintain a file of all measurements and monitoring data, including the CMS performance evaluations; CMS calibration checks; adjustments and maintenance performed on the monitoring system or devices; and all other information required to be recorded by 40 CFR §60.13 in a permanent form suitable for inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7)<sup>1</sup>

6. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

### **Section E. Notification and Reporting Requirements**

#### 1. Excess Emissions

- a. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department and the U.S. EPA, Region 9 for **every semi-annual calendar period**. The report shall include the following:
  - i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions;
  - ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the atmospheric and vacuum furnaces. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted, shall also be reported;
  - iii. The date and time identifying each period during which the CMS was inoperative except for zero (0) and span checks. The nature of each system repair or adjustment shall be described; and
  - iv. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the CMS operated properly during the period and was not subject to any repairs or adjustments except zero (0) and span checks.
- b. All reports shall be postmarked by the **thirtieth (30<sup>th</sup>) day following the end of each semi-annual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form shall also be submitted in addition to the excess emissions and monitoring systems performance report.
- c. Excess emissions shall be defined as any rolling three (3) hour period during which the average concentration of H<sub>2</sub>S in RFG, as measured by the CMS, exceeds 230 mg/dscm (162 ppmv).

- d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission limit for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7, §60.105)<sup>1</sup>

## 2. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Fuel Consumption**, or an equivalent form, shall be used in reporting fuel usage.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

3. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively. These notifications shall include, but not be limited to:

- a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
- b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. The permittee shall report **within five (5) working days any deviations from permit requirements**, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

## 5. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:



- i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
  - c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

6. The permittee shall submit **semi-annually** written reports to the Department 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 exceedances as determined by the required VE 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: Opacity Exceedances** shall be used.
  - b. Any fuel analysis conducted by the permittee or permittee's laboratory during the reporting period showing the sulfur content of the fuel.
  - c. 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)<sup>2</sup>

7. **At least thirty (30) or sixty (60) days (as applicable) prior** to the following events, the permittee shall notify the Department in writing of:

- a. Conducting a performance specification test on the CMS. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13(c).
- b. Conducting a source performance test as required by this Attachment, Section F, Testing Requirements.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.13)<sup>1</sup>

#### **Section F. Testing Requirements**

1. **Within sixty (60) days after** the start of firing RFG in the atmospheric and vacuum furnaces' low NO<sub>x</sub> burners, the permittee shall conduct source performance tests to determine emissions of total PM, SO<sub>2</sub>, NO<sub>x</sub> as NO<sub>2</sub>, and CO from the vacuum and atmospheric furnaces when burning RFG.

On an annual basis, the permittee shall conduct source performance tests to determine emissions of total PM, SO<sub>2</sub>, NO<sub>x</sub> as NO<sub>2</sub>, CO, and filterable PM from the vacuum and atmospheric furnaces while fired on liquid fuel, or a combination of liquid fuel and RFG. Performance tests shall be conducted at the maximum expected operating capacity of the vacuum and atmospheric furnaces, or at other operating loads as may be specified by the Department. Annual performance tests shall be completed no more than thirteen (13) months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of 40 CFR §63.7515, which includes the following:

- a. If the performance test for a given pollutant (filterable PM and CO) for at least two (2) consecutive years show that the emissions are at or below seventy-five (75) percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 of 40 CFR Part 63, Subpart DDDDD, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the vacuum and atmospheric furnaces or air pollution control equipment that could increase emissions, the permittee may choose to conduct performance tests for the pollutant every third year. Each such performance test shall be conducted no more than thirty-seven (37) months after the previous performance test.
- b. If a performance test shows emissions exceeded the emission limit or seventy-five (75) percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 of 40 CFR Part 63, Subpart DDDDD) for a pollutant (filterable PM and CO), the permittee shall conduct annual performance test for that pollutant until all performance tests over a consecutive two (2) year period meet the required level (at or below seventy-five (75) percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 of 40 CFR Part 63, Subpart DDDDD).

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7, §63.7510, §63.7515, §63.7530)<sup>1</sup>

2. Source performance tests shall be conducted in accordance with the test methods set forth below or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department:
  - a. Method 1, Appendix A of 40 CFR Part 60, for sample and velocity traverse;
  - b. Method 2, Appendix A of 40 CFR Part 60, for velocity and volumetric flow rate;
  - c. Method 3, Appendix A of 40 CFR Part 60, for gas analysis;
  - d. Method 4, Appendix A of 40 CFR Part 60, for moisture content;
  - e. Method 5 or 17, Appendix A of 40 CFR Part 60, for concentration of total PM and filterable PM;
  - f. Method 6, Appendix A of 40 CFR Part 60, for concentration of sulfur dioxides;
  - g. Method 7, Appendix A of 40 CFR Part 60, for concentration of nitrogen oxides (as NO<sub>2</sub>);
  - h. Method 10, Appendix A of 40 CFR Part 60, for concentration of carbon monoxides; and
  - i. Method 19, Appendix A of 40 CFR Part 60, for F-factor methodology to convert emission concentration to lb/MMBtu.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7, §63.7510, §63.7515, §63.7520, §63.7530)<sup>1</sup>

3. Note that Method 1 cannot be used under the following conditions:
  - a. Cyclonic or swirling gas flow at the sampling location;
  - b. Stack or duct with a diameter less than twelve (12) inches or a cross-sectional area less than 113 square inches; or
  - c. Sampling location less than two (2) stack or duct diameters downstream or less than a half diameter upstream from a flow disturbance.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

4. The permittee shall provide sampling and testing facilities at its own expense. The Department may monitor any of the required source performance tests.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

5. Each source performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

6. The performance test to determine PM emissions shall consist of six (6) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the six (6) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

6. For Method 5, the sampling time for each run shall be at least sixty (60) minutes and the minimum sample volume shall be at least thirty (30) dry cubic feet at standard conditions (dscf).

(Auth.: HAR §11-60.1-3, §11-60.1-90)

7. Particulate emissions shall be reported in two (2) categories:

- a. Front half (filter and probe); and
- b. Front and back half (probe, filter and impingers).

(Auth.: HAR §11-60.1-3, §11-60.1-90)

8. For each run, the emission rate of PM shall be determined by the equation pounds/hour =  $Q_s \times c_s$ , where  $Q_s$  = volumetric flow rate of the total effluent in dscf/hour as determined in accordance with Method 2, and  $c_s$  = concentration of PM in pounds/dscf as determined in accordance with Method 5.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

9. For each run, the following items shall be provided:

- a. Heat input rate (MMBtu/hr) for each furnace; and
- b. Crude processing rate (thousand barrels per day) for each furnace.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

10. **At least sixty (60) days prior to performing a test**, the permittee shall submit a written source performance test plan to the Department and the U.S. EPA, Region 9 that describes the test date(s), test duration, test locations, test methods, source operation, fuel consumption, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A source performance test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7)<sup>1</sup>

11. **Within sixty (60) days after completion of the source performance test**, the permittee shall submit to the Department and the U.S. EPA, Region 9, the test report which shall include the operating conditions of the boilers at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7)<sup>1</sup>

12. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

13. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual source performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Written waiver requests are not required for the source performance testing of pollutants subject to 40 CFR Part 63, Subpart DDDDD (filterable PM and CO) that qualify for the exemption pursuant to Special Condition No. F.1.a of this attachment. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous source performance test.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7)<sup>1</sup>

14. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H<sub>2</sub>S levels in RFG shall be conducted and results reported in accordance with the instructions and test methods set forth in 40 CFR §60.106, and Appendix A, Method 11.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.106)<sup>1</sup>

### **Section G. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II(F): SPECIAL CONDITIONS  
PROCESS UNIT FURNACES  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:

- a. One (1) - 9 MMBtu/hr Hydrogenation Unit Furnace identified as F-5600;
- b. One (1) - 24.3 MMBtu/hr Hydrogen Unit Furnace identified as F-5700;
- c. One (1) - 4 MMBtu/hr Isomerization Unit Furnace identified as F-5930; and
- d. One (1) - 1.6 MMBtu/hr Isomerization Unit Furnace identified as F-5950.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. Process Unit Furnaces F-5600, F-5700, F-5930, and F-5950 are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):
    - i. Subpart A, General Provisions;
    - ii. Subpart J, Standards of Performance for Petroleum Refineries.
  - b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),
    - i. Subpart A, General Provisions; and
    - ii. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.1, §60.100, §63.1, §63.7480, §63.7485, §63.7490)<sup>1</sup>

2. The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

### **Section C. Operational and Emissions Limitations**

1. Process Unit Furnaces F-5600, F-5700, F-5930, and F-5950 shall be fired only on RFG with a H<sub>2</sub>S content not to exceed 230 mg/dscm (162 ppmv).

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §60.104)<sup>1</sup>

2. For any six (6) minute averaging period, the process unit furnaces shall not exhibit VE of forty (40) percent opacity or greater, except as follows: during start-up, shutdown, or equipment breakdown, the process unit furnaces may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

3. Tune-ups

The permittee shall conduct initial tune-ups of the process unit furnaces no later than January 31, 2016, and shall conduct a tune-up of Process Unit Furnace F-5600 biennially, Process Unit Furnace F-5700 annually, and Process Unit Furnaces F-5930 and F-5950 every five (5) years, to demonstrate continuous compliance. The tune-up shall be conducted while burning the type of fuel (or fuels in the case of units that routinely burn a mixture) that provide the majority of the heat input to the unit over the twelve (12) months prior to the tune-up. Each annual tune-up shall be conducted no more than thirteen (13) months after the previous tune-up. Each biennial tune-up shall be conducted no more than twenty-five (25) months after the previous tune-up. Each five (5) year tune-up shall be conducted no more than sixty-one (61) months after the previous tune-up. The tune-up shall be conducted as follows:

- a. As applicable, inspect the burner and clean or replace any components of the burner as necessary (the burner inspection may be performed at any time prior to the tune-up or the burner inspection may be delayed until the next scheduled unit shutdown. For Process Unit Furnaces F-5930 and F-5950, the burner inspection may be delayed but must be inspected at least once every seventy-two (72) months). At units where entry into a piece of process equipment is required to complete the tune-up inspections, inspections are required only during planned entries in the process equipment;
- b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

- c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the burner inspection may be delayed until the next scheduled unit shutdown);
- d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject;
- e. Measure the concentrations in the effluent stream of CO in parts per million (ppm) by volume and oxygen in volume percent before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer;
- f. Maintain a report on-site containing the following information:
  - i. The concentrations of CO in the effluent stream in ppm by volume and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the unit;
  - ii. A description of any corrective actions taken as part of the tune-up of the unit; and
  - iii. The type and amount of fuel used over the twelve (12) months prior to the tune-up of the unit, but only if the unit was physically and legally capable of using more than one (1) type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.
- g. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within thirty (30) days of startup.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7495, §63.7500, §63.7510, §63.7540)<sup>1</sup>)

#### 4. Energy Assessment

The permittee shall have a one-time energy assessment performed for the Process Unit Furnaces F-5600, F-5700, F-5930, and F-5950 by a qualified energy assessor not later than January 31, 2016. The energy assessment must include the elements listed in 40 CFR Part 63, Subpart DDDDD, Table 3, Item No. 4.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7510)<sup>1</sup>)

### **Section D. Monitoring and Recordkeeping Requirements**

#### 1. Continuous Monitoring System for H<sub>2</sub>S

- a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned.
- b. The CMS shall meet the following requirements:



- i. The span value for the CMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
- ii. All fuel gas combustion devices having a common source of fuel gas may be monitored at one (1) location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.
- iii. Performance evaluations for the H<sub>2</sub>S CMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 7, Specifications and Test Procedures for H<sub>2</sub>S CEMS in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11, 15, 15A, or 16, shall be used in conducting any RATA.
- iv. Cylinder Gas Audits (CGA) shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2. Since performance specification test procedures are only intended for the initial test of the H<sub>2</sub>S CMS, RATA's need not be performed on an annual basis, unless requested by the Department; or there is a significant change or performance deficiency of the CMS.
- v. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-105; 40 CFR §60.105, PS-7)<sup>1</sup>

## 2. Visible Emissions

The permittee shall conduct **monthly** (calendar month) VE observations for each equipment subject to opacity limitations by a certified reader in accordance 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

3. The permittee shall maintain a file of all measurements and monitoring data, including the CMS performance evaluations; CMS calibration checks; adjustments and maintenance performed on the monitoring system or devices; and all other information required to be recorded by 40 CFR §60.13 in a permanent form suitable for inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7)<sup>1</sup>

4. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

## **Section E. Notification and Reporting Requirements**

### 1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Fuel Consumption**, or an equivalent form, shall be used in reporting fuel usage.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

### 2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively. These notifications shall include, but not be limited to:

- a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
- b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

### 3. The permittee shall report **within five (5) working days any deviations from permit requirements**, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

### 4. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

- i. The identification of each term or condition of the permit that is the basis of the certification;

- ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. The permittee shall submit **semi-annually** written reports to the Department 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 exceedances as determined by the required VE 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: Opacity Exceedances** shall be used for reporting.
  - b. 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)<sup>2</sup>

6. Excess Emissions Report

- a. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department and the U.S. EPA, Region 9 every **semi-annual calendar period**. The report shall include the following information:

- i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period shall also be reported.
  - ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the furnaces. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted, shall also be reported.
  - iii. The date and time identifying each period during which the CMS was inoperative except for zero (0) and span checks. The nature of each system repair or adjustment shall be described.
  - iv. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the CMS operated properly during the period and was not subject to any repairs or adjustments.
- b. All reports shall be postmarked by the **thirtieth (30<sup>th</sup>) day following the end of each semi-annual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form shall also be submitted in addition to the excess emissions and monitoring systems performance report.
  - c. For purposes of reports under 40 CFR §60.7(c), periods of excess emissions for the furnaces that shall be determined and reported are defined as all rolling three (3) hour periods during which the average concentration of H<sub>2</sub>S in RFG, as measured by the CMS, exceeds 230 mg/dscm (162 ppmv).
  - d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission limit for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-32, §11-60.1-90; SIP §11-60-24; 40 CFR §60.105, 40 CFR §60.107)<sup>1</sup>

7. **At least thirty (30) days prior** to the following events, the permittee shall notify the Department of Health in writing of conducting a performance specification test on the CMS. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13(c).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.13)<sup>1</sup>

#### **Section F. Testing Requirements**

Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H<sub>2</sub>S levels in the RFG shall be conducted and results reported in accordance with the instructions and test methods set forth in 40 CFR §60.106, and Appendix A, Method 11.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.106)<sup>1</sup>

**Section G. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II(G): SPECIAL CONDITIONS  
ACID PLANT  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:
  - a. One (1) - 4.2 MSCF/hr Acid Plant Combustion Chamber, ID No. 6200 with one (1) Acid Plant Absorbing Tower Stack; and
  - b. One (1) - 5.1 MMBtu/hr Acid Plant Preheater, ID No. F-6262.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The Acid Plant Preheater and its associated appurtenances are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):
    - i. Subpart A, General Provisions; and
    - ii. Subpart J, Standards of Performance for Petroleum Refineries.
  - b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),
    - i. Subpart A, General Provisions; and
    - ii. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.1, §60.100, §63.1, §63.7480, §63.7485, §63.7490)<sup>1</sup>

2. The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

### **Section C. Operational and Emissions Limitations**

1. The acid plant preheater shall be fired only on RFG with a H<sub>2</sub>S content not to exceed 230 mg/dscm (162 ppmv) or commercial propane with a H<sub>2</sub>S copper corrosion content not to exceed 0.35 ppm per ASTM Method D-1838.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.104)<sup>1</sup>

2. Visible Emissions

- a. For any six (6) minute averaging period, the acid plant preheater shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment breakdown, the acid plant preheater may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.
- b. For any six (6) minute averaging period, the acid plant absorbing tower stack shall not exhibit VE of forty (40) percent opacity or greater, except as follows: during startup, shutdown, or equipment breakdown, the acid plant absorbing tower stack may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

3. Tune-ups

The permittee shall conduct an initial tune-up of the acid plant preheater no later than January 31, 2016, and shall conduct a tune-up of the acid plant preheater biennially to demonstrate continuous compliance. The tune-up shall be conducted while burning the type of fuel (or fuels in the case of units that routinely burn a mixture) that provide the majority of the heat input to the unit over the twelve (12) months prior to the tune-up. Each biennial tune-up shall be conducted no more than twenty-five (25) months after the previous tune-up. The tune-up shall be conducted as follows:

- a. As applicable, inspect the burner and clean or replace any components of the burner as necessary (the burner inspection may be performed at any time prior to the tune-up or the burner inspection may be delayed until the next scheduled unit shutdown). At units where entry into a piece of process equipment is required to complete the tune-up inspections, inspections are required only during planned entries in the process equipment;

- b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;
- c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the burner inspection may be delayed until the next scheduled unit shutdown);
- d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject;
- e. Measure the concentrations in the effluent stream of CO in parts per million (ppm) by volume and oxygen in volume percent before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer;
- f. Maintain a report on-site containing the following information:
  - i. The concentrations of CO in the effluent stream in ppm by volume and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the unit;
  - ii. A description of any corrective actions taken as part of the tune-up of the unit; and
  - iii. The type and amount of fuel used over the twelve (12) months prior to the tune-up of the unit, but only if the unit was physically and legally capable of using more than one (1) type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.
- g. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within thirty (30) days of startup.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7495, §63.7500, §63.7510, §63.7540)<sup>1</sup>)

#### 4. Energy Assessment

The permittee shall have a one-time energy assessment performed for the acid plant preheater by a qualified energy assessor not later than January 31, 2016. The energy assessment must include the elements listed in 40 CFR Part 63, Subpart DDDDD, Table 3, Item No. 4.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7510)<sup>1</sup>



**Section D. Monitoring and Recordkeeping Requirements**

1. Continuous Monitoring System for H<sub>2</sub>S

- a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned in the acid plant preheater.
- b. The CMS shall meet the following requirements:
  - i. The span value for the CMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
  - ii. All fuel gas combustion devices, including the acid plant preheater, having a common source of fuel gas may be monitored at one (1) location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.
  - iii. Performance evaluations for the H<sub>2</sub>S CMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 7, Specifications and Test Procedures for H<sub>2</sub>S CEMS in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11, shall be used in conducting any RATA.
  - iv. Cylinder Gas Audits (CGA) shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2. Since performance specification test procedures are only intended for the initial test of the H<sub>2</sub>S CMS, RATA's need not be performed on an annual basis, unless requested by the Department; or there is a significant change or performance deficiency of the CMS.
  - v. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, PS-7)<sup>1</sup>

2. The permittee shall retain records of the fuel analysis, sales specifications of the concentration of H<sub>2</sub>S, and delivery tags of the commercial propane. The commercial propane shall meet performance specifications of the ASTM Method D-1838.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

3. Visible Emissions

The permittee shall conduct **monthly** (calendar month) VE observations for each equipment subject to opacity limitations by a certified reader in accordance 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

4. The permittee shall maintain a file of all measurements and monitoring data, including the CMS performance evaluations; CMS calibration checks; adjustments and maintenance performed on the monitoring system or devices; and all other information required to be recorded by 40 CFR §60.13 in a permanent form suitable for inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7)<sup>1</sup>

5. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

## **Section E. Notification and Reporting Requirements**

### 1. Excess Emissions

- a. The permittee shall submit an excess emissions and monitoring systems performance report for the acid plant preheater pursuant to 40 CFR §60.7(c) to the Department and the U.S. EPA, Region 9 for **every semi-annual calendar period**. The report shall include the following:
  - i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement, and completion of each time period of excess emissions.
  - ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the acid plant preheater. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted, shall also be reported.
  - iii. The date and time identifying each period during which the CMS was inoperative except for zero (0) and span checks. The nature of each system repair or adjustment shall be described.
  - iv. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the CMS operated properly during the period and was not subject to any repairs or adjustments except zero (0) and span checks.
- b. All reports shall be postmarked by the **thirtieth (30<sup>th</sup>) day following the end of each semi-annual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form shall also be submitted in addition to the excess emissions and monitoring systems performance report.

- c. Excess emissions shall be defined as any rolling three (3) hour period during which the average concentration of H<sub>2</sub>S in RFG, as measured by the CMS, exceeds 230 mg/dscm (162 ppmv).
- d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission and concentration limits for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7, §60.105)<sup>1</sup>

## 2. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Acid Plant Preheater - Operating Hours**, or an equivalent form, shall be used in reporting hours of operation.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

3. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively. These notifications shall include, but not be limited to:
  - a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. The permittee shall report **within five (5) working days any deviations from permit requirements**, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

5. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

6. The permittee shall submit **semi-annually** written reports to the Department 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 exceedances as determined by the required VE 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: Opacity Exceedances** shall be used.

b. 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)<sup>2</sup>

7. **At least thirty (30) days prior** to the following events, the permittee shall notify the Department of Health in writing of conducting a performance specification test on the CMS. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13(c).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.13)<sup>1</sup>

#### **Section F. Testing Requirements**

Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H<sub>2</sub>S levels in the RFG shall be conducted and results reported in accordance with the instructions and test methods set forth in 40 CFR §60.106, and Appendix A, Method 11.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.106)<sup>1</sup>

#### **Section G. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No.28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II(H): SPECIAL CONDITIONS  
COGENERATION PLANT  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:

- a. Three (3) - 46 MMBtu/hr (HHV) Gas Turbines, Solar Centaur 40, Model No. 40-4701, each equipped with a 49 MMBtu/hr (HHV) gas-fired Duct Burner and a Heat Recovery Steam Generator (HRSG). The three (3) cogeneration units are identified as K-6701, K-6702, and K-6703 and each produces about 3 MW.
- b. NO<sub>x</sub> Control
  - i. Gas Turbines - Water Injection; and
  - ii. HRSGs - Low NO<sub>x</sub> Burners.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The Gas Turbines with HRSGs and Duct Burners are subject to the provisions of the following federal regulations:

40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

- a. Subpart A, General Provisions;
- b. Subpart J, Standards of Performance for Petroleum Refineries; and
- c. Subpart GG, Standards of Performance for Stationary Gas Turbines.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.100, §60.330)<sup>1</sup>

2. The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

**Section C. Operational and Emission Limitations**

1. Fuel Usage and Specifications

- a. The three (3) 46 MMBtu/hr gas turbines shall be fired only on RFG with a H<sub>2</sub>S content not to exceed 230 mg/dscm (162 ppmv), or liquid fuel with a sulfur content not to exceed 0.03% by weight.
- b. The three (3) HRSGs shall be fired only on RFG with a H<sub>2</sub>S content not to exceed 230 mg/dscm (162 ppmv).
- c. The fuel consumption of the three (3) 46 MMBtu/hr gas turbines while fired on liquid fuel shall not exceed 171,409 barrels per any rolling twelve (12) month period. The fuel consumption of the three (3) 46 MMBtu/hr gas turbines while fired on RFG shall not exceed 955.5 million cubic feet per any rolling twelve (12) month period. The fuel consumption of the three (3) HRSGs fired on RFG shall not exceed 836.1 million cubic feet per any rolling twelve (3) month period.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.104, §60.333)<sup>1</sup>

2. Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from each of the combined gas turbine and HRSG's exhaust stack emissions in excess of the following emission limits:

**Maximum Emission Limits\*  
 (3-hour average)**

SO <sub>2</sub>	150 ppm by volume at 15% O <sub>2</sub>			
	<i>Turbine fired on RFG (with or without Duct Burner)</i>		<i>Turbine fired on Liquid Fuel (with or without Duct Burner)</i>	
	<u>lbs/hr</u>	<u>ppmvd</u>	<u>lbs/hr</u>	<u>ppmvd</u>
NO <sub>x</sub> (as NO <sub>2</sub> )	14.40	67	14.73	69
CO	4.30	25	9.23	70

\*Based on fifteen (15) percent O<sub>2</sub> and atmospheric conditions of 76 °F, seventy (70) percent relative humidity and 14.7 psia

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-38, §11-60.1-90, §11-60.1-161; 40 CFR §60.332, §60.333)<sup>1</sup>

3. Air Pollution Controls

The permittee shall continuously operate and maintain the following air pollution controls to meet the emission limits as specified in Special Condition No. C.2 of this attachment. The following controls shall be fully operational upon startup, except as noted:

- a. Water injection in each of the gas turbines shall be at a minimum rate of 0.5 pound of water per 1.0 pound of fuel or greater. The water injection system shall be fully operational immediately after the gas turbines are brought up to 1.0 MW load, and shall continue to operate until the gas turbines drop below 1.0 MW load.
- b. Low NO<sub>x</sub> burner system in each of the HRSG units.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161)

4. Visible Emissions

For any six (6) minute averaging period, the combined gas turbine and HRSG's exhaust stacks shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during start-up, shutdown, or equipment breakdown, the exhaust stacks may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

5. Provided that no new applicable requirement is triggered by such action, the permittee may perform complete overhauls of the three (3) 46 MMBtu/hr gas turbines, subject to the written notification to and prior approval of the Department. The permittee must demonstrate that a modification or reconstruction under NSPS or a PSD review would not be triggered. Complete overhauls for each gas turbine shall be performed as necessary based on performance indicators for each unit, or as needed based on consultation with the manufacturer. Each gas turbine shall be serviced one at a time. Overhaul entails the removal of one (1) turbine from service, and the replacement of that gas turbine with an identical unit consisting of the same make and model number as the original permitted unit. Each replacement unit shall comply with all applicable requirements of the original permitted unit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

**Section D. Monitoring and Recordkeeping Requirements**

1. The permittee shall operate and maintain non-resetting fuel meters to record the amount of liquid fuel and RFG fired in the three (3) 46 MMBtu/hr gas turbines and amount of RFG fired in the three (3) HRSGs.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.334)<sup>1</sup>



2. The permittee shall operate and maintain a continuous monitoring system to monitor and record the ratio of water- to-fuel being fired in each of the three (3) 46 MMBtu/hr gas turbines. The water-to-fuel monitor/recorder shall be accurate to  $\pm$  five (5) percent.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.334)<sup>1</sup>

3. The permittee shall operate and maintain a CEMS to measure and record the NO<sub>x</sub> and CO<sub>2</sub> or O<sub>2</sub> concentrations in the flue gas exhausted from each of the combined gas turbine and HRSG's exhaust stack. If a CO<sub>2</sub> CEMS is used, 40 CFR Part 60, Appendix A, Method 20, Equations 20.2 and 20.5 shall be used. The system shall meet EPA performance specifications (40 CFR §60.13 and 40 CFR 60, Appendix B and Appendix F).

A single emissions monitoring system operating sequentially to measure emissions from each of the combined gas turbine and HRSG's stack is acceptable. The monitoring system shall sample the stack gas concentration from a combined gas turbine and HRSG's stack for fifteen (15) minutes, then switch to the next combined turbine and HRSG's stack. When sampling from a combined gas turbine and HRSG that is not in operation, the sampling train shall receive clean air. The data collection system shall determine the hourly emission rate for each combined gas turbine and HRSG's stack using the fifteen (15) minute sample analyzed.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

4. Continuous Monitoring System for H<sub>2</sub>S.

- a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned in the gas turbines with HRSG.
- b. The CMS shall meet the following requirements:
  - i. The span value for the CMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
  - ii. All fuel gas combustion devices, including the gas turbines with HRSGs, having a common source of fuel gas may be monitored at one (1) location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.
  - iii. Performance evaluations for the H<sub>2</sub>S CMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 7, Specifications and Test Procedures for H<sub>2</sub>S CEMS in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11, shall be used in conducting any RATA.
  - iv. Cylinder Gas Audits (CGA) shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2. Since performance specification test procedures are only intended for the initial test of the H<sub>2</sub>S CMS, RATA's need not be performed on an annual basis, unless requested by the Department; or there is a significant change or performance deficiency of the CMS.

- v. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, PS-7)<sup>1</sup>

5. Sulfur Content in the Liquid Fuel

The sulfur content of the liquid fuel to be fired in the gas turbines shall be tested in accordance with the most current ASTM methods. ASTM Method D4294-83 is a suitable alternative to Method D129-64 for determining the sulfur content. The liquid fuel sulfur content shall be verified by having a representative sample of each batch of liquid fuel analyzed for sulfur content by weight at least once per **month**.

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

6. Nitrogen Content in the Fuel

The fuel-bound nitrogen content of the liquid fuel or RFG fuel to be fired in the gas turbines shall be verified by analyzing a representative sample on a **monthly** basis.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §60.334)<sup>1</sup>

7. The Department may at any time require the permittee to install, operate, and maintain a transmissometer system for the continuous measurement and recording of the opacity of stack emissions, if it is determined that the VE are in excess of the applicable standard. The system shall meet EPA monitoring performance standards (40 CFR §60.13 and 40 CFR Part 60, Appendix B, Performance Specifications).

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

8. Visible Emissions

The permittee shall conduct **monthly** (calendar month) VE observations for each equipment subject to opacity limitations by a certified reader in accordance 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

9. The permittee shall maintain a file containing records on the following items for the three (3) 46 MMBtu/hr gas turbines with HRSGs:

- a. Total liquid fuel (barrels) consumed by the three (3) 46 MMBtu/hr gas turbines on a **monthly and rolling twelve (12) month** basis;

- b. Total RFG (million cubic feet) consumed by the three (3) 46 MMBtu/hr gas turbines on a **monthly and rolling twelve (12) month** basis;
- c. Total RFG (million cubic feet) consumed by the three (3) HRSGs on a **monthly and rolling twelve (12) month** basis;
- d. Continuous ratio of water injection rate to fuel being fired in each of the three (3) 46 MMBtu/hr gas turbines with HRSGs;
- e. Sulfur content by weight, nitrogen content and H<sub>2</sub>S content of the liquid fuel and RFG burned in the gas turbines and HRSGs on a **monthly** basis (as applicable).

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.334)<sup>1</sup>

10. The permittee shall maintain a file of all measurements and monitoring data, including the CMS performance evaluations; CMS calibration checks; adjustments and maintenance performed on the monitoring system or devices; and all other information required to be recorded by 40 CFR §60.13 in a permanent form suitable for inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7)<sup>1</sup>

11. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

## **Section E. Notification and Reporting Requirements**

### 1. Excess Emissions

- a. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department and the U.S. EPA, Region 9 for **every semi-annual calendar period**. The report shall include the following:
  - i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.
  - ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the gas turbine/HRSG systems. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measures adopted shall also be reported.
  - iii. The date and time identifying each period during which the CMS was inoperative except for zero (0) and span checks. The nature of each system repair or adjustment shall be described.

- iv. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the CMS operated properly during the period and was not subject to any repairs or adjustments except zero (0) and span checks.
- b. All reports shall be postmarked by the **thirtieth (30<sup>th</sup>) day following the end of each semi-annual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form shall also be submitted in addition to the excess emissions and monitoring systems performance report.
- c. Excess emissions shall be defined as follows:
  - i. Any three (3) hour period during which the average emissions of NO<sub>x</sub>, as measured by the CEMS, exceed the emission limits set forth in Special Condition No. C.2 of this attachment; or
  - ii. Any one (1) hour period during which the average water-to-fuel ratio, as measured by the CMS, falls below the water-to-fuel ratio determined to demonstrate compliance with the emission limits set forth in Special Condition No. C.2 of this attachment, except when the operating unit is monitored by a NO<sub>x</sub> CEMS that concurrently shows compliance with the NO<sub>x</sub> limits set forth in Special Condition No. C.2 of this attachment; or
  - iii. Any rolling three (3) hour period during which the average concentration of H<sub>2</sub>S in RFG, as measured by the CMS, exceeds 230 mg/dscm (162 ppmv); or
  - iv. Any opacity measurements, as measured by the transmissometer system (if required to be installed), exceeding the opacity limits and corresponding averaging times set forth in Special Condition No. C.4 of this attachment.
- d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission limit for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7, §60.105)<sup>1</sup>

## 2. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Fuel Consumption**, or an equivalent form, shall be used in reporting fuel usage.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

3. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively. These notifications shall include, but not be limited to:

- a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
- b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. The permittee shall report **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

#### 5. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

6. The permittee shall submit **semi-annually** written reports to the Department 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 exceedances as determined by the required VE 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: Opacity Exceedances** shall be used in reporting.
  - b. Fuel Consumption on the following:
    - i. Total liquid fuel (barrels) consumed by the three (3) 46 MMBtu/hr gas turbines on a monthly and rolling twelve (12) month basis;
    - ii. Total RFG (million cubic feet) consumed by the three (3) 46 MMBtu/hr gas turbines on a monthly and rolling twelve (12) month basis;
    - iii. Total RFG (million cubic feet) consumed by the three (3) HRSGs on a monthly and rolling twelve (12) month basis.

The enclosed **Monitoring Report Form: Fuel Consumption** shall be used in reporting.

- c. Any fuel analysis conducted by the permittee or permittee's laboratory showing the sulfur content of the fuel.
- d. 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)<sup>2</sup>

7. Gas Turbine Overhaul

- a. The permittee shall submit overhaul notifications to the Department for approval at least **thirty (30) days** or such lesser time as designated and approved by the Department, *prior to turbine overhaul*. The notification shall at a minimum include:
  - i. List of the gas turbines to be overhauled. Identify turbine number, make, model, size, serial number, estimated hours of service, and reason for overhaul;
  - ii. Planned dates each gas turbine will be placed out of service and the replacement unit in service;
  - iii. Listing of the replacement gas turbines for each overhauled unit. Identify make, model, size, and serial number; and
  - iv. Any additional information as requested by the Department.

- b. Within **fifteen (15) days of the complete turbine overhaul**, the permittee shall notify the Department in writing of the actual completion date and any problems incurred during the overhaul.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

8. **At least thirty (30) days prior** to the following events, the permittee shall notify the Department of Health in writing of:
  - a. Conducting a performance specification test on the CEMS. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13(c).
  - b. Conducting a source performance test as required by this Attachment, Section F, Testing Requirements.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.13)<sup>1</sup>

#### **Section F. Testing Requirements**

1. The permittee shall conduct or cause to be conducted performance tests on each of the three (3) gas turbines with HRSGs on or off while the gas turbine is fired on RFG and also liquid fuel. Performance tests shall be conducted for SO<sub>2</sub>, NO<sub>x</sub>, and CO. All performance tests shall be conducted at the maximum expected operating capacity of the gas turbine with HRSG being tested or at other operating loads as may be specified by the Department. Performance tests shall be conducted on an annual basis or at such times as may be specified by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.335)<sup>1</sup>

2. Performance tests for the emissions of SO<sub>2</sub> and NO<sub>x</sub> shall be conducted using EPA Method 1 to 4 and 20, or EPA approved equivalent methods with prior written approval from the Department. Performance tests for the emissions of CO shall be conducted using EPA Methods 1 to 4 and 10, or EPA approved equivalent methods with prior written approval from the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.335)<sup>1</sup>

3. Each source performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

4. The permittee shall provide sampling and testing facilities at its own expense. The tests shall be conducted at the operating capacities identified in Special Condition No. F.1 of this attachment, and the Department may monitor the tests.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

5. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

(Auth.: HAR §11-60.1-11, §11-60.1-90)

6. **At least thirty (30) days prior to performing a test**, the permittee shall submit a written *performance test plan* to the Department and the U.S. EPA, Region 9 that describes the test date(s), test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

7. **Within sixty (60) days after completion of the performance test**, the permittee shall submit to the Department and the U.S. EPA, Region 9 the test report which shall include the operating conditions of each of the three (3) gas turbines in combination with the associated HRSG, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

8. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual source performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous source performance test.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

9. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H<sub>2</sub>S levels in the RFG shall be conducted and results reported in accordance with the instructions and test methods set forth in 40 CFR §60.106 and Appendix A, Method 11.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.106)<sup>1</sup>



**Section G. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II(I): SPECIAL CONDITIONS  
COGENERATION UNIT  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:

One (1) Cogeneration Unit, identified as K-6704, consisting of the following:

- a. One (1) 46 MMBtu/hr (HHV) Combustion Turbine, Solar Centaur 40, Model No. 40-4701; equipped with a 49 MMBtu/hr (HHV) Duct Burner and a HRSG;
- b. For NO<sub>x</sub> control, the combustion turbine is equipped with water injection and low NO<sub>x</sub> burners.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The Combustion Turbine with HRSG and Duct Burner is subject to the provisions of the following federal regulations:

40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS),

- a. Subpart A, General Provisions;
- b. Subpart J, Standards of Performance for Petroleum Refineries; and
- c. Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.100, §60.4305)<sup>1</sup>

2. The Combustion Turbine is subject to the provisions of the following federal regulations:

40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),

- a. Subpart A, General Provisions; and
- b. Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.6085)<sup>1</sup>

3. The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

### **Section C. Operational and Emission Limitations**

1. Allowable Fuels

- a. The combustion turbine shall be fired only on liquid fuel with a sulfur content not to exceed 0.03% by weight or RFG with a H<sub>2</sub>S content not to exceed 230 mg/dscm (162 ppmv);
- b. The HRSG duct burner shall be fired only on RFG with a H<sub>2</sub>S content not to exceed 230 mg/dscm (162 ppmv).

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-38, §11-60.1-90, §11-60.1-161; 40 CFR §60.4330, §60.4365)<sup>1</sup>

2. Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the combustion turbine emissions in excess of the following emission limits while fired on liquid fuel or RFG:

**Maximum Emission Limits**

Pollutant	Combustion Turbine Fired on Liquid Fuel		Combustion Turbine Fired on RFG	
	HRSG Duct Burner on	HRSG Duct Burner off	HRSG Duct Burner on	HRSG Duct Burner off
NO <sub>x</sub> (as NO <sub>2</sub> )	12.79 lb/hr	10.15 lb/hr 60 ppmvd @ 15% O <sub>2</sub>	13.70 lb/hr	11.06 lb/hr 67 ppmvd @ 15% O <sub>2</sub>
CO	11.6 lb/hr 60 ppmvd @ 15% O <sub>2</sub>	11.6 lb/hr 60 ppmvd @ 15% O <sub>2</sub>	7.66 lb/hr	5.02 lb/hr 50 ppmvd @ 15% O <sub>2</sub>
Formaldehyde		91 ppbvd @ 15% O <sub>2</sub>		91 ppbvd @ 15% O <sub>2</sub>

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.4325, §63.6100)<sup>1</sup>

3. Air Pollution Controls

The permittee shall continuously operate and maintain the following air pollution controls to meet the emission limits as specified in Special Condition No. C.2. of this attachment. The following controls shall be fully operational upon startup, except as noted:

- a. Water injection in the combustion turbine shall be at a minimum rate of 0.5 pound of water per 1.0 pound of fuel or greater. The water injection system shall be fully operational immediately after the combustion turbine is brought up to 1.0 MW load, and shall continue to operate until the combustion turbine drops below 1.0 MW load.
- b. Low NO<sub>x</sub> burner system in the combustion turbine.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.4335)<sup>1</sup>

4. Visible Emissions

For any six (6) minute averaging period, the combustion turbine/HRSG shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during start-up, shutdown, or equipment breakdown, the combustion turbine/HRSG may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

5. Provided that no new applicable requirement is triggered by such action, the permittee may perform a complete overhaul of the combustion turbine, subject to the written notification to and prior approval of the Department. The permittee must demonstrate that a modification or reconstruction under NSPS or a PSD review would not be triggered. Complete overhaul for the combustion turbine shall be performed as necessary based on performance indicators for the unit, or as needed based on consultation with the manufacturer. Overhaul entails the removal of the combustion turbine from service, and the replacement of the combustion turbine with an identical unit consisting of the same make and model number as the original permitted unit. Each replacement unit shall comply with all applicable requirements of the original permitted unit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

6. The combustion turbine/HRSG shall be properly maintained and kept in good operating condition at all times. The permittee shall follow a regular maintenance schedule, as recommended by the manufacturer or as needed, to ensure proper operation of the combustion turbine/HRSG.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

#### **Section D. Monitoring and Recordkeeping Requirements**

1. Fuel Consumption Monitoring

The permittee shall operate and maintain non-resetting fuel meters for the continuous measurement and recording of the amount of liquid fuel and RFG fired in the combustion turbine and the amount of RFG fired in the HRSG duct burner. Records shall be kept on an annual basis for the purpose of annual emissions reporting.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-114)

2. Liquid Fuel Sulfur Content Monitoring

The sulfur content of the liquid fuel shall be sampled according to the frequency described in Sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D of 40 CFR Part 75 (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with the liquid fuel already in the intended storage tank).

The sulfur content of the liquid fuel shall be tested in accordance with ASTM Method D129, or alternatively Methods D1266, D1552, D2622, D4294, or D5453. Records of the liquid fuel sulfur content shall be kept.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.4360, §60.4370, §60.4415)<sup>1</sup>

3. Continuous Monitoring System for Water to Fuel Ratio

The permittee shall operate and maintain a CMS to monitor and record the fuel consumption and the ratio of water to fuel being fired in the combustion turbine. The water to fuel monitor/recorder shall be accurate to within  $\pm$  five (5) percent. The CMS shall be used to determine compliance with Special Condition No. C.3.a. of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.4335)<sup>1</sup>

4. Continuous Emissions Monitoring System for NO<sub>x</sub>

The permittee shall operate and maintain a CEMS to measure and record the NO<sub>x</sub> and CO<sub>2</sub> or O<sub>2</sub> concentrations in the flue gas exhausted from the combustion turbine's exhaust stack. If a CO<sub>2</sub> CEMS is used, 40 CFR 60, Appendix A, Method 20, Equations 20.2 and 20.5 shall be used. The system shall meet EPA performance specifications (40 CFR §60.13 and 40 CFR 60, Appendix B and Appendix F).

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.4335)<sup>1</sup>

5. Continuous Monitoring System for H<sub>2</sub>S

a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned in the combustion turbine/HRSG.

b. The CMS shall meet the following requirements:

- i. The span value for the CMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
- ii. All fuel gas combustion devices, including the combustion turbine with duct burner, having a common source of fuel gas may be monitored at one (1) location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.

- iii. Performance evaluations for the H<sub>2</sub>S CMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 7, Specifications and Test Procedures for H<sub>2</sub>S CEMS in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11 shall be used in conducting any RATA.
- iv. Cylinder Gas Audits (CGA) shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2. Since performance specification test procedures are only intended for the initial test of the H<sub>2</sub>S CMS, RATA's need not be performed on an annual basis, unless requested by the Department; or there is a significant change or performance deficiency of the CMS.
- v. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, PS-7)<sup>1</sup>

#### 6. Continuous Opacity Monitoring System (COMS)

The Department may at any time require the permittee to install, operate, and maintain a COMS for the continuous measurement and recording of the opacity of stack emissions, if it is determined that the VE are in excess of the applicable standard. The system shall meet EPA monitoring performance standards (40 CFR §60.13 and 40 CFR Part 60, Appendix B, Performance Specifications).

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

#### 7. Visible Emissions

The permittee shall conduct **monthly** (calendar month) VE observations for each equipment subject to opacity limitations by a certified reader in accordance 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

#### 8. Inspection, Maintenance and Repair Log

An inspection, maintenance and repair log shall be maintained for the combustion turbine/HRSG. Replacement of parts and repairs to the combustion turbine/HRSG shall be documented. At a minimum, the following records shall be maintained:

- a. The date of the inspection/repair;
- b. A description of the findings or any maintenance or repair work performed; and
- c. The name and title of the inspector.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

9. The permittee shall maintain a file of all measurements and monitoring data, including the CMS performance evaluations; CMS calibration checks; adjustments and maintenance performed on the monitoring system or devices; and all other information required to be recorded by 40 CFR §60.13 in a permanent form suitable for inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7)<sup>1</sup>

10. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

## **Section E. Notification and Reporting Requirements**

### 1. Excess Emissions Reporting

- a. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department and the U.S. EPA, Region 9 every **semi-annual calendar period**. The report shall include the following information:
  - i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.
  - ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the combustion turbine/HRSG. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted, shall also be reported.
  - iii. The date and time identifying each period during which the CMS was inoperative except for zero (0) and span checks. The nature of each system repair or adjustment shall be described.



- iv. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the CMS operated properly during the period and was not subject to any repairs or adjustments except zero (0) and span checks.
- b. All reports shall be postmarked by the **thirtieth (30<sup>th</sup>) day following the end of each semi-annual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form or an equivalent form shall also be submitted in addition to the excess emissions and monitoring systems performance report.
- c. Excess emissions shall be defined as follows:
  - i. Any operating period in which the four (4) hour rolling average NO<sub>x</sub> emission rate, as measured by the NO<sub>x</sub> CEMS, exceeds the emission limits set forth in Special Condition No. C.2. of this attachment; or
  - ii. Any operating period in which the four (4) hour rolling average water-to-fuel ratio, as measured by the CMS, falls below the water-to-fuel ratio determined to demonstrate compliance with the emission limits set forth in Special Condition No. C.2. of this attachment, except when the operating unit is monitored by a NO<sub>x</sub> CEMS that concurrently shows compliance with the NO<sub>x</sub> limits set for in Special Condition No. C.2 of this attachment; or
  - iii. Any rolling three (3) hour period during which the average concentration of H<sub>2</sub>S in RFG, as measured by the H<sub>2</sub>S continuous monitoring system, exceeds 230 mg/dscm (162 ppmv); or
  - iv. Any opacity measurements, as measured by the COMS (if required to be installed), exceeding the opacity limits and corresponding averaging times set forth in Special Condition No. C.4. of this attachment.
- d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission limit for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7, §60.105, §60.4380)<sup>1</sup>

## 2. Semi-annual Reporting

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

- a. Any opacity exceedances as determined by the required VE 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 semiannual period. The enclosed **Monitoring Report Form: Opacity Exceedances** or an equivalent form shall be used;
- b. The sulfur content of the liquid fuel. The enclosed **Monitoring Form: Fuel Certification** or an equivalent form shall be used;
- c. 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)<sup>2</sup>

### 3. Annual Emissions Reporting

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Fuel Consumption** or an equivalent form shall be used in reporting fuel usage.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

4. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively. These notifications shall include, but not be limited to:
  - a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - c. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

5. Deviations

The permittee shall report (in writing) **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

6. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

7. Combustion Turbine Overhaul

- a. The permittee shall submit overhaul notifications to the Department for approval at least **thirty (30) days** or such lesser time as designated and approved by the Department, *prior to turbine overhaul*. The notification shall at a minimum include:
  - i. List the combustion turbine to be overhauled. Identify turbine number, make, model, size, serial number, estimated hours of service, and reason for overhaul;
  - ii. Planned dates the combustion turbine will be placed out of service and the replacement unit in service;
  - iii. List the replacement combustion turbine for the overhauled unit. Identify make, model, size, and serial number; and
  - iv. Any additional information as requested by the Department.
- b. Within **fifteen (15) days of the complete turbine overhaul**, the permittee shall notify the Department in writing of the actual completion date, and any problems incurred during the overhaul.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

8. **At least thirty (30) or sixty (60) days (as applicable) prior** to the following events, the permittee shall notify the Department in writing of:

- a. Conducting a performance specification test on the CEMS. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13(c).
- b. Conducting a source performance test as required by this Attachment, Section F, Testing Requirements.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.13)<sup>1</sup>

**Section F. Testing Requirements**

1. **Within sixty (60) days after** achieving the maximum production rate of the combustion turbine, **but not later than 180 days after** initial startup of the combustion turbine and annually thereafter (for NO<sub>x</sub>, no more than fourteen (14) calendar months following the previous performance test), the permittee shall conduct or cause to be conducted performance tests on the combustion turbine while fired on liquid fuel and also RFG. Performance tests shall be conducted for NO<sub>x</sub>, CO, and formaldehyde. All performance tests shall be conducted at the maximum expected operating capacity of the combustion turbine with the HRSG duct burner on and off, or at other operating loads as may be specified by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.8, §60.4400, §63.7, §63.6110, §63.6115, §63.6120)<sup>1</sup>

2. The source performance tests shall be conducted and the results reported in accordance with the tests methods set forth in 40 CFR Part 60, Appendix A, 40 CFR Part 63, Appendix A , 40 CFR §60.8 and 40 CFR §63.7. The following test methods or U.S. EPA approved equivalent methods, or alternative methods with prior written approval from the Department of Health, shall be used:
  - a. Performance tests for the emissions of NO<sub>x</sub> shall be conducted using EPA Method 1 to 4 and 7E or 20;
  - b. Performance tests for the emissions of CO shall be conducted using EPA Methods 1 to 4 and 10; and
  - c. Performance tests for the emissions of formaldehyde shall be conducted using EPA Method 320 or ASTM D6348-03.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174; 40 CFR §60.8, §60.4400, §63.7, §63.6110, §63.6120)<sup>1</sup>

3. Each source performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174; 40 CFR §60.8; §63.7)<sup>1</sup>

4. The permittee shall provide sampling and testing facilities at its own expense. The Department may monitor any of the required source performance tests.

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

5. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

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

6. **At least sixty (60) days prior to performing a test**, the permittee shall submit a written *source performance test plan* to the Department and the U.S. EPA, Region 9 that describes the test date(s), test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A source performance test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174; 40 CFR §60.8; §63.7)<sup>1</sup>

7. **Within sixty (60) days after completion of the source performance test**, the permittee shall submit to the Department and the U.S. EPA, Region 9, the test report which shall include the operating conditions of the combustion turbine/HRSG at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174; 40 CFR §60.8; §63.7)<sup>1</sup>

8. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual source performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous source performance test.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174; 40 CFR §60.8; §63.7)<sup>1</sup>

9. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H<sub>2</sub>S levels in the RFG shall be conducted and results reported in accordance with the instructions and test methods set forth in 40 CFR §60.106, and Appendix A, Method 11.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.106)<sup>1</sup>

### **Section G. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup> The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup> The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II(J): SPECIAL CONDITIONS  
BOILERS  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility:

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:

Two (2) 99 MMBtu/hr boilers, Foster Wheeler, Model No. AG-5060, Serial Nos. 7414, National Board No. 585 and 7415, National Board No. 586, identified as F-5205 and F-5206.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on the boilers which identifies the model number, serial number or I.D. number and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The Boilers are subject to the provisions of the following federal regulations:

- a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS),

- i. Subpart A, General Provisions;
- ii. Subpart J, Standards of Performance for Petroleum Refineries; and
- iii. Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

- b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),

- i. Subpart A, General Provisions; and
- ii. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.1, §60.40c, §60.100, §63.1, §63.7480, §63.7485, §63.7490)<sup>1</sup>

2. The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

### **Section C. Operational and Emissions Limitations**

#### 1. Allowable Fuels

The boilers shall be fired only on liquid fuel with a maximum sulfur content not to exceed 0.5% by weight (thirty (30) day rolling average) or RFG with a H<sub>2</sub>S content not to exceed 230 mg/dscm (162 ppmv). The liquid fuel sulfur limit shall apply at all times, including periods of startup, shutdown, and malfunction. The total combined fuel consumption for the two (2) boilers while fired on liquid fuel shall not exceed 140,685 barrels per any rolling twelve (12) month period.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-38, §11-60.1-90, §11-60.1-161; 40 CFR §60.42c, §60.104)<sup>1</sup>

#### 2. Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the boilers total PM/PM<sub>10</sub> emissions in excess of the limits specified below while fired on liquid fuel or RFG. The total PM/PM<sub>10</sub> limit shall apply at all times, except during periods of startup, shutdown, and malfunction.

Pollutant	Fired on Liquid Fuel	Fired on RFG
Total PM/PM <sub>10</sub>	0.03 lb/MMBtu	0.03 lb/MMBtu

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174, §63.7500(FR 9/13/2004))<sup>1</sup>

#### 3. MACT Subpart DDDDD Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the boilers, CO, filterable PM, HCl, and mercury emissions in excess of the limits specified below while fired on liquid fuel or a combination of liquid fuel and RFG, except during periods of startup and shutdown.



Pollutant	MACT Subpart DDDDD Maximum Emission Limits
CO	130 ppmvd @ 3% O <sub>2</sub>
Filterable PM	0.27 lb/MMBtu
Hydrogen Chloride	1.1E-03 lb/MMBtu
Mercury	2.0E-06 lb/MMBtu

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174, §63.7500(FR 3/21/2011))<sup>1</sup>

4. Visible Emissions

- a. The permittee shall not cause the discharge into the atmosphere emissions from the boilers exhibiting an opacity of twenty (20) percent or greater (six (6) minute average), except for one (1) six (6) minute period per hour of not more than twenty-seven (27) percent opacity. The opacity limit shall apply at all times, except during periods of startup, shutdown, and malfunction.
- b. The permittee shall not cause the discharge into the atmosphere emissions from the boilers exhibiting an opacity of ten (10) percent or greater (one (1) hour block average).

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.43c, §63.7530; SIP §11-60-24)<sup>1,2</sup>

5. The boilers shall be properly maintained and kept in good operating condition at all times. The permittee shall follow a regular maintenance schedule, as recommended by the manufacturer or as needed, to ensure proper operation of the boilers.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

6. Tune-ups

The permittee shall conduct initial tune-ups of the boilers no later than January 31, 2016, and shall conduct tune-ups of the boilers annually to demonstrate continuous compliance. The tune-up shall be conducted while burning the type of fuel (or fuels in the case of units that routinely burn a mixture) that provide the majority of the heat input to the unit over the twelve (12) months prior to the tune-up. Each annual tune-up shall be conducted no more than thirteen (13) months after the previous tune-up. The tune-up shall be conducted as follows:

- a. As applicable, inspect the burner and clean or replace any components of the burner as necessary (the burner inspection may be performed at any time prior to the tune-up or the burner inspection may be delayed until the next scheduled unit shutdown). At units where entry into a piece of process equipment is required to complete the tune-up inspections, inspections are required only during planned entries in the process equipment;

- b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;
- c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the burner inspection may be delayed until the next scheduled unit shutdown);
- d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject;
- e. Measure the concentrations in the effluent stream of CO in parts per million (ppm) by volume and oxygen in volume percent before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer;
- f. Maintain a report on-site containing the following information:
  - i. The concentrations of CO in the effluent stream in ppm by volume and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the unit;
  - ii. A description of any corrective actions taken as part of the tune-up of the unit; and
  - iii. The type and amount of fuel used over the twelve (12) months prior to the tune-up of the unit, but only if the unit was physically and legally capable of using more than one (1) type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.
- g. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within thirty (30) days of startup.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7495, §63.7500, §63.7510, §63.7515, §63.7540)<sup>1</sup>

## 7. Energy Assessment

The permittee shall have a one-time energy assessment performed for the boilers by a qualified energy assessor not later than January 31, 2016. The energy assessment must include the elements listed in 40 CFR Part 63, Subpart DDDDD, Table 3, Item No. 4.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7510)<sup>1</sup>

## **Section D. Monitoring and Recordkeeping Requirements**

### 1. Fuel Consumption

The permittee shall operate and maintain non-resetting fuel meters for the continuous measurement and recording of the amount of liquid fuel and RFG fired in each boiler. Daily, monthly, and annual records of the fuel consumption of each fuel for each boiler shall be maintained. Also, the total liquid fuel consumed by the two (2) boilers on a monthly and rolling twelve (12) month basis shall be recorded and maintained.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114; 40 CFR §60.48c)<sup>1</sup>

### 2. Liquid Fuel Sulfur Content Monitoring

Liquid fuel samples may be collected from the fuel tank for each boiler immediately after the fuel tank is filled and before any liquid fuel is combusted. The permittee shall analyze the liquid fuel sample to determine the sulfur content of the liquid fuel. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of liquid fuel is received shall be used as the daily value when calculating the thirty (30) day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the permittee shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the thirty (30) day rolling average sulfur content to be 0.5 weight percent sulfur or less.

The sulfur content of the liquid fuel shall be tested in accordance with the most current ASTM methods. ASTM Method D4294-03 is a suitable alternative to Method D129-00 for determining the sulfur content.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.46c)<sup>1</sup>

### 3. Liquid Fuel Chlorine and Mercury Monitoring

The permittee shall demonstrate compliance with the mercury or HCl emission limits in Special Condition No. C.3 of this attachment for the boilers based on fuel analysis, and shall conduct a monthly fuel analysis according to 40 CFR §63.7521 and Table 6 of 40 CFR Part 63, Subpart DDDDD for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 of 40 CFR Part 63, Subpart DDDDD. The permittee may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least fourteen (14) calendar days. If the permittee burns a new type of fuel, a fuel analysis shall be conducted before burning the new type of fuel in the boilers. The permittee shall still meet all applicable continuous compliance requirements in 40 CFR §63.7540. If each of twelve (12) consecutive monthly fuel analyses demonstrates seventy-five (75) percent or less of the compliance level, the permittee may decrease the fuel analysis frequency to

quarterly for that fuel. If any quarterly sample exceeds seventy-five (75) percent of the compliance level or the permittee begins burning a new type of fuel, the permittee shall return to monitoring for that fuel, until twelve (12) months of fuel analyses are again less than seventy-five (75) percent of the compliance level. If sampling is conducted on one (1) day per month, samples should be no less than fourteen (14) days apart, but if multiple samples are taken per month, the fourteen (14) day restriction does not apply.

- a. The chlorine content of the liquid fuel for the boilers shall be sampled at least once a month and tested in accordance with the EPA Methods SW-846-9056 or SW-846-9076, or equivalent.
- b. The mercury content of the liquid fuel for the boilers shall be sampled at least once a month and tested in accordance with EPA Methods SW-846-7470A or SW-846-7471B, or equivalent.
- c. The permittee shall submit a fuel analysis plan per 40 CFR §63.7521(b).
- d. The permittee shall keep records per 40 CFR §63.7555(d).

Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7510, §63.7515, §63.7521, §63.7530, §63.7540, §63.7555)<sup>1</sup>

#### 4. Continuous Opacity Monitoring System

- a. The permittee shall calibrate, operate, and maintain COMS for the measurement and recording of the opacity of stack emissions from each boiler.
- b. The systems shall meet the U.S. EPA monitoring performance standards of 40 CFR §60.13 and §63.8, and 40 CFR Part 60, Appendix B, Performance Specification 1. The span value of the COMS shall be between sixty (60) and eighty (80) percent.
- c. All six (6) minute average opacity readings shall be recorded in percent.

Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.13, §60.47c, §63.8, §63.7525)<sup>1</sup>

#### 5. Continuous Monitoring System for H<sub>2</sub>S.

- a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned in the boilers.
- b. The CMS shall meet the following requirements:
  - i. The span value for the CMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
  - ii. All fuel gas combustion devices, including the boilers, having a common source of fuel gas may be monitored at one (1) location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.

- iii. Performance evaluations for the H<sub>2</sub>S CEMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CMS shall meet 40 CFR Part 6, Appendix B, Performance Specification 7, Specifications and Test Procedures for H<sub>2</sub>S CEMS in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11, shall be used in conducting any RATA.
- iv. Cylinder Gas Audits (CGA) shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2. Since performance specification test procedures are only intended for the initial test of the H<sub>2</sub>S CMS, RATA's need not be performed on an annual basis, unless requested by the Department; or there is a significant change or performance deficiency of the CMS.
- v. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, PS-7)<sup>1</sup>

6. Inspection, Maintenance and Repair Log

An inspection, maintenance and repair log shall be maintained for the boilers. Replacement of parts and repairs to the boilers shall be documented. At a minimum, the following records shall be maintained:

- a. The date of the inspection/repair;
- b. A description of the findings or any maintenance or repair work performed; and
- c. The name and title of the inspector.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

7. The permittee shall maintain a file of all measurements and monitoring data, including the CMS performance evaluations; CMS calibration checks; adjustments and maintenance performed on the monitoring system or devices; and all other information required to be recorded by 40 CFR §60.13 in a permanent form suitable for inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7)<sup>1</sup>

8. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

**Section E. Notification and Reporting Requirements**

1. Excess Emissions Reporting

- a. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department and the U.S. EPA, Region 9 every **semi-annual calendar period**. The report shall include the following information:
  - i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions, and corrective actions taken.
  - ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the boiler(s). The nature and cause of any malfunction (if known), and the corrective actions taken or preventative measures adopted, shall also be reported.
  - iii. The date and time identifying each period during which the CMS was inoperative except for zero (0) and span checks. The nature of each system repair or adjustment shall be described.
  - iv. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the CMS operated properly during the period and was not subject to any repairs or adjustments except for zero (0) and span checks.
- b. All reports shall be postmarked by the **thirtieth (30<sup>th</sup>) day following the end of the semi-annual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form or an equivalent form shall also be submitted in addition to the excess emissions and monitoring systems performance report.
- c. Excess emissions shall be defined as follows:
  - i. Any opacity measurements, as measured by the COMS, exceeding the opacity limits and corresponding averaging times set forth in Special Condition No. C.4 of this attachment, or
  - ii. Any rolling three (3) hr period during which the average concentration of H<sub>2</sub>S in RFG, as measured by the CMS, exceeds 230 mg/dscm (162 ppmv).
- d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission limit for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7, §60.48c, §60.105)

## 2. Semi-annual Reporting

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

- a. Liquid fuel sulfur content
  - i. Calendar dates covered in the reporting period;
  - ii. Each thirty (30) day average sulfur content (weight percent), calculated during the reporting period, ending with the last thirty (30) day period, reasons for noncompliance with the emission standards, and a description of corrective actions taken;
  - iii. The enclosed **Monitoring Report Form: Fuel Certification** or an equivalent form shall be used;
- b. Total liquid fuel consumed by the two (2) boilers on a monthly and rolling twelve (12) month basis. The enclosed **Monitoring Report Form: Fuel Consumption** shall be used in reporting.
- c. Any deviations from permit requirements shall be clearly identified.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-32, §11-60.1-90, §11-60.1-161;  
40 CFR §60.48c)<sup>1</sup>

## 3. Annual Emissions Reporting

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Fuel Consumption** or an equivalent form shall be used in reporting fuel usage.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

4. Notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 17 and 24, respectively. These notifications shall include, but not be limited to:

- a. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- b. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; §11-60.1-161; 40 CFR §60.48c)<sup>1</sup>

## 5. Deviations

The permittee shall report (in writing) **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

## 6. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.



- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

7. **At least thirty (30) or sixty (60) days (as applicable) prior** to the following events, the permittee shall notify the Department in writing of:

- a. Conducting a performance specification test on the CEMS. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13(c).
- b. Conducting a source performance test as required by this Attachment, Section F, Testing Requirements.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.13)<sup>1</sup>

#### **Section F. Testing Requirements**

1. **Within sixty (60) days** after achieving the maximum production rate of the boilers **but not later than 180 days after** the initial start-up of the boilers and annually thereafter, the permittee shall conduct or cause to be conducted performance tests on the boilers. Performance tests shall be conducted the maximum expected operating capacity of the boilers, or at other operating loads as may be specified by the Department. The performance tests shall be conducted for total PM/PM<sub>10</sub>, filterable PM, and CO while fired on liquid fuel, or a combination of liquid fuel and RFG. Annual performance tests shall be completed no more than thirteen (13) months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of 40 CFR §63.7515, which includes the following:
  - a. If the performance test for a given pollutant (filterable PM and CO) for at least two (2) consecutive years show that the emissions are at or below seventy-five (75) percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 of 40 CFR Part 63, Subpart DDDDD, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the boilers or air pollution control equipment that could increase emissions, the permittee may choose to conduct performance tests for the pollutant every third year. Each such performance test shall be conducted no more than thirty-seven (37) months after the previous performance test.
  - b. If a performance test shows emissions exceeded the emission limit or seventy-five (75) percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 of 40 CFR Part 63, Subpart DDDDD) for a pollutant (filterable PM and CO), the permittee shall conduct annual performance test for that pollutant until all performance tests over a consecutive two (2) year period meet the required level (at or below seventy-five (75) percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 of 40 CFR Part 63, Subpart DDDDD).

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7, §63.7510, §63.7515, §63.7530)<sup>1</sup>

2. Source performance tests shall be conducted in accordance with the test methods set forth below or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department:
  - a. Method 1, Appendix A of 40 CFR Part 60, for sample and velocity traverse;
  - b. Method 2, Appendix A of 40 CFR Part 60, for velocity and volumetric flow rate;
  - c. Method 3, Appendix A of 40 CFR Part 60, for gas analysis;
  - d. Method 4, Appendix A of 40 CFR Part 60, for moisture content;
  - e. Method 5 or 17, Appendix A of 40 CFR Part 60, for concentration of total PM/PM<sub>10</sub> and filterable PM;
  - f. Method 7, Appendix A of 40 CFR Part 60, for concentration of nitrogen oxides (as NO<sub>2</sub>);
  - g. Method 10, Appendix A of 40 CFR Part 60, for concentration of carbon monoxides; and
  - h. Method 19, Appendix A of 40 CFR Part 60, for F-factor methodology to convert emission concentration to lb/MMBtu.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7, §63.7510, §63.7515, §63.7520, §63.7530)<sup>1</sup>

3. Note that Method 1 cannot be used under the following conditions:
  - a. Cyclonic or swirling gas flow at the sampling location;
  - b. Stack or duct with a diameter less than twelve (12) inches or a cross-sectional area less than 113 square inches; or
  - c. Sampling location less than two (2) stack or duct diameters downstream or less than a half diameter upstream from a flow disturbance.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

4. Particulate emissions shall be reported in two (2) categories:
  - a. Front half (filter and probe); and
  - b. Front and back half (probe, filter and impingers).

(Auth.: HAR §11-60.1-3, §11-60.1-90)

5. For each run, the emission rate of PM shall be determined by the equation pounds/hour = Qs x cs, where Qs = volumetric flow rate of the total effluent in dscf/hour as determined in accordance with Method 2, and cs = concentration of particulate matter in pounds/dscf as determined in accordance with Method 5.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

6. Each source performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with the applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174;  
40 CFR §60.8, §63.7)<sup>1</sup>

7. The permittee shall provide sampling and testing facilities at its own expense. The Department may monitor any of the required source performance tests.

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

8. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

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

9. **At least sixty (60) days prior to performing a test**, the permittee shall submit a written source performance test plan to the Department and the U.S. EPA, Region 9 that describes the test date(s), test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A source performance test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174;  
40 CFR §60.8, §63.7)<sup>1</sup>

10. **Within sixty (60) days after completion of the source performance test**, the permittee shall submit to the Department and the U.S. EPA, Region 9, the test report which shall include the operating conditions of the boilers at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174;  
40 CFR §60.8, §63.7)<sup>1</sup>

11. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual source performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Written waiver requests are not required for the source performance testing of pollutants subject to 40 CFR Part 63, Subpart DDDDD (filterable PM and CO) that qualify for the exemption pursuant to Special Condition No. F.1.a of this attachment. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous source performance test.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.8, §63.7)<sup>1</sup>

12. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H<sub>2</sub>S levels in the RFG shall be conducted and results reported in accordance with the instructions and test methods set forth in 40 CFR §60.106, and Appendix A, Method 11.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.106)<sup>1</sup>

### **Section G. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II(K): SPECIAL CONDITIONS  
BLACK START DIESEL ENGINE GENERATOR AND DIESEL ENGINE PUMPS  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the Standard Conditions of the CSP, the following emissions unit(s) is subject to the Special Conditions listed below:

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and related appurtenances:
  - a. One (1) 350 kW (755 HP) Cummins Power Generation Black Start Diesel Engine Generator (DEG), Model No. DFEG, (Tier 2 rated);
  - b. Three (3) diesel engine pumps consisting of the following:
    - i. One (1) Sand Filter Pump No. 1, Tier 3 or higher rated, not to exceed 175 HP, Pump Serial No. 18647355/02, Engine Serial No. Isuzu 680026;
    - ii. One (1) Sand Filter Pump No. 2, Tier 3 or higher rated, not to exceed 175 HP, Pump Serial No. 18646439-02, Engine Serial No. Isuzu 675388; and
    - iii. One (1) Transfer Pump, Tier 3 or higher rated, not to exceed 175 HP, Serial No. PE4024R039307.

(Auth.: HAR §11-60.1-3)

2. An identification tag or name plate shall be displayed on the equipment to show model no., serial no., and manufacturer. The identification tag or name plate shall be permanently attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The one (1) black start DEG and three (3) diesel engine pumps are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):
    - i. Subpart A, General Provisions; and
    - ii. Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines;
  - b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT):
    - i. Subpart A, General Provisions; and

- ii. Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.
2. The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.4200, §63.1, §63.6585)<sup>1</sup>

### **Section C. Emission and Operational Limitations, and/or Standards**

1. The black start DEG shall meet the definition of an Emergency Stationary RICE as described in 40 CFR §60.4219 and 40 CFR §63.6675, and black start engine as described in 40 CFR §63.6675. The Black Start DEG shall comply with the requirements specified in 40 CFR §60.4211(f) and 40 CFR §63.6640(f) with the following exceptions:
  - a. The total hours of operation (emergency operation, maintenance checks, and readiness testing) of the black start DEG shall not exceed 500 hours in any rolling twelve (12) month period;
  - b. The black start DEG may be operated for up to one hundred (100) hours per calendar year for maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine; and
  - c. The black start DEG shall not operate or is not contractually obligated to be available for up to fifteen (15) hours per calendar year for the purposes specified in 40 CFR §63.6640(f)(2)(ii) and (iii).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.4211, §63.6590, §63.6600, §63.6640)<sup>1</sup>

#### 2. Fuel Limits

The one (1) black start DEG and three (3) diesel engine pumps shall be fired only on diesel No. 2 with a maximum sulfur content of 0.0015% by weight, and a minimum cetane index of forty (40) or a maximum aromatic content of thirty five (35) volume percent.

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §60.4207, §63.6590)<sup>1</sup>

3. For any six (6) minute averaging period, the one (1) black start DEG and three (3) diesel engine pumps shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during start-up, shut-down, or equipment breakdown, the DEG and three (3) diesel engine pumps may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

4. The one (1) black start DEG and three (3) diesel engine pumps shall be properly maintained and kept in good operating condition at all times with scheduled inspections and maintenance as recommended by the manufacturer; or as needed.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

#### **Section D. Monitoring and Recordkeeping Requirements**

##### 1. Hours of Operation

- a. The permittee shall operate and maintain a non-resetting hour meter on the black start DEG for the continuous and permanent recording of the total hours of operation of the black start DEG for the purpose of showing compliance with Special Condition No. C.1 of this attachment.
- b. The non-resetting meter shall not allow the manual resetting or other manual adjustments of the meter readings. The installation of any new non-resetting meter or the replacement of any existing non-resetting meter shall be designed to accommodate a minimum of five (5) years of equipment operation, considering any operational limitations, before the meter returns to a zero (0) reading.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; 40 CFR §60.4209)<sup>1</sup>

##### 2. The permittee shall maintain records on the following items:

- a. The total hours of operation of the black start DEG on a monthly and rolling twelve (12) month basis to demonstrate compliance with Special Condition No. C.1.a of this attachment. Records of the hours of operation of the black start DEG should include the reason the black start DEG was in operation during that time. Monthly records shall include:
  - i. Date of meter reading;
  - ii. Meter reading at the beginning of each month;
  - iii. Total hours of operation for each month;
  - iv. Total hours of operation on a rolling twelve (12) month basis;
  - v. Total hours of operation associated with maintenance checks and readiness testing to demonstrate compliance with Special Condition No. C.1.b of this attachment; and

- vi. Total hours of operation associated with the purposes specified in 40 CFR §63.6640(f)(2)(ii) and (iii) to demonstrate compliance with Special Condition No. C.1.c of this attachment.
- b. Fuel delivery receipts showing the fuel type, sulfur content (percent by weight), cetane index or aromatic content (volume percent), date of delivery, and gallons of fuel delivered to the site for use in the one (1) black start DEG and three (3) diesel engine pumps shall be maintained. The fuel sulfur content, cetane index, and aromatic content may be demonstrated by providing the supplier's fuel specification sheet for the type of fuel purchased and received. As an alternative, the fuel usage may be determined through engineering calculations or use of a non-resetting hour meter and the fuel sulfur content, cetane index, and aromatic content may be determined through laboratory testing, including the refinery's on-site laboratory.
- c. Records on inspections, maintenance, and any repair work conducted on the one (1) black start DEG and three (3) diesel engine pumps. At a minimum, these records shall include: the date of the inspection/work, name and title of personnel performing inspection/work, a short description of the action and/or any such repair work, and a description of the part(s) inspected or repaired.
- d. Records of the serial numbers, dates of operation, and appropriate EPA certification specifying the Tier rating for each diesel engine pump identified in Special Condition No. A.1.b. of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §60.4211, §60.4214, §63.6655)<sup>1</sup>

### 3. Visible Emissions

The permittee shall conduct **monthly** (calendar month) VE observations for each equipment subject to opacity limitations by a certified reader in accordance 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

- 4. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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



**Section E. Notification and Reporting Requirements**

1. Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Conditions Nos. 14, 17, and 24, respectively:
  - a. Anticipated date of initial start-up, actual date of construction commencement, and actual date of start-up;
  - b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

2. The permittee shall report within **five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. Monitoring Reports

The permittee shall submit **semi-annually** the following written report to the Department for monitoring purposes. The report 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. The total operating hours of the black start DEG on a monthly and rolling twelve (12) month basis. The enclosed **Monitoring Report Form: Black Start Diesel Engine Generator Hours of Operation**, shall be used for reporting;
- b. The type of fuel fired, maximum sulfur content (percent by weight), minimum cetane index and maximum aromatic content (volume percent). The enclosed **Monitoring Report Form: Fuel Certification**, shall be used for reporting; and
- c. Any opacity exceedances as determined by the required VE 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 are 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: Opacity Exceedances**, shall be used.
- d. Any deviations from permit requirements shall be clearly identified.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

#### 4. Annual Emissions Reports

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit on an **annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days after the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment – Fuel Consumption**, shall be used in reporting.

Upon the written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-114)

#### 5. Compliance Certification Form

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

6. The permittee shall submit the serial numbers of the one (1) black start DEG and three (3) diesel engine pumps to the Department within **five (5) working days** after initial startup of the one (1) black start DEG and after any replacement of the three (3) diesel engine pumps.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

#### **Section F. Agency Notification**

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II(L): SPECIAL CONDITIONS  
FOUL WATER TREATMENT PLANT AND CATALYTIC OXIDATION UNIT  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:
  - a. One (1) Foul Water Treatment Plant; and
  - b. One (1) Catalytic Oxidation Unit (includes a Selective Catalytic Reduction (SCR) catalyst for NO<sub>x</sub> control), non-fired, electrically heated.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The Catalytic Oxidation Unit is subject to the provisions of the following federal regulations:

40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

- a. Subpart A, General Provisions;
- b. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007; and
- c. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.100a, §60.690)<sup>1</sup>

2. The Foul Water Treatment Plant and Catalytic Oxidation Unit is subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP):
    - i. Subpart A, General Provisions; and
    - ii. Subpart FF, National Emission Standards for Benzene Waste Operations.
  - b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT):
    - i. Subpart A, General Provisions; and
    - ii. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174, §11-60.1-180; 40 CFR §61.01, §61.340, §63.1, §63.640)<sup>1</sup>

### **Section C. Operational and Emission Limitations**

#### 1. Foul Water Treatment Plant

The permittee shall maintain the pH of the Foul Water Treatment Plant effluent water greater than or equal to nine (9) and the temperature of the Foul Water Treatment Plant effluent water between 210 °F and 250 °F. The permittee shall also maintain the H<sub>2</sub>S concentration of the Foul Water Treatment Plant offgas less than five (5) ppm.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

#### 2. Catalytic Oxidation Unit - Offgas

- a. The offgas from the Foul Water Treatment Plant shall be routed to the Catalytic Oxidation Unit at all times, or to one of the boilers (F-5205 or F-5206) except during periods of malfunction or maintenance/repair, in which the foul water shall be stored in permitted storage tanks or the offgas shall be routed to either the F-2301 or F-2302 Flare.
- b. The permittee shall not oxidize in the Catalytic Oxidation Unit any offgas from the Foul Water Treatment Plant that contains H<sub>2</sub>S in excess of 162 ppmv determined hourly on a three (3) hour rolling average basis and H<sub>2</sub>S in excess of sixty (60) ppmv determined daily on a 365 successive calendar day rolling average basis.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.102a(g)(1)(ii))<sup>1</sup>

3. Catalytic Oxidation Unit – Visible Emissions

For any six (6) minute averaging period, the Catalytic Oxidation Unit shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during start-up, shut-down, or equipment breakdown, the Catalytic Oxidation Unit may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

4. Catalytic Oxidation Unit – Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the Catalytic Oxidation Unit emissions in excess of the following emission limits:

Pollutant	Emission Limits (lb/hr) <sup>1</sup>
NO <sub>x</sub>	7.0
CO	7.4
VOC, Non-Methane (reported as Carbon MW=12)	0.63

<sup>1</sup>Based on a three (3) hour average

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

5. Catalytic Oxidation Unit – Standards

The Catalytic Oxidation Unit shall be designed and operated in accordance with the design standards set forth 40 CFR §61.349(a)(2).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.340)<sup>1</sup>

**Section D. Monitoring and Recordkeeping Requirements**

1. Foul Water Treatment Plant Monitoring and Recordkeeping

The permittee shall monitor the Foul Water Treatment Plant effluent water for pH and temperature on a daily basis. The permittee shall also monitor the Foul Water Treatment Plant offgas for H<sub>2</sub>S concentration using colorimetric indicator tubes at least twice per year and when the pH drops below nine (9). Records shall be kept of the effluent water pH and temperature and of the offgas H<sub>2</sub>S concentration.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

2. Catalytic Oxidation Unit – H<sub>2</sub>S Monitoring

- a. The permittee shall operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H<sub>2</sub>S in the offgas from the Foul Water Treatment Plant before being oxidized in the Catalytic Oxidation Unit.
- b. The permittee has applied for and has been granted an exemption from the H<sub>2</sub>S monitoring requirements described above for a fuel gas stream that is inherently low in sulfur content. Pursuant to 40 CFR §60.100a(b), a fuel gas stream that is demonstrated to be low-sulfur is exempt from the H<sub>2</sub>S monitoring requirements described above until there are changes in operating conditions or stream composition.
  - i. The permittee submitted to the Department and U.S. EPA, Region 9, a written application for an exemption from monitoring. The application contained the following information:
    - (1) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;
    - (2) A statement that there are no crossover or entry points for sour gas (high H<sub>2</sub>S content) to be introduced into the fuel gas stream/system;
    - (3) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;
    - (4) The supporting test results from sampling the fuel gas stream/system demonstrating that the sulfur content is less than five (5) ppm H<sub>2</sub>S; and
    - (5) A description of how the two (2) weeks of monitoring results compares to the typical range of H<sub>2</sub>S concentration expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare.
  - ii. The effective date of the exemption is the date of submission of the information required above (November 9, 2015).
  - iii. No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the permittee shall follow the procedures in 40 CFR §60.107a(b)(3).
- c. The permittee shall keep records of the specific exemption determined to apply for each fuel stream that is exempted. The permittee shall keep a copy of the application as well as the letter from the Department and U.S. EPA, Region 9, granting approval of the application.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.107a(a)(2), §60.107a(b), §60.108a(c))<sup>1</sup>

3. Catalytic Oxidation Unit - Visible Emissions

The permittee shall conduct **monthly** (calendar month) VE observations for the Catalytic Oxidation Unit by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

4. Catalytic Oxidation Unit – Continuous Process Monitoring System for NO<sub>x</sub> and NH<sub>3</sub>

- a. The permittee shall operate, calibrate, and maintain a continuous process monitoring system including one (1) NO<sub>x</sub> analyzer and one (1) ammonia (NH<sub>3</sub>) analyzer, for continuously monitoring and recording the NO<sub>x</sub> and NH<sub>3</sub> concentrations downstream of the Catalytic Oxidation Unit. The continuous process monitoring system must be in continuous operation whenever the Catalytic Oxidation Unit is in operation. The NH<sub>3</sub> concentration downstream of the Catalytic Oxidation Unit will be used to determine the CO and VOC concentrations downstream of the Catalytic Oxidation Unit using correlation factors for CO and VOC that are to be established during the source performance test specified in Special Condition No. F.3 of this attachment.
- b. As an alternative to establishing and using correlation to monitor and limit VOC emissions, the permittee may install, calibrate, maintain, and operate according to the manufacturer's specifications a device to continuously monitor the control device operation as specified 40 CFR §61.354(c), unless alternative monitoring procedures or requirements are approved for that facility by the Department.
  - i. For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two (2) locations, and have an accuracy of ± one (1) percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.
  - ii. An alternative operation or process parameter may be monitored in accordance with 40 CFR §61.354(e) if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.



- c. For each control device the permittee shall record the following:
- i. If a catalytic vapor incinerator is used, then the permittee shall maintain continuous records of the temperature of the gas stream both upstream and downstream of the catalyst bed of the incinerator, records of all three (3) hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 °C (50 °F) below the design gas stream temperature, and records of all three (3) hour periods of operation during which the average temperature difference across the catalyst bed is less than eighty (80) percent of the design temperature difference.
  - ii. If a boiler or process heater is used, then the permittee shall maintain records of each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone as required by 40 CFR §61.349(a)(2)(i)(C). For a boiler or process heater having a design heat input capacity less than 44 MW (150 × 10<sup>6</sup> Btu/hr), the permittee shall maintain continuous records of the temperature of the gas stream in the combustion zone of the boiler or process heater and records of all three (3) hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature. For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150 × 10<sup>6</sup> Btu/hr), the permittee shall maintain continuous records of the parameter(s) monitored in accordance with the requirements of 40 CFR §61.354(c)(5).

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §61.354, §61.356)<sup>1</sup>

5. The permittee shall maintain a file of all measurements and monitoring data, including the CMS performance evaluations; CMS calibration checks; adjustments and maintenance performed on the monitoring system or devices; and all other information required to be recorded by 40 CFR §60.13 in a permanent form suitable for inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7)<sup>1</sup>

6. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

**Section E. Notification and Reporting Requirements**

1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including HAP. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate** or equivalent form, shall be used in reporting fugitive emissions.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively. These notifications shall include, but not be limited to:

- a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
- b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report **within five (5) working days any deviations from permit requirements**, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan. The unplanned shutdown or bypass of a boiler while serving as a control device or of the Catalytic Oxidation Unit, shall trigger deviation reporting under the provisions of this paragraph if the Foul Water Treatment Plant is operating.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

- i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
  - c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

#### 5. Catalytic Oxidation Unit - Monitoring Reports

- a. The permittee shall submit **semi-annually** the following written report to the Department for monitoring purposes. The report 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:
  - i. Any opacity exceedances as determined by the required VE 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 are 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: Opacity Exceedances** shall be used.
  - ii. Any deviations from permit requirements shall be clearly identified.
- b. The permittee shall submit **quarterly** a written report to the Department for a control device monitored in accordance with 40 CFR §61.354(c), each period of operation monitored during which any of the following conditions occur, as applicable to the control device:

- i. Each three (3) hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design gas stream temperature, and any three (3) hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as measured by the temperature monitoring device, is less than eighty (80) percent of the design temperature difference.
- ii. Each three (3) hour period of operation during which the average temperature of the gas stream in the combustion zone of a boiler or process heater having a design heat input capacity less than 44 MW ( $150 \times 10^6$  Btu/hr), as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; 40 CFR §61.357)<sup>1</sup>

6. **At least thirty (30) days prior** to the following events, the permittee shall notify the Department of Health in writing of:
  - a. Conducting a performance specification test on the CEMS. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13(c).
  - b. Conducting a source performance test as required by this Attachment, Section F, Testing Requirements.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.13)<sup>1</sup>

#### **Section F. Testing Requirements**

1. **Within sixty (60) days after** achieving the maximum production rate of the Catalytic Oxidation Unit, **but not later than 180 days after** initial startup of the Catalytic Oxidation Unit, the permittee shall conduct or cause to be conducted performance tests on the offgas from the Foul Water Treatment Plant to determine compliance with the hourly H<sub>2</sub>S limit in Special Condition No. C.2.b of this attachment. This initial performance test must be repeated in accordance with the provisions of 40 CFR §60.104a if there is an alteration made that could change the H<sub>2</sub>S content of the Foul Water Treatment Plant offgas.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.104a)<sup>1</sup>

2. The performance tests shall be conducted and the results reported in accordance with the test method set forth in 40 CFR Part 60, Appendix A-5, and 40 CFR §60.8. Performance tests for the emissions of H<sub>2</sub>S shall be conducted using EPA Method 11 or U.S. EPA approved equivalent methods or alternative methods with prior written approval from the Department.

For Method 11, the sampling time and sample volume must be at least ten (10) minutes and 0.010 dscm (0.35 dscf). Two (2) samples of equal sampling time must be taken at about one (1) hour intervals. The arithmetic average of these two (2) samples constitutes a run. For most fuel gases, sampling times exceeding twenty (20) minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H<sub>2</sub>S may necessitate sampling for longer periods of time.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.104a(j))<sup>1</sup>

3. **Within sixty (60) days after** achieving the maximum production rate of the Catalytic Oxidation Unit, **but not later than 180 days after** initial startup of the Catalytic Oxidation Unit and annually thereafter, the permittee shall conduct or cause to be conducted performance tests for NO<sub>x</sub>, CO, and VOC on the Catalytic Oxidation Unit outlet stack.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

4. Performance tests for the emissions of NO<sub>x</sub>, CO, and VOC shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A. The following test methods or U.S. EPA approved equivalent methods or alternative methods with prior written approval from the Department shall be used:
  - a. Performance tests for the emissions of NO<sub>x</sub> shall be conducted using 40 CFR Part 60, Methods 1-4 and 7.
  - b. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60, Methods 1-4 and 10.
  - c. Performance tests for the emissions of VOC (non-methane) shall be conducted using 40 CFR Part 60, Methods 1-4 and 18 or 25.

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

5. Each performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

6. The permittee shall provide sampling and testing facilities at its own expense. The Department may monitor any of the required performance tests.

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

7. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

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

8. **At least thirty (30) days prior to performing a test**, the permittee shall submit a written *performance test plan* to the Department and the U.S. EPA, Region 9, that describes the test date(s), test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A performance test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

9. **Within sixty (60) days after completion of the performance test**, the permittee shall submit to the Department and the U.S. EPA, Region 9, the test report which shall include the analysis of the offgas from the Foul Water Treatment Plant, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data. A similar test report for the performance tests on the Catalytic Oxidation Unit outlet stack shall also be submitted.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

10. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous performance test.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §60.8)<sup>1</sup>

### **Section G. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II - INSIG: SPECIAL CONDITIONS  
INSIGNIFICANT ACTIVITIES  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility:

**Section A. Equipment Description**

This attachment encompasses insignificant activities listed in HAR, §11-60.1-82(f) and (g) for which provisions of this permit and HAR, Subchapter 2, General Prohibitions apply.

(Auth.: HAR §11-60.1-3)

**Section B. Operational Limitations**

1. The permittee shall take measures to operate applicable insignificant activities in accordance with the provisions of HAR, Subchapter 2 for VE, fugitive dust, incineration, process industries, sulfur oxides from fuel combustion, storage of VOC, VOC water separation, pump and compressor requirements, and waste gas disposal.

(Auth.: HAR §11-60.1-3, §11-60.1-82, §11-60.1-90)

2. The Department may at any time require the permittee to further abate emissions if an inspection indicates poor or insufficient controls.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-82, §11-60.1-90)

**Section C. Monitoring and Recordkeeping Requirements**

1. The Department reserves the right to require monitoring, recordkeeping, or testing of any insignificant activity to determine compliance with the applicable requirements.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

2. All records, including supporting information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Supporting information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

#### **Section D. Notification and Reporting**

##### Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

1. The identification of each term or condition of the permit that is the basis of the certification;
2. The compliance status;
3. Whether compliance was continuous or intermittent;
4. The methods used for determining the compliance status of the source currently and over the reporting period;
5. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
6. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedances as defined in 40 CFR Part 64 occurred; and
7. Any additional information as required by the Department including information to determine compliance.

The compliance certification shall be submitted **within sixty (60) days** after the end of each calendar year, and shall be signed and dated by a responsible official.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

In lieu of addressing each emission unit as specified in **Compliance Certification Form**, the permittee may address insignificant activities as a single unit provided compliance is met with all applicable requirements. If compliance is not totally attained, the permittee shall identify the specific insignificant activity and provide the details associated with the noncompliance.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

#### **Section E. Agency Notification**

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)



**ATTACHMENT III: ANNUAL FEE REQUIREMENTS  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

The following requirements for the submittal of annual fees are established pursuant to HAR, Title 11, Chapter 60.1, Air Pollution Control. Should HAR, Chapter 60.1, be revised such that the following requirements are in conflict with the provisions of HAR, Chapter 60.1, the permittee shall comply with the provisions of HAR, Chapter 60.1.

1. Annual fees shall be paid in full:
  - a. Within **one-hundred twenty (120) days** after the end of each calendar year; and
  - b. Within **thirty (30) days** after the permanent discontinuance of the covered source.
2. The annual fees shall be determined and submitted in accordance with HAR, Chapter 11-60.1, Subchapter 6.
3. The annual emissions data for which the annual fees are based shall accompany the submittal of any annual fees and be submitted on forms furnished by the Department.
4. The annual fees and the emission data shall be mailed to:

**State of Hawaii  
Clean Air Branch  
2827 Waimano Home Road #130  
Pearl City, HI 96782**

**ATTACHMENT IV: ANNUAL EMISSIONS REPORTING REQUIREMENTS  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department the nature and amounts of emissions.

1. Complete the attached forms:

**Annual Emissions Report Form: Refinery Equipment - Fuel Consumption;  
Annual Emissions Report Form: Refinery Equipment - Process Rate; and  
Annual Emissions Report Form: Acid Plant Preheater - Operating Hours.**

2. The reporting period shall be from January 1 to December 31 of each year. All reports shall be submitted to the Department within **sixty (60) days** after the end of each calendar year and shall be mailed to the following address:

**State of Hawaii  
Clean Air Branch  
2827 Waimano Home Road #130  
Pearl City, HI 96782**

3. The permittee shall retain the information submitted, including all emission calculations. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department upon request.
4. Any information submitted to the Department without a request for confidentiality shall be considered public record.
5. In accordance with HAR, Section 11-60.1-14, the permittee may request confidential treatment of specific information, including information concerning secret processes or methods of manufacture, by submitting a written request to the Director and clearly identifying the specific information that is to be accorded confidential treatment.

**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-01-C  
(PAGE 1 OF \_\_\_)**

**Issuance Date: DATE**

**Expiration Date: DATE**

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following certification at least annually, or more frequently, as requested by the Department of Health.

(Make Copies of the Compliance Certification Form for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Company/Facility Name: \_\_\_\_\_

Responsible Official (Print): \_\_\_\_\_

Title: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

**I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.**

**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-01-C  
(CONTINUED, PAGE 2 OF \_\_\_)**

**Issuance Date: DATE**

**Expiration Date: DATE**

The purpose of this form is to evaluate whether or not the facility was in compliance with the permit terms and conditions during the covered period. If there were any deviations to the permit terms and conditions during the covered period, the deviation(s) shall be certified as *intermittent compliance* for the particular permit term(s) or condition(s). Deviations include failure to monitor, record, report, or collect the minimum data required by the permit to show compliance. In the absence of any deviation, the particular permit term(s) or condition(s) may be certified as *continuous compliance*.

**Instructions:**

Please certify Sections A, B, and C below for continuous or intermittent compliance. Sections A and B are to be certified as a group of permit conditions. Section C shall be certified individually for each operational and emissions limit condition as listed in the Special Conditions section of the permit (list all applicable equipment for each condition). Any deviations shall also be listed individually and described in Section D. The facility may substitute its own generated form in verbatim for Sections C and D.

**A. Attachment I: Standard Conditions**

<u>Permit Term/Condition</u> All standard conditions	<u>Equipment</u> All Equipment listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
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**B. Special Conditions - Monitoring, Recordkeeping, Reporting, Testing, and INSIG**

<u>Permit Term/Condition</u> All monitoring conditions	<u>Equipment</u> All Equipment listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
<u>Permit Term/Condition</u> All recordkeeping conditions	<u>Equipment</u> All Equipment listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
<u>Permit Term/Condition</u> All reporting conditions	<u>Equipment</u> All Equipment listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
<u>Permit Term/Condition</u> All testing conditions	<u>Equipment</u> All Equipment listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
<u>Permit erm/condition</u> All INSIG conditions	<u>Equipment</u> All Equipment listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent

**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-01-C  
(CONTINUED, PAGE \_\_\_\_ OF \_\_\_\_)**

**Issuance Date: DATE**

**Expiration Date: DATE**

**C. Special Conditions - Operational and Emissions Limitations**

Each permit term/condition shall be identified in chronological order using attachment and section numbers (e.g., Attachment II, B.1, Attachment IIA, Special Condition No. B.1.f, etc.). Each equipment shall be identified using the description stated in Section A of the Special Conditions (e.g., unit no., model no., serial no., etc.). Check all methods (as required by permit) used to determine the compliance status of the respective permit term/condition.

<u>Permit Term/Condition</u>	<u>Equipment</u>	<u>Method</u>	<u>Compliance</u>
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent

**(Make Additional Copies if Needed)**

**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-01-C  
(CONTINUED, PAGE \_\_\_ OF \_\_\_)**

**Issuance Date: DATE**

**Expiration Date: DATE**

**D. Deviations**

<u>Permit Term/Condition</u>	<u>Equipment / Brief Summary of Deviation*</u>	<u>Deviation Period time (am/pm) &amp; date (mo/day/yr)</u>	<u>Date of Written Deviation Report to DOH (mo/day/yr)</u>
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	

\*Identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred.

**(Make Additional Copies if Needed)**



**ANNUAL EMISSIONS REPORT FORM  
REFINERY EQUIPMENT - PROCESS RATE  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as Horsepower, kilowatt, tons/hour, Btu/hr, etc.)

Serial/ID No.: \_\_\_\_\_

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

Responsible Official (PRINT): \_\_\_\_\_

Title: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

EMISSION SOURCE <sup>1</sup>	ANNUAL PROCESS RATE <sup>2</sup>	NOTES

<sup>1</sup>Specify emission source. For example, list FCCU, cooling tower, oil/water separator, valves, flanges, compressor seals, etc.

<sup>2</sup>Specify annual process rate. For example, list bbls refinery feed/yr, gallons cooling water/yr, gallons wastewater/yr, etc.



**ANNUAL EMISSIONS REPORT FORM  
ACID PLANT PREHEATER - OPERATING HOURS  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date:** DATE

**Expiration Date:** DATE

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

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

Responsible Official (PRINT): \_\_\_\_\_

Title: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

MONTH	OPERATING HOURS		
	TOTAL OPERATING HOURS	OTHER INFORMATION	NOTES
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
TOTAL			

**MONITORING REPORT FORM  
FUEL CONSUMPTION  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following on a semi-annual basis:

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as Horsepower, kilowatt, tons/hour, etc.)

Serial/ID No.: \_\_\_\_\_

Type of Fuel: \_\_\_\_\_ % Sulfur Content by Weight: \_\_\_\_\_

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

Responsible Official (PRINT): \_\_\_\_\_

Title: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

MONTH	MONTHLY FUEL CONSUMPTION	12-MO. ROLLING AVERAGE	NOTES
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
<b>TOTAL</b>			

**MONITORING REPORT FORM  
FUEL CERTIFICATION  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as Horsepower, kilowatt, tons/hour, Btu/hr, etc.)

Serial/ID No.: \_\_\_\_\_

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

Responsible Official (PRINT): \_\_\_\_\_

TITLE: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

<b>Equipment</b>	<b>Fuel</b>	<b>Sulfur Content (% by weight)<sup>1</sup></b>	<b>Reason(s) for Noncompliance</b>	<b>Description of Corrective Actions Taken</b>
Combustion Turbine	Liquid Fuel			
Boilers	Liquid Fuel	(30-day average)		
Black Start DEG	ULSD			
Diesel Engine Pumps	ULSD			

<sup>1</sup>Report the highest sulfur content during the reporting period.

**MONITORING REPORT FORM  
BLACK START DIESEL ENGINE GENERATOR HOURS OF OPERATION  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Company/Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as horsepower, kilowatt, tons/hour, etc.)

Serial/ID Nos.: \_\_\_\_\_

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

Responsible Official (Print): \_\_\_\_\_

Title: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

MONTH	TOTAL HOURS OF OPERATION MONTHLY BASIS	TOTAL HOURS OF OPERATION ROLLING 12-MONTH BASIS
JANUARY		
FEBRUARY		
MARCH		
APRIL		
MAY		
JUNE		
JULY		
AUGUST		
SEPTEMBER		
OCTOBER		
NOVEMBER		
DECEMBER		



**EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE  
SUMMARY REPORT  
COVERED SOURCE PERMIT NO. 0088-01-C  
(PAGE 1 OF 2)**

**Issuance Date: DATE** **Expiration Date: DATE**

(Make Copies for Future Use)

Facility Name:

\_\_\_\_\_

Equipment Location:

\_\_\_\_\_

Equipment Description: \_\_\_\_\_

Serial/Unit ID No.: \_\_\_\_\_

Covered Source Permit No.: \_\_\_\_\_ Condition

No.: \_\_\_\_\_

PSD Permit No.: \_\_\_\_\_ Condition

No.: \_\_\_\_\_

Code of Federal Regulations (CFR):

\_\_\_\_\_

**Pollutant Monitored:** \_\_\_\_\_

From: Date \_\_\_\_\_ - Time \_\_\_\_\_

To: Date \_\_\_\_\_ - Time \_\_\_\_\_

Emission Limit: \_\_\_\_\_

Date of Last CEMS Certification/Audit . . . . . \_\_\_\_\_

**Total Source Operating Time** . . . . . \_\_\_\_\_

EMISSION DATA SUMMARY

1. Duration (Hours/Periods) of Excess Emissions in Reporting Period due to:

a. Start-Up/Shutdown . . . . . \_\_\_\_\_

b. Cleaning/Soot Blowing . . . . . \_\_\_\_\_

c. Control Equipment Failure . . . . . \_\_\_\_\_

d. Process Problems . . . . . \_\_\_\_\_

e. Other Known Causes . . . . . \_\_\_\_\_

f. Unknown Causes . . . . . \_\_\_\_\_

g. Fuel Problems . . . . . \_\_\_\_\_

Number of incidents of excess emissions . . . . . \_\_\_\_\_



**VISIBLE EMISSIONS FORM REQUIREMENTS  
STATE OF HAWAII  
COVERED SOURCE PERMIT NO. 0088-01-C**

**Issuance Date: DATE**

**Expiration Date: DATE**

The **Visible Emissions (VE) Form** shall be completed **monthly** (*each calendar month*) for each equipment subject to opacity limits by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternative methods with prior written approval from the Department. The VE Form shall be completed as follows:

1. VE observations shall take place during the day only. The opacity shall be noted in five (5) percent increments (e.g., twenty-five (25) percent).
2. Orient the sun within a 140 degree sector to your back. Provide a source layout sketch on the VE Form using the symbols as shown.
3. For VE observations of stacks, stand at least three (3) stack heights but not more than a quarter mile from the stack.
4. For VE observations of fugitive emissions from crushing and screening plants, stand at least 4.57 meters (fifteen (15) feet) from the visible emissions source, but not more than a quarter mile from the VE source.
5. Two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals for each stack or emission point.
6. The six (6) minute average opacity reading shall be calculated for each observation.
7. If possible, the observations shall be performed as follows:
  - a. Read from where the line of sight is at right angles to the wind direction.
  - b. The line of sight shall not include more than one (1) plume at a time.
  - c. Read at the point in the plume with the greatest opacity (without condensed water vapor), ideally while the plume is no wider than the stack diameter.
  - d. Read the plume at fifteen (15) second intervals only. Do not read continuously.
  - e. The equipment shall be operating at the maximum permitted capacity.
8. If the equipment was shut-down for that period, briefly explain the reason for shut-down in the comment column.

The permittee shall retain the completed VE Forms for recordkeeping. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department, or their representative upon request.

Any required initial and annual performance test performed in accordance with Method 9 by a certified reader shall satisfy the respective equipment's VE monitoring requirements for the month the performance test is performed.



<b>VISIBLE EMISSIONS FORM</b> <b>COVERED SOURCE PERMIT NO. 0088-01-C</b>	
<b>Issuance Date: <u>DATE</u></b>	<b>Expiration Date: <u>DATE</u></b>

(Make Copies for Future Use for Each Stack or Emission Point)

Company Name: \_\_\_\_\_

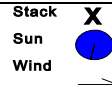
For stacks, describe equipment and fuel: \_\_\_\_\_

For fugitive emissions from crushers and screens, describe:

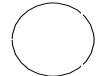
Fugitive emission point: \_\_\_\_\_

Plant Production (tons/hr): \_\_\_\_\_

(During observation)



Draw North Arrow



**Site Conditions:**

Emission point or stack height above ground (ft): \_\_\_\_\_

Emission point or stack distance from observer (ft): \_\_\_\_\_

Emission color (black or white): \_\_\_\_\_

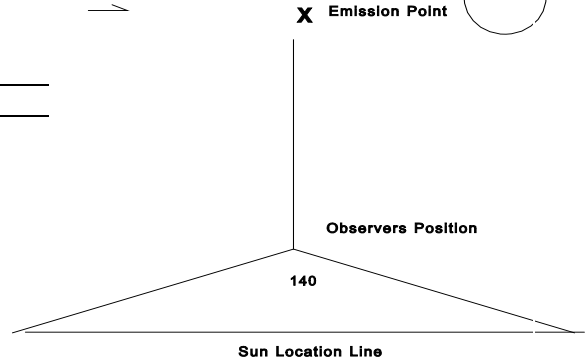
Sky conditions (% cloud cover): \_\_\_\_\_

Wind speed (mph): \_\_\_\_\_

Temperature (EF): \_\_\_\_\_

Observer Name: \_\_\_\_\_

Certified? (Yes/No): \_\_\_\_\_



Observation Date and Start Time: \_\_\_\_\_

MINUTES	Seconds				COMMENTS
	0	15	30	45	
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

Observation Date and Start Time: \_\_\_\_\_

MINUTES	Seconds				COMMENTS
	0	15	30	45	
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

# **Draft Review Summary**

**Permit Application Review Summary**

**Application No.:** Minor Modification Application No. 0088-32 (CSP No. 0088-01-C)  
Renewal Application Nos. 0088-07 and 0088-17 (CSP No. 0088-01-C)  
Renewal Application No. 0088-19 (CSP No. 0088-02-C)  
Renewal Application No. 0088-31 (CSP No. 0088-03-C)

**Permit No.:** Covered Source Permit (CSP) No. 0088-01-C

**Applicant:** Par Hawaii Refining, LLC

**Facility Title:** Par West Refinery (formerly the Kapolei Refinery)  
Located At: 91-480 Malakole Street, Kapolei, Oahu  
UTM: 2,356,430 m N, 591,900 m E, Zone 4, NAD-83

**Mailing Address:** Par Hawaii Refining, LLC  
91-325 Komohana Street  
Kapolei, Hawaii 96707

**Responsible Official:** Mr. Richard L. Creamer  
Vice President and General Manager  
Par Hawaii Refining, LLC  
(808) 547-3841

**Point of Contact:** Mr. Theodore K. Metrose  
Environmental Director  
(808) 479-9886

**Application Dates:** Minor modification application dated December 14, 2018  
(CSP No. 0088-01-C);  
Renewal applications dated August 1, 2003, and December 22, 2010,  
with updated information dated March 2, 2016 (CSP No. 0088-01-C);  
Renewal application dated November 22, 2011  
(CSP No. 0088-02-C); and  
Renewal application dated September 6, 2018  
(CSP No. 0088-03-C).

**Proposed Project:**

SICC 2911 (Petroleum Refining)

The existing petroleum refinery is currently permitted to operate under CSP No. 0088-01-C and is owned by Par Hawaii Refining, LLC and is currently named the Par West Refinery. The former refinery owner and applicant (IES Downstream, LLC) submitted a minor modification application for CSP No. 0088-01-C to separate the Fluid Catalytic Cracking Unit (FCCU), Dimersol, and Alkylation Plants (the Alkylation Plant does not include the Deisobutanizer and Depropanizer systems) from the existing refinery operations as part of the sales agreement with Par Hawaii Refining, LLC, in which Par Hawaii Refining, LLC would acquire the refinery except for the FCCU, Dimersol, and Alkylation Plants. IES Downstream, LLC also submitted an application for an initial CSP for the FCCU, Dimersol, and Alkylation Plants (Application No. 0863-02).

In addition to the minor modification, CSP No. 0088-01-C for the existing refinery operations will be renewed. This permit also consolidates CSP No. 0088-01-C with CSP Nos. 0088-02-C and 0088-03-C and serves as a permit renewal for these permits. There are no proposed changes in operation for the refinery in each of these permit renewals.

This modification is considered a minor modification since it:

- (1) Does not increase the emissions of any air pollutant above the permitted emission limits;
- (2) Does not result in or increase the emissions of any air pollutant not limited by permit to levels equal to or above:
  - (A) 500 pounds per year of a hazardous air pollutant (HAP), except lead;
  - (B) 300 pounds per year of lead;
  - (C) Twenty-five (25) percent of significant amounts of emission as defined in Section 11-60.1-1, Paragraph (1) in the definition of "significant"; or
  - (D) Two (2) tons per year of each regulated air pollutant not already identified above.
- (3) Does not violate any applicable requirement;
- (4) Does not involve significant changes to existing monitoring requirements or any relaxation or significant change to existing reporting or recordkeeping requirements in the permit. Any change to the existing monitoring, reporting, or recordkeeping requirements that reduces the enforceability of the permit is considered a significant change;
- (5) Does not require or change a case-by-case determination of an emission limitation or other standard, a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;
- (6) Does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement, and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:
  - (A) A federally enforceable emissions cap assumed to avoid classification as a modification pursuant to any provision of Title I of the Act or Subchapter 7; and
  - (B) An alternative emissions limit approved pursuant to regulations promulgated pursuant to Section 112(i)(5) of the Act or Subchapter 9; and
- (7) Is not a modification pursuant to any provision of Title I of the Act.

The permit modification and renewal application fees of \$200.00, \$3,000.00, \$3,000.00, and \$3,000.00 were submitted by the applicant and processed.

### **Equipment Description:**

Refinery equipment consists of a crude oil distillation unit, and plants for hydrogen production, hydrogenation, isomerization, and acid manufacturing. Steam is produced by four (4) combustion turbine cogeneration units and two (2) boilers. Support facilities include effluent treatment, flares, cooling tower, black start diesel engine generator (DEG), and three (3) diesel engine pumps. For the purposes of the covered source permit, facility equipment is grouped according to common function and/or common applicable requirements, as follows:

1. Miscellaneous process units and auxiliary equipment
  - a. Process Units, Flare Vapor Recovery Unit, and Flares
    - i. Crude Unit;
    - ii. Vacuum Unit;
    - iii. Hydrogenation Unit;
    - iv. Hydrogen Unit;
    - v. Isomerization Unit;
    - vi. Cogeneration Units;
    - vii. Boiler Plant;
    - viii. Flare Vapor Recovery Unit;
    - ix. Flares (and Flare Gas Header System);
    - x. Deisobutanizer; and
    - xi. Depropanizer.
  - b. Compressors
    - i. Two (2) Flare Vapor Recovery Unit Compressors, identified as K-5604 and K-5604A;
    - ii. Two (2) Hydrogenation Hydrogen Makeup Compressors, identified as K-5601 and K-5602;
    - iii. One (1) Isomerization Hydrogen Recycle Compressor, identified as K-5961;
    - iv. One (1) Isomerization Hydrogen Gas Recycle Compressor, identified as K-5962; and
    - v. One (1) Cogeneration Plant Fuel Gas Compressor, identified as K-6704.
2. One (1) Ten-Cell Induced Draft Cooling Tower
3. Two (2) Flares
  - a. One (1) 20" diameter Flare (steam-assisted), identified as F-2301; and
  - b. One (1) 42" diameter Flare (steam-assisted), identified as F-2302.
4. Effluent treatment facilities and related control devices
  - a. Two (2) Covered API Separators, ID. Nos. D-3617 and D-3618  
Control Devices - Two (2) Carbon Adsorption Canisters (Primary and Secondary);
  - b. BRU consisting of two (2) Nitrogen Gas Strippers and two (2) Carbon Adsorber Towers  
Control Devices -Two (2) Carbon Adsorption Canisters (Primary and Secondary);
  - c. Recovered Oil Sump  
Control Devices - Two (2) Carbon Adsorption Canisters (Primary and Secondary);
  - d. Skim Oil Tank identified as Storage Tank T-3619;
  - e. Wastewater Surge Tank identified as Storage Tank T-301; and
  - f. Recovered Oil Tank identified as Storage Tank T-302.

5. Two (2) Crude Unit Furnaces
  - a. One (1) - 151.5 MMBtu/hr (LHV) Atmospheric Furnace identified as F-5103 with Low Nitrogen Oxide (NO<sub>x</sub>) burners;
  - b. One (1) - 62.5 MMBtu/hr (LHV) Vacuum Furnace identified as F-5153 with Low NO<sub>x</sub> burners; and
  - c. Equipped with a common air preheater for both furnaces identified as E-5104.
6. Process Unit Furnaces
  - a. One (1) - 9 MMBtu/hr Hydrogenation Unit Furnace identified as F-5600;
  - b. One (1) - 24.3 MMBtu/hr Hydrogen Unit Furnace identified as F-5700;
  - c. One (1) - 4 MMBtu/hr Isomerization Unit Furnace identified as F-5930; and
  - d. One (1) - 1.6 MMBtu/hr Isomerization Unit Furnace identified as F-5950.
7. Acid Plant
  - a. One (1) - 4.2 MSCF/hr Acid Plant Combustion Chamber, ID No. 6200 with one (1) Acid Plant Absorbing Tower Stack; and
  - b. One (1) - 5.1 MMBtu/hr Acid Plant Preheater, ID No. F-6262.
8. Cogeneration Plant
  - a. Three (3) - 46 MMBtu/hr (HHV) Gas Turbines, Solar Centaur 40, Model No. 40-4701, each equipped with a 49 MMBtu/hr (HHV) gas-fired Duct Burner and a Heat Recovery Steam Generator (HRSG). The three (3) cogeneration units are identified as K-6701, K-6702, and K-6703 and each produces about 3 MW.
  - b. NO<sub>x</sub> Control
    - i. Gas Turbines - Water Injection; and
    - ii. HRSGs - Low NO<sub>x</sub> Burners.
9. One (1) Cogeneration Unit, identified as K-6704, consisting of the following:
  - a. One (1) 46 MMBtu/hr (HHV) Combustion Turbine, Solar Centaur 40, Model No. 40-4701; equipped with a 49 MMBtu/hr (HHV) Duct Burner and a HRSG;
  - b. For NO<sub>x</sub> control, the combustion turbine is equipped with water injection and low NO<sub>x</sub> burners.
10. Two (2) 99 MMBtu/hr boilers, Foster Wheeler, Model No. AG-5060, Serial Nos. 7414, National Board No. 585 and 7415, National Board No. 586, identified as F-5205 and F-5206.
11. Black Start DEG and Diesel Engine Pumps
  - a. One (1) 350 kW (755 hp) Cummins Power Generation Black Start DEG, Model No. DFEG, (Tier 2 rated).

- b. Three (3) diesel engine pumps consisting of the following:
    - i. One (1) Sand Filter Pump No. 1, Tier 3 or higher rated, not to exceed 175 HP, Pump Serial Number 18647355/02, Engine Serial Number Isuzu 680026;
    - ii. One (1) Sand Filter Pump No. 2, Tier 3 or higher rated, not to exceed 175 HP, Pump Serial Number 18646439-02, Engine Serial Number Isuzu 675388; and
    - iii. One (1) Transfer Pump, Tier 3 or higher rated, not to exceed 175 HP, Serial Number PE4024R039307.
12. Foul Water Treatment Plant and Catalytic Oxidation Unit
- a. One (1) Foul Water Treatment Plant; and
  - b. One (1) Catalytic Oxidation Unit (includes a Selective Catalytic Reduction (SCR) catalyst for NO<sub>x</sub> control), non-fired, electrically heated.

**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 11-60.1-32: Visible Emissions

HAR 11-60.1-38: Sulfur Oxides from Fuel Combustion

HAR 11-60.1-40: Volatile Organic Compound (VOC) Water Separation

HAR 11-60.1-41: Pump and Compressor Requirements

HAR 11-60.1-42: Waste Gas Disposal

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

HAR 11-60.1-161: New Source Performance Standards

Subchapter 9 - Hazardous Air Pollutant Sources

HAR 11-60.1-174: Maximum Achievable Control Technology Standards

HAR 11-60.1-180: National Emission Standards for Hazardous Air Pollutants

Subchapter 11 – Greenhouse Gas Emissions

Federal Requirements

40 CFR Part 60 - Standards of Performance for New Stationary Sources (NSPS)

Subpart A: General Provisions

Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (applies to Boilers)

- Subpart J: Standards of Performance for Petroleum Refineries (applies to the Flares, Atmospheric and Vacuum Furnaces F-5103 and F-5153, Process Unit Furnaces F-5600, F-5700, F-5930, and F-5950, Acid Plant Preheater, Gas Turbines with HRSGs in the Cogeneration Plant, Cogeneration Unit K-6704, and Boilers)
  - Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (applies to the Catalytic Oxidation Unit and Flares)
  - Subpart GG: Standards of Performance for Stationary Gas Turbines (applies to the Gas Turbines with HRSGs in the Cogeneration Plant)
  - Subpart GGG: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and On or Before November 7, 2006 (applies to Process Units, Flares, and Flare Vapor Recovery Unit)
  - Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (applies to Process Units, Flares, and Flare Vapor Recovery Unit)
  - Subpart QQQ: Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (applies to Cogeneration Units, Crude Unit, Vacuum Unit, Crude Desalter, Boiler Plant, Flare Vapor Recovery Unit, API Separators, and Catalytic Oxidation Unit)
  - Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (applies to black start DEG and diesel engine pumps)
  - Subpart KKKK: Standards of Performance for Stationary Combustion Turbines (applies to Cogeneration Unit K-6704)
- 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Subpart A: General Provisions
  - Subpart FF: National Emission Standard for Benzene Waste Operations (applies to the API Separators, Benzene Recovery Unit, Recovered Oil Sump, Skim Oil Tank, Wastewater Surge Tank, Recovered Oil Tank, Foul Water Treatment Plant, and Catalytic Oxidation Unit)
- 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)
- Subpart A: General Provisions
  - Subpart CC: National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (applies to Process Units, Flares, and Flare Vapor Recovery Unit, except for the Boiler Plant; Foul Water Treatment Plant, and Catalytic Oxidation Unit)
  - Subpart YYYY: National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (applies to the Combustion Turbine in Cogeneration Unit K-6704)
  - Subpart ZZZZ: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (applies to black start DEG and diesel engine pumps)



Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters (applies to Atmospheric and Vacuum Furnaces F-5103 and F-5153, Process Unit Furnaces F-5600, F-5700, F-5930, and F-5950, Acid Plant Preheater, and Boilers)

40 CFR Part 68 - Chemical Accident Prevention Provisions (applies to the storage and use of flammable substances in the refinery)

40 CFR Part 98 - Mandatory Greenhouse Gas Reporting

**40 CFR Part 63, Subpart DDDDD Applicability**

Unit	Description		Heat Capacity (MMBtu/hr)	Fuel Type	MACT DDDDD Tune-up Requirement	MACT DDDDD Energy Assessment Requirement	MACT DDDDD Emission Limits Requirement
F-5700	Hydrogen Unit Furnace		24.3	RFG	Annual <sup>1</sup>	yes	NA
F-5103	Atmospheric Furnace		151.5	Liquid Fuel, RFG	Annual <sup>1</sup>	yes	Table 2, Nos. 14, 17
F-5153	Vacuum Furnace		62.5	Liquid Fuel, RFG	Annual <sup>1</sup>	yes	Table 2, Nos. 14, 17
F-5600	Hydrogenation Unit Furnace		9	RFG	Biennial <sup>2</sup>	yes	NA
F-6262	Acid Plant Preheater		5.1	RFG, propane	Biennial <sup>2</sup>	yes	NA
F-5930	Isomerization Unit Furnace		4	RFG	Every five years <sup>3</sup>	yes	NA
F-5950	Isomerization Unit Furnace		1.6	RFG	Every five years <sup>3</sup>	yes	NA
F-5205	Boiler		99	Liquid Fuel, RFG	Annual <sup>1</sup>	yes	Table 2, Nos. 14, 17
F-5206	Boiler		99	Liquid Fuel, RFG	Annual <sup>1</sup>	yes	Table 2, Nos. 14, 17

<sup>1</sup>Existing process heater without a continuous oxygen trim system and with a heat input capacity of 10 MMBtu/hr or greater.

<sup>2</sup>Existing process heater with a heat input capacity of less than 10 MMBtu/hr, but greater than 5 MMBtu/hr.

<sup>3</sup>Existing process heater with a heat input capacity of less than or equal to 5 MMBtu/hr.

**Non-Applicable Requirements:**

Hawaii Administrative Rules (HAR)

Title 11, Chapter 60.1 - Air Pollution Control

Subchapter 7 - Prevention of Significant Deterioration Review

Federal Requirements

40 CFR Part 52.21 – Prevention of Significant Deterioration of Air Quality

**Best Available Control Technology (BACT):**

A BACT analysis is applicable only to new covered sources and significant modifications to covered sources that have the potential to emit or increase emissions above significant levels as defined in HAR §11-60.1-1. A BACT analysis is not applicable since this is a minor modification and permit renewal with no emission increases for an existing covered source.

**Prevention of Significant Deterioration (PSD):**

A PSD major modification is defined as a project at an existing major stationary source that will result in a significant emissions increase and a significant net emissions increase of any pollutant subject to regulations approved pursuant to the Clean Air Act as defined in 40 CFR §52.21. Since there are no significant emission increases for this modification, PSD is not triggered.

**Air Emissions Reporting Requirements (AERR):**

40 CFR Part 51, Subpart A – AERR, is based on the emissions of criteria air pollutants from Type A and B point sources (as defined in 40 CFR Part 51, Subpart A), that emit at the AERR triggering levels as shown in the table below:

Pollutant	Type A Triggering Levels <sup>1,2</sup> (tpy)	Type B Triggering Levels <sup>1</sup> (tpy)	Pollutant	In-house Total Facility Triggering Levels <sup>1</sup> (tpy)	Potential Emissions (tpy)
NO <sub>x</sub>	≥2500	≥100	NO <sub>x</sub>	≥25	1008.8
SO <sub>2</sub>	≥2500	≥100	SO <sub>2</sub>	≥25	2482.5
CO	≥2500	≥1000	CO	≥250	367.8
PM <sub>10</sub> /PM <sub>2.5</sub>	≥250/250	≥100/100	PM/PM <sub>10</sub>	≥25/25	92.9
VOC	≥250	≥100	VOC	≥25	399.2
Pb		≥0.5 (actual)	Pb	≥5	0
			HAPS	≥5	22.059

<sup>1</sup>Based on potential emissions

<sup>2</sup>Type A sources are a subset of Type B sources and are the larger emitting sources by pollutant

The petroleum refinery exceeds the Type A triggering levels. Therefore, AERR requirements are applicable.

The Clean Air Branch also requests annual emissions reporting from those facilities that have facility-wide emissions of a single air pollutant exceeding in-house triggering levels or is a covered source. Annual emissions reporting for the facility will be required for in-house recordkeeping purposes since this is a covered source.

**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 a source to be subject to CAM, each source 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;
- Have pre-control device potential emissions that exceed applicable major source thresholds;
- Be fitted with an “active” air pollution control device; 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.

1. CAM requirements are applicable to the cogeneration units, identified as K-6701, K-6702, and K-6703. The units have existing monitoring devices including, fuel oil and fuel gas non-resetting fuel meters, a continuous monitoring system (CMS) to record the water-to-fuel ratio and a NO<sub>x</sub> continuous emission monitoring system (CEMS) that serves all three (3) cogeneration units sequentially. The indicator to be monitored to demonstrate that the water injection control device is working properly is the NO<sub>x</sub> CEMS.
2. CAM requirements are applicable to the Catalytic Oxidation Unit and Foul Water Treatment Plant for NO<sub>x</sub> and VOC emissions. The indicators to be monitored to demonstrate that the Catalytic Oxidation Unit and SCR are working properly are one (1) NO<sub>x</sub> analyzer and one (1) NH<sub>3</sub> analyzer continuous process monitoring system (CPMS) downstream of the Catalytic Oxidation Unit.
3. As shown in the table below, CAM for the Cogeneration Unit CGT-6704 and Steam Boilers F-5205 and F-5206 are not applicable. Please note that the Cogeneration Unit CGT-6704 has a NO<sub>x</sub> CEMS in addition to the CMS for the water-to-fuel ratio required by NSPS Subpart KKKK.

**CAM APPLICABILITY**

<b>CAM Criteria</b>	<b>Combustion Turbine/HRSG</b>	<b>Boilers</b>
Be located at a major source per Title V of the Clean Air Act Amendments of 1990	Yes	Yes
Be subject to federally enforceable applicable requirements	Yes	Yes
Have pre-control device potential emissions that exceed applicable major source thresholds	Yes	Yes
Be fitted with an “active” air pollution control device	Yes	No
Not be subject to certain regulations that specifically exempt it from CAM.	No <sup>1</sup>	No <sup>2</sup>
Subject to CAM?	No	No

<sup>1</sup>The combustion turbine/HRSG is subject to a post 11/15/90 NSPS, i.e., 40 CFR Part 60 Subpart KKKK, which exempts it from CAM. The combustion turbine is also subject to a post 11/15/90 NESHAP, i.e., 40 CFR Part 63 Subpart YYYY, which exempts it from CAM.

<sup>2</sup>The boilers are subject to a post 11/15/90 NESHAP, i.e., 40 CFR Part 63, Subpart DDDDD, which exempts them from CAM.

**Insignificant Activities:**

*Per HAR §11-60.1-82(f)(1).*

1. Portable chemical tanks.

*Per HAR §11-60.1-82(f)(7).*

2. Meter stations, sampling points and filters.
3. Pump and tank degassing operations.
4. Training fires.
5. Process upset vents.
6. Mercury in instrument and gauge repair.
7. Oily sewer and storm water vents.
8. Maintenance and cleaning activities, including housekeeping, black oil tank sludge removal, and process unit shutdown and turnaround activities.
9. Additives, promoters, passivators, and anti-foam agents.
10. Insignificant heavy liquids. Tank ID Nos. 350 and 351.
11. Storage of regulated pollutants not in VOC service.  
Tank ID Nos. 5211, 5197, AP-4, AP-5, 62AP2, and 2301.
12. Storage of spent sulfuric acid. Tank ID Nos. 62AP1 and 62AP3.
13. Storage of non-regulated pollutants, including water, condensate, caustic, and catalyst.
14. Miscellaneous diesel powered equipment for emergency, maintenance, security, and facility purposes: EP-2077 Tank 352 Firewater Pump, EP-2083 Brine Firewater Pump.

**Alternate Operating Scenarios:**

There are no alternate operating scenarios proposed for this facility.

**Project Emissions:**

The emissions from the refinery combustion units (including flares, furnaces, boilers, turbines, and duct burners) will consist of sulfur dioxide, nitrogen oxides, carbon monoxide (CO), particulate matter, VOC and HAPs. A summary of the potential total annual emissions of criteria pollutants and HAP expected from the refinery are shown below. The refinery may process up to 65,000 barrels of crude oil per day and operates up to a maximum of 8,760 operating hours/year. These emissions represent only an estimate of the potential emissions assuming the refinery operates at its full capacity for the entire year. The actual annual emissions in any given operating year may be significantly less than the emissions presented in this table:

**SUMMARY OF POTENTIAL POLLUTANT EMISSIONS  
(tons/yr)**

Sources	SO <sub>2</sub>	NO <sub>2</sub>	CO	PM <sub>10</sub>	VOC	Total HAPs	CO <sub>2e</sub>
CatOx Unit		14.7	17.0		1.3	0	845.850
Cogen Turbines	27.9	193.2	52.5	11.7	2.3	0.688	165,662.729
Crude Furnaces	482.0	302.9	75.0	44.5	5.1	0.253	170,485.608
Isomerization Furnaces	0.7	2.5	2.1	0.2	0.1	0.046	2,853.713
Hydrogenation & Hydrogen Furnaces	3.9	14.5	12.1	1.1	0.8	0.272	16,816.524
Acid Plant Preheater & Combustion Chamber	1.5	5.7	4.8	0.4	0.3	0.107	6,647.744
Cooling Tower				3.2	9.2		
Acid Plant	1405.3						
Wastewater Treatment		14.7	17.0		74.9	5.623	
Process Fugitives					210.5	13.943	338.961
Tanks (301 and 302)					32.0		
Refinery Flares	319.1	224.2	51.0		9.5	0.002	845.850
Hybrid Energy Plant - Cogen with HRSG	10.06	60.0	50.8	4.68	30.4	0.486	116,596.128
Hybrid Energy Plant - Boilers	232.0	159.6	66.6	26.0	3.9	0.626	61,046.460
Cogen Black Start Generator	0.001	1.62	0.17	0.03	1.62	0.001	138.0
Sand Filter Pump Diesel Engine #1	0.01	5.07	6.25	0.37	5.76	0.004	1007.4
Sand Filter Pump Diesel Engine #2	0.01	5.07	6.25	0.37	5.76	0.004	1007.4
Transfer Pump	0.01	5.07	6.25	0.37	5.76	0.004	1007.4
Totals	2482.5	1008.8	367.8	92.9	399.2	22.059	545,299.77

**Ambient Air Quality Assessment (AAQA):**

An AAQA is not required for a minor modification or permit renewal with no emission increases.

**Significant Permit Conditions:**

1. Incorporated the Petroleum Refinery Sector Rule (Risk and Technology Review and New Source Performance Standards) into the draft permit which revised MACT Subpart CC and UUU and NSPS Subpart Ja. Also, revised the refinery fuel gas (RFG) requirements throughout the draft permit such that the hydrogen sulfide (H<sub>2</sub>S) content shall not exceed 230 mg/dscm (162 ppmv), which is a corrected conversion.

2. The Miscellaneous Process Units and Source Operations section was revised to the Miscellaneous Process Units and Auxiliary Equipment section. The Foul Water Treatment Plant and Catalytic Oxidation Unit was removed from this section and given its own section. Also, this section was revised to list specific equipment as follows:
  - a. Process Units, Flare Vapor Recovery Unit, and Flares
    - i. Crude Unit;
    - ii. Vacuum Unit;
    - iii. Hydrogenation Unit;
    - iv. Hydrogen Unit;
    - v. Isomerization Unit;
    - vi. Cogeneration Units;
    - vii. Boiler Plant;
    - viii. Flare Vapor Recovery Unit;
    - ix. Flares (and flare gas header system);
    - x. Deisobutanizer; and
    - xi. Depropanizer.
  - b. Compressors
    - i. Two (2) - Flare Vapor Recovery Unit Compressors, identified as K-5604 and K-5604A;
    - ii. Two (2) – Hydrogenation Hydrogen Makeup Compressors, identified as K-5601 and K-5602;
    - iii. One (1) – Isomerization Hydrogen Recycle Compressor, identified as K-5961;
    - iv. One (1) – Isomerization Hydrogen Gas Recycle Compressor, identified as K-5962;
    - v. One (1) – Cogeneration Plant Fuel Gas Compressor, identified as K-6704.

The Refinery Sector Rule was also incorporated into this section per 40 CFR §63.648 which added permit conditions for pressure relief devices in organic HAP gas/vapor service.

3. The Cooling Tower section was not revised.
4. The Flare section was revised as follows:
  - a. The Crude and FCC flares was revised to one (1) 20” diameter Flare (steam-assisted), identified as F-2301 and one (1) 42” diameter Flare (steam-assisted), identified as F-2302.
  - b. Deleted the testing requirements for NSPS Subparts J and Ja H<sub>2</sub>S compliance for the flares. The Environmental Protection Agency (EPA) concurred with Par that flaring solely for the purpose of a relative accuracy test audit (RATA) or other performance test is not desirable. The H<sub>2</sub>S CMS will be used solely for compliance purposes, and the RATA for the H<sub>2</sub>S CMS will be conducted using cylinder gas audits.
4. The Effluent Treatment Plant section was not revised.
5. The Crude Unit Furnaces section was revised to the Atmospheric and Vacuum Furnaces
  - a. Updated this section per MACT Subpart DDDDD requirements.
  - b. Changed low sulfur fuel oil (LSFO) to liquid fuel per MACT Subpart DDDDD requirements.

- c. Corrected the maximum emission limits for the Atmospheric and Vacuum Furnaces and added maximum emission limits for the scenario if only the Atmospheric Furnace is operating.
  - d. Allowed the use of fuel analysis for demonstrating compliance with the hydrogen chloride and mercury emission limits.
- 6. The Process Unit Furnaces section was updated per MACT Subpart DDDDD requirements.
  - 7. The Acid Plant section was updated per MACT Subpart DDDDD requirements.
  - 8. The Cogeneration Plant section was revised as follows:
    - a. Changed LSR or HSR gasoline to liquid fuel.
    - b. Revised the equipment description for the three (3) Cogeneration Units K-6701, K-6702, and K-6703 to match Cogeneration Unit K-6704, since these are the same.
    - c. Revised the excess emissions reporting definition by allowing the following:

Any one (1) hour period during which the average water-to-fuel ratio, as measured by the CMS, falls below the water-to-fuel ratio determined to demonstrate compliance with the emission limits set forth in Special Condition No. C.2 of this attachment, except when the operating unit is monitored by a NO<sub>x</sub> CEMS that concurrently shows compliance with the NO<sub>x</sub> limits set forth in Special Condition No. C.2 of this attachment.

- 9. The Cogeneration Unit section was revised as follows:
    - a. Changed naphtha to liquid fuel.
    - b. Revised the excess emissions reporting definition by allowing the following:
- Any operating period in which the four (4) hour rolling average water-to-fuel ratio, as measured by the CMS, falls below the water-to-fuel ratio determined to demonstrate compliance with the emission limits set forth in Special Condition No. C.2. of this attachment, except when the operating unit is monitored by a NO<sub>x</sub> CEMS that concurrently shows compliance with the NO<sub>x</sub> limits set for in Special Condition No. C.2 of this attachment.

- 10. The Boiler section was revised as follows:
  - a. Updated this section per MACT Subpart DDDDD requirements and deleted conflicts with current hydrochloric acid and CO emission limits which were based on outdated MACT Subpart DDDDD requirements.
  - b. Changed LSFO to liquid fuel per MACT Subpart DDDDD requirements.
  - c. Allowed the use of fuel analysis for demonstrating compliance with the hydrogen chloride and mercury emission limits.
  - d. Added a fuel consumption limit for the two (2) boilers to ensure that the original application's design of having the continuous operation of the two (2) boilers at a maximum capacity with no more than 51.1% of the annual fuel input energy supplied by LSFO (140,685 barrels per year total for both boilers) is retained.
- 11. The black start DEG and diesel engine pumps section was not revised.

12. Added a Foul Water Treatment Plant and Catalytic Oxidation Unit section.

a. The Catalytic Oxidation Unit is subject to the provisions of the following federal regulations:

40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

- i. Subpart A, General Provisions;
- ii. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007; and
- ii. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

b. The Foul Water Treatment Plant and Catalytic Oxidation Unit is subject to the provisions of the following federal regulations:

i. 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP):

- (1) Subpart A, General Provisions; and
- (2) Subpart FF, National Emission Standards for Benzene Waste Operations.

ii. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT):

- (1) Subpart A, General Provisions; and
- (2) Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

**Conclusion and Recommendations:**

Recommend issuance of the minor modification and renewal of existing CSP No. 0088-01-C, the renewal of existing CSP No. 0088-02-C and CSP No. 0088-03-C, and the consolidation of CSP No. 0088-01-C with CSP No. 0088-02-C and CSP No. 0088-03-C, subject to the significant permit conditions above. This permit would supersede CSP No. 0088-01-C issued on November 16, 2018, CSP No. 0088-02-C issued on May 23, 2007, and CSP No. 0088-03-C issued on November 15, 2016, in their entireties. A thirty (30) day public comment period and forty-five (45) day EPA review period are also required.

Reviewer: Darin Lum

Date: 8/2020



**Application  
and  
Supporting Information**



Jon Mauer  
President & CEO

RECEIVED  
DEC 14 2018

Headquarters & Refining  
IES Downstream, LLC  
ATTN: Environmental Department  
91-480 Malakole Street  
Kapolei HI 96707-1807  
Tel 808-682-5711  
Fax 808-682-2214  
jonmauer@islandenergyservices.com

December 14, 2018

**HAND DELIVERED**

Ms. Marianne Rossio  
Manager, Clean Air Branch  
State of Hawaii  
2827 Waimano Home Road # 130  
Pearl City, Hawaii 96782

**IES Downstream, LLC**

**Permit Application for a Minor Modification to Covered Source Permit (CSP) 0088-01-C and Initial Title V CSP Application for IES Downstream, LLC – FCCU, Dimersol, and Alkylation Plants (Proposed CSP No. 0863-02-C)**

Dear Ms. Rossio:

IES Downstream, LLC – Kapolei Refinery (IES) is hereby applying for a minor modification to remove equipment currently permitted to operate under CSP 0088-01-C and concurrently applying for a separate Title V CSP for the same equipment under the name “IES Downstream, LLC – FCCU, Dimersol, and Alkylation Plants” The permit application for IES Downstream, LLC – FCCU, Dimersol, and Alkylation Plants covers equipment that is already installed and operating at the Kapolei Refinery under CSP 0088-01-C, the operations of which will not change as a result of these permit submissions.

Enclosed are two sets (1 original and 1 copy) of the project report containing the applicable minor modification application forms for the Kapolei Refinery and two sets (1 original and 1 copy) of the project report containing the initial CSP application forms for the FCCU, Dimersol, and Alkylation Plants. According to the State of Hawaii Department of Health (HDOH) Clean Air Branch, a CSP Minor Modification application requires the submittal of HDOH Forms S-1, S-7, C-1, and an initial CSP application requires the submittal of HDOH Forms S-1, S-2, C-1 and C-2. An additional set of the applications will be mailed directly to the EPA.

Attachments A and B contain additional information supporting the application and includes:

- Attachment A - minor modification project report with appendices including application forms S-1, S-7, C-1, plot plan, process flow diagram, emission calculations, and a redline of current permit with proposed conditions;
- Attachment B – initial CSP project report with appendices including application forms S-1, S-2, C-1, C-2, plot plan, process flow diagram, emission calculations, and a redline of current permit with proposed conditions;

Attachment C is a \$200 check for the Minor Modification and a \$5000 check for the initial CSP as a Major Toxic Covered Source application fees.

Please provide written confirmation that you have received both applications, and that IES may continue to operate the FCCU, Dimersol, and Alkylation Plants under CSP 0088-01-C until such time as a separate

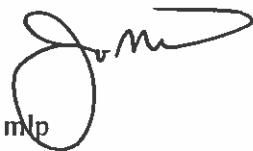
Manager  
Clean Air Branch  
December 14, 2018  
Page 2

permit (Proposed CSP No. 0863-02-C) has been issued to IES Downstream, LLC - FCCU, Dimersol, and Alkylation Plants.

Should you have questions or require further information, please contact Ms. Gail Godenzi at (808) 682-3113 or Mr. Mark Peak at [mpeak@parpacific.com](mailto:mpeak@parpacific.com).

I certify as the company official having supervisory responsibility for the persons who prepared this document that this information is true, accurate, and complete to the best of my knowledge, information and belief.

Sincerely,



mlp

Attachments

cc: **CERTIFIED MAIL 7015 0640 0002 5915 4816**  
**RETURN RECEIPT REQUESTED**  
Chief (Attention: AIR-3)  
Permits Office, Air Division  
U.S. Environmental Protection Agency  
Region 9  
75 Hawthorne Street  
San Francisco, CA 94105

**IES Downstream, LLC – Kapolei Refinery CSP 0088-01-C**  
**Minor Modification Permit Application**

**Attachment A**

- **Project Report  
Minor Modification  
Application for  
Kapolei Refinery  
CSP 0088-01-C**



**PROJECT REPORT**  
IES Downstream, LLC > Kapolei, HI Refinery



**Kapolei Refinery  
Minor Modification to Covered Source Permit**

Prepared By:

Nancy Matthews – Managing Consultant  
Harold Laurence – Senior Consultant

**TRINITY CONSULTANTS**

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Suite 610  
Seattle, WA 98032  
(253) 867-5600

December 2018

Project 184801.0121



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## 1. EXECUTIVE SUMMARY

---

IES Downstream, LLC (IES) owns and operates a petroleum refinery in Kapolei, HI. IES is requesting a minor modification to the refinery's Covered Source Permit (CSP) 0088-01-C, last modified via minor modification on November 16, 2018.

In this minor modification, IES proposes removing all permit conditions authorizing operation of certain equipment currently permitted to operate under CSP 0088-01-C, so that these sources may be authorized to operate under a separate CSP:

- Fluid Catalytic Cracker Unit (FCCU), including the FCCU stack (identified as emission point M1), FCCU furnace (F-5300), FCCU startup heater (F-5310), and certain FCCU equipment components with fugitive emissions (Attachments II(A) and II(I) of the current CSP);
- Alkylation Plant (Attachment II(A)), including certain equipment components with fugitive emissions;
- Dimersol Plant (Attachment II(A)); and
- Miscellaneous insignificant activities.

For process equipment remaining in the permit Attachment II(A), IES also proposes inclusion of an LDAR program equivalent to 40 CFR 60 Subpart GGGa as the compliance demonstration method for process units subject to LDAR requirements. By including the Subpart GGGa conditions as the refinery's LDAR compliance demonstration method, process fugitive emissions from the affected process units are substantially reduced. The Potential to Emit (PTE) of the process units is re-evaluated in this initial CSP application.

In a separate initial CSP application filed with this minor modification application, IES is proposing a new CSP to authorize operation of this set of equipment, under the name "IES Downstream, LLC - FCCU, Dimersol, and Alkylation Plants." These two applications are intended to be approved in tandem, allowing HDOH to remove permit conditions on FCCU, Dimersol, and Alkylation Plant equipment from the current CSP and to issue the separate FCCU, Dimersol, and Alkylation Plants CSP with no gap in permit authority to operate the equipment.

This application contains the following sections:

- Description of Facility;
- Compliance with Applicable Requirements;
- Ambient Air Quality Analysis;
- Appendix A: Application Forms;
- Appendix B: Plot Plan;
- Appendix C: Emission Calculations;
- Appendix D: Proposed Permit Conditions

This application also contains the \$200 fee payable to the Hawaii Department of Health for review of a CSP minor modification application.

As demonstrated by Section 3, "Compliance with Applicable Requirements," this application report with appendices contains all required information for a complete minor modification application.

## 2. DESCRIPTION OF FACILITY

### 2.1. APPLICANT'S NAME AND BUSINESS DESCRIPTION

IES Downstream, LLC (IES) is submitting this application on behalf of its Kapolei, HI refinery (the Refinery). Please refer to Appendix A for a complete set of Covered Source Permit (CSP) modification forms on standard State of Hawaii Department of Health (HDOH) form templates.

### 2.2. APPLICATION TYPE

This is an application for the minor modification of an existing CSP with permit number 0088-01-C. This application is made to HDOH pursuant to Hawaii Administrative Rules, Title 11, Chapter 11-60.1, Air Pollution Control.

### 2.3. FACILITY DESCRIPTION

#### 2.3.1. Location

The project is located at 91-480 Malakole Street, Kapolei, HI, at a latitude of 21° 18' 42" N and a longitude of 158° 6' 50" W on the island of O'ahu. A map of the area surrounding the project site, along with the location of the project, is included in Appendix B.

#### 2.3.2. Existing Equipment

The Refinery operates all existing equipment in CSP 0088-01-C. An inventory of Potential to Emit (PTE) of criteria pollutants and Hazardous Air Pollutants (HAP) for emission points to remain in CSP 0088-01-C is provided in Appendix C. Process flow diagrams for refinery processes in the 2016 CSP renewal application are incorporated by reference.

#### 2.3.3. General Description and Proposed Modifications

In this minor modification, IES proposes removing all permit conditions authorizing operation of certain equipment currently permitted to operate under CSP 0088-01-C, so that these sources may be authorized to operate under a separate CSP:

- Fluid Catalytic Cracker Unit (FCCU), including the FCCU stack (identified as emission point M1), FCCU furnace (F-5300), FCCU startup heater (F-5310), and certain FCCU equipment components with fugitive emissions (Attachments II(A) and II(I) of the current CSP);
- Alkylolation Plant (Attachment II(A)), including certain equipment components with fugitive emissions;
- Dimersol Plant (Attachment II(A)); and
- Miscellaneous insignificant activities.

For clarity within this application, CSP 0088-01-C as amended on November 16, 2018 is referred to as the "current CSP." The CSP that will be created in tandem with the issuance of this minor modification is referred to as the "FCCU, Dimersol and Alkylolation Plants CSP," and the current CSP 0088-01-C after this minor modification is approved is referred to as the "revised Refinery CSP." The revised Refinery CSP will contain the same equipment except for the equipment listed above.

For process equipment remaining in the permit Attachment II(A), IES also proposes inclusion of an LDAR program equivalent to 40 CFR 60 Subpart GGGa as the compliance demonstration method for process units subject to LDAR requirements. By including the Subpart GGGa conditions as the refinery's LDAR compliance demonstration method, process fugitive emissions from the affected process units are substantially reduced. The Potential to Emit (PTE) of the process units is re-evaluated in this minor modification.

A redline text of the revised Refinery CSP is provided in Appendix D.

#### **2.3.4. Insignificant Activities**

Section 11-60.1-82(f) requires the insignificant activities listed in this subsection to be identified in the CSP application. The insignificant activity list from the 2016 renewal application is incorporated by reference, except that the following items may be removed because they are part of equipment and activities to be authorized under the FCCU, Dimersol, and Alkylation Plants CSP, not CSP 0088-01-C:

- FCC process vents, except those vents associated with the fuel gas treating system and H<sub>2</sub>S adsorber tower/system; and
- The three baghouses on the FCCU electrostatic precipitator (ESP).

After the separation of the two permits, the FCC process vents associated with the fuel gas treating system and H<sub>2</sub>S adsorber system will operate under the applicable requirements in the revised Refinery CSP, while all other FCC process vents will operate under the applicable requirements in the FCCU, Dimersol and Alkylation Plants CSP.

#### **2.3.5. Project Emissions**

The PTE submitted with the February 2016 renewal application for the current CSP has been included in Appendix C, with two key changes:

1. Emission points belonging to the FCCU, Dimersol, and Alkylation Plants CSP are removed. The process fugitives emission point includes emissions from the three affected process areas. Therefore, process fugitive emissions from the FCCU and the alkylation plant are separated between the PTE of the revised Refinery CSP and of the FCCU, Dimersol, and Alkylation Plants CSP according to the relative component counts of each equipment type that releases emissions. Emissions belonging to equipment removed in this modification are subtracted from the PTE. All process fugitive emissions from the dimersol process area are part of the FCCU, Dimersol, and Alkylation Plants CSP. The PTE in Appendix C covers only equipment belonging to the revised Refinery CSP.
2. IES also proposes inclusion of an LDAR program equivalent to 40 CFR 60 Subpart GGGa as the compliance demonstration method for process units subject to LDAR requirements. By including the Subpart GGGa conditions as the refinery's LDAR compliance demonstration method, process fugitive emissions from the affected process units are substantially reduced. The Potential to Emit (PTE) of the process units is re-evaluated in this minor modification.

A summary of PTE is provided in Table 2-1.

**Table 2-1. Potential to Emit**

<b>Sources</b>	<b>PM<sub>10</sub></b>	<b>SO<sub>2</sub></b>	<b>CO</b>	<b>NO<sub>2</sub></b>	<b>VOC</b>	<b>Pb</b>
<b>Cogen Turbines</b>	11.7	27.9	52.5	193.2	2.3	0.0
<b>Crude Furnaces</b>	44.5	482.0	75.0	302.9	5.1	0.0
<b>Isom Furnaces</b>	0.2	0.7	2.1	2.5	0.1	0.0
<b>H&amp;H Furnaces</b>	1.1	3.9	12.1	14.5	0.8	0.0
<b>Acid Preheater &amp; Combustion Chamber</b>	0.4	1.5	4.8	5.7	0.3	0.0
<b>Generators</b>	1.3	0.0	21.8	19.0	19.0	-
<b>Cooling Tower</b>	3.2	-	-	-	9.2	-
<b>Acid Plant Absorber Stack<sup>1</sup></b>	-	1,405.3	-	-	-	-
<b>Wastewater Treatment</b>	-	-	17.0	14.7	74.9	0.0
<b>Process Fugitives</b>	-	-	-	-	210.5	0.0
<b>Tanks</b>	-	-	-	-	32.0	0.0
<b>Refinery Flares</b>	-	319.1	51.0	224.2	9.5	-
<b>Totals</b>	<b>62.5</b>	<b>2,240.4</b>	<b>236.3</b>	<b>776.6</b>	<b>363.8</b>	<b>0.0</b>

Source: Appendix C

1. Absorber stack represented without the effects of the SO<sub>2</sub> Scrubbing System project.

## 3. COMPLIANCE WITH APPLICABLE REQUIREMENTS

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The following sections outline this application's required information and the applicability of state and federal requirements to the proposed CSP modifications.

### 3.1. PERMIT APPLICATION REQUIREMENTS

#### 3.1.1. Minor Modification

The proposed project is subject to State of Hawaii Administrative Rules (HAR), Chapter 11-60.1, Air Pollution Control. The Refinery is considered to be a "covered source" for the purposes of Chapter 11-60.1. The proposed changes to the Refinery's CSP are not considered a "significant modification" to the CSP under the definitions of §11-60.1-81. As described in Section 3.1.2 below, the project is a minor modification. HDOH has determined that the project does not fall under any of the permit change tasks that are listed as "administrative permit amendments."

#### 3.1.2. Minor Modification Completeness Checklist

The proposed project is subject to HAR 11-60.1. The data and analyses in this application support document verify that the project will comply with all applicable state and federal air quality requirements. The Refinery is part of IES' "covered source" under Chapter 11-60.1 comprising the Kapolei Terminal and Kapolei Refinery. Pursuant to §11-60.1-104, an application for minor modifications should include eight points of information, which are outlined below, along with the corresponding information for this application.

##### 3.1.2.1. Description of Proposed Changes

*(1) A clear description of all changes;*

This descriptive information on proposed changes can be found on Section 2.3 of this application report.

##### 3.1.2.2. Determination that Modification Is Minor

*(2) A statement of why the modification is determined to be minor, and a request that minor modification procedures be used;*

In order to be classified as a minor modification, the proposed modification needs to meet the seven criteria in the definition of "minor modification" in HAR 11-60.1-81. The seven criteria are listed below, with responses showing that this modification is minor.

*(1) Does not increase the emissions of any air pollutant above the permitted emission limits;*

This modification does not include any physical or operational changes and it does not increase emissions of any air pollutant. It does include a decrease in PTE of VOC based on implementation of a more stringent LDAR program.

*(2) Does not result in or increase the emissions of any air pollutant not limited by permit to levels equal to or above:*

*(A) 500 pounds per year of a hazardous air pollutant;*

*(B) twenty-five percent of significant amounts of emission as defined in section 11-60.1-1, paragraph (1) in the definition of "significant";*

*(C) five tons per year of carbon monoxide; or*

*(D) two tons per year of each regulated air pollutant other than carbon monoxide;*

This modification does not include any physical or operational changes and it does not increase emissions of any air pollutant. It does include a decrease in PTE of VOC based on implementation of a more stringent LDAR program.

*(3) Does not violate any applicable requirement;*

This modification does not affect the Refinery's compliance with any applicable requirement.

*(4) Does not involve significant changes to existing monitoring requirements or any relaxation or significant change to existing reporting or recordkeeping requirements in the permit. Any change to the existing monitoring, reporting, or recordkeeping requirements that reduces the enforceability of the permit is considered a significant change;*

This modification does not involve significant changes to existing monitoring requirements, nor does it reduce the enforceability of the permit. The modification does propose making changes to LDAR monitoring requirements in Attachment II(A) of the CSP; these changes include adding a permit condition regulating connectors in gas/vapor service and in light liquid service, changing LDAR leak detection thresholds, and other minor changes to implement an LDAR program equivalent to 40 CFR 60 Subpart GGGa.

*(5) Does not require or change a case-by-case determination of an emission limitation or other standard, a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;*

This modification does not require a case-by-case determination of an emission limitation or standard.

*(6) Does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement, and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include: (A) A federally enforceable emissions cap assumed to avoid classification as a modification pursuant to any provision of Title I of the Act or subchapter 7; and (B) An alternative emissions limit approved pursuant to regulations promulgated pursuant to Section 112(i)(5) of the Act or subchapter 9; and*

The only permit term or condition changes proposed, other than removal of requirements of certain process equipment transitioning to a new CSP, are the changes to LDAR monitoring requirements in Attachment II(A) of the CSP. These changes include adding a permit condition regulating connectors in gas/vapor service and in light liquid service, changing LDAR leak detection thresholds, and other minor changes to implement an LDAR program equivalent to 40 CFR 60 Subpart GGGa. 40 CFR 60 Subpart GGGa is being implemented as a voluntary

compliance demonstration method for LDAR applicable requirements under Subpart GGG, or 40 CFR 63 Subpart CC. The proposed changes do not cause the Refinery to avoid becoming subject to applicable requirements.

*(7) Is not a modification pursuant to any provision of Title I of the Act.*

Title I of the Clean Air Act governs the federal PSD program. Because this modification will not increase air emissions, this modification is not subject to federal PSD regulations.

### **3.1.2.3. Maximum Emission Rates**

*(3) Maximum emission rates, including fugitive emissions, of all regulated and hazardous air pollutants resulting from the change. Emission rates shall be reported in pounds per hour and tons per year and in such terms necessary to establish compliance consistent with applicable requirements and standard reference test methods. All supporting emission calculations and assumptions shall also be provided;*

Maximum emission rates can be found in Appendix C of this application report. Emissions are reported in both lb/hr and tpy. PTE emission rates for process fugitives are revised to estimate PTE after implementation of the proposed LDAR program.

### **3.1.2.4. New Applicable Requirements**

*(4) The identification of any new applicable requirements that will apply if the minor modification occurs;*

This modification will not cause new applicable requirements to apply. That said, the modification does increase the stringency of the compliance demonstration method with LDAR requirements in Attachment II(A) of the permit. Proposed changes to the permit terms and conditions are included in Appendix D.

### **3.1.2.5. Permit Changes**

*(5) The suggested changes to permit terms or conditions;*

Proposed changes to the permit terms and conditions are included in Appendix D.

### **3.1.2.6. Certification that Modification Is Minor**

*(6) Certification by a responsible official that the proposed modification meets the criteria for minor modification;*

Certification that the proposed modification is a minor modification, along with other materials in this application, can be found on Form S-1 in Appendix A.

### **3.1.2.7. Information Previously Submitted for CSP Renewal**

*(7) All information submitted with the application for the initial covered source permit or any subsequent application for a covered source permit. The owner or operator may*

*reference information contained in a previous application submittal, provided such referenced information has been certified as being current and still applicable; and*

This application incorporates by reference the February 18, 2016 renewal application for the CSP. Also, this application incorporates by reference all applications for modifications to the CSP since the renewal application was filed, including the following:

- The application dated December 20, 2017, to add conditions for operating an SO<sub>2</sub> Scrubbing System on the acid plant.

### 3.1.2.8. Other Information

*(8) Other information, as required by any applicable requirement or as requested and deemed necessary by the director to make a decision on the application.*

Additional information for specific applicable requirements can be found in Sections 3.2 and 3.3 of this report.

IES will provide additional information if requested during the application review process.

## 3.2. STATE REQUIREMENTS

### 3.2.1. HAR Subchapter 1

The following sections of HAR 11-60.1 Subchapter 1 are applicable to this minor modification application:

- §11-60.1-1 Definitions
- §11-60.1-2 Prohibition of air pollution
- §11-60.1-3 General conditions for considering applications
- §11-60.1-4 Certification
- §11-60.1-6 Holding of permit
- §11-60.1-8 Reporting discontinuance
- §11-60.1-9 Cancellation of a noncovered or covered source permit
- §11-60.1-11 Sampling, testing, and reporting methods
- §11-60.1-12 Air quality models
- §11-60.1-14 Public access to information
- §11-60.1-15 Reporting of equipment shutdown
- §11-60.1-16 Prompt reporting of deviations
- §11-60.1-16.5 Emergency provision
- §11-60.1-19 Penalties and remedies

§§ 11-60.1-2 through -4 constitute the duty to file this permit application, and this permit application fulfills these requirements.

§11-60.1-12, Air quality models, applies to the AERMOD modeling analysis in the February 2016 renewal application for the current CSP. This modeling analysis is incorporated by reference.



### 3.2.2. HAR Subchapter 2

The following sections of Subchapter 2, General Prohibitions, are applicable to the Refinery as stated in the current CSP. Applicability will not change in this modification.

- §11-60.1-31 Applicability
- §11-60.1-32 Visible emissions
- §11-60.1-33 Fugitive dust
- §11-60.1-35 Incineration
- §11-60.1-37 Process industries
- §11-60.1-38 Sulfur oxides from fuel combustion
- §11-60.1-39 Storage of volatile organic compounds
- §11-60.1-40 Volatile organic compound water separation
- §11-60.1-41 Pump and compressor requirements
- §11-60.1-42 Waste gas disposal

### 3.2.3. HAR Subchapter 3

HAR 11-60.1 Subchapter 3, Open Burning, does not apply to the Refinery's emission points.

### 3.2.4. HAR Subchapter 4

HAR 11-60.1 Subchapter 4, Noncovered Sources, does not apply to this permit application or the Refinery, because the Refinery is a covered source.

### 3.2.5. HAR Subchapter 5

The following sections of Subchapter 5, Covered Sources, are applicable to this application:

- §11-60.1-81 Definitions
- §11-60.1-82 Applicability
- §11-60.1-84 Duty to supplement or correct permit applications
- §11-60.1-85 Compliance plan
- §11-60.1-86 Compliance certification of covered sources
- §11-60.1-90 Permit content
- §11-60.1-93 Federally-enforceable permit terms and conditions
- §11-60.1-100 Public petitions
- §11-60.1-103 Applications for minor modifications

### 3.2.6. HAR Subchapter 6

The following sections of Subchapter 6, Fees for Covered Sources, Noncovered Sources, and Agricultural Burning, are applicable to this minor modification application:

- §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
- §11-60.1-115 Basis of annual fees for covered sources

Fees under §11-60.1-114, Annual fees for covered sources, are not part of this application but will continue to be applicable to the Refinery based on actual emission estimates from the Refinery's emission points.

### **3.2.7. HAR Subchapter 7**

HAR 11-60.1 Subchapter 7, Prevention of Significant Deterioration Review, does not apply to this minor modification application. Subchapter 7 applies to major modifications, defined as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulations approved pursuant to the Act." Because this modification does not cause an emission increase, Subchapter 7 does not apply to this application.

### **3.2.8. HAR Subchapter 8**

The following sections of Subchapter 8, Standards of Performance for Stationary Sources, are applicable to this minor modification application:

➤ §11-60.1-161 New Source Performance Standards

§11-60.1-161, New Source Performance Standards, is listed as applicable because the Refinery is subject to NSPS. This modification does not affect the applicability of any NSPS; however it does propose changes to compliance demonstration methods with 40 CFR 60 Subpart GGG as shown in Appendix D.

### **3.2.9. HAR Subchapter 9**

The following sections of Subchapter 9, Hazardous Air Pollutant Sources, are applicable to this application. However, this modification does not increase the Refinery's PTE or actual emissions of HAP, and so this modification does not change the Refinery's applicable requirements or require additional review.

- §11-60.1-171 Definitions
- §11-60.1-172 List of hazardous air pollutants
- §11-60.1-173 Applicability
- §11-60.1-174 Maximum achievable control technology (MACT) emission standards
- §11-60.1-180 National emission standards for hazardous air pollutants

§11-60.1-173, Applicability, is listed as applicable because the Refinery is a stationary source that emits HAP. Furthermore, §11-60.1-180, National emission standards for hazardous air pollutants, and §11-60.1-174, Maximum achievable control technology (MACT) emission standards, are listed as applicable because the Refinery is subject to Part 63 Subpart CC.

§11-60.1-179, Ambient air concentrations of hazardous air pollutants, is not applicable because this section applies only to sources of HAP, and this modification does not increase the Refinery's PTE or actual emissions of HAP. Therefore, this permit application is not subject to HAP ambient air concentrations review.

### **3.2.10. HAR Subchapter 10**

HAR 11-60.1 Subchapter 10, Field Citations, establishes HDOH's field citations program. It does not contain applicable requirements for air permitting.

### 3.2.11. HAR Subchapter 11

HAR 11-60.1 Subchapter 11, Greenhouse Gas Emissions, applies to the Refinery because it is a covered source with the potential to emit GHG equal to or above 100,000 tpy as CO<sub>2</sub> equivalent (CO<sub>2</sub>e). The Refinery will comply with its proposed GHG emission reduction plan when incorporated into CSP 0088-01-C permit terms under HAR 11-60.1-204, "Greenhouse Gas Emission Reduction Plan."

## 3.3. FEDERAL REQUIREMENTS

### 3.3.1. New Source Performance Standards (NSPS)

New Source Performance Standards (NSPS) are codified in 40 CFR 60. NSPS apply to certain types of equipment that are newly constructed, modified, or reconstructed after a given applicability date. The following NSPS apply to the emission points in the current CSP:

- Subpart A, General Provisions
- Subpart J, Petroleum Refineries
- Subpart Ja, Petroleum Refineries (After May 14, 2007)
- Subpart GG, Stationary Gas Turbines
- Subpart GGG, Equipment Leaks in Petroleum Refineries
- Subpart QQQ, VOC Emissions from Petroleum Refinery Wastewater Systems

In addition to this list, items from Subpart Kb for storage tanks are cited in applicable requirements under 40 CFR Part 61, Subpart FF, Benzene Waste Operations.

This modification does not change the applicability of NSPS or the applicability of applicable NSPS requirements; however it does propose changes to compliance demonstration methods with 40 CFR 60 Subpart GGGa as shown in Appendix D.

### 3.3.2. National Emissions Standards for Hazardous Air Pollutants

NESHAPs have been established in 40 CFR Part 61 and Part 63 to control emissions of HAP from stationary sources. The applicability of NESHAP rules often depends on a facility's major source status with respect to HAP emissions. Under 40 CFR Part 63, a major source is defined as "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP." The Refinery is considered a major source of HAP.

The following NESHAP apply to the emission points in the current CSP:

- Part 61, Subpart FF, Benzene Waste Operations
- Part 63:
  - Subpart A, General Provisions
  - Subpart CC, Petroleum Refineries

Because the FCCU is being removed from the CSP through this minor modification, Subpart UUU is no longer applicable to the units in the revised Refinery CSP. Requirements from this subpart are proposed to be moved to the FCCU, Dimersol, and Alkylation Plants CSP. This modification does not change the applicability of any other NESHAP or the applicability of applicable NESHAP requirements, though where Attachment II(A) describes 40

CFR 63 Subpart CC LDAR requirements, the more stringent requirements of 40 CFR 60 Subpart GGGa are used for compliance demonstration.

### **3.3.3. Greenhouse Gas Reporting Requirements**

GHG emissions generated by Refinery are reported under 40 CFR 98 Subparts C, P, and Y. This modification will not affect the Refinery's GHG reports under 40 CFR 98.

## 4. AMBIENT AIR QUALITY ANALYSIS

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This minor modification incorporates by reference the air dispersion modeling submitted to HDOH in the February 2016 renewal application for the current CSP. This ambient air quality analysis demonstrates that the Refinery's air emissions under applicable requirements are protective of National Ambient Air Quality Standards (NAAQS) and state ambient air quality standards (SAAQS).

## APPENDIX A: APPLICATION FORMS

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**S-1: Standard Air Pollution Control Permit Application Form**  
(Covered Source Permit and Noncovered Source Permit)

State of Hawaii  
Department of Health  
Environmental Management Division  
Clean Air Branch  
P.O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: IES Downstream, LLC
2. Facility Name (if different from the Company): IES Downstream, LLC - Kapolei Refinery
3. Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707  
 Phone Number: (808) 682-5711
4. Name of Owner/Owner's Agent: Jon Mauer  
 Title: President and CEO Phone: (808) 682-5711  
 Mailing Address: Same as above  
 City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_
5. Plant Site Manager/Other Contact: Jon Mauer  
 Title: President and CEO Phone: (808) 682-5711  
 Mailing Address: Same as above  
 City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_
6. Permit Application Basis: (Check all applicable categories.)  
 Initial Permit for a New Source       Initial Permit for an Existing Source  
 Renewal of Existing Permit       General Permit  
 Temporary Source       Transfer of Permit  
 Modification to a Covered Source: → Is Modification?     Significant     Minor     Uncertain  
 Modification to a Noncovered Source
7. If renewal or modification, include existing permit number: CSP No. 0088-01-C
8. Does the Proposed Source require a County Special Management Area Permit?     Yes     No
9. Type of Source (Check One):     Covered Source     Covered and PSD Source  
 Noncovered Source     Uncertain
10. Standard Industrial Classification Code (SICC), if known: 2911

11. Proposed Equipment/Plant Location (e.g. street address): 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707  
UTM Coordinates (meters): East: 591,940 m E North: 2,357,220 m N  
UTM Zone: 4 UTM Horizontal Datum:  Old Hawaiian  NAD-27  NAD-83

12. General Nature of Business: Petroleum Refining

13. Date of Planned Commencement of Construction or Modification: Upon Approval by DOH

14. Is *any* of the equipment to be leased to another individual or entity?  Yes  No

15. Type of Organization:  Corporation  Individual Owner  Partnership  
 Government Agency (Government Facility Code: \_\_\_\_\_)  
 Other: \_\_\_\_\_

*Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR §11-60.1-64 & 11-60.1-84)*

**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_

Title: President and CEO Phone: (808) 682-5711

Mailing Address: 91-480 Malakole Street

City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Jon Mauer

(Signature): 

Date: 12/14/18

<b>FOR AGENCY USE ONLY:</b>
File/Application No.: _____
Island: _____
Date Received: _____



Submit the following documents as part of your application:

- A. The **Emissions Units Table**, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:
1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SIC number. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirement of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
    - a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
    - b. Indicate the emission points that discharge together for any length of time.
    - c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.
  2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
    - a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO<sub>x</sub>), Sulfur Dioxide (SO<sub>2</sub>), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM<sub>10</sub>). Abbreviations may be used.
    - b. Include fugitive emissions.
    - c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
    - d. **Tons per year** is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.
  3. Describe **Stack Source Parameters**:
    - a. **Stack Height** is the height above the ground.
    - b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
    - c. **Flow Rate** is the actual, not the calculated, flow rate.
  4. Provide any additional information, if applicable, as follows:
    - a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
    - b. For a rectangular stack, indicate the length and width.
    - c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.
- B. A **process flow diagram** identifying all equipment used in the process, including the following:
1. Identify and describe each emission point.
  2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.
- C. A **facility location map**, drawn to a reasonable scale and showing the following:
1. The property involved and all structures on it. Identify property/fence lines plainly.
  2. Layout of the facility.
  3. Location and identification of the proposed emissions unit on the property.
  4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 100 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.
- D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.



Form S-1  
Stack Information

Stack or Flare Emission Unit	Process ID No. (Prepared/Operational)	Emission Unit as Designated in Permit/Order	Equipment Date	UTM Northing (m) (if single process stack, list & round to nearest 1000 ft)	Zone (e.g. NAD 83, Z1, or MDS)	Stack Ht (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (deg. F)	Stack Flow Rate (AGS)	Horizontal Collection Method	Reference Point Code
7	F5103	01 crude furnace	1961	592,053	NAD 83	141	4.9	40.8	350	777	027	106 500
7	F5103	01 crude furnace	1961	592,053	NAD 83	141	4.9	40.8	350	777	027	106 500
7	F5153	02 crude furnace	1961	592,053	NAD 83	141	4.9	40.8	350	777	027	106 500
7	F5153	02 crude furnace	1961	592,053	NAD 83	141	4.9	40.8	350	777	027	106 500
9	F5930	Isom Furnace 01	1961-62	591,979	NAD 83	80	3.0	2.3	800	16	027	106 500
9	F5950	Isom Furnace 02	1961-62	591,979	NAD 83	80	3.0	2.3	800	16	027	106 500
10	F5700	H2 Manufac.	1960-62	592,058	NAD 83	125	5.9	6.2	500	171	027	106 500
11	F5600	Hydrogenation	1961-62	592,046	NAD 83	125	4.9	6.6	1510	125	027	106 500
12	F6200	Acid Plant CC	1961-62	591,907	NAD 83	123	3.0	9.7	175	68	027	106 500
13	F6262	Acid Pt Furnace		591,880	NAD 83	64	2.0	15.1	628	46	027	106 500
4	KC6701	01 cogen, combined cycle		591,824	NAD 83	70	3.9	68.6	399	835	027	106 500
4	KC6701	01 cogen, combined cycle		591,824	NAD 83	70	3.9	68.6	399	835	027	106 500
4	K66701	01 cogen, simple cycle		591,824	NAD 83	70	3.9				027	106 500
4	K66701	01 cogen, simple cycle		591,824	NAD 83	70	3.9				027	106 500
5	KC6702	02 cogen, combined cycle		591,819	NAD 83	70	3.9	68.6	399	835	027	106 500
5	KC6702	02 cogen, combined cycle		591,819	NAD 83	70	3.9	68.6	399	835	027	106 500
5	K66702	02 cogen, simple cycle		591,819	NAD 83	70	3.9				027	106 500
5	K66702	02 cogen, simple cycle		591,819	NAD 83	70	3.9				027	106 500
6	KC6703	03 cogen, combined cycle		591,814	NAD 83	70	3.9	68.6	399	835	027	106 500
6	KC6703	03 cogen, combined cycle		591,814	NAD 83	70	3.9	68.6	399	835	027	106 500
6	K66703	03 cogen, simple cycle		591,814	NAD 83	70	3.9				027	106 500
6	K66703	03 cogen, simple cycle		591,814	NAD 83	70	3.9				027	106 500
63	TkS301	Tk 301 External Floating Roof, Standing Loss		591,965	NAD 83	38	4.2				027	106 500
63	TkS301	Tk 301 External Floating Roof, Standing Loss		591,965	NAD 83	38	4.2				027	106 500
64	TkS302	Tk 302 External Floating Roof, Standing Loss		591,973	NAD 83	38	4.2				027	106 500
64	TkS302	Tk 302 External Floating Roof, Standing Loss		591,973	NAD 83	38	4.2				027	106 500
16	M2	Cooling Tower	1961-62	592,095	NAD 83	60	26.2	26.2	113	14201	027	106 500
17	M3	Acid Plant Absorber Stack	1961-62	591,907	NAD 83	123	3.0	9.7	175	68	027	106 500
18	M4	Catalyst Transfer		591,928	NAD 83						027	106 500
19	M5	Wastewater Treatment		591,675	NAD 83						027	106 500
19	M5	Wastewater Treatment		591,675	NAD 83						027	106 500
20	M6	Process Fugitives		591,675	NAD 83						027	106 500
22	M8	FCC Flare	1961-62	592,141	NAD 83	157	0.6	65.6	1832	42.0	027	106 500
23	M9	Crude Flare	1961-62	592,207	NAD 83	155	0.2	65.6	1832	12.7	027	106 500
23	M9	Crude Flare	1961-62	592,207	NAD 83	155	0.2	65.6	1832	12.7	027	106 500
New		CatOX Unit	2009	591,791	NAD 83	30.8	1.11	61.0	305	58.62	027	106 500

Process No. (see Appendix A)	Control Point (see Appendix B)	Control Measure (see Appendix C)	Primary Control Code	Primary Control Efficiency % (see Appendix D)	Secondary Control Measure (see Appendix E)	Secondary Control Code	Secondary Control Efficiency % (see Appendix F)	Total Control Efficiency % (see Appendix G)
F8103	1	NOX	205	100				
F8103	1	SO2	099	100				
F8103	2	NOX	205	100				
F8103	2	SO2	099	100				
F8153	1	NOX	205	100				
F8153	1	SO2	099	100				
F8153	2	NOX	205	100				
F8153	2	SO2	099	100				
KC6701	2	NOX	205	100	Water Injection	028	100	
KC6701	3	NOX	205	100	Water Injection	028	100	
KC6701	3	SO2	099	100				
KC6702	2	NOX	205	100	Water Injection	028	100	
KC6702	3	NOX	205	100	Water Injection	028	100	
KC6702	3	SO2	099	100				
KC6703	2	NOX	205	100	Water Injection	028	100	
KC6703	3	NOX	205	100	Water Injection	028	100	
KC6703	3	SO2	099	100				
KS6701	2	NOX	205	100	Water Injection	028	100	
KS6701	3	NOX	205	100	Water Injection	028	100	
KS6701	3	SO2	099	100				
KS6702	2	NOX	205	100	Water Injection	028	100	
KS6702	3	NOX	205	100	Water Injection	028	100	
KS6702	3	SO2	099	100				
KS6703	2	NOX	205	100	Water Injection	028	100	
KS6703	3	NOX	205	100	Water Injection	028	100	
KS6703	3	SO2	099	100				
TKS301	13	VOC	097	100	Submerged Filling	093	100	
TKW301	13	VOC	097	100	Submerged Filling	093	100	
TKW302	13	VOC	097	100	Submerged Filling	093	100	
M5	8	VOC	048	100	Carbon Canister	046	100	99.75
M6	9	VOC	023	100				98
M9	9	VOC	023	100				98
M9	22	Ammonia	023	100				98

**S-7: Application for a Minor Modification to a Covered Source**

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)  
Permits Office, Air Division  
U.S. Environmental Protection Agency  
Region 9  
75 Hawthorne Street  
San Francisco, CA 94105

- I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-103, the following information is required: Please refer to the following sections of this application report:
- A. A clear description of all changes. Section 2.3
  - B. A statement of why the modification is determined to be minor, and a request that minor modification procedures be used. Section 3.1.2.2
  - C. Cite and describe any new applicable requirements as defined in HAR §11-60.1-81 that will apply if the minor modification occurs. Section 3.2, Appendix D
  - D. The suggested changes to permit terms or conditions. Appendix D
  - E. Certification by a responsible official that the proposed modification meets the criteria for minor modification. Section 3.1.2.2, Form S-1 Certification
  - F. All information submitted with the application for the Initial Covered Source Permit or any subsequent application for a Covered Source Permit. The owner or operator may reference information contained in a previous application submittal, provided such referenced information has been certified as being current and still applicable. Section 3.1.2.7 and all documents incorporated by reference.
  - G. Other information, as required by any applicable requirement or as requested and deemed necessary by the Director of Health (hereafter, Director) to make a decision on the application.
- II. **Submit an application fee according to the Application Fee Schedule in the Instructions for Applying for an Air Pollution Control Permit.**

- III. An application shall be determined to be complete only when all of the following have been complied with:**
- A. All information required or requested in number I have been submitted.
  - B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.
  - C. All applicable fees have been submitted.
  - D. The Director has certified that the application is complete.
- IV. The Director shall not continue to act upon or consider an incomplete application.**
- A. The applicant shall be notified in writing whether the application is complete. Unless the Director requests additional information or notifies the applicant of incompleteness within thirty days of receipt of an application, the application shall be deemed complete.
  - B. During the processing of an application that has been determined or deemed complete, if the Director determines that additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.
- V. Within ninety days of receipt of a complete application for a minor modification, or upon program approval, within fifteen days after the end of the Administrator's forty-five-day review period, whichever is later, the Director in writing shall:**
- A. Amend the permit to reflect the minor modification as proposed.
  - B. Deny the minor modification.
  - C. Determine that the requested modification does not meet the minor modification criteria, and should be reviewed under the significant modification procedures; or
  - D. Upon program approval, amend the proposed permit and resubmit the amendment to EPA for reevaluation.
- VI. An application for a minor modification to a covered source shall be approved only if the Director determines that the minor modification will be in compliance with all applicable requirements.**
- VII. The Director shall provide a statement that sets forth the legal and factual bases for the proposed permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.**
- VIII. Each application and proposed permit reflecting the minor modification to a covered source shall be subject to EPA oversight in accordance with HAR §11-60.1-95.**

**C-1: Compliance Plan**

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets of paper if necessary.

1. Compliance status with respect to all Applicable Requirements:

Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

YES {If YES, complete items a and c below}

NO {If NO, complete items a, b, and c below}

a. Identify all applicable requirement(s) for which compliance is achieved.

The emission units are in compliance with all applicable requirements.

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

Provide a statement that the source is in compliance and will continue to comply with all such requirements.  
The emission units will continue to comply with all applicable requirements.

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

b. Identify all applicable requirement(s) for which compliance is NOT achieved.

N/A

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

Provide a detailed Schedule of Compliance Schedule and a description of how the source will achieve compliance with all such applicable requirements.

N/A	<u>Description of Remedial Action</u>	<u>Expected Date of Completion</u>
_____	_____	_____
_____	_____	_____
_____	_____	_____

- c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to. These applicable requirements may take effect AFTER permit issuance:

<u>Applicable Requirement</u>	<u>Effective Date</u>	<u>Currently in Compliance?</u>
<u>N/A</u>		

If the source is not currently in compliance, provide a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

<u>Description of Proposed Action/Steps to Achieve Compliance</u>	<u>Expected Date of Achieving Compliance</u>
<u>N/A</u>	

Provide a statement that the source on a timely basis will meet all these applicable requirements:

N/A

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If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of each remedial action and the expected date of completion:

<u>Description of Remedial Action and Explanation</u>	<u>Expected Date of Completion</u>
<u>N/A</u>	

2. Compliance Progress Reports:

- a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: N/A  
(less than or equal to 6 months)

Beginning Date: N/A



b. Date(s) that the Action described in (1)(b) was achieved:

<u>Remedial Action</u>	<u>Date Achieved</u>
N/A	

c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

N/A

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**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_

Title: President and CEO Phone: (808) 682-5711

Mailing Address: 91-480 Malakole Street

City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Jon Mauer

(Signature):  Date: 12/11/18

Facility Name: IES Downstream, LLC - Kapolei Refinery

Location: 91-480 Malakole Street

Permit Number: 0088-01-C

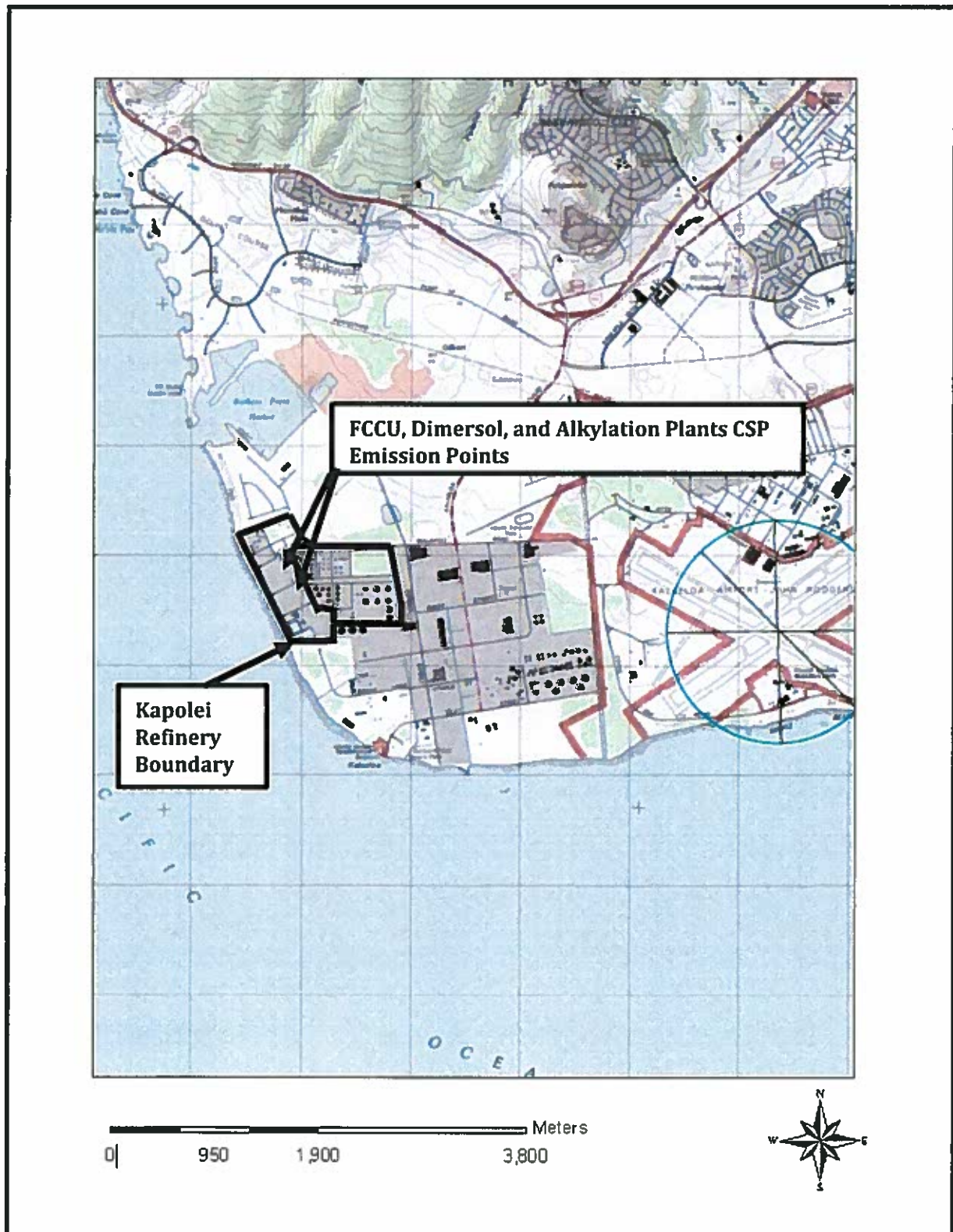
<b>FOR AGENCY USE ONLY</b>	
File/Application No.:	_____
Island:	_____
Date Received:	_____



**Appendix Figure B-1. FCCU, Dimersol, and Alkylation Plants in Kapolei Refinery CSP**

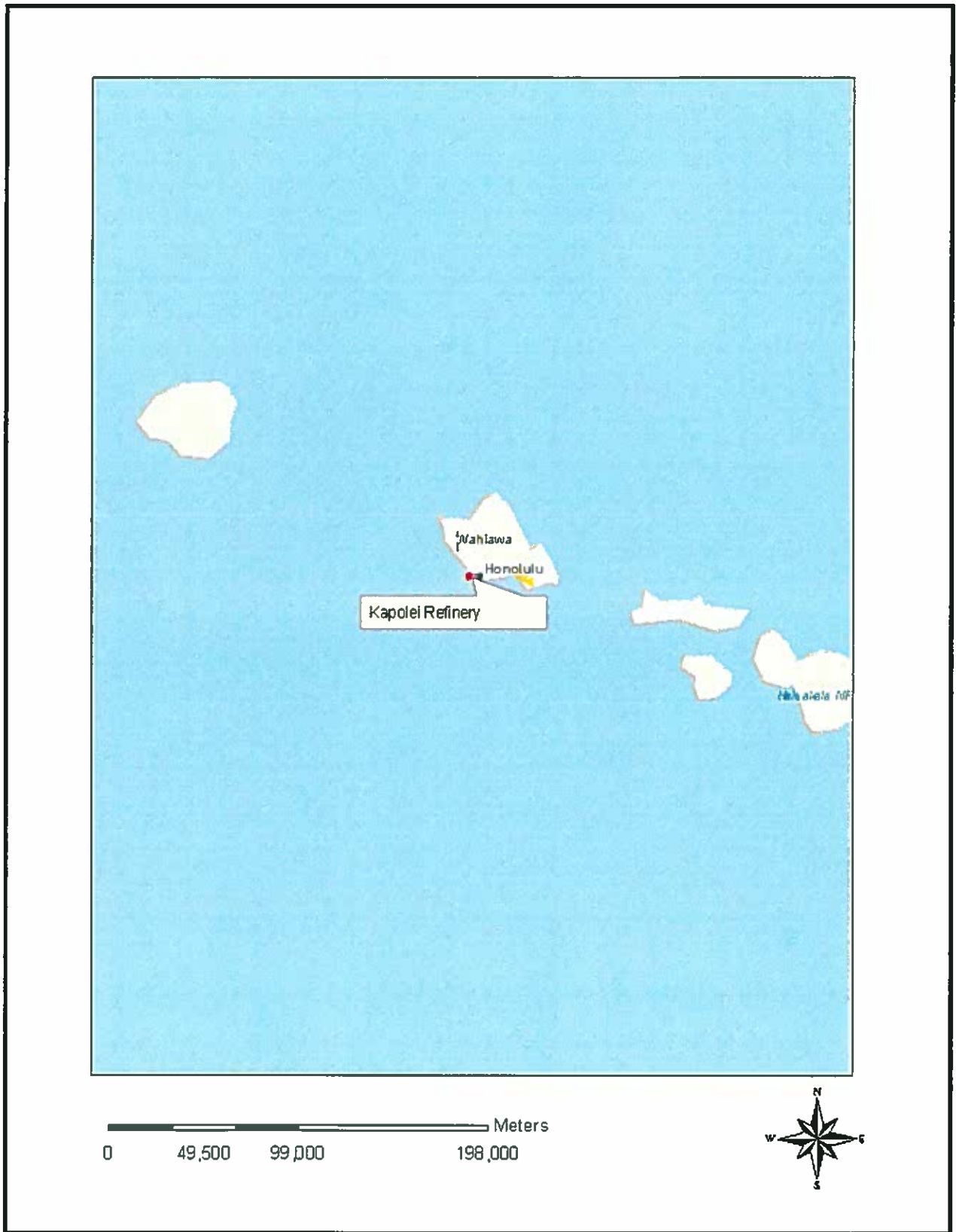


Appendix Figure B-2. Kapolei Refinery CSP with FCCU, Dimersol, and Alkylation Plants





Appendix Figure B-3. General Location of the Kapolei Refinery



## APPENDIX C: EMISSION CALCULATIONS

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## Summary

### IES Downstream, LLC - Kapolei Refinery - PTE Incorporated from 2016 CSP 0088-01-C Renewal Application

SOURCES	Pollutant emission rates (ton/yr)						Total Criteria Pollutant Emissions
	PM10	SO2	CO	NO2	VOC	Lead	
Cogen Turbines	11.7	27.9	52.5	193.2	2.3	0.0	288
Crude Furnaces	44.5	482.0	75.0	302.9	5.1	0.0	909
Isom Furnaces	0.2	0.7	2.1	2.5	0.1	0.0	5
H&H Furnaces	1.1	3.9	12.1	14.5	0.8	0.0	32
Acid preheater & combustion chamber	0.4	1.5	4.8	5.7	0.3	0.0	13
Cooling Tower	3.2	-	-	-	9.2	-	12
Acid plant absorber stack <sup>1</sup>	-	1405.3	-	-	-	-	1405
Wastewater treatment <sup>2</sup>	-	-	17.0	14.7	74.9	0.0	107
Process Fugitives	-	-	-	-	210.5	0.0	210
Tanks	-	-	-	-	32.0	0.0	32
Refinery Flares	-	319.1	51.0	224.2	9.5	-	604
<b>Totals</b>	<b>61.2</b>	<b>2240.4</b>	<b>214.5</b>	<b>757.6</b>	<b>344.7</b>	<b>0.0</b>	<b>3618.3</b>

Notes:

<sup>1</sup> Criteria pollutant emissions from the acid preheater and combustion chamber are vented to the acid plant absorber stack. The listed SO2 emissions from the acid plant absorber stack are only from acid production.

<sup>2</sup> Includes CatOx Unit. Table 3-12 has CatOx listed separately.

**Point sources**

**Summary of Potential Emissions From Point Combustion Sources**

SOURCES	Pollutant emission rates (ton/yr)							Total Criteria Pollutant Emissions
	PM10	SO2	CO	NOx	VOC	Lead		
CatOx Unit	0.00	0.00	17.00	14.70	1.30	0.00	0.00	33
Cogen Turbines	11.72	27.92	52.49	193.16	2.34	0.006	0.006	288
Crude Furnaces	44.49	481.99	74.99	302.88	5.11	0.010	0.010	909
Isom Furnaces	0.19	0.66	2.06	2.45	0.13	0.000	0.000	5
H&H Furnaces	1.10	3.91	12.14	14.45	0.79	0.000	0.000	32
Acid preheater & combustion chamber	0.43	1.54	4.80	5.71	0.31	0.000	0.000	13
<b>Totals</b>	<b>57.9</b>	<b>516.0</b>	<b>163.5</b>	<b>533.4</b>	<b>10.0</b>	<b>0.0</b>	<b>0.0</b>	<b>1280.8</b>



IES DOWNSTREAM, LLC REFINERY ACTUAL VOC EMISSIONS  
FROM STORAGE TANKS

Tank Id	Type of tank	Service of Tank	total (ton)	Total VOC Losses (lb/yr)	Losses (ton/yr)
Tk 301	External Floating Roof	Rec Oil	12.9	25895.65	12.9
Tk 302	External Floating Roof	Rec Oil	12.9	25895.65	12.9
				<u>301</u>	
				<u>302</u>	

Total Emissions for all Tanks: 25.9 51791.30 25.90

PTE % increase Factor 1.24

IES DOWNSTREAM, LLC REFINERY POTENTIAL VOC EMISSIONS  
FROM STORAGE TANKS

Tank Id	Type of tank	Service of Tank	total (ton)	Total VOC Losses (lb/yr)	Losses (ton/yr)
Tk 301	External Floating Roof	Rec Oil	16.0	31994.08	16.0
Tk 302	External Floating Roof	Rec Oil	16.0	31994.08	16.0
				<u>301</u>	
				<u>302</u>	

Total Emissions for all Tanks: 32.0 63988.15 31.99



## Flare

### FLARE POINT SOURCE POTENTIAL TO EMIT CALCULATIONS

**Flare Pilots - F/G acid plant down**

Unit	F/G SCFH	downtime hr/year	S ppm	lbs SO2/MMSCF	SO2 lb/hr	Lbs/Year	Tons/Yr
FCC	15000	8760	36.5809	6.1772	0.09266	811.690	0.40585

lb SO2/MMSCF = 1/379\*ppm S \*64

**Flare Pilots - F/G normal**

Unit	F/G SCFH	op hr/yr	S ppm	lbs SO2/MMSCF	SO2 lb/hr	Lbs/Year	Tons/Yr	lb/day
Crude	100	8760	36.581	6.177	0.00062	5.41	0.00271	0.015
FCC	150	0	36.581	6.177	0.00093	0.00	0.00000	0.022

lb SO2/MMSCF = 1/379\*ppm S \*64

**Acid Plant shutdown FLARE emissions: H2S based on CRTIC analysis that shows 35 lbs.H2S/100 lbs.sulfur in FCC feed**

FCC Feed	%S	lb/bbl	Feed rate (bbl)	Total Sulfur (lb)	% conv to H2S	lb H2S/day	lbs/hr h2s	Hrs downtime	Total lbs H2S	Total lbs SO2	TPY
VGO	0.42	306	22,000	28274	35	9896	412.3	8760	3612055	6799162	3400

Use sulfur and feedrate values for period that Acid Plant was shutdown.

**Flare emissions (from AP-42)**

Pollutant	lb/10 <sup>3</sup> bbl	crude unit throughput (bbl/day)	lb/day	day/yr	TPY
NOX	18.9	65000	1229	365	224.2
VOC	0.8	65000	52	365	9.5
CO	4.3	65000	280	365	51.0
PM	neg				
SO2	26.9	see calculations for when acid plant down	1749	365	319.1
				Total	603.8

now have FSERP

HAP Summary

Fugitive Emission by Area NUMBER		Total speciated VOC emissions (kg/hr)									
AREA DESCRIPTION		BENZENE CAS# 71432 (ton/yr) 1	NAPHTHALENE CAS# 91203 (ton/yr) 2	O-XYLENE CAS# 95476 (ton/yr) 3	ETHYLBENZENE CAS# 100414 (ton/yr) 4	P-XYLENE CAS# 106423 (ton/yr) 5	ETHYLENE DIBROMIDE CAS# 106934 (ton/yr) 6	ETHYLENE DICHLORIDE CAS# 107062 (ton/yr) 7	M-XYLENE CAS# 108383 (ton/yr) 8	TOLUENE CAS# 108883 (ton/yr) 9	1,3-BUTADIENE CAS# 106990 (ton/yr) 10
23	RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	WASTE WATER TREATMENT LAND										
36	TREATMENT UNIT	0.00	0.01	0.01	0.00	0.01	0.00	0.00	0.01	0.01	0.00
51	CRUDE UNIT	0.13	0.09	0.19	0.04	0.07	0.00	0.00	0.26	0.32	0.00
52/55	BOILERS/FOUL WATER OXIDIZER	0.01	0.03	0.05	0.02	0.03	0.00	0.00	0.07	0.04	0.00
53	FLUID CATALYTIC CRACKER UNIT	0.03	0.06	0.10	0.03	0.05	0.00	0.00	0.13	0.10	0.00
56	HYDROGENATION PLANT	0.01	0.02	0.03	0.01	0.01	0.00	0.00	0.03	0.02	0.01
57	HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	ALKYLATION PLANT	0.01	0.03	0.05	0.02	0.02	0.00	0.00	0.06	0.04	0.00
59	ISOMERIZATION PLANT	0.01	0.02	0.03	0.01	0.01	0.00	0.00	0.03	0.02	0.00
61/62	AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
67	COGENERATION PLANT	0.028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.016	0.000
	Process Fugitive Summary	0.22	0.25	0.46	0.13	0.20	0.00	0.00	0.60	0.57	0.02
67	COGEN POINT	0.034	0.018						0.033	0.067	0.008
51	CRUDE POINT	0.001	0.006	0.001	0.00				0.030		
59	ISOM POINT	0.000	0.000						0.000		
56	H&H POINT	0.000	0.000						0.000		
57	H&H POINT	0.000	0.000						0.000		
	H&H summary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
62	ACID PLANT CC AND PREHEATER POINT	0.000	0.000							0.000	
	WASTEWATER	0.1398	0.3458	0.5887	0.1840	0.2796	0.0002	0.0000	0.7211	0.4709	0.0000
	FLARE	0									0.00
	HAPs Summary	0.40	0.62	1.05	0.31	0.48	0.00	0.00	1.36	1.14	0.03

HAP Summary

Total speciated VOC emissions (kg/hr)											
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	n-HEXANE CAS# 110543 (ton/yr)	ANILINE CAS# 62533 (ton/yr)	CRESOL MIXTURE CAS# 1319773 (ton/yr)	PHENOL CAS# 108952 (ton/yr)	STYRENE CAS# 100425 (ton/yr)	METHANOL CAS# 67561 (ton/yr)	NICKEL CAS# (ton/yr)	reported as LEAD CAS# (ton/yr)	HCL CAS# 7647010 (ton/yr)	PERCHLOROETHYLENE CAS# 127184 (ton/yr)
		11	12	13	14	15	16	17	18	19	20
23	RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	WASTE WATER TREATMENT LAND										
36	TREATMENT UNIT	0.02	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51	CRUDE UNIT	0.41	0.00	0.11	0.01	0.00	0.00	0.00	0.00	0.00	0.00
52/55	BOILERS/FOUL WATER OXIDIZER	0.10	0.00	0.10	0.01	0.00	0.00	0.00	0.00	0.00	0.00
53	FLUID CATALYTIC CRACKER UNIT	0.04	0.00	0.16	0.01	0.00	0.00	0.00	0.00	0.00	0.00
56	HYDROGENATION PLANT	0.05	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	ALKYLATION PLANT	0.09	0.00	0.09	0.01	0.00	0.00	0.00	0.00	0.00	0.00
59	ISOMERIZATION PLANT	0.05	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61/62	AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
67	COGENERATION PLANT	0.062	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Process Fugitive Summary	0.82	0.00	0.58	0.04	0.00	0.00	0.00	0.00	0.00	0.00
67	COGEN POINT										
51	CRUDE POINT	0.002									
59	ISOM POINT	0.044									
56	H&H POINT	0.071									
57	H&H POINT	0.189									
	H&H summary	0.260	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
62	ACID PLANT CC AND PREHEATER POINT	0.103									
	WASTEWATER	1.0449	0.0007	1.0670	0.0589	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001
	FLARE										
	HAP's Summary	2.27	0.00	1.65	0.09	0.00	0.00	0.00	0.00	0.00	0.00

HAP Summary

Total speciated VOC emissions (kg/hr)											
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	not HAP CYCLOHEXANE CAS# 110827 (ton/yr) 21	BIPHENYL CAS# 92524 (ton/yr) 22	2,2,4 TRIMETHYLPENTANE CAS# 540841 (ton/yr) 23	CUMENE CAS# 98828 (ton/yr) 24	O-TOLUIDINE CAS# 95534 (ton/yr) 25	ACRYLAMIDE CAS# 79061 (ton/yr) 26	ANTIMONY COMPOUNDS CAS# (ton/yr) 27	ARSENIC CAS# (ton/yr) 28	not HAP PROPYLENE CAS# 115071 (ton/yr) 29	CYANIDE COMPOUNDS CAS# (ton/yr) 30
23	RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00
36	WASTE WATER TREATMENT LAND TREATMENT UNIT	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51	CRUDE UNIT	0.13	0.01	0.30	0.02	0.04	0.00	0.00	0.00	0.54	0.00
52/55	BOILERS/FOUL WATER OXIDIZER	0.00	0.00	0.05	0.01	0.00	0.00	0.00	0.00	0.06	0.00
53	FLUID CATALYTIC CRACKER UNIT	0.00	0.00	0.07	0.02	0.00	0.00	0.00	0.00	0.10	0.00
56	HYDROGENATION PLANT	0.01	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.11	0.00
57	HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	ALKYLATION PLANT	0.00	0.00	0.05	0.01	0.00	0.00	0.00	0.00	0.05	0.00
59	ISOMERIZATION PLANT	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.02	0.00
61/62	AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
67	COGENERATION PLANT	0.044	0.000	0.011	0.000	0.000	0.000	0.000	0.000	0.209	0.000
	Process Fugitive Summary	0.18	0.02	0.34	0.08	0.04	0.00	0.00	0.00	1.15	0.00
67	COGEN POINT										
51	CRUDE POINT										
59	ISOM POINT										
56	H&H POINT										
57	H&H POINT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	H&H summary										
62	ACID PLANT CC AND PREHEATER POINT	0.2575	0.0221	0.5151	0.1251	0.0589	0.0000	0.0001	0.0001	0.0000	0.0001
	WASTEWATER										
	FLARE										
	HAPs Summary	0.44	0.04	0.86	0.20	0.10	0.00	0.00	0.00	1.15	0.00

## HAP Summary

		Total speciated VOC emissions (kg/hr)							
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	not HAP 1,2,4-TMBenzene CAS# 95636 (ton/yr) 31	not HAP ETHYLENE CAS# 74851 (ton/yr) 32	Formaldehyde (ton/yr)	POM/PAH (ton/yr)	Total Haps ton/yr			
23	RELIEF SYSTEMS	0.00	0.06			0.000			
36	WASTE WATER TREATMENT LAND								
51	TREATMENT UNIT	0.00	0.00			0.112			
	CRUDE UNIT	0.08	0.32			1.814			
52/55	BOILERS/FOUL WATER OXIDIZER	0.00	0.06			0.508			
53	FLUID CATALYTIC CRACKER UNIT	0.01	0.01			0.799			
56	HYDROGENATION PLANT	0.00	0.07			0.268			
57	HYDROGEN PLANT	0.00	0.00			0.000			
58	ALKYLATION PLANT	0.00	0.01			0.495			
59	ISOMERIZATION PLANT	0.00	0.02			0.256			
61/62	AMINE/ACID PLANT	0.00	0.01			0.000			
67	COGENERATION PLANT	0.000	0.233			0.120			
	Process Fugitive Summary	0.09	0.80	0.00	0.00	4.372			
67	COGEN POINT			0.506	0.021	0.688			
51	CRUDE POINT			0.208	0.006	0.253			
59	ISOM POINT			0.002	0.000	0.046			
56	H&H POINT			0.003	0.000	0.000			
57	H&H POINT			0.008	0.000	0.074			
	H&H summary	0.000	0.000	0.011	0.000	0.198			
						0.272			
62	ACID PLANT CC AND PREHEATER POINT			0.004	0.000	0.107			
	WASTEWATER	0.5224	0.0000			5.623			
	FLARE					0.002			
	HAP's Summary	0.61	0.80	0.73	0.03	11.36	0.00		

PTE DRAIN EMISSIONS

Worst case speciation is recovered oil for HAPs

Note 1 Note 2

			NUMBER OF DRAINS	VOC P-TRAP (lbs/hr)	VOC NO P-TRAP (lbs/hr)	TOTAL VOC (lbs/hr)
COGEN PLANT	HL	63	51	0.001	0.07	0.051
BOILER PLANT	HL	63	96	0.001	0.07	6.720
MAINTENANCE	HL	63	1	0.001	0.07	0.070
FCC	RO	63	153	0.001	0.07	10.710
ALKYLATION	LA	63	92	0.001	0.07	6.440
ISOMERIZATION	LA	63	47	0.001	0.07	3.290
CRUDE UNIT	ANS	63	101	0.001	0.07	6.794
H2/ H2M	HL	63	49	0.001	0.07	3.430
ACID PLANT	LA	63	0	0.001	0.07	0.000
EFFLUENT	RO	63	20	0.001	0.07	1.400
<b>TOTAL (PER HOUR)</b>						<b>39</b>
<b>TOTAL ANNUAL (LBS)</b>						<b>340808</b>
<b>TOTAL ANNUAL (TONS)</b>						<b>170</b>



AP-42 HAPs Emissions for FGD and FGD Combustion

EF AP-42 Table 3.1.11 for FGD combustion	EF (lb/MM Btu) GJ	Crude GPP (MMBtu/yr)	Crude (lb/yr)	Crude (lb/yr)
Metals				
Aluminum	0.00132	9,771,736	12.80	0.0
Antimony	0.00027	9,771,736	0.27	0.0
Beryllium	0.00003	9,771,736	0.30	0.0
Cadmium	0.00040	9,771,736	3.86	0.0
Chlorine	0.34700	9,771,736	3.38	0.0
Chromium	0.00025	9,771,736	2.42	0.0
Chromium (VI)	0.00002	9,771,736	0.19	0.0
Copper	0.00176	9,771,736	1.76	0.0
Fluoride	0.00370	9,771,736	3.52	0.0
Lead	0.00151	9,771,736	1.51	0.0
Manganese	0.00211	9,771,736	2.11	0.0
Mercury	0.00079	9,771,736	0.79	0.0
Nickel	0.00450	9,771,736	4.35	0.4
Phosphorus	0.00048	9,771,736	0.47	0.0
Selenium	0.00160	9,771,736	1.60	0.0
Vanadium	0.00100	9,771,736	0.97	0.0
Zinc	0.02910	9,771,736	28.32	0.0

Total Hg: 3.83

EF AP-42 Table 3.1.9 for FGD combustion

Organic/Other HAPs	EF (lb/MM Btu) GJ	Crude GPP (MMBtu/yr)	Crude (lb/yr)	Crude (lb/yr)
Benzene	0.0002140	9,771,736	2.08	0.00
Ethylbenzene	0.0000335	9,771,736	0.32	0.00
Formaldehyde	0.0011300	9,771,736	11.04	0.01
1,1,1-Trichloroethane	0.0000000	9,771,736	0.00	0.00
Toluene	0.0002000	9,771,736	1.97	0.00
o-xylene	0.0001050	9,771,736	1.07	0.00
several individual PCBs				

see below

EF AP-42 Table 3.1.3 for FGD combustion

Organic/Other HAPs	EF (lb/MM Btu) GJ	Crude GPP (MMBtu/yr)	Crude (lb/yr)	Crude (lb/yr)
Formaldehyde	0.00250	9,771,736	415.30	0.2
PCB	0.00120	9,771,736	11.73	0.0

EF Gas Turbine AP-42 Table 3.1.4 for Distillate combustion

Metals	EF (lb/MMBtu) LBR/HR	Crude (MMBtu/yr)	Crude (lb/yr)	Crude (lb/yr)
Aluminum	0.00001	1,000,264	1.00	0.0
Antimony	0.00000	1,000,264	0.00	0.0
Beryllium	0.00000	1,000,264	0.00	0.0
Cadmium	0.00000	1,000,264	0.00	0.0
Chromium	0.00001	1,000,264	1.00	0.0
Lead	0.00001	1,000,264	1.00	0.0
Manganese	0.00079	1,000,264	790.22	0.4
Mercury	0.00000	1,000,264	0.00	0.0
Nickel	0.00000	1,000,264	0.00	0.0
Selenium	0.00003	1,000,264	25.01	0.0

EF Gas Turbine AP-42 Table 3.1.4 for Distillate combustion

Organic	EF (lb/MMBtu) LBR/HR	Crude (MMBtu/yr)	Crude (lb/yr)	Crude (lb/yr)
1,2-Dichloroethane	0.00002	1,000,264	18.00	0.0
Benzene	0.00005	1,000,264	55.02	0.0
Formaldehyde	0.00028	1,000,264	280.06	0.1
Furans	0.00050	1,000,264	25.01	0.0
PAH	0.00004	1,000,264	40.01	0.0

EF Gas Turbine AP-42 Table 3.1.3 FGD COMBUSTION

Organic	EF (lb/MMBtu) RFG	Crude (MMBtu/yr)	Crude (lb/yr)	Crude (lb/yr)
1,2-Dichloroethane	0.00000	1,031,628.25	0.04373	0.0
Acetaldehyde	0.00004	1,031,628.25	41.27705	0.0
Acetone	0.00001	1,031,628.25	6.68433	0.0
Benzene	0.00001	1,031,628.25	17.36311	0.0
Ethylbenzene	0.00003	1,031,628.25	33.07184	0.0
Formaldehyde	0.00000	1,031,628.25	0.00000	0.0
Naphthalene	0.00000	1,031,628.25	1.34150	0.0
PAH	0.00000	1,031,628.25	2.70262	0.0
Propylene oxide	0.00003	1,031,628.25	29.82286	0.0
Toluene	0.00013	1,031,628.25	134.15591	0.1
Xylene	0.00008	1,031,628.25	66.04328	0.0

HAPs Point

AP-43 HAPs listing for FGD and FGD Combustion  
 EF AP-43 Table 1A-4 FGD COMBUSTION

Metal	EF (lb/MMBtu)	Copper/iron		Hydrogen		Hydrogenation		Acid Plant	
		Units (K-4781, K-4792, & K-4793)	Crude Furnaces F-4538	Item Furnace F-4538	Hydrogen Manufacturing Furnace F-4798	Hydrogenation Furnace F-4688	Acid Plant Furnace F-4792	Acid Plant Preheater F-4798	
Arsenic	0.0004000	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	
Beryllium	0.0001720	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	
Chromium	0.0014000	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	
Cadmium	0.0005940	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	
Copper	0.0006500	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	
Manganese	0.0008000	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	
Mercury	0.0001000	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	
Nickel	0.0011000	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	
Selenium	0.0002400	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	
Vanadium	0.0020000	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	
Zinc	0.0050000	863.52	1.787.33	49.08	210.24	78.84	70.91	43.36	

EF AP-43 Table 1A-3 FGD COMBUSTION

Dynamics	EF (lb/MMBtu)	Copper/iron		Hydrogen		Hydrogenation		Acid Plant	
		Units (K-4781, K-4792, & K-4793)	Crude Furnaces F-4538	Item Furnace F-4538	Hydrogen Manufacturing Furnace F-4798	Hydrogenation Furnace F-4688	Acid Plant Furnace F-4792	Acid Plant Preheater F-4798	
Dynamics	2.10E-03	863.52	1.96	49.08	210.24	78.84	70.91	43.36	
Dichlorobenzene	1.20E-03	863.52	1.96	49.08	210.24	78.84	70.91	43.36	
Formaldehyde	7.50E-02	863.52	1.96	49.08	210.24	78.84	70.91	43.36	
Hexane	0.10E-03	863.52	1.96	49.08	210.24	78.84	70.91	43.36	
Methane	0.10E-03	863.52	1.96	49.08	210.24	78.84	70.91	43.36	
Toluene	3.00E-03	863.52	1.96	49.08	210.24	78.84	70.91	43.36	
POM	8.87E-05	863.52	1.96	49.08	210.24	78.84	70.91	43.36	

Metal	EF (lb/MMBtu)	Copper/iron		Hydrogen		Hydrogenation		Acid Plant	
		Units (K-4781, K-4792, & K-4793)	Crude Furnaces F-4538	Item Furnace F-4538	Hydrogen Manufacturing Furnace F-4798	Hydrogenation Furnace F-4688	Acid Plant Furnace F-4792	Acid Plant Preheater F-4798	
Arsenic	0.0004000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Beryllium	0.0001720	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Chromium	0.0014000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Cadmium	0.0005940	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Copper	0.0006500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Manganese	0.0008000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Mercury	0.0001000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Nickel	0.0011000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Selenium	0.0002400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Vanadium	0.0020000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Zinc	0.0050000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	

Dynamics	EF (lb/MMBtu)	Copper/iron		Hydrogen		Hydrogenation		Acid Plant	
		Units (K-4781, K-4792, & K-4793)	Crude Furnaces F-4538	Item Furnace F-4538	Hydrogen Manufacturing Furnace F-4798	Hydrogenation Furnace F-4688	Acid Plant Furnace F-4792	Acid Plant Preheater F-4798	
Dynamics	2.10E-03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Dichlorobenzene	1.20E-03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Formaldehyde	7.50E-02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Hexane	0.10E-03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Methane	0.10E-03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Toluene	3.00E-03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
POM	8.87E-05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	

0.00 1.83

**23 - Relief Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS  
FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 23**

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 23  
Date of last revision 3/12/02

<b>H&amp;H VOC</b>	<b>Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Valves		0.03	0.1212
Connections		0.12	0.5311
Pumps		0.00	0.0000
Compressors		0.00	0.0000
PRVs		0.00	0.0000
Drains	Included in FCC process drain count		
<b>TOTALS</b>		<b>0.15</b>	<b>0.65</b>

**36 - WW Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS**

**AREA 36 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE**

Calculated for 2002 reporting year

Date of last revision 9/18/2001

Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
removed 10% growth factor due to no changes since 1993.

FCC VOC Emissions	lb/hr	ton/yr	using API data		using EPA data		Delta
			lb/hr	ton/yr	lb/hr	ton/yr	
Compressors	None	N/A					
Connectors	0.0087	0.0382	0.0085	0.0373	0.0087	0.0382	0.00
PRVs	0.0002	0.0011					
Pumps	0.0036	0.0158					
Valves	0.0036	0.0158					
Drains	1.4	6.1320	2016 Update				
<b>TOTALS</b>	<b>1.42</b>	<b>6.20</b>					

## 51 - Crude Fugitives

### POTENTIAL TO EMIT FUGITIVE EMISSIONS AREA 51 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE

FCC VOC Emissions	using API data		using EPA data		Delta
	lb/hr	ton/yr	lb/hr	ton/yr	
Valves	0.7204	3.1554			
Connections	3.6068	15.7978	1.0099	4.4234	-11.37
Pumps	0.0160	0.0701			
Compressors	0.0011	0.0049			
PRVs	0.0050	0.0218			
Drains	6.794	29.7577	1.549	6.7837	6.76
TOTALS	11.14	48.81			

**5255-FWO Fugitives**

**POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS**  
**2002 FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 52/55**  
**No LDAR program active in Hydrogen. Standard AP-42 emission factors apply.**  
From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 52  
Date of last revision 3/14/02

<b>FWO and Boilers VOC Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Valves	0.05	0.2340
Connections	0.10	0.4355
Pumps	0.00	0.0000
Compressors	0.00	0.0000
PRVs	0.00	0.0000
Drains	6.72	29.4336
<b>TOTALS</b>	<b>6.87</b>	<b>30.10</b>

**53 - FCC Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS**

**AREA 53 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE**

Calculated for 2002 reporting year

Date of last revision 9/18/2001

Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
removed 10% growth factor due to no changes since 1993.

FCC VOC Emissions	lb/hr	% PAR	ton/yr	using API data			using EPA data		
				lb/hr	ton/yr	Delta	lb/hr	ton/yr	Delta
Checkvalves	0.0047	20%	0.0207			0.26	1.13		
Control Valves	0.0049	20%	0.0215			0.17	0.74		
Fittings	0.0861	20%	0.3772	0.0947	0.4155	0.12	0.53	0.16	
Flanges	0.1409	20%	0.6173	0.1117	0.4903	0.14	0.62	0.00	
PRVs	0.0023	40%	0.0099			1.55	6.80	6.79	
Pumps	0.0557	11%	0.2441			0.50	2.20		
Valves	0.1790	20%	0.7840			8.15	35.75		
Drains	10.71	100%	46.9098	2016 Update					
TOTALS	11.18		48.98			10.89	47.78		

**56 - H&H Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS**  
**2002 FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 56**  
**No LDAR program active in Hydrogenation. Standard AP-42 emission factors apply.**  
From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 56 FUG CALC  
Date of last revision 3/5/02

<b>H&amp;H VOC</b>	<b>Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Valves	0.22	0.9546	
Connections	0.45	1.9570	
Pumps	0.01	0.0500	
Compressors	0.00	0.0000	
PRVs	0.00	0.0000	
Drains	3.43	15.0234	
<b>TOTALS</b>	<b>4.11</b>	<b>17.98</b>	



**57 - H&H Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS**

**2002 FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 57**

**No LDAR program active in Hydrogen. Standard AP-42 emission factors apply.**

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 57 FUG CALC

Date of last revision 3/12/02

<b>H&amp;H VOC</b>	<b>Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Valves	0.09		0.3763
Connections	0.50		2.2021
Pumps	0.01		0.0500
Compressors	0.00		0.0000
PRVs	0.00		0.0148
Drains	included in 56 - H&H Fugitives		
<b>TOTALS</b>	<b>0.60</b>		<b>2.64</b>

**58 - Alky Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS**  
**AREA 58 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE**  
 Calculated for 2002 reporting year  
 Date of last revision 9/18/2001  
 Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
 removed 10% growth factor due to no changes since 1993.

FCC VOC Emissions	lb/hr	%PAR	ton/yr	lb/hr	ton/yr	using EPA data ton/yr	Delta
Valves	0.1570	28%	0.6878				
Connections	0.4831	28%	2.1159	0.8303		3.6367	1.52
Pumps	0.0592	27%	0.2594				
Compressors	0.0000	0%	0.0000				
PRVs	0.0000	28%	0.0000				
Drains	6.44	100%	28.2072	2016 Update			
<b>TOTALS</b>	<b>7.14</b>		<b>31.27</b>				

**59 - Isom Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS  
2002 FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 59**

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 59 FUG CALC  
Date of last revision 3/11/02

<b>Isom VOC Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Valves	0.29	1
Connections	0.82	4
Pumps	0.10	0
Compressors	0.00	0
PRVs	0.00	0
Drains	3.29	14
TOTALS	4.51	20

14 2016 Update

## 62 - Acid Fugitives

### POTENTIAL TO EMIT FUGITIVE EMISSIONS

#### 2002 FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 62

No LDAR program active in Asphalt Plant. Standard AP-42 emission factors apply.

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 62 FUG CALC

Date of last revision 3/14/02

H&H VOC	Emissions	lb/hr	ton/yr
Valves	0.01	0.0275	
Connections	0.03	0.1171	
Pumps	0.00	0.0000	
Compressors	0.00	0.0000	
PRVs	0.00	0.0000	
Drains	0	0.0000	2016 Update
TOTALS	0.03	0.14	

**67 - Cogen Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS**

**AREA 67 VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE**

Calculated for 2002 reporting year

Date of last revision 9/18/2001

Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
removed 10% growth factor due to no changes since 1993.

Cogen VOC Emissions	using EPA data				
	lb/hr	ton/yr	lb/hr	ton/yr	Delta
Compressors	0.0011	0.0049			
Connectors	0.6954	3.0457	0.6954	3.0457	0.00
PRVs	None	N/A			
Pumps	0.0228	0.1000			
Valves	0.1307	0.5726			
Drains	0.051	0.2234	2016 Update		
TOTALS	0.90	3.95			

**Detailed Summary**

Summary of potential emissions from the IES Downstream, LLC Koppolei Refinery

Equipment Description/Emission Source	Annual Process Rate	Process Rate Units	Type of Fuel Fired	Fuel Usage Bbl/yr or MSCF/yr	Heating value	Tons/Year Emissions											
						% sulfur content by weight	Units	PM10	SO2	CO	NO2	VOC	Pb				
Cogeneration Units - K-6703 K-6701, K-6702, K-6703 permit limit NOx - 14.4 lb/yr, 67 ppm permit limit CO - 4.3 lb/yr, 25 ppm	192 Bbl/day 76 MMBTU/Hour		Total Fuel Gas Total Fuel Oil	210,240 20,200 20,200 14.7	4757 819 MBTU/bbl	0.03	bbl/yr uptime hr CO emission rate lb/yr NOx emission rate lb/yr										
Cogeneration Units - K-6703 K-6701, K-6702, K-6703	38.8 MSCF/yr 34 MSCF/yr HRSG 76 MMBTU/Hour		Fuel Gas	893,520 MSCF/yr	1154 90 BTU/SCF	0.0160	MSCF/yr	Total Cogeneration	11.72	27.92	52.49	193.16	2.34	0.01			
Crude Furnace - F-5103	151.5 MMBTU/Hour 151.5 MMBTU/Hour 159075		Total Fuel Oil to Crude Total Fuel Gas to Crude (Pilot) Total Fuel Gas to Crude	232,660 bbl/yr 1,961 MSCF/yr 1785371.43 MSCF/yr			bbl/yr MSCF/yr MSCF/yr	Total Energy	11.72	27.92	52.49	193.16	2.34	0.01			
Crude Furnace - F-5153	62.5 MMBTU/Hour 62.5 MMBTU/Hour		Fuel Oil Fuel Gas Pilot Fuel Gas	1,388 bbl/yr 1,263,943 MSCF/yr		0.45 0.0160 0.0160	bbl/yr MSCF/yr MSCF/yr	SubTotal	35.52	341.17	24.14	193.16	3.67	0.01			
Isom Furnace - F-5930 Isom Furnace - F-5950	4 MMBTU/Hour 16 MMBTU/Hour		Fuel Oil Fuel Gas Pilot Fuel Gas Total Fuel Gas	573 bbl/yr 521,429 MSCF/yr 49,056 MSCF/yr		0.0160 0.0160 0.0160	MSCF/yr MSCF/yr MSCF/yr	SubTotal	0.00	0.008	0.02	0.01	0.00	0.0000001			
Hydrogen Manufacturing furnace - F-5700 Hydrogenation furnace - F-5600	24.3 MMBTU/Hour 9 MMBTU/Hour		Fuel Gas Fuel Gas	210,240 MSCF/yr 78,840 MSCF/yr		0.0160 0.0160	MSCF/yr MSCF/yr		0.80	2.84	8.63	10.51	0.58	0.000005			
Acid Plant combustion chamber - F-6200 Acid Plant preheater - F-6262	8.5 MMBTU/Hour 5.1 MMBTU/Hour		Fuel Gas Fuel Gas	70,914 MSCF/yr 43,362 MSCF/yr		0.0160 0.0160	MSCF/yr MSCF/yr		0.27	0.96	2.98	3.55	0.20	0.000002			
Cooling Tower	2,275,940 Gallons/Hour								3.24								
Acid plant absorber stack	110.0 Tons/Day									1405.25			9.20				
Wastewater treatment Ca/Ox	84000 Gallons/Hour 84000							SubTotal	0.00	0.00	17.00	14.70	73.58	0.00			
Process Fugitives											17.00	14.70	74.88	0.00			
Tanks													210.48	0.00			
Refinery Flares											319.10	224.20	31.99	0.00			
								Total Criteria Pollutants	61.2	2240.4	214.5	757.6	344.7	0.0			

## Area Descrip

### REFINERY PROCESS AREAS

AREA NUMBER	AREA DESCRIPTION
23	RELIEF SYSTEMS
36	WASTE WATER TREATMENT LAND TREATMENT UNIT
51	CRUDE UNIT
52/55	BOILERS/FOUL WATER OXIDIZER
53	FLUID CATALYTIC CRACKER UNIT
56	HYDROGENATION PLANT
57	HYDROGEN PLANT
58	ALKYLATION PLANT
59	ISOMERIZATION PLANT
61/62	AMINE/ACID PLANT
67	COGENERATION PLANT

## Component Counts

### COMPONENT COUNTS

AREA NUM	AREA DESCRIPTION	SERVICE	COMPONENT TYPE				
			VALVES	FLANGES	PUMPS	COMPRESSORS	PRVS
23	RELIEF SYSTEMS	ALL	53	220	0	0	0
36	WASTE WATER TREATMENT LAND TREATMENT UNIT	ALL	246	335	12	0	2
51	CRUDE UNIT	ALL	1403	6558	29	1	4
52/55	BOILERS/FOUL WATER OXIDIZER	ALL	103	181	0	0	0
53	FLUID CATALYTIC CRACKER UNIT	ALL	1908	2452	33	0	12
56	HYDROGENATION PLANT	ALL	422	812	1	2	4
57	HYDROGEN PLANT	ALL	166	914	1	0	4
58	ALKYLATION PLANT	ALL	1180	5821	21	1	0
59	ISOMERIZATION PLANT	ALL	570	1493	9	0	0
61/62	AMINE/ACID PLANT	ALL	12	49	0	0	0
67	COGENERATION PLANT	ALL	253	1264	2	1	0
<b>TOTAL</b>		ALL	6317	20099	108	5	27

Note: For summary purposes, Both connectors and fittings have been grouped under the category of flanges



## Fugitive VOC Summary

### REFINERY PROCESS AREAS FUGITIVE EMISSIONS

AREA NUMBER	AREA DESCRIPTION	FUGITIVE VOCs TON/YR
23	RELIEF SYSTEMS	0.7
36	WASTE WATER TREATMENT LAND TREATMENT UNIT	6.2
51	CRUDE UNIT	48.8
52/55	BOILERS/FOUL WATER OXIDIZER	30.1
53	FLUID CATALYTIC CRACKER UNIT	49.0
56	HYDROGENATION PLANT	18.0
57	HYDROGEN PLANT	2.6
58	ALKYLATION PLANT	31.3
59	ISOMERIZATION PLANT	19.7
61/62	AMINE/ACID PLANT	0.1
67	COGENERATION PLANT	3.9
	<b>TOTAL PROCESS AREAS FUGITIVE EMISSIONS</b>	<b>210.5</b>

## Calculation Methods

### Boiler Calculations - Data requirements

from PHD:  
52F4107.PV - Fuel oil to boilers in bbl  
52F4124.PV - Fuel gas to boilers in SCF  
53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

from Lab:  
%sulfur

### AP-42 Emission Factors used

**Fuel Oil** Used AP-42 for Boiler >100MMBtu, tangential firing, Table 1.3-1 for NO<sub>x</sub>, CO, SO<sub>2</sub>, and PM used Table 1.3-3 for VOC, Table 1.3-11 for Pb  
PM = 9.19 \* %S + 3.22 / 1000 gal \* fuel use bbl/yr \* 42 gal/bbl \* ton/2000 lb  
SO<sub>2</sub> = %S \* 157 / 1000 gal \* fuel use bbl/yr \* 42 gal/bbl \* ton/2000 lb  
CO = 5 / 1000 gal \* fuel use bbl/yr \* 42 gal/bbl \* ton/2000 lb  
NO<sub>x</sub> = 32 / 1000 gal \* fuel use bbl/yr \* 42 gal/bbl \* ton/2000 lb  
VOC = .76 / 1000 gal \* fuel use bbl/yr \* 42 gal/bbl \* ton/2000 lb  
Pb = 1.51E-3 / 1000 gal \* fuel use bbl/yr \* 42 gal/bbl \* ton/2000 lb

**Fuel Gas** Used AP-42 for tangential firing, Table 1.4-1 for NO<sub>x</sub> and CO, used Table 1.4-2 VOC and PM. Used mass balance for SO<sub>2</sub>  
PM = 7.6 lb PM / MMSCF fuel \* fuel use MSCF \* (MMSCF / 1000 MSCF) \* ton/2000 lb  
SO<sub>2</sub> = (S ppm \* 64 / 379) lb SO<sub>2</sub> / MMSCF \* fuel use MSCF \* (MMSCF / 1000 MSCF) \* ton/2000 lb  
CO = 24 lb CO / MMSCF fuel \* fuel use MSCF \* (MMSCF / 1000 MSCF) \* ton/2000 lb  
NO<sub>x</sub> = 170 lb NO<sub>x</sub> / MMSCF fuel \* fuel use MSCF \* (MMSCF / 1000 MSCF) \* ton/2000 lb  
CO = 24 lb CO / MMSCF fuel \* fuel use MSCF \* (MMSCF / 1000 MSCF) \* ton/2000 lb  
VOC = 5.5 lb VOC / MMSCF fuel \* fuel use MSCF \* (MMSCF / 1000 MSCF) \* ton/2000 lb  
Pb = 0.0005 lb Pb / MMSCF fuel \* fuel use MSCF \* (MMSCF / 1000 MSCF) \* ton/2000 lb

### Cogeneration Calculation - Data Requirements

from PHD:  
67A8032A.PV, 67A8032B.PV, 67A8032C.PV - emission rate for NO<sub>x</sub> in lb/hr  
53A201.PV - Fuel gas H2S concentration in ppm

from H2S Quarterly report spreadsheet copy the uptime hours already calculated for the cogeneration units

from Lab:  
BTU for LSR  
BTU for F/G

from CEMS:  
total annual fuel consumption rates for F/G for both turbine and HSRG

### AP-42 Emission Factors used

LSR/HSR

Used AP-42 Stationary Gas Turbines, Table 3.1-1 for CO, and 3.1-2a for PM, Pb and VOC and use mass balance for SO<sub>2</sub>  
CO = 7.6E-2 lb CO / MMBtu \* fuel use bbl/yr \* heating value MBtu / bbl \* MMBtu / 1000 Mbtu \* ton/2000 lb  
PM = 1.2E-2 lb PM / MMBtu \* fuel use bbl/yr \* heating value MBtu / bbl \* MMBtu / 1000 Mbtu \* ton/2000 lb  
VOC = 4.1E-4 lb VOC / MMBtu \* fuel use bbl/yr \* heating value MBtu / bbl \* MMBtu / 1000 Mbtu \* ton/2000 lb  
Pb = 1.4E-5 lb Pb / MMBtu \* fuel use bbl/yr \* heating value MBtu / bbl \* MMBtu / 1000 Mbtu \* ton/2000 lb  
SO<sub>2</sub> = (1.01 \* %S) lb SO<sub>2</sub> / MMBtu \* fuel use bbl/yr \* heating value MBtu / bbl \* MMBtu / 1000 Mbtu \* ton/2000 lb

**Fuel Gas** Used AP-42 Stationary Gas Turbines, Table 3.1-2a for PM and VOC and use mass balance for

SO<sub>2</sub>. Used AP-42 Natural Gas Combustion, Table 1.4-1 for NO<sub>x</sub> and CO  
CO = 24 lb / MMSCF \* fuel use MSCF / yr \* MMSCF / 1000 MSCF \* 1 ton / 2000 lb

PM10 = 6.6E-3 lb PM10 / MMBtu \* fuel use MSCF / yr \* heating value Btu / SCF \* 1000 SCF / MSCF \* MMBtu / 1e6 Btu \* ton / 2000 lb

VOC = 2.1E-3 lb VOC / MMBtu \* fuel use MSCF / yr \* heating value Btu / SCF \* 1000 SCF / MSCF \* MMBtu / 1e6 Btu \* ton / 2000 lb  
SO<sub>2</sub> = .94 \* %S lb SO<sub>2</sub> / MMBtu \* fuel use MSCF / yr \* heating value Btu / SCF \* 1000 SCF / MSCF \* MMBtu / 1e6 Btu \* ton / 2000 lb

## Calculation Methods

NOX = for 2000 total lb/hr recorded on PHD  
 $NO_x = 170 \text{ lb/MMSCF} * \text{fuel use MSCF/yr} * \text{MMSCF}/1000\text{MSCF} * 1 \text{ ton}/2000\text{lb}$

### Crude Furnace Calculations - Data requirements

from PHD:

51F464.PV - total fuel oil to boilers in bbl  
51F471.PV - total fuel gas to boilers in MSCF  
53A201.PV - Fuel gas H2S concentration in ppm

need to apportion f/o to furnace by size 71% ( $151.5/(151.5+62.5)$ ) to F5103 and 29% ( $62.5/(151.5+62.5)$ ) to F5153

from Lab:  
F/O %sulfur

### AP-42 Emission Factors used for the 151.5 MMBTU furnace

**Fuel Oil** Used AP-42 for Boiler >100MMBtu, normal firing,  
Table 1.3-1 for NO<sub>x</sub>, CO, SO<sub>2</sub>, and PM  
used Table 1.3-3 for VOC, Table 1.3-11 for Pb  
 $PM = 9.19 * \%S + 3.22 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $SO_2 = \%S * 157 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $CO = 5 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $NO_x = 40 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $VOC = .76 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $Pb = 1.51E-3 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$

**Fuel Gas** Used AP-42 for large >100 boilers, uncontrolled,  
Table 1.4-1 for NO<sub>x</sub> and CO, used Table 1.4-2 VOC,  
Pb, and PM. Used mass balance for SO<sub>2</sub>  
 $PM = 7.6 \text{ lb PM} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $SO_2 = (S \text{ ppm} * 64/379) \text{ lb SO}_2 / \text{MMSCF} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $NO_x = 140 \text{ lb NO}_x / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $CO = 84 \text{ lb CO} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $VOC = 5.5 \text{ lb VOC} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $Pb = 0.0005 \text{ lb Pb} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$

### AP-42 Emission Factors used for the 62.5 MMBTU furnace

**Fuel Oil** Used AP-42 for Boiler <100MMBtu, normal firing,  
Table 1.3-1 for NO<sub>x</sub>, CO, SO<sub>2</sub>, and PM  
used Table 1.3-3 for VOC, Table 1.3-11 for Pb  
 $PM = 10 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $SO_2 = \%S * 157 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $CO = 5 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $NO_x = 55 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $VOC = 28 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $Pb = 1.51E-3 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$

**Fuel Gas** Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NO<sub>x</sub> and CO, used Table 1.4-2 VOC,  
Pb, and PM. Used mass balance for SO<sub>2</sub>  
 $PM = 7.6 \text{ lb PM} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $SO_2 = (S \text{ ppm} * 64/379) \text{ lb SO}_2 / \text{MMSCF} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $NO_x = 50 \text{ lb NO}_x / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $CO = 84 \text{ lb CO} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $VOC = 5.5 \text{ lb VOC} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $Pb = 0.0005 \text{ lb Pb} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$

### H2 Manufacturing/Hydrogenation furnace

from PHD:  
56FC420.PV - total fuel gas to Hydrogenation in SCFH  
57F428.PV - total fuel gas to Hydrogen Manufacturing in MSCFH  
53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

EF same as FCC Furnace

## Calculation Methods

**Fuel Gas** Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NOx and CO, used Table 1.4-2 VOC  
and PM. Used mass balance for SO2

### **Acid Plant Combustion Chamber**

from PHD:

62FC111.PV - total fuel gas to Acid Combustion Chamber in MSCFH  
53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

EF same as FCC Furnace

**Fuel Gas** Used AP-42 for small <100 boilers, uncontrolled,

### **Acid Plant Preheater**

from PHD:

no tag for fuel consumption:

first calculate up time, then multiply by heating value BTU/SCF \* 5.1 MBTU/Hr Design Value = MSCFH/yr  
53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

EF same as FCC Furnace

**Fuel Gas** Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NOx and CO, used Table 1.4-2 VOC  
and PM. Used mass balance for SO2

### **Flare**

from PHD

51FC226.PV - average daily crude unit throughput Mbbl  
need to calculate days/year

Used AP-42 for Blowdown systems vapor recovery  
and flaring, Table 5.1-1 for NOx, CO, and VOC

NOx=18.9 lb NOx /1000 bbl feed \*crude unit feed rate bbl/day \* n days/yr\* ton/2000 lb

VOC=0.8 lb VOC /1000 bbl feed \*crude unit feed rate bbl/day \* n days/yr\* ton/2000 lb

CO=4.3 lb CO/1000 bbl feed \*crude unit feed rate bbl/day \* n days/yr\* ton/2000 lb

SO2 mass balance F/G to flare and acid plant shutdown data

Pilot F/G (100 SCFH crude, 150, SCFH FCC, 15000 SCFH during acid plant shutdown)

assume 379 SCF/lb mole

flare contribution to total SO2

lb SO2/MMSCF = 1/379\*ppm S \*64

SO2 = 1/379\*ppm S\*64 \* operating hr/yr \* fuel rate SCFH \* MMSCFH/10^6SCFH

acid plant shutdown contribution

SO2 emission rate calculated with %S, density of 310 lb/bbl, 35% conversion to coke, 100% of coke converted to SO2

SO2= %S/100\*306 lb/bbl\* annual feed rate bbl/day \* 4.5%conv/100 \* 64/32 \* day/24 hr \* 8760 hr/yr\* ton/2000

### **Cooling Tower**

from PHD:

23F401.PV -Cooling tower flowrate Mgpm

Used AP-42, Table 5.1-2 Cooling Towers

VOC=cooling water flow rate gal/min\*60 \*0.7 lb VOC/1E6 gal \* 8760 hr/yr \* ton/1998

Used AP-42, Section 13.4 alternative method

Total Drift = circ rate gpm\* manufacturer's drift factor\* 8.34 lb/gal \* 60 min/hr

PM= drift lb/hr\* TDS ppm\*cycles/1e6

### **Wastewater treatment**

from PHD:

36FC405.PV - Feed to API Sep gpm

36F200.PV - Storm Bay Flow to API Sep gpm

Used AP-42, Table 5.1-2

VOC=process rate gal/hr \*0.2 lb VOC /1000 gal \* 8760 hr/yr \* ton/2000 lb

### **Acid plant absorber stack**

from PHD:

## Calculation Methods

62FY115.PV - Acid production ton/day

Used AP-42, Table 8.10-1

$SO_2 = \text{process rate ton/day} * 40 \text{ SO}_2/\text{ton acid} * 365 \text{ day/yr} * \text{ton}/2000$



**Cogen Summary**

**COGEN UNITS ONLY**  
 SUMMARY OF POTENTIAL TO EMIT EMISSIONS ESTIMATE  
 Summary of potential emissions from the IES DOWNSTREAM, LLC refinery

Equipment Description/Emission Source	Annual Process Rate	Process Rate Units	Type of Fuel Fired	Fuel Usage Bbls/yr or MSCF/yr	Units	% sulfur content by weight	Heating value	Units	Tons/Year Emissions							
									PM10	SO2	CO	NO2	VOC	Pb		
<b>TURBINES RUNNING LSR/HSR</b>																
Cogeneration Units - K-6703	192 Bbl/day	MMBTU/Hour	LSR/HSR	171,409	bbl/yr	0.03	4757.819	MBTU/bbl	4.9	12.36	31.0	97.86	0.17	0.006		
K-6701, K-6702, K-6703	76			1,997,280	MMBTU/yr	0.03	4757.819	MBTU/bbl	12.0	30.26	75.9	239.67	0.41	0.014		
			Running at Max Daily Emission rate for 8760 hrs/yr →													
<b>TURBINES RUNNING RFG</b>																
Cogeneration Units - K-6703	38.8	MSCF/hr	Fuel Gas	955,500	MSCF/yr	0.0160	1154.90	BTU/SCF	3.6	8.3	11.5	81.2	1.2	0.0		
K-6701, K-6702, K-6703	34	MSCF/hr HRSG		1,019,664	MSCF/yr	0.0160	1154.90	BTU/SCF	3.9	8.9	12.2	86.7	1.2	0.0		
	72.8		Running at Max Daily Emission rate for 8760 hrs/yr →													
<b>HRSGS RUNNING RFG</b>																
Cogeneration Units - K-6703		from CEMS	Fuel Gas	836,100	MSCF/yr	0.0160	1154.90	BTU/SCF	3.2	7.3	10.0	71.1	1.0	0.0		
K-6701, K-6702, K-6703	34	MSCF/hr HRSG		893,620	MSCF/yr	0.0160	1154.90	BTU/SCF	3.4	7.8	10.7	75.9	1.1	0.0		
			Running at Max Daily Emission rate for 8760 hrs/yr →													
			Running at Max Daily Emission rate for 8760 hrs/yr →						11.7	27.9	52.5	250.1	2.3	0.006		
			Running at Max Daily Emission rate for 8760 hrs/yr →						19.3	46.9	98.9	402.3	2.7	0.014		
			Running at Max Daily Emission rate for 8760 hrs/yr →								121.2822	193.158				
			Running at Max Daily Emission rate for 8760 hrs/yr →						11.7	27.9	52.5	193.2	2.3	0.006		
			Running at Max Daily Emission rate for 8760 hrs/yr →													

13.4879472

Max Emissions  
 Running at Max Daily Emission rate for 8760 hrs/yr → Max Emissions  
 Using permit limits →

**POTENTIAL TO EMIT**

**Insignificant Activity Emissions Calculation  
Portable Chemical Containers**

Emissions occur during portafeed filling (air pushed out vent). During injection into the process, air is pulled into vent, and no emissions occur.  
VOC Emissions = concentration VOC \* volume vapor discharged during filling \* density VOC \* number of fillings per year per container \* number of containers

0.1337 units conversion, cu ft/gal  
29 MW air  
60 assumed MW of VOC (typical, from Tanks4 program)  
400 gallons container volume  
53.47 cu ft container volume

Calculate vapor density of VOC

0.403 lb/cu ft air density at amb conditions (70F, 1atm)  
0.834 lb/cu ft VOC density = density of air \* (MW VOC / MW air)

VOC Concentration in ventgas

40000 VOC concentration ppmv; assumed = high LEL concentration  
Calculate mass of VOC vented in each container during filling

53.47 cu ft gas vented each fill  
2.14 cu ft VOC vented each fill  
1.78 lb VOC vented each fill

Estimate number of container fillings per year

24 assume fill container twice a month (typical is closer to 1x per month)

Calculate VOC emissions per year per container

42.8 lb VOC/year for each chemical  
0.02 tpy VOC from one container

Estimate number of portable containers

20.0 conservative number of chemicals containers being used (2015 actual was 13)

Sum total VOC from all containers per year

856.1 total lb VOC/year from all chemical containers  
0.4 tpy VOC from chemical containers



Stationary Emergency RICE Units  
Insignificant Activity

Equipment				Emissions													
Source No.	Description	Location	Fuel Type	Hrs of Operation	bhp	EF Basis	Nox lb/hr	MMHC (VOC) lb/hr	CO lb/hr	PM10/PM 5 lb/hr	SO2 lb/hr	CO2e lb/hr	HAPs lb/hr	ton/yr	ton/yr	ton/yr	ton/yr
14	TK 352 FW Pump	EP-2077 Boiler	Diesel	200	460	AP-42	14.26	1.43	0.22	3.07	0.31	1.01	0.10	0.94300	0.09	0.00	0.00
16	Blime FW Pump	EP-2083 Acid Pit	Diesel	200	260	AP-42	8.06	0.81	0.13	1.74	0.17	0.57	0.06	0.53300	0.05	0.00	0.00

Insignificant activity Emissions Calculation  
Non-stationary Equipment

Description	Typical Refinery Location	Fuel Type	hp	1008 oper hours										Up hours if <1008 hr stated in 2010 Renewal applicatio n		
				Max. lb/hr	CO, lb/hr	SOX, lb/hr	PM10, lb/hr	CO2, lb/hr	Aldehyde, lb/hr	TOC Exhaust, lb/hr	Non. by	CO, tpy	SOX, tpy		PM10, tpy	CO2, tpy
Amoco Aero Washbasin #1	Maintenance Shop	Diesel	150	4.65	1.00	0.31	0.33	172.50	0.07	0.37	0.15	0.17	86.94	0.04	0.19	860
Amoco Aero Washbasin #2	Maintenance Shop	Diesel	150	4.65	1.00	0.31	0.33	172.50	0.07	0.37	0.15	0.17	86.94	0.04	0.19	860
Garman Run Pumps (2 each)	Maintenance Shop	Diesel	125	3.68	0.84	0.26	0.28	143.75	0.06	0.31	0.15	0.14	72.45	0.03	0.16	645
Ingersoll Rand Large Compressor	Boiler Plant	Diesel	200	6.20	1.34	0.41	0.44	230.00	0.09	0.49	0.21	0.22	115.92	0.05	0.25	697
Ingersoll Rand Small Compressor	Maintenance Shop	Diesel	105	5.74	1.24	0.38	0.41	212.75	0.09	0.46	0.21	0.21	107.23	0.04	0.23	697
Waldmaster #1	Boiler Plant	Diesel	130	4.03	0.87	0.27	0.29	149.50	0.06	0.32	0.14	0.14	75.35	0.03	0.16	993
Ar Compressor: 9L 1988 UR 1400 COMP	Refinery Plants	Diesel	485	15.04	3.24	0.99	1.07	557.75	0.22	1.20	0.50	0.54	281.11	0.11	0.60	266
Ar Compressor: 10T 2000 UR 825 COMP	Refinery Plants	Diesel	260	8.06	1.74	0.53	0.57	299.00	0.12	0.64	0.27	0.29	150.70	0.06	0.32	496
Ar Compressor: 10T 2000 UR 1300 COMP	Refinery Plants	Diesel	3300													
55A-1997 AMDA LIGHT TOWER	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
56B-1997 AMDA LIGHT TOWER	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
113-2006 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
114-2006 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
115-2006 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
116-2006 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
119SL1-2003 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
120SL2-2004 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
121SL3-2004 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
122SL4-2004 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
123SL5-2004 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
124SL6-2004 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
125SL7-2004 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
126SL8-2004 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
127SL9-2006 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
128SL10-2006 AMDA LIGHT PLANT	Refinery Plants	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
131-2008 (BARGE LOADING)	Barge Harbor	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
130-2008 AMDMATREX LIGHT PLANT	HECO Area	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
129-2008 AMDMATREX LIGHT PLANT	HECO Area	Diesel	10.5	0.33	0.07	0.02	0.02	12.08	0.00	0.03	0.01	0.01	6.09	0.00	0.01	0.01
Updated inventory 2016																
Sulfare Air Compressor	Boiler Plant		557	17.27	3.72	1.14	1.23	640.55	0.26	1.38	0.58	0.62	322.84	0.13	0.69	232
Garther Denver Hydroblaster	Maintenance Shop		130	4.03	0.87	0.27	0.29	149.50	0.06	0.32	0.14	0.14	75.35	0.03	0.16	993
Portable Whispowall Generator	Maintenance Shop		216	6.70	1.44	0.44	0.48	248.40	0.10	0.53	0.22	0.24	125.19	0.05	0.27	598
Portable Whispowall Generator	Maintenance Shop		216	6.70	1.44	0.44	0.48	248.40	0.10	0.53	0.22	0.24	125.19	0.05	0.27	598
Portable Whispowall Generator	Maintenance Shop		216	6.70	1.44	0.44	0.48	248.40	0.10	0.53	0.22	0.24	125.19	0.05	0.27	598
Portable Whispowall Generator	Maintenance Shop		216	6.70	1.44	0.44	0.48	248.40	0.10	0.53	0.22	0.24	125.19	0.05	0.27	598
Portable Whispowall Generator	Maintenance Shop		216	6.70	1.44	0.44	0.48	248.40	0.10	0.53	0.22	0.24	125.19	0.05	0.27	598
Portable Whispowall Generator	Maintenance Shop		216	6.70	1.44	0.44	0.48	248.40	0.10	0.53	0.22	0.24	125.19	0.05	0.27	598
Harbon High Press Water Tech	Refinery Plants		130	4.03	0.87	0.27	0.29	149.50	0.06	0.32	0.14	0.14	75.35	0.03	0.16	993
IR Air Compressors (6)	Refinery Plants, Parking Lots		85	2.64	0.57	0.17	0.19	97.75	0.04	0.21	0.09	0.09	49.27	0.02	0.11	497
IR Air Compressors (7)	Maintenance Shop		200	8.06	1.74	0.53	0.57	299.00	0.12	0.64	0.27	0.29	150.70	0.06	0.32	497
Lombardini Pressure Washer	Maintenance Shop		130	4.03	0.87	0.27	0.29	149.50	0.06	0.32	0.14	0.14	75.35	0.03	0.16	993
Miller welder	Maintenance Shop		23	0.71	0.15	0.05	0.05	26.45	0.01	0.06	0.08	0.08	4.03	0.01	0.03	0.03
Miller welder Hydrostracker	Refinery Plants		35	1.09	0.23	0.07	0.08	40.25	0.02	0.09	0.12	0.04	6.09	0.01	0.04	0.04
Lincoln Welder 163	Maintenance Shop		56	1.74	0.37	0.11	0.12	64.40	0.03	0.14	0.06	0.06	32.46	0.01	0.07	0.07
Lincoln Welder 163	Maintenance Shop		56	1.74	0.37	0.11	0.12	64.40	0.03	0.14	0.06	0.06	32.46	0.01	0.07	0.07
Lincoln Welder 163	Maintenance Shop		56	1.74	0.37	0.11	0.12	64.40	0.03	0.14	0.06	0.06	32.46	0.01	0.07	0.07
Lincoln Welder 164	Maintenance Shop		56	1.74	0.37	0.11	0.12	64.40	0.03	0.14	0.06	0.06	32.46	0.01	0.07	0.07

Reference AP42 Emission Factors, Table 3.3-2  
7,000 Bu/hr-hr was used to convert from lb/MMBtu to lb/hr-hr as noted in AP42  
\*1008 hours were used for Max Operation per year.

### Equipment

Description	Refinery Area	Fuel Type	hp
Standby generator for black start power to begin turbine operation	cogeneration area	Diesel	335
Amero Aero Waterblaster #1	Maintenance Shop	Diesel	150
Amero Aero Waterblaster #2	Maintenance Shop	Diesel	150
Goman Rup Pumps (2 each)	Maintenance Shop	Diesel	125
Ingersoll-Rand Large Compressor	Boiler Plant	Diesel	200
Ingersoll-Rand Small Compressor	Maintenance Shop	Diesel	185
Waterblaster #1	Reliability	Diesel	130
Air Compressor: 94-1988 I/R 1400 COMP	Refinery Plants	Diesel	485
Air Compressor: 107- 2000 I/R 825 COMP	Refinery Plants	Diesel	260
Air Compressor: 109- 2000 I/R 1300 COMP	Refinery Plants	Diesel	1300
55A- 1997 AMIDA LIGHT TOWER	Refinery Plants	Diesel	10.5
55B- 1997 AMIDA LIGHT TOWER	Refinery Plants	Diesel	10.5
113- 2006 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
114- 2006 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
115- 2006 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
116- 2006 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
119/SL1- 2003 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
120/SL2- 2004 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
121/SL3- 2004 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
122/SL4- 2004 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
123/SL5- 2004 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
124/SL6- 2004 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
125/SL7- 2004 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
126/SL8- 2004 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
127/SL9- 2006 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
128/SL10- 2006 AMIDA LIGHT PLANT	Refinery Plants	Diesel	10.5
131, 2008 (BARGE LOADING	Barge Harbor	Diesel	10.5
130- 2008 AMIDA/TEREX LIGHT PLANT	HECO Area	Diesel	10.5
129- 2008 AMIDA/TEREX LIGHT PLANT	HECO Area	Diesel	10.5
Generator: 136- 2007 25KW	Main Gate	Diesel	32
Generator: 137- 2007 25KW	Gate #2	Diesel	32
Generator: 138- 2007 40KW	Firehouse	Diesel	64
Fire Water Pump: Boiler P-2077	Boiler	Diesel	460
Auxiliary Brine Pump	Acid Plant	Diesel	228
		Total Horsepower	4335.5

Emission Calculations			
Pollutant	EF (lb/hp-hr)	Emissions lb/hr for total hp capacity	lb/yr <sup>1</sup>
NOx	0.031	134.40	135475.70
CO	0.00668	28.96	29192.83
SOX	0.00205	8.89	8958.88
PM10	0.0022	9.54	9614.40
CO2	1.15	4985.83	5025711.60
Aldehydes	0.000463	2.01	2023.40
TOC Exhaust	0.00247	10.71	10794.35
			67.74
			14.60
			4.48
			4.81
			2512.86
			1.01
			5.40

Reference: AP42 Emissions Factors, Table 3.3-1 Diesel Fueled

<sup>1</sup>1008 hours were used for Max Operation per year.

Hazardous Air Pollutant according to Clean Air Act	EF (lb/MMBTU)	EF (lb/hp-hr)	Emissions lb/hr for total hp capacity	lb/yr <sup>1</sup>	tpy
Benzene (CAS#000071432)	0.000933	6.531E-07	0.00	2.85	0.00
Toluene (CAS#000108883)	0.000409	2.863E-07	0.00	1.25	0.00
Xylenes	0.000285	1.995E-07	0.00	0.87	0.00
Propylene	0.00258	0.000001806	0.01	7.89	0.00
1,3 Butadiene (CAS#000106990)	0.0000391	2.737E-08	0.00	0.12	0.00
Formaldehyde (CAS#000050000)	0.00118	0.000000826	0.00	3.61	0.00
Acetaldehyde (CAS#000075070)	0.000767	5.369E-07	0.00	2.35	0.00
Acrolien (CAS#000107028)	0.0000925	6.475E-08	0.00	0.28	0.00
PAH Total	0.000168	1.176E-07	0.00	0.51	0.00
Naphthalene (CAS# 000091203)	0.0000848	5.936E-08	0.00	0.26	0.00

Reference AP42 Emission Factors, Table 3.3-2

7,000 Btu/hp-hr was used to convert from lb/MMBTU to lb/hp-hr as noted in AP42

<sup>1</sup>1008 hours were used for Max Operation per year.

**Insignificant Activity Emissions Calculation**  
**CO2 Stripper Vent**  
**Hydrogen Manufacturing Plant 57**

EPA collected data for CO emissions from hydrogen plant condensate strippers, however, did not finalize an emission factor. Below are calculations of CO emissions from Hawaii Refinery's CO2 stripper using the two sets of emissions data in the EPA reference document. The estimated CO emissions for this source from either method, clearly shows that this source's emissions are less than the insignificant activity threshold of 5 ton/yr CO.

**Method 1**

Emission Factor, EF	0.48	EF, lb CO / MMscf H2 Reference: EPA's "Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations, EP-D-11-084 No. 3-06, April 2015.
Refinery Data	3.6	H2 Produced, MMSCFD Reference Table 2-1 Updated Renewal
Emission Calculation	$\text{CO, ton/yr} = \text{EF} * \text{H2 Produced} * 365 \text{ days/yr} * 2000 \text{ lb/ton}$ <div style="border: 1px solid black; display: inline-block; padding: 2px;">0.32</div> CO, ton/yr	

**Method 2**

Emission Factor, EF	0.0011	EF, lb CO / mscf methane in feed Reference: EPA's "Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations, EP-D-11-084 No. 3-06, April 2015.
Refinery Data	811 0.05 30.6	mscf total feed vol frac methane in feed mscf, Methane Feedrate
Emission Calculation	$\text{CO, ton/yr} = \text{EF} * \text{Methane Feedrate} * 24 \text{ hr/day} * 365 \text{ days/yr} * 2000 \text{ lb/ton}$ <div style="border: 1px solid black; display: inline-block; padding: 2px;">0.15</div> CO, ton/yr	

## APPENDIX D: PROPOSED PERMIT CONDITIONS

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DAVID Y. IGE  
GOVERNOR OF HAWAII



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

November 16, 2018

BRUCE S. ANDERSON, M.D.  
DIRECTOR OF HEALTH

In reply, please refer to  
File

CERTIFIED MAIL  
RETURN RECEIPT REQUESTED  
(7012 2920 0001 3320 4234)

18-743E CAB  
File No. 0088-01

Mr. Jon Mauer  
President and CEO  
IES Downstream, LLC  
Kapolei Refinery  
91-480 Malakole Street  
Kapolei, Hawaii 96707-1883

Dear Mr. Mauer:

**SUBJECT: Covered Source Permit (CSP) No. 0088-01-C  
Minor Modification Application No. 0088-  
310  
IES Downstream, LLC  
Kapolei Refinery  
Located At: 91-480 Malakole Street, Kapolei, Oahu  
Date of Expiration: February 1, 2004 (this date is to be revised upon  
issuance of the renewal for CSP No. 0088-01-C)**

The subject CSP is issued in accordance with Hawaii Administrative Rules, Title 11, Chapter 60.1. The issuance of this permit is based on the plans, specifications, and information submitted as part of your minor modification application dated ~~August 1, 2018~~ December 14, 2018. This permit ~~revises~~ revises CSP No. 0088-01-C issued on February 22, 1999, and amended on January 22, 2002, April 16, 2002, March 3, 2003, June 28, 2006, April 24, 2007, August 13, 2007, November 8, 2007, July 22, 2008, September 11, 2009, November 4, 2009, April 22, 2013, September 30, 2014, June 23, 2015, October 9, 2015, November 2, 2015, and January 4, 2018, and November 16, 2018 in its entirety.

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The CSP is issued subject to the conditions/requirements set forth in the following Attachments:

- Attachment I: Standard Conditions
- Attachment II(A): Special Conditions - Miscellaneous Process Units and Source Operations
- Attachment II(B): Special Conditions - Cooling Tower
- Attachment II(C): Special Conditions - Flares
- Attachment II(D): Special Conditions - Effluent Treatment Plant
- Attachment II(E): Special Conditions - Crude Unit Furnaces
- ~~Attachment II(F): Special Conditions - Fluid Catalytic Cracking Unit (FCCU)~~
- Attachment II(G): Special Conditions - Process Unit Furnaces

Mr. Jon Mauer  
November 16, 2018  
Page 2

Attachment II(H): Special Conditions - Acid Plant  
Attachment II(1): Special Conditions - Cogeneration Plant  
Attachment III: Annual Fee Requirements  
Attachment IV: Annual Emissions Reporting Requirements

The following forms are enclosed for your use and submittal as required:

Compliance Certification Form  
Annual Emissions Report Form: Refinery Equipment - Fuel Consumption  
Annual Emissions Report Form: Refinery Equipment - Process Rate  
Annual Emissions Report Form: Acid Plant Preheater - Operating Hours  
Monitoring Report Form: Gas Turbines - Fuel Consumption  
~~Monitoring Report Form: Vacuum Gas Oil (VGO)~~  
Monitoring Report Form: Opacity Exceedances  
Excess Emission and Monitoring System Performance Summary Report  
Visible Emissions Form Requirements  
Visible Emissions Form  
The Ringelmann Chart

This permit: (a) shall not in any manner affect the title of the premises upon which the equipment is to be located; (b) does not release the permittee from any liability for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment; and (c) in no manner implies or suggests that the Department of Health, Clean Air Branch (herein after referred to as Department), or its officers, agents, or employees, assumes any liability, directly or indirectly, for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment.

If you have any questions regarding this matter, please contact Mr. Darin Lum of the Clean Air Branch at (808) 586-4200.

**Sincerely**

**DER, P.E., ACTING CHIEF**  
Environmental Management Division

DL/rg

Enclosures



**ATTACHMENT II(A): SPECIAL CONDITIONS  
MISCELLANEOUS PROCESS UNITS AND SOURCE OPERATIONS  
COVERED SOURCE PERMIT NO. 0088-01-C**

Issuance Date: XXXX XX, 2019

Expiration Date: February 1, 2004<sup>3</sup>

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

This portion of the CSP encompasses the requirements for miscellaneous process units and/or source operations not included with the Special Conditions of Attachments 11(8) through 11(1).

(Auth.: HAR §11-60.1-3)

**Section B. Applicable Federal Regulations**

1. The ~~FCC Unit~~, Crude Unit, ~~Dimersol Plant~~, Cogeneration Plant Compressor and Liquid Fuel System, and FCC Flare Vapor Recovery System are subject to the provisions of the following federal regulations:

40 CFR Part 60, New Source Performance Standards (NSPS):

- i. Subpart A, General Provisions; and
- ii. Subpart GGG, Standards of Performance for Equipment Leaks in Petroleum Refineries.

Furthermore, the permittee voluntarily complies with 40 CFR 60, Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, as a compliance demonstration with Subpart GGG and to maintain consistency with other Leak Detection and Repair (LDAR) requirements.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.590)<sup>5</sup>

2. The Cogeneration Plant, Crude Unit Furnaces and Desalter, and FCC Flare Vapor Recovery System are subject to the provisions of the following federal regulations:

40 CFR Part 60, New Source Performance Standards (NSPS):

- i. Subpart A, General Provisions; and
- ii. Subpart QQQ, Standards of Performance for Volatile Organic Compounds (VOC) Emissions from Petroleum Refinery Wastewater Systems.

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Commented [HL1]: Mark – to review for accuracy of strategy. I deliberately left the consent decree out. Agencies often do not want to mix consent decree requirements with Clean Air Act applicable requirements.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.690)<sup>1</sup>

3. The ~~FCG-Unit~~, Crude Unit, ~~Dimersol-Plant~~, Cogeneration Plant Compressor and Liquid Fuel System, ~~Alkylation-Plant~~, and Effluent Treatment Plant are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT):
    - i. Subpart A, General Provisions; and
    - ii. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.
  - b. The above regulations are not applicable to any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system that is intended to operate in organic hazardous air pollutant service, as defined in 40 CFR §63.641, for less than 300 hours during the calendar year.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11.60.1-174, 40 CFR §63.640)<sup>1</sup>

4. The storage and use of flammable substances in this facility is subject to the provisions of 40 CFR Part 68, Chemical Accident Prevention Provisions. The permittee shall comply with all applicable requirements, including the submittal of:
  - a. A compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR §68.10(a); or
  - b. As part of the compliance certification submitted pursuant to Attachment I, Standard Condition No. 28, a certification statement that the facility is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of the Risk Management Plan.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §68)<sup>1</sup>

5. The Catalytic Oxidation Unit is subject to the provisions of the following federal regulations:

40 CFR Part 60, New Source Performance Standards (NSPS):

- i. Subpart A, General Provisions; and
- ii. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.100a)<sup>1</sup>

### Section C. Operational and Emission Limitations

1. All pumps and compressors handling VOC having a Reid Vapor Pressure (RVP) of 1.5 pounds per square inch (psi) or greater which can be fitted with mechanical seals shall have mechanical seals or other equipment of equal efficiency for purposes of air pollution control as may be approved by the Department. Pumps and compressors not capable of being fitted with mechanical seals, such as reciprocating pumps, shall be fitted with the best sealing system available for air pollution control given the particular design of pump or compressor as may be approved by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-41, §11-60.1-90)

2. The permittee shall not cause or allow the emissions of gas streams containing VOC from a vapor blowdown system unless these gases are burned by smokeless flares, or abated by an equally effective control device as approved by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-42, §11-60.1-90)

#### 3. Compressor

- a. Each compressor located at the ~~FGG-Unit~~, Crude Unit, Cogeneration Plant and Liquid Fuel System, and FCC Flare Vapor Recovery System shall be equipped and operated with a seal system that includes a barrier fluid system and that prevents leakage of ~~the VOC~~ to the atmosphere, except as provided in 40 CFR §60.482-1(c), 40 CFR §60.482-3(h), and 40 CFR §60.482-3(i).
- b. Each compressor seal system as required in Special Condition No. C.3.a of this attachment shall be as follows:
  - i. Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or
  - ii. Equipped with a barrier fluid system that is connected by a closed vent system to a control device that complies with the requirements of 40 CFR §60.482-10; or

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iii. Equipped with a system that purges the barrier fluid into a process stream with zero ~~vee~~ VOC emissions to the atmosphere.

- c. The barrier fluid system shall be in heavy liquid service or shall not be in ~~vee~~ VOC service.
- d. A compressor is exempt from the requirements of Special Condition Nos. C.3.a and C.3.b of this attachment if it is equipped with a closed vent system capable of capturing and transporting any leakage from the seal to a control device that complies with the requirements of 40 CFR §60.482-10, except as provided in Special Condition No. C.3.e of this attachment.
- e. Any compressor that is designated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by methods specified in 40 CFR §60.485(c) and is tested for compliance initially upon designation, annually, and at other times requested by the Department is exempt from the requirements of Special Condition Nos. C.3.a through C.3.d, D.3.a, and D.3.b of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

4. Pressure Relief Devices in Gas/~~Na~~ Vapor Service

- a. Except during pressure releases, each pressure relief device in gas/vapor service located at the ~~FCG-Unit~~, Crude Unit, ~~Dimersol Plant~~, Cogeneration Plant Compressor and Liquid Fuel System, and FCC Flare Vapor Recovery System shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR §60.485(c).
- b. *After each pressure release*, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, **as soon as practicable**, but no later than five (5) calendar days *after the pressure release*, except as provided in Special Condition No. C.8 of this attachment.
- c. Any pressure relief device is exempt from the requirements of Special Condition Nos. C.4.a and C.4.b of this attachment if it is equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device that complies with the requirements of 40 CFR §60.482-10.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

5. Open Ended Valves/Lines

- a. Each open-ended valve or line at the ~~FCG-Unit~~, Crude Unit, ~~Dimersol Plant~~, Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, ~~Alkylation Plant~~, and Effluent Treatment Plant shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR §60.482-1(c). The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

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- b. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.
- c. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with Special Condition No. C.5.a of this attachment at all other times.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

#### 6. Sampling Connection Systems

- a. Each sampling connection system at the ~~FGG-Unit, Crude Unit, Dimersol Plant,~~ Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, ~~Alkylation Plant,~~ and Effluent Treatment Plant shall be equipped with a closed-purged, closed-loop, or closed-vent system, except as provided in 40 CFR §60.482-1(c) ~~or paragraph c of this condition.~~
- b. Each closed-purged, closed-loop, or closed-vent system shall comply with the following requirements:
  - i. Return the purged process fluid directly to the process line; or
  - ii. Collect and recycle the purged process fluid to a process; or
  - iii. Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of 40 CFR §60.482-10.
- c. In-situ sampling systems and sampling systems without purges are exempt from the requirements of Special Condition Nos. C.6.a and C.6.b of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

#### 7. Individual Drain Systems

- a. Sewer drains located at the Cogeneration Plant, Crude Unit Furnaces and Desalter, and FCC Flare Vapor Recovery System shall be equipped with water seal controls.
- b. Junction boxes located at the Cogeneration Plant shall be equipped with a cover and may have an open vent pipe at least three (3) feet (90 cm) in length and shall not exceed four (4) inches (10.2 cm) in diameter.
- c. Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.
- d. Sewer lines located at the Cogeneration Plant, Crude Unit Furnaces and Desalter, and FCC Flare Vapor Recovery System shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

Commented [HL2]: Not really a GGGa change, just needed.

- e. Refinery wastewater routed through new process drains and a new first common downstream junction box at the Cogeneration Plant, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

8. Delay of Repair

- a. Delay of repair of equipment for which leaks have been detected will be allowed if the repair is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.
- b. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in ~~voc~~ VOC service.
- c. Delay of repair for valves will be allowed if:
  - i. The permittee demonstrates that emissions of purged material resulting from the immediate repair are greater than the fugitive emissions likely to result from the delay of repair; and
  - ii. When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with the requirements of 40 CFR §60.482-10.
- d. Delay of repair for pumps will be allowed if:
  - i. Repair requires the use of a dual mechanical seal system that includes a barrier fluid system; and
  - ii. Repair is completed as soon as practicable, but not later than six (6) months after the leak was detected.
- e. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than six (6) months after the first process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

9. Catalytic Oxidation Unit -Offgas

- a. The offgas from the Foul Water Treatment Plant shall be routed to the Catalytic Oxidation Unit at all times, except during periods of malfunction or maintenance/repair, in which the foul water shall be stored in permitted storage tanks or the offgas shall be routed to the FCC Flare or Crude Flare.

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- b. The permittee shall not oxidize in the Catalytic Oxidation Unit any offgas from the Foul Water Treatment Plant that contains H<sub>2</sub>S in excess of 162 ppmv determined hourly on a three-hour (3-hour) rolling average basis and H<sub>2</sub>S in excess of sixty (60) ppmv determined daily on a 365 successive calendar day rolling average basis.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.102a(g)(1)(ii))<sup>1</sup>

10. Catalytic Oxidation Unit - Visible Emissions

For any six (6) minute averaging period, the Catalytic Oxidation Unit shall not exhibit visible emissions of twenty (20) percent opacity or greater, except as follows: during start-up, shut-down, or equipment breakdown, the Catalytic Oxidation Unit may exhibit visible emissions not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

11. Catalytic Oxidation Unit - Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the Catalytic Oxidation Unit emissions in excess of the following emission limits:

Pollutant	Emission Limits (lb/hr) <sup>1</sup>
NO <sub>x</sub>	7.0
CO	7.4
VOE	0.63

<sup>1</sup>Based on a three-hour (3-hour) average

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

12. Foul Water Treatment Plant

The permittee shall maintain the pH of the Foul Water Treatment Plant effluent water greater than or equal to nine (9) and the temperature of the Foul Water Treatment Plant effluent water between 210 °F and 250 °F. The permittee shall also maintain the H<sub>2</sub>S concentration of the Foul Water Treatment Plant offgas less than five (5) ppm.

(Auth.: HAR §11-60.1-3, §11-60.1-90)



**Section 0. Monitoring and Recordkeeping Requirements**

1. All records, including support information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Support information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

**2. Pumps in Light Liquid Service**

- a. Each pump in light liquid service at the ~~FCC-Unit, Crude Unit, Dimersol-Plant-~~ Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, ~~Alkylation Plant,~~ and Effluent Treatment Plant shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §60.485a(b), except as provided in 40 CFR §60.482a-1(c) and 40 CFR §60.482a-2(d), (e) and (f).
- b. Each pump in light liquid service at the ~~FCC-Unit, Crude Unit, Dimersol-Plant-~~ Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, ~~Alkylation-Plant,~~ and Effluent Treatment Plant shall be checked by visual inspection **each calendar week** for indications of liquids dripping from the pump seal.
- c. If an instrument reading of ~~10,000~~**2,000** ppm or greater is measured, a leak is detected.
- d. If there are indications of liquids dripping from the pump seal, a leak is detected.
- e. When a leak is detected, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected,** except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected.**
- f. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of Special Condition No. D.2.a of this attachment provided the requirements of 40 CFR §60.482-2a(d)(1) through (6) are met.
- g. Any pump that is designated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of Special Condition Nos. D.2.a, D.2.b, D.2.e, and D.2.f of this attachment if the pump:
  - i. Has no externally actuated shaft penetrating the pump housing;
  - ii. Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in 40 CFR §60.485a(c); and
  - iii. Is tested for compliance with Special Condition No. D.2.g.ii of this attachment initially upon designation, annually, and at other times requested by the Department.



- h. If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a control device that complies with the requirements of 40 CFR §60.482~~a~~-10~~a~~, it is exempt from the requirements of Special Condition Nos. D.2.a through D.2.g of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592~~a~~, §63.648)<sup>1</sup>

### 3. Compressors

- a. Each compressor barrier fluid system shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both. Each sensor shall be checked **daily** or shall be equipped with an audible alarm. If the sensor indicates failure of the seal system, the barrier system, or both, a leak is detected.
- b. When a leak is detected, it shall be repaired as **soon as practicable, but not later than fifteen (15) calendar days after it is detected, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made no later than five (5) calendar days after each leak is detected.**

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

### 4. Pressure Relief Devices in Gas~~s~~<sup>N</sup>apor~~Vapor~~ Service

**No later than five (5) calendar days after a pressure release, the pressure relief device subject to the requirements of 40 CFR Part 60, Subpart GGG and complying by demonstrating voluntary compliance with Subpart GGGa,** shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR §60.485(c).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

### 5. Valves in Light Liquid Service and in Gas~~s~~<sup>N</sup>apor Service

- a. Each valve in light liquid service at the ~~FGG-Unit, Crude Unit, Dimersol Plant,~~ Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, ~~Alkylation Plant,~~ and Effluent Treatment Plant shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §60.485~~a~~ (b).
- b. If an instrument reading of ~~10,000~~**500** ppm or greater is measured, a leak is detected.
- c. Any valve for which a leak is **not detected for two (2) successive months** may be monitored the **first month of every quarter**, beginning with the next quarter, **until a leak is detected. If a leak is detected, the valve shall be monitored monthly until a leak is not detected for two (2) successive months.**
- d. **When a leak is detected, it shall be repaired as soon as practicable, but not later than fifteen (15) calendar days after it is detected, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made no later than five (5) calendar days after each leak is detected.**
- e. First attempts at repair include, but are not limited to, the following best practices where practicable:

- i. Tightening of bonnet bolts; Formatted ... [1]
- ii. Replacement of bonnet bolts; Formatted ... [2]
- iii. Tightening of packing gland nuts; and Formatted ... [3]
- iv. Injection of lubricant into lubricated packing. Formatted ... [4]
  
- f. Any valve that is designated, as described in 40 CFR §60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of Special Condition No. D.5.a of this attachment if the valve:
  - i. Has no external actuating mechanism in contact with the process fluid; Formatted ... [6]
  - ii. Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR §60.485a(c), and Formatted ... [7]
  - iii. Is tested for compliance with the Special Condition No. D.5.f.i of this attachment initially upon designation, annually, and at other times requested by the Department. Formatted ... [8]
  
- g. Any valve that is designated, as described in 40 CFR §60.486a(f)(1), as unsafe-to-monitor valve and satisfies the criteria outlined in 40 CFR §60.482a-7(g) is exempt from the requirements of Special Condition No. D.5.a of this attachment Formatted ... [9]
- h. Any valve that is designated, as described in 40 CFR §60.486a(f)(2), as difficult-to-monitor valve and satisfies the criteria outlined in 40 CFR §60.482a-7(h) is exempt from the requirements of Special Condition No. D.5.a of this attachment. Formatted ... [10]
  
- (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648) Formatted ... [11]
  
- 6. Pumps, and Valves, and Connectors in Heavy Liquid Service and, Pressure Relief Devices in Light Liquid or Heavy Liquid Service, and, Flanges, and other Connectors Formatted ... [12]
  - a. Pumps and valves, and connectors in heavy liquid service and, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors at the FCC Unit, Crude Unit, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, Alkylation Plant, and Effluent Treatment Plant shall be monitored within five (5) days by the method specified in 40 CFR §60.485a(b) if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method. Formatted ... [13]
  - b. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Formatted ... [14]
  - c. When a leak is detected, it shall be repaired as soon as practicable, but not later than fifteen (15) calendar days after it is detected, except as provided in Special Condition No. C.8 of this attachment. The first attempt at repair shall be made no later than five (5) calendar days after each leak is detected. Formatted ... [15]
  - d. First attempts at repair include, but are not limited to, the best practices described in Special Condition No. D.5.e of this attachment. Formatted ... [16]
  
- (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648) Formatted ... [17]

7. Connectors in Gas/Vapor Service and in Light Liquid Service

- a. Each connector in gas/vapor service or in light liquid service at the Crude Unit, Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, and Effluent Treatment Plant shall be monitored to detect leaks in accordance with the requirements set forth in 40 CFR 60.485a(b) and, as applicable, 60.485a(c).
- i. The permittee shall initially monitor all connectors in each process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.
- ii. The permittee shall perform monitoring, subsequent to the initial monitoring required in paragraph (i) above, as specified in paragraphs (1) through (3) of this section, and shall comply with the requirements of paragraphs (e) and (f) of this condition. The required period in which monitoring must be conducted shall be determined from paragraphs (1) through (3) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (g) of this condition.
- (1) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).
- (2) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. The permittee may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.
- (3) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (iii) below.
- iii. If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (1) of this section and either paragraph (2) or (3) of this section, as appropriate.
- (1) The permittee shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.
- (2) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the permittee shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.
- (3) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the permittee shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.
- b. If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- c. When a leak is detected, it shall be repaired as soon as practicable, but not later

Commented [HL3]: New section corresponding to 40 CFR 60.482-11a.

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than fifteen (15) calendar days after it is detected, except as provided in Special Condition No. C.8 of this attachment. The first attempt at repair shall be made no later than five (5) calendar days after each leak is detected.

- d. First attempts at repair include, but are not limited to, the best practices described in Special Condition No. D.5.e of this attachment.
- e. If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.
- f. The permittee shall keep a record of the start date and end date of each monitoring period under this section for each process unit.
- g.

- h. For use in determining the monitoring frequency, the percent leaking connectors as used in paragraph (a) of this condition shall be calculated by using the following equation:

$$\%CL = CL / Cr * 100$$

Where:

%CL= Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

CL= Number of connectors measured at 500 ppm or greater, by the method specified in §60.485a(b).

Cr= Total number of monitored connectors in the process unit or affected facility. Any connector that is designated, as described in 40 CFR §60.486a(f)(1), as unsafe-to-monitor connector and satisfies the criteria outlined in 40 CFR §60.482-11a(e)(1) is exempt from the requirements of Special Condition No. D.7.a of this attachment.

- i. Any connector that is designated, as described in 40 CFR §60.486a(f)(2), as difficult-to-monitor connector and satisfies the criteria outlined in 40 CFR §60.482-11a(e)(2) is exempt from the requirements of Special Condition No. D.7.a of this attachment.
- j. Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of Special Condition No. D.7.a of this attachment, from the leak repair requirements of Special Condition No. D.7.c of this attachment, and from the recordkeeping and reporting requirements of §§63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in §60.482-11a(f)(1)(i) through (vi), as applicable.
- k. If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.
- l. Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of Special Condition No. D.7.j of this attachment, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.59a2, §63.648)<sup>1</sup>

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**7.8.** *When each leak is detected, a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.*

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

**8.9.** *The identification on a valve may be removed after it has been monitored for two (2) successive months as specified in Special Condition No. O.5.c of this attachment and no leak has been detected during those two (2) months. The identification on equipment except a valve may be removed after it has been repaired.*

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

**9.10.** *When each leak is detected, the following information shall be recorded in a log and shall be kept for two (2) years in a readily accessible location:*

- a. The instrument and operator identification numbers and the equipment identification number;
- b. The date the leak was detected and the dates of each attempt to repair the leak;
- c. Repair methods applied in each attempt to repair the leak;
- d. "Above 10,000" if the maximum instrument reading measured by the methods specified in 40 CFR §60.485(a) after each repair attempt is equal to or greater than 10,000 ppm;
- e. "Repair delayed" and the reason for the delay if a leak is not repaired within fifteen (15) calendar days after discovery of the leak;
- f. The signature of the permittee whose decision it was that repair could not be effected without a process shutdown;
- g. The expected date of successful repair of the leak if a leak is not repaired within fifteen (15) days;
- h. Dates of process unit shutdown that occur while the equipment is unrepaired; and
- i. The date of successful repair of the leak.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

**10.11.** *The following information pertaining to all equipment subject to the requirements of 40 CFR Part 60, Subpart GGGa, or 40 CFR Part 63, Subpart CC, shall be recorded in a log that is kept in a readily accessible location:*

- a. A list of identification numbers for all equipment;
- b. A list of identification numbers for equipment that are designated for no detectable emissions which is signed by the permittee;
- c. A list of equipment identification numbers for pressure relief devices required to comply with the requirements of Special Condition No. C.4 of this attachment;
- d. The dates of each compliance test used to determine no detectable emissions:
  - i. The background level measured during each compliance test; and
  - ii. The maximum instrument reading measured at the equipment during each compliance test.

- e. A list of identification numbers for equipment in vacuum service.
- f. A list of identification numbers for equipment that the permittee designates as operating in VOC service less than 300 hr/yr in accordance with §60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
- g. The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.
- h. Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and §60.485a(b).
- i. The connector monitoring schedule for each process unit as specified in §60.482-11a(b)(3)(v).
- e.j. Records of each release from a pressure relief device subject to §60.482-4a.

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(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

11.12. The following information pertaining to all valves subject to the requirements of 40 CFR Part 60, Subpart GGG, or 40 CFR Part 63, Subpart CC, shall be recorded in a log that is kept in a readily accessible location:

- a. A list of identification numbers for valves that are designated as unsafe-to-monitor, an explanation for each valve stating why the valve is unsafe-to-monitor, and the plan for monitoring each valve; and
- b. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.
- c. A schedule of monitoring for valves complying with §60.483-2a.
- b.d. The percent of valves found leaking during each monitoring period for valves complying with §60.483-2a.

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(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

12.13. The following information shall be recorded in a log that is kept in a readily accessible location:

- a. Design criterion based on design considerations and operating experience indicating the failure of the seal system, barrier fluid system, or both of each affected pump or compressor.
- b. Any changes to this criterion and the reasons for the changes.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

13.14. Each drain in active service at the Cogeneration Plant, Crude Unit Furnaces and Desalter, and FCC Flare Vapor Recovery System shall be checked by visual inspection or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

14.15. Except for out of service drains where a tightly sealed cap or plug is installed, each drain

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out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions. Drains having tightly sealed caps or plugs shall be inspected initially and semi-annually to ensure caps or plugs are in place and properly installed.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

~~15.16.~~ *Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than twenty-four (24) hours after detection unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.*

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

~~16.17.~~ Junction boxes located at the Cogeneration Plant shall be visually inspected **initially and semi-annually** thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

~~17.18.~~ *If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than fifteen (15) calendar days after the broken seal or gap is identified unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.*

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

~~18.19.~~ The portion of each unburied sewer line located at the Cogeneration Plant and Crude Unit Furnaces and Desalter shall be visually inspected **initially and semi-annually** for indication of cracks, gaps, or other problems that could result in ~~voc~~-VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

~~19.20.~~ *Wherever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than fifteen (15) calendar days after identification unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.*

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

~~20.21.~~ Before using any individual drain system installed in compliance with 40 CFR §60.692-2, the permittee shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of 40 CFR Part 60, Subpart QQQ, not to be met. Points of inspection include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.696)<sup>1</sup>



21-22. For each individual drain systems subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions during the initial and periodic visual or physical inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.697)<sup>1</sup>

22-23. For junction boxes subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for each inspection when a broken seal, gap, or other problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.697)<sup>1</sup>

23-24. For each sewer line subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for inspections when a problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.697)<sup>1</sup>

24-25. Catalytic Oxidation Unit- H<sub>2</sub>S Monitoring

- a. The permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H<sub>2</sub>S in the offgas from the Foul Water Treatment Plant before being oxidized in the Catalytic Oxidation Unit.
- b. The permittee may apply for an exemption from the H<sub>2</sub>S monitoring requirements described above for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the H<sub>2</sub>S monitoring requirements described above until there are changes in operating conditions or stream composition.
  - i. The permittee shall submit to the Department and U.S. EPA, Region 9, a written application for an exemption from monitoring. The application must contain the following information:
    - (1) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;
    - (2) A statement that there are no crossover or entry points for sour gas (high H<sub>2</sub>S content) to be introduced into the fuel gas stream/system;
    - (3) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;
    - (4) The supporting test results from sampling the fuel gas stream/system demonstrating that the sulfur content is less than five (5) ppm H<sub>2</sub>S; and

- (5) A description of how the two (2) weeks of monitoring results compares to the typical range of H<sub>2</sub>S concentration expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare.
- ii. The effective date of the exemption is the date of submission of the information required above.
- iii. No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the permittee shall follow the procedures in 40 CFR §60.107a(b)(3).
- c. The permittee shall keep records of the specific exemption determined to apply for each fuel stream that is exempted. The permittee shall keep a copy of the application as well as the letter from the Department and U.S. EPA, Region 9, granting approval of the application.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.107a(a)(2), §60.107a(b), §60.108a(c))<sup>1</sup>

25 26. Catalytic Oxidation Unit - Visible Emissions (VE)

The permittee shall conduct **monthly** (calendar month) VE observations for the Catalytic Oxidation Unit by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

26 27. Catalytic Oxidation Unit - Continuous Process Monitoring System for NO<sub>x</sub> and NH<sub>3</sub>

The permittee shall install, operate, calibrate, and maintain a continuous process monitoring system including one NO<sub>x</sub> analyzer and one NH<sub>3</sub> analyzer, for continuously monitoring and recording the NO<sub>x</sub> and NH<sub>3</sub> concentrations downstream of the Catalytic Oxidation Unit. The continuous process monitoring system must be in continuous operation whenever the Catalytic Oxidation Unit is in operation. The NH<sub>3</sub> concentration downstream of the Catalytic Oxidation Unit will be used to determine the CO and VOC concentrations downstream of the Catalytic Oxidation Unit using correlation factors for CO and VOC that are to be established during the source performance test specified in Special Condition No. F.3 of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

27-28. Foul Water Treatment Plant Monitoring and Recordkeeping

The permittee shall monitor the Foul Water Treatment Plant effluent water for pH and temperature on a daily basis. The permittee shall also monitor the Foul Water Treatment Plant offgas for H<sub>2</sub>S concentration using colorimetric indicator tubes at least twice per year and when the pH drops below nine (9). Records shall be kept of the effluent water pH and temperature and of the offgas H<sub>2</sub>S concentration.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

**Section E. Notification and Reporting Requirements**

1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate** or equivalent form, shall be used in reporting fugitive emissions.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions 14, 16, 17, and 25, respectively. These notifications shall include, but not be limited to:

- a. Anticipated date of initial start-up, actual date of construction commencement, and actual date of start-up;
- b. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
- c. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- d. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
- i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. For valves, pumps, and compressors subject to the requirements of 40 CFR Part 60, Subpart GGG and complying by demonstrating compliance with Subpart GGGa, or 40 CFR Part 63, Subpart CC, the permittee shall submit **semi-annual** reports to the Department. 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)**. The **initial** semi-annual report shall include the following information:

- a. Process unit identification;
- b. Number of valves subject to the requirements of Special Condition No. D.5 of this attachment, excluding those valves designated for no detectable emissions under the provisions of Special Condition No. D.5.f of this attachment;
- c. Number of pumps subject to the requirements of Special Condition No. D.2 of this attachment, excluding those pumps designated for no detectable emissions under the provisions of Special Condition No. D.2.g of this attachment and those pumps complying with Special Condition No. D.2.h of this attachment; and
- d. Number of compressors subject to the requirements of Special Condition No. C.3 of this attachment, excluding those compressors designated for no detectable emissions under the provisions of Special Condition No. C.3.e of this attachment and those compressors complying with Special Condition No. C.3.d of this attachment;
- e. Number of connectors subject to the requirements of Special Condition No. D.7 of this attachment.

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(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

6. All semi-annual reports, required in Special Condition No. E.5 of this attachment, shall include the following information:

- a. Process unit identification;
- b. For each month during the semi-annual reporting period:
  - i. Number of valves for which leaks were detected;
  - ii. Number of valves for which leaks were not repaired;
  - iii. Number of pumps for which leaks were detected;
  - iv. Number of pumps for which leaks were not repaired;
  - v. Number of compressors for which leaks were detected;
  - vi. Number of compressors for which leaks were not repaired; and
  - vii. Number of connectors for which leaks were detected;
  - viii. Number of connectors for which leaks were not repaired; and
  - ix. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
- ~~vii. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.~~
- c. Dates of process unit shutdowns which occurred within the semi-annual reporting period; and
- d. Revisions to items reported in the initial semi-annual report if changes have occurred since the initial report or subsequent revisions to the initial report.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

7. The permittee shall submit to the Department within sixty (60) days after initial startup a certification that the equipment necessary to comply with 40 CFR Part 60, Subpart QQQ, has been installed and that the required initial inspections or tests of process drains, sewer lines and junction boxes have been carried out in accordance with 40 CFR Part 60, Subpart QQQ. Thereafter, the permittee shall submit semi-annually a certification that all of the required inspections have been carried out in accordance with 40 CFR Part 60, Subpart QQQ.

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**(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.698)<sup>1</sup>**

8. A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted **initially and semi-annually** thereafter to the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.698)<sup>1</sup>

9. If compliance with the provisions of 40 CFR Part 60, Subpart QQQ, is delayed pursuant to 40 CFR §60.692-7, the notification required under 40 CFR §60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standard is technically impossible without a refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.698)<sup>1</sup>

10. Catalytic Oxidation Unit - Notifications

In accordance with 40 CFR §60.108a(b), the permittee shall notify the Department and U.S. EPA, Region 9, of the specific monitoring provisions of 40 CFR §60.107a with which the permittee intends to comply with for an emission limitation in 40 CFR §60.102a.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.108a(b))<sup>1</sup>

11. Catalytic Oxidation Unit Monitoring Reports

The permittee shall submit **semi-annually** the following written report to the Department for monitoring purposes. The report 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 exceedances as determined by the required VE 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 are 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: Opacity Exceedances** shall be used.

- b. Any deviations from permit requirements shall be clearly identified.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

**Section F. Testing Requirements**

1. **Within sixty (60) days after achieving the maximum production rate of the Catalytic Oxidation Unit, but not later than one-hundred eighty (180) days after initial startup of the Catalytic Oxidation Unit, the permittee shall conduct or cause to be conducted performance tests on the offgas from the Foul Water Treatment Plant to determine compliance with the hourly H<sub>2</sub>S limit in Special Condition No. C.9.b of this attachment.**

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161, 40 CFR §60.8, §60.104a)<sup>1</sup>

2. **The performance tests shall be conducted and the results reported in accordance with the test method set forth in 40 CFR Part 60, Appendix A-5, and 40 CFR §60.8. Performance tests for the emissions of H<sub>2</sub>S shall be conducted using EPA Method 11 or U.S. EPA approved equivalent methods or alternative methods with prior written approval from the Department.**

For Method 11, the sampling time and sample volume must be at least ten (10) minutes and 0.010 dscm (0.35 dscf). Two (2) samples of equal sampling time must be taken at about one-hour (1-hour) intervals. The arithmetic average of these two (2) samples constitutes a run. For most fuel gases, sampling times exceeding twenty (20) minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H<sub>2</sub>S may necessitate sampling for longer periods of time.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.104a)<sup>1</sup>

3. **Within sixty (60) days after achieving the maximum production rate of the Catalytic Oxidation Unit, but not later than one-hundred eighty (180) days after initial startup of the Catalytic Oxidation Unit and annually thereafter, the permittee shall conduct or cause to be conducted performance tests for NO<sub>x</sub>, CO, and VOC on the Catalytic Oxidation Unit outlet stack.**

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

4. **Performance tests for the emissions of NO<sub>x</sub>, CO, and VOC shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A. The following test methods or U.S. EPA approved equivalent methods or alternative methods with prior written approval from the Department shall be used:**
  - a. **Performance tests for the emissions of NO<sub>x</sub> shall be conducted using 40 CFR Part 60, Methods 1-4 and 7.**
  - b. **Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60, Methods 1-4 and 10.**



c. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60, Methods 1-4 and 25A.

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

5. Each performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

6. The permittee shall provide sampling and testing facilities at its own expense. The Department may monitor any of the required performance tests.

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

7. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

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

8. **At least thirty (30) days prior to performing a test**, the permittee shall submit a written *performance test plan* to the Department and the U.S. EPA, Region 9, that describes the test date(s), test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A performance test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

9. **Within sixty (60) days after completion of the performance test**, the permittee shall submit to the Department and the U.S. EPA, Region 9, the test report which shall include the analysis of the offgas from the Foul Water Treatment Plant, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data. A similar test report for the performance tests on the Catalytic Oxidation Unit outlet stack shall also be submitted.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

10. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous performance test.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §60.8)<sup>1</sup>

#### Section G. Agency Notifications

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

<sup>3</sup>This date is to be revised upon issuance of the renewal for CSP No. 0088-01-C.

**ATTACHMENT II(F): SPECIAL CONDITIONS  
FLUID CATALYTIC CRACKING UNIT (FCCU)  
COVERED SOURCE PERMIT NO. 0088-01-C**

Issuance Date: November 16, 2018

Expiration Date: February 1, 2004<sup>1</sup>

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:

- a. Catalyst transfer operations;
- b. One (1) Fluid Catalytic Cracking Unit (FCCU) which includes the Regenerator and Reactor;

Particulate Control Devices:

- i. Cyclone and
- ii. Electrostatic Precipitator (ESP) - Manufacturer: Hamon Research Cottrell, Inc., Model No. 8883.

- c. One (1) 61 MMBtu/hr furnace identified as F-5300 equipped with Gallidus Ultra-Blue burners; and
- d. One (1) 52 MMBtu/hr FCC Startup Air Heater identified as F-5310; Manufacturer: John Zink, Model: Direct Fired Air Heater.

(Auth.: HAR§11-60-1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60-1-5, §11-60-1-90)

**Section B. Applicable Federal Regulations**

1. The FCCU is subject to the provisions of the following federal regulations:

a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

- i. Subpart A, General Provisions; and
- ii. Subpart J, Standards of Performance for Petroleum Refineries.

b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories:

- ~~i. Subpart A, General Provisions, and~~
- ~~ii. Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries-Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.~~

~~The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.1, 40 CFR §60.100, 40 CFR §63.1561)~~

- ~~2. The FGG Startup Air Heater is subject to the provisions of the following federal regulations:~~

~~40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):~~

- ~~a. Subpart A, General Provisions, and~~
- ~~b. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007.~~

~~The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.1, 40 CFR §60.100a)~~

### Section C. Operational and Emissions Limitations

- ~~1. The F-5300 furnace shall be fired only on RFG with a H<sub>2</sub>S content not to exceed 230 mg/dscm (160 ppmv).~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-38, §11-60.1-90, 40 CFR §60.104)~~

- ~~2. The permittee shall take measures to control fugitive dust at all catalyst transfer operations. The Department at any time may require the permittee to further abate fugitive dust emissions if an inspection indicates poor or insufficient control.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-33, §11-60.1-90)~~

- ~~3. The permittee shall not cause the discharge of visible emissions of fugitive dust beyond the lot line of the property on which the emissions originate.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-33, §11-60.1-90)~~

- ~~4. The permittee shall maintain and operate the cyclone and electrostatic precipitator in a manner consistent with good air pollution control practices for minimizing emissions.~~

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

5. The vacuum gas oil (VGO) processed by the FCCU shall not exceed the following feed rate and sulfur content limit:

- a. A maximum VGO feed rate of 22,000 bbls/day<sup>\*</sup>;
- b. A maximum sulfur content of VGO of 0.30% by weight<sup>\*\*</sup>.

<sup>\*</sup>Based on a rolling 365-day average

<sup>\*\*</sup>Based on a rolling seven-day (7-day) average, applicable at all times, including periods of startup, shutdown, and malfunctions

(Auth: HAR §11-60-1-3, §11-60-1-90, 40 CFR §60.104, 40 CFR §60.108)<sup>1</sup>

#### 6. Emission Limits

The permittee shall not discharge or cause the discharge from the FCCU emissions in excess of the following:

- a. PM Emission Limit: 1.0 pounds of PM per 1000 pounds (1.0 kg/Mg or 2.0 lb/ton) of coke burn-off in the catalyst regenerator (3-hr average)<sup>\*\*</sup>;
- b. CO Emission Limit: 500 ppmvd @ 0% O<sub>2</sub> (1-hr average)<sup>\*\*</sup>;
- c. SO<sub>2</sub> Emission Limit: 25 ppmvd @ 0% O<sub>2</sub> (365-day rolling average)<sup>\*</sup> and 50 ppmvd @ 0% O<sub>2</sub> (7-day rolling average)<sup>\*\*</sup>;
- d. NO<sub>x</sub> Emission Limit: 50 ppmvd @ 0% O<sub>2</sub> (365-day rolling average)<sup>\*</sup> and 87.9 ppmvd @ 0% O<sub>2</sub> (7-day rolling average)<sup>\*\*</sup>.

<sup>\*</sup>Applicable at all times, including periods of startup, shutdown, and malfunctions.

<sup>\*\*</sup>Applicable at all times, excluding periods of startup, shutdown, and malfunctions.

(Auth: HAR §11-60-1-3, §11-60-1-5, §11-60-1-90, 40 CFR §60.102, 40 CFR §60.103, 40 CFR §63.1564, §63.1565)<sup>1</sup>

#### 7. Visible Emissions (VE)

- a. For any six (6) minute averaging period, the FCCU shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during start-up, shutdown, or equipment breakdown, the FCCU may exhibit visible emissions not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.
- b. For any six (6) minute averaging period, the F-5300 furnace shall not exhibit VE of forty (40) percent opacity or greater, except as follows: during start-up, shutdown, or equipment breakdown, the F-5300 furnace may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth: HAR §11-60-1-3, §11-60-1-5, §11-60-1-32, §11-60-1-90, SIP §11-60-24, 40 CFR §60.102, 40 CFR §63.1564)<sup>1,2</sup>

8.—~~Operation, Maintenance, and Monitoring Plan~~

~~The permittee must prepare and implement an operation, maintenance, and monitoring plan for the FCCU, air-pollution control system, and continuous monitoring system. The purpose of this plan is to detail the operation, maintenance, and monitoring procedures to follow.~~

~~a.—The plan shall be submitted to the Department for review and approval along with the notification of compliance status. Any changes to the plan must be submitted for review and approved by the Department.~~

~~b.—Each plan must include the following information:~~

- ~~i.—Process and control device parameters to be monitored for the FCCU, along with established operating limits.~~
- ~~ii.—Procedures for monitoring emissions and process and control device operating parameters for the FCCU.~~
- ~~iii.—Procedures to determine the coke burn rate and the volumetric flow rate (if you use process data rather than direct measurement).~~
- ~~iv.—Procedures and analytical methods used to determine the equilibrium catalyst Ni concentration, the equilibrium catalyst Ni concentration monthly rolling average, and the hourly or hourly average Ni operating value.~~
- ~~v.—Procedures to determine the gas flow rate for a catalytic cracking unit if you use the alternative procedure based on air flow rate and temperature.~~
- ~~vi.—Monitoring schedule, including when you will monitor and when you will not monitor the FCCU (e.g., during the coke burn-off, regeneration process).~~
- ~~vii.—Quality control plan for each continuous opacity monitoring system and continuous emission monitoring system used to meet an emission limit in 40 CFR Part 63, Subpart UUU. This plan must include procedures for calibrations, accuracy audits, and adjustments to the system needed to meet applicable requirements for the system.~~
- ~~viii.—Maintenance schedule for each monitoring system and control device for the FCCU that is generally consistent with the manufacturer's instructions for routine and long-term maintenance.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §63.1574) <sup>1</sup>~~

9.—~~Startup, Shutdown, and Malfunction Plan (SSMP)~~

~~a.—The permittee shall develop and implement a written SSMP according to the provisions in 40 CFR §63.6(e)(3).~~

~~b.—During periods of startup, shutdown, and malfunction, the permittee must operate in accordance with the SSMP.~~

- ~~c. The permittee must report each instance in which each emission limitation and each operating limitation was not met. This includes periods of startup, shutdown, and malfunction. The permittee shall also report each instance in which the work practice standards were not met. These instances are deviations from the emission limitations and work practices. These deviations must be reported according to the requirements in 40 CFR §63.1575.~~
- ~~d. Consistent with 40 CFR §63.6(e) and 40 CFR §63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Department's satisfaction that you were operating in accordance with 40 CFR §63.6(e)(1). The SSMP must also include elements designed to minimize the frequency of such periods (i.e., root cause analysis). The Department will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in 40 CFR §63.6(e).~~

~~(Auth.: HAR §11-60-1-3, §11-60-1-90, 40 CFR §63.1570)~~

#### 10. FCC Startup Air Heater

- ~~a. The startup air heater may be utilized for up to twenty-two (22) days per year at maximum duty and shall only combust RFG.~~
- ~~b. The startup air heater shall only combust gas that has a H<sub>2</sub>S content that does not exceed 162 ppmv determined hourly on a three-hour (3-hour) rolling average basis and sixty (60) ppmv determined daily on a 365 successive calendar day rolling average basis.~~

~~(Auth.: HAR §11-60-1-3, §11-60-1-38, §11-60-1-90, 40 CFR §60.102a(g)(1)(ii))~~

#### 11. Electrostatic Precipitator (ESP)

- ~~a. The ESP shall operate with total daily power above the minimum level, and with a minimum number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online).~~
- ~~b. The ESP minimum total daily power input level and the minimum number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online) shall be established in the most recent PM source performance test conducted pursuant to Special Condition No. F.1 of this attachment.~~
- ~~c. Except during periods of startup, shutdown, and malfunction, if the ESP total daily power input level falls below the level measured in the most recent PM source performance test conducted pursuant to Special Condition No. F.1 of this attachment that demonstrated compliance with the three-hour (3-hour) average PM emission limit in Special Condition No. C.6.a of this attachment, the permittee may perform a retest of the PM source performance test within 120 days to establish a new ESP minimum total daily power input level and a new minimum number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online).~~

~~(Auth.: HAR §11-60-1-3, §11-60-1-5, §11-60-1-11, §11-60-1-90)~~

**Section D. — ~~Monitoring and Recordkeeping Requirements~~**

~~1. All records, including support information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Support information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be in a permanent form suitable for inspection and made available to the Department or their representatives upon request.~~

~~(Auth: HAR §11-60-1-3, §11-60-1-11, §11-60-1-90)~~

~~2. Vacuum Gas Oil (VGO)~~

~~a. The permittee shall monitor the feed rates (in barrels per day) of the VGO processed by the FCCU. Records shall be kept on a **rolling 365-day average basis**.~~

~~b. Compliance with the maximum sulfur content limit for the fresh feed (VGO) is determined daily on a **rolling seven-day (7-day) average basis** using the following analytical methods and calculation procedures outlined below:~~

~~i. One (1) fresh feed sample shall be collected once per eight-hour (8-hour) period.~~

~~ii. Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods:~~

~~ASTM D129-64, 78, or 95, ASTM D1552-83 or 95, ASTM D2622-87, 94, or 98, or ASTM D1266-87, 91, or 98. (These methods are incorporated by reference; see 40-CFR §60.17). The applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Department.~~

~~iii. If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:~~

~~(1) Individual samples shall be collected once per eight-hour (8-hour) period for each separate fresh feed stream charged directly into the riser or reactor of the FCCU. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.~~

~~(2) Each fresh feed sample shall be analyzed separately using the methods specified in Special Condition No. D.2.b.ii of this attachment.~~



(3)---Fresh-feed sulfur-content shall be-calculated-for-each-eight-hour(8-hour)-period-using-the-following-equation:

$$S_f = \frac{\sum_{i=1}^n S_i Q_i}{Q_f}$$

where:

$S_f$  = fresh-feed-sulfur-content-expressed-in-percent-by-weight-of-fresh-feed.  
 $n$  = number-of-separate-fresh-feed-streams-charged-directly-to-the-riser-or-reactor-of-the-FCCU.  
 $Q_f$  = total-volumetric-flow-rate-of-fresh-feed-charged-to-the-FCCU.  
 $S_i$  = fresh-feed-sulfur-content-expressed-in-percent-by-weight-of-fresh-feed-for-the-"ith"-sampling-location.  
 $Q_i$  = volumetric-flow-rate-of-fresh-feed-stream-for-the-"ith"-sampling-location.

iv---Calculate-a-seven-day-(7-day)-average-(arithmetic-mean)-sulfur-content-of-the-fresh-feed-using-all-of-the-fresh-feed-sulfur-content-values-obtained-during-seven-(7)-successive-twenty-four-hour-(24-hour)-periods.

(Auth: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

### 3. Visible Emissions (VE)

- a---Except-in-those-months-where-VE-observations-are-conducted-by-a-certified-reader-for-the-annual-observations-of-the-F-5300-furnace, the-permittee-shall-conduct-monthly-(calendar-month)-VE-observations-for-the-F-5300-furnace-in-accordance-with-40-CFR-Part-60, Appendix A, Method 9, or-by-use-of-a-Ringelmann-Chart, as-provided. For-each-month, two-(2)-consecutive-six-(6)-minute-observations-shall-be-taken-at-fifteen-(15)-second-intervals-for-the-F-5300-furnace. Records-shall-be-completed-and-maintained-in-accordance-with-the-Visible-Emissions-Form-Requirements.
- b---The-permittee-shall-conduct-annually-(calendar-year)-VE-observations-for-the-F-5300-furnace-by-a-certified-reader-in-accordance-with-40-CFR-Part-60, Appendix A, Method 9. For-the-annual-observations, two-(2)-consecutive-six-(6)-minute-observations-shall-be-taken-at-fifteen-(15)-second-intervals-for-the-F-5300-furnace. Records-shall-be-completed-and-maintained-in-accordance-with-the-Visible-Emissions-Form-Requirements.
- c---Upon-written-request-and-justification, the-Department-may-waive-the-requirements-for-the-annual-VE-observations. The-waiver-request-is-to-be-submitted-prior-to-the-required-annual-VE-observations-and-must-include-documentation-justifying-such-action. Documentation-should-include, but-is-not-limited-to, the-results-of-the-prior-VE-observations-indicating-compliance-by-a-wide-margin, documentation-of-continuing-compliance, and-further-that-operations-of-the-source-have-not-changed-since-the-previous-annual-VE-observations. The-annual-VE-observations-shall-not-be-waived-for-more-than-two-(2)-consecutive-years.

(Auth: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90; SIP §11-60-15, SIP §11-60-24)<sup>2</sup>

~~4. Continuous Emissions Monitoring System (CEMS) for CO~~

- ~~a. The permittee shall install, operate and maintain a CEMS for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions from the FCCU.~~
- ~~b. The CEMS shall meet the following requirements:
  - ~~i. The span value for the CEMS is 1,000 ppm CO.~~
  - ~~ii. Performance evaluations for the CO CEMS shall be in accordance with 40 CFR §60.13 and §63.8. The CO CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 4, Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources, and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 10, shall be used in conducting any RATA.~~
  - ~~iii. CGA shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.~~
  - ~~iv. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.~~~~

~~(Auth.: HAR §11-60-1-3, §11-60-1-11, §11-60-1-90, 40 CFR §60.105, 40 CFR §63.1572)<sup>1</sup>~~

~~5. Continuous Monitoring System (CMS) for H<sub>2</sub>S~~

- ~~a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned.~~
- ~~b. The CMS shall meet the following requirements:
  - ~~i. The span value for the CMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.~~
  - ~~ii. All fuel gas combustion devices having a common source of fuel gas may be monitored at one (1) location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.~~
  - ~~iii. Performance evaluations for the H<sub>2</sub>S CMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CMS shall meet 40 CFR Part 60, Appendix 8, Performance Specification 7, Specifications and Test Procedures for Hydrogen Sulfide Continuous Emissions Monitoring Systems in Stationary Sources, and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11, 15, 15A, or 16, shall be used in conducting any RATA.~~
  - ~~iv. CGA shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.~~
  - ~~v. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.~~~~

~~(Auth.: HAR §11-60-1-3, §11-60-1-11, §11-60-1-90, 40 CFR §60.105)<sup>1</sup>~~

6. Continuous Emissions Monitoring System (CEMS) for O<sub>2</sub>

- a. The permittee shall install, operate and maintain a CEMS for continuously monitoring and recording the concentration by volume (dry basis) of O<sub>2</sub> emissions from the FCCU.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is twenty-five (25) percent O<sub>2</sub>.
  - ii. Performance evaluations for the O<sub>2</sub> CEMS shall be in accordance with 40 CFR §60.13 and §63.8. The O<sub>2</sub> CEMS shall meet 40 CFR Part 60, Appendix 8, Performance Specification 3, Specifications and Test Procedures for O<sub>2</sub> and CO<sub>2</sub> Continuous Emission Monitoring Systems in Stationary Sources, and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 3A or 3B, shall be used in conducting any RATA.
  - iii. CGA shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2. In lieu of the audit points specified in 40 CFR Part 60, Appendix F, Section 5.1.2, the permittee may audit the O<sub>2</sub> CEMS at twenty (20) to thirty (30) percent and fifty (50) to sixty (60) percent of the actual O<sub>2</sub> CEMS span value.
  - iv. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105, 40 CFR §63.1572)

7. Continuous Emissions Monitoring System (CEMS) for SO<sub>2</sub>

- a. The permittee shall install, operate, and maintain a CEMS for continuously monitoring and recording the concentration by volume (dry basis) of SO<sub>2</sub> emissions from the FCCU.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is 50 ppm SO<sub>2</sub>.
  - ii. Performance evaluations for the SO<sub>2</sub> CEMS shall be in accordance with 40 CFR §60.13. The SO<sub>2</sub> CEMS shall meet 40 CFR Part 60, Appendix 8, Performance Specification 2, Specifications and Test Procedures for SO<sub>2</sub> and NO<sub>x</sub> Continuous Emission Monitoring Systems in Stationary Sources, and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 5, 6A, or 6B shall be used in conducting any RATA. In lieu of the requirements of 40 CFR Part 60, Appendix F, Sections 5.1.1, 5.1.3, and 5.1.4, the permittee must conduct either a Relative Accuracy Audit (RAA) or a RATA at least once every three (3) years. The permittee shall conduct a CGA each calendar quarter during which a RAA or a RATA is not performed.
  - iii. CGA shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.
  - iv. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105)

~~8. Continuous Emissions Monitoring System (CEMS) for NO<sub>x</sub>~~

- ~~a. The permittee shall install, operate and maintain a CEMS for continuously monitoring and recording the concentration by volume (dry basis) of NO<sub>x</sub> emissions from the FCCU.~~
- ~~b. The CEMS shall meet the following requirements:
  - ~~i. Performance evaluations for the NO<sub>x</sub> CEMS shall be in accordance with 40 CFR §60.13. The NO<sub>x</sub> CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 2, Specifications and Test Procedures for SO<sub>2</sub> and NO<sub>x</sub> Continuous Emission Monitoring Systems in Stationary Sources, and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, or 7E shall be used in conducting any RATA. In lieu of the requirements of 40 CFR Part 60, Appendix F, Sections 5.1.1, 5.1.3, and 5.1.4, the permittee must conduct either a RAA or a RATA at least once every three (3) years. The permittee shall conduct a CGA each calendar quarter during which a RAA or a RATA is not performed.~~
  - ~~ii. CGA shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.~~
  - ~~iii. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.~~~~

~~(Auth.: HAR §11-60-1-3, §11-60-1-5, §11-60-1-11, §11-60-1-90)~~

~~9. Continuous Opacity Monitoring System (COMS) for Opacity~~

~~The permittee shall install, operate and maintain a COMS for continuously measuring and recording the opacity levels of stack emissions from the FCCU. The system shall meet U.S. EPA monitoring performance standards (40 CFR §60.13; 40 CFR §63.8; and 40 CFR Part 60, Appendix B, Performance Specification 1, Specifications and test procedures for continuous opacity monitoring systems in stationary sources and Appendix F, Procedure 3, Quality Assurance Requirements for Continuous Opacity Monitoring Systems at Stationary Sources). The instrument shall be spanned at sixty (60), seventy (70), or eighty (80) percent opacity. As specified in 40 CFR §63.8(c)(4)(i), each continuous opacity monitoring system must complete a minimum of one (1) cycle of sampling and analyzing for each successive ten-second (10-second) period and one (1) cycle of data recording for each successive six-minute (6-minute) period.~~

~~(Auth.: HAR §11-60-1-3, §11-60-1-11, §11-60-1-90, 40 CFR §60.105, 40 CFR §63.1572)~~

~~10. The following records must be kept:~~

- ~~a. A copy of each notification and report that was submitted to comply with 40 CFR Part 63, Subpart UUU, including all documentation supporting any initial notification or Notification of Compliance Status that was submitted, according to the requirements in 40 CFR §63.10(b)(2)(xiv).~~

- b. ~~The records in 40 CFR §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.~~
- c. ~~Records of performance tests, performance evaluations, and opacity and visible emission observations as required in 40 CFR §63.10(b)(2)(viii).~~
- d. ~~For each continuous emission monitoring system and continuous opacity monitoring system:
 
  - i. ~~Records described in 40 CFR §63.10(b)(2)(vi) through (xi).~~
  - ii. ~~Monitoring data for continuous opacity monitoring systems during a performance evaluation as required in 40 CFR §63.6(h)(7)(i) and (ii).~~
  - iii. ~~Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR §63.8(d)(3).~~
  - iv. ~~Requests for alternatives to the relative accuracy test for continuous emission monitoring systems as required in 40 CFR §63.8(f)(6)(i).~~
  - v. ~~Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.~~~~
- e. ~~Records in 40 CFR §63.6(h) for VE observations.~~
- f. ~~A current copy of the operation, maintenance, and monitoring plan onsite and available for inspection. Also records to show continuous compliance with the procedures in the operation, maintenance, and monitoring plan.~~
- g. ~~Records of any changes that affect emission control system performance.~~
- h. ~~The average coke burn-off rate (Mg or tons per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to 40 CFR §60.102, 40 CFR §60.103, or 40 CFR §60.104(b)(2).~~
- i. ~~Data obtained from the daily feed sulfur tests.~~
- j. ~~Each rolling seven-day (7-day) average compliance determination for sulfur content of the feed.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105, 40 CFR §60.107, 40 CFR §63-1576)~~

~~11--FGC Startup Air Heater~~

- a. ~~The permittee shall maintain records as described in 40 CFR §60.108a(a).~~
- b. ~~The permittee shall maintain a record of the number of days of operation of the unit.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, 40 CFR §60.108a)<sup>4</sup>~~

~~12--Electrostatic Precipitator (ESP)~~

- a. ~~The permittee shall install, operate, and maintain a continuous monitoring and recording system to accurately measure and record the voltage and current for each ESP electrical grid field. The ESP's continuous monitoring and recording system shall be maintained pursuant to Special Condition No. C-8(b)(viii) of this attachment.~~



- b. ~~Daily averages for these parameters must be recorded and maintained for total daily power input level determination. Total daily power is determined by summing the individual ESP electrical grid field power inputs (power = voltage x current).~~
- c. ~~The permittee shall maintain records of the total daily power input level and number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online). Total daily power input level shall be determined from the voltage and current recorded pursuant to Special Condition No. D-12, b of this attachment.~~
- d. ~~The permittee shall maintain records of the dates of operation when the monitored parameters averaged on a daily basis, are below the minimum levels of the ESP parameters listed above, which were established in the most recent PM performance testing conducted pursuant to Special Condition No. F-1 of this attachment.~~

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

#### Section E. ~~Notification and Reporting Requirements~~

##### 1. ~~Annual Emissions~~

~~As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit on an annual basis the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within sixty (60) days following the end of each calendar year. The enclosed Annual Emissions Report Form: Refinery Equipment - Process Rate and Annual Emissions Report Form: Refinery Equipment - Fuel Consumption, or equivalent forms, shall be used in reporting the FCCU feed rate and the fuel consumption of Furnace F-5300, respectively.~~

~~Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.~~

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. ~~Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions 16, 17, and 25, respectively. These notifications shall include, but not be limited to:~~

- a. ~~Intent to shutdown air pollution control equipment for necessary scheduled maintenance;~~
- b. ~~Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and~~
- c. ~~Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.~~

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

~~3—The permittee shall report **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.~~

~~(Auth: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)~~

~~4—Compliance Certification~~

~~a—During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:~~

- ~~i—The identification of each term or condition of the permit that is the basis of the certification;~~
- ~~ii—The compliance status;~~
- ~~iii—Whether compliance was continuous or intermittent;~~
- ~~iv—The methods used for determining the compliance status of the source currently and over the reporting period;~~
- ~~v—Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;~~
- ~~vi—Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and~~
- ~~vii—Any additional information as required by the Department including information to determine compliance.~~

~~b—The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.~~

~~c—Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.~~

~~(Auth: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)~~

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Expiration Date: February 1, 2004

5. The permittee shall submit semi-annually written reports to the Department for monitoring purposes. The permittee shall submit a signed statement certifying the accuracy and completeness of the information contained in the report. The reports for Special Conditions Nos. E.5.a, E.5.b, and E.5.c of this attachment 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 the reports for Special Conditions Nos. E.5.d thru E.5.h of this attachment shall be submitted **within thirty (30) 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. The VGO data consisting of the following:

- i. The maximum VGO feed rate (bbls/day) processed by the FCCU on a rolling 365-day average basis;
- ii. The maximum sulfur content (% by weight) of the VGO on a rolling seven-day (7-day) average basis; and
- iii. Any VGO exceedances as determined by the required VGO monitoring. Each exceedance reported shall include the date the exceedance occurred and the possible reason for the exceedance.

The enclosed **Monitoring Report Form: Vacuum Gas Oil (VGO)**, or an equivalent form, shall be used for reporting.

b. Any opacity exceedances as determined by the required VE monitoring for the F-5300 furnace. 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 there were no exceedances for that semi-annual period.

The enclosed **Monitoring Report Form: Opacity Exceedances** shall be used for reporting.

c. Any deviations from permit requirements shall be clearly identified.

d. Any seven-day (7-day) period during which the average sulfur content of the fresh feed exceeds 0.30 percent by weight. The fresh feed sulfur content on a rolling seven-day (7-day) average, shall be determined using the procedures specified in Special Condition No. D.2.b of this attachment.

e. For each seven-day (7-day) period during which an exceedance has occurred as defined in Special Condition No. E.5.d of this attachment:

- i. The date that the exceedance occurred;
- ii. An explanation of the exceedance;
- iii. Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and
- iv. A description of the corrective action taken, if any.



- f. ~~For each eight-hour (8-hour) period in which a feed sulfur measurement required by Special Condition No. D-2.b of this attachment was not obtained, the date for which, and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Department.~~
- g. ~~Compliance Report~~

The compliance report must contain the following information:

- i. ~~Company name and address.~~
- ii. ~~Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.~~
- iii. ~~Date of report and beginning and ending dates of the reporting period.~~
- iv. ~~If there are no deviations from any emission limitations that applies and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations or work practice standards during the reporting period and that no continuous emission monitoring system or continuous opacity monitoring system was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.~~
- v. ~~For each deviation from an emission limitation occurring at the FCCU where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the following information:~~
  - (1) ~~The total operating time of the FCCU during the reporting period.~~
  - (2) ~~Information on the number, duration, and cause of deviations (including unknown cause, if applicable) as applicable, and the corrective action taken.~~
  - (3) ~~Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero (0) and span and other daily calibration checks).~~
  - (4) ~~The date and time that each malfunction started and stopped.~~
  - (5) ~~The date and time that each continuous opacity monitoring system or continuous emission monitoring system was inoperative, except for zero (low-level) and high-level checks.~~
  - (6) ~~The date and time that each continuous opacity monitoring system or continuous emission monitoring system was out-of-control, including the information in 40 CFR §63.8(c)(8).~~
  - (7) ~~The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.~~
  - (8) ~~A summary of the total duration of the deviation during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging period specified in the regulation for other types of emission limitations), and the total duration as a percent of the total source operating time during the reporting period.~~
  - (9) ~~A breakdown of the total duration of the deviations during the reporting period and into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.~~

- (10) ~~A summary of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging time specified in the regulation for other types of standards), and the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system as a percent of the total source operating time during that reporting period.~~
- (11) ~~A breakdown of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period into periods that are due to monitoring equipment malfunctions, non-monitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.~~
- (12) ~~An identification of each HAP that was monitored at the FCCU.~~
- (13) ~~A brief description of the process units.~~
- (14) ~~The monitoring equipment manufacturer(s) and model number(s).~~
- (15) ~~The date of the latest certification or audit for the continuous opacity monitoring system or continuous emission monitoring system.~~
- (16) ~~A description of any change in the continuous emission monitoring system or continuous opacity monitoring system, processes, or controls since the last reporting period.~~
- (17) ~~A copy of any performance test done during the reporting period on the FCCU. The report may be included in the next semi-annual report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, the permittee must submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief process description, a simplified flow diagram showing affected processes, control equipment, and sampling point locations, sampling site data, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method.~~
- (18) ~~Any requested change in the applicability of an emission standard in the periodic report. The permittee must include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements.~~
- (19) ~~When actions taken to respond are consistent with the startup, shutdown and malfunction plan, the permittee is not required to report these events in the semi-annual compliance report and the reporting requirement in 40 CFR §63.6(e)(3)(iii) and 40 CFR §63.10(d)(5) do not apply.~~

~~(20) When actions taken to respond are not consistent with the startup, shutdown, and malfunction plan, the permittee must report these events and the response taken in the semi-annual compliance report. In this case, the reporting requirements in 40 CFR §63.6(e)(3)(iv) and 40 CFR §63.10(d)(5) do not apply.~~

~~h. Excess Emissions Report~~

~~i. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department and the U.S. EPA for every semi-annual calendar period. The report shall include the following information:~~

- ~~(1) The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period;~~
- ~~(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the FCCU and F-5300 furnace. The nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted;~~
- ~~(3) The date and time identifying each period during which the continuous emissions monitoring system was inoperative except for zero (0) and span checks. The nature of each system repair or adjustment shall be described; and~~
- ~~(4) The report shall so state if no excess emissions have occurred. Also, the report shall so state if the GEMS operated properly during the period and was not subject to any repairs or adjustments except for zero (0) and span checks.~~

~~ii. All reports shall be postmarked by the thirtieth (30<sup>th</sup>) day following the end of each semi-annual calendar period. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form shall also be submitted in addition to the excess emissions and monitoring systems performance report.~~

~~iii. For purposes of reports under 40 CFR §60.7(c), periods of excess emissions for the FCCU and F-5300 furnace that shall be determined and reported are defined as follows:~~

- ~~(1) Opacity. All one-hour (1-hour) periods that contain two (2) or more 6-minute (six-minute) periods during which the average opacity, as measured by the continuous opacity monitoring system, exceeds twenty (20) percent.~~
- ~~(2) Carbon Monoxide. All one-hour (1-hour) periods during which the average CO concentration, as measured by the CO continuous monitoring system under 40 CFR §60.105(a)(2), exceeds 500 ppmvd @ 0% O<sub>2</sub>.~~

- (3) ~~H2S. All rolling three-hour (3-hour) periods during which the average concentration of H2S in RFG, as measured by the H2S continuous emissions monitoring system, exceeds 230 mg/dscm (160 ppmv).~~
- (4) ~~Sulfur Dioxide. All rolling 365-day periods during which the average SO2 concentration, as measured by the SO2 continuous emissions monitoring system, exceeds twenty-five (25) ppmvd @ 0% O2 and all rolling seven-day (7-day) periods during which the average SO2 concentration, as measured by the SO2 continuous emissions monitoring system, exceeds fifty (50) ppmvd @ 0% O2.~~
- (5) ~~Nitrogen Oxides. All rolling 365-day periods during which the average NOx concentration, as measured by the NOx continuous emissions monitoring system, exceeds fifty (50) ppmvd @ 0% O2 and all rolling seven-day (7-day) periods during which the average NOx concentration, as measured by the NOx continuous emissions monitoring system, exceeds 87.9 ppmvd @ 0% O2.~~

iv. ~~Excess emissions indicated by the GEMS shall be considered violations of the applicable emission and concentration limits for the purposes of this permit.~~

~~(Auth: HAR §11-60-1-3, §11-60-1-5, §11-60-1-32, §11-60-1-90, SIP §11-60-24, 40 CFR §60.105, 40 CFR §60.107, 40 CFR §63.1575)~~

6. ~~At least thirty (30) days prior to the following events, the permittee shall notify the Department in writing of:~~

- a. ~~Conducting a performance specification test on any of the GEMS (CO, SO2, NOx, O2, or H2S) or GOMS (opacity);~~
- b. ~~Conducting a source performance test as required by this Attachment, Section F, Testing Requirements.~~

~~(Auth: HAR §11-60-1-3, §11-60-1-90, 40 CFR §60.105, 40 CFR §60.106)~~

#### Section F. Testing Requirements

1. ~~The permittee shall conduct or cause to be conducted annual performance tests for the FCCU, except for the opacity testing specified in Special Condition No. F.3.d of this attachment, which is only required to be conducted initially. Performance tests shall be conducted for CO and PM. All performance tests shall be conducted at the maximum production rate of the FCCU and at the maximum VGO feed rate, or at other production rates as may be specified by the Department. The following ESP parameters shall be monitored and recorded and minimum levels established during the testing for PM demonstrating compliance with the three-hour (3-hour) average PM emission limit in Special Condition No. G.6.a of this attachment:~~

- a. ~~Voltage in each ESP electrical grid field;~~
- b. ~~Current in each ESP electrical grid field; and~~

c. ~~Number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online.~~  
 (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

2. ~~Performance tests for the emissions of CO and PM shall be conducted in accordance with the test methods set forth in 40 CFR Part 60, Appendices A-1 through A-8. Only the test methods specified in Special Condition Nos. F-3 and F-4 of this attachment or U.S. EPA approved equivalent methods with prior written approval from the Department shall be used.~~  
 (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

3. ~~The permittee shall determine compliance with the PM standards in 40 CFR §60.102(a) as follows:~~

a. ~~The emission rate (E) of PM shall be computed for each run using the following equation:~~

$$E = C_p Q_{pg} / KR_c$$

Where:  
 E = Emission rate of PM, kg/Mg (lb/ton) of coke burn-off.  
 C<sub>p</sub> = Concentration of PM, gr/dscm (gr/dscf).  
 Q<sub>pg</sub> = Volumetric flow rate of effluent gas, dscm/hr (dscf/hr).  
 R<sub>c</sub> = Coke burn-off rate, Mg/hr (ton/hr) coke.  
 K = Conversion factor, 1000 g/kg (7000 gr/lb)

b. ~~Method 58 or SF is to be used to determine the PM emissions and associated moisture content from affected facilities without wet FGD systems. The sampling time for each run shall be at least sixty (60) minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Department when process variables or other factors preclude sampling for at least sixty (60) minutes.~~

c. ~~The coke burn-off rate (R<sub>c</sub>) shall be computed for each run using the following equation:~~

$$R_c = K_1 Q_r (\%CO_2 + \%CO) - (K_2 Q_a - K_3 Q_r) / ((\%CO/2) + (\%CO_2 + \%O_2))$$

Where:  
 R<sub>c</sub> = Coke burn-off rate, Mg/hr (ton/hr)  
 Q<sub>r</sub> = Volumetric flow rate of exhaust gas from catalyst regenerator before entering the emission control system, dscm/min (dscf/min).  
 Q<sub>a</sub> = Volumetric flow rate of air to FCCU regenerator, as determined from the FCCU control room instrumentation, dscm/min (dscf/min).  
 %CO<sub>2</sub> = carbon dioxide concentration, percent by volume (dry basis).  
 %CO = carbon monoxide concentration, percent by volume (dry basis).  
 %O<sub>2</sub> = Oxygen concentration, percent by volume (dry basis).  
 K<sub>1</sub> = Material balance and conversion factor, 2.982 x 10<sup>-4</sup> (Mg-min)/(hr-dscm-%)  
 [6.31 x 10<sup>-4</sup> (ton-min)/(hr-dscf-%)]  
 K<sub>2</sub> = Material balance and conversion factor, 2.088 x 10<sup>-1</sup> (Mg-min)/(hr-dscm-%)  
 [5.62 x 10<sup>-6</sup> (ton-min)/(hr-dscf-%)]  
 K<sub>3</sub> = Material balance and conversion factor, 0.914 x 10<sup>-6</sup> (Mg-min)/(hr-dscm-%)  
 [3.1 x 10<sup>-6</sup> (ton-min)/(hr-dscf-%)]



- ~~i. Method 2 shall be used to determine the volumetric flow rate (Or).~~
- ~~ii. The emission correction factor, integrated sampling and analysis procedure of Method 38 shall be used to determine CO<sub>2</sub>, CO, and O<sub>2</sub> concentrations.~~

~~d. Method 9 and the procedures of 40 CFR §60.11 shall be used to determine opacity.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>~~

- ~~4. The permittee shall determine compliance with the CO standard in 40 CFR §60.103(a) by using the integrated sampling or continuous sampling technique of Method 40 to determine the CO concentration (dry basis). The sampling time for each run shall be sixty (60) minutes.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>~~

- ~~5. Each source performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>~~

- ~~6. The permittee shall provide sampling and testing facilities at its own expense. The tests shall be conducted at the operating capacities identified in Special Condition No. F-1 of this attachment. The Department may monitor any of the required source performance tests.~~

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

- ~~7. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.~~

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

- ~~8. **At least thirty (30) days prior to performing a test,** the permittee shall submit a written source performance test plan to the Department and U.S. EPA that describes the test date(s), test duration, test locations, test method, source operation, fuel consumption, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A source performance test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>~~

CSP No. 0088-01-C  
Attachment II(F)  
Page 21 of 21  
Issuance Date: November 16, 2018  
Expiration Date: February 1, 2004<sup>3</sup>

~~9. Within sixty (60) days after completion of the source performance test, the permittee shall submit to the Department and U.S. EPA, the test report which shall include the operating conditions of the FCCU at the time of the test, the ESP parameters used to establish the minimum total daily power input level and minimum number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online), the analysis of the VGO, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8, 40 CFR §63.7)<sup>1</sup>~~

~~10. The Department may waive a specific performance test upon prior written request of the permittee. Such a request would need to be justified on the grounds that prior tests had shown compliance by a wide margin; adequate means exist to show continuing compliance; and operations of the source have not changed since the previous source test. The source performance test shall not be waived for more than two consecutive years.~~

~~(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.8, 40 CFR §63.7)<sup>1</sup>~~

#### ~~Section G. Agency Notifications~~

~~Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.~~

~~(Auth.: HAR §11-60.1-4, §11-60.1-90.~~

---

<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

<sup>3</sup>This date is to be revised upon issuance of the renewal for CSP No. 0088-01-C.

**MONITORING REPORT FORM  
VACUUM GAS OIL (VGO)  
COVERED SOURCE PERMIT NO.0088-01-C  
(PAGE 1 OF 2)**

Issuance Date: **November 16, 2018**

Expiration Date: **February 1, 2004**

(Expiration date to be revised upon issuance of the permit renewal)

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department the following on a semi-annual basis:

*(Make Copies for Future Use)*

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_

Serial/ID No.: \_\_\_\_\_

Responsible Official (PRINT): \_\_\_\_\_

Title: \_\_\_\_\_

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

Responsible Official (Signature): \_\_\_\_\_

1. Maximum VGO Feed Rate: Report the maximum total VGO feed rate (bbls/day) during the reporting period based on a rolling 365-day average: \_\_\_\_\_

2. Maximum VGO Sulfur Content: Report the maximum weight percent of sulfur in the VGO during the reporting period based on a rolling seven-day (7-day) average: \_\_\_\_\_

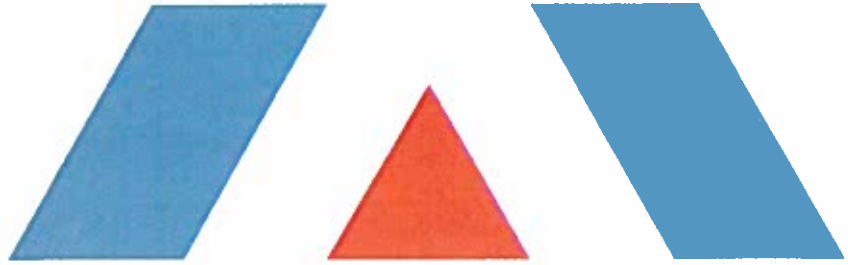




**IES Downstream, LLC – FCCU, Dimersol, and Alkylation Plants  
Initial Permit Application**

**Attachment B**

- **Project Report  
Initial Covered  
Source Permit  
Application for  
FCCU, Dimersol,  
and Alkylation  
Plants (Proposed  
CSP 0863-02-C)**



**PROJECT REPORT**  
**IES Downstream, LLC > Kapolei, HI Terminal**



**IES Downstream, LLC**  
**FCCU, Dimersol, and Alkylation Plants**  
**Initial Covered Source Permit Application**

Prepared By:

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December 2018

Project 184801.0121



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Table 2-1. Insignificant Activities Request for Additional Exemptions

2-3

## 1. EXECUTIVE SUMMARY

---

IES Downstream, LLC (IES) owns and operates a petroleum refinery in Kapolei, HI (the Refinery). Several of the storage and logistics processes in its Covered Source Permit (CSP) 0088-01-C, issued on February 22, 1999, were moved to a new Kapolei Terminal CSP, 0863-01-C, which was issued by the Hawaii Department of Health (HDOH) on November 16, 2018. Following issuance of the new CSP, IES identified several additional process units that also should be permitted under a separate CSP from the bulk of the refining assets. Thus, IES is submitting this application for an initial CSP for those process units. No sources in this CSP are currently operating without a CSP, and all sources were covered in the Refinery's 2016 renewal application for CSP 0088-01-C.

In this initial CSP application, IES proposes creating a separate CSP for the following equipment permitted to operate under CSP 0088-01-C:

- Fluid Catalytic Cracker Unit (FCCU), including the FCCU stack (identified as emission point M1), FCCU furnace (F-5300), FCCU startup heater (F-5310), and certain FCCU equipment components with fugitive emissions (Attachments II(A) and II(I) of the current CSP);
- Alkylation Plant (Attachment II(A)), including certain equipment components with fugitive emissions;
- Dimersol Plant (Attachment II(A)), including all equipment components with fugitive emissions; and
- Miscellaneous insignificant activities.

As outlined in redline permit conditions supplied by IES in this application, IES proposes to make two changes to permit conditions of the included equipment:

1. Changes to FCCU conditions to bring the FCCU stack's requirements in line with current requirements under 40 CFR 63 Subpart UUU, some of which came into effect after the most recent modification of the refinery's FCCU permit section; and
2. Changes to Leak Detection and Repair (LDAR) conditions for process fugitives at each process area, to incorporate the refinery's voluntary compliance with 40 CFR 60 Subpart GGGa.

By including the Subpart GGGa conditions as the refinery's LDAR compliance demonstration method, process fugitive emissions from the affected process units are substantially reduced. The Potential to Emit (PTE) of the process units is re-evaluated in this initial CSP application.

As with the previous permitting activities, the purpose of this initial CSP application is to create a CSP in alignment with IES' internal business structure, in which terminal and related assets are separate from refining assets.

This application contains the following sections:

- Description of Facility;
- Compliance with Applicable Requirements;
- Appendix A: Application Forms;
- Appendix B: Plot Plan and Process Flow Diagram;
- Appendix C: Emission Calculations;
- Appendix D: Proposed Permit Conditions

**This application also contains the \$5,000 fee payable to HDOH for an initial CSP application. The value of the fee is based on IES' finding that the Kapolei Terminal is located at a "major toxics source" as defined in HAR 11-60.1-111.**

**As demonstrated by Section 3, "Compliance with Applicable Requirements," this application report with appendices contains all required information for a complete initial CSP application.**



## 2. DESCRIPTION OF FACILITY

---

### 2.1. APPLICANT'S NAME AND BUSINESS DESCRIPTION

IES Downstream, LLC (IES) is submitting this application to obtain a new Covered Source Permit (CSP) to include equipment currently permitted under CSP 0088-01-C for the Kapolei Refinery (the Refinery). Please refer to Appendix A for a complete set of CSP modification forms on standard State of Hawaii Department of Health (HDOH) form templates.

### 2.2. APPLICATION TYPE

This is an application for a new initial CSP with permit number CSP 0863-02-C. The conditions in this CSP are based on conditions within current CSP 0088-01-C authorizing operation of the equipment to be included in the new CSP. This application is made to HDOH pursuant to Hawaii Administrative Rules, Title 11, Chapter 11-60.1, Air Pollution Control.

### 2.3. FACILITY DESCRIPTION

#### 2.3.1. Location

The project is located at 91-480 Malakole Street, Kapolei, HI, at a latitude of 21° 18' 42" N and a longitude of 158° 6' 50" W on the island of O'ahu. A map of the area surrounding the project site, along with the location of the project, is included in Appendix B.

#### 2.3.2. Existing Equipment and Potential to Emit

The Refinery currently operates all existing equipment in CSP 0088-01-C. An inventory of Potential to Emit (PTE) of criteria pollutants and Hazardous Air Pollutants (HAP) for emission points to be included in the new CSP is provided in Appendix C. Process flow diagrams for refinery processes in the 2016 CSP renewal application are incorporated by reference.

The Kapolei Terminal is part of a covered source, a major source for Prevention of Significant Deterioration (PSD) permitting, and a toxics major source. As outlined in redline permit conditions supplied by IES in this application, IES proposes to make two changes to permit conditions of the included equipment:

1. Changes to FCCU conditions to bring the FCCU stack's requirements in line with current requirements under 40 CFR 63 Subpart UUU, some of which came into effect after the most recent modification of the refinery's FCCU permit section; and
2. Changes to Leak Detection and Repair (LDAR) conditions for process fugitives at each process area, to incorporate the refinery's voluntary compliance with 40 CFR 60 Subpart GGGa.

By including the Subpart GGGa conditions as the refinery's LDAR compliance demonstration method, process fugitive emissions from the affected process units are substantially reduced. The Potential to Emit (PTE) of the process units is re-evaluated in this initial CSP application.

### 2.3.3. General Description

In this application, the following existing equipment is proposed to be listed under a separate CSP with permit number CSP 0863-02-C:

- > Fluid Catalytic Cracker Unit (FCCU), including the FCCU stack (identified as emission point M1), FCCU furnace (F-5300), FCCU startup heater (F-5310), and certain FCCU equipment components with fugitive emissions (Attachments II(A) and II(I) of the current CSP);
- > Alkylation Plant (Attachment II(A)), including certain equipment components with fugitive emissions;
- > Dimersol Plant (Attachment II(A)); and
- > Miscellaneous insignificant activities.

Furthermore, as outlined in redline permit conditions supplied by IES in this application, IES proposes to update the permit conditions of the included equipment, to bring the FCCU stack's requirements in line with current requirements under 40 CFR 63 Subpart UUU, some of which came into effect after the most recent modification of the refinery's FCCU permit section.

For clarity within this application, CSP 0088-01-C as amended on November 16, 2018, is referred to as the "current CSP." The CSP that will be created as an outcome of this initial CSP application is referred to as the "FCCU, Dimersol and Alkylation Plants CSP," and the CSP containing remaining elements in CSP 0088-01-C is referred to as the "revised Refinery CSP." The collection of equipment described in the list above is referred to as the "FCCU, Dimersol and Alkylation Plants," though certain processing units and columns not directly associated with the cracking operation or the alkylation plant will remain part of the revised Refinery CSP. The FCCU, Dimersol and Alkylation Plants will operate under the new FCCU, Dimersol and Alkylation Plants CSP. Their equipment will be part of a single covered source including the Refinery and the Kapolei Terminal, operating under a separate permit.

In a separate permit application filed with this application, IES is proposing a minor modification to remove these process units from the current CSP. These two applications are intended to be approved in tandem, allowing HDOH to remove permit conditions on the FCCU, Dimersol and Alkylation Plants from the current CSP and to issue the separate FCCU, Dimersol and Alkylation Plants CSP with no gap in permit authority to operate the equipment.

A redline text of the proposed conditions of the FCCU, Dimersol and Alkylation Plants CSP is provided in Appendix D.

### 2.3.4. Insignificant Activities

Section 11-60.1-83(a)(18) requires the insignificant activities listed in this subsection to be identified in the CSP application. This initial CSP application reiterates the request for additional insignificant activity determinations made in the 2016 renewal application for CSP 0088-01-C for the equipment and activities listed in Table 2-1.

**Table 2-1. Insignificant Activities Request for Additional Exemptions**

Insignificant Activity	Regulatory Provision
<p><u>Process upset vents</u>            Pressurized equipment such as the FCC unit are equipped with relief vents that open only during malfunctions or severe process upset conditions. The frequency of such occurrences cannot be predicted, and the vents are critical for safe operation. Historically, venting episodes are rare. IES requests that emissions from upset vents be exempted. However, applicable NSPS, Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and National Emission Standards for Hazardous Air Pollutants (NESHAP) standards will continue to be satisfied.</p>	<p>HAR 11-60.1-82(f)(7)</p>
<p><u>FCCU Baghouse</u>            Three baghouses (Flex-Kleen bin vent filter) are located on the electrostatic precipitator of the FCCU to capture potential fugitive dust emissions when the ESP hopper is emptied. The control efficiency of the baghouses is 99.9%. Operation of these three baghouses will meet the insignificant emissions rate of less than 2 tpy of a regulated pollutant.</p>	<p>HAR 11-60.1-82(f)(7)</p>

## 3. COMPLIANCE WITH APPLICABLE REQUIREMENTS

---

The following sections outline this application's required information and the applicability of state and federal requirements to the proposed FCCU, Dimersol and Alkylation Plants CSP.

A detailed review of applicable requirements may be found in Appendix D in the form of redline permit conditions.

### 3.1. PERMIT APPLICATION REQUIREMENTS

#### 3.1.1. Initial CSP Application

The proposed project is subject to State of Hawaii Administrative Rules (HAR), Chapter 11-60.1, Air Pollution Control. The Kapolei Terminal is considered to be part of a "covered source" for the purposes of Chapter 11-60.1. The proposed FCCU, Dimersol and Alkylation Plants CSP will be a new permit issued for equipment in this covered source, so this application is considered as an "initial CSP application" under the definitions of §11-60.1-83.

#### 3.1.2. Initial CSP Application Completeness Checklist

The proposed project is subject to HAR 11-60.1. The data and analyses in this application support document verify that the project will comply with all applicable state and federal air quality requirements. The Kapolei Terminal is considered to be part of a "covered source" for the purposes of Chapter 11-60.1. Pursuant to §11-60.1-83, an initial CSP application should include the information outlined below.

##### 3.1.2.1. Name, Address, and Phone Number

This descriptive information can be found on Section 2.3 of this application report and on Form S-1 in Appendix A.

##### 3.1.2.2. Description of Source

This descriptive information can be found on Section 2.3 of this application report and on Form S-1 in Appendix A.

##### 3.1.2.3. Emission Trading

This application does not propose emission trading permit terms or conditions.

##### 3.1.2.4. Maximum Emission Rates

Maximum emission rates can be found in Appendix C of this application report. Emissions are reported in both lb/hr and tpy. Maximum emission rates for process fugitives have been revised to reflect implementation of an LDAR program based on 40 CFR 60 Subpart GGGa.

##### 3.1.2.5. Stack Identification and Description

Descriptive information on stacks and emission points can be found on Form S-1 in Appendix A of this application.

### ***3.1.2.6. Air Pollution Control Equipment and Compliance Monitoring Description***

The only air pollution control devices in the FCCU, Dimersol, and Alkylation Plants are the cyclone and ESP particulate controls installed on the FCCU. A table of control devices is presented in Appendix C.

Compliance monitoring will be achieved according to the permit conditions in Appendix D. These conditions represent current state and federal requirements. They are consistent with the conditions in the current CSP under which the equipment has operated as of today, except for the two changes (FCCU conditions and LDAR conditions) identified in Section 2.3.2.

### ***3.1.2.7. Applicable Requirements***

Applicable requirements for the equipment at the FCCU, Dimersol, and Alkylation Plants are specified in the permit conditions in Appendix D. These conditions represent current state and federal requirements. They are consistent with the conditions in the current CSP under which the equipment has operated as of today, except for the two changes (FCCU conditions and LDAR conditions) identified in Section 2.3.2.

### ***3.1.2.8. Current Operational Limitations or Work Practices***

Operational limitations and work practices for the equipment at the FCCU, Dimersol, and Alkylation Plants are specified in the permit conditions in Appendix D. These conditions represent current state and federal requirements. They are consistent with the conditions in the current CSP under which the equipment has operated as of today, except for the two changes (FCCU conditions and LDAR conditions) identified in Section 2.3.2.

### ***3.1.2.9. Supporting Calculations and Assumptions***

Supporting calculations for PTE, stack parameters, control equipment, and operational limitations can be found in Appendix C. PTE for process fugitives has been revised to reflect implementation of an LDAR program based on 40 CFR 60 Subpart GGGa.

### ***3.1.2.10. Construction Schedule***

No construction schedule is applicable to this application. All sources currently operate under the current CSP.

### ***3.1.2.11. Existing Source Assessment of Ambient Air Quality Impact***

This application does not request any emission increase or emission change, so the approval of this initial CSP application does not affect compliance with any air quality standard.

### ***3.1.2.12. New Source Assessment of Ambient Air Quality Impact***

This information is not required because the equipment at the FCCU, Dimersol, and Alkylation Plants is not new.

### ***3.1.2.13. Prevention of Significant Deterioration***

This application does not request any emission increase or emission change, so the approval of this initial CSP application does not require review under HAR Subchapter 7 for PSD permitting.

### ***3.1.2.14. Risk Assessment of Air Quality Impacts***

A risk assessment will be supplied upon request from HDOH.

### **3.1.2.15. Source Test and Monitoring Data**

Source testing or monitoring data will be supplied upon request from HDOH. Correlations used to establish site-specific emission factors are provided in Appendix C.

### **3.1.2.16. Information on Other Available Control Technologies**

Information on other available control technologies will be supplied upon request from HDOH. Current control technologies in use on FCCU, Dimersol, and Alkylation Plants sources are consistent with state and federal regulatory requirements.

### **3.1.2.17. Proposed Exemptions from Applicable Requirements**

This application does not request exemptions from applicable requirements for equipment, with the exception of requests that certain activities in Table 2-1 be deemed insignificant.

### **3.1.2.18. Insignificant Activities**

Insignificant activities are listed in Section 2.3.4.

### **3.1.2.19. Compliance Plan**

A compliance plan is provided on Form C-1 in Appendix A.

### **3.1.2.20. Compliance Certification**

A compliance certification is provided on Form C-2 in Appendix A.

### **3.1.2.21. Other Information**

IES will provide additional information if requested during the application review process.

## **3.2. STATE REQUIREMENTS**

### **3.2.1. HAR Subchapter 1**

The following sections of HAR 11-60.1 Subchapter 1 are applicable to this initial CSP application:

- > §11-60.1-1 Definitions
- > §11-60.1-2 Prohibition of air pollution
- > §11-60.1-3 General conditions for considering applications
- > §11-60.1-4 Certification
- > §11-60.1-6 Holding of permit
- > §11-60.1-8 Reporting discontinuance
- > §11-60.1-9 Cancellation of a noncovered or covered source permit
- > §11-60.1-11 Sampling, testing, and reporting methods
- > §11-60.1-12 Air quality models
- > §11-60.1-14 Public access to information
- > §11-60.1-15 Reporting of equipment shutdown
- > §11-60.1-16 Prompt reporting of deviations
- > §11-60.1-16.5 Emergency provision
- > §11-60.1-19 Penalties and remedies

§§ 11-60.1-2 through 60.1-4 constitute the duty to file this permit application, and this permit application fulfills these requirements.

With regard to § 11-60.1-12, this application does not request any emission increase or emission change, so the approval of this initial CSP application does not affect compliance with any air quality standard.

### **3.2.2. HAR Subchapter 2**

Sections of Subchapter 2, General Prohibitions, are applicable to the FCCU, Dimersol, and Alkylation Plants as stated in the redline general conditions in Appendix D.

### **3.2.3. HAR Subchapter 3**

HAR 11-60.1 Subchapter 3, Open Burning, does not apply to the FCCU, Dimersol, and Alkylation Plants' emission points or fugitive emissions.

### **3.2.4. HAR Subchapter 4**

HAR 11-60.1 Subchapter 4, Noncovered Sources, does not apply to this permit application or the, because these units are part of a covered source.

### **3.2.5. HAR Subchapter 5**

The following sections of Subchapter 5, Covered Sources, are applicable to this application:

- §11-60.1-81 Definitions
- §11-60.1-82 Applicability
- §11-60.1-83 Initial covered source permit application
- §11-60.1-84 Duty to supplement or correct permit applications
- §11-60.1-85 Compliance plan
- §11-60.1-86 Compliance certification of covered sources
- §11-60.1-90 Permit content
- §11-60.1-93 Federally-enforceable permit terms and conditions
- §11-60.1-100 Public petitions

### **3.2.6. HAR Subchapter 6**

The following sections of Subchapter 6, Fees for Covered Sources, Noncovered Sources, and Agricultural Burning, are applicable to this minor modification application:

- §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
- §11-60.1-115 Basis of annual fees for covered sources

Fees under §11-60.1-114, Annual fees for covered sources, are not part of this application but will continue to be applicable to the FCCU, Dimersol, and Alkylation Plants based on actual emission estimates from the plants' emission points.

### **3.2.7. HAR Subchapter 7**

HAR 11-60.1 Subchapter 7, Prevention of Significant Deterioration Review, does not apply to this initial CSP application. Subchapter 7 applies to major modifications, defined as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulations approved pursuant to the Act." Because this application does not request an emission increase, Subchapter 7 does not apply to this application.

### **3.2.8. HAR Subchapter 8**

The following sections of Subchapter 8, Standards of Performance for Stationary Sources, are applicable to this initial CSP application:

➤ **§11-60.1-161 New Source Performance Standards**

§11-60.1-161, New Source Performance Standards, is listed as applicable because certain equipment at the FCCU, Dimersol, and Alkylation Plants is subject to NSPS. This initial CSP application does not affect the applicability of any NSPS, and so it does not change the plants' applicable requirements. That said, this application does incorporate the use of an LDAR program consistent with 40 CFR 60 Subpart GGGa as compliance demonstration for LDAR requirements at the affected process units. The compliance demonstration method for these units is proposed to be changed in accordance with Appendix D.

### **3.2.9. HAR Subchapter 9**

The following sections of Subchapter 9, Hazardous Air Pollutant Sources, are applicable to this application. However, this application does not increase the PTE or actual emissions of HAP of the equipment at the FCCU, Dimersol, and Alkylation Plants, and so this application does not change the plants' applicable requirements or require additional review.

- **§11-60.1-171 Definitions**
- **§11-60.1-172 List of hazardous air pollutants**
- **§11-60.1-173 Applicability**
- **§11-60.1-174 Maximum achievable control technology (MACT) emission standards**
- **§11-60.1-180 National emission standards for hazardous air pollutants**

§11-60.1-173, Applicability, is listed as applicable because the FCCU, Dimersol, and Alkylation Plants are a stationary source that emits HAP. Furthermore, §11-60.1-180, National emission standards for hazardous air pollutants, and §11-60.1-174, Maximum achievable control technology (MACT) emission standards, are listed as applicable because the FCCU, Dimersol, and Alkylation Plants are subject to Part 63 Subpart CC and UUU, as the plants are considered part of an "affected source" under these subparts. Certain changes to the FCCU applicable requirements and compliance demonstration methods under Part 63 Subpart UUU are proposed in Appendix D.

§11-60.1-179, Ambient air concentrations of hazardous air pollutants, is not applicable because this section applies only to sources of HAP, and this application does not increase the FCCU, Dimersol, and Alkylation Plants' PTE or actual emissions of HAP. Therefore, this permit application is not subject to HAP ambient air concentrations review.



### 3.2.10. HAR Subchapter 10

HAR 11-60.1 Subchapter 10, Field Citations, establishes HDOH's field citations program. It does not contain applicable requirements for air permitting.

### 3.2.11. HAR Subchapter 11

HAR 11-60.1 Subchapter 11, Greenhouse Gas Emissions, applies to the FCCU, Dimersol, and Alkylation Plants because the plants are part of a covered source with the potential to emit GHG equal to or above 100,000 tpy as CO<sub>2</sub> equivalent (CO<sub>2e</sub>). The FCCU, Dimersol, and Alkylation Plants will report with the Kapolei Terminal as one GHG source under 40 CFR 98.

## 3.3. FEDERAL REQUIREMENTS

### 3.3.1. New Source Performance Standards (NSPS)

New Source Performance Standards (NSPS) are codified in 40 CFR 60. NSPS apply to certain types of equipment that are newly constructed, modified, or reconstructed after a given applicability date. The following NSPS apply to the emission points in the FCCU, Dimersol Plant, and Liquid Fuel System in the new CSP:

- Subpart A, General Provisions
- Subpart GGG, Equipment Leaks in Petroleum Refineries
- Subpart J, Standards of Performance for Petroleum Refineries (applicable to the FCCU stack)
- Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007 (applicable to the FCCU startup heater)

This initial CSP application does not change the applicability of NSPS or the applicability of applicable NSPS requirements. It does propose a change in the compliance demonstration methods in use by the equipment at the FCCU, Dimersol, and Alkylation Plants for one NSPS: 40 CFR 60 Subpart GGGa equivalent LDAR program is proposed as compliance demonstration method for Subpart GGG requirements. NSPS applicable requirements are specified in the redline permit conditions in Appendix D.

### 3.3.2. National Emissions Standards for Hazardous Air Pollutants

NESHAPs have been established in 40 CFR Part 61 and Part 63 to control emissions of HAP from stationary sources. The applicability of NESHAP rules often depends on a facility's major source status with respect to HAP emissions. Under 40 CFR Part 63, a major source is defined as "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP." The stationary source consisting of all equipment under the control of IES at the Kapolei Refinery and Kapolei Terminal is considered a major source of HAP.

The following NESHAP apply to the emission points in the new CSP:

- Part 63:
  - Subpart A, General Provisions
  - Subpart CC, Petroleum Refineries
  - Subpart UUU, Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units at Petroleum Refineries

This initial CSP application does not change the applicability of NESHAP, the applicability of applicable NESHAP requirements, or the compliance demonstration methods in use for these existing emissions units. However, this application does propose to incorporate conditions related to Subpart UUU, which took effect for the existing FCCU on August 1, 2018.

### **3.3.3. Greenhouse Gas Reporting Requirements**

GHG emissions generated by the equipment at the Kapolei Terminal and the FCCU, Dimersol and Alkylation Plants are reported under 40 CFR 98 Subparts C and Y. The FCCU, Dimersol and Alkylation Plants will report GHG emissions as part of the Kapolei Terminal's 40 CFR 98 report.

## APPENDIX A: APPLICATION FORMS

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**S-1: Standard Air Pollution Control Permit Application Form**  
(Covered Source Permit and Noncovered Source Permit)

State of Hawaii  
Department of Health  
Environmental Management Division  
Clean Air Branch  
P.O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: IES Downstream, LLC
2. Facility Name (if different from the Company): IES Downstream, LLC - FCCU, Dimersol, and Alkylation Plants
3. Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707  
Phone Number: (808) 682-5711
4. Name of Owner/Owner's Agent: Jon Mauer  
Title: President and CEO Phone: (808) 682-5711  
Mailing Address: Same as Above  
City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_
5. Plant Site Manager/Other Contact: Jon Mauer  
Title: President and CEO Phone: (808) 682-5711  
Mailing Address: Same as Above  
City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_
6. Permit Application Basis: (Check all applicable categories.)  
 Initial Permit for a New Source       Initial Permit for an Existing Source  
 Renewal of Existing Permit       General Permit  
 Temporary Source       Transfer of Permit  
 Modification to a Covered Source: → Is Modification?     Significant     Minor     Uncertain  
 Modification to a Noncovered Source
7. If renewal or modification, include existing permit number: \_\_\_\_\_
8. Does the Proposed Source require a County Special Management Area Permit?     Yes       No
9. Type of Source (Check One):     Covered Source       Covered and PSD Source  
    Noncovered Source       Uncertain
10. Standard Industrial Classification Code (SICC), if known: 2911

11. Proposed Equipment/Plant Location (e.g. street address): 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707  
UTM Coordinates (meters): East: 591,940 m E North: 2,357,220 m N  
UTM Zone: 4 UTM Horizontal Datum:  Old Hawaiian  NAD-27  NAD-83

12. General Nature of Business: Petroleum Refining

13. Date of Planned Commencement of Construction or Modification: N/A

14. Is *any* of the equipment to be leased to another individual or entity?  Yes  No

15. Type of Organization:  Corporation  Individual Owner  Partnership  
 Government Agency (Government Facility Code: \_\_\_\_\_)  
 Other: \_\_\_\_\_

*Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR §11-60.1-64 & 11-60.1-84)*

**RESPONSIBLE OFFICIAL** (as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_

Title: President and CEO Phone: (808) 682-5711

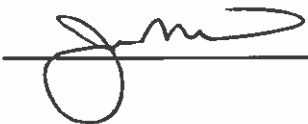
Mailing Address: 91-480 Malakole Street

City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official** (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Jon Mauer

(Signature): 

Date: 12/14/18

<b>FOR AGENCY USE ONLY:</b>
File/Application No.: _____
Island: _____
Date Received: _____

Submit the following documents as part of your application:

- A. The **Emissions Units Table**, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:
1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SIC number. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirement of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
    - a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
    - b. Indicate the emission points that discharge together for any length of time.
    - c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.
  2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
    - a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO<sub>x</sub>), Sulfur Dioxide (SO<sub>2</sub>), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM<sub>10</sub>). Abbreviations may be used.
    - b. Include fugitive emissions.
    - c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
    - d. **Tons per year** is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.
  3. Describe **Stack Source Parameters**:
    - a. **Stack Height** is the height above the ground.
    - b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
    - c. **Flow Rate** is the actual, not the calculated, flow rate.
  4. Provide any additional information, if applicable, as follows:
    - a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
    - b. For a rectangular stack, indicate the length and width.
    - c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.
- B. A **process flow diagram** identifying all equipment used in the process, including the following:
1. Identify and describe each emission point.
  2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.
- C. A **facility location map**, drawn to a reasonable scale and showing the following:
1. The property involved and all structures on it. Identify property/fence lines plainly.
  2. Layout of the facility.
  3. Location and identification of the proposed emissions unit on the property.
  4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 100 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.
- D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Company Name: IES Downstream, LLC - FCCU, Dimersol, and Alkylation Plans

File No.: \_\_\_\_\_

Location: 91-480 Malakole Street, Kapolei, HI 96707

(Make as many copies of this page as necessary)

Page \_\_\_\_\_ of \_\_\_\_\_

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT EMISSION RATE	UTM Zone: _____ Horizontal Datum: _____ Coordinates (mtrs)	STACK SOURCE PARAMETERS									
Stack No	Unit No.	Equipment Name/Description & SIC number	Equipment Date			AIR POLLUTANT	Regulated/ Hazardous Air Pollutant Name & CAS#	#/HR	Tons/ YR	Stack Height (mtrs)	Direction (width) <sup>a</sup>	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)	Temp. (° K)
Emissions for the FCCU, Dimersol, and Alkylation Plants are presented in Appendix C. Source parameters are presented on the following page.															
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Form S-1  
Stack Information

Stack or Fugitive Emission Unit ID	Process ID No. (Reference Manual)	Emission Unit ID (Emission Unit being authorized) (Reference Manual)	Equipment Data	UTM Emission (lb) per hour	UTM Velocity (ft/min)	Zone (A or S)	Dist. (ft) from NAD	Stack Ht (ft)	Stack Diameter (ft)	Stack Velocity (ft/min)	Stack Temperature (deg. F)	Stack Flow Rate (ACFM)	Horizontal Collection Method	Reference Point Code	Horizontal Accuracy (ft)
8	F5300	FCC Furnace	1961-62	591,896	2,356,928	4	NAD 83	140	5.6	22.3	712	545	027	106	500
15	M1	FCC precip	1961-62	591,894	2,356,970	4	NAD 83	125	4.9	107.0	550	2034	027	106	500
15	M1	FCC precip	1961-63	591,894	2,356,970	4	NAD 83	125	4.9	107.0	550	2034	027	106	500
18	M4	Catalyst Transfer		591,928	2,356,901	4	NAD 83						027	106	500
20	M6	Process Fugitives		591,675	2,357,127	4	NAD 83						027	106	500





**S-2: Application for an Initial Covered Source Permit**

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)  
 Permits Office, Air Division  
 U.S. Environmental Protection Agency  
 Region 9  
 75 Hawthorne Street  
 San Francisco, CA 94105

**I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-83, the following information is required:**

**A. Equipment Specifications:**

1. Maximum design capacity.
2. Fuel type.
3. Fuel use.
4. Production capacity.
5. Production rates.
6. Raw materials.
7. Provide any manufacturer's literature.

Equipment specifications are presented in Appendix C. The FCCU contains a process heater fired on refinery fuel gas. Raw materials include crude oil, refined petroleum products, and LPG, for storage and transport. Fuel use data are provided in the attached PTE inventory, based on the Kapolei Refinery's 2016 CSP renewal application

**B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.**

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.
2. List all **insignificant** activities in accordance with HAR §11-60.1-82.

The FCC stack is controlled by one electrostatic precipitator (ESP). Insignificant activities: Section 2.3.4.

**C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):**

1. Total hours per day, per week, and/or per month.
2. Total hours per year.
3. If operation is seasonal or irregular, describe.

The FCCU, Dimersol, and Alkylation Plants operate continuously each day, week, month, and year. Operation is not seasonal or irregular

**D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:**

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement.
2. Explanation of all proposed exemptions from any applicable requirements.

Applicable requirements are described in Appendix D, as proposed permit conditions for the FCCU, Dimersol, and Alkylation Plants equipment/activities. All applicable requirements for the FCC under the current provisions of 40 CFR 64 Subpart UUU are included in the proposed permit conditions.

**E. Identify and describe current operational limitations or work practices, or for covered sources that have not yet begun operation, such limitations or practices which the owner or operator of the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.**

Current operational limitations and work practices are described in Appendix D, as proposed permit conditions for the FCCU, Dimersol, and Alkylation Plants equipment/activities.

**F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable.**

No construction schedule is applicable to this application. All sources currently operate under CSP 0088-01-C.

- G. For **new** covered sources and **significant** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the NAAQS and SAAQS.

This information is not required because the equipment at the FCCU, Dimersol, and Alkylation Plants are not part of a new source. No emission increases or new pollutant emissions are included in this application.

- H. For **new** covered sources and **significant** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7.

This information is not required because the equipment at the FCCU, Dimersol, and Alkylation Plants are not part of a new source. No emission increases or new pollutant emissions are included in this application.

- I. Provide detailed information to define permit terms and conditions for any proposed **emissions trading** within the facility in accordance with HAR §11-60.1-96.

This information is not required because this application does not propose emission trading permit terms or conditions.

- J. Provide the following for compliance purposes:

1. A Compliance Plan, Form C-1.
2. A Compliance Certification, Form C-2.

See forms below.

**II. Submit an application fee according to the Application Fee Schedule in the Instructions for Applying for an Air Pollution Control Permit.**

**III. Provide other information as follows:**

- A. As required by any applicable requirement or as requested and deemed necessary by the Director of Health (hereafter, Director) to make a decision on the application.
- B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

**IV. The Director reserves the right to request the following information:**

- A. An assessment of the ambient air quality impact of the source or modification. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards.
- B. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.
- C. Results of source emissions testing, ambient air quality monitoring, or both.
- D. Information on other available control technologies.

**V. An application shall be determined to be complete only when all of the following have been complied with:**

- A. All information required or requested in numbers I, III, and IV has been submitted.
- B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.
- C. All applicable fees have been submitted.
- D. The Director has certified that the application is complete.

- VI. The Director shall not continue to act upon or consider an incomplete application.**
- A. The applicant shall be notified in writing whether the application is complete:
    - 1. For the requirements of subchapter 7, thirty days after receipt of the application.
    - 2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
    - 3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to VI.A.2 above, the application shall be deemed complete for the requirements of subchapter 5.
  - B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.
- VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.**
- A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.
  - B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.
- VIII. A Covered Source Permit application for a new covered source or a significant modification shall be approved only if the Director determines that the construction or operation of the new covered source or significant modification will be in compliance with all applicable requirements.**
- IX. The Director shall provide for public notice, including the method by which a public hearing can be requested, and an opportunity for public comment on the draft Covered Source Permit in accordance with HAR §11-60.1-99.**
- X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.**
- XI. Each application and proposed Covered Source Permit shall be subject to EPA oversight in accordance with HAR §11-60.1-95.**

**C-1: Compliance Plan**

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets of paper if necessary.

1. Compliance status with respect to all Applicable Requirements:

Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

YES {If YES, complete items a and c below}

NO {If NO, complete items a, b, and c below}

a. Identify all applicable requirement(s) for which compliance is achieved.

The emission units are in compliance with all applicable requirements.

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

Provide a statement that the source is in compliance and will continue to comply with all such requirements.

The emission units will continue to comply with all applicable requirements.

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

b. Identify all applicable requirement(s) for which compliance is NOT achieved.

N/A

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

Provide a detailed Schedule of Compliance Schedule and a description of how the source will achieve compliance with all such applicable requirements.

<u>Description of Remedial Action</u>	<u>Expected Date of Completion</u>
N/A	

- c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to. These applicable requirements may take effect AFTER permit issuance:

<u>Applicable Requirement</u>	<u>Effective Date</u>	<u>Currently in Compliance?</u>
N/A		

If the source is not currently in compliance, provide a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

<u>Description of Proposed Action/Steps to Achieve Compliance</u>	<u>Expected Date of Achieving Compliance</u>
N/A	

Provide a statement that the source on a timely basis will meet all these applicable requirements:

N/A

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If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of each remedial action and the expected date of completion:

<u>Description of Remedial Action and Explanation</u>	<u>Expected Date of Completion</u>
N/A	

2. Compliance Progress Reports:

- a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: N/A Beginning Date: N/A  
(less than or equal to 6 months)



**C-2: Compliance Certification**

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Complete as many copies of this form as needed. Use separate sheets of paper if necessary.

**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_Title: President and CEO Phone: (808) 682-5711Mailing Address: 91-480 Malakole StreetCity: Kapolei State: HI Zip Code: 96707**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Jon Mauer(Signature):  Date: 12/14/18Facility Name: IES Downstream, LLC - FCCU, Dimersol, and Alkylation PlantsLocation: 91-480 Malakole Street, Kapolei, HI 96707Permit Number: TBD**FOR AGENCY USE ONLY**

File/Application No.: \_\_\_\_\_

Island: \_\_\_\_\_

Date Received: \_\_\_\_\_



Complete the following information for *each* applicable requirement that applies to *each* emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal:   N/A                        Beginning Date:   Today  

2. Emissions Unit No./Description:   All units listed herein  

3. Identify the applicable requirement(s) that is/are the basis of this certification:  
  All applicable requirements.    
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES                       NO

b. If YES, will compliance be continuous or intermittent?

Continuous                       Intermittent

c. If NO, explain:

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

See Appendix D

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Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See Appendix D

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements? N/A

YES

NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

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- c. If NO, describe below which requirements will not be met:

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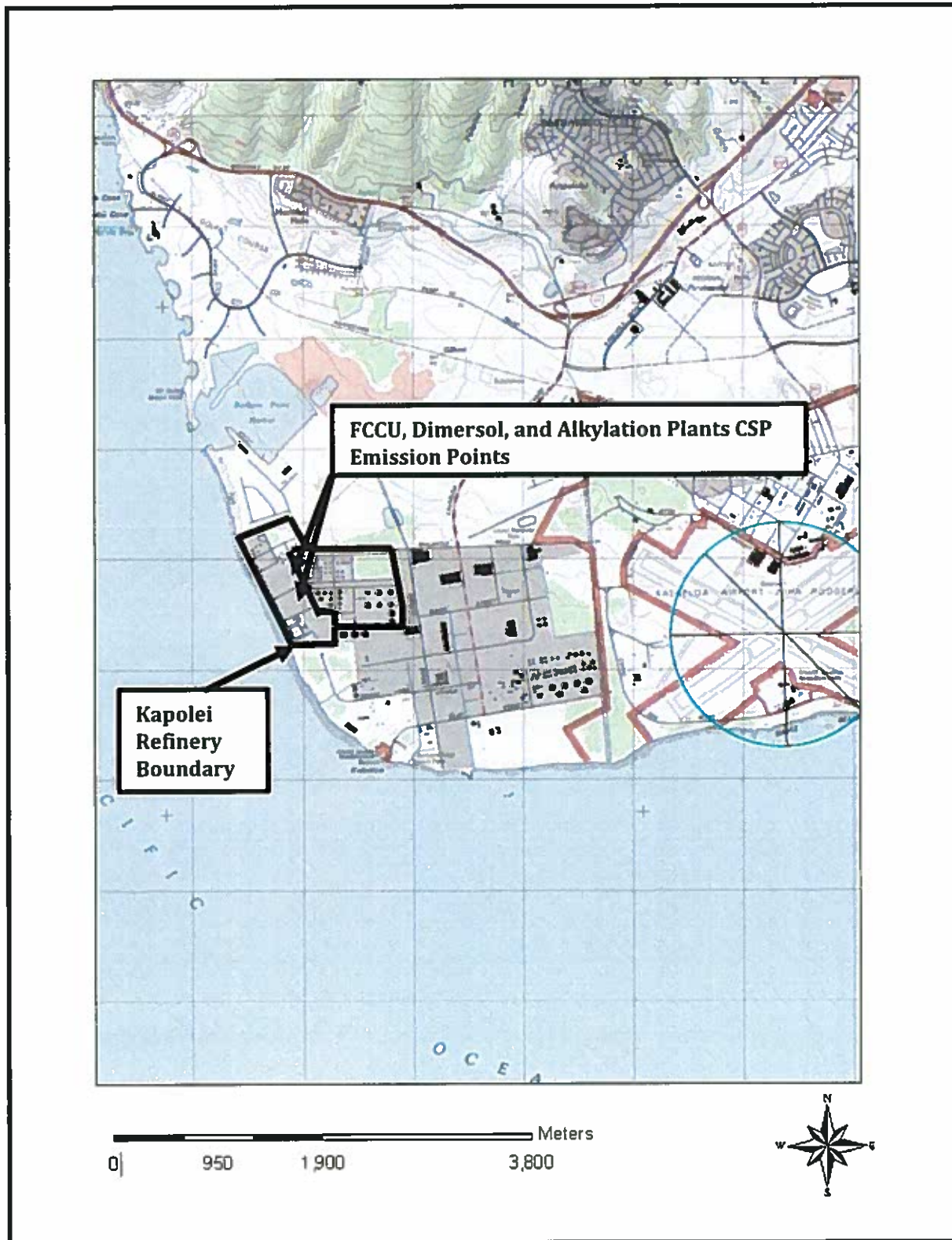
## APPENDIX B: PLOT PLAN

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Appendix Figure B-1. FCCU, Dimersol, and Alkylation Plants in Kapolei Refinery CSP

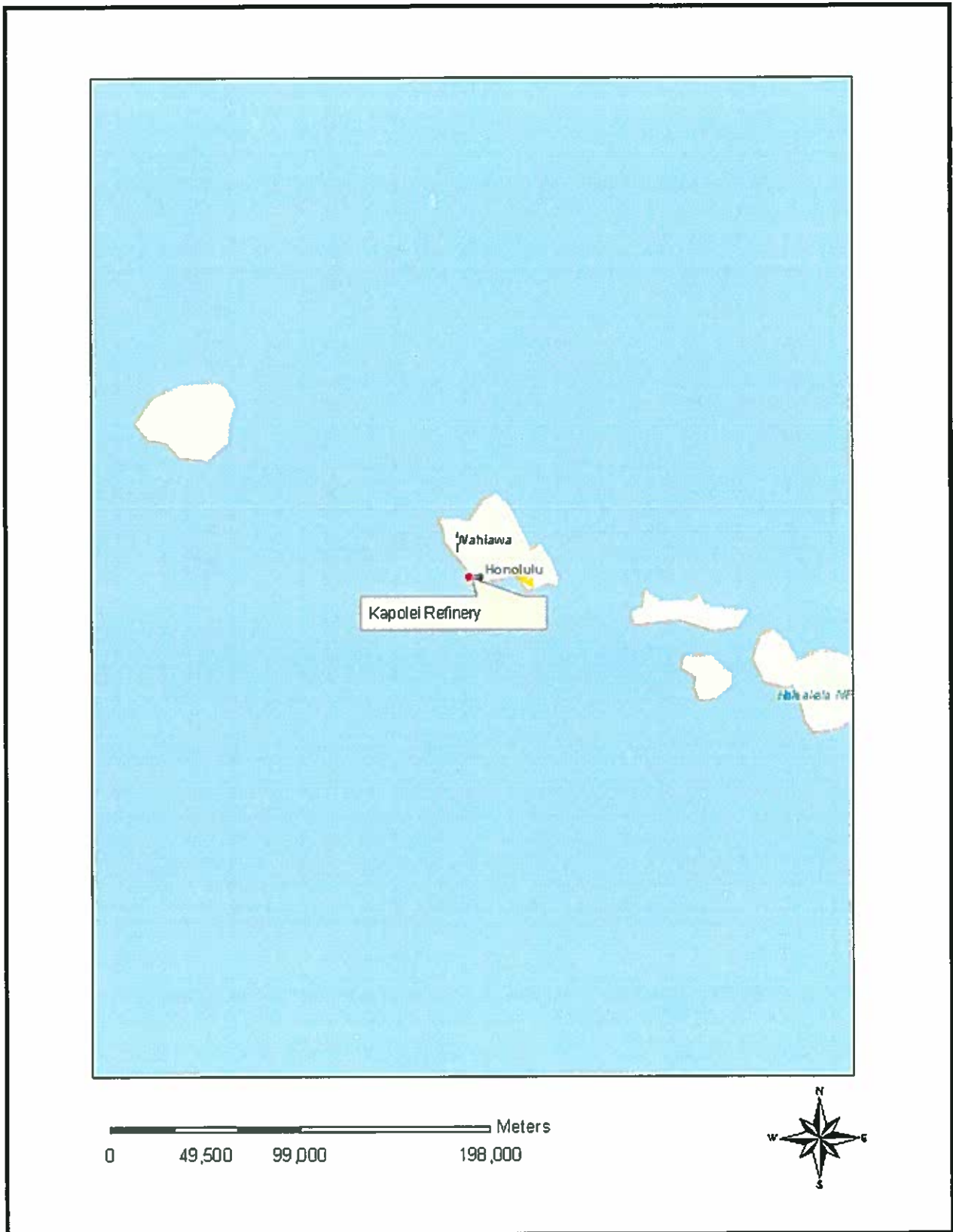


Appendix Figure B-2. Kapolei Refinery CSP with FCCU, Dimersol, and Alkylation Plants





Appendix Figure B-3. General Location of the Kapolei Refinery



## APPENDIX C: EMISSION CALCULATIONS

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Summary

IES Downstream, LLC - Kapolei Refinery - PTE for FCCU, Alkylation, and Dimersol Plants Initial CSP Application

SOURCES	Pollutant emission rates (ton/yr)						Total Criteria Pollutant Emissions
	PM10	SO2	CO	NO2	VOC	Lead	
FCC Furnace	2.1	7.2	23.2	15.1	1.6	0.0	49
FCC Stack	175.2	333.3	499.3	285.1	14.7	0.0	1308
Catalyst Transfer	0.0	-	-	-	-	-	0
Process Fugitives	-	-	-	-	39.7	0.0	40
<b>Totals</b>	<b>177.3</b>	<b>340.5</b>	<b>522.5</b>	<b>300.2</b>	<b>56.0</b>	<b>0.0</b>	<b>1396.5</b>



Point sources

Summary of Potential Emissions From Point Combustion Sources

SOURCES	Pollutant emission rates (ton/yr)							Total Criteria Pollutant Emissions
	PM10	SO2	CO	NOx	VOC	Lead		
FCC Furnace	2.11	7.16	23.21	15.09	1.60	0.000	49	
FCC Stack	175.20	333.35	499.32	285.07	14.67	0.000	1308	
<b>Totals</b>	<b>177.3</b>	<b>340.5</b>	<b>522.5</b>	<b>300.2</b>	<b>16.3</b>	<b>0.0</b>	<b>1356.8</b>	

VOC EE

REFINERY POTENTIAL VOC EMISSION FACTORS

New LDAR		Emission factor* (lb/hr/repair)		Emission factor* (lb/yr/repair)		Emission factor* (lb/yr/repair)		Emission factor* (lb/yr/repair)		Emission factor* (lb/yr/repair)		Emission factor* (lb/yr/repair)		Emission factor* (lb/yr/repair)	
Equipment Type	Service	LDAR	LDAR	LDAR	LDAR	LDAR	LDAR	LDAR	LDAR	LDAR	LDAR	LDAR	LDAR	LDAR	LDAR
Valves	G	0.0248	0.0248	0.0248	0.0248	0.0248	0.0248	0.0248	0.0248	0.0248	0.0248	0.0248	0.0248	0.0248	0.0248
	L	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129	0.0129
Pump Seals	G	0.780	0.780	0.780	0.780	0.780	0.780	0.780	0.780	0.780	0.780	0.780	0.780	0.780	0.780
	L	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Connectors (Flanges)	G	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626
	L	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Connectors (Flanges)	G	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025
	L	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
Open-ended Lines	G	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
	L	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
Heat Exchangers	G	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025
	L	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
Dry Vapor Separators	G	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025
	L	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002

\* Obtained from Table 2 of EPA Document "Procedures for Equipment Leak Emission Estimation" (1995). Values are evaluated as values of gas vapor service, only water separators are evaluated as open-ended lines. \*\* No emission factor available for pump seals in gas service. Emission factor above reflects L.L. service for pump seals adjusted by the ratio of the gas to light liquid service emission factors for L.L. service. \* Based on average leak rate data from leak detection and repair program for each first step area in LDAR program and from EPA correlation equations Table 3 (1)

EPA Screening values correlation equations in light Values  
 2.29E-6 (SV/V) 746 Not used - refinery-specific correlation is used above  
 5.0E-5 (SV/V) 610 Not used in the calculation  
 1.2E-5 (SV/V) 589 Not used - refinery-specific correlation is used above  
 4.81E-6 (SV/V) 703 Not used - refinery-specific correlation is used above  
 1.53710E-6 (SV/V) 735 Not used - refinery-specific correlation is used above  
 2.2E-10E-6 (SV/V) 704 Not used - refinery-specific correlation is used above  
 Used in the calculation

2018 Update

Equipment Type	Service	Emission factor** (lb/repair/yr)
Process Drain - uncontrolled	gas	0.01
Process Drain - Pigging controlled	gas	0.001

\*\* Emission factor for process drains as from EPA AP-42, Chapter 5, Table 5.14 and API Publication 4677

**53 - FCC point**

**53- FCC POINT SOURCE POTENTIAL TO EMIT CALCULATIONS**

FCC SO2 emissions									
FCC Feed	S%	lb/bbl	Bbls/day to FCC	Total lbs S	% conv to coke	lb/day S	lbs/day SO2	day/yr	ton/yr
VGO	0.3	308	22,000	20295	4.5	913	1,826.55	365	333

FCC emissions from source testing - 1996 and 1999 - six values					
Pollutant	lbs/hr	Annual downtime	Op hr/yr	lbs/year	TPY
CO	114	0	8760	998640	499.32
VOC	3.35	0	8760	29346	14.67

Allowed by Permit	
High Sulfur VGO	5500 bbl/day
Low Sulfur VGO	16500 bbl/day

FCC NOx emissions (from AP-42)						
Pollutant	lb/10 <sup>3</sup> bbl	Bbls/day to FCC	lbs/hour	Op hr/yr	lbs/yr	ton/yr
NOx	71	22,000	65.08	8760	570,130	285.07

FCC PM10 emissions (from mass balance)				
Pollutant	lbs/hour	up hours	lbs/year	ton/yr
PM	40	8760	350400	175.2

	wt lb/bbl	% total VGO	wt lb/bbl	% sulfur
HS Crude	324	25%	81	1.26
LS Crude	302	75%	227	0.12
			308	0.405

**HAP Summary**

Fugitive Emission by Area NUMBER	Total speciated VOC emissions (kg/hr)	AREA DESCRIPTION	BENZENE	NAPHTHALENE	O-XYLENE	ETHYLBENZENE	P-XYLENE	ETHYLENE DIBROMIDE	ETHYLENE DICHLORIDE	M-XYLENE	TOLUENE	1,3-BUTADIENE
			CAS# 71432 (ton/yr) 1	CAS# 91203 (ton/yr) 2	CAS# 95476 (ton/yr) 3	CAS# 100414 (ton/yr) 4	CAS# 106423 (ton/yr) 5	CAS# 106934 (ton/yr) 6	CAS# 107062 (ton/yr) 7	CAS# 108383 (ton/yr) 8	CAS# 108883 (ton/yr) 9	CAS# 106990 (ton/yr) 10
53		FLUID CATALYTIC CRACKER UNIT	0.02	0.02	0.06	0.03	0.04	0.00	0.00	0.10	0.14	0.01
58		ALKYLATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66		DIMERSOL PLANT	0.01	0.02	0.03	0.01	0.01	0.00	0.00	0.04	0.02	0.00
		Process Fugitive Summary	0.03	0.04	0.09	0.04	0.05	0.00	0.00	0.14	0.17	0.01
53		FCC POINT	0.001								0.001	
53		FCC STACK	0									
		HAPs Summary	0.03	0.04	0.09	0.04	0.05	0.00	0.00	0.14	0.17	0.01

HAP Summary

Total speciated VOC emissions (kg/hr)											
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	n-HEXANE CAS# 110543 (ton/yr) 11	ANILINE CAS# 62533 (ton/yr) 12	CRESOL MIXTURE CAS# 1319773 (ton/yr) 13	PHENOL CAS# 108952 (ton/yr) 14	STYRENE CAS# 100425 (ton/yr) 15	METHANOL CAS# 67561 (ton/yr) 16	NICKEL CAS# (ton/yr) 17	reported as LEAD CAS# (ton/yr) 18	HCL CAS# 7647010 (ton/yr) 19	PERCHLOROETHYLENE CAS# 127184 (ton/yr) 20
53	FLUID CATALYTIC CRACKER UNIT	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	ALKYLATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	DIMERSOL PLANT	0.05	0.00	0.05	0.00	0.00	0.00	0.02	0.00	0.00	0.00
	Process Fugitive Summary	0.07	0.00	0.05	0.00	0.00	0.00	0.02	0.00	0.00	0.00
53	FCC POINT	0.473									
53	FCC STACK										
	HAP's Summary	0.54	0.00	0.05	0.00	0.00	0.00	0.02	0.00	0.00	0.00

HAP Summary

Total speciated VOC emissions (kg/hr)											
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	<i>not HAP</i> CYCLOHEXANE CAS# 110827 (ton/yr) 21	BIPHENYL CAS# 92524 (ton/yr) 22	2,2,4 TRIMETHYLPENTANE CAS# 540841 (ton/yr) 23	CUMENE CAS# 98828 (ton/yr) 24	O-TOLUIDINE CAS# 95534 (ton/yr) 25	ACRYLAMIDE CAS# 79061 (ton/yr) 26	ANTIMONY COMPOUNDS CAS# (ton/yr) 27	ARSENIC CAS# (ton/yr) 28	<i>not HAP</i> PROPYLENE CAS# 115071 (ton/yr) 29	CYANIDE COMPOUNDS CAS# (ton/yr) 30
53	FLUID CATALYTIC CRACKER UNIT	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.43	0.00
58	ALKYLATION PLANT	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.13	0.00
66	DIMERSOL PLANT	0.00	0.00	0.03	0.01	0.00	0.00	0.00	0.00	2.37	0.00
	Process Fugitive Summary	0.00	0.00	0.04	0.01	0.01	0.00	0.00	0.00	2.94	0.00
53	FCC POINT										
53	FCC STACK										
	HAP's Summary	0.00	0.00	0.04	0.01	0.01	0.00	0.00	0.00	2.94	23.50

**HAP Summary**

Total speciated VOC emissions (kg/hr)							
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	not HAP 1,2,4-TMBenzene CAS# 95636 (ton/yr) 31	not HAP ETHYLENE CAS# 74851 (ton/yr) 32	Formaldehyde (ton/yr)	POM/PAH (ton/yr)	Total Haps ton/yr	
53	FLUID CATALYTIC CRACKER UNIT	0.03	0.04			0.439	
58	ALKYLATION PLANT	0.00	0.03			0.021	
66	DIMERSOL PLANT	0.00	0.01			0.303	
	Process Fugitive Summary	0.03	0.07	0.00	0.00	0.763	
53	FCC POINT			0.020	0.000	0.494	
53	FCC STACK			0.890		24.390	
	HAP's Summary	0.03	0.07	0.91	0.00	25.65	

**PTE DRAIN EMISSIONS**

Worst case speciation is recovered oil for HAPs

	DIMATE	63	Note 1		Note 2		TOTAL VOC (lbs/hr)
			NUMBER OF DRAINS	VOC P-TRAP (lbs/hr)	VOC NO P-TRAP (lbs/hr)		
DIMERSOL			53	0.001	0.07		3.710
			<b>TOTAL (PER HOUR)</b>				<b>4</b>
			<b>TOTAL ANNUAL (LBS)</b>				<b>32500</b>
			<b>TOTAL ANNUAL (TONS)</b>				<b>16</b>



HAPs Point

AP-42 HAPs listing for F/O and F/G Combustion

EF AP-42 Table 1.4-4 F/G COMBUSTION

Metal	EF (lb/MMSCF)	FCC Furnace F-5301	Total MMSCF/yr	FCC Furnace F-5301	Total F/G Combustion
Arsenic	0.0022000	525.60	525.6	0.00	0.00
Barium	0.0044000	-	-	-	-
Beryllium	0.000120	525.60	525.6	0.00	0.00
Cadmium	0.0011000	525.60	525.6	0.00	0.00
Chromium	0.0014000	525.60	525.6	0.00	0.00
Cobalt	0.000840	525.60	525.6	0.00	0.00
Copper	0.0008500	-	-	-	-
Manganese	0.0003800	525.60	525.6	0.00	0.00
Mercury	0.0002600	525.60	525.6	0.00	0.00
Molybdenum	0.0011000	-	-	-	-
Nickel	0.0021000	525.60	525.6	0.00	0.00
Selenium	0.000240	525.60	525.6	0.00	0.00
Vanadium	0.0023000	-	-	-	-
Zinc	0.0290000	-	-	-	-

EF AP-42 Table 1.4-3 F/G COMBUSTION

Organics	EF (lb/MMSCF)	FCC Furnace F-5301	Total MMSCF/yr	FCC Furnace F-5301	Total F/G Combustion
Benzene	2.10E-03	525.60	525.6	0.00	0.00
Dichlorobenzene	1.20E-03	525.60	525.60	0.00	0.00
Formaldehyde	7.50E-02	525.60	525.60	0.02	0.02
Hexane	1.80E+00	525.60	525.60	0.47	0.47
Naphthalene	6.10E-04	525.60	525.60	0.00	0.00
Toluene	3.40E-03	525.60	525.60	0.00	0.00
POM	8.87E-05	525.60	525.60	0.00	0.00

**53 - FCC Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS**  
**AREA 53 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE**  
 Calculated for 2002 reporting year  
 Date of last revision 9/18/2001  
 Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
 removed 10% growth factor due to no changes since 1993.

FCC VOC Emissions	using API data				using EPA data					
	lb/hr	% IES	ton/yr	lb/hr	ton/yr	Delta	lb/hr	ton/yr	Delta	
Checkvalves	0.0189	80%	0.0829				1.03	4.52		
Control Valves	0.0196	80%	0.0860				0.68	2.96		
Fittings	0.3444	80%	1.5083	0.3785	1.6614	0.15	0.49	2.13	0.62	
Flanges	0.5636	80%	2.4686	0.4467	1.9607	-0.51	0.56	2.47	0.01	
PRVs	0.0034	60%	0.0148				2.32	10.20	10.18	
Pumps	0.4737	89%	2.0746				4.27	18.74		
Valves	0.7158	80%	3.1351				32.57	142.96		
Drains	0	0%	0.0000	All drains remain in current refinery permit.						
TOTALS	2.14		9.37				41.92	183.99		

**58 - Alky Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS**  
**AREA 58 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE**  
 Calculated for 2002 reporting year  
 Date of last revision 9/18/2001  
 Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
 removed 10% growth factor due to no changes since 1993.

FCC VOC Emissions	lb/hr	% IES	ton/yr	using EPA data lb/hr	ton/yr	Delta
Valves	0.4044	72%	1.7714			
Connections	1.2442	72%	5.4498	2.1386	9.3670	3.92
Pumps	0.1580	73%	0.6918			
Compressors	0.0011	100%	0.0049			
PRVs	0.0000	72%	0.0000			
Drains	0	0%	0.0000	All drains remain in current refinery permit.		
<b>TOTALS</b>	<b>1.81</b>		<b>7.92</b>			

**66 - Dimersol Fugitives**

**POTENTIAL TO EMIT FUGITIVE EMISSIONS**

AREA 66 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE - Dimersol

Calculated for 2002 reporting year

Date of last revision 9/18/2001

Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
removed 10% growth factor due to no changes since 1993.

Dimersol VOC Emissions	using API/EPA data			using EPA data		
	lb/hr	ton/yr	Delta	lb/hr	ton/yr	Delta
Checkvalves	0.0187	0.0820				
Control Valves	0.0213	0.0931				
Fittings	0.1341	0.5873	0.42	0.2305	1.0115	0.42
Flanges	0.3537	1.5490	0.00	0.3537	1.5522	0.00
PRVs	0.0062	0.0270		4.224	18.540	18.51
Pumps	0.5181	2.2694				
Valves	0.3549	1.5544				
Drains	3.71	16.2498	2016 Update			
TOTALS	5.12	22.41				

Detailed Summary

Summary of potential emissions from the IES Downstream, LLC Kspical Refinery

Equipment Description/Emission Source	Annual Process Rate	Process Rate Units	Type of Fuel Fired	Fuel Usage Bbls/yr or MSCFYr	Units	% sulfur content by weight	Heating value	Units	Tons/Year Emissions					
									PM10	SO2	CO	NO2	VOC	Pb
FCC Furnace - F-5300	61	MMBTU/Hour	Fuel Gas	525,600	MSCFYr	0.0160			2.00	7.10	22.08	13.14	1.45	0.00013
FCC Startup Air Heater	52	MMBTU/Hour	Inherently low S fuel gas			0.0035		Subtotal	0.11	0.06	1.13	1.95	0.15	
FCC Slack	22,000	Bbls/Day Feed						replace with stack limit	2.11	7.16	23.21	15.09	1.60	
Catalyst transfer	924	Tons/Year							175.2	333.35	499.32	285.07	14.67	
Process Fugitives									0.03					
<b>Total Criteria Pollutants</b>									<b>177.2</b>	<b>340.4</b>	<b>521.4</b>	<b>298.2</b>	<b>55.8</b>	<b>0.0</b>

## Component Counts

### COMPONENT COUNTS

AREA NO	AREA DESCRIPTION	SERVICE	COMPONENT TYPE				
			VALVES	FLANGES	PUMPS	COMPRES PRVS	
53	FLUID CATALYTIC CRACKER UNIT	ALL	1908	2452	33	0	12
58	ALKYLATION PLANT	ALL	1180	5821	21	1	0
66	DIMERSOL PLANT	ALL	974	1272	21	0	12
<b>TOTAL</b>		ALL	4062	9545	75	1	24

Note: For summary purposes, Both connectors and fittings have been grouped under the category of flanges

## Fugitive VOC Summary

### REFINERY PROCESS AREAS FUGITIVE EMISSIONS

AREA NUMBER	AREA DESCRIPTION	FUGITIVE VOCs TON/YR
53	FLUID CATALYTIC CRACKER UNIT	9.4
58	ALKYLATION PLANT	7.9
66	DIMERSOL PLANT	22.4
	<b>TOTAL PROCESS AREAS FUGITIVE EMISSIONS</b>	<b>39.7</b>

## Calculation Methods

### **FCC Furnace**

from PHD:

53F4101.PV - total fuel gas to boilers in MSCF

53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

Fuel Gas Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NOx and CO, used Table 1.4-2 VOC  
and PM. Used mass balance for SO2  
PM=7.6 lb PM /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb  
SO2=(S ppm \* 64/379) lb SO2/MMSCF \*fuel use MSCF (MMSCF/1000 MSCF) \* ton/2000 lb  
NOx=50 lb NOx /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb  
CO=84 lb CO /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb  
VOC=5.5 lb VOC /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb

### **Alky/Isom Furnace**

from PHD:

58F403.PV - total fuel gas to Alky/Isom in MSCFH

53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

EF same as FCC Furnace

Fuel Gas Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NOx and CO, used Table 1.4-2 VOC  
and PM. Used mass balance for SO2

### **FCC Stack**

from PHD:

53FC101.PV - FCC feedrate MBPD

53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

need TPY catalyst value from 2001catinv.xls - see Steph Christie

from Lab:

%sulfur for VGO - TOTFD

Used 1996 and 1999 Source test data for CO and VOC emission rate

VOC emission based on average emission rate of 1.71 lb/hr

VOC= 1.71 lb/hr \* op hrs/yr \* ton/2000 lb

CO emission based on average emission rate of 73 lb/hr from

CO= 73 lb/hr \* op hrs/yr \* ton/2000 lb

Used AP-42 for FCC w/ESP, Table 5.1-1 for NOx

NOx=71 lb NOx /1000 bbl feed \*feed rate bbl/day \*day/24 hr \* 8760 hr/yr\* ton/2000 lb

note annual operation rate already accounted for in the average daily feed rate

SO2 emisison rate calculated with %S, density of 310 lb/bbl, 4.5% conversion to coke, 100% of coke converted to SO2

SO2= %S/100\*306 lb/bbl\* annual feed rate bbl/day \* 4.5%conv/100 \* 64/32 \* day/24 hr \* 8760 hr/yr\* ton/2000

calculate weighted average VGO wt lb/bbl from crude slate breakdown from Tad

### **Catalyst Transfer**

from Steph Christie:

2001catinv.xls

Used AP-42, Table 11.24-2 Mineral Processing (Low-moisture ore)

PM=ann process rate ton/yr \*0.06 lb PM10 / ton \* ton/2000 lb



## APPENDIX D: PROPOSED PERMIT CONDITIONS

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**ATTACHMENT I: STANDARD CONDITIONS  
COVERED SOURCE PERMIT NO. 0863-02-C**

**Issuance Date:** XXXX XX, 2019

**Expiration Date:** XXXX XX, 2024

This permit is granted in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and is subject to the following standard conditions:

1. Unless specifically identified, the terms and conditions contained in this permit are consistent with the applicable requirement, including form, on which each term or condition is based.  
  
(Auth.: HAR §11-60.1-90)
2. This permit, or a copy thereof, shall be maintained at or near the source and shall be made available for inspection upon request. The permit shall not be willfully defaced, altered, forged, counterfeited, or falsified.  
  
(Auth.: HAR §11-60.1-6; SIP §11-60-11)<sup>2</sup>
3. This permit is not transferable whether by operation of law or otherwise, from person to person, from place to place, or from one piece of equipment to another without the approval of the Department, except as provided in HAR, Section 11-60.1-91.  
  
(Auth.: HAR §11-60.1-7; SIP §11-60-9)<sup>2</sup>
4. A request for transfer from person to person shall be made on forms furnished by the Department.  
  
(Auth.: HAR §11-60.1-7)
5. In the event of any changes in control or ownership of the facilities to be constructed or modified, this permit shall be binding on all subsequent owners and operators. The permittee shall notify the succeeding owner and operator of the existence of this permit and its conditions by letter, copies of which will be forwarded to the Department and the U.S. Environmental Protection Agency (EPA), Region 9.  
  
(Auth.: HAR §11-60.1-5, §11-60.1-7, §11-60.1-94)
6. The facility covered by this permit shall be constructed and operated in accordance with the application, and any information submitted as part of the application, for CSP. There shall be no deviation unless additional or revised plans are submitted to and approved by the Department, and the permit is amended to allow such deviation.  
  
(Auth.: HAR §11-60.1-2, §11-60.1-4, §11-60.1-82, §11-60.1-84, §11-60.1-90)

7. This permit (a) does not release the permittee from compliance with other applicable statutes of the State of Hawaii, or with applicable local laws, regulations, or ordinances, and (b) shall not constitute, nor be construed to be an approval of the design of the covered source.

(Auth.: HAR §11-60.1-5, §11-60.1-82)

8. The permittee shall comply with all the terms and conditions of this permit. Any permit noncompliance constitutes a violation of HAR, Chapter 11-60.1, and the Clean Air Act and is grounds for enforcement action; for permit termination, suspension, reopening, or amendment; or for denial of a permit renewal application.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-19, §11-60.1-90)

9. If any term or condition of this permit becomes invalid as a result of a challenge to a portion of this permit, the other terms and conditions of this permit shall not be affected and shall remain valid.

(Auth.: HAR §11-60.1-90)

10. The permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the terms and conditions of this permit.

(Auth.: HAR §11-60.1-90)

11. This permit may be terminated, suspended, reopened, or amended for cause pursuant to HAR, Sections, 11-60.1-10 and 11-60.1-98, and Hawaii Revised Statutes (HRS), Chapter 342B-27, after affording the permittee an opportunity for a hearing in accordance with HRS, Chapter 91.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90, §11-60.1-98)

12. The filing of a request by the permittee for the termination, suspension, reopening, or amendment of this permit, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

(Auth.: HAR §11-60.1-90)

13. This permit does not convey any property rights of any sort, or any exclusive privilege.

(Auth.: HAR §11-60.1-90)

14. The permittee shall notify the Department and U.S. EPA, Region 9, in writing of the following dates:

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- a. The anticipated date of initial start-up for each emission unit of a new source or significant modification not more than sixty (60) days or less than thirty (30) days prior to such date;
- b. The actual date of construction commencement within fifteen (15) days after such date; and
- c. The actual date of start-up within fifteen (15) days after such date.

(Auth.: HAR §11-60.1-90)

15. The permittee shall furnish, in a timely manner, any information or records requested in writing by the Department to determine whether cause exists for terminating, suspending, reopening, or amending this permit, or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Department copies of records required to be kept by the permittee. For information claimed to be confidential, the Director of Health (Director) may require the permittee to furnish such records not only to the Department but also directly to the U.S. EPA, Region 9, along with a claim of confidentiality.

(Auth.: HAR §11-60.1-14, §11-60.1-90)16.

16. The permittee shall notify the Department in writing of the intent to shut down air pollution control equipment for necessary scheduled maintenance at least twenty-four (24) hours prior to the planned shutdown. The submittal of this notice shall not be a defense to an enforcement action. The notice shall include the following:
  - a. Identification of the specific equipment to be taken out of service, as well as its location and permit number;
  - b. The expected length of time that the air pollution control equipment will be out of service;
  - c. The nature and quantity of emissions of air pollutants likely to be emitted during the shutdown period;
  - d. Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period; and
  - e. The reasons why it would be impossible or impractical to shut down the source operation during the maintenance period.

(Auth.: HAR §11-60.1-15; SIP §11-60-16)<sup>2</sup>

17. **Except for emergencies which result in noncompliance with any technology-based emission limitation in accordance with HAR, Section 11-60.1-16.5, in the event any emission unit, air pollution control equipment, or related equipment malfunctions or breaks down in such a manner as to cause the emission of air pollutants in violation of HAR, Chapter 11-60.1 or this permit, the permittee shall immediately notify the Department of the malfunction or breakdown, unless the protection of personnel or public health or safety demands immediate attention to the malfunction or breakdown and makes such notification infeasible. In the latter case, the notice shall be provided as soon as practicable. Within five (5) working days of this initial notification, the permittee shall also submit, in writing, the following information:**

- a. Identification of each affected emission point and each emission limit exceeded;
- b. Magnitude of each excess emission;
- c. Time and duration of each excess emission;
- d. Identity of the process or control equipment causing the excess emission;
- e. Cause and nature of each excess emission;
- f. Description of the steps taken to remedy the situation, prevent a recurrence, limit the excessive emissions, and assure that the malfunction or breakdown does not interfere with the attainment and maintenance of the National Ambient Air Quality Standards and state ambient air quality standards;
- g. Documentation that the equipment or process was at all times maintained and operated in a manner consistent with good practice for minimizing emissions; and
- h. A statement that the excess emissions are not part of a recurring pattern indicative of inadequate design, operation, or maintenance.

The submittal of these notices shall not be a defense to an enforcement action.

(Auth.: HAR §11-60.1-16; SIP §11-60-16)<sup>2</sup>

18. The permittee may request confidential treatment of any records in accordance with HAR, Section 11-60.1-14.

(Auth.: HAR §11-60.1-14, §11-60.1-90)

19. This permit shall become invalid with respect to the authorized construction if construction is not commenced as follows:

- a. Within eighteen (18) months after the permit takes effect, is discontinued for a period of eighteen (18) months or more, or is not completed within a reasonable time.
- b. For phased construction projects, each phase shall commence construction within eighteen (18) months of the projected and approved commencement dates in the permit. This provision shall be applicable only if the projected and approved commencement dates of each construction phase are defined in Attachment II, Special Conditions of this permit.

(Auth.: HAR §11-60.1-9, §11-60.1-90)

20. The Department may extend the time periods specified in Standard Condition No. 19 upon a satisfactory showing that an extension is justified. Requests for an extension shall be submitted in writing to the Department.

(Auth.: HAR §11-60.1-9, §11-60.1-90)

21. The permittee shall submit fees in accordance with HAR, Chapter 11-60.1, Subchapter 6.

(Auth.: HAR §11-60.1-90)

22. All certifications shall be in accordance with HAR, Section 11-60.1-4.
- (Auth.: HAR §11-60.1-4, HAR §11-60.1-90)
23. The permittee shall allow the Director, the Regional Administrator for the U.S. EPA, and/or an authorized representative, upon presentation of credentials or other documents required by law:
- To enter the premises where a source is located or emission-related activity is conducted, or where records must be kept under the conditions of this permit and inspect at reasonable times all facilities, equipment, including monitoring and air pollution control equipment, practices, operations, or records covered under the terms and conditions of this permit and request copies of records or copy records required by this permit; and
  - To sample or monitor at reasonable times substances or parameters to ensure compliance with this permit or applicable requirements of HAR, Chapter 11-60.1.
- (Auth.: HAR §11-60.1-11, §11-60.1-90)
24. Within thirty (30) days of permanent discontinuance of the construction, modification, relocation, or operation of a covered source covered by this permit, the discontinuance shall be reported in writing to the Department by a responsible official of the source.
- (Auth.: HAR §11-60.1-8; SIP §11-60-10)<sup>2</sup>
25. Each permit renewal application shall be submitted to the Department and the U.S. EPA, Region 9, no less than twelve (12) months and no more than eighteen (18) months prior to the permit expiration date. The Director may allow a permit renewal application to be submitted no less than six (6) months prior to the permit expiration date, if the Director determines that there is reasonable justification.
- (Auth.: HAR §11-60.1-101, 40 CFR §70.5(a)(1)(iii))<sup>1</sup>
26. The terms and conditions included in this permit, including any provision designed to limit a source's potential to emit, are federally enforceable unless such terms, conditions, or requirements are specifically designated as not federally enforceable.
- (Auth.: HAR §11-60.1-93)
27. The compliance plan and compliance certification submittal requirements shall be in accordance with HAR, Sections 11-60.1-85 and 11-60.1-86. As specified in HAR, Section 11-60.1-86, the compliance certification shall be submitted to the Department and the U.S. EPA, Region 9, once per year, or more frequently as set by any applicable requirement.
- (Auth.: HAR §11-60.1-90)

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28. Any document (including reports) required to be submitted by this permit shall be certified as being true, accurate, and complete by a responsible official in accordance with HAR, Sections 11-60.1-1 and 11-60.1-4, and shall be mailed to the following address:

State of Hawaii  
Clean Air Branch  
2827 Waimano Home Road #130  
Pearl City, HI 96782

Upon request and as required by this permit, all correspondence to the State of Hawaii Department associated with this CSP shall have duplicate copies forwarded to:

Manager  
Enforcement Division, Air Section  
U.S. Environmental Protection Agency, Region 9  
75 Hawthorne Street, ENF-2-1  
San Francisco, CA 94105

(Auth.: HAR §11-60.1-4, §11-60.1-90)

29. To determine compliance with submittal deadlines for time-sensitive documents, the postmark date of the document shall be used. If the document was hand-delivered, the date received ("stamped") at the Clean Air Branch shall be used to determine the submittal date.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

<sup>3</sup>This date is to be revised upon issuance of the renewal for CSP No. 0088-01-C.

**ATTACHMENT II(A): SPECIAL CONDITIONS  
MISCELLANEOUS PROCESS UNITS AND SOURCE OPERATIONS  
COVERED SOURCE PERMIT NO. 0863-02-C**

Issuance Date: XXXX XX, 2019

Expiration Date: XXXX XX, 2024

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

This portion of the CSP encompasses the requirements for miscellaneous process units and/or source operations not included with the Special Conditions of Attachments II(B) through II(I).

(Auth.: HAR §11-60.1-3)

**Section B. Applicable Federal Regulations**

1. The FCC Unit, ~~and Dimersol Plant~~ ~~and Liquid Fuel System~~ are subject to the provisions of the following federal regulations:

40 CFR Part 60, New Source Performance Standards (NSPS):

- i. Subpart A, General Provisions; and
- ii. Subpart GGG, Standards of Performance for Equipment Leaks in Petroleum Refineries.

~~Furthermore, the permittee voluntarily complies with 40 CFR 60, Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, as a compliance demonstration with Subpart GGG and to maintain consistency with other Leak Detection and Repair (LDAR) requirements.~~

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.590a)

2. The FCC Unit, Dimersol Plant, ~~Liquid Fuel System~~, and Alkylation Plant are subject to the provisions of the following federal regulations:

- a. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT):

- i. Subpart A, General Provisions; and
- ii. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

Commented [HL1]: Mark -- to review for accuracy of strategy. I deliberately left the consent decree out. Agencies often do not want to mix consent decree requirements with Clean Air Act applicable requirements.

Commented [PM2]: Removed Liquid Fuel System through this redline. It is already in the terminal permit and does not need to be included in this new permit.



- b. The above regulations are not applicable to any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system that is intended to operate in organic hazardous air pollutant service, as defined in 40 CFR §63.641, for less than 300 hours during the calendar year.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11.60.1-174, 40 CFR §63.640)<sup>1</sup>

3. The storage and use of flammable substances in this facility is subject to the provisions of 40 CFR Part 68, Chemical Accident Prevention Provisions. The permittee shall comply with all applicable requirements, including the submittal of:
  - a. A compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR §68.10(a); or
  - b. As part of the compliance certification submitted pursuant to Attachment I, Standard Condition No. 28, a certification statement that the facility is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of the Risk Management Plan.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §68)<sup>1</sup>

### **Section C. Operational and Emission Limitations**

1. All pumps and compressors handling VOC having a Reid Vapor Pressure (RVP) of 1.5 pounds per square inch (psi) or greater which can be fitted with mechanical seals shall have mechanical seals or other equipment of equal efficiency for purposes of air pollution control as may be approved by the Department. Pumps and compressors not capable of being fitted with mechanical seals, such as reciprocating pumps, shall be fitted with the best sealing system available for air pollution control given the particular design of pump or compressor as may be approved by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-41, §11-60.1-90)

2. The permittee shall not cause or allow the emissions of gas streams containing VOC from a vapor blowdown system unless these gases are burned by smokeless flares, or abated by an equally effective control device as approved by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-42, §11-60.1-90)

### 3. Compressor

- a. Each compressor located at the FCC Unit ~~and Liquid Fuel System~~ shall be equipped and operated with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in 40 CFR §60.482-1~~a~~(c), 40 CFR §60.482-3~~a~~(h), and 40 CFR §60.482-3~~a~~(i).
- b. Each compressor seal system as required in Special Condition No. C.3.a of this attachment shall be as follows:
  - i. Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or
  - ii. Equipped with a barrier fluid system that is connected by a closed vent system to a control device that complies with the requirements of 40 CFR §60.482-10; or
  - iii. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
- c. The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.
- d. A compressor is exempt from the requirements of Special Condition Nos. C.3.a and C.3.b of this attachment if it is equipped with a closed vent system capable of capturing and transporting any leakage from the seal to a control device that complies with the requirements of 40 CFR §60.482-10~~a~~, except as provided in Special Condition No. C.3.e of this attachment.
- e. Any compressor that is designated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by methods specified in 40 CFR §60.485~~a~~(c) and is tested for compliance initially upon designation, annually, and at other times requested by the Department is exempt from the requirements of Special Condition Nos. C.3.a through C.3.d, D.3.a, and D.3.b of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592~~a~~)<sup>1</sup>

### 4. Pressure Relief Devices in Gas/Vapor Service

- a. Except during pressure releases, each pressure relief device in gas/vapor service located at the FCC Unit ~~and Dimersol Plant and Liquid Fuel System~~ shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR §60.485~~a~~(c).
- b. *After each pressure release*, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, *as soon as practicable, but no later than five (5) calendar days after the pressure release*, except as provided in Special Condition No. C.8 of this attachment.

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- c. Any pressure relief device is exempt from the requirements of Special Condition Nos. C.4.a and C.4.b of this attachment if it is equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device that complies with the requirements of 40 CFR §60.482-10~~a~~.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592~~a~~)<sup>1</sup>

#### 5. Open Ended Valves/Lines

Commented [HL4]: No changes

- a. Each open-ended valve or line at the FCC Unit, Dimersol Plant, ~~Liquid Fuel System~~, and Alkylation Plant shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR §60.482-1~~a~~(c). The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.
- b. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.
- c. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with Special Condition No. C.5.a of this attachment at all other times.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592~~a~~, §63.648)<sup>1</sup>

#### 6. Sampling Connection Systems

Commented [HL5]: There are more requirements in the corresponding GGGa section, but they weren't cited for the GGG section so I did not add them.

- a. Each sampling connection system at the FCC Unit, Dimersol Plant, ~~Liquid Fuel System~~, and Alkylation Plant shall be equipped with a closed-purged, closed-loop, or closed-vent system, except as provided in 40 CFR §60.482-1~~a~~(c) or paragraph c of this condition.
- b. Each closed-purged, closed-loop, or closed-vent system shall comply with the following requirements:
  - i. Return the purged process fluid directly to the process line; or
  - ii. Collect and recycle the purged process fluid to a process; or
  - iii. Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of 40 CFR §60.482-10.
- c. In-situ sampling systems and sampling systems without purges are exempt from the requirements of Special Condition Nos. C.6.a and C.6.b of this attachment.

Commented [HL6]: Not really a GGGa change, just needed.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592~~a~~, §63.648)<sup>1</sup>

7. Delay of Repair

Commented [HL7]: No change.

- a. Delay of repair of equipment for which leaks have been detected will be allowed if the repair is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.
- b. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.
- c. Delay of repair for valves will be allowed if:
  - i. The permittee demonstrates that emissions of purged material resulting from the immediate repair are greater than the fugitive emissions likely to result from the delay of repair; and
  - ii. When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with the requirements of 40 CFR §60.482-10<sup>a</sup>.
- d. Delay of repair for pumps will be allowed if:
  - i. Repair requires the use of a dual mechanical seal system that includes a barrier fluid system; and
  - ii. Repair is completed as soon as practicable, but not later than six (6) months after the leak was detected.
- e. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than six (6) months after the first process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592<sup>a</sup>, §63.648)<sup>1</sup>

**Section D. Monitoring and Recordkeeping Requirements**

1. All records, including support information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Support information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

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## 2. Pumps in Light Liquid Service

- a. Each pump in light liquid service at the FCC Unit, Dimersol Plant, ~~Liquid Fuel System~~, and Alkylation Plant shall be monitored monthly to detect leaks in accordance with the requirements set forth in 40 CFR §60.485~~a~~(b), except as provided in 40 CFR §60.482-1~~a~~(c) and 40 CFR §60.482-2~~a~~(d), (e) and (f).
- b. Each pump in light liquid service at the FCC Unit, Dimersol Plant, ~~Liquid Fuel System~~, and Alkylation Plant shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.
- c. If an instrument reading of 402,000 ppm or greater is measured, a leak is detected.
- d. If there are indications of liquids dripping from the pump seal, a leak is detected.
- e. When a leak is detected, it shall be repaired as soon as practicable, but not later than fifteen (15) calendar days after it is detected, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made no later than five (5) calendar days after each leak is detected.
- f. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of Special Condition No. D.2.a of this attachment provided the requirements of 40 CFR §60.482-2~~a~~(d)(1) through (6) are met.
- g. Any pump that is designated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of Special Condition Nos. D.2.a, D.2.b, D.2.e, and D.2.f of this attachment if the pump:
  - i. Has no externally actuated shaft penetrating the pump housing;
  - ii. Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in 40 CFR §60.485~~a~~(c); and
  - iii. Is tested for compliance with Special Condition No. D.2.g.ii of this attachment initially upon designation, annually, and at other times requested by the Department.
- h. If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a control device that complies with the requirements of 40 CFR §60.482~~a~~-10~~a~~, it is exempt from the requirements of Special Condition Nos. D.2.a through D.2.g of this attachment.

Commented [HL8]: Underlying change in requirement for methane span value referenced. Under GGGa the methane calibration gas must be 20,000 ppm not 10,000 ppm.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592~~a~~, §63.648)<sup>1</sup>

## 3. Compressors

- a. Each compressor barrier fluid system shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both. Each sensor shall be checked daily or shall be equipped with an audible alarm. If the sensor indicates failure of the seal system, the barrier system, or both, a leak is detected.
- b. When a leak is detected, it shall be repaired as soon as practicable, but not later than fifteen (15) calendar days after it is detected, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made no later than five (5) calendar days after each leak is detected.

Commented [HL9]: No changes

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592~~a~~)<sup>1</sup>

#### 4. Pressure Relief Devices in Gas/Vapor Service

No later than five (5) calendar days after a pressure release, the pressure relief device subject to the requirements of 40 CFR Part 60, Subpart GGG and complying by demonstrating voluntary compliance with Subpart GGGa, shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR §60.485a(c).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592a)<sup>1</sup>

#### 5. Valves in Light Liquid Service and in Gas/Vapor Service

- a. Each valve in light liquid service at the FCC Unit, Dimersol Plant, ~~Liquid Fuel System~~, and Alkylation Plant shall be monitored monthly to detect leaks in accordance with the requirements set forth in 40 CFR §60.485a(b).
- b. If an instrument reading of ~~10,000~~ 500 ppm or greater is measured, a leak is detected.
- c. Any valve for which a leak is not detected for two (2) successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected. If a leak is detected, the valve shall be monitored monthly until a leak is not detected for two (2) successive months.
- d. When a leak is detected, it shall be repaired as soon as practicable, but not later than fifteen (15) calendar days after it is detected, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made no later than five (5) calendar days after each leak is detected.
- e. First attempts at repair include, but are not limited to, the following best practices where practicable:
  - i. Tightening of bonnet bolts;
  - ii. Replacement of bonnet bolts;
  - iii. Tightening of packing gland nuts; and
  - iv. Injection of lubricant into lubricated packing.
- f. Any valve that is designated, as described in 40 CFR §60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of Special Condition No. D.5.a of this attachment if the valve:
  - i. Has no external actuating mechanism in contact with the process fluid;
  - ii. Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR §60.485a(c); and
  - iii. Is tested for compliance with the Special Condition No. D.5.f.ii of this attachment initially upon designation, annually, and at other times requested by the Department.
- g. Any valve that is designated, as described in 40 CFR §60.486a(f)(1), as unsafe-to-monitor valve and satisfies the criteria outlined in 40 CFR §60.482-7a(g) is exempt from the requirements of Special Condition No. D.5.a of this attachment.
- h. Any valve that is designated, as described in 40 CFR §60.486a(f)(2), as difficult-to-monitor valve and satisfies the criteria outlined in 40 CFR §60.482-7a(h) is exempt from the requirements of Special Condition No. D.5.a of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592a, §63.648)<sup>1</sup>

Commented [HL10]: Again – change in calibration standard gas from 10,000 ppm methane to 20,000 ppm.

Commented [HL11]: Key reduction.



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6. Pumps, ~~and Valves, and Connectors~~ in Heavy Liquid Service, ~~and Pressure Relief Devices in Light Liquid or Heavy Liquid Service, and Flanges and other Connectors~~
- a. Pumps, ~~and valves, and connectors~~ in heavy liquid service, ~~and pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors~~ at the FCC Unit, Dimersol Plant, ~~Liquid Fuel System~~, and Alkylation Plant shall be monitored within five (5) days by the method specified in 40 CFR §60.485a(b) if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method.
- b. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
- c. *When a leak is detected, it shall be repaired as soon as practicable, but not later than fifteen (15) calendar days after it is detected, except as provided in Special Condition No. C.8 of this attachment. The first attempt at repair shall be made no later than five (5) calendar days after each leak is detected.*
- d. First attempts at repair include, but are not limited to, the best practices described in Special Condition No. D.5.e of this attachment.

Commented [HL12]: Remains 10,000 ppm in GGGa

(Auth: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.59a2, §63.648)

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7. ~~Connectors in Gas/Vapor Service and in Light Liquid Service~~

Commented [HL13]: New section corresponding to 40 CFR 60.482-11a

a. ~~Each connector in gas/vapor service or in light liquid service at the FCC Unit, Dimersol Plant, Liquid Fuel System, and Alkylation Plant shall be monitored to detect leaks in accordance with the requirements set forth in 40 CFR §60.485a(b) and, as applicable, 60.485a(c).~~

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i. ~~The permittee shall initially monitor all connectors in each process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.~~

Commented [HL14]: We may be able to slim this down for the specific site.

ii. ~~The permittee shall perform monitoring, subsequent to the initial monitoring required in paragraph (i) above, as specified in paragraphs (1) through (3) of this section, and shall comply with the requirements of paragraphs (e) and (f) of this condition. The required period in which monitoring must be conducted shall be determined from paragraphs (1) through (3) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (g) of this condition.~~

(1) ~~If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).~~

(2) ~~If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. The permittee may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.~~

(3) ~~If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (iii) below.~~

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iii. ~~If the percent leaking connectors in the process unit was less than 0.25~~

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percent, then monitor as provided in paragraph (1) of this section and either paragraph (2) or (3) of this section, as appropriate.

(1) The permittee shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(2) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the permittee shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(3) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the permittee shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

b. If an instrument reading of 500 ppm or greater is measured, a leak is detected.

c. When a leak is detected, it shall be repaired as soon as practicable, but not later than fifteen (15) calendar days after it is detected, except as provided in Special Condition No. C.8 of this attachment. The first attempt at repair shall be made no later than five (5) calendar days after each leak is detected.

d. First attempts at repair include, but are not limited to, the best practices described in Special Condition No. D.5.e of this attachment.

e. If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

f. The permittee shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

g.

d. For use in determining the monitoring frequency, the percent leaking connectors as used in paragraph (a) of this condition shall be calculated by using the following equation:

$$\%CL = CL / Ct * 100$$

Where:

%CL= Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

CL= Number of connectors measured at 500 ppm or greater, by the method specified in §60.485a(b).

Ct= Total number of monitored connectors in the process unit or affected facility.

h. Any connector that is designated, as described in 40 CFR §60.486a(f)(1), as unsafe-to-monitor connector and satisfies the criteria outlined in 40 CFR §60.482-11a(e)(1), is exempt from the requirements of Special Condition No. D.7.a of this attachment.

i. Any connector that is designated, as described in 40 CFR §60.486a(f)(2), as difficult-to-monitor connector and satisfies the criteria outlined in 40 CFR §60.482-11a(e)(2) is exempt from the requirements of Special Condition No. D.7.a of this attachment.

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- l. Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of Special Condition No. D.7.a of this attachment, from the leak repair requirements of Special Condition No. D.7.c of this attachment, and from the recordkeeping and reporting requirements of §§63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in §60.482-11a(f)(1)(i) through (vi), as applicable.
- k. If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.
- l. Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of Special Condition No. D.7.j of this attachment, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

- 7.8. When each leak is detected, a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

- 8.9. The identification on a valve may be removed after it has been monitored for two (2) successive months as specified in Special Condition No. D.5.c of this attachment and no leak has been detected during those two (2) months. The identification on equipment except a valve may be removed after it has been repaired.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

- 9.10. When each leak is detected, the following information shall be recorded in a log and shall be kept for two (2) years in a readily accessible location:

- a. The instrument and operator identification numbers and the equipment identification number;
- b. The date the leak was detected and the dates of each attempt to repair the leak;
- c. Repair methods applied in each attempt to repair the leak;
- d. "Above 10,000" if the maximum instrument reading measured by the methods specified in 40 CFR §60.485(a) after each repair attempt is equal to or greater than 10,000 ppm;
- e. "Repair delayed" and the reason for the delay if a leak is not repaired within fifteen (15) calendar days after discovery of the leak;
- f. The signature of the permittee whose decision it was that repair could not be effected without a process shutdown;
- g. The expected date of successful repair of the leak if a leak is not repaired within fifteen (15) days;
- h. Dates of process unit shutdown that occur while the equipment is unrepaired; and
- i. The date of successful repair of the leak.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

~~10-11.~~ The following information pertaining to all equipment subject to the requirements of 40 CFR Part 60, Subpart GGG~~a~~, or 40 CFR Part 63, Subpart CC, shall be recorded in a log that is kept in a readily accessible location:

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- a. A list of identification numbers for all equipment;
- b. A list of identification numbers for equipment that are designated for no detectable emissions which is signed by the permittee;
- c. A list of equipment identification numbers for pressure relief devices required to comply with the requirements of Special Condition No. C.4 of this attachment;
- d. The dates of each compliance test used to determine no detectable emissions:
  - i. The background level measured during each compliance test; and
  - ii. The maximum instrument reading measured at the equipment during each compliance test.
- ~~e.~~ A list of identification numbers for equipment in vacuum service.
- ~~f.~~ A list of identification numbers for equipment that the permittee designates as operating in VOC service less than 300 hr/yr in accordance with §60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
- ~~g.~~ The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.
- ~~h.~~ Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and §60.485a(b).
- ~~i.~~ The connector monitoring schedule for each process unit as specified in §60.482-11a(b)(3)(v).
- ~~j.~~ Records of each release from a pressure relief device subject to §60.482-4a.
- ~~e.k.~~

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648~~a~~)<sup>1</sup>

~~11-12.~~ The following information pertaining to all valves subject to the requirements of 40 CFR Part 60, Subpart GGG, or 40 CFR Part 63, Subpart CC, shall be recorded in a log that is kept in a readily accessible location:

- a. A list of identification numbers for valves that are designated as unsafe-to-monitor, an explanation for each valve stating why the valve is unsafe-to-monitor, and the plan for monitoring each valve; and
- b. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.
- ~~c.~~ A schedule of monitoring for valves complying with §60.483-2a.
- ~~b-d.~~ The percent of valves found leaking during each monitoring period for valves complying with §60.483-2a.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)

~~12-13.~~ The following information shall be recorded in a log that is kept in a readily accessible location:

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- a. Design criterion based on design considerations and operating experience indicating the failure of the seal system, barrier fluid system, or both of each affected pump or compressor.
- b. Any changes to this criterion and the reasons for the changes.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

### **Section E. Notification and Reporting Requirements**

#### **1. Annual Emissions**

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate** or equivalent form, shall be used in reporting fugitive emissions.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions 14, 16, 17, and 25, respectively. These notifications shall include, but not be limited to:
- Anticipated date of initial start-up, actual date of construction commencement, and actual date of start-up;
  - Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report **within five (5) working days any deviations from permit requirements**, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

#### 4. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within **sixty (60) days** after the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. For valves, pumps, and compressors subject to the requirements of 40 CFR Part 60, Subpart GGG **and complying by demonstrating compliance with Subpart GGGa**, or 40 CFR Part 63, Subpart CC, the permittee shall submit **semi-annual** reports to the Department. 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)**. The initial semi-annual report shall include the following information:
  - a. Process unit identification;
  - b. Number of valves subject to the requirements of Special Condition No. D.5 of this attachment, excluding those valves designated for no detectable emissions under the provisions of Special Condition No. D.5.f of this attachment;
  - c. Number of pumps subject to the requirements of Special Condition No. D.2 of this attachment, excluding those pumps designated for no detectable emissions under the provisions of Special Condition No. D.2.g of this attachment and those pumps complying with Special Condition No. D.2.h of this attachment; and
  - d. Number of compressors subject to the requirements of Special Condition No. C.3 of this attachment, excluding those compressors designated for no detectable emissions under the provisions of Special Condition No. C.3.e of this attachment and those compressors complying with Special Condition No. C.3.d of this attachment.
  - d-e. **Number of connectors subject to the requirements of Special Condition No. D.7 of this attachment.**

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(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

6. All semi-annual reports, required in Special Condition No. E.5 of this attachment, shall include the following information:
- a. Process unit identification;
  - b. For each month during the semi-annual reporting period:
    - i. Number of valves for which leaks were detected;
    - ii. Number of valves for which leaks were not repaired;
    - iii. Number of pumps for which leaks were detected;
    - iv. Number of pumps for which leaks were not repaired;
    - v. Number of compressors for which leaks were detected;
    - vi. Number of compressors for which leaks were not repaired;
    - vii. ~~Number of connectors for which leaks were detected;~~
    - vi-viii. ~~Number of connectors for which leaks were not repaired;~~ and
    - vii-ix. ~~The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.~~
  - c. Dates of process unit shutdowns which occurred within the semi-annual reporting period; and
  - d. Revisions to items reported in the initial semi-annual report if changes have occurred since the initial report or subsequent revisions to the initial report.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

**Section F. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.  
<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.  
<sup>3</sup>This date is to be revised upon issuance of the renewal for CSP No. 0088-01-C

**ATTACHMENT II(B): SPECIAL CONDITIONS  
FLUID CATALYTIC CRACKING UNIT (FCCU)  
COVERED SOURCE PERMIT NO. 0863-02-C**

Issuance Date: XXXX XX, 2019

Expiration Date: XXXX XX, 2024

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the CSP encompasses the following equipment and associated appurtenances:
  - a. Catalyst transfer operations;
  - b. One (1) - Fluid Catalytic Cracking Unit (FCCU) which includes the Regenerator and Reactor:  
  
Particulate Control Devices:
    - i. Cyclone; and
    - ii. Electrostatic Precipitator (ESP), Manufacturer: Hamon Research Cottrell, Inc., Model No. 8883.
  - c. One (1) - 61 MMBtu/hr furnace identified as F-5300 equipped with Callidus Ultra Blue burners; and
  - d. One (1) - 52 MMBtu/hr FCC Startup Air Heater identified as F-5310, Manufacturer: John Zink, Model: Direct Fired Air Heater.

(Auth.: HAR §11-60.1-3)
2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.  
  

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The FCCU is subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):
    - i. Subpart A, General Provisions; and
    - ii. Subpart J, Standards of Performance for Petroleum Refineries.
  - b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories:



- i. Subpart A, General Provisions; and
- ii. Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.1, 40 CFR §60.100, 40 CFR §63.1561)<sup>1</sup>

2. The FCC Startup Air Heater is subject to the provisions of the following federal regulations:

40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

- a. Subpart A, General Provisions; and
- b. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.1, 40 CFR §60.100a)<sup>1</sup>

### **Section C. Operational and Emissions Limitations**

1. The F-5300 furnace shall be fired only on RFG with a H<sub>2</sub>S content not to exceed 230 mg/dscm (160 ppmv).

(Auth.: HAR §11-60.1-3, §11-60.1-38, §11-60.1-90, 40 CFR §60.104)<sup>1</sup>

2. The permittee shall take measures to control fugitive dust at all catalyst transfer operations. The Department at any time may require the permittee to further abate fugitive dust emissions if an inspection indicates poor or insufficient control.

(Auth.: HAR §11-60.1-3, §11-60.1-33, §11-60.1-90)

3. The permittee shall not cause the discharge of visible emissions of fugitive dust beyond the lot line of the property on which the emissions originate.

(Auth.: HAR §11-60.1-3, §11-60.1-33, §11-60.1-90)

4. The permittee shall maintain and operate the cyclone and electrostatic precipitator in a manner consistent with good air pollution control practices for minimizing emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

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5. The vacuum gas oil (VGO) processed by the FCCU shall not exceed the following feed rate and sulfur content limit:

- a. A maximum VGO feed rate of 22,000 bbls/day\*;
- b. A maximum sulfur content of VGO of 0.30% by weight\*\*.

\* Based on a rolling 365-day average

\*\*Based on a rolling seven-day (7-day) average, applicable at all times, including periods of startup, shutdown, and malfunctions

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.104, 40 CFR §60.108)<sup>1</sup>

6. Emission Limits

The permittee shall not discharge or cause the discharge from the FCCU emissions in excess of the following:

- a. PM Emission Limit: 1.0 pounds of PM per 1000 pounds (1.0 kg/Mg or 2.0 lb/ton) of coke burn-off in the catalyst regenerator (3-hr average)\*\*. Alternatively, during periods of startup, shutdown and hot standby, maintain the inlet velocity to the primary internal cyclones of the catalytic cracking unit catalyst regenerator at or above 20 feet per second for each hour during the startup, shutdown, or hot standby event or, for events lasting less than 1 hour, for the duration of the event;
- b. CO Emission Limit: 500 ppmvd @ 0% O<sub>2</sub> (1-hr average)\*\*. Alternatively, during periods of startup, shutdown and hot standby, maintain the oxygen (O<sub>2</sub>) concentration in the exhaust gas from the catalyst regenerator at or above 1 volume percent (dry basis);
- c. SO<sub>2</sub> Emission Limit: 25 ppmvd @ 0% O<sub>2</sub> (365-day rolling average)\* and 50 ppmvd @ 0% O<sub>2</sub> (7-day rolling average)\*\*;
- d. NO<sub>x</sub> Emission Limit: 50 ppmvd @ 0% O<sub>2</sub> (365-day rolling average)\* and 87.9 ppmvd @ 0% O<sub>2</sub> (7-day rolling average)\*\*.

\* Applicable at all times, including periods of startup, shutdown, and malfunctions.

\*\*Applicable at all times, excluding periods of startup, shutdown, and malfunctions.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, 40 CFR §60.102, 40 CFR §60.103, 40 CFR §63.1564, §63.1565)<sup>1</sup>

7. Visible Emissions (VE)

- a. For any six (6) minute averaging period, the FCCU shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during start-up, shutdown, or equipment breakdown, the FCCU may exhibit visible emissions not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.
- b. Maintain the 3-hour rolling average VE from the FCCU to no greater than twenty (20) percent opacity.
- b-c. For any six (6) minute averaging period, the F-5300 furnace shall not exhibit VE of forty (40) percent opacity or greater, except as follows: during start-up, shutdown, or equipment breakdown, the F-5300 furnace may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

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**Attachment II(B)**

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**Issuance Date: XXXX XX, 2019**

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(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-32, §11-60.1-90, SIP §11-60-24,  
40 CFR §60.102, 40 CFR §63.1564)<sup>1,2</sup>

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#### 8. Operation, Maintenance, and Monitoring Plan

The permittee must prepare and implement an operation, maintenance, and monitoring plan for the FCCU, air pollution control system, and continuous monitoring system. The purpose of this plan is to detail the operation, maintenance, and monitoring procedures to follow.

- a. The plan shall be submitted to the Department for review and approval along with the notification of compliance status. Any changes to the plan must be submitted for review and approved by the Department.
- b. Each plan must include the following information:
  - i. Process and control device parameters to be monitored for the FCCU, along with established operating limits.
  - ii. Procedures for monitoring emissions and process and control device operating parameters for the FCCU.
  - iii. Procedures to determine the coke burn-rate and the volumetric flow rate (if you use process data rather than direct measurement).
  - iv. Procedures and analytical methods used to determine the equilibrium catalyst Ni concentration, the equilibrium catalyst Ni concentration monthly rolling average, and the hourly or hourly average Ni operating value.
  - v. Procedures to determine the gas flow rate for a catalytic cracking unit if you use the alternative procedure based on air flow rate and temperature.
  - vi. Monitoring schedule, including when you will monitor and when you will not monitor the FCCU (e.g., during the coke burn-off, regeneration process).
  - vii. Quality control plan for each continuous opacity monitoring system and continuous emission monitoring system used to meet an emission limit in 40 CFR Part 63, Subpart UUU. This plan must include procedures for calibrations, accuracy audits, and adjustments to the system needed to meet applicable requirements for the system.
  - viii. Maintenance schedule for each monitoring system and control device for the FCCU that is generally consistent with the manufacturer's instructions for routine and long-term maintenance.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §63.1574)<sup>1</sup>

#### ~~9.—Startup, Shutdown, and Malfunction Plan (SSMP)~~

- ~~a.—The permittee shall develop and implement a written SSMP according to the provisions in 40 CFR §63.6(e)(3).~~
- ~~b.—During periods of startup, shutdown, and malfunction, the permittee must operate in accordance with the SSMP.~~

- ~~e. The permittee must report each instance in which each emission limitation and each operating limitation was not met. This includes periods of startup, shutdown, and malfunction. The permittee shall also report each instance in which the work practice standards were not met. These instances are deviations from the emission limitations and work practices. These deviations must be reported according to the requirements in 40 CFR §63.1576.~~
- ~~d. Consistent with 40 CFR §63.6(e) and 40 CFR §63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Department's satisfaction that you were operating in accordance with 40 CFR §63.6(e)(1). The SSMP must also include elements designed to minimize the frequency of such periods (i.e., root cause analysis). The Department will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in 40 CFR §63.6(e).~~

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §63.1570)<sup>1</sup>

#### 10.9. FCC Startup Air Heater

- a. The startup air heater may be utilized for up to twenty-two (22) days per year at maximum duty and shall only combust RFG or LPG.
- b. The startup air heater shall only combust gas that has a H<sub>2</sub>S content that does not exceed 162 ppmv determined hourly on a three-hour (3-hour) rolling average basis and sixty (60) ppmv determined daily on a 365 successive calendar day rolling average basis.

(Auth.: HAR §11-60.1-3, §11-60.1-38, §11-60.1-90, 40 CFR §60.102a(g)(1)(ii))<sup>1</sup>

#### 11-10. Electrostatic Precipitator (ESP)

- a. The ESP shall operate with total daily power above the minimum level, and with a minimum number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online).
- b. The ESP minimum total daily power input level and the minimum number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online) shall be established in the most recent PM source performance test conducted pursuant to Special Condition No. F.1 of this attachment.
- c. Except during periods of startup, shutdown, and malfunction, if the ESP total daily power input level falls below the level measured in the most recent PM source performance test conducted pursuant to Special Condition No. F.1 of this attachment that demonstrated compliance with the three-hour (3-hour) average PM emission limit in Special Condition No. C.6.a of this attachment, the permittee may perform a retest of the PM source performance test within 120 days to establish a new ESP minimum total daily power input level and a new minimum number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online).

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

**Section D. Monitoring and Recordkeeping Requirements**

1. All records, including support information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Support information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

2. Vacuum Gas Oil (VGO)
  - a. The permittee shall monitor the feed rates (in barrels per day) of the VGO processed by the FCCU. Records shall be kept on a rolling 365-day average basis.
  - b. Compliance with the maximum sulfur content limit for the fresh feed (VGO) is determined daily on a rolling seven-day (7-day) average basis using the following analytical methods and calculation procedures outlined below:
    - i. One (1) fresh feed sample shall be collected once per eight-hour (8-hour) period.
    - ii. Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods:

ASTM D129-64, 78, or 95, ASTM D1552-83 or 95, ASTM D2622-87, 94, or 98, or ASTM D1266-87, 91, or 98. (These methods are incorporated by reference: see 40 CFR §60.17). The applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Department.
    - iii. If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:
      - (1) Individual samples shall be collected once per eight-hour (8-hour) period for each separate fresh feed stream charged directly into the riser or reactor of the FCCU. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.
      - (2) Each fresh feed sample shall be analyzed separately using the methods specified in Special Condition No. D.2.b.ii of this attachment.

- (3) Fresh feed sulfur content shall be calculated for each eight-hour (8-hour) period using the following equation:

$$S_f = \sum_{i=1}^n S_i Q_i / Q_f$$

where:

$S_f$  = fresh feed sulfur content expressed in percent by weight of fresh feed.

$n$  = number of separate fresh feed streams charged directly to the riser or reactor of the FCCU.

$Q_f$  = total volumetric flow rate of fresh feed charged to the FCCU.

$S_i$  = fresh feed sulfur content expressed in percent by weight of fresh feed for the "ith" sampling location.

$Q_i$  = volumetric flow rate of fresh feed stream for the "ith" sampling location.

- iv. Calculate a seven-day (7-day) average (arithmetic mean) sulfur content of the fresh feed using all of the fresh feed sulfur content values obtained during seven (7) successive twenty-four-hour (24-hour) periods.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

### 3. Visible Emissions (VE)

- a. Except in those months where VE observations are conducted by a certified reader for the annual observations of the F-5300 furnace, the permittee shall conduct monthly (*calendar month*) VE observations for the F-5300 furnace in accordance with 40 CFR Part 60, Appendix A, Method 9, or by use of a Ringelmann Chart, as provided. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals for the F-5300 furnace. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.
- b. The permittee shall conduct annually (*calendar year*) VE observations for the F-5300 furnace by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9. For the annual observations, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals for the F-5300 furnace. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.
- c. Upon written request and justification, the Department may waive the requirements for the annual VE observations. The waiver request is to be submitted prior to the required annual VE observations and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior VE observations indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous annual VE observations. The annual VE observations shall not be waived for more than two (2) consecutive years.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90; SIP §11-60-15, SIP §11-60-24)<sup>2</sup>

4. Continuous Emissions Monitoring System (CEMS) for CO

- a. The permittee shall install, operate and maintain a CEMS for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions from the FCCU.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is 1,000 ppm CO.
  - ii. Performance evaluations for the CO CEMS shall be in accordance with 40 CFR §60.13 and §63.8. The CO CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 4, Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 10, shall be used in conducting any RATA.
  - iii. CGA shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.
  - iv. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105, 40 CFR §63.1572)<sup>1</sup>

5. Continuous Monitoring System (CMS) for H<sub>2</sub>S

- a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned.
- b. The CMS shall meet the following requirements:
  - i. The span value for the CMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
  - ii. All fuel gas combustion devices having a common source of fuel gas may be monitored at one (1) location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.
  - iii. Performance evaluations for the H<sub>2</sub>S CMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 7, Specifications and Test Procedures for Hydrogen Sulfide Continuous Emissions Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11, 15, 15A, or 16, shall be used in conducting any RATA.
  - iv. CGA shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.
  - v. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105)<sup>1</sup>



6. Continuous Emissions Monitoring System (CEMS) for O<sub>2</sub>

- a. The permittee shall install, operate and maintain a CEMS for continuously monitoring and recording the concentration by volume (dry basis) of O<sub>2</sub> emissions from the FCCU.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is twenty-five (25) percent O<sub>2</sub>.
  - ii. Performance evaluations for the O<sub>2</sub> CEMS shall be in accordance with 40 CFR §60.13 and §63.8. The O<sub>2</sub> CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 3, Specifications and Test Procedures for O<sub>2</sub> and CO<sub>2</sub> Continuous Emission Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 3A or 3B, shall be used in conducting any RATA.
  - iii. CGA shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2. In lieu of the audit points specified in 40 CFR Part 60, Appendix F, Section 5.1.2, the permittee may audit the O<sub>2</sub> CEMS at twenty (20) to thirty (30) percent and fifty (50) to sixty (60) percent of the actual O<sub>2</sub> CEMS span value.
  - iv. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105, 40 CFR §63.1572)<sup>1</sup>

7. Continuous Emissions Monitoring System (CEMS) for SO<sub>2</sub>

- a. The permittee shall install, operate, and maintain a CEMS for continuously monitoring and recording the concentration by volume (dry basis) of SO<sub>2</sub> emissions from the FCCU.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is 50 ppm SO<sub>2</sub>.
  - ii. Performance evaluations for the SO<sub>2</sub> CEMS shall be in accordance with 40 CFR §60.13. The SO<sub>2</sub> CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 2, Specifications and Test Procedures for SO<sub>2</sub> and NO<sub>x</sub> Continuous Emission Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 6, 6A, or 6B shall be used in conducting any RATA. In lieu of the requirements of 40 CFR Part 60, Appendix F, Sections 5.1.1, 5.1.3, and 5.1.4, the permittee must conduct either a Relative Accuracy Audit (RAA) or a RATA at least once every three (3) years. The permittee shall conduct a CGA each calendar quarter during which a RAA or a RATA is not performed.
  - iii. CGA shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.
  - iv. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105)<sup>1</sup>

8. Continuous Emissions Monitoring System (CEMS) for NO<sub>x</sub>

- a. The permittee shall install, operate and maintain a CEMS for continuously monitoring and recording the concentration by volume (dry basis) of NO<sub>x</sub> emissions from the FCCU.
- b. The CEMS shall meet the following requirements:
  - i. Performance evaluations for the NO<sub>x</sub> CEMS shall be in accordance with 40 CFR §60.13. The NO<sub>x</sub> CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 2, Specifications and Test Procedures for SO<sub>2</sub> and NO<sub>x</sub> Continuous Emission Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, or 7E shall be used in conducting any RATA. In lieu of the requirements of 40 CFR Part 60, Appendix F, Sections 5.1.1, 5.1.3, and 5.1.4, the permittee must conduct either a RAA or a RATA at least once every three (3) years. The permittee shall conduct a CGA each calendar quarter during which a RAA or a RATA is not performed.
  - ii. CGA shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.
  - iii. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

9. Continuous Opacity Monitoring System (COMS) for Opacity

The permittee shall install, operate and maintain a COMS for continuously measuring and recording the opacity levels of stack emissions from the FCCU. The system shall meet U.S. EPA monitoring performance standards (40 CFR §60.13; 40 CFR §63.8; and 40 CFR Part 60, Appendix B, Performance Specification 1, Specifications and test procedures for continuous opacity monitoring systems in stationary sources and Appendix F, Procedure 3, Quality Assurance Requirements for Continuous Opacity Monitoring Systems at Stationary Sources). The instrument shall be spanned at sixty (60), seventy (70), or eighty (80) percent opacity. As specified in 40 CFR §63.8(c)(4)(i), each continuous opacity monitoring system must complete a minimum of one (1) cycle of sampling and analyzing for each successive ten-second (10-second) period and one (1) cycle of data recording for each successive six-minute (6-minute) period.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105, 40 CFR §63.1572)<sup>1</sup>

10. The following records must be kept:

- a. A copy of each notification and report that was submitted to comply with 40 CFR Part 63, Subpart UUU, including all documentation supporting any initial notification or Notification of Compliance Status that was submitted, according to the requirements in 40 CFR §63.10(b)(2)(xiv).

**Commented [AD22]:** The emission limit for particulate from the FCCU included the alternative operating limit on gas flow rate during periods of startup, shutdown, or hot standby. If electing this limit, there should also be a requirement to operate a continuous parameter monitoring system to measure and record the gas flow rate exiting the catalyst regenerator per MACT UUU Table 3 Item 12 and 63.1564(c)(5).

The gas flow monitoring is mentioned under Condition 8 b v of this permit as needing to be included in the operating plan, but not as a direct requirement anywhere.

- b. The records in 40 CFR §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.
- c. Records of performance tests, performance evaluations, and opacity and visible emission observations as required in 40 CFR §63.10(b)(2)(viii).
- d. For each continuous emission monitoring system and continuous opacity monitoring system:
  - i. Records described in 40 CFR §63.10(b)(2)(vi) through (xi).
  - ii. Monitoring data for continuous opacity monitoring systems during a performance evaluation as required in 40 CFR §63.6(h)(7)(i) and (ii).
  - iii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR §63.8(d)(3).
  - iv. Requests for alternatives to the relative accuracy test for continuous emission monitoring systems as required in 40 CFR §63.8(f)(6)(i).
  - v. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.
- e. Records in 40 CFR §63.6(h) for VE observations.
- f. A current copy of the operation, maintenance, and monitoring plan onsite and available for inspection. Also records to show continuous compliance with the procedures in the operation, maintenance, and monitoring plan.
- g. Records of any changes that affect emission control system performance.
- h. The average coke burn-off rate (Mg or tons per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to 40 CFR §60.102, 40 CFR §60.103, or 40 CFR §60.104(b)(2).
- i. Data obtained from the daily feed sulfur tests.
- j. Each rolling seven-day (7-day) average compliance determination for sulfur content of the feed.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105, 40 CFR §60.107, 40 CFR §63.1576)<sup>1</sup>

#### 11. FCC Startup Air Heater

- a. The permittee shall maintain records as described in 40 CFR §60.108a(a).
- b. The permittee shall maintain a record of the number of days of operation of the unit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, 40 CFR §60.108a)<sup>1</sup>

#### 12. Electrostatic Precipitator (ESP)

- a. The permittee shall install, operate, and maintain a continuous monitoring and recording system to accurately measure and record the voltage and current for each ESP electrical grid field. The ESP's continuous monitoring and recording system shall be maintained pursuant to Special Condition No. C.8(b)(viii) of this attachment.

- b. Daily averages for these parameters must be recorded and maintained for total daily power input level determination. Total daily power is determined by summing the individual ESP electrical grid field power inputs (power = voltage x current).
- c. The permittee shall maintain records of the total daily power input level and number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online). Total daily power input level shall be determined from the voltage and current recorded pursuant to Special Condition No. D.12.b of this attachment.
- d. The permittee shall maintain records of the dates of operation when the monitored parameters averaged on a daily basis, are below the minimum levels of the ESP parameters listed above, which were established in the most recent PM performance testing conducted pursuant to Special Condition No. F.1 of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

#### **Section E. Notification and Reporting Requirements**

##### **1. Annual Emissions**

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit on an annual basis the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate and Annual Emissions Report Form: Refinery Equipment - Fuel Consumption**, or equivalent forms, shall be used in reporting the FCCU feed rate and the fuel consumption of Furnace F-5300, respectively.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

##### **2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions 16, 17, and 25, respectively. These notifications shall include, but not be limited to:**

- a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
- b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- c. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report within five (5) working days any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. Compliance Certification

- a. During the permit term, the permittee shall submit at least annually to the Department and U.S. EPA, Region 9, the attached Compliance Certification Form, pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
- i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedance as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department including information to determine compliance.
- b. The compliance certification shall be submitted within sixty (60) days after the end of each calendar year and shall be signed and dated by a responsible official.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. The permittee shall submit **semi-annually** written reports to the Department for monitoring purposes. The permittee shall submit a signed statement certifying the accuracy and completeness of the information contained in the report. The reports for Special Conditions Nos. E.5.a, E.5.b, and E.5.c of this attachment 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 the reports for Special Conditions Nos. E.5.d thru E.5.h of this attachment shall be submitted **within thirty (30) 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. The VGO data consisting of the following:
    - i. The maximum VGO feed rate (bbls/day) processed by the FCCU on a rolling 365-day average basis;
    - ii. The maximum sulfur content (% by weight) of the VGO on a rolling seven-day (7-day) average basis; and
    - iii. Any VGO exceedances as determined by the required VGO monitoring. Each exceedance reported shall include the date the exceedance occurred and the possible reason for the exceedance.

The enclosed **Monitoring Report Form: Vacuum Gas Oil (VGO)**, or an equivalent form, shall be used for reporting.

- b. Any opacity exceedances as determined by the required VE monitoring for the F-5300 furnace. 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 there were no exceedances for that semi-annual period.

The enclosed **Monitoring Report Form: Opacity Exceedances** shall be used for reporting.

- c. Any deviations from permit requirements shall be clearly identified.
- d. Any seven-day (7-day) period during which the average sulfur content of the fresh feed exceeds 0.30 percent by weight. The fresh feed sulfur content on a rolling seven-day (7-day) average, shall be determined using the procedures specified in Special Condition No. D.2.b of this attachment.
- e. For each seven-day (7-day) period during which an exceedance has occurred as defined in Special Condition No. E.5.d of this attachment:
  - i. The date that the exceedance occurred;
  - ii. An explanation of the exceedance;
  - iii. Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and
  - iv. A description of the corrective action taken, if any.

- f. For each eight-hour (8-hour) period in which a feed sulfur measurement required by Special Condition No. D.2.b of this attachment was not obtained, the date for which, and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Department.
- g. Compliance Report

The compliance report must contain the following information:

- i. Company name and address.
- ii. Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.
- iii. Date of report and beginning and ending dates of the reporting period.
- iv. If there are no deviations from any emission limitations that applies and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations or work practice standards during the reporting period and that no continuous emission monitoring system or continuous opacity monitoring system was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.
- v. For each deviation from an emission limitation occurring at the FCCU where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the following information:
  - (1) The total operating time of the FCCU during the reporting period.
  - (2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable) as applicable, and the corrective action taken.
  - (3) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero (0) and span and other daily calibration checks).
  - (4) The date and time that each malfunction started and stopped.
  - (5) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was inoperative, except for zero (low-level) and high level checks.
  - (6) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was out-of-control, including the information in 40 CFR §63.8(c)(8).
  - (7) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.
  - (8) A summary of the total duration of the deviation during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging period specified in the regulation for other types of emission limitations), and the total duration as a percent of the total source operating time during the reporting period.
  - (9) A breakdown of the total duration of the deviations during the reporting period and into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

- (10) A summary of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging time specified in the regulation for other types of standards), and the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system as a percent of the total source operating time during that reporting period.
- (11) A breakdown of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period into periods that are due to monitoring equipment malfunctions, non-monitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.
- (12) An identification of each HAP that was monitored at the FCCU.
- (13) A brief description of the process units.
- (14) The monitoring equipment manufacturer(s) and model number(s).
- (15) The date of the latest certification or audit for the continuous opacity monitoring system or continuous emission monitoring system.
- (16) A description of any change in the continuous emission monitoring system or continuous opacity monitoring system, processes, or controls since the last reporting period.
- (17) A copy of any performance test done during the reporting period on the FCCU. The report may be included in the next semi-annual report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, the permittee must submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief process description; a simplified flow diagram showing affected processes, control equipment, and sampling point locations; sampling site data; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions during the test; record of preparation of standards; record of calibrations; raw data sheets for field sampling; raw data sheets for field and laboratory analyses; documentation of calculations; and any other information required by the test method.
- (18) Any requested change in the applicability of an emission standard in the periodic report. The permittee must include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements.
- (19) When actions taken to respond are consistent with the startup, shutdown and malfunction plan, the permittee is not required to report these events in the semi-annual compliance report and the reporting requirement in 40 CFR §63.6(e)(3)(iii) and 40 CFR §63.10(d)(5) do not apply.



- (20) When actions taken to respond are not consistent with the startup, shutdown, and malfunction plan, the permittee must report these events and the response taken in the semi-annual compliance report. In this case, the reporting requirements in 40 CFR §63.6(e)(3)(iv) and 40 CFR §63.10(d)(5) do not apply.

h. Excess Emissions Report

- i. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department and the U.S. EPA for every **semi-annual calendar period**. The report shall include the following information:
- (1) The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period;
  - (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the FCCU and F-5300 furnace. The nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted;
  - (3) The date and time identifying each period during which the continuous emissions monitoring system was inoperative except for zero (0) and span checks. The nature of each system repair or adjustment shall be described; and
  - (4) The report shall so state if no excess emissions have occurred. Also, the report shall so state if the CEMS operated properly during the period and was not subject to any repairs or adjustments except for zero (0) and span checks.
- ii. All reports shall be postmarked by the thirtieth (30<sup>th</sup>) day following the end of each **semi-annual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form shall also be submitted in addition to the excess emissions and monitoring systems performance report.
- iii. For purposes of reports under 40 CFR §60.7(c), periods of excess emissions for the FCCU and F-5300 furnace that shall be determined and reported are defined as follows:
- (1) **Opacity**. All one-hour (1-hour) periods that contain two (2) or more 6-minute (six-minute) periods during which the average opacity, as measured by the continuous opacity monitoring system, exceeds twenty (20) percent.
  - (2) **Carbon Monoxide**. All one-hour (1-hour) periods during which the average CO concentration, as measured by the CO continuous monitoring system under 40 CFR §60.105(a)(2), exceeds 500 ppmvd @ 0% O<sub>2</sub>.

- (3) H<sub>2</sub>S. All rolling three-hour (3-hour) periods during which the average concentration of H<sub>2</sub>S in RFG, as measured by the H<sub>2</sub>S continuous emissions monitoring system, exceeds 230 mg/dscm (160 ppmv).
- (4) Sulfur Dioxide. All rolling 365-day periods during which the average SO<sub>2</sub> concentration, as measured by the SO<sub>2</sub> continuous emissions monitoring system, exceeds twenty-five (25) ppmvd @ 0% O<sub>2</sub> and all rolling seven-day (7-day) periods during which the average SO<sub>2</sub> concentration, as measured by the SO<sub>2</sub> continuous emissions monitoring system, exceeds fifty (50) ppmvd @ 0% O<sub>2</sub>.
- (5) Nitrogen Oxides. All rolling 365-day periods during which the average NO<sub>x</sub> concentration, as measured by the NO<sub>x</sub> continuous emissions monitoring system, exceeds fifty (50) ppmvd @ 0% O<sub>2</sub> and all rolling seven-day (7-day) periods during which the average NO<sub>x</sub> concentration, as measured by the NO<sub>x</sub> continuous emissions monitoring system, exceeds 87.9 ppmvd @ 0% O<sub>2</sub>.

iv. Excess emissions indicated by the CEMS shall be considered violations of the applicable emission and concentration limits for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-32, §11-60.1-90, SIP §11-60-24, 40 CFR §60.105, 40 CFR §60.107, 40 CFR §63.1575)<sup>1</sup>

6. At least **thirty (30) days** prior to the following events, the permittee shall notify the Department in writing of:
  - a. Conducting a performance specification test on any of the CEMS (CO, SO<sub>2</sub>, NO<sub>x</sub>, O<sub>2</sub> or H<sub>2</sub>S) or COMS (opacity).
  - b. Conducting a source performance test as required by this Attachment, Section F, Testing Requirements.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.105, 40 CFR §60.106)<sup>1</sup>

#### **Section F. Testing Requirements**

1. The permittee shall conduct or cause to be conducted annual performance tests for the FCCU, except for the opacity testing specified in Special Condition No. F.3.d of this attachment, which is only required to be conducted initially. Performance tests shall be conducted for CO and PM. All performance tests shall be conducted at the maximum production rate of the FCCU and at the maximum VGO feed rate, or at other production rates as may be specified by the Department. The following ESP parameters shall be monitored and recorded and minimum levels established during the testing for PM demonstrating compliance with the three-hour (3-hour) average PM emission limit in Special Condition No. C.6.a of this attachment.
  - a. Voltage in each ESP electrical grid field;
  - b. Current in each ESP electrical grid field; and

c. Number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

2. Performance tests for the emissions of CO and PM shall be conducted in accordance with the test methods set forth in 40 CFR Part 60, Appendices A-1 through A-8. Only the test methods specified in Special Condition Nos. F.3 and F.4 of this attachment, or U.S. EPA-approved equivalent methods with prior written approval from the Department shall be used.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

3. The permittee shall determine compliance with the PM standards in 40 CFR §60.102(a) as follows:

a. The emission rate (E) of PM shall be computed for each run using the following equation:

$$E = C_s Q_{ed} / K R_c$$

Where:

E = Emission rate of PM, kg/Mg (lb/ton) of coke burn-off.  
 C<sub>s</sub> = Concentration of PM, gr/dscm (gr/dscf).  
 Q<sub>ed</sub> = Volumetric flow rate of effluent gas, dscm/hr (dscf/hr).  
 R<sub>c</sub> = Coke burn-off rate, Mg/hr (ton/hr) coke.  
 K = Conversion factor, 1000 g/kg (7000 gr/lb).

b. Method 5B or 5F is to be used to determine the PM emissions and associated moisture content from affected facilities without wet FGD systems. The sampling time for each run shall be at least sixty (60) minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Department when process variables or other factors preclude sampling for at least sixty (60) minutes.

c. The coke burn-off rate (R<sub>c</sub>) shall be computed for each run using the following equation:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) - (K_2 Q_a - K_3 Q_r) ((\%CO/2) + (\%CO_2 + \%O_2))$$

Where:

R<sub>c</sub> = Coke burn-off rate, Mg/hr (ton/hr)  
 Q<sub>r</sub> = Volumetric flow rate of exhaust gas from catalyst regenerator before entering the emission control system, dscm/min (dscf/min).  
 Q<sub>a</sub> = Volumetric flow rate of air to FCCU regenerator, as determined from the FCCU control room instrumentation, dscm/min (dscf/min).  
 %CO<sub>2</sub> = carbon dioxide concentration, percent by volume (dry basis).  
 %CO = carbon monoxide concentration, percent by volume (dry basis).  
 %O<sub>2</sub> = Oxygen concentration, percent by volume (dry basis).  
 K<sub>1</sub> = Material balance and conversion factor, 2.982 x 10<sup>-4</sup> (Mg-min)/(hr-dscm-%) [9.31 x 10<sup>-6</sup> (ton-min)/(hr-dscf-%)].  
 K<sub>2</sub> = Material balance and conversion factor, 2.088 x 10<sup>-3</sup> (Mg-min)/(hr-dscm-%) [6.52 x 10<sup>-5</sup> (ton-min)/(hr-dscf-%)].  
 K<sub>3</sub> = Material balance and conversion factor, 9.94 x 10<sup>-4</sup> (Mg-min)/(hr-dscm-%) [3.1 x 10<sup>-6</sup> (ton-min)/(hr-dscf-%)].

- i. Method 2 shall be used to determine the volumetric flow rate ( $Q_r$ ).
- ii. The emission correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine CO<sub>2</sub>, CO, and O<sub>2</sub> concentrations.

d. Method 9 and the procedures of 40 CFR §60.11 shall be used to determine opacity.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

4. The permittee shall determine compliance with the CO standard in 40 CFR §60.103(a) by using the integrated sampling or continuous sampling technique of Method 10 to determine the CO concentration (dry basis). The sampling time for each run shall be sixty (60) minutes.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

5. Each source performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>

6. The permittee shall provide sampling and testing facilities at its own expense. The tests shall be conducted at the operating capacities identified in Special Condition No. F.1 of this attachment. The Department may monitor any of the required source performance tests.

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

7. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

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

8. At least thirty (30) days prior to performing a test, the permittee shall submit a written source performance test plan to the Department and U.S. EPA that describes the test date(s), test duration, test locations, test method, source operation, fuel consumption, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A source performance test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>

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Issuance Date: November 16, 2018  
Expiration Date: February 1, 2004<sup>3</sup>

9. Within sixty (60) days after completion of the source performance test, the permittee shall submit to the Department and U.S. EPA, the test report which shall include the operating conditions of the FCCU at the time of the test, the ESP parameters used to establish the minimum total daily power input level and minimum number of ESP electrical grid fields energized (transformer/rectifier (TR) sets online), the analysis of the VGO, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>

10. The Department may waive a specific performance test upon prior written request of the permittee. Such a request would need to be justified on the grounds that prior tests had shown compliance by a wide margin, adequate means exist to show continuing compliance, and operations of the source have not changed since the previous source test. The source performance test shall not be waived for more than two consecutive years.

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>

#### **Section G. Agency Notifications**

Any document (including reports) required to be submitted by this CSP shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90,

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

<sup>3</sup>This date is to be revised upon issuance of the renewal for CSP No. 0088-01-C.

**ATTACHMENT IV: ANNUAL EMISSIONS REPORTING REQUIREMENTS  
COVERED SOURCE PERMIT NO. 0863-02-C**

Issuance Date: XXXX XX, 2019

Expiration Date: XXXX XX, 2024

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department the nature and amounts of emissions.

1. Complete the attached forms:

**Annual Emissions Report Form: FCCU Fuel Consumption; and  
Annual Emissions Report Form: FCCU, Dimersol, and Alkylation Unit  
Process Rates;**

2. The reporting period shall be from January 1 to December 31 of each year. All reports shall be submitted to the Department within sixty (60) days after the end of each calendar year and shall be mailed to the following address:

**State of Hawaii  
Clean Air Branch  
2827 Waimano Home Road #130  
Pearl City, HI 96782**

3. The permittee shall retain the information submitted, including all emission calculations. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department upon request.
4. Any information submitted to the Department without a request for confidentiality shall be considered public record.
5. In accordance with HAR, Section 11-60.1-14, the permittee may request confidential treatment of specific information, including information concerning secret processes or methods of manufacture, by submitting a written request to the Director and clearly identifying the specific information that is to be accorded confidential treatment.

<sup>1</sup>This date is to be revised upon issuance of the renewal for CSP No. 0088-01-C.

**ANNUAL EMISSIONS REPORT FORM  
FCCU FUEL CONSUMPTION  
COVERED SOURCE PERMIT NO. 0863-02-C**

Issuance Date: XXXX XX, 2019

Expiration Date: XXXX XX, 2024

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department the nature and amounts of emissions.

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as Horsepower, kilowatt, tons/hour, Btu/hr, etc.)

Serial/ID No.: \_\_\_\_\_

Responsible Official (PRINT): \_\_\_\_\_

Title: \_\_\_\_\_

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

Responsible Official (Signature): \_\_\_\_\_

Type of Fuel Fired	Fuel Usage Barrels/yr or Ft <sup>3</sup> /yr	% Sulfur Content by weight	Identify % Nitrogen, % Ash, & % Lead, if applicable

Types of Fuel:      • Residual Oil: Specify Grade, No. 6, 5, or 4.      • Fuel Oil Reclaimed or Spec Used Oil.  
                          • Distillate Oil (No. 2)      • If Other, specify  
                          • Liquefied Petroleum Gas, Butane or Propane.

Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency, % Reduction
_____	Yes or No	_____	_____
_____	Yes or No	_____	_____
_____	Yes or No	_____	_____

**ANNUAL EMISSIONS REPORT FORM  
FCCU, DIMERSOL, AND ALKYLATION EQUIPMENT - PROCESS RATE  
COVERED SOURCE PERMIT NO. 0088-01-C**

Issuance Date: XXXX XX, 2019

Expiration Date: XXXX XX, 2024

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department the nature and amounts of emissions.

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as Horsepower, kilowatt, tons/hour, Blu/hr, etc.)

Serial/ID No.: \_\_\_\_\_

Responsible Official (PRINT): \_\_\_\_\_

Title: \_\_\_\_\_

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

Responsible Official (Signature): \_\_\_\_\_

EMISSION SOURCE <sup>1</sup>	ANNUAL PROCESS RATE <sup>2</sup>	NOTES

<sup>1</sup>Specify emission source. For example, list FCCU, cooling tower, oil/water separator, valves, flanges, compressor seals, etc.

<sup>2</sup>Specify annual process rate. For example, list bbls refinery feed/yr, gallons cooling water/yr, gallons wastewater/yr, etc.



**MONITORING REPORT FORM  
VACUUM GAS OIL (VGO)  
COVERED SOURCE PERMIT NO. 0863-02-C  
(PAGE 1 OF 2)**

Issuance Date: XXXX XX, 2019

Expiration Date: XXXX XX, 2024

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department the following on a semi-annual basis:

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_

Serial/ ID No.: \_\_\_\_\_

Responsible Official (PRINT): \_\_\_\_\_

Title: \_\_\_\_\_

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

Responsible Official (Signature): \_\_\_\_\_

1. Maximum VGO Feed Rate: Report the maximum total VGO feed rate (bbls/day) during the reporting period based on a rolling 365-day average: \_\_\_\_\_
  
2. Maximum VGO Sulfur Content: Report the maximum weight percent of sulfur in the VGO during the reporting period based on a rolling seven-day (7-day) average:  
\_\_\_\_\_





**EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE  
SUMMARY REPORT**

(PAGE 1 OF 2)

(Make Copies for Future Use)

Facility Name \_\_\_\_\_  
Equipment Location \_\_\_\_\_  
Equipment Description: \_\_\_\_\_  
Serial/Unit ID No.: \_\_\_\_\_  
Covered Source Permit No.: \_\_\_\_\_ Condition No.: \_\_\_\_\_  
PSD Permit No.: \_\_\_\_\_ Condition No.: \_\_\_\_\_  
Code of Federal Regulations (CFR): \_\_\_\_\_  
Pollutant Monitored: \_\_\_\_\_  
From: Date \_\_\_\_\_ - Time \_\_\_\_\_  
To: Date \_\_\_\_\_ - Time \_\_\_\_\_  
Emission Limit: \_\_\_\_\_  
Date of Last CEMS Certification/Audit . . . . . \_\_\_\_\_  
Total Source Operating Time . . . . . \_\_\_\_\_

**EMISSION DATA SUMMARY**

1. Duration (Hours/Periods) of Excess Emissions in Reporting Period due to:
  - a. Start-Up/Shutdown . . . . . \_\_\_\_\_
  - b. Cleaning/Soot Blowing . . . . . \_\_\_\_\_
  - c. Control Equipment Failure . . . . . \_\_\_\_\_
  - d. Process Problems . . . . . \_\_\_\_\_
  - e. Other Known Causes . . . . . \_\_\_\_\_
  - f. Unknown Causes . . . . . \_\_\_\_\_
  - g. Fuel Problems . . . . . \_\_\_\_\_
- Number of incidents of excess emissions . . . . . \_\_\_\_\_
2. Total Duration of Excess Emissions . . . . . \_\_\_\_\_
3. Total Duration of Excess Emissions  
(% of Total Source Operating Time) . . . . . \_\_\_\_\_

**CEMS PERFORMANCE SUMMARY**

1. CEMS Downtime (Hours/Periods) in Reporting Period Due to:
  - a. Monitor Equipment Malfunctions . . . . . \_\_\_\_\_
  - b. Non-Monitor Equipment Malfunctions . . . . . \_\_\_\_\_
  - c. Quality Assurance Calibration . . . . . \_\_\_\_\_
  - d. Other Known Causes . . . . . \_\_\_\_\_
  - e. Unknown Causes . . . . . \_\_\_\_\_
- Number of incidents of monitor downtime . . . . . \_\_\_\_\_
2. Total CEMS Downtime . . . . . \_\_\_\_\_
3. Total CEMS Downtime  
(% of Total Source Operating Time) . . . . . \_\_\_\_\_

**EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE  
SUMMARY REPORT  
(PAGE 2 OF 2)**

**CERTIFICATION by Responsible Official**

Responsible Official (Print): \_\_\_\_\_

Title: \_\_\_\_\_

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

Responsible Official (Signature): \_\_\_\_\_

**VISIBLE EMISSIONS FORM REQUIREMENTS  
STATE OF HAWAII  
COVERED SOURCE PERMIT NO. 0863-02-C**

Issuance Date: XXXX XX, 2019

Expiration Date: XXXX XX, 2024

The following Visible Emissions (VE) Form shall be completed **monthly** (*each calendar month*) for each equipment subject to opacity limits in accordance with Method 9 or by use of a Ringelmann Chart as provided. At least **annually** (*calendar year*), VE observations shall be conducted for each equipment subject to opacity limits by a certified reader in accordance with Method 9. The VE Form shall be completed as follows:

1. Visible emissions observations shall take place during the day only and shall be compared to the Ringelmann Chart provided. The opacity shall be noted in five (5) percent increments (i.e., 25%).
2. Orient the sun within a one hundred forty (140) degree sector to your back. Provide a source layout sketch on the VE Form using the symbols as shown.
3. Stand at least three (3) stack heights, but not more than a quarter mile from the stack.
4. Two (2) observations shall be taken at fifteen (15) second intervals for six (6) consecutive minutes for each equipment.
5. The six (6) minute average opacity reading shall be calculated for each observation.
6. If possible, the observations shall be performed as follows:
  - a. Read from where the line of sight is at right angles to the wind direction.
  - b. The line of sight shall not include more than one (1) plume at a time.
  - c. Read at the point in the plume with the greatest opacity (without condensed water vapor), ideally while the plume is no wider than the stack diameter.
  - d. Read the plume at fifteen (15) second intervals only. Do not read continuously.
  - e. The equipment shall be operating at maximum permitted capacity.
7. If the equipment was shut-down for that period, briefly explain the reason for shut-down in the comment column.

The permittee shall retain the completed VE Forms for recordkeeping. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department of Health, or their representative upon request.

**VISIBLE EMISSIONS FORM  
STATE OF HAWAII  
COVERED SOURCE PERMIT NO. 0863-02-C**

Issuance Date: XXXX XX, 2018

Expiration Date: XXXX XX, 2024

Permit No: \_\_\_\_\_

Company Name: \_\_\_\_\_

Equipment and Fuel: \_\_\_\_\_

**Site Conditions:**

Stack height above ground (ft): \_\_\_\_\_

Stack distance from observer (ft): \_\_\_\_\_

Emission color: black / white

Sky conditions (% cloud cover): \_\_\_\_\_

Wind speed (mph): \_\_\_\_\_

Temperature (EF): \_\_\_\_\_

Observer Name: \_\_\_\_\_

Certified? Yes / No

Observation Date and Time: \_\_\_\_\_

Stack   
Sun   
Wind



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SEC. MIN.	0	15	30	45	COMMENTS
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%)					

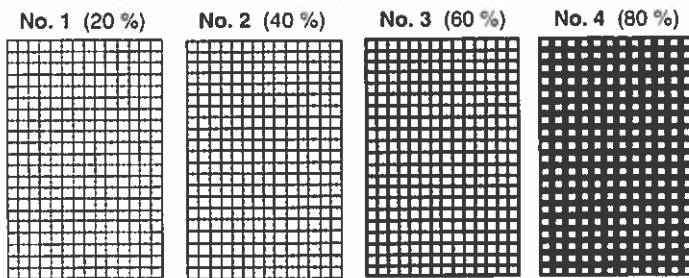
Observation Date and Start Time: \_\_\_\_\_

SEC. MIN.	0	15	30	45	COMMENTS
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%)					

## The Ringelmann Chart

In the late 1800's in Paris, France, Professor Maximilian Ringelmann developed the **Ringelmann Chart** to measure the combustion efficiency of coal-fired boilers. The shade of the smoke plume shows how well a boiler is operating - the poorer its combustion efficiency, the more unburned carbon particles in the smoke and the darker the plume.

Professor Ringelmann's chart established four measured shades of gray between white, valued at zero, and black, at five. These specific shades of gray, Ringelmann No. 1 to Ringelmann No. 4, can be accurately reproduced by placing a grid of black lines of a given width and spacing on a white background. Viewed from a distance, the grid lines and background merge into the shades of gray, to be compared to the shade of the smoke plume.



Ringelmann Chart (not to scale)

## Regulating Visible Emissions

The Ringelmann Chart became one of the first tools used to measure visible emissions. Introduced into the United States in 1897, it was soon accepted as the standard measure of smoke density and was used by engineers for power plant testing and smokeless combustion studies. In 1910, the Chart was officially adopted as part of the Smoke Ordinance for Boston, Mass.

Many city, state, and federal regulations now set smoke density limits based on the Ringelmann Smoke Chart. Although not originally designed as a regulatory tool to control air pollution, it gives good practical results when used by well-trained observers.





Jon Mauer  
President & CEO

FOOTMARK

SEP 16 2018

SEP 10 2018

Headquarters & Refining  
IES Downstream, LLC  
ATTN: Environmental Department  
91-480 Malakole Street  
Kapolei HI 96707-1807  
Tel 808-682-5711  
Fax 808-682-2214  
jonmauer@islandenergyservices.com

September 6, 2018

**CERTIFIED MAIL NO. 7015 0640 0002 5911 8177**  
**RETURN RECEIPT REQUESTED**

Ms. Marianne Rossio  
Manager, Clean Air Branch  
State of Hawaii  
2827 Waimano Home Road #130  
Pearl City, Hawaii 96782

**Renewal Application**  
**Covered Source Permit (CSP) No. 0088-03-C**

Dear Ms. Rossio:

IES Downstream, LLC is hereby applying for renewal of the referenced Covered Source Permit, CSP No. 0088-03-C, issued by the Department of Health Clean Air Branch on September 11, 2014 and modified on November 15, 2016 for one (1) 350 kW Black Start Diesel Engine Generator and three (3) diesel engine pumps located at 91-480 Malakole Street, Kapolei, Oahu. Attachment 1 contains the State of Hawaii Department of Health (HDOH) Clean Air Branch permit renewal application forms S-1, S-3, C-1 and C-2. Attachment 2 contains a check for the permit renewal fee in the amount of \$3,000 as required by Hawaii Administrative Rules (HAR) 11-60.1-113(b)(6)(B). Two sets (1 original and 1 copy) of all the application materials have been provided and an additional set will be mailed to the EPA.

Should you have questions or require further information, please contact Ms. Anna Chung of our Environmental Staff at (808) 682-2366.

I certify as the company official having supervisory responsibility for the persons who prepared this document that this information is true, accurate, and complete to the best of my knowledge, information and belief.

Sincerely,

A handwritten signature in black ink, appearing to read "Jon Mauer".

asc

**Attachments**

cc: Chief (Attention: AIR-3)  
Permits Office, Air Division  
US Environmental Protection Agency, Region 9  
75 Hawthorne Street  
San Francisco, CA 94105

**Black Start Diesel Generator and Diesel Engine Pump  
Permit Renewal Application**

**Attachment 1**

- **Permit Renewal  
Application Forms**



11. Proposed Equipment/Plant Location (e.g. street address): 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707  
 UTM Coordinates (meters): East: 592,190 North: 2,356,665  
 UTM Zone: 4 UTM Horizontal Datum:  Old Hawaiian  NAD-27  NAD-83
12. General Nature of Business: Petroleum Refining
13. Date of Planned Commencement of Construction or Modification: n/a
14. Is *any* of the equipment to be leased to another individual or entity?  Yes  No
15. Type of Organization:  Corporation  Individual Owner  Partnership  
 Government Agency (Government Facility Code: \_\_\_\_\_)  
 Other: \_\_\_\_\_

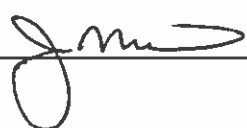
*Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR §11-60.1-64 & 11-60.1-84)*

**RESPONSIBLE OFFICIAL** (as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_  
 Title: President & CEO Phone: (808)682-5711  
 Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official** (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Jon Mauer  
 (Signature):  Date: 9/6/18

<b>FOR AGENCY USE ONLY:</b>	
File/Application No.:	_____
Island:	_____
Date Received:	_____

Submit the following documents as part of your application:

- A. The **Emissions Units Table**, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:
1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SICC number. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirement of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
    - a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
    - b. Indicate the emission points that discharge together for any length of time.
    - c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.
  2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
    - a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO<sub>x</sub>), Sulfur Dioxide (SO<sub>2</sub>), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM<sub>10</sub>). Abbreviations may be used.
    - b. Include fugitive emissions.
    - c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
    - d. **Tons per year** is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.
  3. Describe **Stack Source Parameters**:
    - a. **Stack Height** is the height above the ground.
    - b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
    - c. **Flow Rate** is the actual, not the calculated, flow rate.
  4. Provide any additional information, if applicable, as follows:
    - a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
    - b. For a rectangular stack, indicate the length and width.
    - c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.
- B. A **process flow diagram** identifying all equipment used in the process, including the following:
1. Identify and describe each emission point.
  2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.
- C. A **facility location map**, drawn to a reasonable scale and showing the following:
1. The property involved and all structures on it. Identify property/fence lines plainly.
  2. Layout of the facility.
  3. Location and identification of the proposed emissions unit on the property.
  4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 100 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.
- D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.



Company Name: IES Downstream, LLC – Kapolei Refinery

File No.: \_\_\_\_\_

Location: Kapolei

(Make as many copies of this page as necessary)

Page 2 of 3

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA				EMISSION POINTS		AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone 4 Horizontal Datum * NAD-83		STACK SOURCE PARAMETERS					
Stack No.	Unit No.	Equipment Name/ Description & SICC number	Equipment Date	Regulated/ Hazardous Air Pollutant Name & CAS#	# HR	Tons/ YR	AIR POLLUTANT	Coordinates (mtrs)	Stack Height (mtrs)	Direction (u/d/h) <sup>b</sup>	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)	Temp. (* K)	Capped (Y/N)		
Sand Filter Pump #1	Effluent Treating Plant	Sand Filter Pump Diesel Engine #1	2006 <sup>c</sup>	PM/PM10	0.099	0.43	PM/PM10	East	592074.33	u	0.1	0.01	0.1	705	N		
					1.3	5.8		North	2356424.03								
					1.6	7.2											
				CO	1.3	5.8											
				VOC (NMHC)	1.3	5.8											
				SOx	0.0019	0.0085											
				HAPs	0.00052	0.0040											
				CO2e	230	1007											
Sand Filter Pump #2	Effluent Treating Plant	Sand Filter Pump Diesel Engine #2	2007 <sup>c</sup>	PM/PM10	0.099	0.43	PM/PM10	East	592074.33	u	0.1	0.01	0.1	705	N		
					1.3	5.8		North	2356424.03								
					1.6	7.2											
				NOx	1.3	5.8											
				CO	1.3	5.8											
				VOC (NMHC)	1.3	5.8											
				SOx	0.0019	0.0085											
				HAPs	0.00052	0.0040											
				CO2e	0.099	0.43											

\* Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27  
<sup>b</sup> Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal  
<sup>c</sup> Compliant with NSPS IIII 60.4208

Company Name: IES Downstream, LLC – Kapolei Refinery

File No.: \_\_\_\_\_

Location: Kapolei

(Make as many copies of this page as necessary)

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**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

Stack No.	AIR POLLUTANT DATA - EMISSION POINTS			AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone Horizontal Datum * <u>NAD-83</u>	STACK SOURCE PARAMETERS						
	Unit No.	Equipment Name/Description & SIC number	Equipment Date		Regulated/Hazardous Air Pollutant Name & CAS#	#/HR		Tons/YR	Coordinates (mrs)	Slack Height (mrs)	Direction (u/d/h) *	Inside Diameter (mrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)
Transfer Pump	Effluent Treating Plant	Transfer pump	2010	PMPFM10	0.099	0.43	East North	592063.32 2356490.10	1.83	u	0.01	0.1	705	N
				NOx	1.3	5.8								
				CO	1.6	7.2								
				VOC (NMHC)	1.3	5.8								
				SOx	0.0019	0.0085								
				HAPs	0.00092	0.0040								
				CO2e	230	1007								

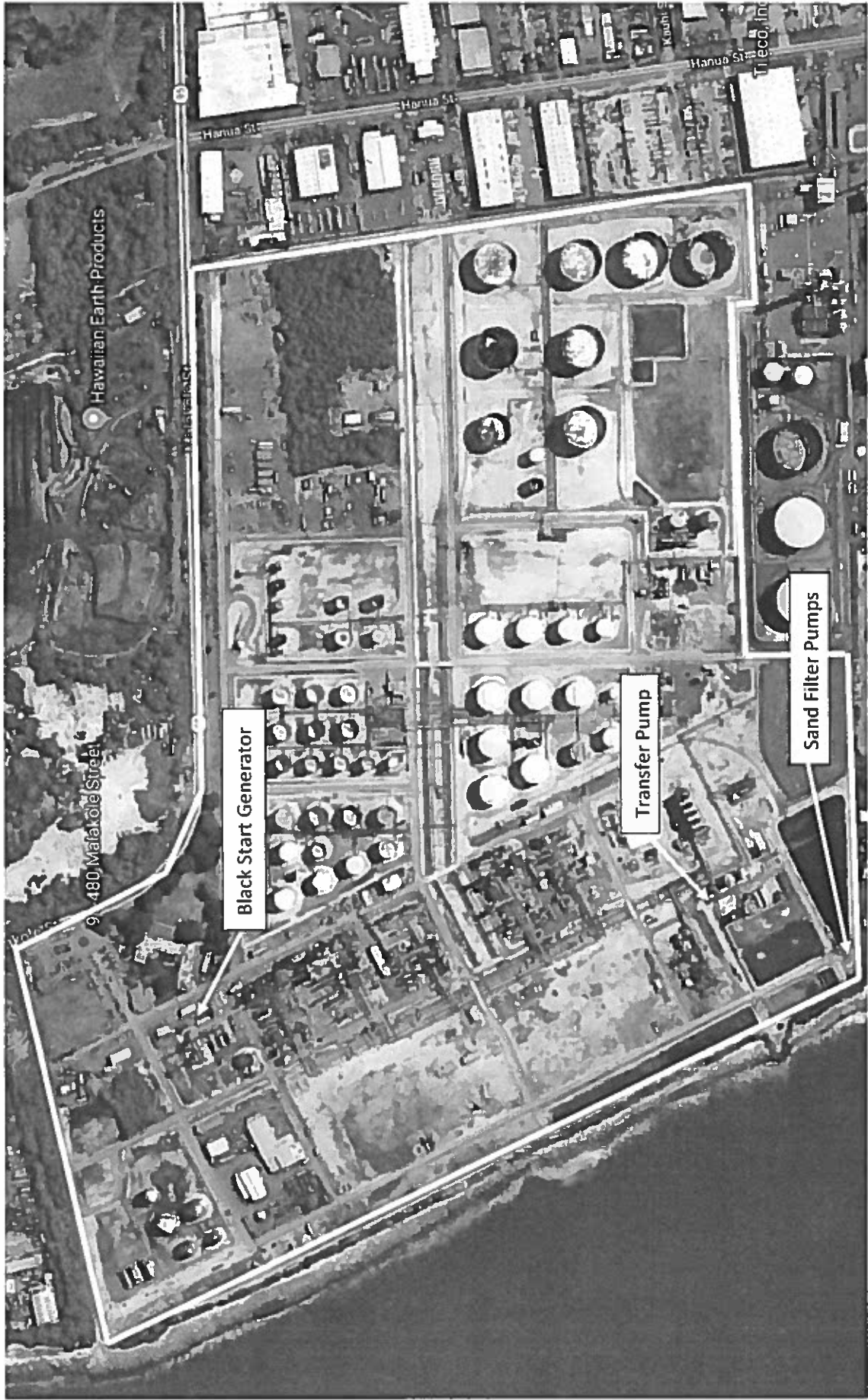
\* Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

\* Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal



IES Downstream, LLC – Kapolei Refinery

Form S-1 Facility Location Map



**S-3: Application for a Covered Source Permit Renewal**

Each application for permit renewal shall be submitted to the Director of Health, (hereafter, Director) a minimum of **twelve months** prior to the date of permit expiration. In providing the required information, please reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)  
Permits Office, Air Division  
U.S. Environmental Protection Agency  
Region 9  
75 Hawthorne Street  
San Francisco, CA 94105

**I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-101, the following information is required:**

- A. Statement certifying that no changes have been made in the design or operation of the source as proposed in the initial and any subsequent Covered Source Permit applications. If changes have occurred or are being proposed, the applicant shall provide a description of those changes such as work practices, operations, equipment design, and monitoring procedures, including the affected applicable requirements associated with the changes and the corresponding information to determine the applicability of all applicable requirements.
- **No changes have been made in the design and operation of the source as proposed in the initial permit application and in this renewal application.**

**B. Equipment Specifications:**

**Black Start Generator (BSG), Model No. DFEG**

1. Maximum design capacity: **350 kW**
2. Fuel type: **ULSD (Ultra Low Sulfur Diesel)**
3. Fuel use: **As needed (used for emergency purposes only, along with required maintenance)**
4. Production capacity: **Not Applicable**
5. Production rates: **Not Applicable**
6. Raw materials: **Not Applicable**
7. Provide any manufacturer's literature: **Submitted with initial permit application**

**Sand Filter Pump #1, serial number 18647355-02**

1. Maximum design capacity: **200 hp**
2. Fuel type: **ULSD (Ultra Low Sulfur Diesel)**
3. Fuel use: **Continuous when operating**
4. Production capacity: **Not Applicable**
5. Production rates: **Not Applicable**
6. Raw materials: **Not Applicable**
7. Provide any manufacturer's literature: **The original permitted pump was replaced with an equivalent unit and separate notification was sent to DOH.**

**Sand Filter Pump #2, serial number PE4045R951353**

1. Maximum design capacity: 200 hp
2. Fuel type: **ULSD (Ultra Low Sulfur Diesel)**
3. Fuel use: **Continuous when operating**
4. Production capacity: **Not Applicable**
5. Production rates: **Not Applicable**
6. Raw materials: **Not Applicable**
7. Provide any manufacturer's literature: **Submitted with permit mod application**

**Transfer Pump #1, serial number PE4024R039307**

1. Maximum design capacity: 300 hp
2. Fuel type: **ULSD (Ultra Low Sulfur Diesel)**
3. Fuel use: **Continuous when operating**
4. Production capacity: **Not Applicable**
5. Production rates: **Not Applicable**
6. Raw materials: **Not Applicable**
7. Provide any manufacturer's literature: **Submitted with permit mod application**

- C. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

- **The purpose of the generator is to supply power to one of the refinery's cogeneration unit turbines in the event of a power and cogeneration failure. The generator provides "black start" or "start up" power to begin turbine operation.**
- **Sand Filter Pump #1 and #2, which includes a diesel-driven engine, routes treated waste water in the refinery's Effluent Treatment Plant through and filters as needed for water quality compliance. Sand Filter Pump #1 operation alternates with Pump #2 during normal operations.**
- **The Transfer Pump routes skim oil and/or wastewater from the refinery's Effluent Treatment Plant to tankage in the Blending and Shipping area.**
- **Due to the portability of the Sand Filter Pump #1 and #2 and the transfer pump, these units may be replaced with an equivalent unit as necessary while maintenance or reliability activities are performed on the pump.**

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

- **Operating hours of the BSG will be collected from a non-resettable timer for emissions estimation.**
- **The sand filter and transfer pumps are subject to NSPS Subpart IIII and the fuel used for the units will be ULSD. Emissions in the initial application were estimated assuming a 100% operating factor.**

2. List all *insignificant* activities in accordance with HAR §11-60.1-82.

- **None**

- D. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

**Black Start Generator (BSG):**

1. Total hours per day, per week, and/or per month: **0.25 hrs/week estimated for safety/maintenance testing**
2. Total hours per year: **500 hrs/yr**
3. If operation is seasonal or irregular, describe: **Generator is for emergency "black start" use only. Other operation hours for required maintenance and service testing.**

**Sand Filter Pump #1 & Sand Filter Pump #2:**

1. Total hours per day, per week, and/or per month: 24 hrs/day
2. Total hours per year: 8760 hrs/yr
3. If operation is seasonal or irregular, describe: Pump #1 operation alternates with Pump #2 during normal operation.

**Transfer Pump:**

1. Total hours per day, per week, and/or per month: 24 hrs/day
2. Total hours per year: 8760 hrs/yr
3. If operation is seasonal or irregular, describe: The Transfer Pump operates as needed to transfer material from the Effluent Treatment Plant to tankage in the Blending and Shipping area.

- E. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:
1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement.
  2. Explanation of all proposed exemptions from any applicable requirements.
  - The new equipment will be subject to the following requirements:
    - 40 CFR 60, Standards of Performance for New Stationary Sources, Subpart A General Provisions;
    - 40 CFR 60, Standards of Performance for New Stationary Sources, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines;
    - 40 CFR 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards, Subpart A General Provisions;
    - 40 CFR 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.
  - If replaced with an equivalent pump, the replacement unit will meet the requirements of 60.4208 for installation of previous model engines.
  - No exemptions are proposed.
- F. Identify and describe current operational limitations or work practices that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.
- The generator is for providing emergency backup power to a cogeneration unit turbine in the event of a power loss. The unit is to be only run during emergency situations and required maintenance/performance testing.
  - No operational limitations are proposed for Sand Filter Pump #1 and #2. In normal operation, Pump #1 operation alternates with Pump #2, however, emissions were estimated assuming a 100% operating factor. Due to the portability of these units, Pump #2 or Pump #2 may be replaced with an equivalent unit, as necessary, while maintenance or reliability activities are performed on the pump. The fuel for this unit will be ULSD (Ultra Low Sulfur Diesel).
  - No operational limits are proposed for the Transfer Pump. In normal operation, the Transfer Pump is utilized to transfer material to tankage in the Blending and Shipping area, as needed. Emissions were estimated assuming a 100% operating factor. Due to the portability of this unit, the Transfer Pump may be replaced with an equivalent unit, as necessary, while maintenance or reliability activities are performed on the pump. The fuel for this unit will be ULSD (Ultra Low Sulfur Diesel).
  - There are no emission changes to the calculations submitted in the initial application.

- G. For *new* covered sources and *significant* modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the NAAQS and SAAQS.
  - This application for a permit renewal does not pertain to a new covered source or a significant modification that would increase the emissions of any pollutant not previously emitted. Thus, dispersion modeling to evaluate the facility's potential impacts on onshore ambient air quality is not required.
- H. For *new* covered sources and *significant* modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7.
  - This application for a permit renewal does not pertain to a new covered source or to a significant modification subject to the Prevention of Significant Deterioration provisions of Subchapter 7 of HAR 11-60.1, and is therefore not required to submit the analyses, assessments, monitoring, and other application requirements of Subchapter 7.
- I. Provide detailed information to define permit terms and conditions for any proposed *emissions trading* within the facility in accordance with HAR §11-60.1-96.
  - No emissions trading is proposed.
- J. Provide the following for Compliance purposes:
  1. A Compliance Plan, Form C-1.
  2. A Compliance Certification, Form C-2.

II. **Submit an application fee according to the Application Fee Schedule in the Instructions for Applying for an Air Pollution Control Permit.**

III. **Provide other information as follows:**

- A. As required by any applicable requirement or as requested and deemed necessary by the Director to make a decision on the application.
- B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

**IV. The Director reserves the right to request the following information:**

- A. An assessment of the ambient air quality impact of the source or modification. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards.
- B. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.
- C. Results of source emissions testing, ambient air quality monitoring, or both.
- D. Information on other available control technologies.

**V. An application shall be determined to be complete only when all of the following have been complied with:**

- A. All information required or requested in numbers I, III, and IV has been submitted.
- B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.
- C. All applicable fees have been submitted.
- D. The Director has certified that the application is complete.

**VI. The Director shall not continue to act upon or consider an incomplete application.**

- A. The applicant shall be notified in writing whether the application is complete. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days of receipt of an application, the application shall be deemed complete.
- B. During the processing of an application that has been determined or deemed complete, if the Director determines that additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response. As set forth in HAR §11-60.1-82, the covered source's ability to operate and the validity of the Covered Source Permit shall continue beyond the permit expiration date until the final permit is issued or denied, provided the applicant submits all additional information within the reasonable deadline specified by the Director.

**VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application:**

- A. Within twelve months, *except* for applications for renewal for coverage under a covered source general permit. If the application for renewal has not been approved or denied within twelve months, the Covered Source Permit and all its terms and conditions shall remain in effect and not expire until the application for renewal has been approved or denied and provided the applicant has submitted any additional information within the reasonable deadline specified by the Director.
- B. Within six months for applications for renewal requesting coverage under a covered source general permit. If the application for renewal has not been approved or denied within six months, the coverage under the covered source general permit and all its terms and conditions shall remain

in effect and not expire until the application for renewal has been approved or denied and provided the applicant has submitted any additional information within the reasonable deadline specified by the Director.

- VIII. A Covered Source Permit renewal application shall be approved only if the Director determines that the operation of the covered source will be in compliance with all applicable requirements.**
- IX. The Director shall provide for public notice, including the method by which a public hearing can be requested, and an opportunity for public comment on the draft Covered Source Permit renewal in accordance with HAR §11-60.1-99.**
- X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.**
- XI. Each application for renewal and proposed Covered Source Permit shall be subject to EPA oversight in accordance with HAR §11-60.1-95.**

**C-1: Compliance Plan**

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets of paper if necessary.

1. Compliance status with respect to all Applicable Requirements:

Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

- YES      {If YES, complete items a and c below}
- NO        {If NO, complete items a, b, and c below}

a. Identify all applicable requirement(s) for which compliance is achieved.

National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63 Subparts A & ZZZZ,  
New Source Performance Standards (NSPS) 40 CFR 60 Subparts A and IIII, General Compliance for  
Highway, Stationary, and NonRoad Programs 40 CFR 1068 Subpart A, and Control of Emission for In-  
Use NonRoad Compression-Ignition Engines 40 CFR 1039, as listed in current permit CSP 0088-03-C.

Provide a statement that the source is in compliance and will continue to comply with all such requirements.  
All permitted units are in compliance with all applicable requirements and will continue to comply with  
all applicable requirements.

b. Identify all applicable requirement(s) for which compliance is NOT achieved.

N/A

Provide a detailed Schedule of Compliance Schedule and a description of how the source will achieve compliance with all such applicable requirements.

<u>Description of Remedial Action</u>	<u>Expected Date of Completion</u>
<u>N/A</u>	



- c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to. These applicable requirements may take effect AFTER permit issuance:

<u>Applicable Requirement</u>	<u>Effective Date</u>	<u>Currently in Compliance?</u>
N/A		

If the source is not currently in compliance, provide a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

<u>Description of Proposed Action/Steps to Achieve Compliance</u>	<u>Expected Date of Achieving Compliance</u>
N/A	

Provide a statement that the source on a timely basis will meet all these applicable requirements:

N/A

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If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of each remedial action and the expected date of completion:

<u>Description of Remedial Action and Explanation</u>	<u>Expected Date of Completion</u>
N/A	

2. Compliance Progress Reports:

- a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: N/A Beginning Date: N/A  
(less than or equal to 6 months)

b. Date(s) that the Action described in (1)(b) was achieved:

<u>Remedial Action</u>	<u>Date Achieved</u>
N/A	

c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

N/A

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**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI):

Title: President & CEO Phone: (808)682-5711

Mailing Address: 91-480 Malakole Street

City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Jon Mauer

(Signature):  Date: 9/6/18

Facility Name: IES Downstream, LLC - Kapolei Refinery

Location: Kapolei

Permit Number: 0088-03-C

<b>FOR AGENCY USE ONLY</b>
File/Application No.: _____
Island: _____
Date Received: _____

**C-2: Compliance Certification**

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Complete as many copies of this form as needed. Use separate sheets of paper if necessary.

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**RESPONSIBLE OFFICIAL** (as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_

Title: President & CEO Phone: (808)682-5711

Mailing Address: 91-480 Malakole Street

City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official** (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Jon Mauer

(Signature):  Date: 9/6/18

Facility Name: IES Downstream, LLC - Kapolei Refinery

Location: Kapolei

Permit Number: 0088-03-C

**FOR AGENCY USE ONLY**

File/Application No.: \_\_\_\_\_

Island: \_\_\_\_\_

Date Received: \_\_\_\_\_

Complete the following information for *each* applicable requirement that applies to *each* emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: Annually Beginning Date: 2014

2. Emissions Unit No./Description: 350 kW (755 HP) Black Start Generator for Cogeneration Unit, Sand Filter Pump #1, Sand Filter Pump #2, and Transfer Pump

3. Identify the applicable requirement(s) that is/are the basis of this certification:

Refer to current CSP and renewal application.  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Refer to current CSP and renewal application.

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Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

Refer to current CSP and renewal application.

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

Not Applicable

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

N/A

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- c. If NO, describe below which requirements will not be met:

N/A

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# **Black Start Diesel Generator and Diesel Engine Pump Permit Renewal Application**

## **Attachment 2**

- **Permit Renewal  
Fee Check**



Jon Mauer  
President & CEO

POSTMARK  
SEP 6 2018  
SEP 10 2018  
Headquarters & Refining  
IES Downstream, LLC  
ATTN: Environmental Department  
91-480 Malakole Street  
Kapolei HI 96707-1807  
Tel 808-682-5711  
Fax 808-682-2214  
jonmauer@islandenergyservices.com

September 6, 2018

**CERTIFIED MAIL NO. 7015 0640 0002 5911 8177**  
**RETURN RECEIPT REQUESTED**

Ms. Marianne Rossio  
Manager, Clean Air Branch  
State of Hawaii  
2827 Waimano Home Road #130  
Pearl City, Hawaii 96782

**Renewal Application**  
**Covered Source Permit (CSP) No. 0088-03-C**

Dear Ms. Rossio:

IES Downstream, LLC is hereby applying for renewal of the referenced Covered Source Permit, CSP No. 0088-03-C, issued by the Department of Health Clean Air Branch on September 11, 2014 and modified on November 15, 2016 for one (1) 350 kW Black Start Diesel Engine Generator and three (3) diesel engine pumps located at 91-480 Malakole Street, Kapolei, Oahu. Attachment 1 contains the State of Hawaii Department of Health (HDOH) Clean Air Branch permit renewal application forms S-1, S-3, C-1 and C-2. Attachment 2 contains a check for the permit renewal fee in the amount of \$3,000 as required by Hawaii Administrative Rules (HAR) 11-60.1-113(b)(6)(B). Two sets (1 original and 1 copy) of all the application materials have been provided and an additional set will be mailed to the EPA.

Should you have questions or require further information, please contact Ms. Anna Chung of our Environmental Staff at (808) 682-2366.

I certify as the company official having supervisory responsibility for the persons who prepared this document that this information is true, accurate, and complete to the best of my knowledge, information and belief.

Sincerely,

A handwritten signature in black ink, appearing to read "J Mauer".  
asc

**Attachments**

cc: Chief (Attention: AIR-3)  
Permits Office, Air Division  
US Environmental Protection Agency, Region 9  
75 Hawthorne Street  
San Francisco, CA 94105

**Black Start Diesel Generator and Diesel Engine Pump  
Permit Renewal Application**

**Attachment 1**

- **Permit Renewal  
Application Forms**



FOOTPRINT  
SEP 6 2018

SEP 10 2018

File/Application No.: \_\_\_\_\_

**S-1: Standard Air Pollution Control Permit Application Form**  
(Covered Source Permit and Noncovered Source Permit)

State of Hawaii  
Department of Health  
Environmental Management Division  
Clean Air Branch  
P.O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: IES Downstream, LLC

2. Facility Name (if different from the Company): IES Downstream, LLC - Kapolei Refinery

3. Mailing Address: 91-480 Malakole Street

City: Kapolei State: HI Zip Code: 96707

Phone Number: (808)682-5711

4. Name of Owner/Owner's Agent: Jon Mauer

Title: President & CEO Phone: (808)682-5711

Mailing Address: same as above

City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_

5. Plant Site Manager/Other Contact: Jon Mauer

Title: President & CEO Phone: (808)682-5711

Mailing Address: same as above

City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_

6. Permit Application Basis: (Check all applicable categories.)

- Initial Permit for a New Source       Initial Permit for an Existing Source
- Renewal of Existing Permit       General Permit
- Temporary Source       Transfer of Permit
- Modification to a Covered Source: → Is Modification?     Significant     Minor     Uncertain
- Modification to a Noncovered Source

7. If renewal or modification, include existing permit number: CSP No. 0088-03-C

8. Does the Proposed Source require a County Special Management Area Permit?     Yes     No

9. Type of Source (Check One):     Covered Source       Covered and PSD Source  
    Noncovered Source       Uncertain

10. Standard Industrial Classification Code (SICC), if known: 2911

11. Proposed Equipment/Plant Location (e.g. street address): 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707  
 UTM Coordinates (meters): East: 592,190 North: 2,356,665  
 UTM Zone: 4 UTM Horizontal Datum:  Old Hawaiian  NAD-27  NAD-83
12. General Nature of Business: Petroleum Refining
13. Date of Planned Commencement of Construction or Modification: n/a
14. Is any of the equipment to be leased to another individual or entity?  Yes  No
15. Type of Organization:  Corporation  Individual Owner  Partnership  
 Government Agency (Government Facility Code: \_\_\_\_\_)  
 Other: \_\_\_\_\_

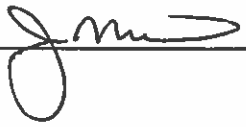
*Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR §11-60.1-64 & 11-60.1-84)*

**RESPONSIBLE OFFICIAL** (as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_  
 Title: President & CEO Phone: (808)682-5711  
 Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official** (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Jon Mauer  
 (Signature):  Date: 9/6/18

<b>FOR AGENCY USE ONLY:</b>	
File/Application No.:	_____
Island:	_____
Date Received:	_____

Submit the following documents as part of your application:

- A. The **Emissions Units Table**, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:
1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SIC number. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirement of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
    - a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
    - b. Indicate the emission points that discharge together for any length of time.
    - c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.
  2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
    - a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO<sub>x</sub>), Sulfur Dioxide (SO<sub>2</sub>), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM<sub>10</sub>). Abbreviations may be used.
    - b. Include fugitive emissions.
    - c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
    - d. **Tons per year** is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.
  3. Describe **Stack Source Parameters**:
    - a. **Stack Height** is the height above the ground.
    - b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
    - c. **Flow Rate** is the actual, not the calculated, flow rate.
  4. Provide any additional information, if applicable, as follows:
    - a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
    - b. For a rectangular stack, indicate the length and width.
    - c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.
- B. A **process flow diagram** identifying all equipment used in the process, including the following:
1. Identify and describe each emission point.
  2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.
- C. A **facility location map**, drawn to a reasonable scale and showing the following:
1. The property involved and all structures on it. Identify property/fence lines plainly.
  2. Layout of the facility.
  3. Location and identification of the proposed emissions unit on the property.
  4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 100 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.
- D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Company Name: IES Downstream, LLC - Kapolei Refinery

File No.: \_\_\_\_\_

Location: Kapolei

(Make as many copies of this page as necessary)

Page 1 of 3

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone 4 Horizontal Datum - NAD-83		STACK SOURCE PARAMETERS						
Stack No	Unit No	Equipment Name/ Description & SICC number	Equipment Date	Regulated/ Hazardous Air Pollutant Name & CAS#	# / HR	Tons/ YR	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h) *	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)	Temp (°K)	Capped (Y/N)	
Cogen Black Start	Cogen Plant	Cogen Unit Black Start Generator	2014	PM/PM10	0.13	0.03	East	591,894	2.69	u	0.15	67.25	1.23	705	N	
					6.49	1.62	North	2,356,970								
					0.67	0.17	East									
				NOx	6.49	1.62	North									
				CO	0.67	0.17	East									
				VOC (NMHC)	6.49	1.62	North									
				SOx	0.005	0.001	East									
							North									
							East									
							North									
							East									
							North									
							East									
							North									
							East									
							North									
							East									
							North									
							East									
							North									

\* Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

\*\* Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal

(Make as many copies of this page as necessary)

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				STACK SOURCE PARAMETERS									
Stack No.	Unit No.	Equipment Name/Description & SIC number	Equipment Date	AIR POLLUTANT	AIR POLLUTANT EMISSION RATE	UTM Zone <u>4</u> Horizontal Datum * <u>NAD-83</u>	Stack Height (mtrs)	Direction (u/d/h) *	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)	Temp. (*K)	Capped (Y/N)
				Regulated/ Hazardous Air Pollutant Name & CAS#	#/HR Tons/ YR	Coordinates (mtrs)							
Sand Filter Pump #1	Effluent Treating Plant	Sand Filter Pump Diesel Engine #1	2006*	PM10	0.099 0.43	East 592074.33 North 2356424.03	1.83	u	0.1	0.01	0.1	705	N
				NOx	1.3 5.8								
				CO	1.6 7.2								
				VOC (NMHC)	1.3 5.8								
				SOx	0.0019 0.0085								
				HAPs	0.00092 0.0040								
				CO2e	230 1007								
Sand Filter Pump #2	Effluent Treating Plant	Sand Filter Pump Diesel Engine #2	2007*	PM10	0.099 0.43	East 592074.33 North 2356424.03	1.83	u	0.1	0.01	0.1	705	N
				NOx	1.3 5.8								
				CO	1.6 7.2								
				VOC (NMHC)	1.3 5.8								
				SOx	0.0019 0.0085								
				HAPs	0.00092 0.0040								
				CO2e	0.099 0.43								

\* Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27  
 \* Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal  
 \* Compliant with NSPS III 60.420b

Company Name: IES Downstream, LLC – Kapolei Refinery File No.: \_\_\_\_\_

Location: Kapolei

(Make as many copies of this page as necessary)

Page 3 of 3

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

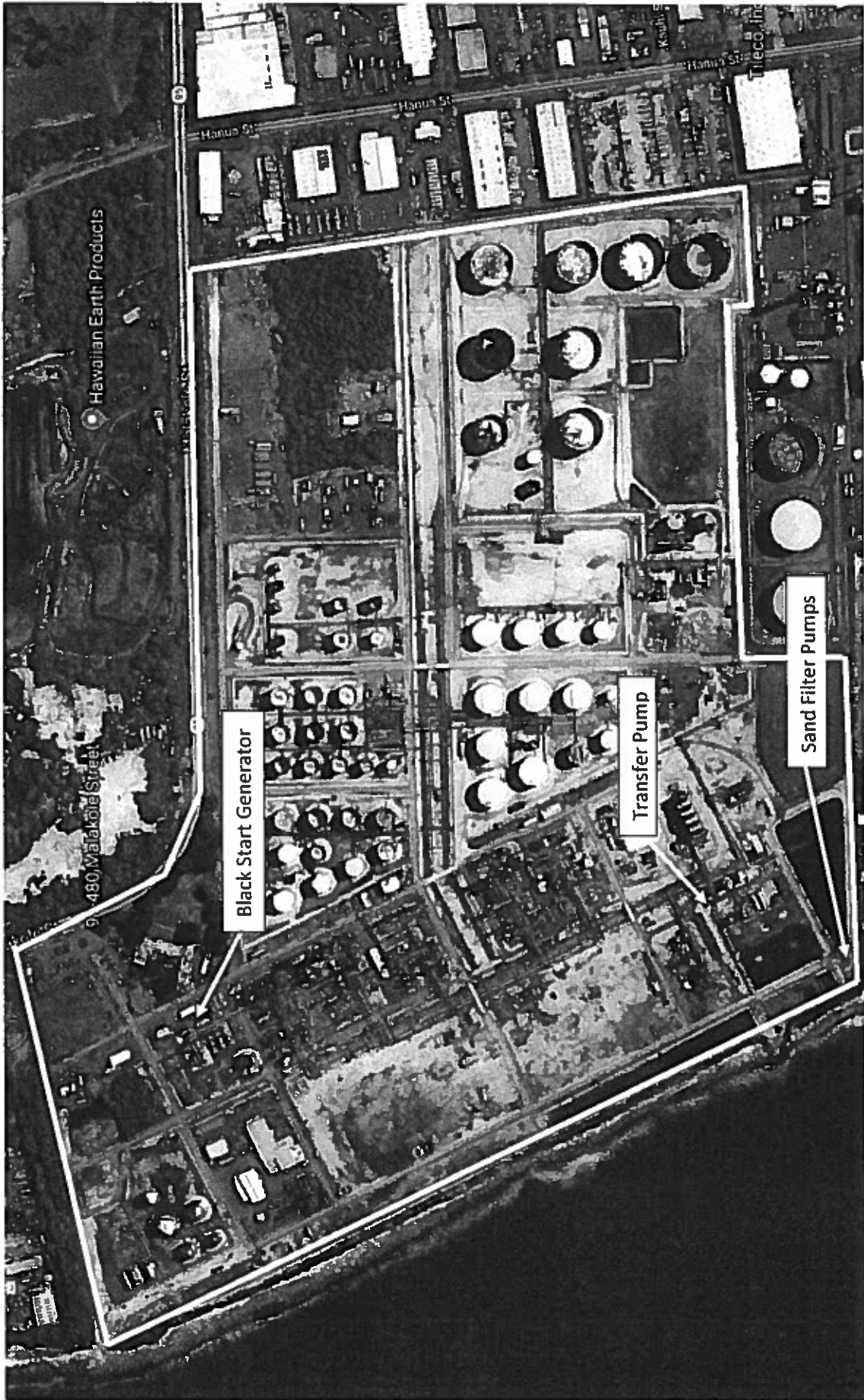
AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT EMISSION RATE				UTM Zone 4 Horizontal Datum * NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SICC number	Equipment Date	Air Pollutant	Regulated/Hazardous Air Pollutant Name & CAS#	# HR	Tons/ YR	East	North	Stack Height (mtrs)	Direction (uldrh) *	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)	Temp. (*K)	Capped (Y/N)
Transfer Pump	Effluent Treating Plant	Transfer pump	2010	PMPM10	PMPM10	0.089	0.43	592063.32	2356490.10	1.83	u	0.1	0.01	0.1	705	N
				NOx	NOx	1.3	5.8									
				CO	CO	1.6	7.2									
				VOC (NMHC)	VOC (NMHC)	1.3	5.8									
				SOx	SOx	0.0019	0.0085									
				HAPs	HAPs	0.00062	0.0040									
				CO2e	CO2e	230	1007									

\* Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

\*\* Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal

IES Downstream, LLC – Kapolei Refinery

Form S-1 Facility Location Map



**S-3: Application for a Covered Source Permit Renewal**

Each application for permit renewal shall be submitted to the Director of Health, (hereafter, Director) a minimum of **twelve months** prior to the date of permit expiration. In providing the required information, please reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)  
Permits Office, Air Division  
U.S. Environmental Protection Agency  
Region 9  
75 Hawthorne Street  
San Francisco, CA 94105

**I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-101, the following information is required:**

- A. Statement certifying that no changes have been made in the design or operation of the source as proposed in the initial and any subsequent Covered Source Permit applications. If changes have occurred or are being proposed, the applicant shall provide a description of those changes such as work practices, operations, equipment design, and monitoring procedures, including the affected applicable requirements associated with the changes and the corresponding information to determine the applicability of all applicable requirements.
- **No changes have been made in the design and operation of the source as proposed in the initial permit application and in this renewal application.**

**B. Equipment Specifications:**

**Black Start Generator (BSG), Model No. DFEG**

1. Maximum design capacity: **350 kW**
2. Fuel type: **ULSD (Ultra Low Sulfur Diesel)**
3. Fuel use: **As needed (used for emergency purposes only, along with required maintenance)**
4. Production capacity: **Not Applicable**
5. Production rates: **Not Applicable**
6. Raw materials: **Not Applicable**
7. Provide any manufacturer's literature: **Submitted with initial permit application**

**Sand Filter Pump #1, serial number 18647355-02**

1. Maximum design capacity: **200 hp**
2. Fuel type: **ULSD (Ultra Low Sulfur Diesel)**
3. Fuel use: **Continuous when operating**
4. Production capacity: **Not Applicable**
5. Production rates: **Not Applicable**
6. Raw materials: **Not Applicable**
7. Provide any manufacturer's literature: **The original permitted pump was replaced with an equivalent unit and separate notification was sent to DOH.**



**Sand Filter Pump #2, serial number PE4045R951353**

1. Maximum design capacity: 200 hp
2. Fuel type: ULSD (Ultra Low Sulfur Diesel)
3. Fuel use: Continuous when operating
4. Production capacity: Not Applicable
5. Production rates: Not Applicable
6. Raw materials: Not Applicable
7. Provide any manufacturer's literature: Submitted with permit mod application

**Transfer Pump #1, serial number PE4024R039307**

1. Maximum design capacity: 300 hp
2. Fuel type: ULSD (Ultra Low Sulfur Diesel)
3. Fuel use: Continuous when operating
4. Production capacity: Not Applicable
5. Production rates: Not Applicable
6. Raw materials: Not Applicable
7. Provide any manufacturer's literature: Submitted with permit mod application

- C. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

- The purpose of the generator is to supply power to one of the refinery's cogeneration unit turbines in the event of a power and cogeneration failure. The generator provides "black start" or "start up" power to begin turbine operation.
- Sand Filter Pump #1 and #2, which includes a diesel-driven engine, routes treated waste water in the refinery's Effluent Treatment Plant through and filters as needed for water quality compliance. Sand Filter Pump #1 operation alternates with Pump #2 during normal operations.
- The Transfer Pump routes skim oil and/or wastewater from the refinery's Effluent Treatment Plant to tankage in the Blending and Shipping area.
- Due to the portability of the Sand Filter Pump #1 and #2 and the transfer pump, these units may be replaced with an equivalent unit as necessary while maintenance or reliability activities are performed on the pump.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.
  - Operating hours of the BSG will be collected from a non-resettable timer for emissions estimation.
  - The sand filter and transfer pumps are subject to NSPS Subpart IIII and the fuel used for the units will be ULSD. Emissions in the initial application were estimated assuming a 100% operating factor.

2. List all *insignificant* activities in accordance with HAR §11-60.1-82.
  - None

- D. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

**Black Start Generator (BSG):**

1. Total hours per day, per week, and/or per month: 0.25 hrs/week estimated for safety/maintenance testing
2. Total hours per year: 500 hrs/yr
3. If operation is seasonal or irregular, describe: Generator is for emergency "black start" use only. Other operation hours for required maintenance and service testing.

**Sand Filter Pump #1 & Sand Filter Pump #2:**

1. Total hours per day, per week, and/or per month: **24 hrs/day**
2. Total hours per year: **8760 hrs/yr**
3. If operation is seasonal or irregular, describe: **Pump #1 operation alternates with Pump #2 during normal operation.**

**Transfer Pump:**

1. Total hours per day, per week, and/or per month: **24 hrs/day**
2. Total hours per year: **8760 hrs/yr**
3. If operation is seasonal or irregular, describe: **The Transfer Pump operates as needed to transfer material from the Effluent Treatment Plant to tankage in the Blending and Shipping area.**

- E. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:
1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement.
  2. Explanation of all proposed exemptions from any applicable requirements.
  - **The new equipment will be subject to the following requirements:**
    - **40 CFR 60, Standards of Performance for New Stationary Sources, Subpart A General Provisions;**
    - **40 CFR 60, Standards of Performance for New Stationary Sources, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines;**
    - **40 CFR 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards, Subpart A General Provisions;**
    - **40 CFR 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.**
  - **If replaced with an equivalent pump, the replacement unit will meet the requirements of 60.4208 for installation of previous model engines.**
  - **No exemptions are proposed.**
- F. Identify and describe current operational limitations or work practices that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.
- **The generator is for providing emergency backup power to a cogeneration unit turbine in the event of a power loss. The unit is to be only run during emergency situations and required maintenance/performance testing.**
  - **No operational limitations are proposed for Sand Filter Pump #1 and #2. In normal operation, Pump #1 operation alternates with Pump #2, however, emissions were estimated assuming a 100% operating factor. Due to the portability of these units, Pump #2 or Pump #2 may be replaced with an equivalent unit, as necessary, while maintenance or reliability activities are performed on the pump. The fuel for this unit will be ULSD (Ultra Low Sulfur Diesel).**
  - **No operational limits are proposed for the Transfer Pump. In normal operation, the Transfer Pump is utilized to transfer material to tankage in the Blending and Shipping area, as needed. Emissions were estimated assuming a 100% operating factor. Due to the portability of this unit, the Transfer Pump may be replaced with an equivalent unit, as necessary, while maintenance or reliability activities are performed on the pump. The fuel for this unit will be ULSD (Ultra Low Sulfur Diesel).**
  - **There are no emission changes to the calculations submitted in the initial application.**

- G. For *new* covered sources and **significant** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the NAAQS and SAAQS.
- This application for a permit renewal does not pertain to a new covered source or a significant modification that would increase the emissions of any pollutant not previously emitted. Thus, dispersion modeling to evaluate the facility's potential impacts on onshore ambient air quality is not required.
- H. For *new* covered sources and **significant** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7.
- This application for a permit renewal does not pertain to a new covered source or to a significant modification subject to the Prevention of Significant Deterioration provisions of Subchapter 7 of HAR 11-60.1, and is therefore not required to submit the analyses, assessments, monitoring, and other application requirements of Subchapter 7.
- I. Provide detailed information to define permit terms and conditions for any proposed **emissions trading** within the facility in accordance with HAR §11-60.1-96.
- No emissions trading is proposed.
- J. Provide the following for Compliance purposes:
1. A Compliance Plan, Form C-1.
  2. A Compliance Certification, Form C-2.
- II. **Submit an application fee according to the Application Fee Schedule in the Instructions for Applying for an Air Pollution Control Permit.**
- III. **Provide other information as follows:**
- A. As required by any applicable requirement or as requested and deemed necessary by the Director to make a decision on the application.
  - B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

**IV. The Director reserves the right to request the following information:**

- A. An assessment of the ambient air quality impact of the source or modification. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards.
- B. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.
- C. Results of source emissions testing, ambient air quality monitoring, or both.
- D. Information on other available control technologies.

**V. An application shall be determined to be complete only when all of the following have been complied with:**

- A. All information required or requested in numbers I, III, and IV has been submitted.
- B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.
- C. All applicable fees have been submitted.
- D. The Director has certified that the application is complete.

**VI. The Director shall not continue to act upon or consider an incomplete application.**

- A. The applicant shall be notified in writing whether the application is complete. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days of receipt of an application, the application shall be deemed complete.
- B. During the processing of an application that has been determined or deemed complete, if the Director determines that additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response. As set forth in HAR §11-60.1-82, the covered source's ability to operate and the validity of the Covered Source Permit shall continue beyond the permit expiration date until the final permit is issued or denied, provided the applicant submits all additional information within the reasonable deadline specified by the Director.

**VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application:**

- A. Within twelve months, *except* for applications for renewal for coverage under a covered source general permit. If the application for renewal has not been approved or denied within twelve months, the Covered Source Permit and all its terms and conditions shall remain in effect and not expire until the application for renewal has been approved or denied and provided the applicant has submitted any additional information within the reasonable deadline specified by the Director.
- B. Within six months for applications for renewal requesting coverage under a covered source general permit. If the application for renewal has not been approved or denied within six months, the coverage under the covered source general permit and all its terms and conditions shall remain

in effect and not expire until the application for renewal has been approved or denied and provided the applicant has submitted any additional information within the reasonable deadline specified by the Director.

- VIII. A Covered Source Permit renewal application shall be approved only if the Director determines that the operation of the covered source will be in compliance with all applicable requirements.**
  
- IX. The Director shall provide for public notice, including the method by which a public hearing can be requested, and an opportunity for public comment on the draft Covered Source Permit renewal in accordance with HAR §11-60.1-99.**
  
- X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.**
  
- XI. Each application for renewal and proposed Covered Source Permit shall be subject to EPA oversight in accordance with HAR §11-60.1-95.**

**C-1: Compliance Plan**

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets of paper if necessary.

1. Compliance status with respect to all Applicable Requirements:

Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

- YES      {If YES, complete items a and c below}
- NO      {If NO, complete items a, b, and c below}

a. Identify all applicable requirement(s) for which compliance is achieved.

National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63 Subparts A & ZZZZ,  
New Source Performance Standards (NSPS) 40 CFR 60 Subparts A and IIII, General Compliance for  
Highway, Stationary, and NonRoad Programs 40 CFR 1068 Subpart A, and Control of Emission for In-  
Use NonRoad Compression-Ignition Engines 40 CFR 1039, as listed in current permit CSP 0088-03-C.

Provide a statement that the source is in compliance and will continue to comply with all such requirements.  
All permitted units are in compliance with all applicable requirements and will continue to comply with  
all applicable requirements.

b. Identify all applicable requirement(s) for which compliance is NOT achieved.

N/A

Provide a detailed Schedule of Compliance Schedule and a description of how the source will achieve compliance with all such applicable requirements.

<u>Description of Remedial Action</u>	<u>Expected Date of Completion</u>
N/A	

- c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to. These applicable requirements may take effect AFTER permit issuance:

<u>Applicable Requirement</u>	<u>Effective Date</u>	<u>Currently in Compliance?</u>
N/A		

If the source is not currently in compliance, provide a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

<u>Description of Proposed Action/Steps to Achieve Compliance</u>	<u>Expected Date of Achieving Compliance</u>
N/A	

Provide a statement that the source on a timely basis will meet all these applicable requirements:

N/A

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If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of each remedial action and the expected date of completion:

<u>Description of Remedial Action and Explanation</u>	<u>Expected Date of Completion</u>
N/A	

2. Compliance Progress Reports:

- a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: N/A  
(less than or equal to 6 months)

Beginning Date: N/A

b. Date(s) that the Action described in (1)(b) was achieved:

<u>Remedial Action</u>	<u>Date Achieved</u>
N/A	

c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

N/A

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**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_

Title: President & CEO Phone: (808)682-5711

Mailing Address: 91-480 Malakole Street

City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Jon Mauer

(Signature):  Date: 9/6/18

Facility Name: IES Downstream, LLC - Kapolei Refinery

Location: Kapolei

Permit Number: 0088-03-C

<b>FOR AGENCY USE ONLY</b>	
File/Application No.:	_____
Island:	_____
Date Received:	_____



### C-2: Compliance Certification

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

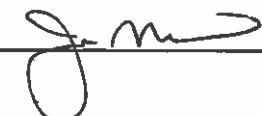
Complete as many copies of this form as needed. Use separate sheets of paper if necessary.

**RESPONSIBLE OFFICIAL** (as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_  
Title: President & CEO Phone: (808)682-5711  
Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official** (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Jon Mauer  
(Signature):  Date: 9/6/18

Facility Name: IES Downstream, LLC - Kapolei Refinery  
Location: Kapolei  
Permit Number: 0088-03-C

<b>FOR AGENCY USE ONLY</b>
File/Application No.: _____
Island: _____
Date Received: _____

Complete the following information for *each* applicable requirement that applies to *each* emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: Annually Beginning Date: 2014

2. Emissions Unit No./Description: 350 kW (755 HP) Black Start Generator for Cogeneration Unit, Sand Filter Pump #1, Sand Filter Pump #2, and Transfer Pump

3. Identify the applicable requirement(s) that is/are the basis of this certification:

Refer to current CSP and renewal application.  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Refer to current CSP and renewal application.

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Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

Refer to current CSP and renewal application.

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

X Not Applicable

b. If YES, identify the requirements and the provisions being taken to achieve compliance:

N/A

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c. If NO, describe below which requirements will not be met:

N/A

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Jon Mauer  
Refinery Manager

MAR 2 2016  
POSTMARK  
FEB 29 2016  
Hawaii Refinery  
Chevron Products Company  
91-480 Malakole Street  
Kapolei HI 96707-1807  
Tel 808-682-5711  
Fax 808-682-2324  
JonMauer@chevron.com

February 18, 2016

**CERTIFIED MAIL NO. 7015 0640 0003 9266 0366**  
**RETURN RECEIPT REQUESTED**

Mr. Nolan Hirai  
Manager, Clean Air Branch  
Hawaii Department of Health  
919 Ala Moana Boulevard  
Honolulu, HI 96814

**Refinery Covered Source Permit No. 0088-01-C**  
**2010 Renewal Application – Updated Information**

Dear Mr. Hirai:

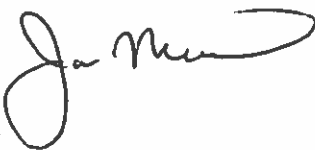
The Chevron Refinery is hereby providing updated information for the CSP 0088-01-C Renewal Application that was submitted in December 2010. The updated information includes revisions for new regulations, updated regulatory applicability, proposed permit language for new applicable requirements, tanks and minor clarifications on refinery activities and existing equipment.

We appreciate the opportunities in this endeavor to meet with and discuss these revisions with your staff in order to provide complete and accurate information in the CSP permit renewal application. As directed by Mr. Darin Lum, the permit fee for the 2010 renewal was processed, and an additional fee is not required.

Should you have any questions or require further information, please contact Marcus Ruscio of our Environmental Staff at (808) 682-2282.

I certify as the company official having supervisory responsibility for the persons who, acting under my direct instructions, made the verification that this knowledge is true, accurate, and complete to the best of their knowledge, information, and belief.

Sincerely,

  
mr

Enclosure

cc: Chief, Permits Office (Air-3)  
Air Division  
U.S. Environmental Protection Agency, Region IX  
75 Hawthorne Street  
San Francisco, California 94105

2np



MAR 2 2016

POSTMARK

FEB 29 2016

RENEWAL APPLICATION  
COVERED SOURCE PERMIT (0088-01C)  
CHEVRON HAWAII REFINERY  
KAPOLEI, HAWAII

PREPARED FOR:  
STATE OF HAWAII  
DEPARTMENT OF HEALTH

PREPARED BY:  
CHEVRON PRODUCTS  
COMPANY

INITIAL SUBMITTAL DECEMBER 27, 2010

FEBRUARY 2016 UPDATE

RENEWAL APPLICATION  
COVERED SOURCE PERMIT (0088-01C)  
CHEVRON HAWAII REFINERY  
KAPOLEI, HAWAII

PREPARED FOR:  
**STATE OF HAWAII**  
**DEPARTMENT OF HEALTH**

PREPARED BY:  
**CHEVRON PRODUCTS**  
**COMPANY**

**INITIAL SUBMITTAL DECEMBER 27, 2010**

**FEBRUARY 2016 UPDATE**

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# 1. Introduction

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## 1.1 Application for Permit

*Chevron Products Company, a division of Chevron U.S.A. (Chevron)* hereby makes application to the Hawaii Department of Health (DOH) Clean Air Branch for a renewal of Covered Source Permit No. 0088-01-C for the Chevron Hawaii Refinery located at Kapolei, Ewa, Oahu, Hawaii. The Hawaii Refinery began operation in 1960. In September 1994, Chevron filed an application for an initial Covered Source Permit. The Covered Source Permit was issued by DOH on February 22, 1999 and was valid through February 22, 2004. In August 2003, an application for a renewal of the Covered Source Permit was submitted to DOH. DOH issued six of the 13 Attachment II permits by process area throughout the 2007 calendar year which expire 27 June 2011. In August 2006, an application for significant modification was submitted for the Hybrid Energy Plant. ~~DOH modified the covered source permits for those source categories impacted and issued those amendment permits on 23 May 2007 and expire 22 May 2012.~~ This 2010 application is being submitted six months prior to covered source permit expiration date of 27 June 2011 to meet the permit shield requirements as allowed in §11-60.1-101 (5)(b). It is anticipated that this renewal will be for the timeframe from June 28, 2011 through June 27, 2016.

This renewal application is made pursuant to the regulations and requirements contained in the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1 (Air Pollution Control). According to these Rules, the Hawaii Refinery is classified as a major, covered source under the Hawaii permitting program. This document consists of the complete permit renewal application, including all the information required in Title 11, Chapter 60, Section 11-60.1-101 and the application forms provided by the DOH. Because Section 11-60.1-101 essentially requires permit renewal applications to contain the same types of information needed for initial permit applications, much of the data presented in this document is unchanged from material provided in the 2003 renewal application. This application, however, also includes the significant modifications requested in 2006 and identifies the facility changes that have occurred during the current permit time frame (2006 through 2011), as well as proposed facility and permit changes for the renewal permit time frame (2011 through 2016).

### 2016 Update:

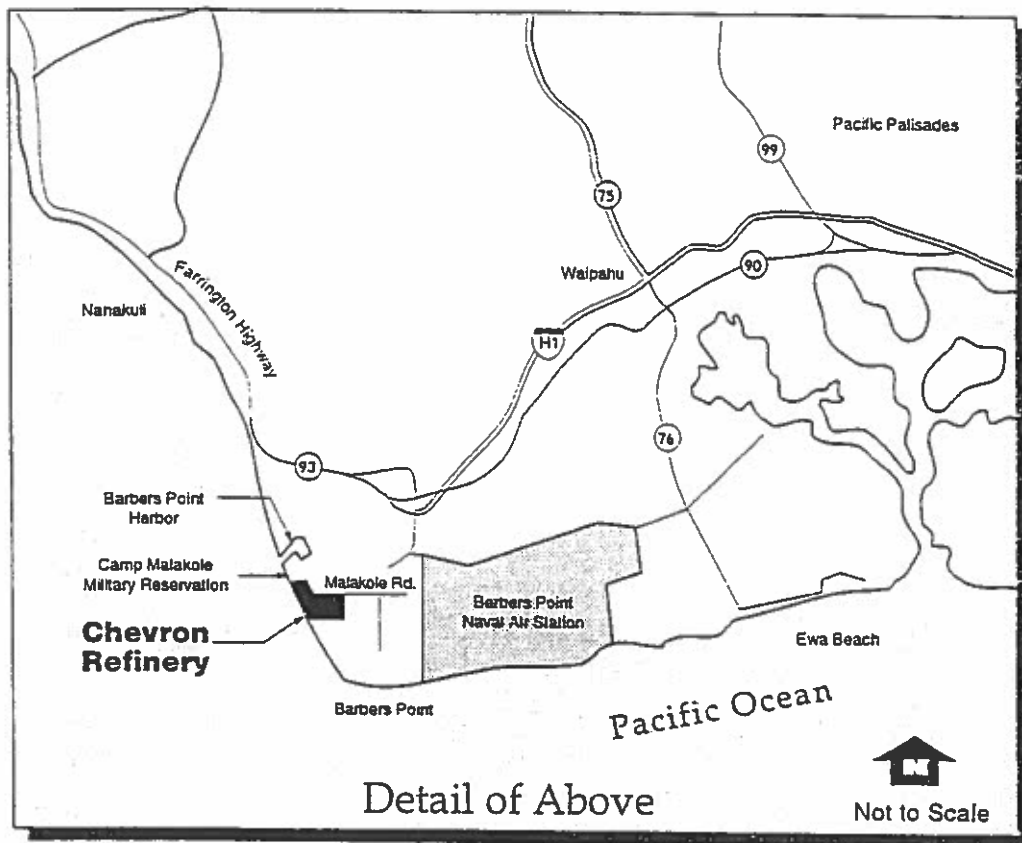
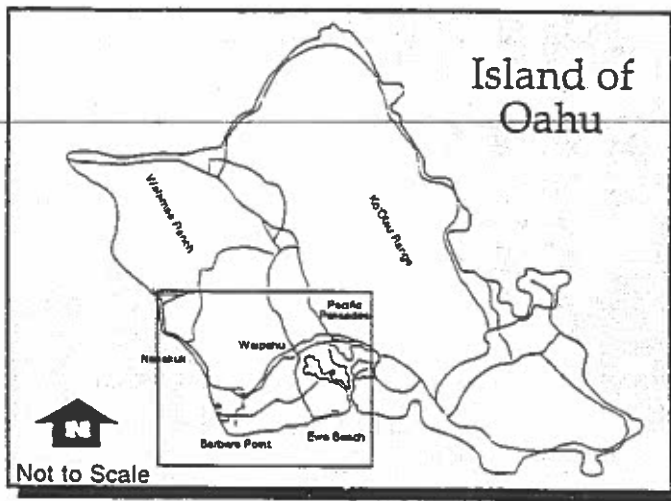
*This submittal updates the 2010 Renewal application for changes that have occurred since the December 2010 renewal submittal (2016 Update). The 2016 Update brings the 2010 Renewal current for requirements in HAR §11.60.1-101. Update changes are indicated by inserted information with a preceding "2016 Update" statement, or wording corrections indicated by original text strikethroughs, followed by corrected italicized wording. Inserts to original text and tables are highlighted yellow. As discussed with DOH staff, the required application fees were provided with the 2010 Renewal.*

*The Hybrid Energy Plant permit was issued separately as CSP 0088-02-C on 23 May 2007 with an expiration date of 22 May 2012. A renewal application for the Hybrid Energy permit was submitted to DOH in November 2011. All references to the Hybrid Energy Plant have been removed from the 2016 Update to the December 2011 Renewal application for CSP 0088-01-C.*

## **1.2 Facility Information**

The Hawaii Refinery is operated by ~~Chevron U.S.A. Products Company~~ **Chevron Products Company**, a division of Chevron U.S.A, Inc.. (Chevron). The responsible official is the Refinery Manager. The contact for questions regarding this application is the Air Environmental Specialist, who may be reached at (808) 682-5711.

The refinery is located within the Campbell Industrial Park at Kapolei, Ewa, Oahu, Hawaii, as shown on Figure 1-1. The refinery property consists of 248 acres situated at 21°18'40" North latitude and 158°06'57" West longitude.



SITE VICINITY MAP  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE: OCT 2010

FIG. NO:

1-1

The refinery address is:

~~Chevron U.S.A. Products Company, Hawaii Refinery~~  
*Chevron Products Company, Hawaii Refinery*  
91-480 Malakole Street  
Kapolei, HI 96707

The zoning of the refinery property is I-2, Heavy Industrial.

## 1.3 Overview

This application package has been designed to respond to the requirements of the DOH operating permit program regulations, including the requirements of §11.60-101, Covered Source Renewal. This section (Section 1) contains introductory and applicant information, as well as a completed DOH application form. Section 2 presents background information and a technical description of the refinery and its processes and operations. The estimated maximum potential emissions of regulated pollutants from refinery processes are presented in Section 3, along with a list of insignificant activities, as required in the DOH rules. This section also contains requests to continue the current exemptions for selected small sources in accordance with §11-60.1-82(e) through (g).

Section 4 presents information showing that the dispersion modeling analysis presented in the original Title V permit application (and updated modeling that has been done in association with subsequent facility modifications) remains adequate to represent the refinery's maximum impacts to local air quality. Section 5 is an assessment of regulatory requirements applicable to refinery operations and the associated monitoring and reporting activities.

## 1.4 Application Forms

The Standard Permit Application Form, S-1 is included at the end of this section. The form has been completed and a directory indicating the locations within this application of specific items requested on Page 3 of the form is provided below. Responses to the substantive information requirements of Form S-3 are also provided below.

### 1.4.1 Form S-1

The following information is provided in response to the information requested on DOH Form S-1, page 3 of 4. The items listed below are numbered according to the section designations used on Form S-1.

#### A. Emission Units Table

1. Section 2 and 3 describes the types and locations of emissions.
  - 1.1. Unique numbers for plant sites and equipment unit identification are in Table 2.1. These plant area site numbers match the unit description used on the location map in Figure 2.1.
  - 1.2. Emission point identification is provided by equipment numbers in Figures 2.3 through 2.13. These Figures are consistent with the unique numbers for plant sites provided in Table 2.1.
  - 1.3. SIC number is in Section 2.1.

- 1.4. Emission points are identified and described in Sections 2.3.1 through 2.3.15
  - 1.5. Emission points regulated and hazardous air pollutant data are provided in Section 3, Tables 3.1 through 3.13.
  - 1.6. Equipment Date is provided as an attachment to the S-1 Forms below.
  2. Emission rates are provided in Section 3
    - 2.1. Maximum facility emissions of regulated air pollutants are shown in Tables 3-12 and 3-13.
    - 2.2. Maximum pollutant emissions from the refinery processes are quantified in Section 3 of this application and summarized in Tables 3.1 through 3.11. Detailed emission calculations are presented in Appendix B.
    - 2.3. Fugitive emissions are quantified in Section 3, Tables 3.10 and 3.11. Detailed emission calculations are presented in Appendix B.
    - 2.4. Maximum potential emission rates expected are provided in pounds per hour or tons per year in Tables 3.1 through 3.13 with detailed emission calculations in Appendix B.
  3. Stack parameter information has been included as an attachment to the S-1 Forms below.
  4. Additional information
    - 4.1. Equipment units capable of using different fuels are listed in different rows in the attachment to the S-1 Forms below.
    - 4.2. All stacks provide a diameter as no rectangular stacks are currently on site.
    - 4.3. No stack parameters or height limitations were developed because of CAA Section 123. Stacks were all in existence prior to December 31, 1970.
- B. A process flow diagram of the Hawaii Refinery is shown in Figure 2-2 by plant site area number.
- B.1 Emission points are identified and described in the Form S-1 section 1.1 and 1.2. Process Flow diagrams in detail by plant site area are provided in Figures 2.3 through 2.13. Equipment unit numbers are included where applicable.
  - B.2 Emission Points where air pollutants are released to the atmosphere are also included in Figures 2.3 through 2.13. Combustion release points, controlled vents and exhaust gas release points are labeled where applicable.
- C. The general facility location is shown in Figure 1.1.
- C.1 The property involved, structures, property lines and fence lines are provided in Figure 2.1.
  - C.2 The layout of the facility is provided in Figure 2.1.
  - C.3 The approximate location of each emission unit is labeled by plant site area.
  - C.4 Location of the property is defined in Figure 1.1 providing major roads and key featured landmarks adjacent to the property. Location of equipment and adjacent streets are provided in Figure 2.1 by plant site areas.
- D. Facility changes and modifications are provided in Section 5.3.2.

#### 1.4.2 Form S-3

The following information is provided in response to the information requested on DOH Form S-3. The items listed below are numbered according to the section designations used on Form S-3.

- I.A This application describes facility changes that have occurred since submittal of the 2003 Covered Source Permit renewal application and the associated applicable requirements.
- I.B Equipment specifications, including applicable maximum design capacity, fuel type, fuel use, production capacity, production rates, and raw materials, are presented in Sections 2.2 through 2.8 and Appendix B.
- I.C A description of all facility processes and products defined by Standard Industrial Code is provided in Section 2.3. No anticipated alternative operating scenarios are proposed. Pollution control equipment used in the refinery is described in Section 3.3. List of insignificant activities is provided in 3.5.
- I.D The operating schedule for the refinery is described in Section 2.7.
- I.E Applicable air quality regulatory requirements, as defined in §11-60.1-81, and the associated compliance monitoring and reporting requirements are presented in Section 5.
- I.F The basis for estimating maximum facility emissions is provided in Section 3, including equipment and/or operating limitations that affect maximum emissions.
- I.G As described in Section 4, air quality assessments of the refinery's impacts on local air quality have been conducted for the initial Covered Source Permit application and in connection with subsequent applications for modifications to refinery facilities. These previous assessments are adequate to demonstrate that the refinery does not cause applicable ambient air quality standards to be exceeded.
- I.H This application for permit renewal does not pertain to a new covered source or to a significant modification subject to the Prevention of Significant Deterioration provisions of Subchapter 7 of HAR Chapter 11-60.1, and is therefore not required to submit the analyses, assessments, monitoring and other applicable requirements of Subchapter 7.
- I.I Chevron does not propose to conduct any emissions trading among sources of the Hawaii Refinery.
- I.J A completed compliance plan, DOH Form C-1, and a compliance certification, Form C-2, are provided in Section 5 of this application.

**S-1: Standard Air Pollution Control Permit Application Form<sup>1</sup>**  
(Covered Source Permit and Noncovered Source Permit)

State of Hawaii  
Department of Health  
Environmental Management Division  
Clean Air Branch  
P.O. Box 3378 · Honolulu, HI 96801-3378 · Phone: (808) 586-4200

1. Company Name: Chevron Products Company, a division of Chevron U.S.A. Inc.
2. Facility Name (if different from the Company): Chevron Hawaii Refinery
3. Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707
4. Name of Owner/Owner's Agent: Jon Mauer  
Title: Refinery Manager Phone: (808) 682-5711  
Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707
5. Plant Site Manager/Other Contact: Jon Mauer  
Title: Refinery Manager Phone: (808) 682-5711  
Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707
6. Permit Application Basis: (Check all applicable categories.)  
 Initial Permit for a New Source       Initial Permit for an Existing Source  
 Renewal of Existing Permit\*       General Permit  
\*Update to 2010 Renewal  
 Temporary Source       Transfer of Permit  
 Modification: ==> Is Modification?    Significant    Minor    Uncertain  
 Modification to a Noncovered Source
7. If renewal or modification, include existing permit number: CSP No. 0088-01-C
8. Does the Proposed Source require a County Special Management Area Permit?  Yes  No
9. Type of Source (Check One):       Covered Source       Covered and PSD Source  
 Noncovered Source       Uncertain
10. Standard Industrial Classification Code (SICC), if known: 2911

11. Proposed Equipment/Plant Location (e.g. street address): 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707

UTM Coordinates (meters): East: 591,657 North: 2,357,127

UTM Zone: 4 UTM Horizontal Datum:  Old Hawaiian  NAD-27  NAD-83

12. General Nature of Business: Petroleum Refining

13. Date of Planned Commencement of Construction or Modification: N/A

14. Is any of the equipment to be leased to another individual or entity  Yes  No

15. Type of Organization:  Corporation  Individual Owner  Partnership

Government Agency (Government Facility Code:     )

Other:

*Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit.*

(511-60.1-64 & 11-60.1-84)

'2016 Update to 2010 December Renewal Application form

**RESPONSIBLE OFFICIAL**

(as defined in 511-60.1-1)

Name (Last): Mauer (First): Jon (MI):     

Title: Refinery Manager Phone: (808) 682-5711

Mailing Address: 91-480 Malakole Street

City: Kapolei State: HI Zip Code: 96707

**CERTIFICATION by Responsible Official**

(pursuant to 511-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution control, and any permit issued thereof.

NAME (Print/Type): Jon Mauer

(Signature):  Date: 2/18/16

<b>FOR AGENCY USE ONLY:</b>
File/Application No.: _____
Island: _____
Date Received: _____



Submit the following documents as part of your application:

- A. The **Emissions Units Table**, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:
1. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SIC number. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirement of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
    - a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
    - b. Indicate the emission points that discharge together for any length of time.
    - c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.
  2. State the maximum emission rates in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
    - a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO<sub>x</sub>), Sulfur Dioxide (SO<sub>2</sub>), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM<sub>10</sub>). Abbreviations may be used.
    - b. Include fugitive emissions.
    - c. Pounds per hour (#/HR) is the maximum potential emission rate expected by applicant.
    - d. Tons per year is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.
  3. Describe **Stack Source Parameters**:
    - a. **Stack Height** is the height above the ground.
    - b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
    - c. **Flow Rate** is the actual, not the calculated, flow rate.
  4. Provide any additional information, if applicable, as follows:
    - a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
    - b. For a rectangular stack, indicate the length and width.
    - c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.
- B. A **process flow diagram** identifying all equipment used in the process, including the following:
1. Identify and describe each emission point.
  2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.
- C. A **facility location map**, drawn to a reasonable scale and showing the following:
1. The property involved and all structures on it. Identify property/fence lines plainly.
  2. Layout of the facility.
  3. Location and identification of the proposed emissions unit on the property.
  4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 100 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.
- D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.



Form S-1  
Stack Information

Stack or Fugitive Emission Release Point ID	Emission Unit ID	Process ID No. (Fuel/Product/Material ID No.)	Emission Unit Description that is being exhausted (78 characters max.)	Equipment Date	If single process exhausts to multiple stacks list % routed to each stack	UTM Easting (m) Horizontal X	UTM Northing (m) Vertical Y	Zone (4 or 5)	Datum (Old Hwm NAD-27, or NAD-83)	Stack Ht (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (deg. F)	Stack Flow Rate (ACFS)	Horizontal Collection Method	Reference Point Code	Horizontal Ac Measure
7	F5103	1	01 crude furnace	1961		592,053	2,356,683	4	NAD 83	141	4.9	40.8	350	777	027	106	500
7	F5103	2	01 crude furnace	1961		592,053	2,356,683	4	NAD 83	141	4.9	40.8	350	777	027	106	500
7	F5153	1	02 crude furnace	1961		592,053	2,356,683	4	NAD 83	141	4.9	40.8	350	777	027	106	500
7	F5153	2	02 crude furnace	1961		592,053	2,356,683	4	NAD 83	141	4.9	40.8	350	777	027	106	500
1	F5201	1	01 boiler	1961		591,888	2,356,981	4	NAD 83	125	9.2	19.7	500	1305	027	106	500
1	F5201	2	01 boiler	1961		591,888	2,356,981	4	NAD 83	125	9.2	19.7	500	1305	027	106	500
1	F5201	21	01 boiler	1961		591,888	2,356,981	4	NAD 83	125	9.2	19.7	500	1305	027	106	500
2	F5202	1	02 boiler	1961		591,884	2,356,989	4	NAD 83	125	5.6	36.1	370	882	027	106	500
2	F5202	2	02 boiler	1961		591,884	2,356,989	4	NAD 83	125	5.6	36.1	370	882	027	106	500
2	F5202	21	02 boiler	1961		591,884	2,356,989	4	NAD 83	125	5.6	36.1	370	882	027	106	500
3	F5203	1	03 boiler	1961		591,880	2,356,997	4	NAD 83	125	5.6	36.1	370	882	027	106	500
3	F5203	2	03 boiler	1961		591,880	2,356,997	4	NAD 83	125	5.6	36.1	370	882	027	106	500
3	F5203	21	03 boiler	1961		591,880	2,356,997	4	NAD 83	125	5.6	36.1	370	882	027	106	500
8	F5300	2	FCC Furnace	1961-62		591,896	2,356,928	4	NAD 83	140	5.6	22.3	712	545	027	106	500
9	F5930	2	Isom Furnace 01	1961-62		591,979	2,356,793	4	NAD 83	80	3.0	2.3	800	16	027	106	500
9	F5950	2	Isom Furnace 02	1961-62		591,979	2,356,793	4	NAD 83	80	3.0	2.3	800	16	027	106	500
10	F5700	2	H2 Manufac.	1960-62		592,058	2,356,642	4	NAD 83	125	5.9	6.2	500	171	027	106	500
11	F5600	2	Hydrogenation	1961-62		592,046	2,356,626	4	NAD 83	125	4.9	6.6	1510	125	027	106	500
12	F6200	2	Acid Plant CC	1961-62		591,907	2,356,434	4	NAD 83	123	3.0	9.7	175	68	027	106	500
13	F6262	2	Acid Pt Furnace			591,880	2,356,433	4	NAD 83	64	2.0	15.1	628	46	027	106	500
14	F6003	2	Asphalt Furnace			592,405	2,356,492	4	NAD 83	30	1.0	43.3	275	33	027	106	500
4	KC6701	2	01 cogen, combined cycle			591,824	2,357,038	4	NAD 83	70	3.9	68.6	399	835	027	106	500
4	KC6701	3	01 cogen, combined cycle			591,824	2,357,038	4	NAD 83	70	3.9	68.6	399	835	027	106	500
4	KS6701	2	01 cogen, simple cycle			591,824	2,357,038	4	NAD 83	70	3.9				027	106	500
4	KS6701	3	01 cogen, simple cycle			591,824	2,357,038	4	NAD 83	70	3.9				027	106	500
5	KC6702	2	02 cogen, combined cycle			591,819	2,357,047	4	NAD 83	70	3.9	68.6	399	835	027	106	500
5	KC6702	3	02 cogen, combined cycle			591,819	2,357,047	4	NAD 83	70	3.9	68.6	399	835	027	106	500
5	KS6702	2	02 cogen, simple cycle			591,819	2,357,047	4	NAD 83	70	3.9				027	106	500
5	KS6702	3	02 cogen, simple cycle			591,819	2,357,047	4	NAD 83	70	3.9				027	106	500
6	KC6703	2	03 cogen, combined cycle			591,814	2,357,057	4	NAD 83	70	3.9	68.6	399	835	027	106	500
6	KC6703	3	03 cogen, combined cycle			591,814	2,357,057	4	NAD 83	70	3.9	68.6	399	835	027	106	500
6	KS6703	2	03 cogen, simple cycle			591,814	2,357,057	4	NAD 83	70	3.9				027	106	500
6	KS6703	3	03 cogen, simple cycle			591,814	2,357,057	4	NAD 83	70	3.9				027	106	500
25	TkS104	11	Tk 104 External Floating Roof, Standing Loss			592,574	2,356,694	4	NAD 83	56	138				027	106	500
25	TkW104	11	Tk 104 External Floating Roof, Withdrawal Loss			592,574	2,356,694	4	NAD 83	56	138				027	106	500
26	TkS105	11	Tk 105 External Floating Roof, Standing Loss			592,675	2,356,692	4	NAD 83	61	176				027	106	500
26	TkW105	11	Tk 105 External Floating Roof, Withdrawal Loss			592,675	2,356,692	4	NAD 83	61	176				027	106	500
27	TkS106	11	Tk 106 External Floating Roof, Standing Loss			592,678	2,356,586	4	NAD 83	61	176				027	106	500
27	TkW106	11	Tk 106 External Floating Roof, Withdrawal Loss			592,678	2,356,586	4	NAD 83	61	176				027	106	500
28	TkS107	11	Tk 107 External Floating Roof, Standing Loss			592,782	2,356,695	4	NAD 83	55	176				027	106	500
28	TkW107	11	Tk 107 External Floating Roof, Withdrawal Loss			592,782	2,356,695	4	NAD 83	55	176				027	106	500
29	TkS108	11	Tk 108 External Floating Roof, Standing Loss			592,785	2,356,588	4	NAD 83	54	176				027	106	500
29	TkW108	11	Tk 108 External Floating Roof, Withdrawal Loss			592,785	2,356,588	4	NAD 83	54	176				027	106	500
30	TkS109	14	Tk 109 External Floating Roof, Standing Loss			592,577	2,356,582	4	NAD 83	61	176				027	106	500
30	TkW109	14	Tk 109 External Floating Roof, Withdrawal Loss			592,577	2,356,582	4	NAD 83	61	176				027	106	500
31	TkS110	11	Tk 110 External Floating Roof, Standing Loss			592,792	2,356,508	4	NAD 83	61	189				027	106	500

Form S-1  
Stack Information

Stack or Fugitive Emission Point ID	Emission Unit ID	Process ID No. (Fuel/Product/Material ID No.)	Emission Unit Description that is being exhausted (78 characters max.)	Equipment Date	If single process exhausts to multiple stacks, list % routed to each stack	UTM Easting (m) Horizontal-X	UTM Northing (m) Vertical-Y	Zone (4 or 5)	Datum (Old Hwn, NAD-27, or NAD-83)	Stack Ht (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (deg. F)	Stack Flow Rate (ACFS)	Horizontal Collection Method	Reference Point Code	Horizontal Ac Measure
55	TkW265	20	Tk 265 External Floating Roof, Withdrawal Loss			592,092	2,356,913	4	NAD 83	46	80				027	106	500
56	TkS266	3	Tk 266 External Floating Roof, Standing Loss			592,093	2,356,872	4	NAD 83	46	80				027	106	500
56	TkW266	3	Tk 266 External Floating Roof, Withdrawal Loss			592,093	2,356,872	4	NAD 83	46	80				027	106	500
57	TkS267	20	Tk 267 External Floating Roof, Standing Loss			592,094	2,356,828	4	NAD 83	46	80				027	106	500
57	TkW267	20	Tk 267 External Floating Roof, Withdrawal Loss			592,094	2,356,828	4	NAD 83	46	80				027	106	500
58	TkS269	3	Tk 269 External Floating Roof, Standing Loss			592,050	2,356,913	4	NAD 83	46	60				027	106	500
58	TkW269	3	Tk 269 External Floating Roof, Withdrawal Loss			592,050	2,356,913	4	NAD 83	46	60				027	106	500
59	TkS271	20	Tk 271 External Floating Roof, Standing Loss			592,052	2,356,828	4	NAD 83	43	77				027	106	500
59	TkW271	20	Tk 271 External Floating Roof, Withdrawal Loss			592,052	2,356,828	4	NAD 83	43	77				027	106	500
66	TkS272	18	Tk 272 Vertical Fixed Roof, Breathing Loss			592,011	2,356,909	4	NAD 83	48	77				027	106	500
66	TkW272	18	Tk 272 Vertical Fixed Roof, Working Loss			592,011	2,356,909	4	NAD 83	48	77				027	106	500
60	TkS273	12	Tk 273 External Floating Roof, Standing Loss			592,159	2,356,852	4	NAD 83	45	55				027	106	500
60	TkW273	12	Tk 273 External Floating Roof, Withdrawal Loss			592,159	2,356,852	4	NAD 83	45	55				027	106	500
61	TkS274	18	Tk 274 Vertical Fixed Roof, Breathing Loss			591,989	2,356,957	4	NAD 83	48	87				027	106	500
61	TkW274	18	Tk 274 Vertical Fixed Roof, Working Loss			591,989	2,356,957	4	NAD 83	48	87				027	106	500
62	TkS275	3	Tk 275 External Floating Roof, Standing Loss			592,019	2,356,941	4	NAD 83	31	34				027	106	500
62	TkW275	3	Tk 275 External Floating Roof, Withdrawal Loss			592,019	2,356,941	4	NAD 83	31	34				027	106	500
63	TkS301	13	Tk 301 External Floating Roof, Standing Loss			591,965	2,356,392	4	NAD 83	38	42				027	106	500
63	TkW301	13	Tk 301 External Floating Roof, Withdrawal Loss			591,965	2,356,392	4	NAD 83	38	42				027	106	500
64	TkS302	13	Tk 302 External Floating Roof, Standing Loss			591,973	2,356,376	4	NAD 83	38	42				027	106	500
64	TkW302	13	Tk 302 External Floating Roof, Withdrawal Loss			591,973	2,356,376	4	NAD 83	38	42				027	106	500
15	M1	4	FCC precip	1961-62		591,894	2,356,970	4	NAD 83	125	4.9	107.0	550	2034	027	106	500
15	M1	22	FCC precip	1961-63		591,894	2,356,970	4	NAD 83	125	4.9	107.0	550	2034	027	106	500
16	M2	5	Cooling Tower	1961-62		592,095	2,356,455	4	NAD 83	60	26.2	26.2	113	14201	027	106	500
17	M3	6	Acid Plant Absorber Stack	1961-62		591,907	2,356,434	4	NAD 83	123	3.0	9.7	175	68	027	106	500
18	M4	7	Catalyst Transfer			591,928	2,356,901	4	NAD 83						027	106	500
19	M5	8	Wastewater Treatment			591,675	2,357,127	4	NAD 83						027	106	500
19	M5	22	Wastewater Treatment			591,675	2,357,127	4	NAD 83						027	106	500
20	M6	9	Process Fugitives			591,675	2,357,127	4	NAD 83						027	106	500
21	M7	10	Load Rack			592,336	2,357,016	4	NAD 83						027	106	500
22	M8	9	FCC Flare	1961-62		592,141	2,356,378	4	NAD 83	157	0.6	65.6	1832	42.0	027	106	500
23	M9	9	Crude Flare	1961-62		592,207	2,356,412	4	NAD 83	155	0.2	65.6	1832	12.7	027	106	500
23	M9	22	Crude Flare	1961-62		592,207	2,356,412	4	NAD 83	155	0.2	65.6	1832	12.7	027	106	500
New			CatOX Unit	2009		591,791	2,356,909	4	NAD 83	30.8	1.11	61.0	305	58.62	027	106	500
New			Cogen Unit Black Start Generator	2014		591,894	2,356,970	4	NAD 83	8.83	0.49	220.6	809	43.44	027	106	500
New			Sand Filter Pump Diesel Engine #1	2006		592,074	2,356,424	4	NAD 83	6.00	0.3	0.0	809	3.53	027	106	500
New			Sand Filter Pump Diesel Engine #1	2007		592,074	2,356,424	4	NAD 83	6.00	0.3	0.0	809	3.53	027	106	500
New			Transfer Pump	2010		592,063	2,356,490	4	NAD 83	6.00	0.3	0.0	809	3.53	027	106	500





The basic steps used in refining crude oil feedstock at the Hawaii Refinery are as follows. First, crude oil is separated into several components using distillation methods. Heavier hydrocarbon compounds are further processed by cracking and subsequent combining or rearranging. Undesirable compounds containing sulfur, such as hydrogen sulfide or mercaptans, are removed or transformed to useful compounds. The various hydrocarbon components are blended together according to product specifications. For example, motor gasoline may include straight-run naphtha, cracked gasoline, reformate, alkylate and other components. Refinery operations also include auxiliary systems, such as hydrogen production, wastewater treating, acid production, and steam production.

## 2.3 Refinery Process Descriptions and Relationship to Marine Mooring Facility

The Hawaii Refinery is considered a major stationary source, and therefore is subject to the Title V permit program. A general process flow diagram for the refinery is presented in Figure 2-2. Marine tankers deliver crude oil from various locations to the Hawaii Refinery for processing. Marine vessel operations are exempted from the permitting requirements of the Hawaii program by HAR §11-60.1-82(d)(3). The marine mooring facility that services the refinery is approximately 1½ miles offshore and is not contiguous to the refinery. Accordingly, that facility operates under a separate Covered Source Permit, No. 0098-01-C. Chevron has submitted and received a separate permit renewal from DOH for the marine mooring facility.

### 2.3.1 Crude Unit

#### 2.3.1.1 Current Process

Crude oil processed at the refinery is transferred from tankers via pipeline to the blending and shipping area of the refinery, where it is placed in storage tanks. The crude oil is then pumped to the crude unit, where the refining process begins.

A simplified flow diagram of the crude distillation unit is presented as Figure 2-3. The crude feed enters the crude unit and is routed to the primary feed pump. This pump boosts the pressure of the feed to enable it to flow through the various heat exchangers and the desalter. The primary feed exchangers increase the temperature of the crude feed from approximately 100°F to about 300°F.

Crude oil frequently contains brine and inorganic salts from underground deposits. To minimize the fouling and corrosion of refining equipment, the crude is run through a desalter. The desalter reduces the velocity of the crude oil flow and, with the aid of electrical grids, separates additional water from the crude. Because most of the solids present are soluble in water, they leave the desalter with the water phase.

The crude oil out of the desalter is routed through a preheat exchanger to a flash drum to vaporize the light hydrocarbons and route them directly to the atmospheric column (bypassing the atmospheric furnace). The crude oil from the bottom of the flash drum is routed to the suction side of the crude booster pump, which pumps the oil through the secondary preheat train exchangers. The oil exiting the preheat exchangers is pumped through the atmospheric furnace into the atmospheric column, at a temperature of about 680 F.

## 2. Facility Description

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This section presents information describing operations at the Hawaii Refinery, as required by HAR §11-60.1-83(a)(2). The refinery receives various crude oils delivered by marine tankers and produces a wide variety of products. Operations vary depending on the material being processed and the products being manufactured. Information on these operations, equipment, and fuels, and other project description details are provided below.

The initial Covered Source Permit application package for the Hawaii Refinery was submitted to DOH in 1994 and included then current process descriptions and identified specific equipment and/or process changes that were anticipated at that time. The updated process descriptions provided in Sections 2.4.1 through 2.4.15 for individual refinery units include information on the current status of the changes that were anticipated in 1994. Additionally, several modification projects may be implemented during the renewal period from 2010 through 2016, and these are summarized in the appropriate process descriptions as well. Many of these prospective changes are intended to optimize existing operations, and are not considered modifications pursuant to State or Federal requirements. The Hybrid Project is the only proposed significant modification and is addressed in Section 3.5.3. Applicable regulatory requirements that would be triggered by these proposed changes are discussed in Section 5.

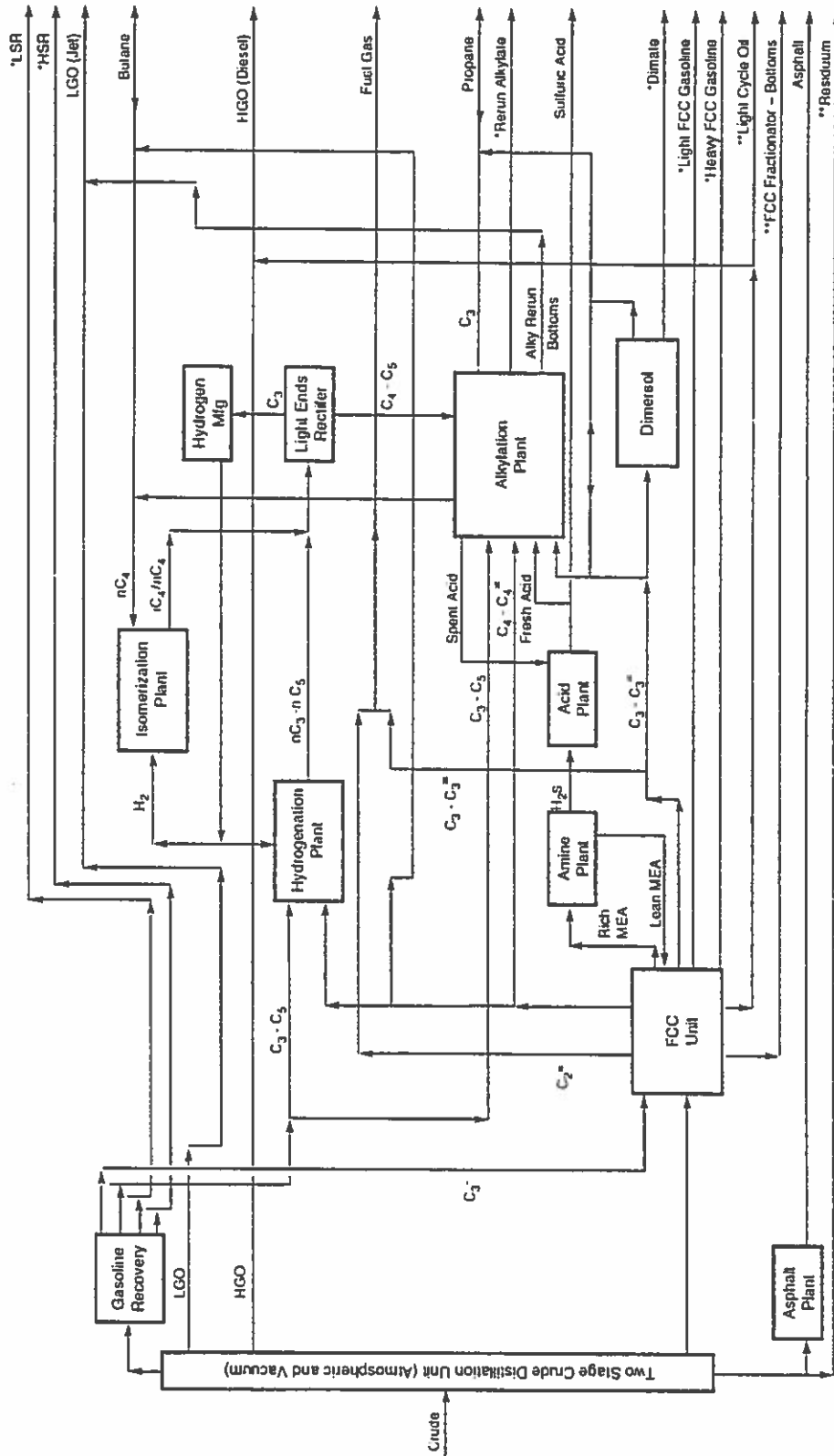
### 2.1 Nature and Location of Facility

The Hawaii Refinery is an integrated petroleum refinery on the island of Oahu, Hawaii. Please refer to Section 1 for a description of the facility location. The Standard Industrial Classification Code (SICC) for the refinery is 2911. The North American Industrial Classification System (NAICS) Code is 324110. A facility plot plan is presented as Figure 2-1.

### 2.2 Overview of Petroleum Refining

Crude oils are complex mixtures of chemical compounds ranging from dissolved gases to compounds that are solids at room temperature. Almost all of these compounds, however, are composed of hydrogen and carbon (hydrocarbon compounds). Also included in crude oil are water and trace contaminants such as inorganic salts, metals, and sulphur compounds.

The steps by which crude oil is processed into numerous saleable products are known collectively as refining. Crude oils from various locations may have differing compounds and properties that affect specific refinery operations. The initial refining process separates crude oil into different fractions based on their respective boiling point ranges. Some of the lighter and intermediate fractions are blended into products. Heavier fractions may be further processed by cracking the large hydrocarbon molecules into smaller ones. The structures of some molecules may also be rearranged to provide the desired components.



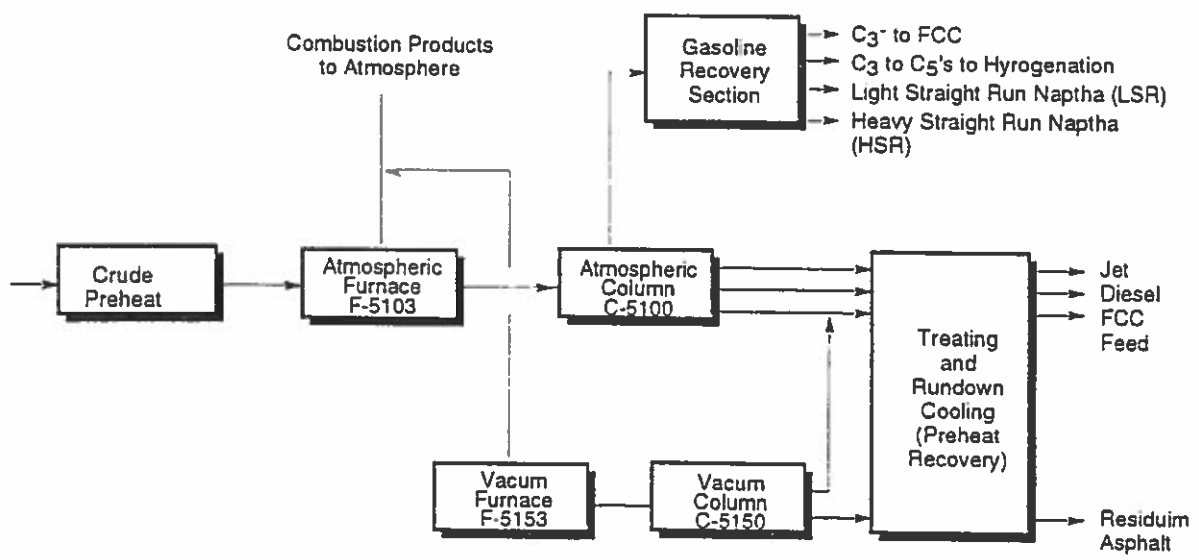
\* GASOLINE BLEND STOCKS  
 \*\* FUEL OIL BLEND STOCKS

HAWAII REFINERY GENERAL PROCESS FLOW  
 CHEVRONTXACO HAWAII TITLE V RENEWAL

DATE: 13	FIG. NO: 2-2
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CRUDE UNIT SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE: OCT 2010

FIG. NO:  
2-3

In the atmospheric column, the hot crude oil vaporizes and several product streams are drawn off, as follows:

- *Atmospheric overhead* – All material lighter than jet, which includes whole straight run naphtha and light ends such as methane, ethane, propane and butane
- *First side cut* – Normally commercial jet fuels (Jet A-40, Jet A-50, Jet JP-8)
- *Second side cut* – Not normally produced
- *Third side cut* – Low Sulfur Diesel fuel *Fourth side cut* – Atmospheric gas oil, which is fluid catalytic cracker (FCC) feed
- *Bottoms* – Feed to the vacuum column

The atmospheric tower bottoms product is routed through the vacuum furnace, where it is heated to approximately 790°F. Because products at lower pressure boil at lower temperatures, the vacuum column operates under vacuum to promote distillation of the heavy bottoms product without cracking of molecules. Two side product streams are both vacuum gas oil (VGO), which is used as a feed to the fluid catalytic cracker (FCC) unit. Residual product (residuum) is routed through exchangers to storage, where it is blended into fuel oil or a road asphalt base. Residuum may also be used as a feedstream to the FCC. Air pollutant emissions from the crude unit occur in the form of fugitive releases from piping components in gas and liquid service and as combustion products from the vacuum and atmospheric furnaces.

### 2.3.1.2 Future Process

~~Following is a description of potential crude unit alteration that may be implemented during the renewal period from 2011 through 2016. This change is primarily to optimize existing operations that may not require any modification to the current permit. The project consists of changing the fixed speed motors to variable speed motors for the forced draft fan and induced draft fan at the crude unit. This is an energy savings project that will optimize performance of the combustion process. The change would not increase the unit's operation beyond its original (permitted) capacity, although it could result in a slight increase in fuel combustion relative to operations in recent years.~~

#### 2016 Update:

*This change was not implemented.*

## 2.3.2 Fluid Catalytic Cracker (FCC) Unit

### 2.3.2.1 Current Process

The purpose of the fluid catalytic cracker (FCC) unit is to convert material from the crude unit into gasoline blend components. Additionally, the FCC produces refinery fuel gas, propane and propylene, butane and butylene, light cycle oil and fractionator bottoms.

The conversion of the FCC feed to higher valued products is accomplished by cracking the heavier hydrocarbon molecules into lighter molecules by contacting the feed with an air-assisted circulating catalyst at relatively high temperature (980-1010 F). The process of cracking the molecules results in the formation of coke on the catalyst. This coke inhibits the cracking process, so it is burned off to restore catalyst activity. The heat of combustion of the coke is a major source of heat to maintain the needed reaction temperature. The flue gas

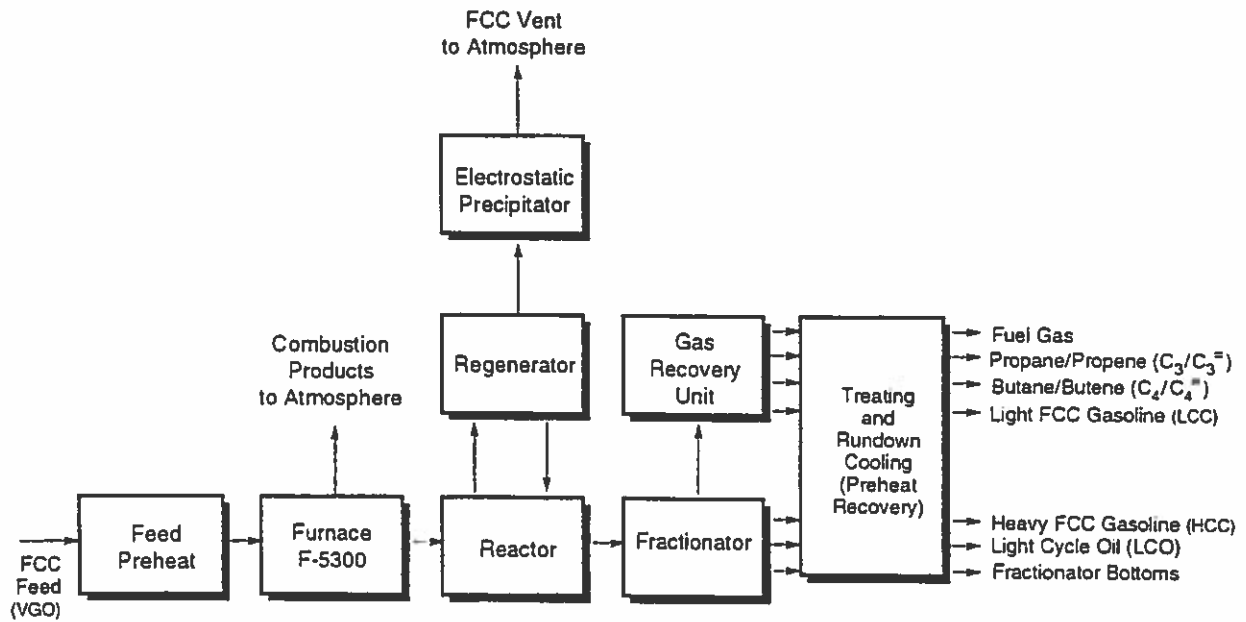
exiting the FCC is mixed with some particles of catalyst and routed through cyclones and an electrostatic precipitator to remove this particulate matter.

Products are routed to the fractionator and separated, as shown in Figure 2-4. The gas recovery unit separates gaseous products and includes removal of hydrogen sulfide. Products from the crude distillation towers and the FCC are treated by several other refinery process units, as discussed in the following subsections.

Since the initial covered source permit was issued, a low NO<sub>x</sub> burner has been installed on the FCC furnace that operates on RFG. This equipment change took place in 2008 and DOH was notified.

The refinery has been operating the FCC and regenerator with an electrostatic precipitator (ESP) since 1961. In 2002, the ESP was replaced, following application for and DOH approval of a minor modification to the existing Covered Source Permit. Emissions from the FCC and gas recovery unit consist of piping component fugitives, as well as PM<sub>10</sub> and combustion gases from the precipitator and FCC furnace.

In 2002, Chevron also applied for a permit modification to enable a FCC Revamp Project to modernize the technology of the FCC to current industry standards. The DOH issued a permit amendment to the Covered Source Permit for this project on March 3, 2003. The project included installation of a slide valve control to improve the ability of the operators to balance the operation of the catalyst reaction and regeneration vessels, as well as other upgrades. The project has resulted in improved reliability, ability to implement advanced controls, improved turndown capability/environmental performance, and better operational flexibility to process low sulfur feeds to meet the future low sulfur gasoline requirements.



FCC UNIT SIMPLIFIED PROCESS FLOW DIAGRAM  
 CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE: OCT 2010

FIG. NO:

2-4

The FCC Revamp Project application presented to DOH showed that the project would not cause an emission increase and therefore would not trigger any new federal New Source Performance Standards (NSPS) or the Prevention of Significant Deterioration (PSD) permitting process. The DOH processed the application as a major modification, because DOH added federally enforceable permit conditions to maintain emissions below PSD levels. Dispersion modeling was conducted that showed the project would have a negligibly small effect on local air quality. The project was completed in May 2003.

A Flare Vapor Recovery Compressor (FVR) has been added to the Miscellaneous Process Units and source operations. This equipment reduces the plant emissions from the FCCU although it is physically located in the Crude Unit area. PTE were not accounted for as fuel streams vary based on plant activity. As this equipment does not account for an increase in emissions it was not considered a significant modification.

Monitoring equipment for continuous measurement of opacity and CO emissions were installed and in operation to comply with MACT 'UUU' standards before April 2005. Additional CEMS and COMS were installed in 2005 and 2006 to monitor for NO<sub>x</sub>, SO<sub>2</sub> and O<sub>2</sub>.

2016 Update:

*The following changes were implemented since the 2010 Renewal submittal:*

- a. *The FCC Startup air heater was replaced in 2013. The replacement was permitted as a minor modification. A copy of the permit amendment for Attachment II(I) is included in Appendix G.*
- b. *The FCC regenerator catalyst air grid was replaced in 2013 as discussed in Section 2.3.2.2 below.*
- c. *The FCC opacity COMs was replaced with a newer unit in 2015.*
- d. *FCCU NO<sub>x</sub> limits were permitted October 9, 2015. A copy of the permit amendment for Attachment II(I) is included in AppendixG .*

**2.3.2.2 Future Process**

A redesign of the air grid at the FCCU is currently being considered as a proposed change for 2013. The FCCU Regenerator currently has a plate grid. The plate grid consists of a plate with holes in it, that allows air to come through to ensure fluidization and combustion in the bed. The plate grid is prone to mechanical stress and causes grid differential pressure problems which can lead to de-fluidization. Chevron is investigating a change in design to a pipe grid in which air flow through pipes and out nozzles. The new design of the pipe grid will ensure fluidization and allows improved turndown of feed rates.

2016 Update

*The air grid change described above was installed in 2013.*

*The FCCU startup air heater was permitted to combust inherently low sulfur content (sulfur content not to exceed 30 ppmv H<sub>2</sub>S) commercial grade LPG NSPS Ja 60.107a(a)(3)(ii). The facility proposed a fuel description change to inherently low sulfur fuel gas (sulfur content not to exceed 30 ppmv H<sub>2</sub>S) as allowed by NSPS Ja 60.107a(a)(3)(ii). This change in fuel description language does not alter the emissions, monitoring requirements, or permit limits for the heater.*

## **2.3.3 Hydrogen Manufacturing Plant**

### **2.3.3.1 Current Process**

The purpose of the hydrogen plant is to convert butane, propane and the lighter hydrocarbons into hydrogen and carbon dioxide. The hydrogen is used in the hydrogenation, dimersol, and isomerization processes. The carbon dioxide generated in the unit is vented to the atmosphere. The hydrogen manufacturing process separates the hydrogen atoms from hydrocarbon molecules in a catalytic reforming furnace. The hydrogen unit emits fugitive emissions from piping components and combustion products from the furnace. A simplified flow diagram of the hydrogen plant is provided in Figure 2-5.

### **2.3.3.2 Future Process**

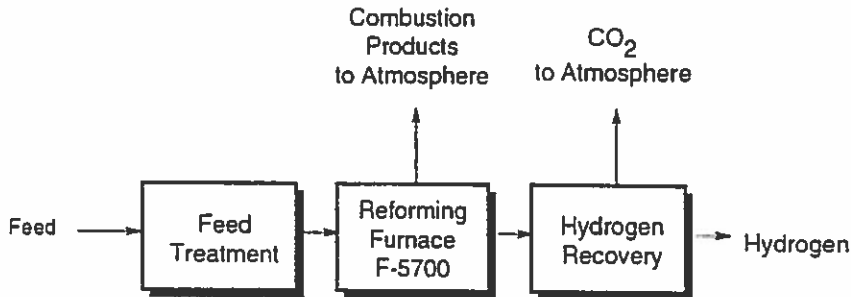
No changes have occurred in the Hydrogen Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

## **2.3.4 Hydrogenation Plant**

### **2.3.4.1 Current Process**

The hydrogenation plant saturates butene with hydrogen to form a saturated butane molecule. The butane is then fed to the isomerization process or used for gasoline blending. The hydrogenation process uses a fixed-bed reactor with a hydrogen rich atmosphere. The hydrogenation plant emits fugitive emissions from piping components and combustion emissions from the hydrogenation furnace. A simplified representation of the unit's process flow is shown in Figure 2-6.

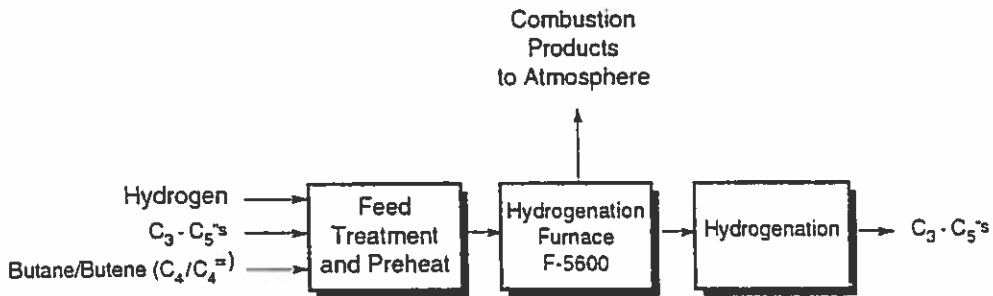
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HYDROGEN PLANT SIMPLIFIED  
PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE: OCT 2010

FIG. NO:  
2-5



HYDROGENATION PLANT SIMPLIFIED  
PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE: OCT 2010

FIG. NO:

2-6



### 2.3.4.2 Future Process

~~The Ultra Low Sulfur Diesel Project is being proposed at the refinery at this time. The project includes modifying the existing Hydrogenation Plant to allow it to process FCC Heavy Cat Crack, a gasoline blend component, and Crude Unit diesel in addition to the existing streams it processes today. The objectives of the modified plant will be the removal of sulfur and nitrogen from the feed streams. The project will require new pumps, vessels, piping, distillation columns and their associated equipment, and potentially a new reactor. No analysis of the proposed equipment changes has taken place at this time to understand the air quality impacts. The following proposed facility modification is described below for information purposes only. As further information on the project develops, the quantitative effects on emissions, if any, will be evaluated and applicable rules will be addressed on a case-by-case basis.~~

#### 2016 Update:

*This project is no longer being proposed by the refinery.*

## 2.3.5 Dimersol Plant

### 2.3.5.1 Current Process

A Dimersol reactor and associated facilities were installed in 1987 as part of the gasoline manufacturing section to improve C3 handling within the refinery and to reduce flaring. The Dimersol plant converts propylene into dimate (hexene isomers), a gasoline blend component. The dimate is routed to a storage tank for blending. Propylene feed is supplied from the FCC unit and is converted in the Dimersol Reactor.

The Dimersol process is a closed-loop system that does not emit pollutants directly to the atmosphere. Fugitive piping component emissions, however, are released from the Dimersol Plant. A simplified process flow diagram for this unit is presented as Figure 2-7.

### 2.3.5.2 Future Process

No changes have occurred in the Dimersol Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

## 2.3.6 Isomerization

### 2.3.6.1 Current Process

The purpose of the Isomerization Plant is to convert normal butane into isobutane. Isobutane is required as one of the two feed components in the alkylation process. The isomerization process uses a fixed bed reactor with a catalyst of aluminum beads. The feed stream is dehydrated upstream of the isomerization process, as water will deactivate the catalyst. Combustion emissions from the isomerization furnace and fugitive emissions from piping components result from operation of the Isomerization Plant. The products of the isomerization process are fed to the Alkylation Plant. A simplified process flow diagram for this unit is presented as Figure 2-8.

### 2.3.6.2 Future Process

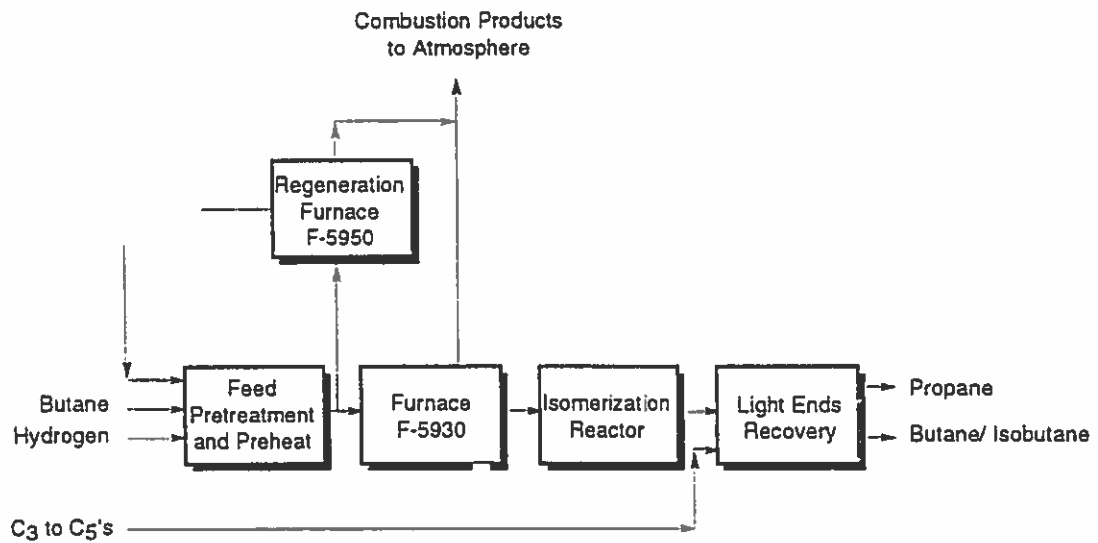
No changes have occurred in the Isomerization Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.



DIMERSOL PLANT SIMPLIFIED  
PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE: OCT 2010

FIG. NO:  
2-7



ISOMERIZATION PLANT SIMPLIFIED PROCESS FLOW  
 DIAGRAM [INCLUDING LIGHT ENDS RECTIFIER (LER)]  
 CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE: OCT 2010

FIG. NO:  
 2-8 15

## 2.3.7 Alkylation

### 2.3.7.1 Current Process

The alkylation process joins the isobutane from the Isomerization Plant with propylene or butene to form alkylate, a gasoline-blending component. This reaction is catalyzed by high-concentration sulfuric acid. The reaction is exothermic and the heat of reaction is captured by heat exchangers. The alkylation process emits fugitive piping component emissions. A simplified process flow diagram for this unit is presented as Figure 2-9.

### 2.3.7.2 Future Process

No changes have occurred in the Alkylation Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

## 2.3.8 Acid Manufacturing

### 2.3.8.1 Current Process

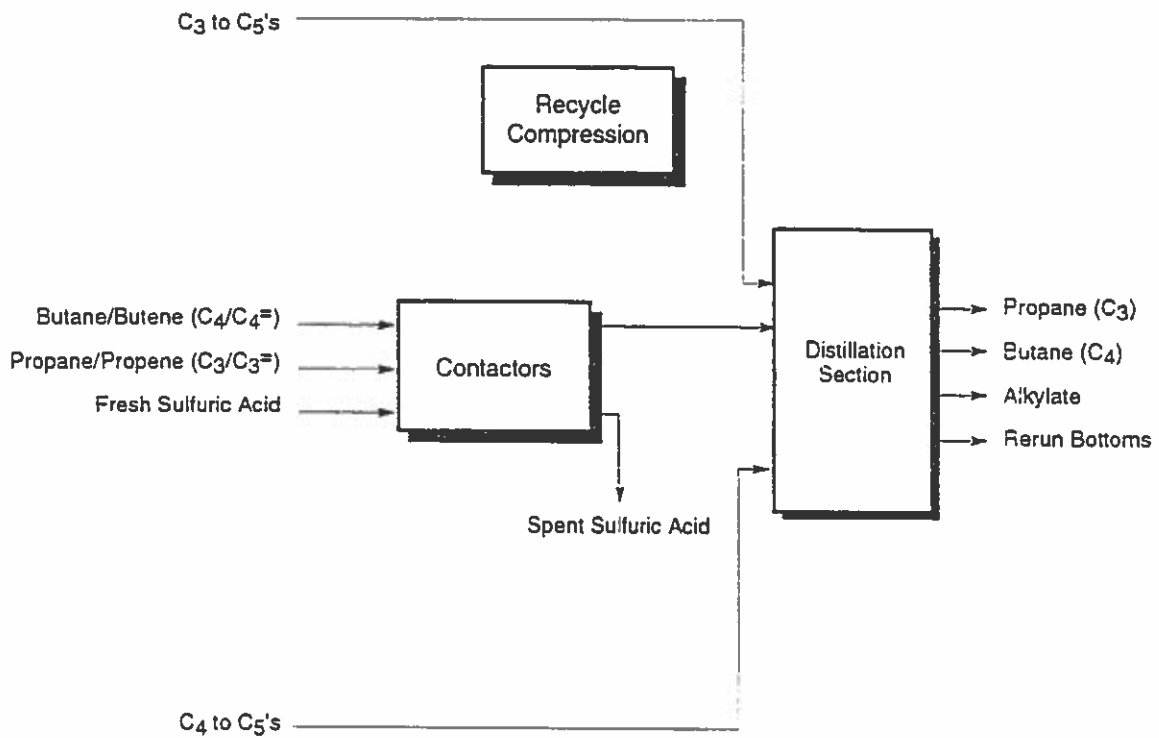
The Acid Manufacturing area of the Hawaii Refinery includes sulfuric acid manufacturing, acid storage, and amine processing facilities. The Amine Plant is an amine regeneration system used to recover hydrogen sulfide. The Acid Plant manufactures sulfuric acid from feedstocks available in the refinery.

The principal feeds are spent acid returned from the alkylation plant and H<sub>2</sub>S gas from the amine regeneration system. The Acid Plant produces acid by decomposition of spent acid and combustion of hydrogen sulfide gas to form sulfur dioxide (SO<sub>2</sub>). The SO<sub>2</sub> is then oxidized to form sulfur trioxide (SO<sub>3</sub>). Finally, the SO<sub>3</sub> is absorbed in a strong sulfuric acid solution to form sulfuric acid. Residual unconverted SO<sub>2</sub> is emitted from the absorber stack. Fugitive component emissions result from the acid and amine regeneration facilities. The acid plant combustion chamber and preheater emit combustion products. The combustion chamber exhaust passes through the plant and is emitted from the adsorbing tower stack. A simplified process flow diagram is presented as Figure 2-10.

A Caustic Scrubber Project was installed during 2003. The project entailed utilization of a caustic system to remove hydrogen sulfide from the acid gas feed stream during periods when the acid plant is shut down and all the acid plant gas is routed to the FCC unit flare. This change was implemented to improve process operations, rather than as an air pollution project.

### 2.3.8.2 Future Process

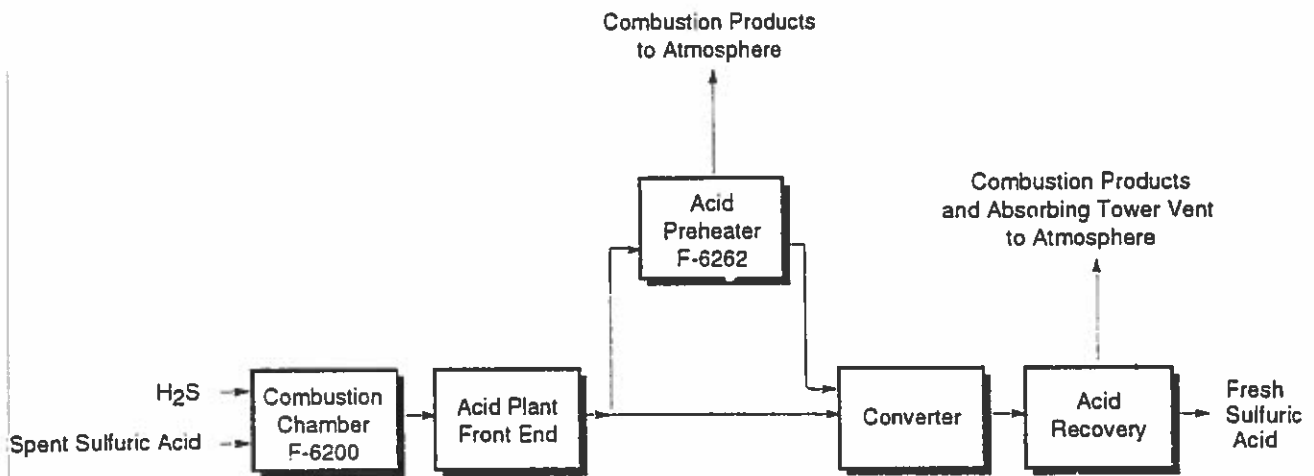
No changes have occurred in the Acid Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.



ALKYLATION PLANT SIMPLIFIED  
PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE: OCT 2010

FIG. NO:  
2-9



ACID PLANT SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE: OCT 2010

FIG. NO:  
2-10

## 2.3.9 Boiler Plant

### 2.3.9.1 Current Process

Steam is critical to the refinery processes and 600-pound steam is used throughout the facility. Steam is supplied by three boilers in the Boiler Plant and three Cogeneration Plant turbines, each of which is equipped with a heat recovery steam generator (HRSG). The Boiler Plant consists of the three boilers and ancillary fuel supply systems. Both RFG and fuel oil are used as fuels in the boilers.

In April 2007, Chevron accepted 40 CFR 60 Subpart J, Standards of Performance for Petroleum Refineries, for the boilers and furnaces at the refinery.

### 2.3.9.2 Future Process

~~The only change in this area being considered for implementation during the term of the renewed permit is the hybrid energy project that would replace the steam generation function of the three existing boilers with two new boilers and a new cogeneration plant (see Section 2.3.10). The proposed details of the hybrid energy project were provided to DOH on May 25, 2006 and updated on August 23, 2006 in the significant modification application available in Appendix E. These proposed equipment changes have been accounted for in the Covered Source Permit issued on May 23, 2007. Implementation of the hybrid energy project is slated for 2011.~~

#### 2016 Update:

*The Hybrid Energy Project was issued a separate covered source permit: CSP 0088-02-C.*

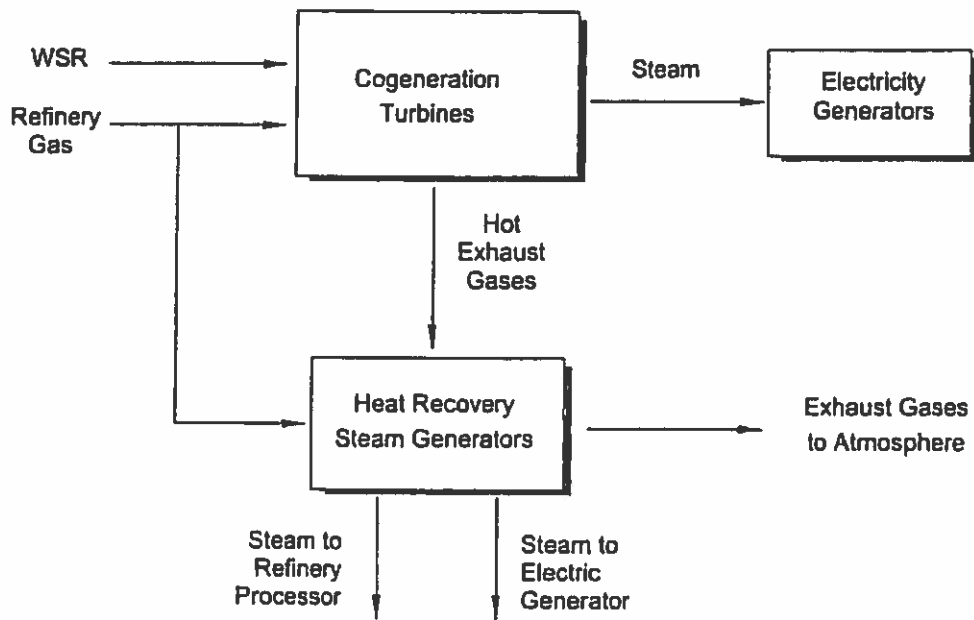
## 2.3.10 Cogeneration Plant

### 2.3.10.1 Current Process

This area includes three 40 MMBtu/hr gas turbines with Heat Recovery Steam Generators (HRSGs). These units are equipped with low-NO<sub>x</sub> burners and water injection for control of NO<sub>x</sub> emissions. Refinery fuel gas (RFG) and whole straight run naphtha (WSR) are used as fuels in the cogeneration turbines. Only RFG is combusted in the HRSGs. Fuel combustion products are emitted from these units. A process flow diagram for the Cogeneration Plant is provided in Figure 2-11.

### 2.3.10.2 Future Process

The hybrid energy project was proposed to DOH in May 2006 to install one new 46 MMBTU/hr cogeneration turbine and a new Heat Recovery Steam Generator (HRSG). Controls and fuels used will be consistent with existing turbines. The modified Covered Source Permit accounting for this change in equipment was issued from DOH on May 23, 2007.



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**COGENERATION PLANT  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRON HAWAII REFINERY**

DATE: OCT 2010

FIG. NO:  
2-11



## 2.3.11 Blending and Shipping

### 2.3.11.1 Current Process

The blending and shipping area includes the refinery tank farm, LPG handling system and truck loading racks. Fugitive emissions from tanks and piping components are emitted from this process area, which contains no fuel-burning equipment.

The refinery tank farm consists of storage tanks for the following hydrocarbon liquids: crude oil, refinery products, blending components and recovered oil. The capacities, control equipment and types of service that have been assumed in postulating the maximum emission scenario for the refinery, including tank emissions, are described in Section 3.

Chevron has installed secondary seals or equivalent controls on storage tanks at the facility to meet 40 CFR 63 Subpart CC requirements. Tanks 249, 250 were changed to Domed External Floating Roof for storage of Aviation gasoline in December 2001. Tank 275 changed to Domed External Floating Roof in August 2006. Tanks 268, 270 and 272 contain Diesel fuel and do not have secondary seals installed.

The current Covered Source Permit allows the storage capacities of Storage Tanks 105 through 111 to be increased by 12 percent, provided that no new applicable requirement is triggered by such action and the seal requirements pursuant to 40 CFR Part 63, Subpart CC have been met. Since the issuance of the initial permit, Tanks 105, 106, 109, 110 and 111 have received course additions that increased their capacities by about 12 percent. Tanks 107 and 108 may be similarly expanded during the term of the renewed Covered Source Permit. Tanks 232, 235 and 253 had 1% increases in capacity. Tanks 237 and 271 had 3% increases. Tank 269 had a 5% increase in capacity. These smaller increases were not because of changes in the capacity of the tank itself. Rather, these capacities were changed from the safe oil height capacity to the maximum capacity of the tank as a conservative assumption for calculations.

Since the initial issuance of the Covered Source Permit some of the tanks have changed service type. Tank 109 went from Crude to Gasoline and those tanks storing LSR/HSR are now storing WSR.

All tank changes have been accounted for in the maximum emission calculations in Table 3.4 and 3.5. Detailed emission calculations are provided in Appendix B.

Typically, products from the refinery are shipped offsite via pipeline, and the truck loading rack is not used. If the pipeline is unavailable, the truck loading rack at the refinery will be used. Estimated loading volumes during such periods, based on the assumption that the refinery would need to meet the outer island fuel demands, are as follows:

- Motor gasoline – 20,000 barrels per day
- Aviation gasoline – 110 barrels per day
- Jet Fuel – 13,000 barrels per day
- Diesel – 10,000 barrels per day

2016 Update:

*The following changes in tank services have been made since the December 2010 Renewal Application:*

- 1) *Tank 109 service has changed from gasoline to Crude Oil. This service change results in lower air emissions and does not change or cause new or additional Subchapter 8 or 9 requirements. Therefore, a permit modification was not required.*
- 2) *Tank 111 service has changed from gasoline to Crude Oil. This service change results in lower air emissions and does not change or cause new or additional Subchapter 8 or 9 requirements. Therefore, a permit modification was not required.*
- 3) *Tank 104 service was permitted for both Crude and Recovered Oil. A copy of the permit change is included in Appendix C.*
- 4) *Tank 152 is no longer in crude service and stores heavy liquid stock. This tank should be removed from the point source list, and moved to Insignificant Activities Heavy Liquids #10.*

**2.3.11.2 Future Process**

No additional changes to storage tanks are being considered for implementation during the term of the renewed permit.

**2.3.12 Asphalt Plant****2.3.12.1 Current Process**

The asphalt plant consists of tanks, pumps, a fired furnace and loading racks. In early 2008, the asphalt plant was taken out of operation and activity of associated equipment ceased. ~~With the exception of the furnace, equipment has been altered to prevent operation. The furnace has not operated and has no plans during the renewal term of this permit to come back online. As the furnace is still capable of combusting fuel, potential to emit calculations were included in Section 3.~~

2016 Update:

*The asphalt furnace has been removed from the facility. Potential to emit calculations have been removed from Section 3. The Asphalt Plant and associated equipment can be removed from the permit.*

**2.3.12.2 Future Process**

No operation of the asphalt plant equipment is expected through the permit renewal term.

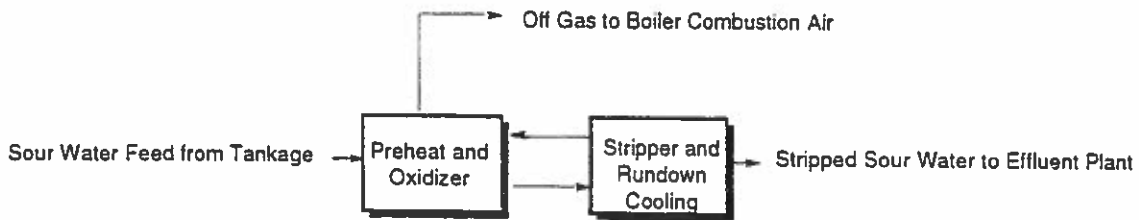
**2.3.13 Effluent Treatment****2.3.13.1 Current Process**

Wastewater consists of process area sampling waste, process (oily) wastewater, and stormwater waste. Wastewater containing ammonia, sulfides, and hydrocarbons is routed to the sour water tanks, then treated in the Foul Water Oxidizer and pumped to the wastewater treatment plant. Off-gas (primarily ammonia) from the Oxidizer is sent via the combustion air to one of the boilers. A simplified process flow diagram of the Foul Water Oxidizer is presented in Figure 2-12.

Wastewater not sent to the Foul Water Oxidizer (i.e., possibly containing hydrocarbons) is routed to the API separators, where oil is recovered and the resulting wastewater is treated. Treatment for process wastewater uses a nitrogen gas stripper for benzene control. Gaseous hydrocarbons from the nitrogen stripper are removed in a carbon adsorber. Both process wastewater and stormwater waste are then treated by aggressive biological oxidation in

ponds. A simplified process flow diagram of the Effluent (Wastewater Treatment) Plant is presented in Figure 2-13. Minimal fugitive emissions result from the foul water and wastewater treatment plants.

The landfarm previously used to biodegrade hydrocarbon-contaminated soils ceased to receive such materials in July 1995, was capped in November 1997 and received formal closure from EPA in 1998. This facility is no longer in use, but ongoing activities include monthly inspections of the cap integrity and quarterly monitoring of permitted wells for BTEX and semi-volatiles. Groundwater monitoring in this area is to be included in the annual—plume-wide Groundwater Monitoring Program-submitted to DOH.

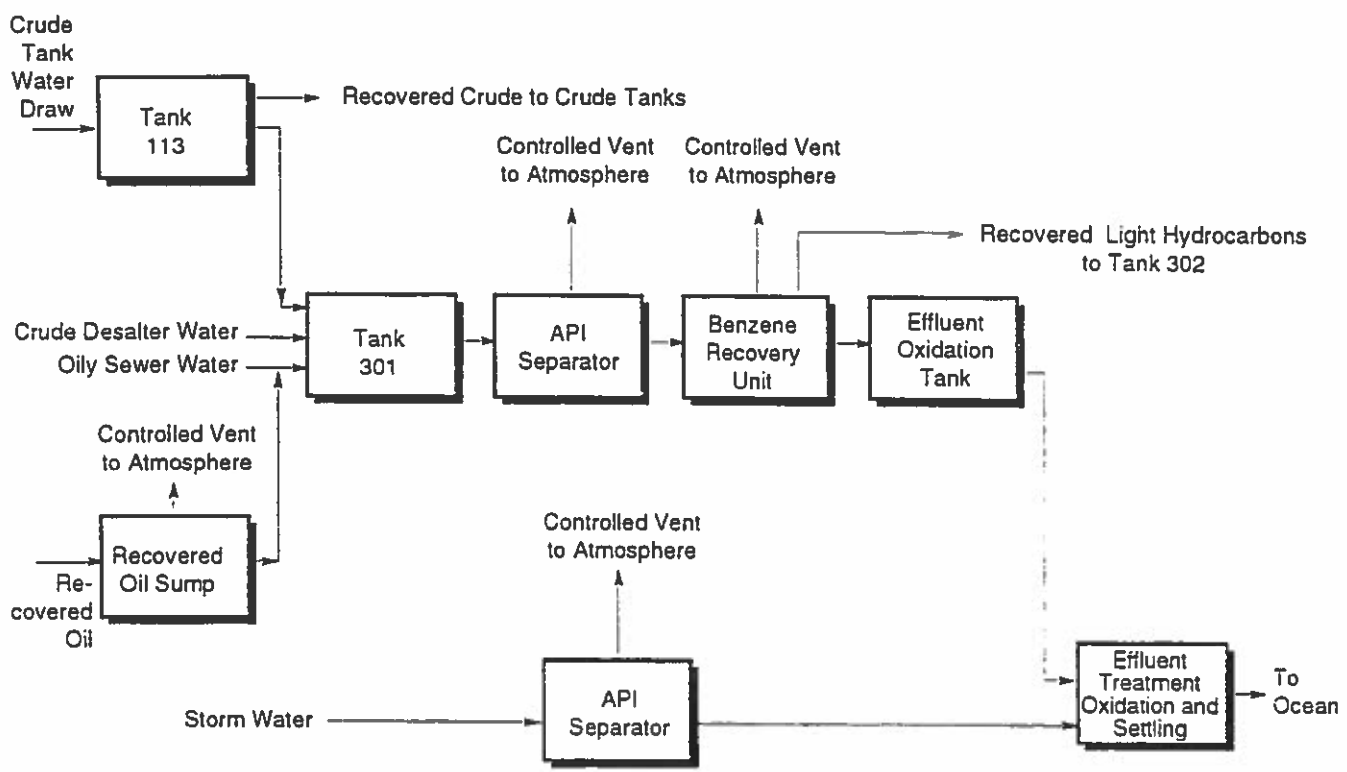


**FOUL WATER OXIDIZER  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL**

DATE: OCT 2010

FIG. NO:  
2-12

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**EFFLUENT PLANT  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL**

DATE: OCT 2010	FIG. NO: 2-13
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### 2.3.13.2 Future Process

~~Except for closure of the landfarm, no changes have occurred in the Effluent Treatment Area since the original Title V permit for the refinery was issued, and no future changes are under consideration at the time of this permit renewal application.~~

#### 2016 Update:

*In addition to closure of the landfarm, the facility received a permit to treat the off gas (primarily ammonia) from the Foul Water Oxidizer referenced in Section 2.3.13.1 and Section 3.6, to a Catalytic Oxidation ("CatOx") Unit. The CatOx Unit is anticipated to be put into service during 2016.*

## 2.3.14 Flares

### 2.3.14.1 Current Process

Safety is a critical concern in refinery operation. In case of equipment failure or other malfunctions, systems are in place to protect the equipment from damage and the facility's workers from harm. The refinery has many safety systems, including two flares. ~~During normal operations, the FCC Flare primarily combusts off-gases from the FCC Unit, Isomerization Plant, Alkylation Plant, Cogeneration Plant, Acid and Amine Plants, sour water tankage, and fuel gas system. The Crude Unit Flare serves the Crude Unit, Hydrogen Plant, Hydrogenation Plant and Dimersol Plant, LPG area, as well as the sour water tankage and has a CEMS. Each flare handles gases for their associated equipment units during shutdown. Historically, during Acid Plant shutdowns, the H<sub>2</sub>S stream to the plant was routed to the FCC Flare for destruction. However this no longer occurs because of the Caustic Scrubber project discussed below.~~

As described in Section 2.3.8, the Caustic Scrubber project has been implemented and will send acid gas streams through a caustic system for H<sub>2</sub>S removal before routing it to the flare when the Acid Plant is down, thus sharply reducing the SO<sub>2</sub> emissions of the refinery during Acid Plant downtime.

#### 2016 Update:

*During normal operations, the majority of the processing unit relief gases are recovered by the Flare Vapor Recovery Unit (FVRU) referenced in Section 2.3.21. In situations where the FVRU cannot recover all the relief gases, the FCC Flare primarily combusts off-gases from the FCC Unit, Isomerization Plant, Alkylation Plant, Cogeneration Plant, Acid and Amine Plants, sour water tankage, and the fuel gas system. The Crude Unit Flare serves the Crude Unit, Hydrogen Plant, Hydrogenation Plant and Dimersol Plants, and the LPG area.*

*Additionally, since the December 2010 Renewal Application, the facility has installed total sulfur CMS on each flare to meet newly effective NSPS Ja flare monitoring requirements. In addition, the Crude Flare H<sub>2</sub>S CMS was replaced in October 2015.*

### 2.3.14.2 Future Process

No future changes are under consideration at the time of this permit renewal application.

## 2.3.15 Cooling Tower

### 2.3.15.1 Current Process

The refinery employs an induced draft evaporative cooling tower to dissipate waste heat from several refinery processes. The cooling tower has ten cells.

### **2.3.15.2 Future Process**

No changes in the cooling system have been undertaken since issuance of the initial Title V permit for the Hawaii Refinery, and none are under consideration at the time of this permit renewal application.

### **2.3.16 Tier 3 Future Project**

A project to modify some of the refinery processing units in order to comply with Tier 3 gasoline standards is being considered for implementation during the term of the renewed permit. The Crude Unit, FCCU, Dimersol, Hydrogenation Plant, and Blending and Shipping equipment may require some modifications, and will be addressed in a separate permit application.

## **2.4 Design and Production Rate and Capacity**

As discussed above, the refinery consists of numerous interrelated process units. Table 2-1 presents design capacity and production capacity/rate information for the major refinery process units and equipment. Actual throughputs of the units will vary over time, depending on numerous variables; however, any one process or piece of equipment may operate at its design capacity periodically or for extended periods.

## **2.5 Fuels and Fuel Use**

Combustion sources at the refinery are fueled primarily by RFG or refinery fuel oil. The cogeneration turbines may be fired on either RFG or whole straight run naphtha. Fuel types and fuel use rates for specific equipment unit are presented in Table 2-2. Fuel usage rates have been estimated based on equipment design heat rates and the estimated average lower heating value (LHV) of the applicable fuels. RFG has an estimated average lower heating value of approximately 1030 Btu per standard cubic foot. Whole straight run naphtha has an estimated average lower heating value of approximately 4758 MBTU/bbl.

Actual fuel heating values vary according to refinery operations. Fuel oil has an estimated average LHV of approximately 5.78 MMBtu per barrel. Fuel flow rates in the cogeneration turbines and HRSGs are limited by DOH permit conditions.

## **2.6 Raw Materials**

The primary raw material used in the Hawaii Refinery is crude oil. The base operating scenario for the refinery is the processing of a wide variety of crude oils from various sources. Crude oil is processed at a maximum rate of approximately 65,000 barrels per day. A list of the raw materials used at the refinery is presented in Table 2-3.

## 2.7 Plant Layout and Operating Schedule

The plant layout is presented on Figure 2-1. The refinery operates 24 hours per day, 7 days per week, 52 weeks per year.

## 2.8 Equipment Specifications

The types of processes that are present at the Hawaii Refinery have been described above. There are literally hundreds of pieces of equipment in each process unit. Table 2-1 provided the design capacity for the major pieces of equipment and process units in the refinery. Detailed specifications for each piece of equipment have not been included in this application, because of the large number of equipment and component types.



**Table 2-1**  
**REFINERY DESIGN CAPACITY AND PRODUCTION RATE INFORMATION**

Plant Area	Unit	Equipment	Capacity
20	Storage	Storage tanks	(see Section 3)
23	Cooling tower	Cooling tower	750 mmbtu/hr
	Crude flare	Flare 2301	253 mlb gas/hr
	FCC flare	Flare 2302	1.85 mmlb gas/hr
36	Wastewater	API separators	1400 gal/min combined
51	Crude	Distillation towers	65,000 bbls per day
		Furnace 5103	151.5 mmbtu/hr
		Furnace 5153	62.5 mmbtu/hr
52/55	Boilers	Boiler 5201	220 mmbtu/hr
		Boiler 5202	160.8 mmbtu/hr
		Boiler 5203	160.8 mmbtu/hr
53	FCC	FCC unit	22,000 bbl per day
		Furnace 5300	61 mmbtu/hr
		<i>Startup Air Heater F-5310<sup>1</sup></i>	<i>52 mmbtu/hr<sup>1</sup></i>
		Catalyst regenerator	266 mmbtu/hr
56	Hydrogenation Manufacturing Plant	Hydrogenation unit	3200 bbl/day
		Furnace 5600	9 mmbtu/hr
57	Hydrogen Plant	Hydrogen unit	<i>2500 90 mscf/hr<sup>1</sup></i>
		Furnace 5700	24.3 mmbtu/hr
58	Alkylation Plant	Alkylation unit	7500 bbl per day
59	Isomerization Plant	Isomerization unit	2500 bbl/day
		Furnace 5930	4 mmbtu/hr
		Furnace 5950	1.6 mmbtu/hr
60	Asphalt Plant	Asphalt plant	Storage for transfer
		Furnace 6003	5.7 mmbtu/hr
61/62	Amine/acid plant	Acid plant	110 ton acid/day
		Combustion chamber 6200	4.2 mscf/hr
		Furnace 6262	5.1 mmbtu/hr
66	Dimersol Plant	Dimersol plant	3000 bbl per day
67	Cogeneration	Turbine 6701	76 mmbtu/hr
		Turbine 6702	76 mmbtu/hr
		Turbine 6703	76 mmbtu/hr

<sup>1</sup>Updates to this table are indicated in shaded italics.

**Table 2-2  
FUELS AND FUEL USE**

Area	Equipment	Fuel	Design Fuel Use
51	Furnace 5103 Furnace 5153	Fuel Oil/RFG with RFG Pilot	630 bbl/Day 260 bbl/Day
52/55	Boiler 5201 Boiler 5202 Boiler 5203	Fuel Oil and RFG	914 bbl/Day or 214 MSCF/Hr 668 bbl/Day or 156 MSCF/Hr 668 bbl/Day or 156 MSCF/Hr
53	Furnace 5300 Startup Heater 5310  FCC Stack	Fuel Oil and RFG Inherently low sulfur fuel gas (<30 ppm H <sub>2</sub> S)  Cat. Coke	254 bbl./Day or 60 MSCF/Hr 23 MSCF/Hr  22,000 bbl/Day
56	Furnace 5600	RFG	9 MSCF/Hr
57	Furnace 5700	RFG	24 MSCF/Hr
59	Furnace 5930 Furnace 5950	RFG RFG	4 MSCF/Hr 1.6 MSCF/Hr
60	Furnace 6003	RFG	5.5 MSCF/Hr
61/62	Comb. Chamber 6200 Furnace 6262	RFG RFG	4.2 MSCF/Hr 4.95 MSCF/Hr
67	Turbine 6701, 6702, 6703 Turbine 6701, 6702, 6703 HRSG 6701, 6702, 6703	RFG Whole Straight Run Naphtha RFG	38.8 MSCF/Hr (Per Turbine) 192 bbl/Day (Per Turbine) 34 MSCF/Hr (Per HRSG)
67	Black Start Generator	ULSD	24.3 gal/hr
36	Sand Filter Pump #1	ULSD	9.2 gal/hr
36	Sand Filter Pump #2	ULSD	9.2 gal/hr
36	Transfer Pump	ULSD	9.2 gal/hr

**Table 2-3  
RAW MATERIALS**

Raw Material	Source
Crude oil	Tankers
Gasoline blending components (example: reformate)	Pipeline, made on site
Sulfuric acid	Made on site (may be imported)
Fuel oil components (example: low sulfur waxy residuum)	Pipeline, made on site
Other feed/blend stocks (example: vacuum gas oil)	Pipeline, made on site

## 2.9 Base Operating Scenarios

The base refinery operating scenario consists of the processing of crude oils in the process units and equipment, as indicated in the refinery description in Section 2.3. During normal operations, the refinery may process crude oils from a variety of sources and with various characteristics. Likewise, the refinery normally produces a wide range of intermediate and final products. Although each type of crude oil is processed in a similar manner, each requires specific refining techniques.

Therefore, the base operating scenario for this facility is the receiving and processing of various crude oils, without differentiating the make-up of the different crudes or the mix of refinery products generated. Maximum potential air pollutant emissions for this base scenario can be estimated by assuming operation of all equipment and process units at design capacity and the use of those raw materials and products that would produce the highest emissions. Estimation of these maximum potential emissions, which generally overestimate actual refinery emissions, is presented in Section 3.

## 2.10 Alternative Operating Scenarios

Alternative operating scenarios represent operational characteristics outside the range of normal operations. All operating scenarios for the Hawaii Refinery that are considered likely to occur have been incorporated within the base operating scenario, as described in the previous section. The maximum emissions scenario presented in Section 3 reflects the assumptions of refinery and process unit operations at maximum capacity, as well as the combination of raw materials and products that would correspond to the highest emissions of air pollutants among all the possible variations.

Therefore, there are no alternative operating scenarios, and it will not be necessary to implement inter-facility or process area emissions trading.

## 3. Emission Information

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This section provides information required in HAR §11-60.1-83(3), (4), (5), and (6). Maximum air pollutant emission estimates are presented for the base operating scenario, as described in Section 2. The following text explains the refinery emission inventory methods and summarizes the results. Detailed calculations of maximum criteria pollutant and HAPs emissions by source type are presented in Appendix B. It should be noted that the calculations of emissions presented in this report represent the maximum potential emissions from the refinery, which are greater than the actual emissions produced by refinery operations.

### 3.1 Inventory of Refinery Potential to Emit

The Chevron Hawaii Refinery includes several types of sources that have the potential to emit criteria air pollutants and hazardous air pollutants (HAPs). For purposes of developing the facility's emissions inventory, the refinery sources have been divided into the following eight categories:

- Point combustion sources
- Storage tanks
- Truck loading rack
- Process unit fugitives
- Cooling tower
- Wastewater treatment facilities
- Flaring
- Catalyst transfer operations at the FCC

#### 2016 Update:

*Tables 3-1 through 3-5, and 3-8 through 3-14 have been updated to include the following changes to the refinery emissions inventory since 2010. A new table, 3-15 has been added for insignificant activity stationary emergency RICE units.*

- *Added F-5310 FCC Startup Air Heater, permitted April 22, 2013 in Attachment II(I) of permit CSP No. 0088-01-C*
- *Added CatOx Unit point emissions, permitted November 02, 2015 in Attachment II(a) of permit CSP No. 0088-01-C*
- *Generators*
  - *Added Black Start generator, permitted September 11, 2014 under separate permit CSP No. 0088-03-C*
  - *Added three stationary non-emergency generators, permit application submitted April 30, 2015*
  - *Updated insignificant activities list to include emergency and non-emergency stationary generators*
- *Asphalt Plant emissions removed due to shutdown of that unit*
- *Emissions totals in Section 3 tables were adjusted for the changes listed above*
- *Updated Insignificant Activities list in Section 3.5*

### 3.1.1 Point Combustion Sources

The point combustion sources at the refinery consist of boilers, furnaces, and turbines. Fuels used by these units consist primarily of RFG and fuel oil. The turbines may also be fueled by whole straight run naphtha. In order to estimate the Potential to Emit (PTE) for these units, maximum fuel use rates based on equipment design capacities were multiplied by appropriate emission factors, except for sources that have federally enforceable DOH permit limits on either their emission rates or fuel usage rates. Information on the fuel type, maximum fuel use, the origins of emission factors, and comments regarding the emission calculation methods for all point combustion sources are presented in Table 3-1. Emission factors and calculation spreadsheets are contained in Appendix B.

The primary source of emission factors used to quantify criteria pollutant and HAP emissions from combustion sources is EPA Publication AP-42 (EPA, 1985 et seq). Fuel use rates for the furnaces and boilers were derived from the design fuel heat input rate and the lower heating value of the fuel used in each unit. The refinery's fuel oil has a nominal lower heating value of 5.78 million Btu per barrel, whereas RFG has a nominal lower heating value of 1030 Btu per standard cubic foot. The actual heating values vary according to refinery operations.

#### 2016 Update:

*Emissions for the diesel fueled reciprocating internal combustion engines (RICE) have been updated to provide emissions separately for stationary emergency and non-emergency and non-stationary RICE as follows:*

- *The black start generator emissions are included directly from the significant modification application submitted December 18, 2013 and amended January 22, 2014*
- *Stationary non-emergency emissions are provided for three pumps, as previously submitted in the significant modification application submitted April 30, 2015*
- *Emissions for stationary emergency engines and non-stationary units as previously included in the 2010 renewal application as insignificant activities have been updated in Section 3.5 to reflect an updated inventory. Emissions for insignificant activities are included in Appendix B.*

Table 3-1 2016 Update  
**MAXIMUM EMISSION ESTIMATE BASIS FOR POINT COMBUSTION SOURCES**

Area	Equipment	Fuel	Maximum Fuel Use	Emissions Estimate Basis
23(Cooling towers, flares)	Flares	RFG	N/A	Emission Factors From AP-42 Section 5.1-1
51 (Crude Unit)	Furnace 5103 Furnace 5153	Fuel Oil Fuel Oil (gas pilots)	630 bbl/Day 260 bbl/Day	SO <sub>2</sub> , NO <sub>2</sub> , and CO Limited By Permit VOC, PM and HAP emission factors from AP-42 Section 1.3 (Oil) and Section 1.4 (Gas)
52/55 (Boiler Plant)	Boiler 5201 Boiler 5202 Boiler 5203	Fuel Oil and RFG	914 bb/Day or 214 MSCF/Hr 668 bb/Day or 156 MSCF/Hr 668 bb/Day or 156 MSCF/Hr	Emission factors from AP-42 Section 1.3 (Oil) and Section 1.4 (Gas)
53 (FCCU)	Furnace 5300 FCC Stack Startup Air Heater	RFG Cat. Coke Inherently low sulfur fuel gas <sup>1</sup>	60 MSCF/Hr 22,000 bbl/day 52 Mmbtu/Hr	- Emission factors from AP-42 Sections 1.3 and 1.4 HAP emission factors for FCC stack from Chevron source emissions tests and Permit Limits -F-5310 limited to 22 days/yr Limited By Permit
56 (Hydrogenation Plant)	Furnace 5600	RFG	9 MSCF/Hr	Emission factors from AP-42 Section 1.4
57 (Hydrogen Manufacturing Plant)	Furnace 5700	RFG	24 MSCF/Hr	Emission factors from AP-42 Section 1.4 and NSPS J sulfur limits
59 (Isomerization Plant)	Furnace 5930 Furnace 5950	RFG RFG	4 MSCF/Hr 1.6 MSCF/Hr	Emission factors from AP-42 Section 1.4 and NSPS J sulfur limits
60 (Asphalt Plant)	Furnace 6003	RFG	5.5 MSCF/Hr	Emission factors from AP-42 Section 1.4
61/62 (Amine, Acid Plant)	Furnace 6262 Comb. Chamber F-6200 Acid Plant	RFG RFG	4.95 MSCF/Hr 8.5 Mmbtu/Hr (Max in 2002) 110 Ton Acid Production/Day	Emission factors from AP-42 Section 1.4
67 (Cogeneration Plant)	Turbine 6701, 6702, 6703 Turbine 6701, 6702, 6703 HRSG 6701, 6702, 6703	RFG WSR RFG	38.8 MSCR/Hr (Per Turbine) 192 bbl/Day (Per Turbine) 34 MSCF/Hr (Per HRSG)	Mass balance for SO <sub>2</sub> emissions NO <sub>2</sub> and CO fuel use limited by permit and factors from AP-42 Section 1.4 and 3.1 VOC and PM factors from AP-42 Section 3.1

<sup>1</sup> Inherently low sulfur content fuel gas as defined in NSPS Ja §60.107a(a)(3)(ii)

**Table 3-1 2016 Update (continued)**  
**MAXIMUM EMISSION ESTIMATE BASIS FOR POINT COMBUSTION SOURCES**

Generators	<u>Emergency Stationary Generators:</u> Black Start Generator <u>Non-Emergency Stationary Generators</u> Sand Filter Pump Diesel Engine #1 Sand Filter Pump Diesel Engine #2 Transfer Pump	ULSD (all)	755 hp  200 hp 200 hp 300 hp	Emission Factors from AP-42 Section 3.3 and Tier 3 Exhaust Standards for RICE Non-emergency units
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<sup>1</sup> Inherently low sulfur content fuel gas as defined in NSPS Ja §60.107a(a)(3)(ii)

The particulate emissions from the FCC precipitator are conservatively assumed to be at the DOH prohibitory limit.

Emissions of SO<sub>2</sub>, NO<sub>x</sub> and CO from the Crude Unit and Cogeneration Plant were based on federally enforceable DOH permit limits. Consumption of RFG and whole straight run naphtha (WSR) in the cogeneration turbines is limited by federally enforceable DOH permit conditions. Crude unit furnaces 5103 and 5153 are currently permitted to combust RFG on only 12 of 36 burners. Maximum estimated emissions for these furnaces were obtained assuming that these units operate to the full limit of the permit conditions.

WSR sulfur content in the cogeneration units is no more than 0.03 percent, as allowed by the current Title V permit. Fuel oil burned in the boilers (5201, 5202, and 5203) and crude unit furnaces (5103 and 5153) may contain up to 0.5 percent sulfur and fuel gas up to 160ppmv sulfur. Hazardous Air Pollutant (HAP) emission factors were taken from the EPA AP-42 compilation or from Chevron source tests.

Chevron has had a number of diesel fueled generators that were previously identified as insignificant sources with a capacity of 200 brake horsepower (bhp) or lower. These units support maintenance activities and the Boiler Plant. An additional 335 bhp standby emergency generator is used at the cogeneration area during power and cogeneration failures. Maritime Security Requirements required the installation of three emergency generators; one at each gate entrance, and one at the firehouse. Other emergency generators include fire water pumps and light plant operations. As these units are all used on an intermittent basis for refinery plant maintenance and repairs an hour limitation of 1008 hours per year was used for emission calculations. This hour limitation was derived from the worst case plant maintenance scenario. Every five years, the refinery plant is taken offline to perform maintenance for up to 6 weeks. Worst case scenario for operating time was assumed to be 24 hours per day, 7 days a week for 6 weeks a year. The criteria and hazardous air pollutants were calculated using AP-42 emission factors.

Maximum potential criteria pollutant emissions for refinery point sources are presented in Table 3-2. HAP emissions from point sources are summarized in Table 3-3. Please note that these tables present the maximum emission rates. Thus, if fuel oil combustion results in higher emissions for a given pollutant than RFG, the use of fuel oil is assumed in calculating emissions. Additionally, it is unlikely—if not impossible—for all of the refinery processes to operate concurrently at their maximum potential emission rates for all pollutants.

### 3.1.2 Storage Tanks

Crude oil, intermediate products, blending components, and finished products are placed in storage tanks. The refinery stores different classes of material in designated tanks. For example, specific tanks may store motor gasoline or several of its blend components. These same tanks, however, would not store diesel fuel. To estimate emissions, each storage tank is classified according to the class of material it contains, based on similar characteristics. Data from a Year 2009 tank emission inventory were used as the basis for calculating the tanks' PTE. Because the maximum crude oil throughput for the refinery (65,000 bbl/day) is 24 percent higher than the crude oil throughput during 2009, the throughput quantities and turnovers for all tanks were increased by 24 percent over the values in the 2009 inventory data in order to estimate their corresponding maximum potential emissions.



The classes of regulated hydrocarbon materials stored at the refinery are as follows:

- Crude oil
- Motor gasoline and its blend components
- Aviation gas
- Jet fuel Heavy
- liquids
- Liquid propane gas (LPG)
- Recovered oil

Table 3-2 2016 Update  
**MAXIMUM CRITERIA POLLUTANT EMISSIONS FROM POINT SOURCES**

Sources	Pollutant Emission Rates (ton/yr)							Total Criteria Pollutant Emissions
	PM <sub>10</sub>	SO <sub>2</sub>	CO	NO <sub>2</sub>	VOC	Lead		
Boilers	134.78	1353.83	86.23	551.88	13.11	0.026		2140
CatOx Unit <sup>2</sup>			17.0	14.7	1.3			33
Cogen Turbines	11.72	27.92	52.49	193.16	2.34	0.006		288
Crude Furnaces	44.49	481.99	74.99	302.88	5.11	0.010		909
FCC Furnaces <sup>1</sup>	2.11	7.16	23.21	15.09	1.60	0.000		49
Isomerization Furnaces	0.19	0.66	2.06	2.45	0.13	0.000		5
Hydrogenation & Hydrogen Plant Furnaces	1.10	3.91	12.14	14.45	0.79	0.000		32
Acid preheater & combustion chamber	0.43	1.54	4.80	5.71	0.31	0.000		13
Asphalt Furnace <sup>3</sup>	0	0	0	0	0	0.000		0
FCC Stack	175.20	333.35	499.32	285.07	14.67	0.000		1308
<u>Emergency Stationary Generators:</u>								
Black Start Generator	0.03	0.001	0.17	1.62	1.62	0		3
<u>Non-Emergency Stationary Generators</u>								
Sand Filter Pump Diesel Engine #1	0.43	0.0085	7.2	5.8	5.8	0		19
Sand Filter Pump Diesel Engine #2	0.43	0.0085	7.2	5.8	5.8	0		19
Transfer Pump	0.43	0.0085	7.2	5.8	5.8	0		19
<b>Totals</b>	<b>371.3</b>	<b>2210.4</b>	<b>794.0</b>	<b>1404.4</b>	<b>58.4</b>	<b>0.0</b>		<b>4838.6</b>

<sup>1</sup> FCC furnaces updated to include FCC Startup Air Heater, F-5310.

<sup>2</sup> The CatOx is in the Effluent Treating Plant. The CatOx NH<sub>3</sub> emission rate is 1.5 ton/yr.

<sup>3</sup> Asphalt Plant is permanently out of service and emissions have been removed from the inventory

Table 3-3 2016 Update  
 MAXIMUM HAP EMISSIONS FROM POINT SOURCES

Number	Area Description	Benzene CAS# 71432 (Ton/Yr)	Naphthalene CAS# 91203 (Ton/Yr)	o-Xylene CAS# 95476 (Ton/Yr)	Ethylbenzene CAS# 100414 (Ton/Yr)	p-Xylene CAS# 106423 (Ton/Yr)	Ethylene Dibromide CAS# 106934 (Ton/Yr)	Ethylene Dichloride CAS# 107062 (Ton/Yr)
52	Boiler	0.003	0.008	0.001	0.00			
52	CatOx Unit							
67	Cogen	0.034	0.018					
51	Crude	0.001	0.006	0.001	0.00			
53	FCC <sup>2</sup>	0.001	0.000					
59	Isom	0.000	0.000					
56	Hydrogenation							
57	Hydrogen Manufacturing	0.000	0.000					
62	Acid Plant CC and Preheater	0.000	0.000					
60	Asphalt Plant <sup>1</sup>	0.000	0.000					
53	FCC Stack							
	Flare							
	<u>Emergency Stationary Generators:</u>							
	Black Start Generator							
	Non-Emergency Stationary Generators							
	Sand Filter Pump Diesel Engine #1	5.7E-4	1E-05	1.7E-4		Incl in oXyl		
	Sand Filter Pump Diesel Engine #2	5.7E-4	1E-05	1.7E-4		Incl in oXyl		
	Transfer Pump	5.7E-4	1E-05	1.7E-4		Incl in oXyl		
	<b>Total</b>	<b>0.040</b>	<b>0.032</b>	<b>0.002</b>	<b>0.001</b>	<b>0.000</b>	<b>0.000</b>	<b>0.000</b>

<sup>1</sup> Asphalt Plant is permanently out of service, and emissions have been removed from the table.

<sup>2</sup> HCN emissions at the FCCU regenerator stack are estimated 23.5 tpy, based on 2011 ICR test results. This estimate is included in the Total HAPs Ton/Yr

Table 3-3 2016 Update (continued)  
MAXIMUM HAP EMISSIONS FROM POINT SOURCES

Number	Area Description	m-Xylene CAS# 108383 (Ton/Yr)	Toluene CAS# 108883 (Ton/Yr)	1,3- Butadiene CAS# 106990 (Ton/Yr)	n-Hexane CAS# 110543 (Ton/Yr)	Formaldehyde CAS# 50000 (Ton/Yr)	POM/PAH CAS# EDF047 (Ton/Yr)	Total HAPs Ton/Yr
52	Boiler Plant		0.046		1.230	0.349	0.298	1.935
52	CatOx Unijt							
67	Cogen Plant	0.033	0.067	0.00		0.506	0.021	0.688
51	Crude Unit		0.030		0.002	0.208	0.006	0.253
53	FCC <sup>2</sup>		0.001		0.473	0.020	0.000	26
59	Isomerization Plant		0.000		0.044	0.002	0.000	0.046
56	Hydrogenation Plant		0.000		0.071	0.003	0.000	0.074
57	Hydrogen Manufacturing Plant		0.000		0.189	0.008	0.000	0.198
62	Acid Plant CC and Preheater		0.000		0.103	0.004	0.000	0.107
60	Asphalt Plant <sup>1</sup>		0		0	0	0	0
53	FCC Stack					0.890		0.890
	Flare			0.002				0.002
	<u>Emergency Stationary Generators:</u> Black Start Generator <u>Non-Emergency Stationary Generators</u> Sand Filter Pump Diesel Engine #1 Sand Filter Pump Diesel Engine #2 Transfer Pump	Incl in oXyl Incl in oXyl Incl in oXyl	2.5E-4 2.5E-4 2.5E-4	2E-5 2E-5 2E-5		7.2E-4 7.2E-4 7.2E-4	1E-4 1E-4 1E-4	0.004 0.004 0.004
	<b>Total</b>	<b>0.033</b>	<b>0.146</b>	<b>0.010</b>	<b>2.111</b>	<b>1.992</b>	<b>0.325</b>	<b>28.19</b>

<sup>1</sup> Asphalt Plant is permanently out of service, and emissions have been removed from the table.

<sup>2</sup> HCN emissions at the FCCU regenerator stack are estimated 23.5 tpy, based on 2011 ICR test results. This estimate is included in the Total HAPs Ton/Yr.

To date, 33 external floating roof petroleum storage tanks have been fitted with secondary seals or domed roofs. Storage tank emissions were estimated using the EPA TANKS4.09d computer software package, with partial speciation (EPA, 2006). A list of each regulated tank in hydrocarbon service, its class of service, and estimated maximum total VOC emissions is provided in Table 3-4. A summary of maximum total HAP emissions by tank is presented in Table 3-5. Detailed emission reports for each tank, as generated by the TANKS4.09d emissions model, are presented in an accompanying document (Appendix B-2).

Storage tanks in LPG service are pressurized and have negligible emissions. Emissions from heavy liquids, specifically materials with vapor pressures less than 0.3 kPa (EPA, 1993a), are also excluded from this inventory. This exclusion is consistent with the December 15, 1993, Model Permit for Leaking Sources published by the EPA, and is discussed further in Section 3.6 of this application. For clarity, liquids having a vapor pressure less than 0.3 kPa will subsequently be referred to as insignificant heavy liquids. Section 3.6.10 contains justification for the exemption of these materials from the refining PTE inventory.

2016 Update:

*The tank emissions in the December 2010 Renewal application provide a reasonable estimate of overall storage emissions at the refinery's maximum crude oil throughput of 65,000 bb/day, based on the 2009 storage tank emission inventory. These emissions are worst case for the estimating year (2009), however, the PTE emissions for the tanks were provided in the initial covered source permit application by estimating emissions for each tank assuming it stored the most conservative material from the following categories:*

- Crude oil
- Gasoline, intermediates and products
- Jet Fuel
- Heavy Liquids (vapor pressure > 0.3 kPa)
- Liquefied petroleum gas (LPG)
- Recovered oil

### 3.1.3 Truck Loading Rack

Typically, products are shipped from the refinery via pipeline. If Chevron were unable to use the pipeline (for example, in case of a shutdown for extended repairs), certain products would be loaded into trucks at the refinery truck loading rack. The current Covered Source Permit specifies the following maximum daily material loading rates:

- Motor gasoline – 7,300,000 barrels per any rolling 12-month period
- Aviation gasoline – 47,450 barrels per any rolling 12-month period
- Diesel – 2,920,000 barrels per any rolling 12-month period
- Jet Fuel – 438,000 barrels per any rolling 12-month period

Section 5.2 of AP-42 provides the following equation to estimate VOC emissions from loading activities:

Where:

$$L_L = 12.46 \text{ SPM/T}$$

- L = VOC Emissions, lb/1000 gal. liquid loaded
- S = Saturation factor (Chevron employs submerged loading)
- P = True vapor pressure, psia
- M-Molecular weight of vapors, lb/lbmole
- T=Temperature of material, °R

Estimated emissions and the parameter values used in the emission calculations are presented in Table 3-6. The PTE calculations assume that the maximum allowable quantities shown above for all fuels would be loaded during the year.

**Table 3-4 2016 Update  
MAXIMUM POTENTIAL VOC EMISSIONS FROM STORAGE TANKS<sup>1</sup>**

Tank ID	Type of Tank	Service of Tank	Losses (lb/yr)	Losses (ton/yr)
Tk 104	External Floating Roof	Crude: Nanhi Group	5432.73	2.7
Tk 105	External Floating Roof	Crude: Tapis Group	8540.88	4.3
Tk 106	External Floating Roof	Crude: Tapis Group	8534.19	4.3
Tk 107	External Floating Roof	Crude: MinasGroup	5495.79	2.7
Tk 108	External Floating Roof	Crude: Widuri Group	8943.03	4.5
Tk 109	External Floating Roof	U/L	67697.10	33.8
Tk 110	External Floating Roof	Crude: Tapis Group	8751.16	4.4
Tk 111	External Floating Roof	WSR	39400.48	19.7
Tk 113	External Floating Roof	Rec Crude	14.99	0.0
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.00	0.0
Tk 162	External Floating Roof	Rec Oil	18448.29	9.2
Tk 163	External Floating Roof	Rec Oil	18448.29	9.2
Tk 232	External Floating Roof	HCC	2719.92	1.4
Tk 233	External Floating Roof	HCC	1876.24	0.9
Tk 235	External Floating Roof	Transmix	26156.81	13.1
Tk 236	External Floating Roof	U/L	56340.62	28.2
Tk 237	External Floating Roof	SUP	56291.42	28.1
Tk 249	External Floating Roof	Avgas	2580.58	1.3
Tk 250	External Floating Roof	Avgas	2114.93	1.1
Tk 252	External Floating Roof	LCC	61048.48	30.5
Tk 253	External Floating Roof	LCC	61050.45	30.5
Tk 254	External Floating Roof	U/L	55727.19	27.9
Tk 255	External Floating Roof	SUP	24360.42	12.2
Tk 256	External Floating Roof	U/L	56340.62	28.2
Tk 257	External Floating Roof	Dimate Gasoline	49414.54	24.7
Tk 258	External Floating Roof	Alkylate Gasoline	32763.93	16.4
Tk 262	External Floating Roof	SUP	55247.25	27.6
Tk 263	External Floating Roof	JetA	4276.30	2.1
Tk 264	External Floating Roof	JetA	4286.38	2.1
Tk 265	External Floating Roof	JetA	1790.07	0.9
Tk 266	External Floating Roof	WSR	32279.51	16.1
Tk 267	External Floating Roof	JetA	4377.14	2.2
Tk 268	External Floating Roof	Diesel	352.19	0.2
Tk 269	External Floating Roof	WSR	30980.76	15.5
Tk 270	External Floating Roof	Diesel	333.66	0.2
Tk 271	External Floating Roof	JetA or gasoline	1613.02	0.8
Tk 272	Vertical Fixed Roof	ULSD	2819.86	1.4
Tk 273	External Floating Roof	U/L	50696.68	25.3
Tk 274	Vertical Fixed Roof	ULSD	3599.85	1.8
Tk 275	External Floating Roof	WSR	651.43	0.3
Tk 301	External Floating Roof	Rec Oil	31994.08	16.0
Tk 302	External Floating Roof	Rec Oil	31994.08	16.0
Total Emissions for all Tanks:			935785.28	467.89

Table 3-5 2016 Update  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS<sup>1</sup>**

Tank Id	Type of tank	Service of Tank	BENZENE CAS# 71432	NAPHTHALENE CAS# 91203	O-XYLENE CAS# 95476	ETHYL BENZENE CAS# 100414	P-XYLENE CAS# 106423	ETHYLENE DIBROMIDE CAS# 106934
Tk 104	External Floating Roof	Crude: Nanthi Group	5.755	0.000	0.000	0.000	0.000	0.000
Tk 105	External Floating Roof	Crude: Tapis Group	20.587	0.000	0.000	0.000	0.000	0.000
Tk 106	External Floating Roof	Crude: Tapis Group	20.561	0.000	0.000	0.000	0.000	0.000
Tk 107	External Floating Roof	Crude: Minas Group	7.039	0.000	0.000	0.000	0.000	0.000
Tk 108	External Floating Roof	Crude: Widuri Group	3.577	0.000	0.000	0.000	0.000	0.000
Tk 109	External Floating Roof	U/L	18.757	1.648	28.995	21.787	13.813	0.000
Tk 110	External Floating Roof	Crude: Tapis Group	21.151	0.000	0.000	0.000	0.000	0.000
Tk 111	External Floating Roof	WSR	276.453	0.000	13.750	0.000	153.662	0.000
Tk 113	External Floating Roof	Rec Crude	0.058	0.000	0.000	0.000	0.000	0.000
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.000	0.000	0.000	0.000	0.000	0.000
Tk 162	External Floating Roof	Rec Oil	16.908	0.516	5.535	2.532	1.584	0.041
Tk 163	External Floating Roof	Rec Oil	16.908	0.516	5.535	2.532	1.584	0.041
Tk 232	External Floating Roof	HCC	2.719	9.086	79.491	28.188	22.480	0.000
Tk 233	External Floating Roof	HCC	1.877	6.175	56.288	19.972	15.461	0.000
Tk 235	External Floating Roof	Transmix	0.000	0.000	0.000	0.000	0.000	6.592
Tk 236	External Floating Roof	U/L	15.551	0.949	22.582	17.330	10.303	0.000
Tk 237	External Floating Roof	SUP	15.502	0.421	5.329	2.063	1.488	0.000
Tk 249	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	0.000	0.650
Tk 250	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	0.000	0.533
Tk 252	External Floating Roof	LCC	119.869	0.000	17.497	19.281	11.086	0.000
Tk 253	External Floating Roof	LCC	119.884	0.000	17.522	19.301	11.112	0.000
Tk 254	External Floating Roof	U/L	15.380	0.922	22.275	17.110	10.142	0.000



Table 3-5 2016 Update (continued)  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANK<sup>1</sup>**

Tank Id	Type of tank	Service of Tank	BENZENE CAS# 71432	NAPHTHALENE CAS# 91203	O-XYLENE CAS# 95476	ETHYLBENZENE CAS# 100414	P-XYLENE CAS# 106423	ETHYLENE DIBROMIDE CAS# 106934
Tk 255	External Floating Roof	SUP	6.593	0.192	2.228	0.865	0.673	0.000
Tk 256	External Floating Roof	U/L	15.551	0.949	22.582	17.330	10.303	0.000
Tk 257	External Floating Roof	Dimate Gasoline	0.000	0.000	0.000	0.000	0.000	0.000
Tk 258	External Floating Roof	Alkylate Gasoline	0.000	0.000	0.000	0.000	0.000	0.000
Tk 262	External Floating Roof	SUP	15.214	0.411	5.227	2.024	1.459	0.000
Tk 263	External Floating Roof	JetA	0.001	6.780	84.041	34.211	22.015	0.000
Tk 264	External Floating Roof	JetA	0.001	6.911	84.282	34.291	22.122	0.000
Tk 265	External Floating Roof	JetA	0.000	3.138	34.889	14.321	9.886	0.000
Tk 266	External Floating Roof	WSR	225.930	0.000	10.666	0.000	125.890	0.000
Tk 267	External Floating Roof	JetA	0.001	6.962	86.032	35.017	22.545	0.000
Tk 268	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000	0.000
Tk 269	External Floating Roof	WSR	216.778	0.000	10.169	0.000	120.825	0.000
Tk 270	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000	0.000
Tk 271	External Floating Roof	JetA or gasoline	0.000	3.022	31.971	12.904	8.393	0.000
Tk 272	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000	0.000
Tk 273	External Floating Roof	U/L	14.009	0.778	20.131	15.512	9.025	0.000
Tk 274	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000	0.000
Tk 275	External Floating Roof	WSR	4.928	0.000	0.600	0.000	2.541	0.000
Tk 301	External Floating Roof	Rec Oil	29.284	0.702	9.281	4.293	2.592	0.071
Tk 302	External Floating Roof	Rec Oil	29.284	0.702	9.281	4.293	2.592	0.071

Table 3-5 2016 Update (continued)  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANK<sup>1</sup>**

Tank Id	Type of tank	Service of Tank	ETHYLENE DICHLORIDE CAS# 107062	M-XYLENE CAS# 108983	TOLUENE CAS# 108883	1,3- BUTADIENE CAS# 106990	n-HEXANE CAS# 110543	ANILINE CAS# 62533
Tk 104	External Floating Roof	Crude: Nantni Group	0.000	0.000	0.000	0.000	0.000	0.500
Tk 105	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.000	0.083
Tk 106	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.000	0.082
Tk 107	External Floating Roof	Crude: MinasGroup	0.000	0.000	0.000	0.000	0.000	0.083
Tk 108	External Floating Roof	Crude: Widuri Group	0.000	0.000	0.000	0.000	0.000	0.068
Tk 109	External Floating Roof	U/L	0.000	67.644	371.837	0.000	393.641	0.032
Tk 110	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.000	0.088
Tk 111	External Floating Roof	WSR	0.000	30.985	249.063	0.000	801.791	0.247
Tk 113	External Floating Roof	Rec Crude	0.000	0.000	0.000	0.000	0.000	0.001
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.000	0.000	0.000	0.000	0.000	0.000
Tk 162	External Floating Roof	Rec Oil	0.000	83.897	17.654	0.000	1982.911	0.184
Tk 163	External Floating Roof	Rec Oil	0.000	83.897	17.654	0.000	1982.911	0.184
Tk 232	External Floating Roof	HCC	0.000	124.505	20.671	0.000	0.000	0.264
Tk 233	External Floating Roof	HCC	0.000	88.192	14.259	0.000	0.000	0.183
Tk 235	External Floating Roof	Transmix	1.887	0.062	0.000	0.000	5.371	0.000
Tk 236	External Floating Roof	U/L	0.000	53.359	304.608	0.000	326.995	0.062
Tk 237	External Floating Roof	SUP	0.000	8.818	8.110	0.000	326.335	0.062
Tk 249	External Floating Roof	Avgas	0.187	0.006	0.000	0.000	0.530	0.000
Tk 250	External Floating Roof	Avgas	0.152	0.005	0.000	0.000	0.434	0.000
Tk 252	External Floating Roof	LCC	0.000	51.943	371.903	0.000	202.587	0.062
Tk 253	External Floating Roof	LCC	0.000	52.005	372.049	0.000	202.603	0.062
Tk 254	External Floating Roof	U/L	0.000	52.661	301.100	0.000	323.411	0.062

Table 3-5 2016 Update (continued)  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANK<sup>1</sup>**

Tank Id	Type of tank	Service of Tank	ETHYLENE DICHLORIDE CAS# 107062	M-XYLENE CAS# 108383	TOLUENE CAS# 108883	1,3- BUTADIENE CAS# 106990	n-HEXANE CAS# 110543	ANILINE CAS# 62533
Tk 255	External Floating Roof	SUP	0.000	3.692	3.424	0.000	139.292	0.062
Tk 256	External Floating Roof	U/L	0.000	53.359	304.608	0.000	326.995	0.062
Tk 257	External Floating Roof	Dimate Gasoline	0.000	0.000	0.000	0.000	0.000	0.000
Tk 258	External Floating Roof	Alkylate Gasoline	0.000	0.000	0.000	0.000	6.397	0.000
Tk 262	External Floating Roof	SUP	0.000	8.650	7.959	0.000	320.280	0.062
Tk 263	External Floating Roof	JetA	0.000	112.039	0.000	0.000	0.000	0.043
Tk 264	External Floating Roof	JetA	0.000	112.303	0.000	0.000	0.000	0.043
Tk 265	External Floating Roof	JetA	0.000	46.900	0.000	0.000	0.000	0.018
Tk 266	External Floating Roof	WSR	0.000	24.296	201.553	0.000	656.303	0.142
Tk 267	External Floating Roof	JetA	0.000	114.682	0.000	0.000	0.000	0.044
Tk 268	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000	0.000
Tk 269	External Floating Roof	WSR	0.000	23.195	193.163	0.000	629.836	0.130
Tk 270	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000	0.000
Tk 271	External Floating Roof	JetA or gasoline	0.000	42.262	0.000	0.000	0.000	0.016
Tk 272	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000	0.000
Tk 273	External Floating Roof	U/L	0.000	47.684	274.012	0.000	294.582	0.062
Tk 274	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000	0.000
Tk 275	External Floating Roof	WSR	0.000	1.191	5.682	0.000	13.639	0.062
Tk 301	External Floating Roof	Rec Oil	0.000	14.164	30.395	0.000	343.779	0.320
Tk 302	External Floating Roof	Rec Oil	0.000	14.164	30.395	0.000	343.779	0.320

Table 3-5 2016 Update (continued)  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANK<sup>1</sup>**

Tank Id	Type of tank	Service of Tank	CRESOL MIXTURE CAS# 1319773	PHENOL CAS# 108952	STYRENE CAS# 100425	METHANOL CAS# 67561
Tk 104	External Floating Roof	Crude: Nanti Group	7.606	0.499	0.000	0.000
Tk 105	External Floating Roof	Crude: Tapis Group	11.957	0.082	0.000	0.000
Tk 106	External Floating Roof	Crude: Tapis Group	11.948	0.080	0.000	0.000
Tk 107	External Floating Roof	Crude: MinasGroup	7.694	0.082	0.000	0.000
Tk 108	External Floating Roof	Crude: Widuri Group	12.520	0.064	0.000	0.000
Tk 109	External Floating Roof	U/L	0.000	0.062	0.000	0.000
Tk 110	External Floating Roof	Crude: Tapis Group	12.252	0.086	0.000	0.000
Tk 111	External Floating Roof	WSR	0.000	0.000	0.000	0.000
Tk 113	External Floating Roof	Rec Crude	0.021	0.001	0.000	0.000
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.000	0.000	0.000	0.000
Tk 162	External Floating Roof	Rec Oil	267.500	0.062	0.000	0.000
Tk 163	External Floating Roof	Rec Oil	267.500	0.062	0.000	0.000
Tk 232	External Floating Roof	HCC	0.000	0.062	0.000	0.000
Tk 233	External Floating Roof	HCC	0.000	0.062	0.000	0.000
Tk 235	External Floating Roof	Transmix	0.000	0.000	0.000	0.000
Tk 236	External Floating Roof	U/L	0.000	0.062	0.000	0.000
Tk 237	External Floating Roof	SUP	0.000	0.062	0.000	0.000
Tk 249	External Floating Roof	Avgas	0.000	0.000	0.000	0.000
Tk 250	External Floating Roof	Avgas	0.000	0.000	0.000	0.000
Tk 252	External Floating Roof	LCC	0.000	0.062	1.348	0.000
Tk 253	External Floating Roof	LCC	0.000	0.062	1.349	0.000
Tk 254	External Floating Roof	U/L	0.000	0.062	0.000	0.000

Table 3-5 2016 Update (continued)  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANK<sup>1</sup>**

Tank Id	Type of tank	Service of Tank	CREOSOL MIXTURE CAS# 1319773	PHENOL CAS# 108952	STYRENE CAS# 100425	METHANOL CAS# 67561
Tk 255	External Floating Roof	SUP	0.000	0.062	0.000	0.000
Tk 256	External Floating Roof	U/L	0.000	0.062	0.000	0.000
Tk 257	External Floating Roof	Dinate Gasoline	0.000	0.000	0.000	0.000
Tk 258	External Floating Roof	Alkylate Gasoline	0.000	0.000	0.000	0.000
Tk 262	External Floating Roof	SUP	0.000	0.062	0.000	0.000
Tk 263	External Floating Roof	JetA	4.276	0.336	0.000	0.000
Tk 264	External Floating Roof	JetA	4.286	0.346	0.000	0.000
Tk 265	External Floating Roof	JetA	1.790	0.148	0.000	0.000
Tk 266	External Floating Roof	WSR	0.000	0.000	0.000	0.000
Tk 267	External Floating Roof	JetA	4.377	0.345	0.000	0.000
Tk 268	External Floating Roof	Diesel	0.000	0.062	0.000	0.000
Tk 269	External Floating Roof	WSR	0.000	0.000	0.000	0.000
Tk 270	External Floating Roof	Diesel	0.000	0.062	0.000	0.000
Tk 271	External Floating Roof	JetA or gasoline	1.613	0.168	0.000	0.000
Tk 272	Vertical Fixed Roof	ULSD	0.000	0.410	0.000	0.000
Tk 273	External Floating Roof	U/L	0.000	0.062	0.000	0.000
Tk 274	Vertical Fixed Roof	ULSD	0.000	0.524	0.000	0.000
Tk 275	External Floating Roof	WSR	0.000	0.000	0.000	0.000
Tk 301	External Floating Roof	Rec Oil	463.914	0.069	0.000	0.000
Tk 302	External Floating Roof	Rec Oil	463.914	0.069	0.000	0.000

Table 3-5 2016 Update (continued)  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANK<sup>1</sup>**

Tank Id	Type of tank	Service of Tank	HCL CAS# 7647010	PERCHLOROETHYLENE CAS# 127184	CYCLOHEXANE CAS# 110827	BIPHENYL CAS# 92524	2,2,4 TRIMETHYLPENTANE CAS# 540841	CUMENE CAS# 98828
Tk 104	External Floating Roof	Crude: Nanhui Group	0.000	0.000	0.000	0.000	0.520	0.502
Tk 105	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.314	0.104
Tk 106	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.314	0.104
Tk 107	External Floating Roof	Crude: MinasGroup	0.000	0.000	0.000	0.000	0.301	0.103
Tk 108	External Floating Roof	Crude: Widuri Group	0.000	0.000	0.000	0.000	0.744	0.131
Tk 109	External Floating Roof	U/L	0.000	0.000	82.349	0.000	49.536	0.120
Tk 110	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.325	0.110
Tk 111	External Floating Roof	WSR	0.000	0.000	618.646	0.000	69.812	2.359
Tk 113	External Floating Roof	Rec Crude	0.000	0.000	0.000	0.000	0.001	0.001
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.000	0.000	0.000	0.000	0.000	0.000
Tk 162	External Floating Roof	Rec Oil	0.000	0.018	31.803	5.534	32.743	0.892
Tk 163	External Floating Roof	Rec Oil	0.000	0.018	31.803	5.534	32.743	0.892
Tk 232	External Floating Roof	HCC	0.000	0.000	0.000	0.000	0.000	0.122
Tk 233	External Floating Roof	HCC	0.000	0.000	0.000	0.000	0.000	0.086
Tk 235	External Floating Roof	Transmix	0.000	0.000	0.000	0.000	575.450	0.000
Tk 236	External Floating Roof	U/L	0.000	0.000	68.280	0.000	40.869	0.091
Tk 237	External Floating Roof	SUP	0.000	0.000	3.167	0.000	40.623	0.086
Tk 249	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	56.773	0.000
Tk 250	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	46.528	0.000
Tk 252	External Floating Roof	LCC	0.000	0.000	0.000	0.000	0.000	1.059
Tk 253	External Floating Roof	LCC	0.000	0.000	0.000	0.000	0.000	1.061
Tk 254	External Floating Roof	U/L	0.000	0.000	67.527	0.000	40.411	0.090

Table 3-5 2016 Update (continued)  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANK<sup>1</sup>**

Tank Id	Type of tank	Service of Tank	HCL CAS# 7647010	PERCHLOROETHYLENE CAS# 127184	CYCLOHEXANE CAS# 110827	BIPHENYL CAS# 92524	2,2,4 TRIMETHYLPENTANE CAS# 540841	CUMENE CAS# 98828
Tk 255	External Floating Roof	SUP	0.000	0.000	1.348	0.000	17.235	0.062
Tk 256	External Floating Roof	U/L	0.000	0.000	68.280	0.000	40.869	0.091
Tk 257	External Floating Roof	Dimate Gasoline	0.000	0.000	0.000	0.000	0.000	0.000
Tk 258	External Floating Roof	Alkylate Gasoline	0.000	0.000	0.000	0.000	159.850	0.000
Tk 262	External Floating Roof	SUP	0.000	0.000	3.107	0.000	39.867	0.085
Tk 263	External Floating Roof	JetA	0.000	0.000	0.000	4.276	0.000	2.658
Tk 264	External Floating Roof	JetA	0.000	0.000	0.000	4.286	0.000	2.669
Tk 265	External Floating Roof	JetA	0.000	0.000	0.000	1.790	0.000	1.103
Tk 266	External Floating Roof	WSR	0.000	0.000	505.627	0.000	56.826	1.798
Tk 267	External Floating Roof	JetA	0.000	0.000	0.000	4.377	0.000	2.722
Tk 268	External Floating Roof	Diesel	0.000	0.000	0.000	0.141	0.000	0.000
Tk 269	External Floating Roof	WSR	0.000	0.000	485.151	0.000	54.498	1.710
Tk 270	External Floating Roof	Diesel	0.000	0.000	0.000	0.133	0.000	0.000
Tk 271	External Floating Roof	JetA or gasoline	0.000	0.000	0.000	1.613	0.000	1.023
Tk 272	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	1.128	0.000	0.000
Tk 273	External Floating Roof	U/L	0.000	0.000	61.506	0.000	36.794	0.082
Tk 274	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	1.440	0.000	0.000
Tk 275	External Floating Roof	WSR	0.000	0.000	11.001	0.000	1.386	0.124
Tk 301	External Floating Roof	Rec Oil	0.000	0.032	55.087	9.598	56.576	1.479
Tk 302	External Floating Roof	Rec Oil	0.000	0.032	55.087	9.598	56.576	1.479

Table 3-5 2016 Update (continued)  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANK<sup>1</sup>**

Tank Id	Type of tank	Service of Tank	O-TOLUIDINE CAS# 95534	ACRYLAMIDE CAS# 79061	PROPYLENE CAS# 115071	1,2,4-TMBenzene CAS# 95636	ETHYLENE CAS# 74851
Tk 104	External Floating Roof	Crude: Nantni Group	0.543	0.000	0.054	0.000	0.000
Tk 105	External Floating Roof	Crude: Tapis Group	0.854	0.000	0.085	0.000	0.000
Tk 106	External Floating Roof	Crude: Tapis Group	0.853	0.000	0.085	0.000	0.000
Tk 107	External Floating Roof	Crude: MinasGroup	0.550	0.000	0.055	0.000	0.000
Tk 108	External Floating Roof	Crude: Widuri Group	0.894	0.000	0.089	0.000	0.000
Tk 109	External Floating Roof	U/L	6.770	0.068	0.000	11.747	0.000
Tk 110	External Floating Roof	Crude: Tapis Group	0.875	0.000	0.088	0.000	0.000
Tk 111	External Floating Roof	WSR	0.000	0.000	0.000	0.000	0.000
Tk 113	External Floating Roof	Rec Crude	0.001	0.000	0.000	0.000	0.000
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt id)	0.000	0.000	0.000	0.000	0.000
Tk 162	External Floating Roof	Rec Oil	14.759	0.000	0.018	1.724	0.000
Tk 163	External Floating Roof	Rec Oil	14.759	0.000	0.018	1.724	0.000
Tk 232	External Floating Roof	HCC	27.199	0.000	0.000	27.354	0.000
Tk 233	External Floating Roof	HCC	18.762	0.000	0.000	19.266	0.000
Tk 235	External Floating Roof	Transmix	0.000	0.000	0.000	0.000	0.000
Tk 236	External Floating Roof	U/L	5.634	0.056	0.000	8.153	0.000
Tk 237	External Floating Roof	SUP	5.629	0.056	0.000	3.919	0.000
Tk 249	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	0.000
Tk 250	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	0.000
Tk 252	External Floating Roof	LCC	0.000	0.000	0.000	0.445	0.000
Tk 253	External Floating Roof	LCC	0.000	0.000	0.000	0.446	0.000
Tk 254	External Floating Roof	U/L	5.573	0.056	0.000	8.000	0.000



Table 3-5 2016 Update (continued)  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANK<sup>1</sup>**

Tank Id	Type of tank	Service of Tank	O-TOLUIDINE CAS# 95534	ACRYLAMIDE CAS# 79061	PROPYLENE CAS# 115071	1,4-TMBenzene CAS# 95636	ETHYLENE CAS# 74851
Tk 255	External Floating Roof	SUP	2.436	0.024	0.000	1.628	0.000
Tk 256	External Floating Roof	U/L	5.634	0.056	0.000	8.153	0.000
Tk 257	External Floating Roof	Dimate Gasoline	0.000	0.000	0.062	0.000	0.000
Tk 258	External Floating Roof	Alkylate Gasoline	0.000	0.000	0.000	0.000	0.000
Tk 262	External Floating Roof	SUP	5.525	0.055	0.000	3.839	0.000
Tk 263	External Floating Roof	JetA	42.763	0.000	0.000	36.557	0.000
Tk 264	External Floating Roof	JetA	42.864	0.000	0.000	36.864	0.000
Tk 265	External Floating Roof	JetA	17.901	0.000	0.000	15.330	0.000
Tk 266	External Floating Roof	WSR	0.000	0.000	0.000	0.000	0.000
Tk 267	External Floating Roof	JetA	43.771	0.000	0.000	37.463	0.000
Tk 268	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000
Tk 269	External Floating Roof	WSR	0.000	0.000	0.000	0.000	0.000
Tk 270	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000
Tk 271	External Floating Roof	JetA or gasoline	16.130	0.000	0.000	14.807	0.000
Tk 272	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000
Tk 273	External Floating Roof	U/L	5.070	0.051	0.000	7.091	0.000
Tk 274	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000
Tk 275	External Floating Roof	WSR	0.000	0.000	0.000	0.000	0.000
Tk 301	External Floating Roof	Rec Oil	25.595	0.000	0.000	2.700	0.000
Tk 302	External Floating Roof	Rec Oil	25.595	0.000	0.000	2.700	0.000

<sup>1</sup> Table 3-4 and 3-5 tank emissions are based on 2009 actual emissions with a x1.24 adjustment to throughputs and tank turnovers to estimate emissions at the refinery's crude oil capacity

Table 3-6  
**POTENTIAL EMISSIONS FROM REFINERY TRUCK LOADING RACK**

(Note: emissions from this source normally do not occur and the indicated emissions represent an extremely conservative scenario in which the normal delivery of refinery products by pipeline is interrupted for a full year)

Product Loaded	S	P	M	T	VOC Factor (lb/103 gal)	Throughput (103 gal/year)	VOC Emission (ton/yr)	Benzene tons/yr	Naphthalene tons/yr	o-Xylene tons/yr	Ethylbenzene tons/yr
Motor Gasoline	0.5	8.27	66	537	6.3	306600	970.75	4.8537	4.2713	13.6875	7.1835
Aviation Gas	0.5	5.22	60	537	3.6	1993	3.62	0.0000	0.0000	0.0000	0.0000
Diesel	0.5	0.0143	130	537	0.0	122640	1.32	0.0000	0.0000	0.0000	0.0000
Jet Fuel	0.5	0.205	130	537	0.3	183960	28.44	0.0000	0.3697	0.6797	0.2275

Product Loaded	p-Xylene tons/yr	Ethylene Dibromide tons/yr	Ethylene Dichloride tons/yr	m-Xylene tons/yr	Toluene tons/yr	1,3-Butadiene tons/yr	n-Hexane tons/yr	Aniline tons/yr	Cresol Mixture tons/yr
Motor Gasoline	10.1928	0.0000	0.0000	25.9189	42.6157	0.0000	13.0080	0.0971	0.0000
Aviation Gas	0.0000	0.0009	0.0000	0.0000	0.0000	0.0000	0.0011	0.0000	0.0000
Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0013
Jet Fuel	0.2986	0.0000	0.0000	0.7451	0.0000	0.0000	0.0000	0.0003	0.0284

Table 3-6 (continued)  
**POTENTIAL EMISSIONS FROM REFINERY TRUCK LOADING RACK**

Product Loaded	Phenol tons/yr	Styrene tons/yr	Methanol tons/yr	Nickel tons/yr	HCL tons/yr	Perchloroethylene tons/yr	Biphenyl tons/yr
Motor Gasoline	0.0971	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Aviation Gas	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Diesel	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0013
Jet Fuel	0.0284	0.0000	0.0000	0.0000	0.0000	0.0000	0.0284

Product Loaded	2,2,4 Trimethylpentane tons/yr	Cumene tons/yr	o-Toluidine tons/yr	Acrylamide tons/yr	Antimony Compounds tons/yr	Arsenic tons/yr	Cyanide Compounds tons/yr
Motor Gasoline	4.8537	0.0971	0.0971	0.0010	0.0000	0.0000	0.0000
Aviation Gas	0.0797	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Jet Fuel	0.0000	0.0284	0.2844	0.0000	0.0000	0.0000	0.0000

### 3.1.4 Process Unit Fugitives

As discussed in Section 2, the refinery incorporates numerous processes and storage facilities. These facilities are interconnected by piping, which uses tens of thousands of components such as valves, flanges, connectors, pumps, and compressors necessary for safe and efficient refinery operation. Fugitive emissions are defined as emissions that could not reasonably be expected to pass through a stack or vent. VOC emissions and emissions of the associated HAPs that occur due to leakage from piping components are defined as process fugitive emissions.

The estimation of process fugitive emissions was accomplished using published emission factors for specific components (e.g., valves, flanges, pumps, etc.) in a specific service (light liquid, heavy liquid, gas), and applying these factors to the total number of components in each process area. The refinery process areas are summarized in Table 3-7. The emission factors used for estimating total VOC emissions from components are presented in the EPA document Protocol for Equipment Leak Estimates (EPA, 1995). The fugitive emissions estimates were based on the Protocol's refinery average VOC emission factors, which are summarized in Table 3-8. Although a leak detection and repair (LDAR) program has been put in place within a number of refinery areas, non-LDAR emission factors are conservatively used to estimate the worst-case potential fugitive emissions from process units throughout the facility.

Calculation of fugitive emissions requires estimates of the total numbers of refinery components by type. In the original Covered Source Permit application, actual component counts for refinery process units were largely unavailable and the basis of the counts was the refinery Piping and Instrumentation Diagrams (P&IDs). Actual component counts obtained from implementation of the refinery LDAR program were used in this renewal application for those process areas where the LDAR program has been implemented. Component counts for the remaining refinery areas continue to rely on the data provided by the P&IDs.

The numbers of components by process area using non-LDAR emission factors are summarized in Table 3-9. Calculated VOC fugitive emissions by process area are summarized in Table 3-10. Detailed spreadsheets of component counts and emission estimates for individual components are provided on CD in Appendix B-3.

The above estimates reflect only streams in VOC service, which are defined as streams having a VOC content in excess of 10 percent by weight (EPA, 1995).

Pressure relief devices (PRV) that vent to a flare or control device are excluded from the fugitive emissions inventory because these emissions are controlled. As discussed previously, streams in insignificant liquid service (vapor pressure less than 0.3 kPa) have also been excluded from the inventory.

**Table 3-7**  
**REFINERY PROCESS AREAS**

<b>Area Number</b>	<b>Area Description</b>
20	LPG area and field piping Blending and shipping storage tanks
23	Relief systems/cooling towers
36	Waste water treatment Land treatment unit Foul water tanks
51	Crude unit
52/55	Boilers/foul water oxidizer
53/54	Fluid catalytic cracker unit
56	Hydrogenation plant
57	Hydrogen plant
58	Alkylation plant
59	Isomerization plant
60	Asphalt plant
61/62	Amine/acid plant
66	Dimersol plant
67	Cogeneration plant

**Table 3-8**  
**REFINERY AVERAGE PROCESS FUGITIVE VOC EMISSION FACTORS (\*)**

Equipment Type	Service <sup>1</sup>	Emission Factor (kg/hr/source)
Valves	G	0.0268
	LL	0.0109
	HL	0.00023
Pump Seals	G	0.2803**
	LL	0.114
	HL	0.021
Compressor Seals	G	0.636
PRVs	G	0.16
Connectors	ALL	0.00025
Open-ended Lines	ALL	0.0023
Sampling Connections	ALL	0.015
Process Drains – Uncontrolled <sup>2</sup>	ALL	0.07 lb/hr/source
Process Drains – Controlled <sup>2</sup>	ALL	0.001 lb/hr/source

\* Obtained from Table 2-2 of EPA Document "Protocol for Equipment Leak Emission Estimates" 1995

\*\* No emission factor available for pump seals in gas service. Emission factor above reflects LL service for pump seals adjusted by the ratio of the gas to light liquid service emission factors for valves.

<sup>1</sup>G=Gas, LL=Light Liquid, HL=Heavy Liquid

<sup>2</sup> Emission factor for process drains is from EPA AP-42, Chapter 5, Table 5.1-4 and API Publication 4677.

**Table 3-9  
COMPONENT COUNTS BY REFINERY AREA**

	Area Description	Service	Valves	Flanges	Pumps	Com-pressors	PRVS	Process Drains <sup>1</sup>	Process Drains <sup>2</sup>
20	LPG area and field piping Blending and shipping	All	2,421	11,432	58	4	32	85	
23	Relief systems	All	53	220	0	0	0	0	
36	Waste water treatment	All	246	335	12	0	2	20	
51	Crude unit	All	1,403	6,558	29	1	4	97	4
52/55	Boilers/foul water	All	103	181	0	0	0	97	
53	Fluid catalytic cracker	All	1,908	2,452	33	0	12	153	
56	Hydrogenation plant	All	422	812	1	2	4	49	
57	Hydrogen plant	All	166	914	1	0	4	Incl in pit 56	
58	Alkylation plant	All	1,180	5,821	21	1	0	92	
59	Isomerization plant	All	570	1,493	9	0	0	47	
60	Asphalt plant	All	53	236	0	0	0	0	
61/62	Amine/acid plant	All	12	49	0	0	0	0	
66	Dimersol plant	All	974	1,272	21	0	12	53	
67	Cogeneration plant	All	253	1,264	2	1	0		51
	<b>Total</b>	<b>All</b>	<b>9,765</b>	<b>33,039</b>	<b>187</b>	<b>9</b>	<b>71</b>	<b>693</b>	<b>55</b>

Note: For summary purposes, both connectors and fittings have been grouped under the category of flanges

<sup>1</sup> Uncontrolled drain count

<sup>2</sup> Controlled drain count

**Table 3-10 2016 Update  
MAXIMUM FUGITIVE VOC EMISSIONS FROM  
FIELD PIPING COMPONENT LEAKS BY PROCESS AREA**

Area Number	Area Description	VOC Emissions (Ton/Yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	464.3
23	Relief Systems	14.3
36	Waste Water Treatment Foul Water Tanks	7.7
51	Crude Unit	234.6
52/55	Boilers/Foul Water Oxidizer	56.5
53/54	Fluid Catalytic Cracker Unit	268.9
56	Hydrogenation Plant	86.5
57	Hydrogen Plant	34.4
58	Alkylation Plant	208.1
59	Isomerization Plant	122.3
60	Asphalt Plant	-
61/62	Amine/Acid Plant	3.3
66	Dimersol Plant	36.7
67	Cogeneration Plant	62.7
Total <sup>1</sup>		1600.4

<sup>1</sup>This value may be different from the sum on the counterparts due to rounding from truncation of insignificant digits.

<sup>2</sup>TProcess fugitives include estimated emissions from process drains



The total VOC emissions estimated by means of the above methods served as the basis for estimating fugitive emissions of HAPs from the refinery process units. Each component, or group of components in the same service, was assigned a stream code that corresponds to a specific distribution of HAPs by weight. The stream compositions were developed by Chevron based on process engineering information, stream analyses or available literature. The total VOC emission estimate was then multiplied by the weight fractions for individual HAPs to estimate the corresponding species emissions.

Maximum estimated fugitive HAP emissions from process units are summarized in Table 3-11.

#### 2016 Update:

*Fugitive emissions from process drains, both uncontrolled and controlled (with inverted p-traps), have been estimated and included in the fugitives inventory. The estimation of process drain fugitive emissions was accomplished using published emission factors and applying these factors to the total number of drains in each process area. The refinery process areas are summarized in Table 3-7. The emission factors used for estimating total VOC emissions from components are presented in the EPA document AP-42, Chapter 5, Table 5.1-4 (April 2015) and API Publication 4677, Fugitive Emissions from Refinery Process Drains, Volume I. The fugitive drain emissions factors are included in Table 3-8.*

### **3.1.5 Wastewater and Foul Water Treatment**

Wastewater and foul water treatment facilities process units are physically covered and controlled emission sources, excluding the downstream oxidizers after the Benzene Recovery Unit (BRU). AP-42 provides an emission factor of 0.2 pounds of VOC per thousand gallons of throughput for effluent treatment systems having control measures such as carbon adsorbers. The maximum capacity of the wastewater treatment system is 1,400 gallons per minute, yielding a maximum estimated VOC emission of 73.6 tons/year (147,200 lbs/year). HAP emissions are based on the VOC emissions and the speciation profile for recovered oil.

### **3.1.6 Cooling Tower**

The primary source of VOC emissions from cooling towers is leakage from process equipment that results in organic liquids mixing with the cooling water. Chevron has a monitoring and maintenance program to minimize the occurrence of such leaks. Section 5.1 of AP-42 presents a VOC emission factor for cooling towers at refineries with a program to minimize leaks. This factor is 0.7 pounds of VOC per million gallons of water. The cooling tower at the Chevron Hawaii Refinery has a cooling water rate of 50,000 gallons per minute, resulting in an estimated VOC emission rate of 2.1 pounds per hour (9.2 tons per year).

### **3.1.7 Flaring**

The refinery flares are necessary to control emissions from various equipment vents and to provide for safe operations in case of upset conditions or an emergency. Catastrophic upset condition gas rates are highly variable and difficult to predict; therefore, Chevron has primarily estimated emissions using AP-42 emission factors that are functions of the maximum refinery throughput. The flaring emission factors are based on an estimate of gas flaring rates as a function of refinery process rates. Note that the emissions are only provided as an estimate and that actual emissions may vary. Chevron attempts to minimize flaring events; however, in case of an emergency, flaring rates cannot be limited.

Table 5.1-1 of EPA document AP-42 provides the following refinery flaring emission factors (in pounds per thousand barrels of feed):

- Carbon monoxide – 4.3
- VOC – 0.8
- Nitrogen oxides – 18.9
- Sulfur oxides (as SO<sub>2</sub>) – 26.9

**Table 3-11 2016 Update  
MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS**

Number	Area Description	Benzene CAS# 71432 (ton/yr)	Naphthalene CAS# 91203 (ton/yr)	o-Xylene CAS# 95476 (ton/yr)	Ethylbenzene CAS# 100414 (ton/yr)	p-Xylene CAS# 106423 (ton/yr)	Ethylene Dibromide CAS# 106934 (ton/yr)	Ethylene Dichloride CAS# 107062 (ton/yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	0.83	1.43	3.37	1.26	1.71	0.45	0.27
23	Relief Systems	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Waste Water Treatment Unit	0.01	0.01	0.02	0.01	0.01	0.00	0.00
51	Crude Unit	1.17	0.26	0.80	0.20	0.36	0.00	0.00
52/55	Boilers/Foul Water Oxidizer	0.01	0.03	0.05	0.02	0.03	0.00	0.00
53	Fluid Catalytic Cracker Unit	0.89	0.66	1.89	0.94	1.34	0.00	0.00
56	Hydrogenation Plant	0.01	0.02	0.03	0.01	0.01	0.00	0.00
57	Hydrogen Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Alkylation Plant	0.01	0.03	0.05	0.02	0.02	0.00	0.00
59	Isomerization Plant	0.01	0.02	0.03	0.01	0.01	0.00	0.00
60	Asphalt Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61/62	Amine/Acid Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Dimersol Plant	0.01	0.02	0.03	0.01	0.01	0.00	0.00
67	Cogeneration Plant	0.271	0.000	0.000	0.000	0.000	0.000	0.000
	Process Fugitive Summary	3.22	2.48	6.27	2.46	3.51	0.45	0.27

<sup>1</sup> Table 3-11 is updated to include HAP emissions from process drain fugitives

Table 3-11 2016 Update (continued)  
**MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS**  
**UNITS**

Number	Area Description	m-Xylene CAS# 108383 (ton/yr)	Toluene CAS# 108883 (ton/yr)	1,3-Butadiene CAS# 106990 (ton/yr)	n-Hexane CAS# 110543 (ton/yr)	Aniline CAS# 62533 (ton/yr)	Cresol Mixture CAS# 1319773 (ton/yr)	Phenol CAS# 108952 (ton/yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	4.69	4.64	0.30	1.29	0.02	0.25	0.10
23	Relief Systems	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Waste Water Treatment Unit	0.03	0.03	0.00	0.05	0.00	0.04	0.00
51	Crude Unit	1.29	2.61	0.02	3.60	0.01	0.15	0.02
52/55	Boilers/Foul Water Oxidizer	0.07	0.04	0.00	0.10	0.00	0.10	0.01
53	Fluid Catalytic Cracker Unit	3.43	5.26	0.25	0.41	0.02	0.16	0.01
56	Hydrogenation Plant	0.03	0.02	0.13	0.05	0.00	0.05	0.00
57	Hydrogen Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Alkylation Plant	0.06	0.04	0.05	0.10	0.00	0.09	0.01
59	Isomerization Plant	0.03	0.02	0.05	0.05	0.00	0.05	0.00
60	Asphalt Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61/62	Amine/Acid Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Dimersol Plant	0.04	0.02	0.00	0.05	0.00	0.05	0.00
67	Cogeneration Plant	0.000	0.153	0.000	0.592	0.000	0.001	0.000
	Process Fugitive Summary	9.67	12.85	0.80	6.28	0.05	0.94	0.16

<sup>1</sup> Table 3-11 is updated to include HAP emissions from process drain fugitives

**Table 3-11 2016 Update (continued)  
MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS**

Number	Area Description	Styrene CAS# 100425 (ton/yr)	Methanol CAS# 67561 (ton/yr)	Nickel CAS# 7440020 (ton/yr)	HCL CAS# 7647010 (ton/yr)	Perchloroethylene CAS# 127184 (ton/yr)	Biphenyl CAS# 92524 (ton/yr)	2,2,4 Trimethylpentane CAS# 540841 (ton/yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	0.02	0.03	0.00	0.00	0.00	0.09	0.49
23	Relief Systems	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Waste Water Treatment Unit	0.00	0.00	0.00	0.00	0.00	0.00	0.02
51	Crude Unit	0.00	0.00	0.00	0.00	0.00	0.01	0.60
52/55	Boilers/Foul Water Oxidizer	0.00	0.00	0.00	0.00	0.00	0.00	0.05
53	Fluid Catalytic Cracker Unit	0.04	0.00	0.00	0.00	0.00	0.01	0.08
56	Hydrogenation Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.02
57	Hydrogen Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Alkylation Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.44
59	Isomerization Plant	0.00	0.00	0.00	0.00	0.05	0.00	0.02
60	Asphalt Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61/62	Amine/Acid Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Dimersol Plant	0.00	0.00	0.34	0.00	0.00	0.00	0.03
67	Cogeneration Plant	0.000	0.000	0.000	0.000	0.000	0.000	0.104
	Process Fugitive Summary	0.07	0.03	0.34	0.00	0.05	0.13	1.85

<sup>1</sup> Table 3-11 is updated to include HAP emissions from process drain fugitives

Table 3-11 2016 Update (continued)  
**MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS**

Number	Area Description	Cumene CAS# 98828 (ton/yr)	o-Toluidine CAS# 95534 (ton/yr)	Acrylamide CAS# 79061 (ton/yr)	Antimony Compounds CAS# ADQ500 (ton/yr)	Arsenic CAS# 740382 (ton/yr)	Cyanide Compounds CAS# 1073 (ton/yr)	Total HAPs ton/yr
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	0.18	0.86	0.00	0.00	0.01	0.01	22.30
23	Relief Systems	0.00	0.00	0.00	0.00	0.00	0.00	0.003
36	Waste Water Treatment Unit	0.00	0.00	0.00	0.00	0.00	0.00	0.236
51	Crude Unit	0.09	0.09	0.00	0.00	0.01	0.01	11.308
52/55	Boilers/Foul Water Oxidizer	0.01	0.00	0.00	0.00	0.00	0.00	0.513
53	Fluid Catalytic Cracker Unit	0.06	0.18	0.00	0.00	0.02	0.02	15.675
56	Hydrogenation Plant	0.01	0.00	0.00	0.00	0.00	0.00	0.403
57	Hydrogen Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.000
58	Alkylation Plant	0.01	0.00	0.00	0.00	0.00	0.00	0.946
59	Isomerization Plant	0.01	0.00	0.00	0.00	0.00	0.00	0.344
60	Asphalt Plant	0.00	0.00	0.00	0.00	0.00	0.00	0
61/62	Amine/Acid Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.001
66	Dimersol Plant	0.01	0.00	0.00	0.00	0.00	0.00	0.626
67	Cogeneration Plant	0.000	0.000	0.000	0.000	0.005	0.005	1.133
	Process Fugitive Summary	0.37	1.14	0.00	0.01	0.05	0.05	53.49

† Table 3-11 is updated to include HAP emissions from process drain fugitives

During normal operations, sulfur is stripped from the RFG in the acid plant (before it is flared). In the past when the acid plant was down, the sulfur was not removed from the acid plant gas stream, and additional SO<sub>2</sub> was produced by flaring. However, with the addition of the Caustic Scrubber, such high-SO<sub>2</sub> events will no longer occur. In addition the refinery has installed a flare vapor recovery system. This is described in Section 2.3.2.1.

Applying the AP-42 factors for CO, VOC, SO<sub>2</sub> and NO<sub>x</sub> to a rate of 65,000 bbl/day of crude oil feed, results in the following estimated emissions (tons per year) from both flares combined. This conservative approach to estimating flaring emissions was selected because of safety concerns associated with limiting the throughput to the flares. HAP emissions for the flare have not been quantified, because the flares combust a variety of process streams. Therefore, neither the specific HAPs present nor their quantities can be meaningfully determined.

- Carbon monoxide – 51.0 tons per year
- VOC – 9.5 tons per year
- Nitrogen oxides – 224.2 tons per year
- Sulfur dioxide – 319.1 tons per year

### 3.1.8 Catalyst Transfer Operations at the FCC

Operation of the FCC unit requires the removal and disposal of spent catalyst and the addition of fresh catalyst. Based on historical records, it is estimated that 77 tons per month of catalyst is disposed of and replaced with fresh catalyst. No emission factor was identified to address this specific catalyst handling activity. AP-42 (Section 8.23), however, provides factors for material transfer operations in the metallic minerals processing industry. The transfer of catalyst was assumed to be represented by the factor for material transfer (0.06 pounds of particulate per ton of material transferred [i.e., removal of spent catalyst plus replacement with new catalyst]). Using this factor results in an estimated particulate matter emission of .03 tons per year.

## 3.2 Summary

The refinery inventory of maximum potential criteria pollutant emissions is summarized in Table 3-12. The corresponding maximum potential HAP emissions are summarized in Table 3-13. These emissions reflect the estimation methods and assumptions for the individual source types described in Sections 3.1.1 through 3.1.8.

## 3.3 Identification of Control Devices

Emission control devices exist on the cogeneration turbines and compressor, the FCC stack, on many storage tanks, and the wastewater treatment system. The cogeneration turbines have low-NO<sub>x</sub> burners and water injection to reduce emissions of nitrogen oxides. This turbine control system is designed to limit NO<sub>x</sub> emissions to a level of no more than 67 and 69 parts per million on a volume basis at 15 percent O<sub>2</sub> for RFG and WSR fuels, respectively. The cogeneration compressor vents directly to the flare. The FCC Furnace has low-NO<sub>x</sub> burners to reduce emissions of nitrogen oxides.

**Table 3-12 2016 Update**  
**SUMMARY OF MAXIMUM POTENTIAL CRITERIA POLLUTANT EMISSIONS**  
**FROM THE CHEVRON HAWAII REFINERY**

Sources	Pollutant Emission Rates (ton/yr)						Total Criteria Pollutant Emissions
	PM10	SO2	CO	NO2	VOC	Lead	
Boilers	134.8	1353.8	86.2	551.9	13.1	0.0	2140
CatOx Unit	0.0	0.0	17	14.7	1.3	0.0	33
Cogen Turbines	11.7	27.9	52.5	193.2	2.3	0.0	288
Crude Furnaces	44.5	482.0	75.0	302.9	5.1	0.0	909
FCC Furnaces <sup>1</sup>	2.1	7.2	23.2	15.1	1.6	0.0	49
Isom Furnaces	0.2	0.7	2.1	2.5	0.1	0.0	5
H&H Furnaces	1.1	3.9	12.1	14.5	0.8	0.0	32
Acid preheater & combustion chamber	0.4	1.5	4.8	5.7	0.3	0.0	13
Asphalt Furnace <sup>2</sup>	0	0	0	0	0	0	0
FCC Stack	175.2	333.3	499.3	285.1	14.7	0.0	1308
<u>Emergency Stationary Generators:</u>							
Black Start Generator	0.03	0.001	0.17	1.62	1.62	0	3
<u>Non-Emergency Stationary Generators</u>							
Sand Filter Pump #1	0.43	0.0085	7.2	5.8	5.8	0	19
Sand Filter #2	0.43	0.0085	7.2	5.8	5.8	0	19
Transfer Pump	0.43	0.0085	7.2	5.8	5.8	0	19
Cooling Tower	3.2	-	-	-	9.2	-	12
Acid plant absorber stack (*)	-	1405.3	-	-	-	-	1405
Catalyst transfer	0.0	-	-	-	-	-	0
Wastewater treatment	-	-	-	-	73.6	0.0	74
Loading Rack	-	-	-	-	1117.7	0.0	1118
Process Fugitives	-	-	-	-	1616.5	1.4	1618
Tanks	-	-	-	-	467.9	0.0	468
Marine loading	-	-	-	-	196.6	0.0	197
Refinery Flares	-	319.1	51.0	224.2	9.5	-	604
<b>Totals</b>	<b>374.6</b>	<b>3935.7</b>	<b>845.0</b>	<b>1628.6</b>	<b>3419.6</b>	<b>1.4</b>	<b>10204</b>

Notes: (\*) Criteria pollutant emissions from the acid preheater and combustion chamber are vented to the acid plant absorber stack. The listed SO<sub>2</sub> emissions from the acid plant absorber stack are only from acid production.

<sup>1</sup> FCC Furnaces include Startup Air Heater

<sup>2</sup> Asphalt Plant is permanently out of service. Emissions have been removed from this table



Table 3-13 2016 Update  
 SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY

	BENZENE CAS# 71432	NAPHTHALENE CAS# 91203	O-XYLENE CAS# 95476	ETHYLBENZENE CAS# 100414	P-XYLENE CAS# 106423	DIBROMIDE CAS# 106934	DICHLORIDE CAS# 107062	M-XYLENE CAS# 108383	TOLUENE CAS# 108883	1,3-BUTADIENE CAS# 106990
LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	0.83	1.43	3.37	1.26	1.71	0.45	0.27	4.69	4.64	0.30
RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE WATER TREATMENT LAND TREATMENT UNIT	0.01	0.01	0.02	0.01	0.01	0.00	0.00	0.03	0.03	0.00
CRUDE UNIT	1.17	0.26	0.80	0.20	0.36	0.00	0.00	1.29	2.61	0.02
BOILERS/FOUL WATER OXIDIZER	0.01	0.03	0.05	0.02	0.03	0.00	0.00	0.07	0.04	0.00
FLUID CATALYTIC CRACKER UNIT	0.89	0.66	1.89	0.94	1.34	0.00	0.00	3.43	5.26	0.25
HYDROGENATION PLANT	0.01	0.02	0.03	0.01	0.01	0.00	0.00	0.03	0.02	0.13
HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALKYLATION PLANT	0.01	0.03	0.05	0.02	0.02	0.00	0.00	0.06	0.04	0.05
ISOMERIZATION PLANT	0.01	0.02	0.03	0.01	0.01	0.00	0.00	0.03	0.02	0.05
ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DIMERSOL PLANT	0.01	0.02	0.03	0.01	0.01	0.00	0.00	0.04	0.02	0.00
COGENERATION PLANT	0.271	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.153	0.000

Table 3-13 2016 Update (continued)  
 SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY

	BENZENE CAS# 71432	NAPHTHALENE CAS# 91203	O-XYLENE CAS# 95476	ETHYLBENZENE CAS# 100414	P-XYLENE CAS# 106423	DIBROMIDE CAS# 106934	DICHLORIDE CAS# 107062	M-XYLENE CAS# 108383	TOLUENE CAS# 108883	1,3-BUTADIENE CAS# 106990
BOILER POINT	0.003	0.008	0.001	0.00					0.046	
COGEN POINT	0.034	0.018						0.033	0.067	0.008
CRUDE POINT	0.001	0.006	0.001	0.00					0.030	
FCC POINT	0.001	0.000							0.001	
ISOM POINT	0.000	0.000							0.000	
H&H POINT	0.000	0.000							0.000	0.000
H&H POINT	0.000	0.000							0.000	0.000
ACID PLANT CC AND PREHEATER POINT	0.000	0.000							0.000	
ASPHALT POINT	0.000	0.000							0.000	
FCC STACK										
WASTEWATER	0.1398	0.3458	0.5887	0.1840	0.2796	0.0002	0.0000	0.7211	0.4709	0.0000
LOAD RACK	4.85	4.64	14.37	7.41	10.49	0.00	0.00	26.66	42.62	0.00
MARINE LOADING	4.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.32	0.00
FLARE										0.00
Emergency Stationary Generators:										
Black Start Generator										
Non-Emergency Stationary Generators										
Sand Filter Pump	5.7E-4	1E-05	1.7E-4		Incl in oXyl			Incl in oXyl	2.5E-4	2E-5
Diesel Engine #1	5.7E-4	1E-05	1.7E-4		Incl in oXyl			Incl in oXyl	2.5E-4	2E-5
Sand Filter Pump	5.7E-4	1E-05	1.7E-4		Incl in oXyl			Incl in oXyl	2.5E-4	2E-5
Diesel Engine #2										
Transfer Pump										
HAPs Summary (ton/yr)	12.36	7.50	21.23	10.06	14.28	0.45	0.27	37.09	58.40	0.81

Table 3-13 2016 Update (continued)  
**SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY**

	n-HEXANE CAS# 110543	ANILINE CAS# 62533	CRESOL MIXTURE CAS# 1319773	PHENOL CAS# 108952	STYRENE CAS# 100425	METHANOL CAS# 67561	NICKEL CAS# 7440020	HCL CAS# 7647010	PERCHLORO ETHYLENE CAS# 127184	BIPHENYL CAS# 92524
LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	1.29	0.02	0.25	0.10	0.02	0.03	0.00	0.00	0.00	0.09
RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE WATER TREATMENT LAND TREATMENT UNIT	0.05	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CRUDE UNIT	3.60	0.01	0.15	0.02	0.00	0.00	0.00	0.00	0.00	0.01
BOILERS/FOUL WATER OXIDIZER	0.10	0.00	0.10	0.01	0.00	0.00	0.00	0.00	0.00	0.00
FLUID CATALYTIC CRACKER UNIT	0.41	0.02	0.16	0.01	0.04	0.00	0.00	0.00	0.00	0.01
HYDROGENATION PLANT	0.05	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALKYLATION PLANT	0.10	0.00	0.09	0.01	0.00	0.00	0.00	0.00	0.00	0.00
ISOMERIZATION PLANT	0.05	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.05	0.00
ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DIMERSOL PLANT	0.05	0.00	0.05	0.00	0.00	0.00	0.34	0.00	0.00	0.00
COGENERATION PLANT	0.592	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000
BOILER POINT	1.230									
COGEN POINT										
CRUDE POINT	0.002									
FCC POINT	0.473									
ISOM POINT	0.044									
H&H POINT	0.071								0.000	0.000
H&H POINT	0.189								0.000	0.000
ACID PLANT CC AND PREHEATER POINT	0.103									
ASPHALT POINT	0.043									
FCC STACK										
WASTEWATER	1.0449	0.0007	1.0670	0.0589	0.0000	0.0000	0.0000	0.0000	0.0001	0.0221
LOAD RACK	13.01	0.10	0.03	0.13	0.00	0.00	0.00	0.00	0.00	0.03
MARINE LOADING FLARE	8.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 3-13 2016 Update (continued)  
**SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY**

	n-HEXANE CAS# 110543	ANILINE CAS# 62533	CRESOL MIXTURE CAS# 1319773	PHENOL CAS# 108952	STYRENE CAS# 100425	METHANOL CAS# 67561	NICKEL CAS# 7440020	HCL CAS# 7647010	PERCHLORO ETHYLENE CAS# 127184	BIPHENYL CAS# 92524
<u>GENERATORS</u>										
<u>Emergency</u>										
<u>Stationary</u>										
<u>Generators:</u>										
Black Start Generator										
<u>Non-Emergency</u>										
<u>Stationary</u>										
<u>Generators</u>										
Sand Filler Pump Diesel Engine #1										
Sand Filler Pump Diesel Engine #2										
<u>Transfer Pump</u>										
HAP's Summary (ton/yr)	31.43	0.14	2.03	0.34	0.07	0.03	0.34	0.00	0.05	0.18

Table 3-13 2016 Update (continued)  
**SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY**

	2,2,4 TRIMETHYLPENTANE CAS# 540841	CUMENE CAS# 98828	O-TOLUIDINE CAS# 95534	ACRYLAMIDE CAS# 79061	ANTIMONY COMPOUNDS CAS# ADQ500	ARSENIC CAS# 740382	CYANIDE COMPOUNDS CAS# 1073	Formaldehyde CAS# 50000	POMPAH CAS# EDF047
LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	0.49	0.18	0.86	0.00	0.00	0.01	0.01		
RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
WASTE WATER TREATMENT LAND TREATMENT UNIT	0.02	0.00	0.00	0.00	0.00	0.00	0.00		
CRUDE UNIT	0.60	0.09	0.09	0.00	0.00	0.01	0.01		
BOILERS/FOUL WATER OXIDIZER	0.05	0.01	0.00	0.00	0.00	0.00	0.00		
FLUID CATALYTIC CRACKER UNIT	0.08	0.06	0.18	0.00	0.00	0.02	0.02		
HYDROGENATION PLANT	0.02	0.01	0.00	0.00	0.00	0.00	0.00		
HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
ALKYLATION PLANT	0.44	0.01	0.00	0.00	0.00	0.00	0.00		
ISOMERIZATION PLANT	0.02	0.01	0.00	0.00	0.00	0.00	0.00		
ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
DIMERSOL PLANT	0.03	0.01	0.00	0.00	0.00	0.00	0.00		
COGENERATION PLANT	0.104	0.000	0.000	0.000	0.000	0.005	0.005		
BOILER POINT								0.349	0.298
COGEN POINT								0.506	0.021
CRUDE POINT								0.208	0.006
FCC POINT <sup>1</sup>							23.5	0.020	0.000
ISOM POINT								0.002	0.000
H&H POINT								0.003	0.000
H&H POINT								0.008	0.000
ACID PLANT CC AND PREHEATER POINT								0.004	0.000
ASPHALT POINT								0.002	0.000
FCC STACK								0.890	
WASTEWATER	0.5151	0.1251	0.0589	0.0000	0.0001	0.0001	0.0001		
LOAD RACK	4.93	0.13	0.38	0.00	0.00	0.00	0.00	0.00	0.00

Table 3-13 (continued)  
 SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY

	2,2,4 TRIMETHYLPENTANE CAS# 540841	CUMENE CAS# 98828	O-TOLUIDINE CAS# 95534	ACRYLAMIDE CAS# 79061	ANTIMONY COMPOUNDS CAS# AD0500	ARSENIC CAS# 7440382	CYANIDE COMPOUNDS CAS# 1073	Formaldehyde CAS# 50000	POM/PAH CAS# EDF047
MARINE LOADING	1.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FLARE									
Emergency Stationary Generators:									
Black Start Generator									
Non-Emergency Stationary Generators									
Sand Filter Pump								7.2E-4	1E-4
Diesel Engine #1								7.2E-4	1E-4
Sand Filter Pump								7.2E-4	1E-4
Diesel Engine #2									
Transfer Pump									
HAPs Summary (ton/yr)	8.87	0.62	1.58	0.00	0.01	0.05	23.55	1.99	0.33

<sup>1</sup>HCN emissions at the FCCU regenerator stack are estimated to be 23.5 tpy, based on 2011 ICR test results. This estimate is included in the FCC Point and Total HAPs Ton/Yr.

Both flare stacks are also considered control devices because they are used to combust emissions from the venting of equipment that is regulated under NSPS and MACT requirements.

The FCC stack is routed through a cyclone and electrostatic precipitator (ESP). These devices remove particulate matter from the FCC flue gas. The removal efficiency of these controls ranges from 95 to more than 99 percent.

The wastewater treatment plant uses several devices to control emissions. The foul water tanks are vented to a flare and the foul water oxidizer is vented to the Boiler Plant boilers. The nitrogen strippers of the benzene recovery unit (BRU) remove hydrocarbons from the wastewater. These hydrocarbons are controlled by carbon absorbers and are subsequently sent to the recovered oil tankage. The BRU vents some nitrogen at the end of the adsorber regeneration. This vent is controlled by carbon canisters, as is the purge gas from the API separators. The recovered oil sump is connected to carbon canisters.

Secondary seals or equivalent (i.e., dome roofs) are installed on tanks subject to Subpart CC.

A detailed list of controls is provided in Appendix B.

#### 2016 Update:

*The CatOx Unit is a pollution control device for the Foul Water Treating Plant's (FWTP) offgas vent. The FWTP offgas contains primarily ammonia and some VOC's which are destroyed by the CatOx Unit. The NO<sub>x</sub> formed during this step is controlled by selective catalytic reduction (SCR).*

*The non-emergency stationary RICE engines, included in the Covered Source Permit significant modification application, submitted to DOH April 2015, are EPA certified engines that combust ULSD as the fuel.*

### **3.4 Identification of Compliance Monitoring Devices**

Chevron monitors numerous surrogate parameters that are used to estimate emissions from specific processes, and operates several monitors for compliance tracking. Usage of both fuel oil and RFG is monitored for each furnace and cogeneration turbine. For each storage tank, records are maintained on the material stored, its chemical properties, and the throughput of the tank.

Specific compliance monitors within the Hawaii Refinery consist of RFG H<sub>2</sub>S monitoring at the effluent from the gas treatment unit, NO<sub>x</sub> and O<sub>2</sub> monitors on the cogeneration turbine exhaust stacks, flare pilot light monitors, crude flare continuous emissions monitors, FCC monitors for SO<sub>2</sub>, NO<sub>x</sub> and O<sub>2</sub>. Additionally, at the BRU, control device outlet VOC content, regeneration steam flow, temperature, and duration of regeneration are monitored. Further information on compliance monitoring requirements is provided in Section 5 of this application.

Emissions trading between process areas or group designations is not proposed. Information regarding compliance monitoring and reporting for each source group within the refinery is presented in Section 5.

**2016 Update:**

*In addition to the specific compliance monitors listed above, the facility monitors compliance with the following monitors:*

- 1) FCC and Crude Flares total sulfur continuous emissions monitors (CMS)*
- 2) Operating hours for the Black Start generator using a non-resettable meter (CMS)*
- 3) Flare gas flow meters (CMS) for the Crude and FCC Flares*
- 4) NO<sub>x</sub> and NH<sub>3</sub> monitors (CMS) at the CatOx Unit*
- 5) Heater and Boiler O<sub>2</sub> monitors (CEMS)*

### **3.5 Insignificant Activities**

The operating permit regulations (Section 11-60.1-82(d)(e)(f)(g)) exempt specific activities from permitting requirements, but requires that such activities be listed. The following activities are exempted under 11-60.1-82(f)(g):

- Numerous tanks storing organic liquids have a capacity of less than 40,000 gallons and are not subject to other requirements in Sections 111 and 112 of the Act. These tanks are summarized as follows:

**2016 Update:**

*Portable chemical storage containers were added to this list. Various chemicals, including additives, promoters, passivators, and antifoam agents are used in the refinery operation to facilitate the refining process. These chemicals are typically stored in portable 200-400 gallon totes, known as portafeeds, and have insignificant VOC and HAP emissions. The example emission calculation for these portable containers is included in Appendix B.*



Tank Number	Service	Capacity (gallons)
20TD1	Anti Icing Additive	11,340
20TD2	HCC	11,340
20TD3	Out of Service	11,340
20TD4	ULMidgrade	11,340
20TD6	Anti Icing Additive	8,148
2010	Aviation Lead	15,288
5198	Nalco 5300	8,068
Portable Chemical Tanks	Additives, promoters, passivators, and antifoam agents	200-400

### 3.6 Request for Additional Exemptions

Section 11-60.1-82(f)(7) allows the Director to exempt —other activities as determined on a case-by-case basis to be insignificant. Petroleum refineries are complex facilities with numerous types and sizes of sources. Some of these sources are small and will have no significant impact on ambient air quality, are not covered by any applicable requirement, and were granted exemption status in the original Title V permit. Chevron requests that the Director again exempt the following sources from the requirements of 11-60.1-82:

1. *Meter stations, sampling points and filters.* These sources are present throughout the various process areas. Leakage from the connections and fittings associated with such equipment has been accounted for in the fugitive emissions estimates for each process unit. When sampling occurs or filters are changed, however, a small amount of VOC may be emitted. It is estimated that emissions are typically less than 10 pounds per occurrence. Inclusion of such equipment emissions and operations in the permit would impose a significant burden for monitoring and recordkeeping without significant air quality benefit. Chevron uses good engineering and operating practices to minimize emissions during these operations.
2. *Pump and tank degassing operations.* Occasionally, pumps in liquid service malfunction if a gas bubble is encountered in the fuel flow. The only practical method of returning the pump to operation is to vent the gas bubble, and prime the pump with liquid. Most pumps are tied into the flare relief system, so that such venting is controlled. Some pumps are not tied into the flare system, however, and must be vented to atmosphere in order to prime the pump with liquid. Pumps are vented only when degassing is required.

There are 98 tanks in hydrocarbon service at the refinery. Tank degassing is performed approximately once every 10 years to enable tank interiors to be inspected. Degassing may be done more frequently (three or four times in 10 years), however, if maintenance issues arise. Degassing operations consist of draining a tank to the minimum pump-out level. Vapors under the area of the floating roof are vented to the atmosphere. It is impossible to control these emissions using the flare because the tanks are not under pressure during degassing.

3. *Training fires.* The regulations exempt smoke generating equipment used in certified fire training facilities. Chevron requests DOH concurrence that this exemption also applies to open pit fires used by Chevron for fire training.
4. *Process upset vents.* Pressurized equipment such as the crude towers and FCC unit are equipped with relief vents that open only during malfunctions or severe process upset conditions. The frequency of such occurrences cannot be predicted, and the vents are critical for safe operation. Historically, venting episodes are rare. Chevron requests that emissions from upset vents be exempted. However, applicable NSPS, Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and National Emission Standards for Hazardous Air Pollutants (NESHAP) standards will be satisfied.
5. *Refinery gasoline pump.* A single service station style gasoline pump is located at the refinery, and is used to fill all gasoline-powered vehicles. Its typical monthly throughput is less than 2,000 gallons. Gasoline service station operations are exempted from permitting requirements and Chevron requests this exemption be extended to the single gasoline pump.
6. *Mercury.* The instrumentation repair shop and the laboratory periodically repair instruments and gauges that contain liquid mercury. Only small amounts of mercury are removed from such equipment and the mercury is in an unheated liquid state. The total inventory of mercury at the refinery is estimated to be less than 1 gallon. Insignificant emissions are expected from this activity.
7. *Oily sewer and stormwater vents.* Oily water and stormwater sewers exist beneath the refinery. The oily water sewer routes to an oil/water separator and contains minor amounts of oil mixed with water. Additionally, some trace amounts of oil may be present in the stormwater system. To prevent over-pressure, vent pipes 3 inches in diameter and less are placed along the sewer route. There are 76 of these vent pipes, plus six manholes with vent openings. These vent pipes are expected to have insignificant emissions.
8. *Maintenance and cleaning activities.* Routine maintenance and cleaning activities at the refinery use small amounts of commercial chemicals. These chemicals are delivered to the refinery in small containers or drums. Their use is expected to result in insignificant emissions.

Black Oil Tanks must be cleaned to remove accumulated sludge before inspection. It is estimated that approximately two tanks per year are cleaned. Insignificant emissions are expected from this activity.

Process unit shutdown and turnaround activities are performed infrequently as needed for maintenance. Typically, turnaround is performed every 2 to 4 years depending on the process unit. Process fluids are removed and displaced by water. The unit is drained and steamed. Steam is vented to the flares.

9. *Additives, promoters, passivators, and antifoam agents.* Various chemicals are used in the refinery operation to facilitate the refining process. Addition of these chemicals is not anticipated to materially change facility VOC or HAP emissions, and results in insignificant incremental emissions.

10. *Insignificant Heavy Liquids.* Chevron has reviewed applicable requirements for numerous source categories to determine the implication of developing an insignificant heavy liquids source category. Insignificant heavy liquids are hydrocarbon liquids that have a vapor pressure less than 0.3 kPa. In general, this includes diesel and the heavier hydrocarbon liquids.

Emission calculation equations and emission factors were reviewed to assess the impact of excluding insignificant heavy liquids from the refinery inventory. Fugitive and storage tank emissions factors for heavy liquids are one to two orders of magnitude less than those for light liquids. As stated in the initial Permit Review Summary (and including tanks 350 and 351 from #12 below), the heavy liquid tanks are stored in Tank ID nos. 101, 102, 170, 171, 174, 176-184, 103, 151-158, 160, 161, 164, 165, 166, 268, 270 and 272, 350 and 351.

11. *FCCU Baghouse.* Three baghouses (Flex-Kleen bin vent filter) are located on the electrostatic precipitator of the FCCU to capture potential fugitive dust emissions when the ESP hopper is emptied. The control efficiency of the baghouses is 99.9%. Operation of these three baghouses will meet the insignificant emissions rate of less than 2 tpy of a regulated pollutant.
12. *Storage of Regulated Pollutants not in VOC service.* Numerous onsite tanks store substances containing regulated pollutants. ~~These tanks are not in VOC service, consistent with Subpart VV 40 CFR 60.481. In addition, these tanks are not in petroleum liquid service, consistent with Subpart K 40 CFR 60.111.~~ Insignificant fugitive emissions result from these tanks, which are listed below:

Tank Number	Service	Capacity (gallons)
350	Refinery Fuel Oil	120,918
351	Refinery Fuel Oil	120,918
175	Out of Service	50,904
5211	25% Aqueous Ammonia	11,760
5481	Out of service	10,164
6673	Nickel Catalyst	5,418
5197	25% Aqueous Ammonia	120
AP-4	Regenerated MEA	504 bbls
AP-5	Regenerated MEA	504 bbls
62AP1	Sulfuric Acid	2422 bbls
62AP2	Sulfuric Acid	14 bbls

2016 Update:

Refinery fuel oil tanks 350 and 351, are heavy liquid service tanks, and are included in #10 insignificant activity above. Sulfuric acid is a regulated pollutant, and the fresh acid tanks have been moved from the table for #15 insignificant activity below.

13. *Storage of Spent Sulfuric Acid.* Spent sulfuric acid is stored in up to two tanks at the refinery. Sulfuric acid is not a regulated pollutant; however, spent acid may contain residual amounts of VOC. Insignificant emissions are anticipated from these tanks, which are numbered 62AP1 and 62AP3.

~~14. Foul Water Offgas Treatment with Catalytic Oxidizer. The foul water offgas with ammonia is currently going to the boilers for combustion. With the proposed installation of new boilers as described in the Hybrid Energy Plant Project, the addition of a skid mounted catalytic oxidizer is proposed to process the ammonia to nitrogen. The catalyst used is electrically heated and produces minimal NO<sub>x</sub> emissions. The NO<sub>x</sub> emission rate under normal operating conditions is .27 lb/hr or 1.18 tpy. This equipment unit is deemed insignificant as emissions are less than 2 tpy of a regulated air pollutant.~~

2016 Update:

*As described in Section 2.3.13.2 and 3.3, the CatOx Unit is a control device that was permitted in 2015. This unit is no longer proposed as an insignificant activity.*

15. *Storage of Non-Regulated Pollutants.* The tanks shown in Table 3-14 contain non-regulated pollutants. These tanks are not subject to federal or state requirements. The list is provided to clarify the contents of all tanks at the refinery.
16. *Diesel powered Reciprocating Internal Combustion Engines (RICE)* The refinery operates miscellaneous diesel powered equipment for emergency, maintenance, security and facility purposes. Some units (firewater and security emergency generators) are considered stationary emergency units and have applicable requirements, yet have emissions that are insignificant levels. The applicable requirements are summarized in the Regulatory Review spreadsheet, RICE Summary Requirements, Step 2(a)(i). The remaining units are non-stationary (portable), do not have applicable requirements and have insignificant activity emissions. Tables 3-15 below contains the stationary emergency units that are insignificant activities. Appendix B Emissions contains an updated of of non-stationary (portable) equipment.

**Table 3-14  
NON-REGULATED POLLUTANT STORAGE TANKS\***

Tank Number	Service	Roof Type	Capacity (bbls)
305	Neutralized Water	Cone	24
306	Neutralized Water	Cone	72
62AP2 <sup>†</sup>	Sulfuric Acid	Cone	2,422
120	Gutwater	Cone	240
352	Raw Water	None	24,000
353	Condensate	Cone	253
354	Hot Line Reactor Bottoms Accumulator	Cone	810
381	Dirty Backwash Water Tank	Cone	758
382	De-ionized Water	Cone	274
AP-4 <sup>†</sup>	Regenerated MEA	Cone	504
AP-5 <sup>†</sup>	Regenerated MEA	Cone	504
AP-6	Caustic (25° Be)	Cone	280
2301 <sup>†</sup>	Sulfuric Acid	Cone	14
V-5182A&B	Caustic (25° Be & 5° Be)	Cone	242
5206	20° Be Caustic	Cone	179
5210	50° Be Caustic	Cone	1360
5390	Condensate	Cone	107
5480	Caustic	Cone	70
V-5486	Water	Cone	2
V-5897	Water	Cone	11
6646	Caustic	Cone	155
6658	Condensate	Cone	40
5311	Spent Catalyst (FCC)	Cone	4,000
5312	Catalyst Fines (FCC)	Cone	317
5313	Catalyst Fines (FCC)	Cone	317
5314	Fresh Catalyst (FCC)	Cone	60
5316	Fresh Catalyst (FCC)	Cone	1,128

\* Does not include Reverse Osmosis boiler water tank or caustic tank for Caustic Scrubber project.

<sup>†</sup>These tanks are moved to Insignificant Activity #12 above, Regulated Pollutants storage tanks

## 4. Dispersion Modeling

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The initial Title V permit application for the Chevron Refinery included a dispersion modeling analysis that demonstrated that the facility's emissions would not cause or contribute to pollutant concentrations in excess of federal or Hawaii ambient standards. In recognition that the refinery's normal operations entail processing of a variety of crude oil feedstocks to produce numerous different products, the representation of emissions from the various sources was undertaken in a manner to ensure that the resulting pollutant concentration estimates would not be underestimated for any foreseeable operational condition of the refinery.

Accordingly, the dispersion modeling analysis to estimate maximum short-term impacts (24 hours or less) assumed that any source capable of using multiple fuels was operating with the fuel that would result in the highest potential emissions. Additionally, despite the actual intermittent operation of some sources, the emissions used for modeling were based on the worst-case assumption of continuous operation at maximum capacity for all hours of the year. This is an extremely conservative representation of emissions, especially for the annual averaging period.

Since the initial Covered Source Permit Application was submitted, Chevron has applied for several minor and major permit modifications to implement various refinery projects. In each such instance, DOH has made a decision as to whether additional dispersion modeling was required as part of the application to ensure that the proposed modification would not result in pollutant concentrations in excess of applicable ambient standards. These analyses have been conducted and submitted to DOH when required, and, in each case, have shown that compliance with the standards continues to be maintained.

Of the six proposed changes to existing conditions of the Covered Source Permit being requested in this application (Section 5.3.2), none would result in increased emissions or changes in the conditions of pollutant releases to the atmosphere that would justify remodeling for this renewal application.

- The request to implement the Hybrid Energy Project as submitted to DOH in Appendix E to include a new cogeneration turbine, HRSG and two new boilers are proposed equipment changes. Conditions for the construction of this equipment was granted by DOH on 23 May 2007. Air Dispersion Modeling for these equipment changes was accepted by DOH as complying with ambient air quality standards.
- The request to remove the Asphalt Plant and all associated equipment as it is no longer operational. This has resulted in a decrease in emissions.

Thus, it is Chevron's position that there is no reason to conduct additional dispersion modeling as part of this permit renewal package.

### 2016 Update:

*The following provides an update to Section 4, Dispersion Modeling, of the 2010 Chevron Renewal Application for Covered Source CSP 0088-01-C.*

Data collected by the ambient monitoring stations operated by the Department of Health, including the Kapolei monitor approximately one mile north of the facility, indicates continuous compliance with the ambient air quality standards. These ambient monitoring stations use the reference methods prescribed by the applicable regulations and are the basis for determining compliance with the State and Federal standards. Since the 2010 renewal application was submitted, Chevron has performed dispersion modeling analysis, using conservative modeling parameters, that indicates certain emissions could cause or contribute to potential exceedances of the SO<sub>2</sub> and NO<sub>x</sub> standards listed in HAR §11-59-4(g), 40 CFR §50.4, §50.5, §50.17, and §50.11.

In addition, Chevron has applied for several minor and major permit modifications to implement various refinery projects. In each instance, DOH has made a decision as to whether additional dispersion modeling was required as part of the application, to ensure that the proposed modification would not result in pollutant concentrations in excess of applicable ambient standards. These analyses have been conducted and submitted to DOH when required, and, in each case, have shown that compliance with the standards to be maintained. Since the 2010 Renewal submittal, the following modeling has been submitted to DOH:

1. Black Start Generator, submitted with the revised permit application, January 22, 2014
2. RICE units, submitted with the permit application, April 30, 2015
3. CatOx Unit, submitted January 9, 2015

One proposed change included in the 2010 Renewal is deleted in this update. The request to implement the Hybrid Energy Project, included in the 2010 Renewal Application as Appendix E, was approved by DOH as a separate permit, CSP 0088-02-C. Applicable requirements, emissions and regulatory analysis for the Hybrid Energy Project are therefore not included in the refinery permit, CSP 0088-01-C, or this update to the 2010 Renewal of CSP 0088-01-C.

Chevron proposes adding language to the covered source permit to specify the demonstration for compliance with the DOH applicable requirement, HAR §11-60.1-81. The proposed language is included in Appendix A.

## **5. Applicable Requirements and Compliance**

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### **5.1 Introduction**

As required by HAR §11.60.1-83(a) and §11-60.1-86, this chapter presents information describing air quality requirements applicable to operations at the Chevron Hawaii Refinery and methods for monitoring compliance. The Chevron Hawaii Refinery was built and commenced operation in 1960. No changes triggering air quality requirements were implemented from 1960 through 1976. Several source modifications were implemented from 1976 through September 1994, and these changes were addressed when Chevron filed the application for the initial Title V Covered Source Permit in September 1994. On February 22, 1999 the State of Hawaii, Department of Health (DOH) Environmental Management Division issued the initial Title V Covered Sources Permit No. 0088-01-C to Chevron USA Products Company for the Hawaii Refinery. The Covered Source Permit issued by DOH addressed all applicable requirements and compliance monitoring for the facility, including modifications through 1994 and compliance with NESHAP Subpart CC, which was adopted between the times the application was submitted and the Covered Source Permit was issued.

The initial Covered Source Permit is incorporated by reference into this renewal application and a detailed analysis of requirements and compliance monitoring has not been reiterated. However, Section 5.2 contains a summary of the applicable requirements taken directly from the initial Title V Covered Source Permit Review Summary (File #0088-01) prepared by DOH to support issuance of the initial Covered Source Permit. Section 5.3.1 addresses applicable requirements and compliance for modifications or regulations that have been implemented since the time of initial Covered Source Permit issuance in 1999 through the current operations. Section 5.3.2 describes proposed facility changes and regulations that may take effect during the term of the permit renewal through 2016, including changes to the DOH insignificant source classifications. Section 5.4 addresses MACT applicability and Compliance Assurance Monitoring. Section 5.5 presents the required compliance forms pursuant to §11-60.1-86.

### **5.2 Initial Covered Source Permit Application Requirements**

The initial permit application and resulting Title V Covered Source Permit along with any amendments since 1999 identified the facility applicable requirements, and the permit incorporated conditions to confirm compliance with these requirements. This section is a summary of the applicable rules and methods for monitoring compliance at the Chevron Hawaii Refinery, as required by §11-60.1-86. The following discussion was excerpted from the Covered Source Permit Review Summary prepared by DOH in support of the initial Covered Source Permit. This section is intended to be a comprehensive summary of applicable requirements and these requirements will also apply to the Renewed Covered Source Permit.



## 5.2.1 Applicable Federal Regulations

### 40 CFR 60: New Source Performance Standards (NSPS)

Subpart A: General Provisions (apply to all units that are subject to one or more of the following NSPS Subparts)

Subpart J: Standards of Performance for Petroleum Refineries (applies to the Crude Unit Furnaces, Asphalt Furnace, Acid Plant Preheater, FCC Flare, Crude Flare, Boilers, Hydrogenation Furnace, Hydrogen Furnace, Isomerization Furnaces and the Gas Turbines with Heat Recovery Steam Generators (HRSGs) in the Cogeneration Plant)

Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (applies to new Foster Wheeler Boilers)

Subpart GG: Standards of Performance for Stationary Gas Turbines (applies to the Gas Turbines with HRSGs in the Cogeneration Plant)

Subpart GGG: Standards of Performance for Equipment Leaks in Petroleum Refineries (applies to equipment -- valves, pumps, flanges, etc. -- in VOC/VOL service associated with the FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor, Boilers and Flares)

Subpart QQQ: Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems (applies to process drains and sewer lines associated with the Crude Unit Furnaces and Desalter, Cogeneration Plant, Boilers, FCC Flare Vapor Recovery System, and API Separators)

~~Subpart KKKK: Standards of Performance for Stationary Combustion Turbines (applies to new Solar Centaur combustion turbine/HRSG)~~

#### 2016 Update:

*This regulation applies only to Hybrid Energy Project equipment; the Hybrid Energy Project is permitted separately in CSP 0088-02-C, and is therefore, removed from this renewal application and update.*

### 40 CFR Part 61: National Emission Standards for Hazardous Air Pollutants (NESHAP)

Subpart A: General Provisions (applicable to units that are subject to the following NESHAP Subpart):

Subpart FF: National Emission Standards for Hazardous Air Pollutants From Benzene Waste Operations (applies to the API Separators, Benzene Recovery Unit, Recovered Oil Sump, Skim Oil Tank, Wastewater Surge Tank, Recovered Oil Tank, and Crude Water Draw Tank)

### 40 CFR Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)

Subpart A: General Provisions (apply to units that are subject to the following Category-Specific NESHAP Subpart)

Subpart CC: National Emission Standards from Petroleum Refineries applies to streams in the FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol

Plant, Cogeneration Plant Compressor and Liquid Fuel System, Boiler Plant, Alkylation Plant and Effluent Treatment Plant, all Group 1 and Group 2 petroleum storage tanks, flares, and the petroleum truck loading rack. Specifically, the equipment leaks provisions of Subpart CC apply to streams in organic HAP service (at least 5% by weight total HAPs). These existing streams must comply with the equipment leak provisions in 40 CFR Part 60, Subpart VV. The processes at the Chevron Hawaii Refinery mentioned above must comply with Subpart VV for those streams in organic HAP service.

Subpart UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries (applies to FCCU)

Subpart YYY: National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters

2016 Update:

*On November 5, 2015, EPA finalized the reconsideration of the Boiler MACT (Subpart DDDDD).*

*This regulation applies to the existing refinery heaters and boilers listed in Form S-1 and Table 2-2.*

Compliance Dates: All noted units, except for the petroleum storage tanks and petroleum truck loading rack, have a compliance date on or before August 18, 1998. The Group 1 petroleum storage tanks (all storage tanks except for storage tanks 152, 263, 267 and 274) have a compliance date of August 18, 2005, or the next time the storage vessel is emptied or degassed after August 18, 1998. The petroleum truck loading rack is currently classified as a Group 2 gasoline loading rack, and must comply with Subpart CC upon classification as a Group 1 gasoline loading rack.

2016 Update:

*The Boiler MACT (Subpart DDDDD) compliance dates are summarized in Appendix K.*

CFR Part 68: Chemical Accident Prevention Provisions (applies to the storage and use of flammable substances in the facility.)

**Notes on Applicability**

Although the Crude flare and FCC flare were constructed in 1959, prior to promulgation of NSPS requirements, these flares are now subject to NSPS Subpart GGG, NSPS Subpart Ja, and 40 CFR 60.18, *General Pollution Control Requirements for Flares*.

Chevron requested in the initial Covered Source Permit application to increase the storage capacity of petroleum storage tanks Nos. 105, 106, 107, 108, 109, 110, and 111 by 12 percent over a five-year period. This increase in tank capacity was determined by DOH to result in a net decrease in tank emissions, due to fewer tank turnovers (tank filling and emptying operations). The secondary seals required by Subpart CC are being installed at the same times when the tank capacities are increased. Reconstruction and modification requirements under NSPS were deemed by DOH not to be triggered by these changes in tank capacity and seal configuration.

**2016 Update:**

*Since the 2010 Renewal submittal, several federal regulations have been promulgated or revised, that have applicability to refinery units. These new regulations are listed below.*

**40 CFR 60: New Source Performance Standards (NSPS)**

*Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007  
(this new regulation applies to refinery flares, FCC Startup Air Heater, and CatOx Unit)*

**5.2.2 State Regulations**

The requirements governing sources of air contaminants in Hawaii are contained in Hawaii's Administrative Rules (HAR) Title 11, Department of Health Chapter 59 *Ambient Air Quality Standards*, and Chapter 60.1 – *Air Pollution Control*. Chapter 59 establishes the ambient air quality standards for the State of Hawaii and prohibits any person from contributing to a violation of these standards. Chapter 59 is applicable to the Chevron refinery; consequently, compliance with the National Ambient Air Quality Standards is a state enforceable requirement. Chapter 60.1 establishes the air pollution permit program for the State of Hawaii, and contains many general and equipment-specific regulations. The following applicable requirements are addressed in the facility initial Covered Source Permit and will continue to apply to the renewed permit.

HAR Title 11, Chapter 59 – Ambient Air Quality Standards

HAR Title 11, Chapter 60.1 – Air Pollution Control

Subchapter 1: General Requirements

Subchapter 2: General Prohibitions

HAR 11-60.1-31: Applicability

HAR 11-60.1-32: Visible Emissions (applies to Crude Furnaces, Boilers, FCCU, Process Unit Furnaces, Asphalt Plant, Acid plant, and Cogeneration Plant)

HAR 11-60.1-33: Fugitive Dust (applies to FCCU catalyst transfer operations)

HAR 11-60.1-38: Sulfur Oxides from Fuel Combustion (Crude Furnaces, Boilers, FCCU, Process Unit Furnaces, Asphalt Plant, Acid Plant Preheater, and Cogeneration Plant)

HAR 11-60.1-39: Storage of Volatile Organic Compounds (applies to Petroleum Storage Tanks)

HAR 11-60.1-40: Volatile Organic Compound Water Separation (applies to API Separators)

HAR 11-60.1-41: Pump and Compressor Requirements (seal requirements apply to pumps and compressors handling VOC with a Reid vapor pressure greater than or equal to 1.5 psia in FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor)

HAR 11-60.1-42: Waste Gas Disposal (flare/abatement requirement for VOC vapor blowdown applies to equipment in FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor)

Subchapter 5: Covered Sources

Subchapter 6: Fees for Covered Sources, Noncovered Sources, and Agricultural Burning

Subchapter 8: Standards of Performance for Stationary Sources

HAR 11-60.1-161: New Source Performance Standards (apply to all units that are subject to one or more of the NSPS Subparts in 40 CFR 60, as noted above under Federal Requirements)

Subchapter 9: Hazardous Air Pollutant Sources

HAR 11-60.1-174: Maximum Achievable Control Technology Standards (apply to units that are subject to the Category-Specific NESHAP in Subpart in 40 CFR 63 as noted above under Federal Requirements)

HAR 11-60.1-180: National Emission Standards for Hazardous Air Pollutants (apply to units that are subject to the NESHAP Subpart in 40 CFR 61 noted above under Federal Requirements)

Subchapter 7, Prevention of Significant Deterioration (PSD) was not applicable for the initial Covered Source Permit, because this facility was not a new major stationary source, nor did Chevron propose any major modifications to a major stationary source as defined in HAR 11-60.1-131. Applicability of PSD will need to be addressed on a project-by-project basis for future proposed facility modifications.

**BACT Requirements** – A Best Available Control Technology (BACT) analysis is required for new or modified sources that have the potential to cause a net increase of air emissions above specified significance levels as defined in HAR 11-60.1. The initial Covered Source Permit did not consider the facility to be a new source, nor were any modifications proposed that had the potential to cause a significant net increase in air emissions. Therefore, a BACT analysis was not required. Applicability of BACT requirements will need to be assessed on a project-by-project basis for all future proposed modifications to refinery facilities.

**Compliance Data System (CDS)** – CDS annual emissions reporting is applicable, because the Hawaii Refinery emits more than 100 tpy of PM, PM<sub>10</sub>, SO<sub>2</sub>, VOC, or NO<sub>x</sub>.

**National Emissions Data System (NEDS)** – NEDS annual emissions reporting is applicable to a number of sources within the refinery [except for the process unit furnaces (5600, 5700, 5930, and 5950), asphalt furnace, and cooling tower], since these are point sources within the facility that emit more than 25 tpy for PM, PM<sub>10</sub>, SO<sub>2</sub>, VOC, or NO<sub>x</sub> or more than 250 tpy of CO. The DOH also requires reporting of annual emissions for facilities that: (1) have total combined emissions of a single criteria pollutant equal to or exceeding 25 tpy; or (2) for which the sum of all hazardous air pollutants (HAPs) equals or exceeds 5 tpy.

**Compliance Assurance Monitoring (CAM)** – CAM was not applicable to the initial Covered Source Permit, because a complete Title V application was submitted before April 20, 1998. However, certain CAM requirements are applicable to this permit renewal, as discussed in Section 5.4.3.

**Alternate Operating Scenarios:**

There were no alternate operating scenarios proposed in the initial covered source application for this facility, and none are requested in this application for permit renewal.

**2016 Update:**

*Hawaii's Administrative Rule (HAR) Title 11, Department of Health Chapter 60.1-Air Pollution Control was revised June 19, 2014 for the main purpose of initiating the regulation of greenhouse gases (GHGs) for stationary sources. The amended Chapter 60.1 subchapters listed in the December 2010 Renewal application will continue to apply to the renewed permit, and the following new subchapter also applies:*

*HAR Title 11, Chapter 60.1 – Hawaii Administrative Rules  
Subchapter 11: Greenhouse Gas Emissions*

## **5.3 Applicable Requirements for Modifications**

This section addresses facility operations, applicable requirements, and compliance issues for modifications to the Hawaii Refinery that have been implemented since the time of the initial Covered Source Permit issuance in 1999, or that may be implemented during the term of the renewed permit, which will extend into 2016. Section 5.3.1 identifies facility changes and requirements for the past permit term of 1999 through 2003. Future facility changes through the end of the renewed permit term in 2016 and the requirements potentially triggered by such changes are discussed in Section 5.3.2.

### **5.3.1 Facility Changes and Requirements: 1999 through 2010**

The facility modifications that have already been implemented for the timeframe from 1999 through the submittal of this renewal application include the following:

1. The initial Covered Source Permit allowed tanks 105 through 111 to be modified to increase storage capacity by 12 percent. Tanks 105, 106, 109, 110, and 111 have been modified and secondary seals have been installed, as required by 40 CFR Part 63, Subpart CC. Tank numbers 107 and 108 have yet to be modified. DOH has determined that this increase in tank capacity will result in a net decrease in tank emissions due to fewer tank turnovers (tank filling and emptying). Due to the reduction in emissions and based on the cost to alter the tanks, DOH has previously determined that the change does not constitute a modification or reconstruction, and that the requirements of NSPS Subpart K are not triggered. Since the tanks have been modified, they have complied with the standards of 40 CFR Part 63, Subpart A, General Provisions and Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. The Subpart CC requirements applicable to these tanks are specified in the facility Covered Source Permit Attachment II(B), Section G, 40 CFR Part 63, Subpart CC Requirements. Additionally, these tanks must comply with the conditions specified in the facility Covered Source Permit, Attachment II(b), Section C through F. No additional amendments to the Covered Source Permit are necessary to accommodate this alteration.
2. Group 1 storage tanks at the first tank degassing and cleaning activity after August 18, 1998 or before August 18, 2005, whichever comes first, must comply with 40 CFR Part

63, Subpart CC. As of August 2003, 17 Group 1 storage tanks have been modified to date; the affected tank numbers are 105, 106, 109, 110, 111, 113, 162, 163, 232, 233, 237, 249, 250, 262, 271, 301 and 302. Secondary seals (or equivalent devices) will be installed on the remaining Group 1 storage tanks no later than August 18, 2005 and monitoring, notification, testing and recordkeeping as required by Subpart CC will be implemented. The Subpart CC requirements applicable to these tanks are specified in the facility Covered Source Permit Attachment II(B), Section G, 40 CFR Part 63, Subpart CC Requirements. Additionally, the tanks need to comply with the conditions specified in the facility Covered Source Permit Attachment II(B), Section C through F. No additional amendments or changes to the Covered Source Permit are required to allow for ongoing tank upgrades to achieve compliance with Part 63, Subpart CC.

3. The Chevron Hawaii Refinery applied for and obtained DOH approval for the installation of dome roofs on Tanks 249 and 250. This request was processed as a minor modification, and the DOH issued an amendment to the Covered Source Permit on April 16, 2002 consisting of a replacement of Attachment II(B). The same request was also submitted for Tank 275 and DOH issued an amended Covered Source Permit on August 13, 2007. The revised Attachment IIB, which also reflects the changes described in Items 1 and 2 above is provided as Appendix C.
4. The Chevron Hawaii Refinery has applied for and received approval for a modification to the FCC unit. The FCC Revamp project consisted of installing a slide control valve to improve the ability to balance the operation of the catalyst reaction vessel and the catalyst regenerator vessel. The application presented to DOH for this change in equipment showed that the project would not cause an emission increase, and therefore would not trigger any new federal New Source Performance Standards (NSPS) or the Prevention of Significant Deterioration (PSD) permitting process. The DOH processed the application as a significant modification, because DOH added federally enforceable permit conditions to maintain emissions below PSD levels. Dispersion modeling showed that the project would have a negligible effect on local air quality. This modification resulted in an amendment to Covered Source Permit No. 0088-01-C Attachment II(I) on March 3, 2003. Construction of the modification was completed in May 2003.

The amendment requirements resulting from the FCC Revamp project were incorporated into the Covered Source Permit amended on 24 April 2007. The Chevron Hawaii Refinery installed an equivalent replacement electrostatic precipitator on the FCC regenerator exhaust in 2002. Chevron coordinated with DOH on the proposed replacement and obtained prior approval for the installation of the equipment. The equivalent replacement does not alter the description of permitted equipment or the applicable requirements currently contained in the Covered Source Permit.

### 5.3.2 Facility Changes for 2011 through 2016

This section describes the proposed facility changes to be implemented during the renewal permit term from 2011 through 2016. It is requested that DOH process the proposed changes to current permit conditions as summarized below. Descriptions of several other proposed facility alterations that are currently less well developed are also provided for notification purposes only.

**Proposed Condition Change 1**

The following proposed facility modification is described below for information purposes only. As further information on the project develops, the quantitative effects on emissions, if any, will be evaluated and applicable rules will be addressed on a case-by-case basis.

Fixed speed motors may be changed to variable speed motors for the forced draft fan and induced draft fan at the crude unit. This is an energy savings project that will optimize performance of the combustion process. The change would not increase the unit's operation beyond its original capacity, although it could result in a slight increase in fuel combustion relative to recent years. Emissions will remain below the limits specified in the current Operating Permit, Section IIG, Section C, Items 1 through 5. It is anticipated that this proposed modification may trigger New Source Review (NSR), but will not be subject to NSPS.

**Proposed Condition Change 2**

~~The Hybrid Energy Project as submitted to DOH in Appendix E is proposed for installation during the renewal permit period. This project includes the installation of a new cogeneration turbine, HRSC and two new boilers. This project also includes the shutdown of the three existing boilers causing no net increase in emissions. The amended Covered Source Permit for this modification was issued on 23 May 2007.~~

**2016 Update:**

*The Hybrid Energy Project was permitted as a separate Covered Source Permit, No. 0088-02-C. This update to the December 2010 Renewal application does not propose incorporation of this permit into the Refinery CSP 0088-01-C at this time.*

**Proposed Condition Change 3**

Storage tanks at the refinery plant are currently designated with a fuel service type. Under existing storage tanks covered source permit, Attachment II (B), Section E, Condition 5.a the permittee shall notify DOH 30 days prior to changing the VOC liquid stored in any of the storage tanks identified in Section A.1.a of this attachment. A.1.a includes gasoline intermediates and finished products storage tanks. Chevron is requesting the removal of this condition E.5.a to provide flexibility to meet refinery operational needs.

**Proposed Condition Change 4**

A universal administrative change is requested to change all permit references of LSR or HSR over to WSR. LSR and HSR are no longer separated at the refinery. WSR is now used in refinery operations.

**Proposed Condition Change 5**

Remove the Asphalt Plant and all associated equipment units from permit as its operation has been cancelled from the refinery production activities.

**Proposed Condition Change 6**

The refinery operation contains a number of grandfathered equipment units that were installed prior to permit requirements. These units do not have operating limits or emission limits. Chevron is requesting that normal operation of grandfathered units be defined as described in this permit renewal application. This permit defines the operation and

maintenance required according to manufacturer design specifications. These design specifications were used in the potential to emit calculations and are considered normal operation in this permit to operate. Emission releases from grandfathered units while operating under normal conditions are not reportable to meet CERCLA reporting guidelines if federally enforceable. Appendix A recommends proposed language for inclusion in permit.

#### 2016 Update

*In addition to the proposed changes above, a project to modify some of the refinery processing units in order to comply with Tier 3 gasoline standards is being considered for implementation during the term of the renewed permit. The Crude Unit, FCCU, Dimersol, Hydrogenation Plant, and Blending and Shipping equipment may require some modifications, and will be addressed in a separate permit application.*

### **5.3.3 Regulatory Changes for 2011 through 2016**

*The facility is subject to several regulations that were finalized since the December 2010 Renewal Submittal. These regulations have requirements with compliance deadlines that will occur in the permit period. In addition, applicability for one regulation has been updated, and applicabilities for two regulations clarified. These regulation changes are listed below, with reference to the location of applicable requirements in the updated appendices.*

- NSPS Ja (FCC SU, flare and catox)
- Heater and Boiler MACT DDDDD
- Refinery Sector Review update to MACT CC and UUU, NSPS J and Ja
- 40 CFR Part 63 Subpart GGGGG – National Emission Standards for Hazardous Air Pollutants: Site Remediation

## **5.4 MACT and CAM Requirements**

The Chevron Hawaii Refinery is a major source of hazardous air pollutants as described in Section 3 of this Covered Source Permit renewal application. As a major air toxic source, the refinery is potentially subject to MACT regulations that are codified under NESHAP. USEPA has adopted and proposed several MACT requirements over the past several years that pertain to refinery operations. Section 5.4.1 addresses potential applicable MACT standards that have already been adopted, and identifies the associated applicable requirements for the Chevron Hawaii Refinery. Section 5.4.2 discusses the applicability of Compliance Assurance Monitoring requirements.

### **5.4.1 Applicability of Adopted MACT Standards**

The following MACT requirements have been adopted and finalized in the Code of Federal Regulations. Therefore, the determination of applicability of these requirements for the Covered Source Permit renewal can be considered final.

40 CFR 63, Subpart A, National Emission Standards for Hazardous Air Pollutants General Provisions. Subpart A contains general NESHAP definitions and notifications that are applicable to the Chevron Hawaii Refinery. These requirements are applicable to emission



units that must comply with MACT standards. Compliance requirements for Subpart A were incorporated into the initial Covered Source Permit and are briefly addressed above in Section 5.2.

40 CFR 63, Subpart R, National Emission Standards for Hazardous Air Pollutants from Gasoline Distribution. The final Subpart R rule appeared in the Federal Register on 12/14/1994. Subpart R is applicable to the aviation gas storage tanks. For other storage tanks this is not an applicable requirement pursuant to 40 CFR 63.420(i), which exempts loading racks at refineries that are subject to Subpart CC. As specified in the current Covered Source Permit Attachment II(C), Section B, Condition 1, the Chevron Hawaii

Refinery loading rack is subject to Subpart CC requirements and complies with the requirements contained in Attachment II(C). Therefore, Subpart R is not an applicable requirement.

40 CFR 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. The final Subpart CC rule appeared in the Federal Register August 18, 1995 and the date for compliance was 8/18/98. Subpart CC requires refineries to monitor and control emissions from tanks, process vents, piping components and wastewater operations. Compliance requirements for Subpart CC are applicable to the refinery. These requirements were incorporated into the initial Covered Source Permit, and are briefly addressed above in Section 5.2.

40 CFR 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries that occur at Catalytic Cracking Units, Catalytic Reforming Units and Sulphur Plants. The final Subpart UUU rule appeared in the Federal Register on April 11, 2002 and the date for compliance is April 11, 2005. Subpart UUU will apply to the FCC Unit at the Chevron Hawaii Refinery. The refinery does not have Catalytic Reforming Units or Sulphur Plants that are regulated under Subpart UUU. Subpart UUU limits emissions of metals and organic HAPs from FCC units. To demonstrate compliance with this MACT standard, particulate matter and nickel are used as surrogates for metals. Carbon monoxide (CO) is used as a surrogate for organic HAPs. Chevron chose to comply with the requirements of Option 2 in Subpart UUU. Under Option 2, the FCCU will need to meet emissions limits of 1 pound of PM<sub>10</sub> per 1,000 pounds of coke burned and 500 ppm CO. To demonstrate initial compliance, Chevron prepared a site-specific test plan and implemented a performance test to demonstrate that the facility complies with a PM<sub>10</sub> limit of 1 pound PM<sub>10</sub> per 1000 pounds of coke burned. During the performance test a site-specific opacity limit was established. To demonstrate ongoing continuous compliance with the PM<sub>10</sub> limit a Continuous Opacity Monitor (COM) was installed to confirm that the site-specific opacity limit is achieved. Compliance with the CO limit will be demonstrated initially and continuously using a CO CEMS. The facility installed an opacity monitor and a CO CEMS to satisfy monitoring requirements by the April 11, 2005 deadline.

40 CFR 63, Subpart LLLLL, National Emission Standards for Hazardous Air Pollutants for Asphalt Processing and Asphalt Roof Manufacturing. The final Subpart LLLLL rule appeared in the Federal Register on April 29, 2003. The Chevron Hawaii Refinery no longer produces asphalt; therefore Subpart LLLLL is not an applicable requirement.

40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines appeared in the Federal Register on July 11, 2006. Generators operated at the refinery plant support maintenance activities, emergency backup power or are used in fire suppression. Those units that commenced installation after July 11, 2005 are applicable to this subpart.

40 CFR 63, Subpart GGGGG, National Emission Standards for Hazardous Air Pollutants for Site Remediation. Subpart GGGGG appeared in the Federal Register on October 8, 2003. ~~The Chevron Hawaii Refinery no longer performs remediation onsite and, therefore, Subpart GGGGG is not anticipated to be applicable.~~

2016 Update:

*As discussed in Section 5.33, Regulatory Change 3, Chevron has reviewed its site remediation activities for applicability to the Site Remediation MACT. The site remediations conducted at the Refinery meet the conditions of 40 CFR 63.7881(c), therefore, the Refinery's site remediations are not subject to the requirements of the Site Remediation MACT, except for the recordkeeping requirements described in §63.7881(c)(2). The Refinery has prepared the required documentation described in §63.7881(c)(2) to verify compliance with the Facility Wide, annual, 1 megagram (Mg) Exemption.*

40 CFR 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines. Subpart ZZZZ appeared in the Federal Register on June 15, 2007. The compliance date for existing sources is three years after the rule is finalized or June 15 2010. Subpart ZZZZ applies to all internal combustion engines weather above or below 500 brake horsepower (bhp). Requirements for units over 500 bhp are detailed in this regulation. Requirements for units 500 bhp or less are regulated under 40 CFR 60 IIII or 40 CFR JJJJ. All of the internal combustion engines at the Hawaii Refinery are below this bhp rating, and therefore the requirements in this Subpart are not applicable.

40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters. Subpart DDDDD appeared in the Federal Register on September 13, 2004. The compliance date for existing sources is three years after the rule is finalized or September 13, 2007. The MACT was remanded on June 8, 2007 making the September 2007 compliance date no longer enforceable. The new Subpart DDDDD is scheduled to be promulgated in January 2011. The Hawaii Refinery boiler and furnace units that burn RFG or Natural Gas would be subject to these requirements.

40 CFR 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. Subpart YYYY appeared in the Federal Register on March 5, 2004. Compliance with the regulation for existing sources is proposed to be three years after the rule is finalized or March 5, 2007. The Hawaii Refinery cogeneration units 6701, 6702, and 6703 are existing diffusion flame stationary combustion sources. Based on the Federal Register, Vol. 68, No 9 subsection 63.6090 (b) Exceptions (3), existing diffusion flame turbines do not have to meet the requirements of this Subpart or Subpart A. ~~The new Solar-Centaur Cogeneration unit is applicable to Subpart YYYY.~~

## 5.4.2 Compliance Assurance Monitoring

Compliance Assurance Monitoring (CAM) requirements are codified in 40 CFR 64. These requirements are applicable to specific units of a facility on a pollutant-specific emissions basis. For these requirements to be applicable, all of the following three criteria must be met:

- The unit must use a control device to achieve compliance with emission standards
- The unit must be subject to an emission standard for the applicable regulated pollutant
- The unit pre-control device potential to emit must be greater than 100 tons per year

Pursuant to 64.2(b) the CAM applicability requirements do not apply to emissions limitations or standards that are proposed by EPA after November 1990 under Section 111

or 112 of the Clean Air Act. Simply stated, CAM is not applicable to units that are subject to NSPS, NESHAP, or MACT standards that were developed after 1990.

As stated in the preamble to the CAM rule, the rule does not apply to process fugitive emissions or tanks.

Most emission units at the Hawaii Refinery do not use control devices to comply with emissions standards, and therefore CAM is not applicable to these units. Specifically, furnaces, process heaters, flares, and the acid plant absorbing tower do not utilize control devices in order to satisfy emission standards. Based on the first of the three criteria presented above, CAM is not an applicable requirement for these units.

The FCC unit uses an electrostatic precipitator and a cyclone to meet applicable Hawaii rules 11-60.1-32 (opacity limits) and 11-60.1-38 (sulfur oxide emissions). The pre-control device  $PM_{10}$  and  $SO_2$  potential to emit are greater than 100 tons per year. However, the unit is subject to the MACT 40 CFR 63 Subpart UUU, which was promulgated after 1990, and therefore CAM is not applicable to  $PM_{10}$  emissions from the FCC unit. The  $SO_2$  emission limits in 11-60.1-38 are not incorporated into the Hawaii State Implementation Plan and, accordingly, do not constitute an emission limit. Therefore, CAM requirements are not applicable to the FCC unit.

The cogeneration units use low- $NO_x$  burners and water injection to reduce  $NO_x$  emissions. Based on discussions in the preamble to 40 CFR 64, the low  $NO_x$  burners are not considered a control device and do not trigger CAM applicability. Water injection is considered a control device and can trigger CAM requirements. The cogeneration units are subject to NSPS Subpart GG, which was promulgated prior to 1990 and contains an emissions standard for both  $NO_x$  and  $SO_x$ . However, the water injection is only used to control  $NO_x$  emissions and there is no control device for  $SO_x$  emissions. The  $NO_x$  emissions with water injection are less than 100 tons per year per unit, although emissions without water injection would be anticipated to exceed the 100 ton per year threshold. Therefore, CAM is applicable to  $NO_x$  emissions from the cogeneration units. The cogeneration units already utilize a CEMS to monitor  $NO_x$  emissions, as required by the existing (initial) Covered Source Permit. Further, Attachment II(M), Section D, Condition 3 of this permit requires that the CEMS system meet EPA performance specification 40 CFR 60.13 and 40 CFR 60, Appendix B. Pursuant to CAM requirements contained in 40 CFR 64.4(b)(2) and 64.3(d)(2)(ii), a CEMS system is presumptively acceptable if it meets the requirements of Section 60.13 and Appendix B of part 60. Therefore, while CAM is applicable to the cogeneration units, no additional or new monitoring is required. Chevron does need to meet the submittal requirements of 40 CFR 64.4 and these are addressed in Appendix D.

The Hybrid Energy Project will also trigger CAM requirements when the new cogeneration unit is installed. 40 CFR 60 Subpart KKKK and 40 CFR 63 Subpart YYYY will be applicable. Monitoring requirements as required by 40 CFR 64.4 will be met. Those monitoring systems are described in the Hybrid Energy Project significant modification application and Hybrid Energy Permit included in Appendix E.

~~CAM is not an applicable requirement for any other units within the Hawaii Refinery.~~

2016 Update:

Compliance Assurance Monitoring (CAM) requirements are also applicable to the newly permitted CatOx unit referenced in Section 2.3.13.2 for VOC and  $NO_x$ . The CatOx Unit is a pollution control

device that destroys ammonia and VOCs contained in the FWTP offgas stream. In addition, the CatOx Unit has selective catalytic reduction catalyst for the control of NOx formed through the oxidation of ammonia. The CatOx Unit consists of three different sections containing different types of catalysts as follows.

*Ceramic Guard Bed-* The ceramic guard bed consists of three split levels of uncoated alumina beads. These beads serve the function of absorbing possible catalyst poisons from the process air before they reach the downstream catalyst beds. This bed does not have any effect on the environmental or ammonia emissions through the system.

*Ammonia & VOC Removal Catalyst-* The second section of catalyst is a platinum based ammonia (NH<sub>3</sub>) removal catalyst which oxidizes the ammonia and VOCs.

*NOx Removal Catalyst-* The third section of catalyst is a Selective Catalytic Reduction (SCR) catalyst to remove NOx formed by the oxidation of ammonia in the previous catalyst section.

*Pursuant to Chevron's Covered Source Permit 0088-01—C Attachment II(A) Condition D.26, the refinery is required to install a NOx and a NH<sub>3</sub> continuous process monitoring system (CPMS) for continuously monitoring the NOx and NH<sub>3</sub> concentrations on the outlet of the CatOx unit.*

*Based on review of 40 CFR 64.4(b)(4), it is anticipated that the NOx and NH<sub>3</sub> CPMS is acceptable to comply with CAM. However, the facility is still required under §64.4 Submittal Requirements to provide information to the Hawaii Department of Health and EPA on the monitoring equipment configuration and operation. These submittal requirements of 40 CFR 64.4 are addressed in Appendix D.*

## 5.5 Compliance Forms

The facility complies with the applicable regulations, as identified in the attached Form C-1, pages 1-3, Compliance Plan. Chevron personnel have evaluated the applicable requirements, performed site inspections, reviewed monitoring data, and confirmed work practices to determine that the facility is in compliance. Continued adherence to these requirements will result in on-going compliance. The attached Form C-2, page 1, Compliance Certification verifies compliance with the applicable regulations. Monitoring, as required by applicable regulations, will be used to confirm continuing compliance. The information presented in this section is consistent with the information requested in the Form C-2, pages 2 and 3.

Chevron has previously demonstrated compliance with the NAAQS, based on maximum facility emissions of criteria pollutants and ambient dispersion modeling, which is discussed in Section 4 of this application. Note that verifying compliance with the NAAQS is a state requirement. The facility does not propose to adopt an emissions cap to avoid having to comply with any federal regulations. There are no applicable federal regulations that stipulate that an emissions cap must be placed on the facility.

### 2016 Update:

Updated application forms, Form C-1 and C-2 are attached to this Update to the December 2010 Renewal application.

**C-1: Compliance Plan<sup>1</sup>**

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets of paper if necessary.

1. Compliance status with respect to all Applicable Requirements:

Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

- YES (If YES, complete items a and c below)
- NO (If NO, complete items a, b, and c below)

a. Identify all applicable requirement(s) for which compliance is achieved.

Please refer to attached Regulatory Review Spreadsheet and Section 5 of Covered Source Permit Renewal Application and all requirements listed in the current permit CSP 0088-01-C.

Provide a statement that the source is in compliance and will continue to comply with all such requirements. The source is in compliance and will continue to comply with all such requirements.

b. Identify all applicable requirement(s) for which compliance is NOT achieved.

SO2 State Ambient Air Quality Standards at HAR § 11-59-4(g), SO2 National Ambient Air Quality Standards at 40 CFR §50.4, § 50.5, and § 50.17, and NOX National Ambient Air Quality Standard at 40 CFR § 50.11. Data collected by the ambient monitoring stations operated by the Department of Health, including at the Kapolei monitor approximately one mile north of the facility, indicates continuous compliance with the ambient air quality standards. These ambient monitoring stations use the reference methods prescribed by the applicable regulations and are the basis for determining compliance with the State and Federal standards. However, dispersion modeling, using conservative modeling parameters, conducted during preparation of this Covered Source Permit renewal application indicates that certain emissions from the Chevron Hawaii Refinery could cause or contribute to potential exceedances of the listed standards. Although the compliance for these ambient standards is determined by actual monitoring data, because the initial results of the conservative modeling suggest a potential exceedance of the standards, Chevron is noting a potential noncompliance with the listed standards.

Provide a detailed Schedule of Compliance Schedule and a description of how the source will achieve compliance with all such applicable requirements.

<u>Description of Remedial Action</u>	<u>Expected Date of Completion</u>
<u>Appendix A of this Update to the December 2010 Renewal application includes proposed permit language that would clarify the requirements to demonstrate compliance with the applicable requirements.</u>	<u>Permit issuance</u>
_____	_____
_____	_____

c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to. These applicable requirements may take effect AFTER permit issuance:

<u>Applicable Requirement</u>	<u>Effective Date</u>	<u>Currently in Compliance?</u>
<u>Please refer to attached Regulatory Review Spreadsheet</u>	_____	<u>Yes</u>
_____	_____	_____
_____	_____	_____

If the source is not currently in compliance, provide a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

<u>Description of Proposed Action/Steps to Achieve Compliance</u>	<u>Expected Date of Achieving Compliance</u>
<u>Not applicable.</u>	_____
_____	_____
_____	_____

Provide a statement that the source on a timely basis will meet all these applicable requirements:

Not applicable.

\_\_\_\_\_

\_\_\_\_\_

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of each remedial action and the expected date of completion:

<u>Description of Remedial Action and Explanation</u>	<u>Expected Date of Completion</u>
_____	_____
_____	_____
_____	_____

2. Compliance Progress Reports:

a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: Not applicable. Beginning Date: \_\_\_\_\_  
(less than or equal to 6 months)

b. Date(s) that the Action described in (1)(b) was achieved:

<u>Remedial Action</u>	<u>Date Achieved</u>
<u>Not applicable.</u>	

c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

Not applicable.

2016 Update to 2010 December Renewal Application form

**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_  
Title: Refinery Manager Phone: (808) 682-5711  
Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Jon Mauer

Signature:  Date: 2/18/16

Facility Name: Chevron Products Company

Location: Kapolei

Permit Number: CSP No. 0088-01-C

<b>FOR AGENCY USE ONLY</b>
File/Application No.: _____
Island: _____
Date Received: _____

**C-2: Compliance Certification<sup>1</sup>**

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Complete as many copies of this form as needed. Use separate sheets of paper if necessary.

<sup>1</sup>2016 Update to 2010 December Renewal Application form

**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_Title: Refinery Manager Phone: (808) 682-5711Mailing Address: 91-480 Malakole StreetCity: Kapolei State: HI Zip Code: 96707**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Jon MauerSignature:  \_\_\_\_\_Date: 2/18/16Facility Name: Chevron Hawaii RefineryLocation: KapoleiPermit Number: 0098-01-C**FOR AGENCY USE ONLY**

File/Application No.: \_\_\_\_\_

Island: \_\_\_\_\_

Date Received: \_\_\_\_\_



Complete the following information for *each* applicable requirement that applies to *each* emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: Annual Beginning Date: \_\_\_\_\_

2. Emissions Unit No./Description: Please refer to Section 5 of CSP Renewal Application

3. Identify the applicable requirement(s) that is/are the basis of this certification:

Please refer to Section 5 of CSP Renewal Application, except for the SO2 State Ambient Air  
Quality Standards at HAR §11-59-4(g), SO2 National Ambient Air Quality Standards at 40 CFR  
§50.17 and NOx National Ambient Air Quality Standards at 40 CFR §50.11.  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

4. Compliance status:

- a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES       NO

- b. If YES, will compliance be continuous or intermittent?

Continuous       Intermittent

- c. If NO, explain.

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

5. Identify the applicable requirement(s) that is/are the basis of this certification:

Please see attached Regulatory Review Spreadsheet and Section 5 of the 2010 CSP Renewal Application and Appendices A and K.

Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

Please see attached Regulatory Review Spreadsheet and Section 5 of the 2010 CSP Renewal Application and Appendices A and K.

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES                       NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

A continuous emissions monitoring system (CEMS) for NOx and fuel flow meters (CPMS) for water-to-fuel ratio have been installed on cogeneration combustion turbines pursuant to 40 CFR 60 Subpart GG (water injection control measure). The CEMS is required to meet EPA performance specifications in 40 CFR 60.13 and 40 CFR 60, Appendix B, as well as the submittal requirements of 40 CFR 64.4. An FCCU CO and Continuous Opacity Monitoring System (COMS) has been installed pursuant to 40 CFR 63 Subpart UUU. In addition, the FCCU also has a CEMS for monitoring O2, SO2, and NOx. CMS for hydrogen sulfide (H2S) have been installed on the refinery fuel gas system (mix drum) per NSPS J and crude flare pursuant to 40 CFR 60 Subparts J and Ja. CMS for Total Sulfur (TS) and vent gas flow meters have been installed on the crude and FCC flare header lines pursuant to 40 CFR 60 Subparts Ja. Requirements and methods of compliance for new regulations are attached in Appendix K.

- c. If NO, describe below which requirements will not be met:

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Complete the following information for *each* applicable requirement that applies to *each* emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: Annual Beginning Date: \_\_\_\_\_

2. Emissions Unit No./Description: Please refer to Section 2 of CSP Renewal Application

3. Identify the applicable requirement(s) that is/are the basis of this certification:

SO<sub>2</sub> State Ambient Air Quality Standards at HAR §11-59-4(g), SO<sub>2</sub> National Ambient Air Quality Standards at 40 CFR §50.17 and NO<sub>x</sub> National Ambient Air Quality Standards at 40 CFR §50.11.  
\_\_\_\_\_  
\_\_\_\_\_

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain.

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

5. Identify the applicable requirement(s) that is/are the basis of this certification:

Ambient monitoring conducted by the Department of Health using the reference methods prescribed by the applicable regulations, including at the Kapolei monitor approximately one mile north of the facility, indicates continuous compliance. However, dispersion modeling, using conservative modeling parameters, conducted during the preparation of the 0088-02-C Covered Source renewal application in 2011 indicated the potential that certain emissions from the Chevron Hawaii Refinery could cause or contribute to exceedances of the listed ambient standards. Although the compliance for these ambient standards is determined by actual monitoring data, because the initial results of the conservative modeling suggests a potential exceedance of the standards, Chevron is noting a potential noncompliance with the listed standards.  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See above.

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification requirements.

a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

b. If YES, identify the requirements and the provisions being taken to achieve compliance:

Chevron will submit annual compliance certifications.

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c. If NO, describe below which requirements will not be met:

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**40 CFR Part 60 - Standards of Performance for New Stationary Sources**

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart A	(§§ 1 - 19) - General Provisions	Y	All Units as applicable	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart B	(§§ 20 - 29) - Adoption and Submittal of State Plans for Designated Facilities	N			
60	Subpart C	(§§ 30 - 31) - Emission Guidelines and Compliance Times	N			
60	Subpart C-b	(§§ 30 - 39) - Emissions Guidelines and Compliance Times for Large Municipal Waste Combustors that are Constructed on or Before September 20, 1994	N			
60	Subpart C-c	(§§ 30 - 36) - Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills	N			
60	Subpart C-d	(§§ 30 - 32) - Emissions Guidelines and Compliance Times for Sulfuric Acid Production Units	N			
60	Subpart C-e	(§§ 30 - 39) - Emission Guidelines and Compliance Times for Hospital/Medical/Infectious Waste Incinerators	N			
60	Subpart D	(§§ 40 - 46) - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971	N			
60	Subpart D-a	(§§ 40 - 52) - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978	N			
60	Subpart D-b	(§§ 40 - 49) - Standards of Performance for Industrial-Commercial- Institutional Steam Generating Units	N			
60	Subpart D-c	(§§ 40 - 48) - Standards of Performance for Small Industrial-Commercial- Institutional Steam Generating Units	Y-N		For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	This regulation applies to equipment in the Hybrid Energy Plant permit
60	Subpart E	(§§ 50 - 54) - Standards of Performance for Incinerators	N			
60	Subpart E-a	(§§ 50 - 59) - Standards of Performance for Municipal Waste Combustors for Which Construction is Commenced After December 20, 1989 and on or Before September 20, 1994	N			
60	Subpart E-b	(§§ 50 - 59) - Standards of Performance for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996	N			
60	Subpart E-c	(§§ 50 - 58) - Standards of Performance for Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	N			
60	Subpart F	(§§ 60 - 66) - Standards of Performance for Portland Cement Plants	N			
60	Subpart G	(§§ 70 - 74) - Standards of Performance for Nitric Acid Plants	N			
60	Subpart H	(§§ 80 - 85) - Standards of Performance for Sulfuric Acid Plants	N			
60	Subpart I	(§§ 90 - 93) - Standards of Performance for Hot Mix Asphalt Facilities	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart J	(§§ 100 - 109) - Standards of Performance for Petroleum Refineries	Y	All unit furnaces, Cogen turbines, the FCC, Flares	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	Update: Amended in FR December 1, 2015. Appendix A and K contains the new applicable requirements.
60	Subpart J-a	(§§ 100a - 109a) - STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER MAY 14, 2007	N Y	Applies to FCCU, FCU, fuel gas combustion devices, flares, process heaters and sulfur recovery plants that begin construction after 14 May 2007.	Applies to the Flares, CatOx Unit and FCC Startup Air Heater. For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see Section 5.3.  The Energy Project was permitted in a separate Covered Source Permit CSP No. 0088-02-C, therefore, the following is removed: <del>Energy Project commenced construction on 15 Feb 2007.</del>	New 24 June 2008, 73 FR 35867  Update: Amended in FR December 1, 2015. Appendix A and K contain the new applicable requirements.
60	Subpart K	(§§ 110 - 113) - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	N			
60	Subpart K-a	(§§ 110 - 115) - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	N			
60	Subpart K-b	(§§ 110 - 117) - 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	N			
60	Subpart L	(§§ 120 - 123) - Standards of Performance for Secondary Lead Smelters	N			
60	Subpart M	(§§ 130 - 133) - Standards of Performance for Secondary Brass and Bronze Production Plants	N			
60	Subpart N	(§§ 140 - 144) - Standards of Performance for Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	N			
60	Subpart N-a	(§§ 140 - 145) - Standards of Performance for Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	N			
60	Subpart O	(§§ 150 - 156) - Standards of Performance for Sewage Treatment Plants	N			
60	Subpart P	(§§ 160 - 166) - Standards of Performance for Primary Copper Smelters	N			
60	Subpart Q	(§§ 170 - 176) - Standards of Performance for Primary Zinc Smelters	N			
60	Subpart R	(§§ 180 - 186) - Standards of Performance for Primary Lead Smelters	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart S	(§§ 190 - 195) - Standards of Performance for Primary Aluminum Reduction Plants	N			
60	Subpart T	(§§ 200 - 204) - Standards of Performance for the Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants	N			
60	Subpart U	(§§ 210 - 214) - Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants	N			
60	Subpart V	(§§ 220 - 224) - Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants	N			
60	Subpart W	(§§ 230 - 234) - Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants	N			
60	Subpart X	(§§ 240 - 244) - Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	N			
60	Subpart Y	(§§ 250 - 254) - Standards of Performance for Coal Preparation Plants	N			
60	Subpart Z	(§§ 260 - 266) - Standards of Performance for Ferroalloy Production Facilities	N			
60	Subpart AA	(§§ 270 - 276) - Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974, and on or Before August 17, 1983	N			
60	Subpart AA-a	(§§ 270 - 276) - Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 17, 1983	N			
60	Subpart BB	(§§ 280 - 285) - Standards of Performance for Kraft Pulp Mills	N			
60	Subpart CC	(§§ 290 - 296) - Standards of Performance for Glass Manufacturing Plants	N			
60	Subpart DD	(§§ 300 - 304) - Standards of Performance for Grain Elevators	N			
60	Subpart EE	(§§ 310 - 316) - Standards of Performance for Surface Coating of Metal Furniture	N			
60	Subpart GG	(§§ 330 - 335) - Standards of Performance for Stationary Gas Turbines	Y	Cogen turbines	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart HH	(§§ 340 - 344) - Standards of Performance for Lime Manufacturing Plants	N			
60	Subpart KK	(§§ 370 - 374) - Standards of Performance for Lead-Acid Battery Manufacturing Plants	N			
60	Subpart LL	(§§ 380 - 386) - Standards of Performance for Metallic Mineral Processing Plants	N			
60	Subpart MM	(§§ 390 - 398) - Standards of Performance for Automobile and Light Duty Truck Surface Coating Operations	N			
60	Subpart NN	(§§ 400 - 404) - Standards of Performance for Phosphate Rock Plants	N			
60	Subpart PP	(§§ 420 - 424) - Standards of Performance for Ammonium Sulfate Manufacture	N			
60	Subpart QQ	(§§ 430 - 435) - Standards of Performance for the Graphic Arts Industry: Publication Rotogravure Printing	N			
60	Subpart RR	(§§ 440 - 447) - Standards of Performance for Pressure Sensitive Tape and Label Surface Coating Operations	N			
60	Subpart SS	(§§ 450 - 456) - Standards of Performance for Industrial Surface Coating: Large Appliances	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart TT	(§§ 460 - 466) - Standards of Performance for Metal Coil Surface Coating	N			
60	Subpart UU	(§§ 470 - 474) - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture	N			
60	Subpart VV	(§§ 480 - 489) - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JANUARY 5, 1981, AND ON OR BEFORE NOVEMBER 7, 2006	Y	pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart VV - a	(§§ 480a - 489a) - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER NOVEMBER 7, 2006	Y	pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	New 16 Nov 2007, 72 FR 64883
60	Subpart WW	(§§ 490 - 496) - Standards of Performance for the Beverage Can Surface Coating Industry	N			
60	Subpart XX	(§§ 500 - 506) - Standards of Performance for Bulk Gasoline Terminals	N			
60	Subpart AAA	(§§ 530 - 539) - Standards of Performance for New Residential Wood Heaters	N			
60	Subpart BBB	(§§ 540 - 548) - Standards of Performance for the Rubber Tire Manufacturing Industry	N			
60	Subpart DDD	(§§ 560 - 566) - Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry	N			
60	Subpart FFF	(§§ 580 - 585) - Standards of Performance for Flexible Vinyl and Urethane Coating and Printing	N			
60	Subpart GGG	(§§ 590 - 593) - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JANUARY 4, 1983, AND ON OR BEFORE NOVEMBER 7, 2006	Y	Equipment Leaks at FCC, Crude, LPG, Dimersol, Cogen and Flares	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart GGG - a	(§§ 590 - 593) - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER NOVEMBER 7, 2006	N		Facilities subject to subpart VV, subpart VVa, subpart GGG, or subpart KKK of this part are excluded from this subpart.	New 16 Nov 2007, 72 FR 64896



Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart HHH	(§§ 600 - 604) - Standards of Performance for Synthetic Fiber Production Facilities	N			
60	Subpart III	(§§ 610 - 618) - Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	N			
60	Subpart JJJ	(§§ 620 - 625) - Standards of Performance for Petroleum Dry Cleaners	N			
60	Subpart KKK	(§§ 630 - 636) - Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.	N			
60	Subpart LLL	(§§ 640 - 648) - Standards of Performance for Onshore Natural Gas Processing: So2 Emissions	N			
60	Subpart NNN	(§§ 660 - 668) - Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	N			
60	Subpart OOO	(§§ 670 - 676) - Standards of Performance for Nonmetallic Mineral Processing Plants	N			
60	Subpart PPP	(§§ 680 - 685) - Standard of Performance for Wool Fiberglass Insulation Manufacturing Plants	N			
60	Subpart QQQ	(§§ 690 - 699) - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems	Y	VOC from wastewater systems at Crude furnaces and desalter, Cogen and API separators	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart RRR	(§§ 700 - 708) - Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	N			
60	Subpart SSS	(§§ 710 - 718) - Standards of Performance for Magnetic Tape Coating Facilities	N			
60	Subpart TTT	(§§ 720 - 726) - Standards of Performance for Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	N			
60	Subpart UUU	(§§ 730 - 737) - Standards of Performance for Calciners and Dryers in Mineral Industries	N			
60	Subpart VVV	(§§ 740 - 748) - Standards of Performance for Polymeric Coating of Supporting Substrates Facilities	N			
60	Subpart WWW	(§§ 750 - 759) - Standards of Performance for Municipal Solid Waste Landfills	N			
60	Subpart AAAA	(§§ 1000 - 1465) - Standards of Performance for Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	N			
60	Subpart BBBB	(§§ 1500 - 1940) - Emission Guidelines and Compliance Times for Small Municipal Waste Combustion Units Constructed on or Before August 30, 1999	N			
60	Subpart CCCC	(§§ 2000 - 2265) - Standards of Performance for Commercial and Industrial Solid Waste Incineration Units for Which Construction is Commenced After November 30, 1999 or for Which Modification or Reconstruction is Commenced on or After June 1, 2001	N			
60	Subpart DDDD	(§§ 2500 - 2875) - Emissions Guidelines and Compliance Times for Commercial and Industrial Solid Waste Incineration Units that Commenced Construction on or Before November 30, 1999	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart EEEE	(§§ 2880 - 2891) - Standards of Performance for Other Solid Waste Incineration Units for Which Construction Is Commenced After December 9, 2004, or for Which Modification or Reconstruction Is Commenced on or After June 16, 2006.	N			
60	Subpart FFFF	(§§ 2980 - 3078) - Emission Guidelines and Compliance Times for Other Solid Waste Incineration Units That Commenced Construction On or Before December 9, 2004	N			
60	Subpart HHHH	(§§ 4101 - 4176) - Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units	N			
60	Subpart IIII	(§§ 4200 - 4219) - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	Y	Generators and Fire Water Pumps installed after July 11, 2005 Update: Applies to the following stationary ICE: Black Start Generator, Emergency Security Generators, Sand Filter Pump #1 Sand Filter Pump #2 Transfer Pump	Applicable units: ICE of all sizes whether new or existing that commence installation after July 11, 2005. Monitor: non-resettable hour meter, labeling requirement. Test Methods: EPA Methods 1, 1A, 3, 3A, 3B, 4, 5, 7E, 320. Recordkeeping: Maintenance, emission standards certification Reporting: Notification Update: The list above is general and does not apply to all NSPS IIII ICE. For the Sand Filters Pump 1&2, Transfer Pump, applicable monitoring, recordkeeping, notification, reporting and test methods required are in the CSP sig mod application, Appendix H. For the Black Start Generator, the information is available in the current covered source permit, CSP No. 0088-03-C attached in Appendix G	New 11 July 2006, 71 FR 39172
60	Subpart JJJJ	(§§ 4230 - 4248) - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	N			New 18 Jan 2008, 73 FR 3591
60	Subpart KKKK	(§§ 4300 - 4420) - Standards of Performance for Stationary Combustion Turbines	Y N	Gegen	Applicable units: Peak load of 10 MMBTU/hr or greater. Monitor: Continuous Monitoring System or CEMS for NOx. Total Sulfur Content. Test Method: Annual Performance Test in accordance with §60.8. EPA Methods 1, 2, 3A, 6, 6C, 8, 7E, 19, 20. Recordkeeping: usage, maintenance, emissions Reporting: Every 6 months in accordance with §60.7 ( c).	New 6 July 2006, 71 FR 38497 Hybrid Energy Plant only
<b>Part 61 - National Emission Standards for Hazardous Air Pollutants</b>						

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
61	Subpart A	(§§ 1 - 19) - General Provisions	Y	All Units	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
61	Subpart B	(§§ 20 - 26) - National Emission Standards for Radon Emissions from Underground Uranium Mines	N			
61	Subpart C	(§§ 30 - 34) - National Emission Standard for Beryllium	N			
61	Subpart D	(§§ 40 - 44) - National Emission Standard for Beryllium Rocket Motor Firing	N			
61	Subpart E	(§§ 50 - 56) - National Emission Standard for Mercury	N			
61	Subpart F	(§§ 60 - 71) - National Emission Standard for Vinyl Chloride	N			
61	Subpart H	(§§ 90 - 97) - National Emission Standards for Emissions of Radionuclides Other Than Radon from Department of Energy Facilities	N			
61	Subpart I	(§§ 100 - 108) - National Emission Standards for Radionuclide Emissions from Federal Facilities Other Than Nuclear Regulatory Commission Licensees and Not Covered by Subpart H	N			
61	Subpart J	(§§ 110 - 112) - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene	N			
61	Subpart K	(§§ 120 - 127) - National Emission Standards for Radionuclide Emissions from Elemental Phosphorus Plants	N			
61	Subpart L	(§§ 130 - 139) - National Emission Standard for Benzene Emissions from Coke by-Product Recovery Plants	N			
61	Subpart M	(§§ 140 - 157) - National Emission Standard for Asbestos	Y		For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
61	Subpart N	(§§ 160 - 165) - National Emission Standard for Inorganic Arsenic Emissions from Glass Manufacturing Plants	N			
61	Subpart O	(§§ 170 - 177) - National Emission Standard for Inorganic Arsenic Emissions from Primary Copper Smelters	N			
61	Subpart P	(§§ 180 - 186) - National Emission Standard for Inorganic Arsenic Emissions from Arsenic Trioxide and Metallic Arsenic Production Facilities	N			
61	Subpart Q	(§§ 190 - 193) - National Emission Standards for Radon Emissions from Department of Energy Facilities	N			
61	Subpart R	(§§ 200 - 210) - National Emission Standards for Radon Emissions from Phosphogypsum Stacks	N			
61	Subpart T	(§§ 220 - 226) - National Emission Standards for Radon Emissions from the Disposal of Uranium Mill Tailings	N			
61	Subpart V	(§§ 240 - 247) - National Emission Standard for Equipment Leaks (Fugitive Emission Sources)	N			
61	Subpart W	(§§ 250 - 256) - National Emission Standards for Radon Emissions from Operating Mill Tailings	N			
61	Subpart Y	(§§ 270 - 277) - National Emission Standard for Benzene Emissions from Benzene Storage Vessels	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
61	Subpart BB	(§§ 300 - 306) - National Emission Standard for Benzene Emissions from Benzene Transfer Operations	N			
61	Subpart FF	(§§ 340 - 359) - National Emission Standard for Benzene Waste Operations	Y	API separators, BRU, recovered oil sump, skim oil tank, wastewater surge tank, recovers oil tank, and crude water draw tank Update: Tanks 104, 303, 304, 3643, 162-163, 235-236, 103, 166; Oily Water Sewer (OWS), NESHAP Liquabins and aboveground piping connecting to OWS	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
<b>Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories</b>						
63	Subpart A	(§§ 1 - 16) - General Provisions	Y	All Units as applicable	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
63	Subpart B	(§§ 40 - 56) - Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)	N			
63	Subpart C	(§§ 60 - 64) - List of Hazardous Air Pollutants, Petitions Process, Lesser Quantity Designations, Source Category List	N			
63	Subpart D	(§§ 70 - 81) - Regulations Governing Compliance Extensions for Early Reductions of Hazardous Air Pollutants	N			
63	Subpart E	(§§ 90 - 99) - Approval of State Programs and Delegation of Federal Authorities	N			
63	Subpart F	(§§ 100 - 107) - National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry	N			
63	Subpart G	(§§ 110 - 153) - National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater	N			
63	Subpart H	(§§ 160 - 183) - National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks	N			
63	Subpart I	(§§ 190 - 193) - National Emission Standards for Organic Hazardous Air Pollutants for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks	N			
63	Subpart J	(§§ 210 - 217) - National Emission Standards for Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production	N			
63	Subpart L	(§§ 300 - 313) - National Emission Standards for Coke Oven Batteries	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart N	(§§ 340 - 348) - National Emission Standards for Chromium Emissions from Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks	N			
63	Subpart O	(§§ 360 - 368) - Ethylene Oxide Emissions Standards for Sterilization Facilities	N			
63	Subpart Q	(§§ 400 - 407) - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers	N			
63	Subpart R	(§§ 420 - 429) - National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)	Y		For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
				Avgas load rack		
63	Subpart S	(§§ 440 - 459) - National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry	N			
63	Subpart T	(§§ 460 - 470) - National Emission Standards for Halogenated Solvent Cleaning	N			
63	Subpart U	(§§ 480 - 507) - National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins	N			
63	Subpart W	(§§ 520 - 529) - National Emission Standards for Hazardous Air Pollutants for Epoxy Resins Production and Non-Nylon Polyamides Production	N			
63	Subpart X	(§§ 541 - 551) - National Emission Standards for Hazardous Air Pollutants from Secondary Lead Smelting	N			
63	Subpart Y	(§§ 560 - 569) - National Emission Standards for Marine Tank Vessel Loading Operations	N			
63	Subpart AA	(§§ 600 - 611) - National Emission Standards for Hazardous Air Pollutants from Phosphoric Acid Manufacturing Plants	N			
63	Subpart BB	(§§ 620 - 632) - National Emission Standards for Hazardous Air Pollutants from Phosphate Fertilizers Production Plants	N			
63	Subpart CC	(§§ 640 - 656) - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries	Y	FCCU, Crude Unit Furnace, B&S, Dimersol, Cogen, Liquid Fuel System, Alky, Effluent treatment plant, Group 1 tanks, Avgas load rack, heat exchangers	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit. Update: New applicable requirements are contained in Appendix K.	Update: Amended by Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards in FR December 1, 2015
63	Subpart DD	(§§ 680 - 698) - National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations	N			
63	Subpart EE	(§§ 701 - 708) - National Emission Standards for Magnetic Tape Manufacturing Operations	N			
63	Subpart GG	(§§ 741 - 759) - National Emission Standards for Aerospace Manufacturing and Rework Facilities	N			
63	Subpart HH	(§§ 760 - 778) - National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities	N			
63	Subpart II	(§§ 780 - 789) - National Emission Standards for Shipbuilding and Ship Repair (Surface Coating)	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart JJ	(§§ 800 - 809) - National Emission Standards for Wood Furniture Manufacturing Operations	N			
63	Subpart KK	(§§ 820 - 832) - National Emission Standards for the Printing and Publishing Industry	N			
63	Subpart LL	(§§ 840 - 854) - National Emission Standards for Hazardous Air Pollutants for Primary Aluminum Reduction Plants	N			
63	Subpart MM	(§§ 860 - 868) - National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills	N			
63	Subpart OO	(§§ 900 - 908) - National Emission Standards for Tanks-Level 1	N			
63	Subpart PP	(§§ 920 - 929) - National Emission Standards for Containers	N			
63	Subpart QQ	(§§ 940 - 949) - National Emission Standards for Surface Impoundments	N			
63	Subpart RR	(§§ 960 - 967) - National Emission Standards for Individual Drain Systems	N			
63	Subpart SS	(§§ 980 - 999) - National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process	N			
63	Subpart TT	(§§ 1000 - 1018) - National Emission Standards for Equipment Leaks-Control Level 1	N			
63	Subpart UU	(§§ 1019 - 1039) - National Emission Standards for Equipment Leaks-Control Level 2 Standards	N			
63	Subpart VV	(§§ 1040 - 1050) - National Emission Standards for Oil-Water Separators and Organic-Water Separators	N			
63	Subpart WW	(§§ 1060 - 1067) - National Emission Standards for Storage Vessels (Tanks)-Control Level 2	N			
63	Subpart XX	(§§ 1080 - 1097) - National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations	N			
63	Subpart YY	(§§ 1100 - 1114) - National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards	N			
63	Subpart CCC	(§§ 1155 - 1167) - National Emission Standards for Hazardous Air Pollutants for Steel Pickling-Hcl Process Facilities and Hydrochloric Acid Regeneration Plants	N			
63	Subpart DDD	(§§ 1175 - 1197) - National Emission Standards for Hazardous Air Pollutants for Mineral Wool Production	N			
63	Subpart EEE	(§§ 1200 - 1221) - National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors	N			
63	Subpart GGG	(§§ 1250 - 1261) - National Emission Standards for Pharmaceuticals Production	N			
63	Subpart HHH	(§§ 1270 - 1288) - National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities	N			
63	Subpart III	(§§ 1290 - 1309) - National Emission Standards for Hazardous Air Pollutants for Flexible Polyurethane Foam Production	N			
63	Subpart JJJ	(§§ 1310 - 1335) - National Emission Standards for Hazardous Air Pollutant Emissions: Group IV Polymers and Resins	N			
63	Subpart LLL	(§§ 1340 - 1359) - National Emission Standards for Hazardous Air Pollutants from the Portland Cement Manufacturing Industry	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart MMM	(§§ 1360 - 1369) - National Emission Standards for Hazardous Air Pollutants for Pesticide Active Ingredient Production	N			
63	Subpart NNN	(§§ 1380 - 1389) - National Emission Standards for Hazardous Air Pollutants for Wool Fiberglass Manufacturing	N			
63	Subpart OOO	(§§ 1400 - 1419) - National Emission Standards for Hazardous Air Pollutant Emissions: Manufacture of Amino/Phenolic Resins	N			
63	Subpart PPP	(§§ 1420 - 1439) - National Emission Standards for Hazardous Air Pollutant Emissions for Polyether Polyols Production	N			
63	Subpart QQQ	(§§ 1440 - 1459) - National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting	N			
63	Subpart RRR	(§§ 1500 - 1520) - National Emission Standards for Hazardous Air Pollutants for Secondary Aluminum Production	N			
63	Subpart TTT	(§§ 1541 - 1550) - National Emission Standards for Hazardous Air Pollutants for Primary Lead Smelting	N			
63	Subpart UUU	(§§ 1560 - 1579) - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units	Y	FCC	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit. Update: New requirements are in Appendix K.	Update: Amended by Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards in FR December 1, 2015
63	Subpart VVV	(§§ 1580 - 1595) - National Emission Standards for Hazardous Air Pollutants: Publicly Owned Treatment Works	N			
63	Subpart XXX	(§§ 1620 - 1662) - National Emission Standards for Hazardous Air Pollutants for Ferroalloys Production: Ferromanganese and Silicomanganese	N			
63	Subpart AAAA	(§§ 1930 - 1990) - National Emission Standards for Hazardous Air Pollutants: Municipal Solid Waste Landfills	N			
63	Subpart CCCC	(§§ 2130 - 2192) - National Emission Standards for Hazardous Air Pollutants: Manufacturing of Nutritional Yeast	N			
63	Subpart DDDD	(§§ 2230 - 2292) - National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products	N			
63	Subpart EEEE	(§§ 2330 - 2406) - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)	N			
63	Subpart FFFF	(§§ 2430 - 2550) - National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing	N			
63	Subpart GGGG	(§§ 2830 - 2872) - National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production	N			
63	Subpart HHHH	(§§ 2980 - 3005) - National Emission Standards for Hazardous Air Pollutants for Wet-Formed Fiberglass Mat Production	N			
63	Subpart IIII	(§§ 3080 - 3176) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Automobiles and Light-Duty Trucks	N			
63	Subpart JJJJ	(§§ 3280 - 3420) - National Emission Standards for Hazardous Air Pollutants: Paper and Other Web Coating	N			
63	Subpart KKKK	(§§ 3480 - 3561) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Metal Cans	N			
63	Subpart MMMM	(§§ 3880 - 3981) - National Emission Standards for Hazardous Air Pollutants for Surface Coating of Miscellaneous Metal Parts and Products	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart NNNN	(§§ 4080 - 4181) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Large Appliances	N			
63	Subpart OOOO	(§§ 4280 - 4371) - National Emission Standards for Hazardous Air Pollutants: Printing, Coating, and Dyeing of Fabrics and Other Textiles	N			
63	Subpart PPPP	(§§ 4480 - 4581) - National Emission Standards for Hazardous Air Pollutants for Surface Coating of Plastic Parts and Products	N			
63	Subpart QQQQ	(§§ 4680 - 4781) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Wood Building Products	N			
63	Subpart RRRR	(§§ 4880 - 4981) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Metal Furniture	N			
63	Subpart SSSS	(§§ 5080 - 5201) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Metal Coil	N			
63	Subpart TTTT	(§§ 5280 - 5460) - National Emission Standards for Hazardous Air Pollutants for Leather Finishing Operations	N			
63	Subpart UUUU	(§§ 5480 - 5610) - National Emission Standards for Hazardous Air Pollutants for Cellulose Products Manufacturing	N			
63	Subpart VVVV	(§§ 5680 - 5779) - National Emission Standards for Hazardous Air Pollutants for Boat Manufacturing	N			
63	Subpart WWWW	(§§ 5780 - 5935) - National Emissions Standards for Hazardous Air Pollutants: Reinforced Plastic Composites Production	N			
63	Subpart XXXX	(§§ 5980 - 6015) - National Emissions Standards for Hazardous Air Pollutants: Rubber Tire Manufacturing	N			
63	Subpart YYYY	(§§ 6080 - 6175) - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines	Y	Cogen	Applicable units: All Stationary Combustion Turbines Monitor: Fuel Used, Hours Used, Formaldehyde emissions, catalyst inlet temperature Test Methods: 1, 1A, 3A, 3B, 4 Recordkeeping: Maintenance, startup, shutdown and malfunction Reporting: Notification, Semi Annual Report, Annual Performance Testing	5 Mar 2004, 69 FR 10537



Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart ZZZZ	(§§ 6580 - 6675) - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	Y	<del>Generators and Fire Water Pumps</del> Update: Black Start Generator, Sand Filter Pumps #1 and 2, Transfer Pump, and Stationary Emergency Generators and Firewater Pumps	Applicable units: All engines are subject.  Please see attached RICE NESHAP tab for detailed requirements for the following applicable engine categories: -Engines installed after 12 Jun 2006 must meet requirements in 40 CFR 60 IIII and JJJJ. No other requirements from ZZZZ are applicable. -CI engines 100 hp or less and installed before 12 Jun 2006. -Non-emergency CI at or between 100 and 500 hp installed before 12 Jun 2006. -Emergency CI (including Fire Water Pumps) installed prior to 12 Jun 2006 Update: This subpart applies to stationary reciprocating internal combustion engines only.	15 Jun 2004, 69 FR 33506
63	Subpart AAAAA	(§§ 7080 - 7143) - National Emission Standards for Hazardous Air Pollutants for Lime Manufacturing Plants	N			
63	Subpart BBBBB	(§§ 7180 - 7195) - National Emission Standards for Hazardous Air Pollutants for Semiconductor Manufacturing	N			
63	Subpart CCCCC	(§§ 7280 - 7352) - National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing, Quenching, and Battery Stacks	N			
63	Subpart DDDDD	(§§ 7480 - 7575) - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters	Y		Proposed Rule expected to be finalized in Jan 2011. Would impact all units using natural gas, fuel oil or refinery gas. Update: Rule finalized. Applies to refinery heaters and boilers, except for F-5310 FCC Startup Air Heater.. Applicable monitoring, recordkeeping, notification, reporting, and test methods required are in Appendix K.	
63	Subpart EEEEE	(§§ 7680 - 7765) - National Emission Standards for Hazardous Air Pollutants for Iron and Steel Foundries	N			
63	Subpart FFFFF	(§§ 7780 - 7852) - National Emission Standards for Hazardous Air Pollutants for Integrated Iron and Steel Manufacturing Facilities	N			
63	Subpart GGGGG	(§§ 7880 - 7957) - National Emission Standards for Hazardous Air Pollutants: Site Remediation	N Update: Y		Applicable monitoring, recordkeeping, notification, reporting, and test methods required are in Appendix K.	

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart HHHHH	(§§ 7980 - 8105) - National Emission Standards for Hazardous Air Pollutants: Miscellaneous Coating Manufacturing	N			
63	Subpart IIIII	(§§ 8180 - 8266) - National Emission Standards for Hazardous Air Pollutants: Mercury Emissions from Mercury Cell Chlor-Alkali Plants	N			
63	Subpart JJJJJ	(§§ 8380 - 8515) - National Emission Standards for Hazardous Air Pollutants for Brick and Structural Clay Products Manufacturing	N			
63	Subpart KKKKK	(§§ 8530 - 8665) - National Emission Standards for Hazardous Air Pollutants for Clay Ceramics Manufacturing	N			
63	Subpart LLLLL	(§§ 8680 - 8698) - National Emission Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing Manufacturing	N			
63	Subpart MMMMM	(§§ 8780 - 8830) - National Emission Standards for Hazardous Air Pollutants: Flexible Polyurethane Foam Fabrication Operations	N			
63	Subpart NNNNN	(§§ 8980 - 9075) - National Emission Standards for Hazardous Air Pollutants: Hydrochloric Acid Production	N			
63	Subpart PTTTT	(§§ 9280 - 9375) - National Emission Standards for Hazardous Air Pollutants for Engine Test Cells/Standards	N			
63	Subpart QQQQQ	(§§ 9480 - 9571) - National Emission Standards for Hazardous Air Pollutants for Friction Materials Manufacturing Facilities	N			
63	Subpart RRRRR	(§§ 9580 - 9652) - National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing	N			
63	Subpart SSSSS	(§§ 9780 - 9824) - National Emission Standards for Hazardous Air Pollutants for Refractory Products Manufacturing	N			
63	Subpart TTTTT	(§§ 9880 - 9942) - National Emissions Standards for Hazardous Air Pollutants for Primary Magnesium Refining	N			
63	Subpart WWWW	(§§ 10382 - 10448) - National Emissions Standards for Hazardous Air Pollutants for Hospital Ethylene Oxide Sterilizers	N			New but assumed by Description that its not applicable
63	Subpart YYYYY	(§§ 10680 - 10692) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: ELECTRIC ARC FURNACE STEELMAKING FACILITIES	N			New but assumed by Description that its not applicable
63	Subpart ZZZZ	(§§ 10880 - 10906) - National Emissions Standards for Hazardous Air Pollutants FOR IRON AND STEEL FOUNDRIES AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart BBBBB	(§§ 11080 - 11100) - National Emissions Standards for Hazardous Air Pollutants FOR SOURCE CATEGORY: GASOLINE DISTRIBUTION BULK TERMINALS, BULK PLANTS, AND PIPELINE FACILITIES	N			New 10 Jan 2008, 73 FR 1933 Not applicable if subject to 63 subpart R and CC, which Chevron is.
63	Subpart CCCCC	(§§ 11110 - 11132) - National Emissions Standards for Hazardous Air Pollutants FOR SOURCE CATEGORY: GASOLINE DISPENSING FACILITIES	N			New but assumed by Description that its not applicable
63	Subpart DDDDD	(§§ 11140 - 11145) - National Emissions Standards for Hazardous Air Pollutants FOR POLYVINYL CHLORIDE AND COPOLYMERS PRODUCTION AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart EEEEE	(§§ 11146 - 11152) - National Emissions Standards for Hazardous Air Pollutants FOR PRIMARY COPPER SMELTING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart FFFFF	(§§ 11153 - 11159) - National Emissions Standards for Hazardous Air Pollutants FOR SECONDARY COPPER SMELTING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart GGGGG	(§§ 11160 - 11168) - National Emissions Standards for Hazardous Air Pollutants FOR PRIMARY NONFERROUS METALS AREA SOURCES-- ZINC, CADMIUM, AND BERYLLIUM	N			New but assumed by Description that its not applicable

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart HHHHHH	(§§ 11169 - 11180) - National Emissions Standards for Hazardous Air Pollutants: PAINT STRIPPING AND MISCELLANEOUS SURFACE COATING OPERATIONS AT AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart LLLLLL	(§§ 11393 - 11399) - National Emissions Standards for Hazardous Air Pollutants FOR ACRYLIC AND MODACRYLIC FIBERS PRODUCTION AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart MMMMM	(§§ 11400 - 11406) - National Emissions Standards for Hazardous Air Pollutants FOR CARBON BLACK PRODUCTION AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart NNNNNN	(§§ 11407 - 11413) - National Emissions Standards for Hazardous Air Pollutants FOR CHEMICAL MANUFACTURING AREA SOURCES: CHROMIUM COMPOUNDS	N			New but assumed by Description that its not applicable
63	Subpart OOOOOO	(§§ 11414 - 11420) - National Emissions Standards for Hazardous Air Pollutants FOR FLEXIBLE POLYURETHANE FOAM PRODUCTION AND FABRICATION AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart PPPPPP	(§§ 11421 - 11427) - National Emissions Standards for Hazardous Air Pollutants FOR LEAD ACID BATTERY MANUFACTURING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart QQQQQQ	(§§ 11428 - 11434) - National Emissions Standards for Hazardous Air Pollutants FOR WOOD PRESERVING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart RRRRRR	(§§ 11435 - 11447) - National Emissions Standards for Hazardous Air Pollutants FOR CLAY CERAMICS MANUFACTURING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart SSSSSS	(§§ 11448 - 11460) - National Emissions Standards for Hazardous Air Pollutants FOR GLASS MANUFACTURING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart NNNNNN	(§§ 11407 - 11413) - National Emissions Standards for Hazardous Air Pollutants FOR CHEMICAL MANUFACTURING AREA SOURCES: CHROMIUM COMPOUNDS	N			New but assumed by Description that its not applicable
63	Subpart TTTTTT	(§§ 11462 - 11474) - National Emissions Standards for Hazardous Air Pollutants FOR SECONDARY NONFERROUS METALS PROCESSING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart VVVVVV	(§§ 11494 - 11503) - National Emissions Standards for Hazardous Air Pollutants FOR CHEMICAL MANUFACTURING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart WWWWWW	(§§ 11504 - 11513) - National Emissions Standards for Hazardous Air Pollutants: AREA SOURCE STANDARDS FOR PLATING AND POLISHING OPERATIONS	N			New but assumed by Description that its not applicable
63	Subpart XXXXXX	(§§ 11514 - 11523) - National Emissions Standards for Hazardous Air Pollutants AREA SOURCE STANDARDS FOR NINE METAL FABRICATION AND FINISHING SOURCE CATEGORIES	N			New but assumed by Description that its not applicable
63	Subpart YYYYYY	(§§ 11524 - 11543) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: FERROALLOYS PRODUCTION FACILITIES	N			New but assumed by Description that its not applicable
63	Subpart ZZZZZZ	(§§ 11544 - 11558) - National Emissions Standards for Hazardous Air Pollutants: AREA SOURCE STANDARDS FOR ALUMINUM, COPPER, AND OTHER NONFERROUS FOUNDRIES	N			New but assumed by Description that its not applicable
63	Subpart AAAAAA	(§§ 11559 - 11567) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: ASPHALT PROCESSING AND ASPHALT ROOFING MANUFACTURING	N			New but assumed by Description that its not applicable

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart BBBB	(§§ 11579 - 11588) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: CHEMICAL PREPARATIONS INDUSTRY	N			New but assumed by Description that its not applicable
63	Subpart CCCCC	(§§ 11599 - 11638) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: PAINTS AND ALLIED PRODUCTS MANUFACTURING	N			New but assumed by Description that its not applicable
63	Subpart DDDDD	(§§ 11619 - 11638) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: PREPARED FEEDS MANUFACTURING	N			New but assumed by Description that its not applicable
<b>Part 68 - Chemical Accident Prevention Provisions</b>			Y	All Units		

40 CFR part 63, subpart ZZZZ  
National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Engine Category	Date Constructed	Emission Limitations	Operating Limitations	Fuel Requirements	Performance Tests	Monitoring, Installation, Collection, Operation and Maintenance Requirements	Initial Compliance	Continuous Compliance	Notification Requirements	Recordkeeping Requirements	Reporting Requirements	General Provisions (40 CFR part 63)
<b>Stationary RICE at Area Sources</b>												
<b>STEP 1a - Existing Area Sources</b>												
<b>Existing Stationary Engine ≤500 HP Located at Area Sources of HAP</b>												
Emergency CI	Before 6/12/2006	63.6603 Table 2d	No Requirements	No Requirements	No Requirements	63.6625(e), (f), (h)	No Requirements	63.6635 63.6640	No Requirements	63.6655	63.6650 (except 63.6650(g))	Yes
Non-Emergency CI 300<HP≤500	Before 6/12/2006	63.6603 Table 2d	No Requirements	>300 HP with displacement <30 l/cyl: 63.6604	63.6612 63.6615 63.6620 Table 4	63.6625(e), (h), (i) ≥300 HP: 63.6625(g)	63.6630	63.6635 63.6640	63.6645	63.6655 (except 63.6655(f))	63.6650 (except 63.6650(g))	Yes
Non-Emergency CI ≤300 HP	Before 6/12/2006	63.6603 Table 2d	No Requirements	No Requirements	No Requirements	63.6625(e), (h), (i)	No Requirements	63.6635 63.6640	No Requirements	63.6655 (except 63.6655(f))	63.6650 (except 63.6650(g))	Yes
SI 4SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
SI 2SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
SI 4SRB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
Landfill/Digester Gas	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
Residential/Commercial/Institutional Emergency	Before 6/12/2006	No Requirements										
<b>Existing Stationary Engine &gt;500 HP Located at Area Sources of HAP</b>												
Emergency CI	Before 6/12/2006	63.6603 Table 2d	No Requirements	No Requirements	No Requirements	63.6625(e), (f), (h)	No Requirements	63.6635 63.6640	No Requirements	63.6655	63.6650 (except 63.6650(g))	Yes
Non-Emergency CI	Before 6/12/2006	63.6603 Table 2d	63.6603 Table 2h	>300 HP with displacement <30 l/cyl: 63.6604	63.6610 63.6615 63.6620 Table 4	63.6625(g), (h)	63.6630	63.6635 63.6640	63.6645	63.6655 (except 63.6655(f))	63.6650 (except 63.6650(g))	Yes
SI 4SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
SI 2SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
SI 4SRB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
Landfill/Digester Gas	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
Residential/Commercial/Institutional Emergency	Before 6/12/2006	No Requirements										
<b>Stationary RICE at Area Sources</b>												
<b>STEP 1b - New &amp; Reconstructed Area Sources</b>												
<b>New &amp; Reconstructed Stationary Engine ≤500 HP Located at Area Sources of HAP</b>												
Limited Use	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJJ (SI NSPS), as applicable.										
Emergency	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJJ (SI NSPS), as applicable.										
Non-Emergency CI	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS)										
SI 4SLB	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)										
SI 2SLB	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)										



40 CFR part 63, subpart ZZZZ  
National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Summary of Requirements													
SI 4SRB	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart JJJ (SI NSPS)											
Landfill/Digester Gas	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJ (SI NSPS)											
New & Reconstructed Stationary Engine >500 HP Located at Area Sources of HAP													
Limited Use	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJ (SI NSPS), as applicable.											
Emergency	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJ (SI NSPS), as applicable.											
Non-Emergency CI	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS)											
SI 4SLB	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJ (SI NSPS)											
SI 2SLB	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJ (SI NSPS)											
SI 4SRB	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart JJJ (SI NSPS)											
Landfill/Digester Gas	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJ (SI NSPS)											
Stationary RICE at Major Sources													
STEP 2(a)(i)													
Existing Stationary Engine ≤500 HP Located at Major Sources of HAP													
Emergency CI	Before 6/12/2006	63.6602 Table 2c	63.6602 Table 2c	No Requirements	No Requirements	63.6625(e), (f), (h)	No Requirements	63.6635 63.6640	No Requirements	63.6655	63.6650 (except 63.6650(g))	Yes	
Non-Emergency CI 100≤HP≤500	Before 6/12/2006	63.6602 Table 2c	63.6602 Table 2c	>300 HP with displacement <30 l/cyl: 63.6604	63.6612 63.6620	63.6615 Table 4	63.6625(h), (i) HP: 63.6625(g) ≥300	63.6630	63.6635 63.6640	63.6645	63.6655 (except 63.6655(f))	63.6650 (except 63.6650(g))	Yes
CI <100 HP	Before 6/12/2006	63.6602 Table 2c	63.6602 Table 2c	No Requirements	No Requirements	63.6625(h), (i)	No Requirements	63.6635 63.6640	No Requirements	63.6655 (except 63.6655(f))	63.6650 (except 63.6650(g))	Yes	
SI 4SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)											
SI 2SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)											
SI 4SRB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)											
Landfill/Digester Gas	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)											
STEP 2(a)(ii)													
Existing Stationary Engine >500 HP Located at Major Sources of HAP													
Limited Use	Before 12/19/2002	No Requirements											
Emergency CI	Before 12/19/2002	No Requirements											
Non-Emergency CI	Before 12/19/2002	63.6600(d) Table 2c	63.6600(d) Table 2b	>300 HP and <30 l/cyl: 63.6604	63.6610 63.6620	63.6615 Table 3	63.6625(a), (b), (h), (i) HP: 63.6625(g) ≥300	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
SI 4SLB	Before 12/19/2002	No Requirements											
SI 2SLB	Before 12/19/2002	No Requirements											
SI 4SRB	Before 12/19/2002	63.6600(a) Table 1a	63.6600(a) Table 1b	No Requirements	63.6610 63.6620	63.6615 Table 3	63.6625(a), (b), (h)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
Landfill/Digester Gas	Before 12/19/2002	No Requirements											
Stationary RICE at Major Sources													
STEP 2(b)(i)													
New & Reconstructed Stationary Engine ≤500 HP Located at Major Sources of HAP													





40 CFR part 63, subpart ZZZZ  
National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Summary of Requirements												
Limited Use	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJJ (SI NSPS), as applicable.										
Emergency	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJJ (SI NSPS), as applicable.										
Non-Emergency CI	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS)										
SI 4SLB <250 HP	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)										
Non-Emergency SI 4SLB ≥250 HP	On or After 6/12/2006 and before 1/1/2008	No Requirements										
Non-Emergency SI 4SLB ≥250 HP	Manufactured on or after 1/1/2008	63.6601 Table 2a	63.6601 Table 2b	No Requirements	63.6611 63.6615 63.6620 Table 4	63.6625(b), (i)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
Emergency SI 4SLB ≥250 HP	Manufactured on or after 1/1/2008	No Requirements	No Requirements	No Requirements	No Requirements	63.6625(j)	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	Yes
SI 2SLB	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)										
SI 4SRB	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)										
Landfill/Digester Gas	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)										
STEP 2(b)(ii)												
New & Reconstructed Stationary Engine >500 HP Located at Major Sources of HAP												
Limited Use	On or After 12/19/02	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	63.6645(f)	No Requirements	No Requirements	No (except as specified in 63.6645(f))
Emergency	On or After 12/19/2002	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	63.6645(f)	No Requirements	No Requirements	No (except as specified in 63.6645(f))
CI	On or After 12/19/02	63.6600(b) Table 2a	63.6600(b) Table 2b	No Requirements	63.6610 63.6615 63.6620 Table 4	63.6625(a), (b), (h)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
SI 4SLB	On or After 12/19/02	63.6600(b) Table 2a	63.6600(b) Table 2b	No Requirements	63.6610 63.6615 63.6620 Table 4	63.6625(a), (b), (h)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
SI 2SLB	On or After 12/19/02	63.6600(b) Table 2a	63.6600(b) Table 2b	No Requirements	63.6610 63.6615 63.6620 Table 4	63.6625(a), (b), (h)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
SI 4SRB	On or After 12/19/02	63.6600(a) Table 1a	63.6600(a) Table 1b	No Requirements	63.6610 63.6615 63.6620 Table 4	63.6625(a), (b), (h)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
Landfill/Digester Gas	On or After 12/19/02	No Requirements	No Requirements	No Requirements	No Requirements	≥10 percent of the gross heat input on an annual basis; 63.6625(c), (h)			≥10 percent of the gross heat input on an annual basis; 63.6645(f)	≥10 percent of the gross heat input on an annual basis; 63.6655(c)	≥10 percent of the gross heat input on an annual basis; 63.6650(g)	No (except as specified in 63.6645(f))

\*Note that certain engines covered under 40 CFR part 63, subpart ZZZZ, may be subject to additional requirements under 40 CFR part 60, subparts IIII and JJJJ.

\*\*For assistance in determining the potential to emit, please refer to <http://www.epa.gov/ttn/chieff/ap42/index.html> or contact your EPA regional office or state permitting staff. To determine the potential to emit, you may use emission factors from <http://www.epa.gov/ttn/chieff/ap42/ch03/index.html>, test data, or other published information.

Abbreviations:  
CI-Compression Ignition  
SI-Spark Ignition  
4SLB-4 Stroke Lean Burn  
2SLB-2 Stroke Lean Burn  
4SRB-4 Stroke Rich Burn



Hawaii State Requirements Title 11

REGULATION - NAME	APPLICABLE	EMISSION UNITS
Chapter 59 - Ambient Air Quality Standards	Y	
Chapter 60.1 - Air Pollution Control	Y	
<b>Subchapter 1 General Requirements</b>	Y	
§11-60.1-1 Definitions	Y	
§11-60.1-2 Prohibition of air pollution	Y	
§11-60.1-3 General conditions for considering applications		
§11-60.1-4 Certification	Y	
§11-60.1-5 Permit conditions		
§11-60.1-6 Holding of permit	Y	
§11-60.1-7 Transfer of permit		
§11-60.1-8 Reporting discontinuance	Y	
§11-60.1-9 Cancellation of a noncovered or covered source permit		
§11-60.1-10 Permit termination, suspension, reopening, and amendment	Y	
§11-60.1-11 Sampling, testing, and reporting methods	Y	
§11-60.1-12 Air quality models		
§11-60.1-13 Operations of monitoring stations		
§11-60.1-14 Public access to information	Y	
§11-60.1-15 Reporting of equipment shutdown	Y	
§11-60.1-16 Prompt reporting of deviations	Y	
§11-60.1-16.5 Emergency provision		
§11-60.1-17 Prevention of air pollution emergency episodes		
§11-60.1-18 Variances		
§11-60.1-19 Penalties and remedies	Y	
§11-60.1-20 Severability	Y	
<b>Subchapter 2 General Prohibitions</b>	Y	
§11-60.1-31 Applicability	Y	
§11-60.1-32 Visible emissions	Y	Crude Furnaces, Boilers, FCCU, Process Unit Furnaces, <del>Asphalt Plant</del> , Acid plant, and Cogeneration Plant
§11-60.1-33 Fugitive dust	Y	FCCU catalyst transfer operations
§11-60.1-34 Motor vehicles		
§11-60.1-35 Incineration		
§11-60.1-36 Biomass fuel burning boilers		
§11-60.1-37 Process industries		
§11-60.1-38 Sulfur oxides from fuel combustion	Y	Crude Furnaces, Boilers, FCCU, Process Unit Furnaces, <del>Asphalt Plant</del> , Acid plant, and Cogeneration Plant
§11-60.1-39 Storage of volatile organic compounds	Y	Petroleum Storage Tanks
§11-60.1-40 Volatile organic compound water separation	Y	API Separators
§11-60.1-41 Pump and compressor requirements	Y	Seal requirements apply to pumps and compressors handling VOC with a Reid vaport presser greater than or equal to 1.5 psia in FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor
§11-60.1-42 Waste gas disposal	Y	Flare/abatement requirement for VOC vapor blowdown applies to equipment in FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor

Hawaii State Requirements Title 11

REGULATION - NAME	APPLICABLE	EMISSION UNITS
<b>Subchapter 3 Open Burning</b>	N	
§11-60.1-51 Definitions		
§11-60.1-52 General provisions		
§11-60.1-53 Agricultural burning: permit requirement		
§11-60.1-54 Agricultural burning: applications		
§11-60.1-55 Agricultural burning: "no-burn" periods		
§11-60.1-56 Agricultural burning: recordkeeping and monitoring		
§11-60.1-57 Agricultural burning: action on application		
<b>Subchapter 4 Noncovered Sources</b>	N	
§11-60.1-61 Definitions		
§11-60.1-62 Applicability		
§11-60.1-63 Initial noncovered source permit application		
§11-60.1-64 Duty to supplement or correct permit applications		
§11-60.1-65 Compliance plan		
§11-60.1-66 Transition into the noncovered source permit program		
§11-60.1-67 Permit term		
§11-60.1-68 Permit content		
§11-60.1-69 Temporary noncovered source permits		
§11-60.1-70 Noncovered source general permits		
§11-60.1-71 Transmission of information to the administrator		
§11-60.1-72 Permit reopening		
§11-60.1-73 Public participation		
§11-60.1-74 Noncovered source permit renewal applications		
§11-60.1-75 Administrative permit amendment		
§11-60.1-76 Applications for modifications		
<b>Subchapter 5 Covered Sources</b>	Y	
§11-60.1-81 Definitions	Y	
§11-60.1-82 Applicability	Y	
§11-60.1-83 Initial covered source permit application	Y	
§11-60.1-84 Duty to supplement or correct permit applications	Y	
§11-60.1-85 Compliance plan	Y	
§11-60.1-86 Compliance certification of covered sources	Y	
§11-60.1-87 Transition period		
§11-60.1-88 Action on applications submitted within one year of the effective date of this chapter		
§11-60.1-88.5 Permit action on insignificant activities		
§11-60.1-89 Permit term	Y	
§11-60.1-90 Permit content	Y	
§11-60.1-91 Temporary covered source permits		
§11-60.1-92 Covered source general permits		

Hawaii State Requirements Title 11

REGULATION - NAME	APPLICABLE	EMISSION UNITS
§11-60.1-93 Federally-enforceable permit terms and conditions		
§11-60.1-94 Transmission of information to the administrator		
§11-60.1-95 EPA oversight		
§11-60.1-96 Operational flexibility	Y	
§11-60.1-97 Repealed.		
§11-60.1-98 Permit reopening	Y	
§11-60.1-99 Public participation		
§11-60.1-100 Public petitions		
§11-60.1-101 Covered source permit renewal applications		
§11-60.1-102 Administrative permit amendment		
§11-60.1-103 Applications for minor modifications		
§11-60.1-104 Applications for significant modifications		
<b>Subchapter 6 Fees for Covered Sources, Noncovered Sources, and Agricultural Burning</b>	Y	
§11-60.1-111 Definitions		
§11-60.1-112 General fee provisions for covered sources	Y	
§11-60.1-113 Application fees for covered sources	Y	
§11-60.1-114 Annual fees for covered sources	Y	
§11-60.1-115 Basis of annual fees for covered sources		
§11-60.1-116 Repealed.		
§11-60.1-117 General fee provisions for noncovered sources		
§11-60.1-118 Application fees for noncovered sources		
§11-60.1-119 Annual fees for noncovered sources		
§11-60.1-120 Repealed.		
§11-60.1-121 Application fees for agricultural burning permits		
<b>Subchapter 7 Prevention of Significant Deterioration Review</b>	N	Was not applicable for the initial Covered Source Permit, because this facility was not a new major stationary source, nor did Chevron propose any major modifications to a major stationary source as defined in HAR 11-60.1-131. Applicability of PSD will need to be addressed on a project-by-project basis for future proposed facility modifications.
§11-60.1-131 Definitions	N	
§11-60.1-132 Source applicability	N	
§11-60.1-133 Exemptions	N	
§11-60.1-134 Ambient air increments	N	
§11-60.1-135 Ambient air ceilings	N	
§11-60.1-136 Restriction on area classifications	N	
§11-60.1-137 Exclusions from increment consumption	N	
§11-60.1-138 Redesignation	N	
§11-60.1-139 Stack heights	N	
§11-60.1-140 Control technology review	N	

Hawaii State Requirements Title 11

REGULATION - NAME	APPLICABLE	EMISSION UNITS
§11-60.1-141 Source impact analysis	N	
§11-60.1-142 Air quality models	N	
§11-60.1-143 Air quality analysis	N	
§11-60.1-144 Source information	N	
§11-60.1-145 Additional impact analyses	N	
§11-60.1-146 Sources impacting Class I areas - additional requirements	N	
§11-60.1-147 Public participation	N	
§11-60.1-148 Source obligation	N	
§11-60.1-149 Innovative control technology	N	
§11-60.1-150 Permit rescission	N	
<b>Subchapter 8 Standards of Performance for Stationary Sources</b>	Y	
§11-60.1-161 New source performance standards	Y	All units that are subject to one or more of the NSPS Subparts in 40 CFR 60
§11-60.1-162 Repealed		
§11-60.1-163 Federal plans		
<b>Subchapter 9 Hazardous Air Pollutant Sources</b>	Y	
§11-60.1-171 Definitions		
§11-60.1-172 List of hazardous air pollutants		
§11-60.1-173 Applicability		
§11-60.1-174 Maximum achievable control technology (MACT) emission standards	Y	Units that are subject to the Category-Specific NESHAP in Subpart in 40 CFR 63
§11-60.1-175 Equivalent maximum achievable control technology (MACT) limitation		
§11-60.1-176 Repealed		
§11-60.1-177 Early reduction		
§11-60.1-178 Accidental releases		
§11-60.1-179 Ambient air concentrations of hazardous air pollutants		
§11-60.1-180 National emission standards for hazardous air pollutants	Y	Units that are subject to the NESHAP Subpart in 40 CFR 61
<b>Subchapter 10 Field Citations</b>	Y	
§11-60.1-191 Purpose		
§11-60.1-192 Offer to settle; penalties		
§11-60.1-193 Acceptance or withdrawal of citation		
§11-60.1-194 Form of citation		
<b>Subchapter 11 Greenhouse Gas Emissions</b>	Y	
§11-60.1-201 Purpose		
§11-60.1-202 Definitions		
§11-60.1-203 Greenhouse Gas Emission Limit		
§11-60.1-204 Greenhouse Gas Emission Reduction Plan	Y	
§11-60.1-205 Public Participation		
§11-60.1-206 Public Petitions		

**Appendix A**  
**Proposed Language**

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**APPENDIX A**  
**Proposed Language**

~~I. Chevron seeks to include the following as a standard condition in Attachment I:~~

~~Emission releases from grandfathered units while operating under normal conditions are not reportable to meet CERCLA reporting guidelines if federally enforceable.~~

2016 Update:

NAAQS/SAAQS

1. *Chevron seeks to include the following as a standard condition in Attachment I:*

*Compliance with the HAR §11-60.1-81 applicable requirement for NAAQS and SAAQS, shall be demonstrated using data collected by the ambient monitoring stations operated by the Department of Health, including the Kapolei monitor approximately one mile north of the facility, supported, as necessary, by dispersion modeling analysis of refinery actual operating emissions.*

- II. *Chevron seeks to include the following proposed language changes in the following special conditions in Attachment II:*

Attachment II(A) - Miscellaneous

1. *Section B.2 - include CatOx in list of units subject to NSPS QQQ*

Attachment II(B) - Tanks

1. *Incorporate language from September 30, 2014 Minor Modification for Tank 104.*
2. *Section A.1.b.vi - Chevron proposes removing Tk-152 from the list of crude tanks. This tank no longer stores crude. Tk-152 stores heavy liquids, and should be included in the Insignificant Activities, #10, Insignificant Heavy Liquids.*
3. *Section C.3 and C.4 - Chevron proposes removing Attachment II(B) permit conditions C.3 and C.4 as indicated in Appendix C. These two permit conditions unnecessarily restrict the referenced tanks to specific services with no regulatory requirements specific to those services. The tank services should be limited to services that meet permit condition C.1 and B.1 (MACT CC Group 1 and Group 2 applicable requirements).*
4. *Section B.1.a - update to remove T-152 from Group 1 list as shown in App C*
5. *Section C.2 - update to remove T-152 as shown in App C*
6. *Section E.1 - Chevron proposes adding following wording:*

*Upon written request of the permittee or upon notification from the Department of Health, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.*

7. *Section E.5 - Chevron proposes the following language:*

*The permittee shall notify the Department of Health at least thirty (30) days or such lesser time as designated and approved by the Department of Health, prior to:*

- a. *Changing the volatile organic liquid stored in any of the storage tanks identified in*



- b. *Increasing the storage capacity of Storage Tanks 105 thru 111 in accordance with Special Condition No. C.8. of this Attachment.*

**Attachment II(C) - TTLR**

1. *Section E.2 - Chevron proposes adding following language:*

*Upon written request of the permittee, or upon notification from the Department of Health, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.*

**Attachment II(D) - Cooling Tower**

1. *Section D - Chevron proposes adding following language:*

*Upon written request of the permittee, or upon notification from the Department of Health, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.*

**Attachment II(E) - Flares**

1. *Section B.1.a - update J to Ja, and update citation reference from 60.100 to 60.100a*
2. *Section C.4: Chevron proposes the following language to reflect compliance with NSPS Ja, 40 CFR 60.103a(h) . This proposed language replaces in full, the current:*

*The Crude Flare shall be fired only on routinely-generated gases with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 162 ppmv, determined hourly on a 3-hour rolling average basis. The combustion in the flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit.*

3. *Section C.5 – Chevron proposes adding the following new language:*

*Chevron shall maintain and operate the Flare Vapor Recovery Unit to divert gas from the flare and into the fuel gas system.*

4. *Section D.3.b.iii - correct typo, should be CGA*
5. *Revised Section D.4 - Chevron proposes adding the following TRS CMs language:*

**Continuous Emissions Monitoring System CMS for total reduced sulfur**

- a. *The owner or operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration of total reduced sulfur in gas discharged to the flare according to Performance Specification 5 of Appendix B to part 60, except as described in 60.107a(e)(4).*
- b. *The CEMS shall meet the following requirements:*
  - i. *The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (e.g., roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.*

- ii. *The permittee shall conduct performance evaluations pursuant to the requirements of 60.107a(e)(1)(ii), as applicable.*
- iii. *The permittee shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each total reduced sulfur monitor.*

- 6. *Move existing Section D.4 - Chevron proposes moving language from existing permit Section D.4 to a new Section D.6.*
- 7. *Add new Section D.5 – Chevron proposes adding the following new language:*

*Permittee shall develop and implement a written flare management plan (FMP) as described in 40 CFR 60.103a(a) for the refinery's interconnected flare system. The purpose of the plan is to detail the flare system design and specifications, flare minimization assessment, monitoring, and procedures for flaring reduction.*

*-(Auth: §60.103a)*

- 8. *Section E.1 - Chevron proposes adding following language:*

*Upon written request of the permittee, or upon notification from the Department of Health, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.*

#### **Attachment II(F) - Effluent Plant**

- 1. *Incorporate language from September 30, 2014 Minor Modification for Tank 104.*
- 2. *Section E.1 - Chevron proposes adding the following language:*

*Upon written request of the permittee, or upon notification from the Department of Health, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.*

#### **Attachment II(G) - Crude Furnaces**

- 1. *Chevron requests a correction to the NSPS J sulfur limit in Section C.1. The correct conversion of the NSPS J sulfur limit, 230 mg/dscm, is 162 ppmv at standard conditions of 1 atm and 68 °F (reference 40 CFR §60.2).*
  - i. *The atmospheric and vacuum furnaces shall be fired only on low sulfur fuel oil (LSFO) with a maximum sulfur content not to exceed 0.5% by weight or refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (~~160 ppmv~~ 0.10 gr/dscf) or vaporized liquefied petroleum gas (LPG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (~~160 ppmv~~ 0.1 gr/dscf).*
  - ii. *(Auth: 40 CFR §60.104(a)(1))*
- 2. *Section E.1 - Chevron proposes revising Excess Emissions reporting to semi-annual basis to be consistent with other fuel gas combustion device reporting :*
  - a. *The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department of Health by the 30th day following the end of each semi-annual calendar period ~~for every calendar quarter~~. The report shall include the following:*

3. Section E.2 - Chevron proposes adding the following language:

*Upon written request of the permittee, or upon notification from the Department of Health, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.*

**Attachment II(H) - Boiler Plant**

1. Chevron requests a correction to the NSPS J sulfur limit in Section C.1. The correct conversion of the NSPS J sulfur limit, 230 mg/dscm, is 162 ppmv at standard conditions of 1 atm and 68 °F (reference 40 CFR §60.2).
  - i. The boilers shall be fired only on low sulfur fuel oil (LSFO) with a maximum sulfur content not to exceed 0.5% by weight or refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (~~160 ppmv~~ 0.10 gr/dscf).
  - ii. (Auth: 40 CFR §60.104(a)(1))
2. Section E.2 - Chevron proposes adding the following language:

*Upon written request of the permittee, or upon notification from the Department of Health, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.*

**Attachment II(I) - FCCU**

1. In Section D.8, Continuous Opacity Monitoring System (COMS) for Opacity, add 40 CFR 60.11 to the list of U.S. EPA monitoring performance standards that the system must meet
2. Chevron proposes adding the following language to Section C, Operational and Emissions Limitations:

*Torch oil may be used as a fuel in the FCCU to assist in starting, restarting, hot standby, or to maintain regenerator heat balance.*

3. Update Section C.6, the long term NO<sub>x</sub> limit from 50 ppmvd @ 0% O<sub>2</sub> (365-day rolling average) to 50.0 ppmvd @0% O<sub>2</sub> (365-day rolling average)
4. Section E.1 - Chevron proposes adding the following language:

*Upon written request of the permittee, or upon notification from the Department of Health, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.*

**Attachment II(J) - Process Unit Furnaces**

1. Chevron requests a correction to the NSPS J sulfur limit in Section C.1. The correct conversion of the NSPS J sulfur limit, 230 mg/dscm, is 162 ppmv at standard conditions of 1 atm and 68 °F (reference 40 CFR §60.2).

Process Unit Furnaces F-5600, F-5700, F-5930, and F-5950 shall be fired only on refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (~~160 ppmv~~ 0.10 gr/dscf).

2. Section E.1 - Chevron proposes adding the following language:

Upon written request of the permittee, or upon notification from the Department of Health, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.

**Attachment II(K) - Asphalt Plant**

1. Chevron requests removal of this attachment from the permit.

**Attachment II(L) - Acid Plant**

1. Chevron requests a correction to the NSPS J sulfur limit in Section C.1. The correct conversion of the NSPS J sulfur limit, 230 mg/dscm, is 162 ppmv at standard conditions of 1 atm and 68 °F (reference 40 CFR §60.2).

The acid plant preheater shall be fired only on refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (~~160 ppmv~~ 0.10 gr/dscf).

2. Section E.1 - Chevron proposes revising Excess Emissions reporting to semi-annual basis to be consistent with other fuel gas combustion device reporting :
  - a. The permittee shall submit an excess emissions and monitoring systems performance report for the acid plant preheater pursuant to 40 CFR §60.7(c) to the Department of Health by the 30th day following the end of each semi-annual calendar period ~~for every calendar quarter~~. The report shall include the following:
    - i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.
    - ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the acid plant preheater. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted, shall also be reported.
    - iii. The date and time identifying each period during which the continuous emissions monitoring system was inoperative except for zero and span checks. The nature of each system repair or adjustment shall be described.
    - iv. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the continuous emissions monitoring system operated properly during the period and was not subject to any repairs or adjustments except zero and span checks.
  - b. All reports shall be postmarked by the 30th day following the end of each semi-annual calendar period ~~following the end of each calendar quarter~~. The enclosed Excess Emissions and Monitoring System Performance Summary Report form shall also be submitted in addition to the excess emissions and monitoring systems performance report.
  - c. Excess emissions shall be defined as any rolling 3-hour period during which the average

concentration of H<sub>2</sub>S in RFG, as measured by the continuous emissions monitoring system, exceeds 230 mg/dscm (~~160 ppmv~~ 0.10 gr/dscf).

- d. Excess emissions indicated by the continuous emissions monitoring system shall be Section considered violations of the applicable emission and concentration limits for the purposes of this permit.
3. Section E.2 - Chevron proposes adding the following language:

Upon written request of the permittee, or upon notification from the Department of Health, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.

#### Attachment II(M) - Cogeneration

1. Chevron requests a correction to the NSPS J sulfur limit in Section C.1. The correct conversion of the NSPS J sulfur limit, 230 mg/dscm, is 162 ppmv at standard conditions of 1 atm and 68 °F (reference 40 CFR §60.2).
  1. Fuel Usage and Specifications.
    - a. The three (3) 40 MMBtu/hr gas turbines shall be fired only on refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (160 ppmv), or whole straight run (WSR) naphtha ~~light straight run (LSR) gasoline or heavy straight run (HSR) gasoline~~ with a sulfur content not to exceed 0.03% by weight.
    - b. The three (3) heat recovery steam generators shall be fired only on refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (~~160 ppmv~~ 0.10 gr/dscf).
    - c. The fuel consumption of the three (3) 40 MMBtu/hr gas turbines while fired on whole straight run (WSR) naphtha ~~LSR or HSR gasoline~~ shall not exceed 171,409 barrels per any rolling 12-month period. The fuel consumption of the three (3) 40 MMBtu/hr gas turbines while fired on RFG shall not exceed 955.5 million cubic feet per any rolling 12-month period. The fuel consumption of the three (3) heat recovery steam generators fired on RFG shall not exceed 836.1 million cubic feet per any rolling 12-month period
2. Chevron requests that the minimum water-to-fuel ratio of 0.5 pound of water per 1.0 pound of fuel (0.5 lb/lb) limit not apply when the NO<sub>x</sub> CEMS required pursuant to Special Condition D.3 demonstrates compliance with the applicable emissions limits specified in Special Condition C.2. The following language is proposed for Section E.1.c.ii:

#### Section E. Notification and Reporting Requirements.

##### 1. Excess Emissions

- c. Excess emissions shall be defined as follows:
  - ii. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with the emission limits set forth in Special Condition No. C.2. of this Attachment, except when the operating unit is monitored by a NO<sub>x</sub> CEMS that concurrently shows compliance with the NO<sub>x</sub> limits in Special Condition C.2.; or

**Attachment II - General Comments**

*Chevron requests that only one Excess Emissions report for H<sub>2</sub>S CEMS associated with fuel gas combustion devices be submitted for each reporting period.*

**Black Start Generator (CSP-0088-03-C)**

**Attachment II**

*The Black Start Generator is operated regularly for readiness testing and maintenance checks and normally these periods are short and do not exceed 15 minutes. Chevron requests an exemption from monthly visible emissions monitoring by EPA Method 9 (two consecutive six minute observations) when the generator is operated for these routine, short periods, and proposes the following language addition:*

**Section D.3 - Visible Emissions (VE)**

*The permittee shall conduct monthly (calendar month) VE observations for the black start diesel engine generator by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the Visible Emissions Form Requirements. This monitoring requirement is waived during short duration readiness testing and maintenance checks that are of duration not exceeding 15 minutes.*

**Appendix B**  
**Detailed Emission Calculations**

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**APPENDIX B**  
**Detailed Emission Calculations**

- Appendix B      Detailed Potential to Emit Calculation Spreadsheets  
*Update: An updated Detailed Potential to Emit Calculation Spreadsheets is attached.*
- Appendix B-2      TANKS4 Emission Model Runs for Chevron Hawaii Refinery (Separate Volume)
- Appendix B-3      Detailed spreadsheets of component counts and emission estimates for individual components are provided on CD



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53 - FCC Fugitives	Potential to Emit NonLDAR Fugitive Emissions
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57 - H&H Fugitives	Potential to Emit NonLDAR Fugitive Emissions
58 - Alky Fugitives	Potential to Emit NonLDAR Fugitive Emissions
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## Summary

SOURCES	Pollutant emission rates (ton/yr)							Total Criteria Pollutant Emissions
	PM10	SO2	CO	NO2	VOC	Lead		
Boilers	134.8	1353.8	86.2	551.9	13.1	0.0	2140	
Cogen Turbines	11.7	27.9	52.5	193.2	2.3	0.0	288	
Crude Furnaces	44.5	482.0	75.0	302.9	5.1	0.0	909	
FCC Furnace	2.1	7.2	23.2	15.1	1.6	0.0	49	
Isom Furnaces	0.2	0.7	2.1	2.5	0.1	0.0	5	
H&H Furnaces	1.1	3.9	12.1	14.5	0.8	0.0	32	
Acid preheater & combustion chamber	0.4	1.5	4.8	5.7	0.3	0.0	13	
Asphalt Furnace	0.0	0.0	0.0	0.0	0.0	0.0	0	
FCC Stack	175.2	333.3	499.3	285.1	14.7	0.0	1308	
Generators	1.3	0.0	21.8	19.0	19.0	-	61	
Cooling Tower	3.2	-	-	-	9.2	-	12	
Acid plant absorber stack <sup>1</sup>	-	1405.3	-	-	-	-	1405	
Catalyst transfer	0.0	-	-	-	-	-	0	
Wastewater treatment <sup>2</sup>	-	-	17.0	14.7	74.9	0.0	107	
Loading Rack	-	-	-	-	1004.1	0.0	1004	
Process Fugitives	-	-	-	-	1600.4	1.4	1602	
Tanks	-	-	-	-	467.9	0.0	468	
Marine loading	-	-	-	-	196.6	0.0	197	
Refinery Flares	-	319.1	51.0	224.2	9.5	-	604	
<b>Totals</b>	<b>374.6</b>	<b>3934.7</b>	<b>845.0</b>	<b>1628.6</b>	<b>3419.6</b>	<b>1.4</b>	<b>10204.0</b>	
	371.34	2210.38	777.00	1389.71	57.09	0.04	4805.56	

Notes:

<sup>1</sup> Criteria pollutant emissions from the acid preheater and combustion chamber are vented to the acid plant absorber stack. The listed SO2 emissions from the acid plant absorber stack are only from acid production.

## Point sources

**Summary of Potential Emissions From Point Combustion Sources**

SOURCES	Pollutant emission rates (ton/yr)										Total Criteria Pollutant Emissions		
	PM10	SO2	CO	NOX	VOC	Lead	PM10	SO2	CO	NOX		VOC	Lead
Boilers	134.78	1353.83	86.23	551.88	13.11	0.026							2140
CatOx Unit	0.00	0.00	17.00	14.70	1.30	0.00							33
Cogen Turbines	11.72	27.92	52.49	193.16	2.34	0.006							288
Crude Furnaces	44.49	481.99	74.99	302.88	5.11	0.010							909
FCC Furnace	2.11	7.16	23.21	15.09	1.60	0.000							49
Isom Furnaces	0.19	0.66	2.06	2.45	0.13	0.000							5
H&H Furnaces	1.10	3.91	12.14	14.45	0.79	0.000							32
Acid preheater & combustion chamber	0.43	1.54	4.80	5.71	0.31	0.000							13
Asphalt Furnace													0
FCC Stack	175.20	333.35	499.32	285.07	14.67	0.000							1308
Generators (Note 1)													
Emergency Stationary Generator: Black Start Generator	0.03	0.0010	0.17	1.62	1.62	0.00							3
Non-Emergency Stationary Generator: Sand Filter Pump #1	0.43	0.0085	7.20	5.80	5.80	0.00							19
Non-Emergency Stationary Generator: Sand Filter Pump #2	0.43	0.0085	7.20	5.80	5.80	0.00							19
Non-Emergency Stationary Generator: Transfer Pump	0.43	0.0085	7.20	5.80	5.80	0.00							19
<b>Totals</b>	<b>371.3</b>	<b>2210.4</b>	<b>794.0</b>	<b>1404.4</b>	<b>58.4</b>	<b>0.0</b>							<b>4838.6</b>

Note 1: Generator Point Combustion Sources are listed in this table. All other generators are insignificant activities.

	2010 Renewal												
Asphalt	0.18	0.65	2.02	2.41	0.13	0.00							5.40
Generators	5.5	5.1	16.7	77.6	6.2								111.1
<b>Totals</b>	<b>375.7</b>	<b>2216.1</b>	<b>791.0</b>	<b>1465.4</b>	<b>45.7</b>	<b>0.0</b>							<b>4893.9</b>





## VOC EF

### REFINERY POTENTIAL VOC EMISSION FACTORS

Non-LDAR		
Equipment Type	Service	Emission factor * (kg/hr/source) All non-LDAR
Valves	G	0.0268
	LL	0.0109
	HL	0.00023
Pump Seals	G	0.280
	LL	0.114
	HL	0.021
Compressor Seals	G	0.636
PRVs	G	0.16
Connectors (Flanges)	ALL	0.00025
Connectors (Fittings)	ALL	0.00025
Open-ended Lines	ALL	0.0023
Sampling Connections	ALL	0.015

\* Obtained from Table 2-2 of EPA Document "Protocol for Equipment Leak Emission Estimates" (1995)

\*\* No emission factor available for pump seals in gas service. Emission factor above reflects LL service for pump seals adjusted by the ratio of the gas to light liquid service emission factors for valves.

#### 2016 Update

Equipment Type	Service	Emission factor ** (lb/hr/source)
Process Drain - uncontrolled	na	0.07
Process Drain - Ptrap controlled	na	0.001

\*\* Emission factor for process drains is from EPA AP-42, Chapter 5, Table 5.1-4 and API Publication 4677.

Speciation Data

HAPS COMPOSITIONS IN REFINERY  
TITLE V AIR PERMIT  
CHEVRON HAWAII REFINERY

Table with columns for PLANT, BLEND COMPONENTS, and various chemical species (PHENOL, STYRENE, METHANOL, NICKEL, LEAD, HCL, PERCHLOROETHYLENE, CYCLOHEXANE, BIPHENYL, 2,2,4 TRIMETHYLPENTANE, CUMENE, O-TOLUIDINE, ACRYLAMIDE, COMPOUNDS, ARSENIC, PROPYLENE, COMPOUNDS, 1,2,4-TM-Benzene, ETHYLENE). Rows include categories like CU, FCC, AI KY, HAP, DIM, B&S, and MISC.





**53 - FCC point**

**53- FCC POINT SOURCE POTENTIAL TO EMIT CALCULATIONS**

FCC SO2 emissions									
FCC Feed	S%	lb/bbl	Bbls/day to FCC	Total lbs S	% conv to coke	lb/day S	lbs/day SO2	day/yr	ton/yr
VGO	0.3	308	22,000	20295	4.5	913	1,826.55	365	333

FCC emissions from source testing - 1996 and 1999 - six values					
Pollutant	lbs/hr	Annual downtime	Op hr/yr	lbs/year	TPY
CO	114	0	8760	998640	499.32
VOC	3.35	0	8760	29346	14.67

Allowed by Permit	
High Sulfur VGO	5500 bbl/day
Low Sulfur VGO	16500 bbl/day

FCC NOx emissions (from AP-42)					
Pollutant	lb/10 <sup>3</sup> bbl	Bbls/day to FCC	lbs/hour	Op hr/yr	lbs/yr
NOx	71	22,000	65.08	8760	570,130

FCC PM10 emissions (from mass balance)				
Pollutant	lbs/hour	up hours	lbs/year	ton/yr
PM	40	8760	350400	175.2

HS Crude	wt lb/bbl	% total VGO	wt lb/bbl	% sulfur
LS Crude	324	25%	81	1.26
	302	75%	227	0.12
			308	0.405

**Flare**

**FLARE POINT SOURCE POTENTIAL TO EMIT CALCULATIONS**

Flare Pilots - F/G acid plant down

Unit	F/G SCFH	downtime hr/year	S ppm	lbs SO2/MMSCF	SO2 lb/hr	Lbs/Year	Tons/Yr
FCC	15000	8760	36.5809	6.1772	0.092266	811.690	0.40585

lb SO2/MMSCF = 1/379\*ppm S \*64

Flare Pilots - F/G normal

Unit	F/G SCFH	op hrs/yr	S ppm	lbs SO2/MMSCF	SO2 lb/hr	Lbs/Year	Tons/Yr	lb/day
Crude	100	8760	36.581	6.177	0.00062	5.41	0.00271	0.015
FCC	150	0	36.581	6.177	0.00093	0.00	0.00000	0.022

lb SO2/MMSCF = 1/379\*ppm S \*64

Acid Plant shutdown FLARE emissions: H2S based on CRTG analysis that shows 35 lbs.H2S/100 lbs.sulfur in FCC feed

FCC Feed	%S	lb/bbl	Feed rate (bbl)	Total Sulfur (lb)	% conv to H2S	lb H2S/day	lbs/hr h2s	Hrs downtime	Total Lbs H2S	Total lbs SO2	TPY
VGO	0.42	306	22,000	28274	35	9896	412.3	8760	3612055	6799162	3400

Use sulfur and feedrate values for period that Acid Plant was shutdown.

Flare emissions (from AP-42)

Pollutant	lb/10 <sup>3</sup> bbl	crude unit throughput (bbl/day)	lb/day	day/yr	TPY
NOx	18.9	65000	1229	365	224.2
VOC	0.8	65000	52	365	9.5
CO	4.3	65000	280	365	51.0
PM	neg				
SO2		see calculations for when acid plant down		3400.0	
SO2	26.9	65000	1749	365	319.1
				Total	603.8

now have FSERP

HAP Summary

Fugitive Emission by Area NUMBER	Total speciated VOC emissions (kg/hr)	AREA DESCRIPTION	BENZENE	NAPHTHALENE	O-XYLENE	ETHYLBENZENE	P-XYLENE	ETHYLENE DIBROMIDE	ETHYLENE DICHLORIDE	M-XYLENE	TOLUENE	1,3-BUTADIENE
			CAS# 71432 (ton/yr) 1	CAS# 91203 (ton/yr) 2	CAS# 95476 (ton/yr) 3	CAS# 100414 (ton/yr) 4	CAS# 106423 (ton/yr) 5	CAS# 106934 (ton/yr) 6	CAS# 107062 (ton/yr) 7	CAS# 108383 (ton/yr) 8	CAS# 108883 (ton/yr) 9	CAS# 106990 (ton/yr) 10
		LPG AREA AND FIELD PIPING										
20		BLENDED AND SHIPPING	0.83	1.43	3.37	1.26	1.71	0.45	0.27	4.69	4.64	0.30
23		STORAGE TANKS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		RELIEF SYSTEMS										
		WASTE WATER TREATMENT LAND										
36		TREATMENT UNIT	0.01	0.01	0.02	0.01	0.01	0.00	0.00	0.03	0.03	0.00
51		CRUDE UNIT	1.17	0.26	0.80	0.20	0.36	0.00	0.00	1.29	2.61	0.02
52/55		BOILERS/FOUL WATER OXIDIZER	0.01	0.03	0.05	0.02	0.03	0.00	0.00	0.07	0.04	0.00
53		FLUID CATALYTIC CRACKER UNIT	0.89	0.66	1.89	0.94	1.34	0.00	0.00	3.43	5.26	0.25
56		HYDROGENATION PLANT	0.01	0.02	0.03	0.01	0.01	0.00	0.00	0.03	0.02	0.13
57		HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58		ALKYLATION PLANT	0.01	0.03	0.05	0.02	0.02	0.00	0.00	0.06	0.04	0.05
59		ISOMERIZATION PLANT	0.01	0.02	0.03	0.01	0.01	0.00	0.00	0.03	0.02	0.05
60		ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61/62		AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66		DIMERSOL PLANT	0.01	0.02	0.03	0.01	0.01	0.00	0.00	0.04	0.02	0.00
67		COGENERATION PLANT	0.271	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.153	0.000
		Process Fugitive Summary	3.22	2.48	6.27	2.46	3.51	0.45	0.27	9.67	12.85	0.80
52		BOILER POINT	0.003	0.008	0.001	0.00	0.00				0.046	
67		COGEN POINT	0.034	0.018	0.018					0.033	0.067	0.008
51		CRUDE POINT	0.001	0.006	0.001	0.00	0.00				0.030	
53		FCC POINT	0.001	0.000	0.000						0.001	
59		ISOM POINT	0.000	0.000	0.000						0.000	
56		H&H POINT	0.000	0.000	0.000						0.000	
57		H&H POINT	0.000	0.000	0.000						0.000	
		H&H summary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
62		ACID PLANT CC AND PREHEATER	0.000	0.000							0.000	
60		ASPHALT POINT										
53		FCC STACK	0.1398	0.3458	0.5867	0.1840	0.2796	0.0002	0.0000	0.7211	0.4709	0.0000
		WASTEWATER	4.85	4.84	14.37	7.41	10.49	0.00	0.00	26.66	42.62	0.00
		LOAD RACK	4.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.32	0.00
		MARINE LOADING										
		FLARE	0									
		GENERATORS - RICE (3)	1.71E-03	3.00E-05	5.10E-04						7.50E-04	6.00E-05
		HAPs Summary	12.36	7.50	21.23	10.06	14.28	0.45	0.27	37.09	58.40	0.81
		Table 3.3 SubTotals	0.040	0.032	0.018	0.001	0.000	0.000	0.000	0.033	0.146	0.010

**HAP Summary**

Total specified VOC emissions (kg/hr)											
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	n-HEXANE CAS# 110543 (ton/yr) 11	ANILINE CAS# 62533 (ton/yr) 12	CRESOL MIXTURE CAS# 1319773 (ton/yr) 13	PHENOL CAS# 108952 (ton/yr) 14	STYRENE CAS# 100425 (ton/yr) 15	METHANOL CAS# 67561 (ton/yr) 16	NICKEL CAS# (ton/yr) 17	reported as LEAD CAS# (ton/yr) 18	HCL CAS# 7647010 (ton/yr) 19	PERCHLOROETHYLENE CAS# 127184 (ton/yr) 20
	LPG AREA AND FIELD PIPING										
20	BLENDING AND SHIPPING STORAGE TANKS	1.29	0.02	0.25	0.10	0.02	0.03	0.00	1.37	0.00	0.00
23	RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	WASTE WATER TREATMENT LAND										
36	TREATMENT UNIT	0.05	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51	CRUDE UNIT	3.60	0.01	0.15	0.02	0.00	0.00	0.00	0.00	0.00	0.00
52/55	BOILERS/FOUL WATER OXIDIZER	0.10	0.00	0.10	0.01	0.00	0.00	0.00	0.00	0.00	0.00
53	FLUID CATALYTIC CRACKER UNIT	0.41	0.02	0.16	0.01	0.04	0.00	0.00	0.00	0.00	0.00
56	HYDROGENATION PLANT	0.05	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	ALKYLATION PLANT	0.10	0.00	0.09	0.01	0.00	0.00	0.00	0.00	0.00	0.00
59	ISOMERIZATION PLANT	0.05	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.05
60	ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61/62	AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	DIMERSOL PLANT	0.05	0.00	0.05	0.00	0.00	0.00	0.34	0.00	0.00	0.00
67	COGENERATION PLANT	0.592	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Process Fugitive Summary	6.28	0.05	0.94	0.16	0.07	0.03	0.34	1.37	0.00	0.05
52	BOILER POINT	1.230									
67	COGEN POINT										
51	CRUDE POINT	0.002									
53	FCC POINT	0.473									
59	ISOM POINT	0.044									
56	H&H POINT	0.071									
57	H&H POINT	0.189									
	H&H summary	0.260	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
62	ACID PLANT CC AND PREHEATER POINT	0.103									
60	ASPHALT POINT										
53	FCC STACK	1.0449	0.0007	1.0670	0.0589	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001
	WASTEWATER	13.01	0.10	0.03	0.13	0.00	0.00	0.00	0.00	0.00	0.00
	LOAD RACK	8.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MARINE LOADING										
	FLARE										
	GENERATORS - RICE (3)										
	HAPs Summary	31.43	0.14	2.03	0.34	0.07	0.03	0.34	1.38	0.00	0.05
	Table 3.3 SubTotals	2.111	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

**HAP Summary**

Total speciated VOC emissions (kg/hr)

Fugitive Emission by Area NUMBER	AREA DESCRIPTION	not HAP CYCLOHEXANE CAS# 110827 (ton/yr) 21	BIPHENYL CAS# 92524 (ton/yr) 22	2,2,4 TRIMETHYLPENTANE CAS# 540841 (ton/yr) 23	CUMENE CAS# 98828 (ton/yr) 24	O-TOLUIDINE CAS# 95534 (ton/yr) 25	ACRYLAMIDE CAS# 79061 (ton/yr) 26	ANTIMONY COMPOUNDS CAS# (ton/yr) 27	ARSENIC CAS# (ton/yr) 28	not HAP PROPYLENE CAS# 115071 (ton/yr) 29	CYANIDE COMPOUNDS CAS# (ton/yr) 30
20	LPG AREA AND FIELD PIPING										
23	BLENDED AND SHIPPING STORAGE TANKS	1.05	0.09	0.49	0.18	0.86	0.00	0.00	0.01	19.22	0.01
36	WASTE WATER TREATMENT LAND TREATMENT UNIT	0.01	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51	CRUDE UNIT	1.36	0.01	0.60	0.09	0.09	0.00	0.00	0.01	7.78	0.01
52/55	BOILERS/FOUL WATER OXIDIZER	0.00	0.00	0.05	0.01	0.00	0.00	0.00	0.00	2.22	0.00
53	FLUID CATALYTIC CRACKER UNIT	0.00	0.01	0.08	0.06	0.18	0.00	0.00	0.02	14.00	0.02
56	HYDROGENATION PLANT	0.09	0.00	0.02	0.01	0.00	0.00	0.00	0.00	4.40	0.00
57	HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	ALKYLATION PLANT	0.00	0.00	0.44	0.01	0.00	0.00	0.00	0.00	3.41	0.00
59	ISOMERIZATION PLANT	0.05	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.65	0.00
60	ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.24	0.00
61/62	AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.28	0.00
66	DIMERSOL PLANT	0.00	0.00	0.03	0.01	0.00	0.00	0.00	0.00	14.97	0.00
67	COGENERATION PLANT	0.425	0.000	0.104	0.000	0.000	0.000	0.000	0.005	4.326	0.005
	Process Fugitive Summary	2.98	0.13	1.85	0.37	1.14	0.00	0.01	0.05	73.76	0.05
52	BOILER POINT										
67	COGEN POINT										
51	CRUDE POINT										
53	FCC POINT										
59	ISOM POINT										
56	H&H POINT										
57	H&H POINT										
	H&H summary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
62	ACID PLANT CC AND PREHEATER POINT										
60	ASPHALT POINT										
53	FCC STACK	0.2575	0.0221	0.5151	0.1251	0.0589	0.0000	0.0001	0.0001	0.0000	23.5
	WASTEWATER	2.70	0.03	4.93	0.13	0.38	0.00	0.00	0.00	0.00	0.0001
	LOAD RACK	6.45	0.00	1.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MARINE LOADING										
	FLARE										
	GENERATORS - RICE (3)										
	HAPs Summary	12.39	0.18	8.87	0.62	1.58	0.00	0.01	0.05	73.76	23.55
	Table 3.3 SubTotals	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	23.500

HAP Summary

Total speciated VOC emissions (kg/hr)							
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	not HAP 1,2,4-TMBenzene CAS# 95636 (ton/yr) 31	not HAP ETHYLENE CAS# 74851 (ton/yr) 32	Formaldehyde (ton/yr)	POM/PAH (ton/yr)	Total Haps ton/yr	
20	LPG AREA AND FIELD PIPING						
23	BLENDING AND SHIPPING STORAGE TANKS	3.27	1.99			22.300	
	RELIEF SYSTEMS	0.00	1.40			0.003	
36	WASTE WATER TREATMENT LAND TREATMENT UNIT	0.01	0.00			0.236	
51	CRUDE UNIT	0.25	7.10			11.308	
52/55	BOILERS/FOUL WATER OXIDIZER	0.00	2.48			0.513	
53	FLUID CATALYTIC CRACKER UNIT	0.87	3.20			15.675	
56	HYDROGENATION PLANT	0.00	3.62			0.403	
57	HYDROGEN PLANT	0.00	0.00			0.000	
58	ALKYLATION PLANT	0.00	1.14			0.946	
59	ISOMERIZATION PLANT	0.00	0.72			0.344	
60	ASPHALT PLANT	0.00	1.39			0.003	
61/62	AMINE/ACID PLANT	0.00	0.32			0.001	
66	DIMERSOL PLANT	0.00	0.05			0.626	
67	COGENERATION PLANT	0.000	4.828			1.133	
	Process Fugitive Summary	4.40	28.23	0.00	0.00	53.490	
52	BOILER POINT			0.349	0.298	1.935	
67	COGEN POINT			0.506	0.021	0.688	
51	CRUDE POINT			0.208	0.006	0.253	
53	FCC POINT			0.020	0.000	0.494	
59	ISOM POINT			0.002	0.000	0.046	
56	H&H POINT			0.003	0.000	0.000	
57	H&H POINT	0.000	0.000	0.008	0.000	0.074	
	H&H summary	0.000	0.000	0.011	0.000	0.198	
						0.272	
62	ACID PLANT CC AND PREHEATER POINT			0.004	0.000	0.107	
60	ASPHALT POINT					0.000	
53	FCC STACK			0.890		24.390	
	WASTEWATER	0.5224	0.0000			5.623	
	LOAD RACK	16.59	0.00	0.00	0.00	0.00	
	MARINE LOADING	0.00	0.00	0.00	0.00	16.983	
	FLARE					0.002	
	GENERATORS - RICE (3)			2.16E-03	3.00E-04	0.006	
	HAPs Summary	21.51	28.23	1.99	0.33	104.29	
	Table 3.3 SubTotals	0.000	0.000	1.992	0.325	28.192	

PTE DRAIN EMISSIONS  
Worst case speciation is recovered oil for HAPs

	NUMBER OF DRAINS	Note 1		Note 2		TOTAL VOC (lbs/hr)	1	2	3	4	5	6	7
		VOC P-TRAP (lbs/hr)	VOC NO P-TRAP (lbs/hr)	BENZENE	NAPHTHALENE								
COGEN PLANT HL	63	0.001	0.07	0.051	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
BOILER PLANT HL	63	0.001	0.07	6.720	0.032	0.054	0.017	0.025	0.000	0.000	0.000	0.000	0.000
MAINTENANCE HL	63	0.001	0.07	0.070	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FCC RO	63	0.001	0.07	10.710	0.050	0.086	0.027	0.041	0.000	0.000	0.000	0.000	0.000
ALKYLATION LA	63	0.001	0.07	6.440	0.030	0.052	0.016	0.024	0.000	0.000	0.000	0.000	0.000
ISOMERIZATION LA	63	0.001	0.07	3.290	0.015	0.026	0.008	0.013	0.000	0.000	0.000	0.000	0.000
CRUDE UNIT ANS	63	0.001	0.07	6.794	0.032	0.054	0.017	0.026	0.000	0.000	0.000	0.000	0.000
H2/ H2M HL	63	0.001	0.07	3.430	0.016	0.027	0.009	0.013	0.000	0.000	0.000	0.000	0.000
DIMERSOL DIMATE	63	0.001	0.07	3.710	0.017	0.030	0.009	0.014	0.000	0.000	0.000	0.000	0.000
ACID PLANT LA	63	0.001	0.07	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
EFFLUENT RO	63	0.001	0.07	1.400	0.007	0.011	0.004	0.005	0.000	0.000	0.000	0.000	0.000
TANK FARM/LFG RO	63	0.001	0.07	5.950	0.011	0.048	0.015	0.023	0.000	0.000	0.000	0.000	0.000
ASPHALT HL	63	0.001	0.07	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
				49		0	0	0	0	0	0	0	0
				TOTAL ANNUAL (LBS)		425429	808	2000	3403	1064	1617	939	0
				TOTAL ANNUAL (TONS)		213	0.404	1.000	1.702	0.532	0.808	0.000	0.000

	8	9	10	11	12	13	14	15	16	17	18	19	20	21
	TOLUENE	1,3-BUTADIENE	n-HEXANE	ANILINE	CRESOL MIXTURE	PHENOL	STYRENE	METHANOL	NICKEL	LEAD	HCL	PERCHLOROETHYLENE	CYCLOHEXANE	
	0.000	0.000	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	0.066	0.043	0.000	0.095	0.000	0.097	0.005	0.000	0.000	0.000	0.000	0.000	0.000	0.024
	0.001	0.000	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	0.105	0.069	0.000	<b>0.042</b>	0.000	0.155	0.009	0.000	0.000	0.000	0.000	0.000	0.000	0.037
	0.063	0.041	0.000	0.091	0.000	0.093	0.005	0.000	0.000	0.000	0.000	0.000	0.000	0.023
	0.032	0.021	0.000	0.047	0.000	0.048	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.012
	0.067	0.043	0.000	0.096	0.000	0.099	0.005	0.000	0.000	0.000	0.000	0.000	0.000	0.024
	0.034	0.022	0.000	0.049	0.000	0.050	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.012
	0.036	0.024	0.000	0.053	0.000	0.054	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.013
	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	0.014	0.009	0.000	0.020	0.000	0.020	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.005
	0.058	0.038	0.000	0.084	0.000	0.086	0.005	0.000	0.000	0.000	0.000	0.000	0.000	0.021
	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	0	0	0	1	0	1	0	0	0	0	0	0	0	0
	4169	2723	0	5073	4	6169	340	0	0	0	0	0	0	1489
	2.085	1.361	0.000	2.537	0.002	3.084	0.170	0.000	0.000	0.000	0.000	0.000	0.000	0.745



	22	23	24	25	26	27	28	29	30	31	32	
	BIPHENYL	2,2,4 TRIMETHYLPENTANE	CUMENE	O-TOLUIDINE	ACRYLAMIDE	ANTIMONY COMPOUNDS	ARSENIC	PROPYLENE	CYANIDE COMPOUNDS	1,2,4-TRI-Benzene	ETHYLENE	HYDROGEN SULFIDE
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.002	0.047	0.011	0.011	0.005	0.000	0.000	0.000	0.000	0.000	0.048	0.000	0.001
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.003	0.075	0.018	0.018	0.009	0.000	0.000	0.000	0.000	0.000	0.076	0.000	0.001
0.002	0.045	0.011	0.011	0.005	0.000	0.000	0.000	0.000	0.000	0.046	0.000	
0.001	0.023	0.006	0.006	0.003	0.000	0.000	0.000	0.000	0.000	0.023	0.000	
0.002	0.048	0.012	0.012	0.005	0.000	0.000	0.000	0.000	0.000	0.048	0.000	
0.001	0.024	0.006	0.006	0.003	0.000	0.000	0.000	0.000	0.000	0.024	0.000	0.000
0.001		0.006	0.006	0.003	0.000	0.000	0.000	0.000	0.000	0.026	0.000	
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
0.000	0.010	0.002	0.002	0.001	0.000	0.000	0.000	0.000	0.000	0.010	0.000	0.000
0.002	0.042	0.010	0.010	0.005	0.000	0.000	0.000	0.000	0.000	0.042	0.000	0.001
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0	0	0	0	0	0	0	0	0	0	0	0	0
128	2978	723	723	340	0	0	0	0	0	3021	0	29
0.064	1.489	0.362	0.362	0.170	0.000	0.000	0.000	0.000	0.000	1.510	0.000	0.012

AP-42 HAPs listing for FO and FQ Combustion

EF AP-42 Table 1.3-11 for FO combustion

Metal	EF (lb/1000 Gal)	Crude Oil	Boilers	Crude Oil	Boilers	Crude Oil	Boilers	Crude Oil	Boilers
		lb/yr	lb/yr	lb/yr	lb/yr	lb/yr	lb/yr	lb/yr	lb/yr
Antimony	0.0025	9,771,736	14,011,620	51.30	73.56	0.00	0.00	0.00	0.00
Barium	0.0000	9,771,736	14,011,620	12.80	18.50	0.00	0.00	0.00	0.00
Beryllium	0.0000	9,771,736	14,011,620	0.00	0.00	0.00	0.00	0.00	0.00
Bismuth	0.0000	9,771,736	14,011,620	0.00	0.00	0.00	0.00	0.00	0.00
Chromium	0.0000	9,771,736	14,011,620	0.00	0.00	0.00	0.00	0.00	0.00
Chromium (VI)	0.0000	9,771,736	14,011,620	0.00	0.00	0.00	0.00	0.00	0.00
Cobalt	0.0002	9,771,736	14,011,620	2.43	3.47	0.00	0.00	0.00	0.00
Copper	0.0000	9,771,736	14,011,620	58.83	84.35	0.00	0.00	0.00	0.00
Fluorine	0.0000	9,771,736	14,011,620	0.00	0.00	0.00	0.00	0.00	0.00
Lead	0.0015	9,771,736	14,011,620	29.32	42.03	0.00	0.00	0.00	0.00
Manganese	0.0000	9,771,736	14,011,620	1.10	1.59	0.00	0.00	0.00	0.00
Mercury	0.0000	9,771,736	14,011,620	0.00	0.00	0.00	0.00	0.00	0.00
Nickel	0.0000	9,771,736	14,011,620	625.71	893.08	0.00	0.00	0.00	0.00
Nickel (hex)	0.0000	9,771,736	14,011,620	1.44	2.06	0.00	0.00	0.00	0.00
Selenium	0.0000	9,771,736	14,011,620	6.87	9.87	0.00	0.00	0.00	0.00
Vanadium	0.0180	9,771,736	14,011,620	1.07	1.53	0.00	0.00	0.00	0.00
Zinc	0.02910	9,771,736	14,011,620	0.00	0.00	0.00	0.00	0.00	0.00

EF AP-42 Table 1.3-6 for FO combustion

Organic/Other HAPs	EF (lb/1000 Gal)	Crude Oil	Boilers	Crude Oil	Boilers	Crude Oil	Boilers	Crude Oil	Boilers
		lb/yr	lb/yr	lb/yr	lb/yr	lb/yr	lb/yr	lb/yr	lb/yr
Acetylene	0.000140	9,771,736	14,011,620	2.08	3.00	0.00	0.00	0.00	0.00
Ethylbenzene	0.000036	9,771,736	14,011,620	0.62	0.89	0.00	0.00	0.00	0.00
Formaldehyde	see below	9,771,736	14,011,620	11.04	15.83	0.01	0.01	0.00	0.00
Naphthalene	0.000000	9,771,736	14,011,620	60.58	86.87	0.00	0.00	0.00	0.00
1,1,1-Trichloroethane	0.000000	9,771,736	14,011,620	1.07	1.53	0.00	0.00	0.00	0.00
Toluene	0.000000	9,771,736	14,011,620	1.07	1.53	0.00	0.00	0.00	0.00
o-xylene	0.0001080	9,771,736	14,011,620	1.07	1.53	0.00	0.00	0.00	0.00
meta-xylene	0.0001080	9,771,736	14,011,620	1.07	1.53	0.00	0.00	0.00	0.00
PCMs	see below								

EF AP-42 Table 1.3-8 for FO combustion

Organic/Other HAPs	EF (lb/1000 Gal)	Crude Oil	Boilers	Crude Oil	Boilers	Crude Oil	Boilers	Crude Oil	Boilers
		lb/yr	lb/yr	lb/yr	lb/yr	lb/yr	lb/yr	lb/yr	lb/yr
Formaldehyde	0.00250	9,771,736	14,011,620	415.30	595.49	0.02	0.03	0.00	0.00
PCMs	0.00120	9,771,736	14,011,620	11.73	16.81	0.00	0.00	0.00	0.00

EF Gas Turbine AP-42 Table 1.1-4 for Distillate combustion

Metal	EF (lb/MMBtu)	Crude Oil	Crude Oil	Crude Oil	Crude Oil
		lb/yr	lb/yr	lb/yr	lb/yr
Aluminum	0.0000	1,000,284	11.00	0.00	0.00
Beryllium	0.0000	1,000,284	0.31	0.00	0.00
Chromium	0.0000	1,000,284	0.00	0.00	0.00
Cadmium	0.0000	1,000,284	0.00	0.00	0.00
Lead	0.0000	1,000,284	11.00	0.00	0.00
Manganese	0.0000	1,000,284	790.22	0.4	0.4
Mercury	0.0000	1,000,284	1.20	0.00	0.00
Nickel	0.0000	1,000,284	4.50	0.00	0.00
Selenium	0.0000	1,000,284	25.01	0.00	0.00

EF Gas Turbine AP-42 Table 1.1-4 for Distillate combustion

Organic	EF (lb/MMBtu)	Crude Oil	Crude Oil	Crude Oil	Crude Oil
		lb/yr	lb/yr	lb/yr	lb/yr
1,3-Butadiene	0.00002	1,000,284	18.00	0.00	0.00
Benzene	0.00006	1,000,284	55.02	0.00	0.00
Formaldehyde	0.00028	1,000,284	280.08	0.1	0.1
1,1,1-Trichloroethane	0.00000	1,000,284	0.00	0.00	0.00
PAN	0.00004	1,000,284	40.01	0.00	0.00

EF Gas Turbine AP-42 Table 1.1-3 for FO Combustion

Organic	EF (lb/MMBtu)	Crude Oil	Crude Oil	Crude Oil	Crude Oil
		lb/yr	lb/yr	lb/yr	lb/yr
1,3-Butadiene	0.00000	1,001,826.25	0.00	0.00	0.00
Benzene	0.00000	1,001,826.25	0.00	0.00	0.00
Acetone	0.00001	1,001,826.25	6.60433	0.00	0.00
Benzene	0.00001	1,001,826.25	12.36311	0.00	0.00
Ethylbenzene	0.00003	1,001,826.25	30.02164	0.00	0.00
Formaldehyde	0.00071	1,001,826.25	792.66764	0.4	0.4
Naphthalene	0.00000	1,001,826.25	3.94150	0.00	0.00
PAH	0.00000	1,001,826.25	2.72724	0.00	0.00
Polycyclic aromatic hydrocarbons	0.00000	1,001,826.25	2.72724	0.00	0.00
Toluene	0.00013	1,001,826.25	131.16031	0.1	0.1
Xylene	0.00016	1,001,826.25	68.04328	0.0	0.0

EF AP-42 Table 1.4-4 FQ Combustion  
 double counted for FO

AP-42 HAPs Rating for FGD and FGD Combustion

Organics	EF (lb/MMBtu)	Boilers	Cogenation Units	FCC Furnace	Isom Furnace	Hydrogen Manufacturing Furnace	Hydrogenation Furnace	Acid Plant preheater	Asphalt Furnace	Total FGD Combustion
Benzene	2.10E-03	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzofuran	0.000000									
Benzylalcohol	0.000170	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzonitrile	0.001100	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzophenone	0.001000	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzothiazole	0.000040	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzotrifluoride	0.000000									
Benzyl alcohol	0.000000									
Benzylamine	0.000000									
Benzylidene chloride	0.001000	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzylidene diethylamine	0.000240	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzylidene dimethylamine	0.000000									
Benzylidene diethylamine	0.000000									

AP-42 Table 1-A-3 FGD COMBUSTION

Organics	EF (lb/MMBtu)	Boilers	Cogenation Units	FCC Furnace	Isom Furnace	Hydrogen Manufacturing Furnace	Hydrogenation Furnace	Acid Plant preheater	Asphalt Furnace	Total FGD Combustion
Benzene	2.10E-03	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzofuran	0.000000									
Benzylalcohol	0.000170	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzonitrile	0.001100	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzophenone	0.001000	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzothiazole	0.000040	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzotrifluoride	0.000000									
Benzyl alcohol	0.000000									
Benzylamine	0.000000									
Benzylidene chloride	0.001000	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzylidene diethylamine	0.000240	1,368.56	893.52	1,787.33	49.06	210.24	78.84	43.36	48.18	5,073.6
Benzylidene dimethylamine	0.000000									
Benzylidene diethylamine	0.000000									

AP-42 Emission Factors, Table 3.3: Uncontrolled Diesel Engines

Organics	EF (lb/MMBtu)	Boilers	Cogenation Units	FCC Furnace	Isom Furnace	Hydrogen Manufacturing Furnace	Hydrogenation Furnace	Acid Plant preheater	Asphalt Furnace	Total FGD Combustion
Organics	EF (lb/MMBtu)	Boilers	Cogenation Units	FCC Furnace	Isom Furnace	Hydrogen Manufacturing Furnace	Hydrogenation Furnace	Acid Plant preheater	Asphalt Furnace	Total FGD Combustion
Benzene	0.000023	6,531E-07	8.15	9224.20	4.61					
Benzofuran	0.000000									
Benzylalcohol	0.000009	2.862E-07	4.01	4043.62	2.02					
Benzonitrile	0.000285	2.862E-07	2.85	2817.68	1.41					
Benzophenone	0.000284	0.00001600	23.35	23307.43	12.15					
Benzothiazole	0.0000391	2.717E-08	0.38	388.57	0.19					
Benzotrifluoride	0.00118	0.00000000	11.57	11668.19	5.83					
Benzyl alcohol	0.000187	5.369E-07	7.52	7583.02	3.79					
Benzylamine	0.0000225	6.473E-08	0.81	814.51	0.40					
Benzylidene chloride	0.000168	1.176E-07	1.65	1650.95	0.83					
Benzylidene diethylamine	0.0000848	5.936E-08	0.83	838.38	0.42					

Note: 7,000 Btu/lb-H<sub>2</sub> was used to convert from lb/MMBtu to lb/bo-hr as noted in AP-42  
 \*1,008 hours were used for Max Operation per year.

**20 -LPG ref Fugitives**

**POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS  
AREA 20 LPG Refrigeration SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE**

FCC VOC Em	lb/hr	ton/yr	using EPA data		Delta
			lb/hr	ton/yr	
Compressors	None	N/A			
Connectors	0.1530	0.6699	0.1530	0.6699	0.00
PRVs	0.0000	0.0000			
Pumps	None	N/A			
Valves	2.2631	9.9126			
Drains	incl in 20 B&S Fugitives				
TOTALS	2.42	10.58			

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 20 (VALVES)

## 20 - B&S Fugitives

### POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS AREA 20 B&S + non LDAR LPG SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE

<b>FCC VOC Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Compressors	5.5968	24.5140
Connectors	6.1062	26.7451
PRVs	8.1312	35.6147
Pumps	14.2454	62.3950
Valves	63.5694	278.4338
Drains	<b>5.95</b>	<b>26.0610</b>
<b>TOTALS</b>	103.60	453.76

## 23 - Relief Fugitives

### POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 23

No LDAR program active in Hydrogen. Standard AP-42 emission factors apply.

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 23

Date of last revision 3/12/02

H&H VOC Emissions	lb/hr	ton/yr
Valves	3.15	13.8083
Connections	0.12	0.5311
Pumps	0.00	0.0000
Compressors	0.00	0.0000
PRVs	0.00	0.0000
Drains	Included in FCC process drain count	
TOTALS	3.27	14.34

**36 - WW Fugitives**

**POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS**  
**AREA 36 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE**  
 Calculated for 2002 reporting year 9/18/2001  
 Date of last revision  
 Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
 removed 10% growth factor due to no changes since 1993.

FCC VOC Emissions	lb/hr	ton/yr	using API data		using EPA data		Delta
			lb/hr	ton/yr	lb/hr	ton/yr	
Compressors	None	N/A					
Connectors	0.0087	0.0382	0.0085	0.0373	0.0087	0.0382	0.00
PRVs	0.0774	0.3392					
Pumps	0.0620	0.2715					
Valves	0.2147	0.9404					
Drains	1.4	6.1320	2016 Update				
TOTALS	1.76	7.72					

## 51 - Crude Fugitives

### POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS AREA 51 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE

FCC VOC Emissions	using API data		using EPA data		Delta
	lb/hr	ton/yr	lb/hr	ton/yr	
Valves	35.0765	153.6351			
Connections	3.6068	15.7978	1.0099	4,4234	-11.37
Pumps	5.1295	22.4673			
Compressors	1.3992	6.1285			
PRVs	1.5488	6.7837	1.549	6.7837	0.00
Drains	<b>6.794</b>	<b>29.7577</b>	<b>2016 Update</b>		
<b>TOTALS</b>	53.55	234.57			



**5255-FWO Fugitives**

**POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS**

**2002 FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 52/55**

**No LDAR program active in Hydrogen. Standard AP-42 emission factors apply.**

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 52

Date of last revision 3/14/02

<b>FWO and Boilers VOC Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Valves	6.09	26.6726
Connections	0.10	0.4355
Pumps	0.00	0.0000
Compressors	0.00	0.0000
PRVs	0.00	0.0000
Drains	<b>6.72</b>	<b>29.4336</b>
<b>TOTALS</b>	<b>12.91</b>	<b>56.54</b>

2016 Update

## 53 - FCC Fugitives

### POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS

AREA 53 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE

Calculated for 2002 reporting year

Date of last revision 9/18/2001

Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
removed 10% growth factor due to no changes since 1993.

FCC VOC Emissions	using API data			using EPA data		
	lb/hr	ton/yr	Delta	lb/hr	ton/yr	Delta
Checkvalves	1.2876	5.6399		1.29	5.65	
Control Valves	0.8440	3.6969		0.84	3.70	
Fittings	0.6067	2.6571	0.01	0.61	2.66	0.01
Flanges	0.7046	3.0859	-0.63	0.70	3.09	0.01
PRVs	1.7600	7.7088		3.87	16.99	9.29
Pumps	4.7718	20.9005		4.77	20.94	
Valves	40.7179	178.3444		38.18	167.56	
Drains	10.71	46.9098	2016 Update			
TOTALS	61.40	268.94		50.26	220.61	

**56 - H&H Fugitives**

**POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS**

**2002 FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 56**

**No LDAR program active in Hydrogenation. Standard AP-42 emission factors apply.**

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 56 FUG CALC

Date of last revision 3/5/02

<b>H&amp;H VOC Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Valves	15.62	68.3950
Connections	0.45	1.9570
Pumps	0.25	1.0985
Compressors	0.00	0.0000
PRVs	0.00	0.0000
Drains	<b>3.43</b>	<b>15.0234</b>
<b>TOTALS</b>	<b>19.74</b>	<b>86.47</b>

15.0234 2016 Update

**57 - H&H Fugitives**

**POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS**

**2002 FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 57**

**No LDAR program active in Hydrogen. Standard AP-42 emission factors apply.**

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 57 FUG CALC

Date of last revision 3/12/02

<b>H&amp;H VOC Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Valves	6.04	26.4712
Connections	0.50	2.2021
Pumps	0.25	1.0985
Compressors	0.00	0.0000
PRVs	1.06	4.6253
Drains	included in 56 - H&H Fugitives	
<b>TOTALS</b>	<b>7.85</b>	<b>34.40</b>

**58 - Alky Fugitives**

**POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS**  
**AREA 58 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE**  
 Calculated for 2002 reporting year  
 Date of last revision 9/18/2001  
 Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
 removed 10% growth factor due to no changes since 1993.

FCC VOC Emissions	lb/hr	ton/yr	using EPA data		Delta
			lb/hr	ton/yr	
Valves	31.9300	139.8533			
Connections	2.9689	13.0037	2.9689	13.0037	0.00
Pumps	4.7702	20.8935			
Compressors	1.3992	6.1285			
PRVs	0.0000	0.0000			
Drains	6.44	28.2072	2016 Update		
TOTALS	47.51	208.09			

**59 - Isom Fugitives**

**POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS**

**2002 FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 59**

**No LDAR program active in Isom. Standard AP-42 emission factors apply.**

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 59 FUG CALC

Date of last revision 3/11/02

<b>Isom VOC Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Valves	21.60	95
Connections	0.82	4
Pumps	2.21	10
Compressors	0.00	0
PRVs	0.00	0
Drains	<b>3.29</b>	<b>14</b>
<b>TOTALS</b>	<b>27.92</b>	<b>122</b>

14 2016 Update

## 62 - Acid Fugitives

### POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS

#### 2002 FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 62

**No LDAR program active in Asphalt Plant. Standard AP-42 emission factors apply.**

From FUGITIVE EMISSION CALCULATION SPREADSHEET - AREA 62 FUG CALC

Date of last revision 3/14/02

<b>H&amp;H VOC Emissions</b>	<b>lb/hr</b>	<b>ton/yr</b>
Valves	0.72	3.1360
Connections	0.03	0.1171
Pumps	0.00	0.0000
Compressors	0.00	0.0000
PRVs	0.00	0.0000
Drains	0	0.0000
<b>TOTALS</b>	0.74	3.25

0.0000 2016 Update

## 66 - Dimersol Fugitives

**POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS**  
**AREA 66 SPECIATED VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE - Dimersol**  
 Calculated for 2002 reporting year  
 Date of last revision 9/18/2001  
 Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
 removed 10% growth factor due to no changes since 1993.

Dimersol VOC Emissions	using API/EPA data			using EPA data		
	lb/hr	ton/yr	Delta	lb/hr	ton/yr	Delta
Checkvalves	0.0187	0.0820				
Control Valves	0.0797	0.3491				
Fittings	0.2305	1.0094	0.00	0.2305	1.0115	0.00
Flanges	0.3537	1.5490	0.00	0.3537	1.5522	0.00
PRVs	1.9200	8.4096		4.224	18.540	10.13
Pumps	0.7854	3.4401				
Valves	1.2900	5.6501				
Drains	<b>3.71</b>	<b>16.2498</b>	<b>2016 Update</b>			
TOTALS	8.39	36.74				



## 67 - Cogen Fugitives

### POTENTIAL TO EMIT NON-LDAR FUGITIVE EMISSIONS AREA 67 VOC EMISSIONS (TON/YEAR) BY COMPONENT TYPE

Calculated for 2002 reporting year

Date of last revision 9/18/2001

Revised leak rates based on average leak data from LDAR program FOR 2002 YEAR.  
removed 10% growth factor due to no changes since 1993.

Cogen VOC Emissions	using EPA data				
	lb/hr	ton/yr	lb/hr	ton/yr	Delta
Compressors	1.3992	6.1285			
Connectors	0.6954	3.0457	0.6954	3.0457	0.00
PRVs	None	N/A			
Pumps	0.5016	2.1970			
Valves	11.6694	51.1119			
Drains	0.051	0.2234	2016 Update		
TOTALS	14.32	62.71			

# Loadrack

Product Loaded	S	P	M	T	L <sub>L</sub> (lb/10 <sup>3</sup> )	Throughput (10 <sup>3</sup> gal)	Throughput (10 <sup>3</sup> bbl)	Emission (ton/yr)	Stream ID
Marine on-loading	--	--	--	--	2.6	151200	3,600	196.56	3
<b>HOURLY Marine loading</b>	--	--	--	--	2.6	336	8	873.60	3
Marine off-loading						536550	12,775	268.28	44

## 2002 Loading Emission Calculations

Motor Gasoline	0.5	8.27	66	537	6.3	306600		970.75	47
Aviation Gas	0.5	5.22	60	537	3.6	1993		3.62	50
Diesel	0.5	0.0143	130	537	0.0	122640		1.32	6
Jet Fuel	0.5	0.205	130	537	0.3	183960		28.44	51

Table 3.13 S

### load rack

$$L_L = 12.46 \cdot \text{SPM/T}$$

S = 0.5 saturation factor from AP-42 Table 5.2-1 for submerged truck loading

P = true vapor pressure of liquid loaded psia from TANKS4.0 run

M = molecular weight of vapors lb/lb mole from TANKS4.0 run

T = temperature °R (°F+460), mean temperature data taken from TANKS4.0 for Barbers Point (77.°F)

PTE for VOC 1004.13

	bbl/yr	bbl/day
Motor Gasoline	7300000	20000
Aviation Gasoline	47450	130
Diesel	2920000	8000
Jet fuel	4380000	12000

Motor Gasoline: 7,300,000 barrels per any rolling twelve (12) month period;  
 Aviation Gasoline: 47,450 barrels per any rolling twelve (12) month period;  
 Diesel: 2,920,000 barrels per any rolling twelve (12) month period; and  
 Jet fuel: 4,380,000 barrels per any rolling twelve (12) month period.

Total:

14,647,450  
 6.15E+08 gal/yr

Detailed Summary

Summary of potential emissions from the Chevron-Hawaii refinery

Equipment Description/Emission Source	Annual Process Rate	Process Rate Units	Type of Fuel Fired	Fuel Usage Bbls/yr or MSCF/yr	% sulfur content by weight	Heating value	Units	Total Year Emissions						
								PM10	SO2	CO	NO2	VOC	Ph	
Boilers F-5201	220	MMBTU/Year	Total Fuel Gas Total Fuel Oil	333,610 bbl/yr 1,374,567 MSCF/yr	0.0160 0.5			7.12 54.75	25.32 549.96	32.50 35.03	159.34 224.10	5.16 5.32	0.00 0.01	
Boilers F-5202, F-5203	180.6	MMBTU/Year	Total Fuel Gas Total Fuel Oil	1,529,552 MSCF/yr 243,870 bbl/yr	0.0160 0.5			5.10 40.01	18.46 401.94	16.40 25.60	116.16 163.85	3.76 3.89	0.00 0.01	
Boilers F-5202, F-5203	180.6	MMBTU/Year	Total Fuel Gas Total Fuel Oil	1,529,552 MSCF/yr 243,870 bbl/yr	0.0160 0.5			5.10 40.01	18.46 401.94	16.40 25.60	116.16 163.85	3.76 3.89	0.00 0.01	
All Integritably fired							Total Boiler	134.72	1353.83	88.23	551.88	13.31	0.03	
Cogeneration Units - K-6703 K-6701, K-6702, K-6703 permi limit NOx - 14.4 lb/hr, 67 ppm permi limit CO - 4.3 lb/hr, 25 ppm	182 76	MMBTU/Year		319,240 bbl/yr 1,236,000 MSCF/yr	0.03	4757.819 MBTU/bbl								
Cogeneration Units - K-6703 K-6701, K-6702, K-6703	36.6 76	MMBTU/Year	Fuel Gas	693,520 MSCF/yr	0.0160	1154.90 BTUSCF	Total Cogen	11.72	27.92	52.48	193.16	2.34	0.01	
Crude Furnace - F-5103	151.5 151.5 159075	MMBTU/Year	Fuel Oil Fuel Gas Pilot Fuel Gas	232,650 bbl/yr 1,388 MSCF/yr 1,263,943 MSCF/yr	0.45 0.0160 0.0160		Total Energy	148.50	1381.79	139.72	745.04	15.45	0.03	
Crude Furnace - F-5153	62.5 62.5	MMBTU/Year	Fuel Oil Fuel Gas Pilot Fuel Gas	573 MSCF/yr 521,429 MSCF/yr	0.45 0.0160			39.42						
FCC Furnace - F-5300	61	MMBTU/Year	Fuel Gas Inherently low S fuel gas	525,600 MSCF/yr	0.0160			2.00	7.10	22.08	13.14	1.45	0.00013	
FCC Startup Air Heater	52	MMBTU/Year			0.0035			0.11	0.06	1.13	1.95	0.15		
Isom Furnace - F-5930	4	MMBTU/Year	Total Fuel Gas	49,056 MSCF/yr	0.0160			0.19	0.66	2.06	2.45	0.13	0.00001	
Isom Furnace - F-5950	1.6	MMBTU/Year												
Hydrogen Manufacturing (urnace - F-5700 Hydrogen (urnace - F-5600	24.3 9	MMBTU/Year	Fuel Gas Fuel Gas	210,240 MSCF/yr 78,840 MSCF/yr	0.0160 0.0160			0.80 0.30	2.84 1.07	8.63 3.31	10.51 3.94	0.58 0.22	0.00005 0.00002	
Acid Plant combustion chamber - F-6200	8	MMBTU/Year	Fuel Gas	70,916 MSCF/yr	0.0160			0.27	0.96	2.98	3.55	0.20	0.00002	
Acid Plant preheater - F-6262	5.1	MMBTU/Year	Fuel Gas	43,362 MSCF/yr	0.0160			0.16	0.59	1.63	2.17	0.12	0.00001	
Amine (urnace - F-6003	5.7	MMBTU/Year	Fuel Gas	48,180 MSCF/yr	0.0160			0.19	0.65	2.02	2.41	0.13	0.00001	
FCC Stack	22,000	lb/day Feed				replace with stack limit		175.2	333.35	499.32	265.07	14.67		
Cloning tower	2,275,940	Gallons/Year						3.24				9.20		
Acid plant absorber stack	110.0	tons/Day							1405.25					
Catalyst transfer	924	tons/Year												
Wastewater treatment Ca(OH) <sub>2</sub>	84000	Gallons/Year												
Process fugitives	84000	Gallons/Year												
Load Stack	615182300	Gallons/Year												
Tanks														
Marine Loading	3600	8605/year												
Refinery Flares														
Generators														
<b>Total Criteria Pollutants</b>								<b>374.7</b>	<b>3935.3</b>	<b>823.8</b>	<b>1614.4</b>	<b>3418.3</b>	<b>1.4</b>	

## Area Descrip

### REFINERY PROCESS AREAS

AREA NUMBER	AREA DESCRIPTION
20	LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS
23	RELIEF SYSTEMS
36	WASTE WATER TREATMENT LAND TREATMENT UNIT
51	CRUDE UNIT
52/55	BOILERS/FOUL WATER OXIDIZER
53	FLUID CATALYTIC CRACKER UNIT
56	HYDROGENATION PLANT
57	HYDROGEN PLANT
58	ALKYLATION PLANT
59	ISOMERIZATION PLANT
60	ASPHALT PLANT
61/62	AMINE/ACID PLANT
66	DIMERSOL PLANT
67	COGENERATION PLANT

## Component Counts

### COMPONENT COUNTS

AREA NO	AREA DESCRIPTION	SERVICE	COMPONENT TYPE				
			VALVES	FLANGES	PUMPS	COMPRESSORS	
20	LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	ALL	2421	11432	58	4	32
23	RELIEF SYSTEMS	ALL	53	220	0	0	0
36	WASTE WATER TREATMENT LAND TREATMENT UNIT	ALL	246	335	12	0	2
51	CRUDE UNIT	ALL	1403	6558	29	1	4
52/55	BOILERS/FOUL WATER OXIDIZER	ALL	103	181	0	0	0
53	FLUID CATALYTIC CRACKER UNIT	ALL	1908	2452	33	0	12
56	HYDROGENATION PLANT	ALL	422	812	1	2	4
57	HYDROGEN PLANT	ALL	166	914	1	0	4
58	ALKYLATION PLANT	ALL	1180	5821	21	1	0
59	ISOMERIZATION PLANT	ALL	570	1493	9	0	0
60	ASPHALT PLANT	ALL	53	236	0	0	0
61/62	AMINE/ACID PLANT	ALL	12	49	0	0	0
66	DIMERSOL PLANT	ALL	974	1272	21	0	12
67	COGENERATION PLANT	ALL	253	1264	2	1	0
<b>TOTAL</b>		ALL	9765	33039	187	9	71

Note: For summary purposes, Both connectors and fittings have been grouped under the category of flanges

## Fugitive VOC Summary

### REFINERY PROCESS AREAS FUGITIVE EMISSIONS

AREA NUMBER	AREA DESCRIPTION	FUGITIVE VOCs TON/YR
20	LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	464.3
23	RELIEF SYSTEMS	14.3
36	WASTE WATER TREATMENT LAND TREATMENT UNIT	7.7
51	CRUDE UNIT	234.6
52/55	BOILERS/FOUL WATER OXIDIZER	56.5
53	FLUID CATALYTIC CRACKER UNIT	268.9
56	HYDROGENATION PLANT	86.5
57	HYDROGEN PLANT	34.4
58	ALKYLATION PLANT	208.1
59	ISOMERIZATION PLANT	122.3
60	ASPHALT PLANT	
61/62	AMINE/ACID PLANT	3.3
66	DIMERSOL PLANT	36.7
67	COGENERATION PLANT	62.7
	<b>TOTAL PROCESS AREAS FUGITIVE EMISSIONS</b>	<b>1600.4</b>

## Calculation Methods

### Boiler Calculations - Data requirements

from PHD:

52F4107.PV - Fuel oil to boilers in bbl

52F4124.PV - Fuel gas to boilers in SCF

53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

from Lab:

%sulfur

### AP-42 Emission Factors used

**Fuel Oil** Used AP-42 for Boiler >100MMBtu, tangential firing,  
Table 1.3-1 for NOx, CO, SO2, and PM  
used Table 1.3-3 for VOC, Table 1.3-11 for Pb  
 $PM = 9.19 * \%S + 3.22 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $SO_2 = \%S * 157 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $CO = 5 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $NO_x = 32 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $VOC = .76 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$   
 $Pb = 1.51E-3 / 1000 \text{ gal} * \text{fuel use bbl/yr} * 42 \text{ gal/bbl} * \text{ton}/2000 \text{ lb}$

**Fuel Gas** Used AP-42 for tangential firing, Table 1.4-1 for NOx  
and CO, used Table 1.4-2 VOC and PM. Used mass  
balance for SO2  
 $PM = 7.6 \text{ lb PM} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $SO_2 = (S \text{ ppm} * 64/379) \text{ lb SO}_2 / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $CO = 24 \text{ lb CO} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $NO_x = 170 \text{ lb NO}_x / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $CO = 24 \text{ lb CO} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $VOC = 5.5 \text{ lb VOC} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$   
 $Pb = 0.0005 \text{ lb Pb} / \text{MMSCF fuel} * \text{fuel use MSCF} * (\text{MMSCF}/1000 \text{ MSCF}) * \text{ton}/2000 \text{ lb}$

### Cogeneration Calculation - Data Requirements

from PHD:

67A8032A.PV, 67A8032B.PV, 67A8032C.PV - emission rate for NOx in lb/hr

53A201.PV - Fuel gas H2S concentration in ppm

from H2S Quarterly report spreadsheet copy the uptime hours already calculated for the cogeneration units

from Lab:

BTU for LSR

BTU for F/G

from CEMS:

total annual fuel consumption rates for F/G for both turbine and HSRG

### AP-42 Emission Factors used

LSR/HSR

Used AP-42 Stationary Gas Turbines, Table 3.1-1 for CO, and 3.1-2a for PM, Pb and VOC and  
use mass balance for SO2  
 $CO = 7.6E-2 \text{ lb CO} / \text{MMBtu} * \text{fuel use bbl/yr} * \text{heating value MBtu/ bbl} * \text{MMBtu}/1000 \text{ Mbtu} * \text{ton}/2000 \text{ lb}$   
 $PM = 1.2E-2 \text{ lb PM} / \text{MMBtu} * \text{fuel use bbl/yr} * \text{heating value MBtu/ bbl} * \text{MMBtu}/1000 \text{ Mbtu} * \text{ton}/2000 \text{ lb}$   
 $VOC = 4.1E-4 \text{ lb VOC} / \text{MMBtu} * \text{fuel use bbl/yr} * \text{heating value MBtu/ bbl} * \text{MMBtu}/1000 \text{ Mbtu} * \text{ton}/2000 \text{ lb}$   
 $Pb = 1.4E-5 \text{ lb Pb} / \text{MMBtu} * \text{fuel use bbl/yr} * \text{heating value MBtu/ bbl} * \text{MMBtu}/1000 \text{ Mbtu} * \text{ton}/2000 \text{ lb}$   
 $SO_2 = (1.01 * \%S) \text{ lb SO}_2 / \text{MMBtu} * \text{fuel use bbl/yr} * \text{heating value MBtu/ bbl} * \text{MMBtu}/1000 \text{ Mbtu} * \text{ton}/2000 \text{ lb}$

**Fuel Gas** Used AP-42 Stationary Gas Turbines, Table 3.1-2a for PM and VOC and use mass balance for  
SO2. Used AP-42 Natural Gas Combustion, Table 1.4-1 for NOx and CO

## Calculation Methods

$CO = 24 \text{ lb/MMSCF} \cdot \text{fuel use MSCF/yr} \cdot \text{MMSCF}/1000\text{MSCF} \cdot 1 \text{ ton}/2000\text{lb}$

$PM_{10} = 6.6E-3 \text{ lb PM}_{10}/\text{MMBtu} \cdot \text{fuel use MSCF/yr} \cdot \text{heating value Btu/SCF} \cdot 1000 \text{ SCF/MMSCF} \cdot \text{MMBtu}/1e6 \text{ Btu}$

$VOC = 2.1E-3 \text{ lb VOC}/\text{MMBtu} \cdot \text{fuel use MSCF/yr} \cdot \text{heating value Btu/SCF} \cdot 1000 \text{ SCF/MMSCF} \cdot \text{MMBtu}/1e6 \text{ Btu} \cdot$   
 $SO_2 = .94\%S \text{ lb SO}_2/\text{MMBtu} \cdot \text{fuel use MSCF/yr} \cdot \text{heating value Btu/SCF} \cdot 1000 \text{ SCF/MMSCF} \cdot \text{MMBtu}/1e6 \text{ Btu} \cdot$

NOX = for 2000 total lb/hr recorded on PHD

$NO_x = 170 \text{ lb/MMSCF} \cdot \text{fuel use MSCF/yr} \cdot \text{MMSCF}/1000\text{MSCF} \cdot 1 \text{ ton}/2000\text{lb}$

### Crude Furnace Calculations - Data requirements

from PHD:

51F464.PV - total fuel oil to boilers in bbl

51F471.PV - total fuel gas to boilers in MSCF

53A201.PV - Fuel gas H<sub>2</sub>S concentration in ppm

need to apportion f/o to furnace by size 71% (151.5/(151.5+62.5)) to F5103 and 29% (62.5/(151.5+62.5)) to F5153

from Lab:

F/O %sulfur

AP-42 Emission Factors used for the 151.5 MMBTU furnace

Fuel Oil Used AP-42 for Boiler >100MMBtu, normal firing,  
Table 1.3-1 for NO<sub>x</sub>, CO, SO<sub>2</sub>, and PM  
used Table 1.3-3 for VOC, Table 1.3-11 for Pb  
 $PM = 9.19\%S + 3.22/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$   
 $SO_2 = \%S \cdot 157/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$   
 $CO = 5/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$   
 $NO_x = 40/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$   
 $VOC = .76/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$   
 $Pb = 1.51E-3/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$

Fuel Gas Used AP-42 for large >100 boilers, uncontrolled, Table  
1.4-1 for NO<sub>x</sub> and CO, used Table 1.4-2 VOC, Pb,  
and PM. Used mass balance for SO<sub>2</sub>  
 $PM = 7.6 \text{ lb PM} / \text{MMSCF fuel} \cdot \text{fuel use MSCF} \cdot (\text{MMSCF}/1000 \text{ MSCF}) \cdot \text{ton}/2000 \text{ lb}$   
 $SO_2 = (S \text{ ppm} \cdot 64/379) \text{ lb SO}_2/\text{MMSCF} \cdot \text{fuel use MSCF} \cdot (\text{MMSCF}/1000 \text{ MSCF}) \cdot \text{ton}/2000 \text{ lb}$   
 $NO_x = 140 \text{ lb NO}_x / \text{MMSCF fuel} \cdot \text{fuel use MSCF} \cdot (\text{MMSCF}/1000 \text{ MSCF}) \cdot \text{ton}/2000 \text{ lb}$   
 $CO = 84 \text{ lb CO} / \text{MMSCF fuel} \cdot \text{fuel use MSCF} \cdot (\text{MMSCF}/1000 \text{ MSCF}) \cdot \text{ton}/2000 \text{ lb}$   
 $VOC = 5.5 \text{ lb VOC} / \text{MMSCF fuel} \cdot \text{fuel use MSCF} \cdot (\text{MMSCF}/1000 \text{ MSCF}) \cdot \text{ton}/2000 \text{ lb}$   
 $Pb = 0.0005 \text{ lb Pb} / \text{MMSCF fuel} \cdot \text{fuel use MSCF} \cdot (\text{MMSCF}/1000 \text{ MSCF}) \cdot \text{ton}/2000 \text{ lb}$

AP-42 Emission Factors used for the 62.5 MMBTU furnace

Fuel Oil Used AP-42 for Boiler <100MMBtu, normal firing,  
Table 1.3-1 for NO<sub>x</sub>, CO, SO<sub>2</sub>, and PM  
used Table 1.3-3 for VOC, Table 1.3-11 for Pb  
 $PM = 10/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$   
 $SO_2 = \%S \cdot 157/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$   
 $CO = 5/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$   
 $NO_x = 55/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$   
 $VOC = .28/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$   
 $Pb = 1.51E-3/1000 \text{ gal} \cdot \text{fuel use bbl/yr} \cdot 42 \text{ gal/bbl} \cdot \text{ton}/2000 \text{ lb}$



## Calculation Methods

**Fuel Gas** Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NOx and CO, used Table 1.4-2 VOC,  
Pb, and PM. Used mass balance for SO2

PM=7.6 lb PM /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb  
SO2=(S ppm \* 64/379) lb SO2/MMSCF \*fuel use MSCF (MMSCF/1000 MSCF) \* ton/2000 lb  
NOx=50 lb NOx /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb  
CO=84 lb CO /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb  
VOC=5.5 lb VOC /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb  
Pb=0.0005 lb Pb /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb

### **FCC Furnace**

from PHD:

53F4101.PV - total fuel gas to boilers in MSCF

53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

**Fuel Gas** Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NOx and CO, used Table 1.4-2 VOC  
and PM. Used mass balance for SO2

PM=7.6 lb PM /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb  
SO2=(S ppm \* 64/379) lb SO2/MMSCF \*fuel use MSCF (MMSCF/1000 MSCF) \* ton/2000 lb  
NOx=50 lb NOx /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb  
CO=84 lb CO /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb  
VOC=5.5 lb VOC /MMSCF fuel \*fuel use MSCF\* (MMSCF/1000 MSCF) \* ton/2000 lb

### **Alky/Isom Furnace**

from PHD:

58F403.PV - total fuel gas to Alky/Isom in MSCFH

53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

EF same as FCC Furnace

**Fuel Gas** Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NOx and CO, used Table 1.4-2 VOC  
and PM. Used mass balance for SO2

### **H2 Manufacturing/Hydrogenation furnace**

from PHD:

56FC420.PV - total fuel gas to Hydrogenation in SCFH

57F428.PV - total fuel gas to Hydrogen Manufacturing in MSCFH

53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

EF same as FCC Furnace

**Fuel Gas** Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NOx and CO, used Table 1.4-2 VOC  
and PM. Used mass balance for SO2

### **Acid Plant Combustion Chamber**

from PHD:

62FC111.PV - total fuel gas to Acid Combustion Chamber in MSCFH

53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

EF same as FCC Furnace

**Fuel Gas** Used AP-42 for small <100 boilers, uncontrolled,

### **Acid Plant Preheater**

from PHD:

no tag for fuel consumption:

## Calculation Methods

first calculate up time, then multiply by heating value BTU/SCF \* 5.1 MBTU/Hr Design Value = MSCF/yr  
53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

EF same as FCC Furnace

Fuel Gas Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NOx and CO, used Table 1.4-2 VOC  
and PM. Used mass balance for SO2

### **Asphalt Furnace**

from PHD:

20F200.PV - total fuel gas to Asphalt in SCFH

53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

EF same as FCC Furnace

Fuel Gas Used AP-42 for small <100 boilers, uncontrolled,  
Table 1.4-1 for NOx and CO, used Table 1.4-2 VOC  
and PM. Used mass balance for SO2

### **FCC Stack**

from PHD:

53FC101.PV - FCC feedrate MBPD

53A201.PV - Fuel gas H2S concentration in ppm (same tag as cogen)

need TPY catalyst value from 2001catinv.xls - see Steph Christie

from Lab:

%sulfur for VGO - TOTFD

Used 1996 and 1999 Source test data for CO and VOC emission rate

VOC emission based on average emission rate of 1.71 lb/hr

VOC= 1.71 lb/hr \* op hrs/yr \* ton/2000 lb

CO emission based on average emission rate of 73 lb/hr from

CO= 73 lb/hr \* op hrs/yr \* ton/2000 lb

Used AP-42 for FCC w/ESP, Table 5.1-1 for NOx

NOx=71 lb NOx /1000 bbl feed \* feed rate bbl/day \* day/24 hr \* 8760 hr/yr\* ton/2000 lb

note annual operation rate already accounted for in the average daily feed rate

SO2 emission rate calculated with %S, density of 310 lb/bbl, 4.5% conversion to coke, 100% of coke converted to SO2

SO2= %S/100\*306 lb/bbl\* annual feed rate bbl/day \* 4.5%conv/100 \* 64/32 \* day/24 hr \* 8760 hr/yr\* ton/2000

calculate weighted average VGO wt lb/bbl from crude slate breakdown from Tad

### **Flare**

from PHD

51FC226.PV - average daily crude unit throughput Mbbl

need to calculate days/year

Used AP-42 for Blowdown systems vapor recovery

and flaring, Table 5.1-1 for NOx, CO, and VOC

NOx=18.9 lb NOx /1000 bbl feed \* crude unit feed rate bbl/day \* n days/yr\* ton/2000 lb

VOC=0.8 lb VOC /1000 bbl feed \* crude unit feed rate bbl/day \* n days/yr\* ton/2000 lb

CO=4.3 lb CO/1000 bbl feed \* crude unit feed rate bbl/day \* n days/yr\* ton/2000 lb

SO2 mass balance F/G to flare and acid plant shutdown data

Pilot F/G (100 SCFH crude, 150, SCFH FCC, 15000 SCFH during acid plant shutdown)

assume 379 SCF/lb mole

## Calculation Methods

flare contribution to total SO<sub>2</sub>

lb SO<sub>2</sub>/MMSCF = 1/379 \* ppm S \* 64

SO<sub>2</sub> = 1/379 \* ppm S \* 64 \* operating hr/yr \* fuel rate SCFH \* MMSCFH/10<sup>6</sup>SCFH

acid plant shutdown contribution

SO<sub>2</sub> emission rate calculated with %S, density of 310 lb/bbl, 35% conversion to coke, 100% of coke converted to SO<sub>2</sub>

SO<sub>2</sub> = %S/100 \* 306 lb/bbl \* annual feed rate bbl/day \* 4.5%conv/100 \* 64/32 \* day/24 hr \* 8760 hr/yr \* ton/2000

**Cooling Tower**

from PHD:

23F401.PV - Cooling tower flowrate Mgpm

Used AP-42, Table 5.1-2 Cooling Towers

VOC = cooling water flow rate gal/min \* 60 \* 0.7 lb VOC/1E6 gal \* 8760 hr/yr \* ton/1998

Used AP-42, Section 13.4 alternative method

Total Drift = circ rate gpm \* manufacturer's drift factor \* 8.34 lb/gal \* 60 min/hr

PM = drift lb/hr \* TDS ppm \* cycles/1e6

**Wastewater treatment**

from PHD:

36FC405.PV - Feed to API Sep gpm

36F200.PV - Storm Bay Flow to API Sep gpm

Used AP-42, Table 5.1-2

VOC = process rate gal/hr \* 0.2 lb VOC /1000 gal \* 8760 hr/yr \* ton/2000 lb

**Acid plant absorber stack**

from PHD:

62FY115.PV - Acid production ton/day

Used AP-42, Table 8.10-1

SO<sub>2</sub> = process rate ton/day \* 40 SO<sub>2</sub>/ton acid \* 365 day/yr \* ton/2000

**Load Rack**

$L_L = 12.46 * SPM/T$

S = 0.5 saturation factor from AP-42 Table 5.2-1 for submerged truck loading

P = true vapor pressure of liquid loaded psia from TANKS4.0 run

M = molecular weight of vapors lb/lb mole from TANKS4.0 run

T = temperature °R (°F+460), mean temperature data taken from TANKS4.0 for Honolulu (77.22°F)

**Marine Loading**

total bbl/yr from the semi annual fuel use report

Used AP-42, Table 5.2-2

Marine loading emission factor = 2.6 lb VOC/1000 gal product transferred from AP-42 Table 5.2-2

**Catalyst Transfer**

from Steph Christie:

2001catinv.xls

Used AP-42, Table 11.24-2 Mineral Processing (Low-moisture ore)

PM = ann process rate ton/yr \* 0.06 lb PM<sub>10</sub> / ton \* ton/2000 lb

Cooling

**COOLING TOWER POTENTIAL TO EMIT EMISSIONS ESTIMATE**

Cooling Water Circulation rate 50000 gpm (Maximum)

Circulation Rate (gpm)	Emission Factor (lb VOC/MM gal)	VOC Emissions	
		(lb/hr)	(tpy)
50000	0.7	2.100	9.20

Circulation Rate (gpm)	Drift Factor (gal drift/gal circulated)	Density (lb/gal)	Time Conversion (min/hr)	Drift (lbs/hr)	Supply Water Concentration (ppmw)	Cycles of Concentration	PM/PM <sub>10</sub> Emissions (lbs/hr)	PM/PM <sub>10</sub> Emissions (tpy)
50000	0.00002	8.34	60	500.40	400.00	3.7	0.74	3.24

TDS ppm = conductivity\*2/3  
Per Matt from Nalco use 600\*2/3

**Cogen Summary**

**COGEN UNITS ONLY**

**SUMMARY OF POTENTIAL TO EMIT EMISSIONS ESTIMATE**

Summary of potential emissions from the Chevron-Hawaii refinery

Equipment Description/Emission Source	Annual Process Rate	Process Rate Units	Type of Fuel Fired	Fuel Usage Bbls/yr or MSCF/yr	Units	% sulfur content by weight	Heating value	Units	Tons/Year Emissions					
									PM10	SO2	CO	NO2	VOC	Pb
<b>TURBINES RUNNING LSR/HSR</b>														
Cogeneration Units - K-6703 K-6701, K-6702, K-6703	192	Bbl/day	LSR/HSR	171,409	bbl/yr	0.03	4757.819	MBTU/bbl	4.9	12.36	31.0	97.86	0.17	0.006
Running at Max Daily Emission rate for 8760 hrs/yr -->				1,997,280	MMBTU/yr	0.03	4757.819	MBTU/bbl	12.0	30.26	75.9	239.67	0.41	0.014
<b>TURBINES RUNNING RFG</b>														
Cogeneration Units - K-6703 K-6701, K-6702, K-6703	38.8	from CEMS lb/hr MSCF/Hr	Fuel Gas	955,500	MSCF/yr	0.0160	1154.90	BTU/SCF	3.6	8.3	11.5	81.2	1.2	0.0
Running at Max Daily Emission rate for 8760 hrs/yr -->				1,019,664	MSCF/yr	0.0160	1154.90	BTU/SCF	3.9	8.9	12.2	86.7	1.2	0.0
72.8		1913184												
<b>HRSGS RUNNING RFG</b>														
Cogeneration Units - K-6703 K-6701, K-6702, K-6703	34	from CEMS lb/hr MSCF/Hr	Fuel Gas	836,100	MSCF/yr	0.0160	1154.90	BTU/SCF	3.2	7.3	10.0	71.1	1.0	0.0
Running at Max Daily Emission rate for 8760 hrs/yr -->				893,520	MSCF/yr	0.0160	1154.90	BTU/SCF	3.4	7.8	10.7	75.9	1.1	0.0
<b>Max Emissions</b>									11.7	27.9	52.5	250.1	2.3	0.006
Running at Max Daily Emission rate for 8760 hrs/yr --> Max Emissions									19.3	46.9	98.9	402.3	2.7	0.014
Using permit limits -->											121.2822	193.158		
13.4879472	<b>POTENTIAL TO EMIT</b>								<b>11.7</b>	<b>27.9</b>	<b>52.5</b>	<b>193.2</b>	<b>2.3</b>	<b>0.006</b>
Permit Limits				26280	uptime hr	Using permit limits -->			121.3	193.158				
				9.23	CO emission rate lb/hr									
				14.7	NOx emission rate lb/hr									

**ALL 3 Turbines**

	lb/hr	Emissions (Tons/year)						
		Hours		Using AP-42 Emission Factors				
		running	running on	CO	NOx	PM10	SO2	VOC
<b>CO</b>		8760	0	19.1	132.1	7.3	16.6	1.2
MAX LSR	9.45	8000	760	21.0	132.8	8.0	18.5	1.2
MAX FG	4.35	7000	1760	23.5	133.7	8.9	20.9	1.1
		6000	2760	26.1	134.5	9.8	23.4	1.0
<b>NOx</b>		5000	3760	28.6	135.4	10.8	25.8	0.9
MAX LSR	30.17	4000	4760	31.2	136.2	11.7	28.2	0.8
MAX FG	31.89	3000	5760	33.7	137.1	12.6	30.7	0.7
		2000	6760	36.3	138.0	13.5	33.1	0.6
<b>PM10</b>		1000	7760	38.8	138.8	14.5	35.6	0.5
MAX LSR	3.5134787	0	8760	41.4	139.7	15.4	38.0	0.4
MAX FG	1.6647191							
		<b>Current Potential To Emit</b>		52.5	193.2	11.7	27.9	2.3
<b>SO2</b>								
MAX LSR	8.680109							
MAX FG	3.7935416							
<b>VOC</b>								
MAX LSR	0.09348							
MAX FG	0.2823038							

<i>Type</i>	<i>Material Code</i>	<i>Worksheet Name</i>	<i>Old Process Number</i>	<i>Revised Process Number</i>
LSFO	923	Fuel Burning	1	1
RFG	553	Fuel Burning	2	2
WSR	127	Fuel Burning	3	3
Petroleum Products	724	Misc	1	4
Process Water	5	Misc	2	5
Sulfuric Acid	329	Misc	3	6
Catalyst	693	Misc	4	7
Wastewater	4	Misc	5	8
VOC's	553	Misc	6	9
Aviation Gas	127	Misc	7	10
Crude Oil	275	Tanks	1	11
RUL	127	Tanks	2	12
Rec. Oil	275	Tanks	3	13
Gasoline	127	Tanks	4	14
LCC	908	Tanks	5	15
Dimate Gasoline	908	Tanks	6	16
Alkylate Gasoline	908	Tanks	7	17
Diesel	58	Tanks	11	18
HCC	908	Tanks		19
Jet-A	864	Tanks		20
Ammonia	599	Fuel Burning		21
Ammonia	635	Misc		22



### Insignificant Activity Emissions Calculation Portable Chemical Containers

Emissions occur during portafeed filling (air pushed out vent). During injection into the process, air is pulled into vent, and no emissions occur.  
VOC Emissions = concentration VOC \* volume vapor discharged during filling \* density VOC \* number of fillings per year per container \* number of containers

0.1337 units conversion, cu ft/gal  
29 MW air  
60 assumed MW of VOC (typical, from Tanks4 program)  
400 gallons container volume  
53.47 cu ft container volume

Calculate vapor density of VOC

0.403 lb/cu ft air density at amb conditions (70F, 1atm)  
0.834 lb/cu ft VOC density = density of air \* (MW VOC / MW air)

VOC Concentration in ventgas

40000 VOC concentration ppmv; assumed = high LEL concentration  
Calculate mass of VOC vented in each container during filling

53.47 cu ft gas vented each fill  
2.14 cu ft VOC vented each fill  
1.78 lb VOC vented each fill

Estimate number of container fillings per year

24 assume fill container twice a month (typical is closer to 1x per month)

Calculate VOC emissions per year per container

42.8 lb VOC/year for each chemical  
0.02 tpy VOC from one container

Estimate number of portable containers

20.0 conservative number of chemicals containers being used (2015 actual was 13)

Sum total VOC from all containers per year

856.1 total lb VOC/year from all chemical containers  
0.4 tpy VOC from chemical containers



Equipment										Emissions										
Source No.	Description	Location	Fuel Type	Hrs of Operation	bhp	EF Basis	Nox lb/hr	ton/yr	MMHC (VOC) lb/hr	ton/yr	CO lb/hr	ton/yr	PM10/PM 5 lb/hr	ton/yr	SO2 lb/hr	ton/yr	CO2e lb/hr	ton/yr	HAPs lb/hr	ton/yr

13	TK Farm FW Pump	EP-2076	B&S	200	370	AP-42	11.47	1.15	0.18	0.02	0.02	2.47	0.25	0.81	0.08	0.75850	0.08	0.00	0.00	0.00
14	TK 352 FW Pump	EP-2077	Boiler	200	460	AP-42	14.26	1.43	0.22	0.02	0.02	3.07	0.31	1.01	0.10	0.94300	0.09	0.00	0.00	0.00
15	LPG Area FW Pump	EP-2088	LPG	200	228	AP-42	7.07	0.71	0.11	0.01	0.01	1.52	0.15	0.50	0.05	0.46740	0.05	0.00	0.00	0.00
16	Brine FW Pump	EP-2083	Acid Pit	200	260	AP-42	8.06	0.81	0.13	0.01	0.01	1.74	0.17	0.57	0.06	0.53300	0.05	0.00	0.00	0.00
17	Emergency Generator	UNL-	Main Gate	200	47	Tier 3	0.31	0.03	0.31	0.03	0.03	0.27	0.03	0.02	0.00	0.00000	0.00	0.00	0.00	0.00
18	Emergency Generator	UNL-	Gate #2	200	47	Tier 3	0.31	0.03	0.31	0.03	0.03	0.27	0.03	0.02	0.00	0.00000	0.00	0.00	0.00	0.00
19	Emergency Generator	UNL-	Firehouse	200	85	Tier 3	0.56	0.06	0.56	0.06	0.06	0.49	0.05	0.03	0.00	0.00000	0.00	0.00	0.00	0.00



**CO Emissions Calculation**  
**CO2 Stripper Vent**  
**Hydrogen Manufacturing, Plant 57**

EPA collected data for CO emissions from hydrogen plant condensate strippers, however, did not finalize an emission factor. Below are calculations of CO emissions from Hawaii Refinery's CO2 stripper using the two sets of emissions data in the EPA reference document.  
 The estimated CO emissions for this source from either method, clearly shows that this source's emissions are less than the insignificant activity threshold of 5 ton/yr CO.

<b>Method 1</b>		
Emission Factor, EF	0.48	EF, lb CO / MMscf H2 . Reference: EPA's "Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations, EP-D-11-084 No. 3-06, April 2015.
Refinery Data	3.6	H2 Produced, MMSCFD . Reference Table 2-1 Updated Renewal
Emission Calculation	$\text{CO, ton/yr} = \text{EF} \cdot \text{H2 Produced} \cdot 365 \text{ days/yr} \div 2000 \text{ lb/ton}$ <div style="border: 1px solid black; display: inline-block; padding: 2px;">0.32</div> CO, ton/yr	

<b>Method 2</b>		
Emission Factor, EF	0.0011	EF, lb CO / mscf methane in feed . Reference: EPA's "Review of Emissions Test Reports for Emissions Factors Development for Flares and Certain Refinery Operations, EP-D-11-084 No. 3-06, April 2015.
Refinery Data	611 0.05 30.6	mscf total feed vol frac methane in feed mscf, Methane Feedrate
Emission Calculation	$\text{CO, ton/yr} = \text{EF} \cdot \text{Methane Feedrate} \cdot 24 \text{ hr/day} \cdot 365 \text{ days/yr} \div 2000 \text{ lb/ton}$ <div style="border: 1px solid black; display: inline-block; padding: 2px;">0.15</div> CO, ton/yr	

**Appendix C**  
**Covered Source Permit Tanks**

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

In reply, please refer to:  
File:

September 30, 2014

**CERTIFIED MAIL**  
**RETURN RECEIPT REQUESTED**  
(7010 3090 0002 5271 7046)

14-778E CAB  
File No. 0088-22

Mr. Alan Davis  
Refinery Manager  
Chevron USA Products Company  
Hawaii Refinery  
91-480 Malakole Street  
Kapolei, Hawaii 96707-1807

Dear Mr. Davis:

**Subject: Amendment of Covered Source Permit (CSP) No. 0088-01-C  
Minor Modification Application No. 0088-22  
Storage Tank 104  
Chevron USA Products Company  
Petroleum Refinery  
Located At: 91-480 Malakole Street, Kapolei, Oahu  
Date of Expiration: June 27, 2011 (this date is to be revised upon issuance  
of the renewal for CSP No. 0088-01-C)**

In accordance with Hawaii Administrative Rules, Chapter 11-60.1, and pursuant to your application for a Minor Modification dated June 19, 2014 the Department of Health hereby amends CSP No. 0088-01-C issued to Chevron USA Products Company. The amendment allows Tank 104 to be used as a swing tank for crude oil and recovered oil (crude water draw and crude sump). The amendment consists of the following:

1. Revised Attachment II(B), Special Condition No. C.3 as follows:
  3. Storage tanks identified in Special Condition No. A.1.b of this Attachment shall only store crude oil, except Storage Tanks 104 (T-104) and 113 (T-113) may store crude oil or recovered oil.  
  
(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)
2. Revised Attachment II(F), Special Condition No. A.1.g as follows:
  - g. Crude Water Draw/Recovered Oil Tanks identified as Storage Tanks T-104 and T-113.
3. Revised Attachment II(F), Special Condition No. B.2 as follows:
  2. The API Separators, Benzene Recovery Unit, Recovered Oil Sump, Skim Oil Tank, Wastewater Surge Tank, Recovered Oil Tank, and Crude Water Draw/Recovered Oil Tanks are subject to the following federal requirements:

- a. 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP):
  - i. Subpart A, General Provisions; and
  - ii. Subpart FF, National Emission Standard for Benzene Waste Operations.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.180; 40 CFR §61.01, §61.340)<sup>1</sup>

4. Revised Attachment II(F), Special Condition No. C.11 as follows:

11. The Wastewater Surge Tank, Recovered Oil Tank, and Crude Water Draw/Recovered Oil Tanks shall be equipped with an external floating roof meeting the requirements of 40 CFR §60.112b(a)(2).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.351)<sup>1</sup>

5. Revised Attachment II(F), Special Condition No. D.23 as follows:

23. For the Wastewater Surge Tank, Recovered Oil Tank, and Crude Water Draw/Recovered Oil Tanks, the permittee shall comply with the recordkeeping requirements in 40 CFR §60.115b.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.356)<sup>1</sup>

6. Revised Attachment II(F), Special Condition No. E.11 as follows:

11. For the Wastewater Surge Tank, Recovered Oil Tank, and Crude Water Draw/Recovered Oil Tanks, the permittee shall comply with the reporting requirements in 40 CFR §60.115b.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180, 40 CFR §61.357)<sup>1</sup>

All other permit conditions issued with CSP No. 0088-01-C on February 22, 1999, and amended on January 22, 2002, April 16, 2002, March 3, 2003, June 28, 2006, April 24, 2007, August 13, 2007, November 8, 2007, July 22, 2008, September 11, 2009, November 4, 2009, and April 22, 2013, shall not be affected and shall remain valid.

If there are any questions regarding these matters, please contact Mr. Darin Lum of the Clean Air Branch at (808) 586-4200.

Sincerely,



STUART YAMADA, P.E., CHIEF  
Environmental Management Division

DL:nn

c: CAB Monitoring Section

**ATTACHMENT I(B): SPECIAL CONDITIONS  
COVERED SOURCE PERMIT NO. 0088-01-C  
PETROLEUM STORAGE TANKS**

**Amended Date: August 13, 2007**

**Expiration Date: June 27, 2011**

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the Covered Source Permit encompasses the following equipment and associated appurtenances:
  - a. Twenty-Seven (27) Gasoline Intermediates and Finished Products Storage Tanks
    - i. One (1) - 272,000 bbl external floating roof storage tank identified as Tank 111;
    - ii. Two (2) - 19,200 bbl external floating roof storage tanks identified as Tanks 232 and 235;
    - iii. Two (2) - 19,000 bbl external floating roof storage tanks identified as Tanks 233 and 273;
    - iv. Four (4) - 38,000 bbl external floating roof storage tanks identified as Tanks 236, 237, 255, and 256;
    - v. One (1) - 9,500 bbl external floating roof storage tanks identified as Tank 251;
    - vi. One (1) - 37,000 bbl external floating roof storage tank identified as Tank 252;
    - vii. One (1) - 37,400 bbl external floating roof storage tank identified as Tank 253;
    - viii. One (1) - 33,000 bbl external floating roof storage tank identified as Tank 254;
    - ix. Three (3) - 29,000 bbl external floating roof storage tanks identified as Tanks 257, 258, and 262;
    - x. Three (3) - 41,000 bbl external floating roof storage tanks identified as Tanks 264, 265, and 266;
    - xi. One (1) - 23,000 bbl external floating roof storage tank identified as Tank 269;
    - xii. One (1) - 36,000 bbl external floating roof storage tank identified as Tank 271;
    - xiii. Two (2) - 4,700 bbl external floating roof storage tanks identified as Tanks 162 and 163;
    - xiv. One (1) - 235,000 bbl external floating roof storage tank identified as Tank 109;
    - xv. One (1) - 9,500 bbl external floating roof storage tank converted to an internal floating roof storage tank identified as Tank 249; and
    - xvi. Two (2) - 5,000 bbl external floating roof storage tanks converted to internal floating roof storage tanks identified as Tanks 250 and 275.
  - b. Eight (8) Crude Oil Storage Tanks
    - i. One (1) - 149,000 bbl external floating roof storage tank identified as Tank 104;
    - ii. Two (2) - 237,000 bbl external floating roof storage tanks identified as Tanks 105 and 107;
    - iii. Two (2) - 235,000 bbl external floating roof storage tanks identified as Tanks 106 and 108;

- iv. One (1) - 272,000 bbl external floating roof storage tank identified as Tank 110;
- v. One (1) - 23,000 bbl external floating roof storage tank identified as Tank 113; and
- vi. ~~One (1) - 81,250 bbl vertical fixed roof storage tank identified as Tank 152.~~

c. Three (3) Jet Fuel Storage Tanks

- i. One (1) - 50,827 bbl vertical fixed roof storage tank identified as Tank 274;
- ii. One (1) - 38,000 bbl external floating roof storage tank identified as Tank 263; and
- iii. One (1) - 41,000 bbl external floating roof storage tank identified as Tank 267.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each tank. The identification tag or nameplate shall be attached to the tank in a conspicuous location. Information shall also be made available upon request that identifies the capacity, date of construction, serial number or I.D. number and manufacturer of each tank.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

----- **Section B. Applicable Federal Regulations**

1. Each of the storage tanks identified in Section A of this Attachment are subject to the provisions of the following federal regulations:
- a. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),
    - i. Subpart A, General Provisions; and
    - ii. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

For Group 1 storage tanks (all storage tanks except for Storage tanks ~~152, 263, 267, and 274~~), the permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements, at the first tank degassing and cleaning activity after August 18, 1998, or before August 18, 2005, whichever comes first. The major requirements of these standards are detailed in **Section G - 40 CFR Part 63, Subpart CC Requirements** of this Attachment. Group 1 storage tanks shall comply with Sections C through G below. Group 2 storage tanks (Storage tanks ~~152, 263, 267 and 274~~) shall comply with Sections C through F below.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174, 40 CFR §63.640, §63.646)<sup>1</sup>



### Section C. Operational and Emissions Limitations

1. The true vapor pressure of the volatile organic liquid stored in each of the storage tanks identified in Special Condition A.1.a. of this Attachment shall not be greater than or equal to 11.0 pounds per square inch absolute (psia).

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

2. The true vapor pressure of the volatile organic liquid stored in Storage Tanks 152 and 274 shall not be greater than or equal to 1.5 pounds per square inch absolute (psia).

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

- ~~3. Storage tanks identified in Special Condition No. A.1.b. of this Attachment shall only store crude oil.~~

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

- ~~4. Storage tanks identified in Special Condition No. A.1.c. of this Attachment shall only store jet fuel.~~

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

5. Each storage tank identified in Section A of this Attachment, except for Storage Tanks 152 and 274, shall be equipped with a floating roof which will rest on the surface of the liquid contents and be equipped with a closure seal or seals to close the space between the roof edge and tank wall.

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

6. All tank gauging and sampling devices for each of the storage tanks identified in Section A of this Attachment, except for Storage Tanks 152 and 274, shall be gas-tight except when tank gauging or sampling is taking place.

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

7. Each storage tank identified in Section A of this Attachment shall be equipped with a permanent submerged fill pipe.

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

8. The permittee may increase the storage capacities of Storage Tanks 105 through 111 by 12% to the capacities listed below, provided that no new applicable requirement is triggered by such action and the permittee has installed the seal requirements pursuant to 40 CFR

Part 63, Subpart CC. The permittee must obtain prior written approval of the Department of Health and must demonstrate that a modification or reconstruction under NSPS or a PSD review would not be triggered.

Storage Tanks 105 and 107 - 265,440 bbl  
Storage Tanks 106, 108 and 109 - 263,200 bbl  
Storage Tanks 110 and 111 - 304,640 bbl

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

#### **Section D. Monitoring and Recordkeeping Requirements**

1. The permittee shall maintain a record of the volatile organic liquid stored, the period of storage, and the maximum true vapor pressure (psia) of that liquid for each storage tank identified in Section A of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

2. The permittee shall keep readily accessible records showing the dimensions of each storage tank identified in Section A of this Attachment and an analysis showing the capacity of the storage tank. This record shall be kept as long as the storage tank retains Group 1 or Group 2 status and is in operation. If a storage tank is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources, a record of any data, assumptions, and procedures used to make this determination shall be retained. The permittee shall use the Group 1 and Group 2 storage vessel definitions in 40 CFR §63.641.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; 40 CFR §63.646, §63.654)<sup>1</sup>

3. Records shall be retained for five (5) years in a permanent form suitable for inspection and made available to the Department of Health or their representatives upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; 40 CFR §63.646, §63.654)<sup>1</sup>

#### **Section E. Notification and Reporting Requirements**

1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons

per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due **within sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Forms: External/Internal Floating Roof Petroleum Storage Tank, and Fixed Roof Petroleum Storage Tank** or equivalent forms, shall be used in reporting emissions.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions 16, 17, and 25, respectively. These notifications shall include, but not be limited to:
  - a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - c. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report **within five (5) working days any deviations from permit requirements**, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

#### 4. Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department of Health and EPA Region 9, the attached **Compliance Certification Form** pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall be submitted **within ninety (90) days after** the end of each calendar year, and shall be signed and dated by an authorized representative.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. The permittee shall notify the Department of Health at least **thirty (30) days** prior to:
  - a. Changing the volatile organic liquid stored in any of the storage tanks identified in Section A.1.a. of this Attachment; and
  - b. Increasing the storage capacity of Storage Tanks 105 thru 111 in accordance with Special Condition No. C.8. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

#### **Section F. Agency Notifications**

Any document (including reports) required to be submitted by this Covered Source permit shall be in accordance with Attachment I, Standard Condition No. 29.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

#### **Section G. 40 CFR Part 63. Subpart CC Requirements**

##### **1. Operational and Emission Limitations**

- a. Group 1 storage tanks consisting of an external floating roof converted to an internal floating roof (petroleum storage tanks 249, 250 and 275) shall comply with the provisions of 40 CFR §63.646 including the following:
  - i. The internal floating roof shall rest or float on the liquid surface inside a storage tank that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage tank is completely emptied and degassed or subsequently emptied and refilled. When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as soon as practical.
  - ii. The petroleum storage tanks shall be equipped with one of the following closure devices between the wall of the storage tank and the edge of the internal floating roof:

- (1) A foam or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal);
  - (2) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage tank and the edge of the internal floating roof. The lower seal may be vapor mounted, but both must be continuous; or
  - (3) A mechanical shoe seal.
- iii. If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.
  - iv. Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seals exceeds the manufacturer's recommended setting.
  - v. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.
- b. Group 1 storage tanks with an external floating roof (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, **111**, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271 and 273) shall comply with the provisions of 40 CFR §63.646 including the following:
- i. Each external floating roof shall be equipped with a primary seal and secondary seal to close the space between the wall of the storage tank and roof edge. The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. The primary and secondary seals shall completely cover the annular space between the edge of the floating roof and tank wall in a continuous fashion, except during the inspections required by Special Condition No. G.2.b. of this Attachment.
  - ii. The floating roof is to be floating on the liquid at all times (i.e., off the roof leg supports), except during initial fill until the floating roof is lifted off leg supports and during those intervals when the storage tank is completely emptied and degassed or when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the floating roof is resting on the leg supports shall be continuous and shall be accomplished as soon as practical.
  - iii. If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

- iv. Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seals exceeds the manufacturer's recommended setting.
- v. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.646)<sup>1</sup>

## 2. Monitoring and Recordkeeping Requirements

- a. For the Group 1 storage tanks consisting of an external floating roof converted to an internal floating roof (petroleum storage tanks 249, 250 and 275), the permittee shall demonstrate compliance by complying with the requirements of 40 CFR §63.120(a)(1) through (a)(7) including the following:
  - i. The permittee shall visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), according to the schedule specified below:
    - (1) For storage tanks equipped with a single-seal system, the permittee shall perform the inspections specified below:
      - (a) Visually inspect the internal floating roof and the seal through manholes and roof hatches on the fixed roof at least once every **twelve (12) months** after initial fill, or at least once every **twelve (12) months** after the compliance date specified in Special Condition No. B.1. of this Attachment; and
      - (b) Visually inspect the internal floating roof, the seal, gaskets, slotted membranes, and sleeve seals (if any) each time the storage tank is emptied and degassed, and at least once every **ten (10) years** after the compliance date specified in Special Condition No. B.1. of this Attachment.
    - (2) For storage tanks equipped with a double-seal system, the permittee shall perform either one of the inspections indicated below:
      - (a) Visually inspect the internal floating roof, the primary seal, the secondary seal, gaskets, slotted membranes, and sleeve seals (if any) each time the storage tank is emptied and degassed and at least once every **five (5) years** after the compliance date specified in Special Condition No. B.1. of this Attachment; or

- (b) Visually inspect the internal floating roof and the secondary seal through manholes and roof hatches on the fixed roof at least once every **twelve (12) months** after initial fill, or at least once every **twelve (12) months** after the compliance date specified in Special Condition No. 8.1. of this Attachment, and
  - (c) Visually inspect the internal floating roof, the primary seal, the secondary seal, gaskets, slotted membranes, and sleeve seals (if any) each time the vessel is emptied and degassed and at least once every **ten (10) years** after the compliance date specified in Special Condition No. 8.1. of this Attachment.
- ii. If during the inspections required by Special Condition Nos. G.2.a.i.(1)(a) or G.2.a.i.(2)(b) of this Attachment, the internal floating roof is not resting on the surface of the liquid inside the storage tank and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached; or there are holes or tears in the seal fabric; or there are visible gaps between the seal and the wall of the storage tank, the permittee shall repair the items or empty and remove the storage tank from service within **forty-five (45) calendar days**. If a failure that is detected during inspections required by Special Condition Nos. G.2.a.i.(1)(a) or G.2.a.i.(2)(b) of this Attachment cannot be repaired within **forty-five (45) calendar days** and if the tank cannot be emptied within **forty-five (45) calendar days**, the permittee may utilize up to 2 extensions of up to **thirty (30)** additional calendar days each. Documentation of a decision to utilize an extension shall include a description of the failure, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the tank will be emptied as soon as practical.
- iii. Except as provided in Special Condition No. G.2.a.iv. of this Attachment, for all the inspections required by Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a), and G.2.a.i.(2)(c) of this Attachment, the permittee shall notify the Department of Health in writing at least **thirty (30) calendar days** prior to the refilling of each storage tank to afford the Department of Health the opportunity to have an observer present.
- iv. If the inspections required by Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a), and G.2.a.i.(2)(c) of this Attachment is not planned and the permittee could not have known about the inspection **thirty (30) calendar days** in advance of refilling the tank, the permittee shall notify the Department of Health at least **seven (7) calendar days** prior to the refilling of the storage tank. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, the notification including the written documentation may be made in writing and sent so that it is received by the Department of Health at least **seven (7) calendar days** prior to refilling.

- v. If during the inspections required by Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a), and G.2.a.i.(2)(c) of this Attachment, the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or the gaskets no longer close off the liquid surface from the atmosphere; or the slotted membrane has more than 10 percent open area, the permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage tank with organic HAP.
  
- b. For Group 1 storage tanks with external floating roofs (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271 and 273), the permittee shall demonstrate compliance by complying with the requirements of 40 CFR §63.120(b)(1) through (b)(10) including the following:
  - i. Except as provided in Special Condition No. G.2.b.vii. of this Attachment, the permittee shall determine the gap areas and maximum gap widths between the primary seal and the wall of the storage tank, and the secondary seal and the wall of the storage tank as follows:
    - (1) Within **ninety (90) calendar days** of installation of the secondary seal, inspection of both the primary and secondary seals; and
    - (2) At least **once every five (5) years** for the primary seal and at least **once per year** for the secondary seal thereafter.
  
  - ii. Except as provided in Special Condition No. G.2.b.vii. of this Attachment, the permittee shall determine gap widths and gap areas in the primary and secondary seals (seal gaps) individually by the procedures described below:
    - (1) Seal gaps, if any, shall be measured at one or more floating roof levels when the roof is not resting on the roof leg supports.
  
    - (2) Seal gaps, if any shall be measured around the entire circumference of the tank in each place where an 0.32 centimeter (1/8 inch) diameter uniform probe passes freely (without forcing or binding against the seal) between the seal and the wall of the storage tank. The circumferential distance of each such location shall also be measured.
  
    - (3) The total surface area of each gap described in Special Condition No. G.2.b.ii.(2) of this Attachment shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.



- iii. The permittee shall add the gap surface area of each gap location for the primary seal and divide the sum by the nominal diameter of the tank. The accumulated area of gaps between the tank wall and the primary seal shall not exceed 212 square centimeters per meter of tank diameter and the width of any portion of any gap shall not exceed 3.81 centimeters (1-1/2 inches).
- iv. The permittee shall add the gap surface area of each gap location for the secondary seal and divide the sum by the nominal diameter of the tank. The accumulated area of the gaps between the tank wall and the secondary seal shall not exceed 21.2 square centimeters per meter of tank diameter and the width of any portion of any gap shall not exceed 1.27 centimeters (1/2 inch). These seal gap requirements may be exceeded during the measurement of primary seal gaps as required by Special Condition No. G.2.b.i. of this Attachment.
- v. The primary seal shall meet the following requirements:
  - (1) Where a metallic shoe seal is in use, one end of the metallic shoe shall extend into the stored liquid and the other end shall extend a minimum vertical distance of 61 centimeters (24 inches) above the stored liquid surface.
  - (2) There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.
- vi. The secondary seal shall meet the following requirements:
  - (1) The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall, except as provided in Special Condition No. G.2.b.iv. of this Attachment.
  - (2) There shall be no holes, tears, or other openings in the seal or seal fabric.
- vii. If the permittee determines that it is unsafe to perform the seal gap measurements required in Special Condition No. G.2.b.i. of this Attachment or to inspect the tank to determine compliance with Special Condition No. G.2.b.v. and G.2.b.vi. of this Attachment because the floating roof appears to be structurally unsound and poses an imminent or potential danger to inspecting personnel, the permittee shall comply with one of the following:
  - (1) The permittee shall measure the seal gaps or inspect the storage tank no later than **thirty (30) calendar days** after the determination that the roof is unsafe, or
  - (2) The permittee shall empty and remove the storage tank from service no later than **forty-five (45) calendar days** after determining that the roof is unsafe. If the tank cannot be emptied within **forty-five (45) calendar days**, the permittee may utilize up to two extensions of up to **thirty (30) additional**

calendar days each. Documentation of a decision to utilize an extension shall include an explanation of why it was unsafe to perform the inspection or seal gap measurement, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the tank will be emptied as soon as practical.

- viii. The permittee shall repair conditions that do not meet the requirements listed in Special Condition Nos. G.2.b.iii., G.2.b.iv., G.2.b.v. and G.2.b.vi. of this Attachment (i.e., failures), no later than **forty-five (45) calendar days** after identification, or shall empty and remove the storage tank from service no later than **forty-five (45) calendar days** after identification. If during seal gap measurements required in Special Condition No. G.2.b.i. of this Attachment or during inspections necessary to determine compliance with Special Condition Nos. G.2.b.v. and G.2.b.vi. of this Attachment a failure is detected that cannot be repaired within **forty-five (45) calendar days** and if the tank cannot be emptied within **forty-five (45) calendar days**, the permittee may utilize up to two extensions of up to **thirty (30) additional calendar days** each. Documentation of a decision to utilize an extension shall include a description of the failure, shall document that alternative storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the tank will be emptied as soon as practical.
- ix. The permittee shall notify the Department of Health in writing **thirty (30) calendar days** in advance of any gap measurements to afford the Department of Health the opportunity to have an observer present.
- x. The permittee shall visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the tank is emptied and degassed.
- (1) If the external floating roof has defects; the primary seal has holes, tears or other openings in the seal or seal fabric; or the secondary seal has holes, tears or other openings in the seal or seal fabric; the permittee shall repair the items as necessary so that none of the conditions specified above exist before filling or refilling the storage tank with organic HAP.
- (2) Except as provided below, for all the inspections required above, the permittee shall notify the Department of Health in writing as least **thirty (30) calendar days** prior to filling or refilling each storage tank with organic HAP to afford the Department of Health the opportunity to inspect the storage tank prior to refilling.
1. (3) If the inspections required above is not planned and the permittee could not have known about the inspection **thirty (30) calendar days** in advance of refilling the tank with organic HAP, the permittee shall notify the Department of Health at least **seven (7) calendar days** prior to refilling of the storage tank.

Take out of service →

1. (3)  
action

Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent so that it is received by the Department of Health at least **seven (7) calendar days** prior to the refilling.

- c. For Group 1 storage tanks consisting of an external floating roof converted to an internal floating roofs (petroleum storage tanks 249, 250 and 275):
  - i. The permittee shall keep a record that each inspection required by Special Condition No. G.2.a. of this Attachment was performed.
- d. For Group 1 storage tanks with external floating roofs (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271 and 273):
  - i. The permittee shall keep records describing the results of the seal gap measurements made in accordance with Special Condition No. G.2.b. of this Attachment. The records shall include the date of the measurement, the raw data obtained in the measurement, and the calculations described in Special Condition Nos. G.2.b.iii. and G.2.b.iv. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.646)<sup>1</sup>

### 3. Notification and Reporting Requirements

- a. The permittee shall submit **semi-annually** written reports to the Department of Health. 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:
  - i. For Group 1 storage tanks consisting of an external floating roof converted to an internal floating roof (petroleum storage tanks 249, 250 and 275):
    - (1) Results of each inspection conducted in accordance with Special Condition No. G.2.a. of this Attachment in which a failure is detected in the control equipment. For storage tanks for which annual inspections are required under Special Condition Nos. G.2.a.i.(1)(a) and G.2.a.i.(2)(b) of this Attachment, the following specifications and requirements apply:
      - (a) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage tank and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears,

or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage tank.

- (b) Reports shall include the date of the inspection, identification of each storage tank in which a failure was detected, and a description of the failure. The report shall also describe the nature of and date the repair was made or the date the storage tank was emptied.
  - (c) If an extension is utilized in accordance with Special Condition No. G.2.a.ii. of this Attachment, the permittee shall, in the next semi-annual report, identify the tank; include the documentation specified in Special Condition No. G.2.a.ii. of this Attachment; and describe the date the storage tank was emptied and the nature of and date the repair was made.
- (2) For storage tanks for which inspections are required under Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a) or G.2.a.i.(2)(c) of this Attachment (i.e., internal inspections), the following specifications and requirements apply:
- (a) A failure is defined as any time in which the internal floating roof has defects; or the the primary seal has holes, tears, or other openings in the seal or seal fabric; or the secondary seal (if one has been installed) has holes, tears or other openings in the seal or the seal fabric; or, for a storage tank that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage tank that is part of a new source, the slotted membrane has more than a 10 percent open area.
  - (b) The report shall include the date of the inspection, identification of each storage tank in which a failure was detected, and a description of the failure. The report shall also describe the nature of and date the repair was made.
- ii. Group 1 storage tanks with external floating roofs (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271 and 273):
- (1) Documentation of the results of each seal gap measurement made in accordance with Special Condition No. G.2.b. of this Attachment in which the seal and seal gap requirements of Special Condition Nos. G.2.b.iii., G.2.b.iv., G.2.b.v. or G.2.b.vi. of this Attachment are not met. The documentation shall include the following information:

- (a) The date of the seal gap measurement;
  - (b) The raw data obtained in the seal gap measurement and the calculations described in Special Condition Nos. G.2.b.iii. and G.2.b.iv. of this Attachment;
  - (c) A description of any seal condition specified in Special Condition Nos. G.2.b.v. or G.2.b.vi. of this Attachment that is not met; and
  - (d) A description of the nature of and date the repair was made, or the date the storage tank was emptied.
- (2) If an extension is utilized in accordance with Special Condition Nos. G.2.b.vii. or G.2.b.viii. of this Attachment, the permittee shall, in the next semi-annual report, identify the tank; include the documentation specified in Special Condition Nos. G.2.b.vii. or G.2.b.viii. of this Attachment, as applicable; and describe the date the tank was emptied and the nature of and date the repair was made.
- (3) Documentation of any failures that are identified during the visual inspections required by Special Condition No. G.2.b.x. of this Attachment.
- (a) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears or other openings in the seal or the seal fabric.
  - (b) Documentation shall include the date of the inspection, identification of each storage tank in which a failure was detected, and a description of the failure. The nature of and the date the repair was made shall also be documented.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.654)<sup>1</sup>

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**Appendix D**  
**40CFR 64.4 Submittal Requirements**

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**APPENDIX D**  
**40CFR 64.4 Submittal Requirements**  
**(Updated)**

The Compliance Assurance Monitoring (CAM) requirements are applicable to the Chevron cogeneration units, identified as K-6701, K-6702 and K-6703. The units already have existing monitoring devices including, fuel oil and fuel gas non-resetting fuel meters, a continuous monitoring system to record the water-to-fuel ratio and a NO<sub>x</sub> Continuous Emission Monitoring system (CEMS) that serves all three cogeneration units sequentially.

Requirements for the operation and maintenance of these systems are already addressed in the existing Covered Source Permit for the refinery. Based on review of 40 CFR 64.4(b)(1), it is anticipated that the NO<sub>x</sub> CEMS is presumptively acceptable to comply with CAM.

However, the facility is still required under Section 64.4 Submittal Requirements to provide information to the Hawaii Department of Health and EPA on the monitoring equipment configuration and operation. Since this monitoring equipment has previously been reviewed by the DOH, a brief response to each of the submittal requirements specified in 40 CFR 64.4 is presented below.

64.4(a)(1) – The indicator to be monitored to demonstrate that the water injection control device is working properly is a NO<sub>x</sub> CEMS. This is an appropriate indicator as the concentration of NO<sub>x</sub> would increase and be detected by the CEMS in the event that the control device is not working properly.

64.4(a)(2) – The range of the NO<sub>x</sub> monitor is zero to 100 ppmv. The covered source maximum emissions limits are 67 and 69 ppmvd, depending on the fuel used by the cogeneration turbines. Chevron has previously submitted data to the Department of Health that indicates the typical value NO<sub>x</sub> emissions from the units are compliant with these limits. The range of the monitor is appropriate to demonstrate compliance under all process operating conditions.

64.4(a)(3) The performance criteria for the monitor are specified in 40 CFR 60.13 and 40 CFR 60 Appendix B. The Covered Source Permit already requires that the monitor be operated consistent with these criteria and specifies the frequency for monitoring.

64.4(a)(4) The performance criteria for the monitor is 40 CFR 60.13 and 40 CFR 60 Appendix B. The covered source permit already requires that the monitor be operated consistent with this criteria and specifies the frequency for monitoring.

64.4(b) No further justification for the proposed elements of the monitoring is required, since as specified in 64.4(b)(2) the monitoring is anticipated to be presumptively acceptable.

64.4 (c) The facility has previously provided to the Department of Health operating parameter data obtained during performance tests.

64.4(d) This requirement is not applicable, since operating data have previously been submitted.

64.4(e) The NO<sub>x</sub> CEMS has already been installed and therefore an implementation plan and schedule are not required.

64.4(f) This requirement is not applicable. The control devices are unique to each emission unit and are not a shared device.

64.49(g) This requirement is not applicable, since the emissions units are only controlled by one "control device" which consists of water injection. As noted in the preamble to the CAM rule low NOx burners are not a control device.

*Update:*

*The following CAM plan is provided for the CatOx Unit.*



**APPENDIX D**  
**40CFR 64.4 Submittal Requirements**  
**Compliance Assurance Monitoring Plan for CatOx Unit (New)**

The Compliance Assurance Monitoring (CAM) requirements are applicable to the Chevron Catalytic Oxidation ("CatOx") Unit and Foul Water Treatment Plant (FWTP) for NOx and VOC emissions. DOH issued a Covered Source Permit amendment November 2, 2015 for the modification and restart of the CatOx Unit to treat offgas from the FWTP. Requirements for the operation and maintenance of this unit are addressed in the amended Attachment II(A): Special Conditions for Miscellaneous Process Unit and Source Operations. Based on review of 40 CFR §64.4(a)(1), it is anticipated that the NOx and NH3 CPMS is presumptively acceptable to comply with CAM for NOx and VOC.

The facility is required under Section 64.4 Submittal Requirements to provide information to the Hawaii Department of Health and EPA on the monitoring equipment configuration and operation. Since the monitoring equipment has previously been reviewed by the DOH, a brief response to each of the submittal requirements specified in 40 CFR §64.4 is presented below.

Emissions Unit: Foul Water Treatment Plant (FWTP) and Catalytic Oxidation ("CatOx") Unit  
Control Devices: VOC: Catalytic Oxidation Unit  
NOx: Selective Catalytic Oxidation

<b>CAM Plan Requirements</b>	
§64.4(a)(1)	The indicators to be monitored to demonstrate that the CatOx Unit and SCR are working properly are one NOx analyzer and one NH3 analyzer Continuous Process Monitoring System (CPMS) downstream of the CatOx Unit.
§64.4(a)(2)	The range of the NOx monitor is zero to 0 - 1100 ppmv. The range of the NH3 monitor is zero to 0 - 300 ppmv. Outlet stack readings will be used to control NH3 injection for NOx reduction. Correlation factors for CO and VOC will be developed during the initial performance test to establish compliance levels.
§64.4(a)(3) and §64.4(a)(4)	The performance criteria for the monitor are specified in 40 CFR§60.13 and 40 CFR 60 Appendix B. The CSP already requires that the monitor be operated consistent with these criteria and specifies the frequency for monitoring.
§64.4(b)	No further justification for the proposed elements of the monitoring is required, since as specified in §64.4(b)(2) the monitoring is anticipated to be presumptively acceptable.
§64.4(c) (d) and (e)	The facility will conduct performance testing and submit the results to DOH per CSP 0088-01-C Attachment II(A)(F) Testing Requirements, requirements 3-10.
§64.4(f)	This requirement is not applicable. The control devices are unique to each emission unit and are not shared.
§64.4(g)	This requirement is not applicable, since the emissions units are only controlled by one control device as described above.

**Appendix E**  
**Hybrid Energy Project Application and Permit**

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***This appendix has been removed from CSP  
0088-01-C Renewal and Update***

# Appendix F

## Alternative Monitoring Plans

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**APPENDIX F**  
**Alternative Monitoring Plans (AMPs)**

Feb 08, 2006 EPA letter approving NSPS J AMP for FWTP offgas stream, Boilers F5201 and F5202

Jan 10, 2007 EPA letter approving NSPS J AMP for FWTP offgas stream, Boiler F5203

Dec 14, 2006 EPA letter approving AMP for an alternative sulfur oxides test method to comply with Subpart J at the FCCU

Nov 09, 2015 Request for NSPS Ja AMP for FWTP offgas stream, CatOx



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IX

75 Hawthorne Street  
San Francisco, CA 94105-3901

FEB 08 2006

Mr. David E. Rogers  
Refinery Manager  
Chevron Products Company  
Hawaii Refinery  
91-480 Malakole St.  
Kapolei, HI 96707-1807

Dear Mr. Rogers:

On December 5, 2005, Chevron Products Company (Chevron) submitted to the United States Environmental Protection Agency (EPA) an Alternative Monitoring Plan (AMP) request for the off-gas stream from the Foul Water Treating Plant (FWTP), which is combusted in the boilers F-5201 and F-5202 at the Chevron Hawaii Refinery (Refinery). The AMP proposes that the FWTP off-gas does not need to be continuously monitored for hydrogen sulfide (H<sub>2</sub>S) content; instead the pH of the FWTP effluent will be maintained at greater than or equal to 9 and the temperature of the FWTP effluent will be maintained at between 210 and 250°F. Samples of the FWTP off-gas will be collected at least twice per year and analyzed for H<sub>2</sub>S content with Sensidyne gas detector tubes. For the reasons proposed by Chevron and outlined below, the United States Environmental Protection Agency (EPA) approves the requested AMP.

Regulatory Background

The Standards of Performance for New Stationary Sources (NSPS) Subpart J (Standards of Performance for Petroleum Refineries) at 40 C.F.R. § 60.104(a)(1) requires the owner or operator of a fuel gas combustion device at a petroleum refinery to burn no refinery fuel gas that contains H<sub>2</sub>S in excess of 230 milligrams per dry standard cubic meter (0.10 grain per dry standard cubic foot). This limit is equivalent to 160 parts per million (ppm) H<sub>2</sub>S. Pursuant to 40 C.F.R. § 60.105(a)(3), the owner or operator of a fuel gas combustion device subject to 40 C.F.R. § 60.104(a)(1) is required to install, calibrate, maintain, and operate a continuous monitoring system (CMS) to monitor and record the concentration by volume of sulfur dioxide emitted to the atmosphere. Alternatively, a CMS to monitor and record the H<sub>2</sub>S in fuel gases before being burned in any fuel gas combustion device may be used. Pursuant to 40 C.F.R. § 60.13(i), after receipt and consideration of written application, the Administrator may approve alternative procedures to any monitoring procedures or requirements of [Part 60].

The EPA issued guidance titled "Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas" (RFG Guidance). The RFG Guidance is divided into four subjects: conditions for approval; data requirements; monitoring schedules for approved alternative plans; and general conditions for approved monitoring plans. Chevron's request for an AMP included the information required by the RFG Guidance:

- a description of the gas stream to be considered including submission of the appropriate piping diagrams indicating the boundaries of the gas streams/system;
- the affected fuel gas combustion device(s) to be considered;
- an identification of the proposed sampling point for the alternative monitoring;
- a statement that there are no sour gas crossover points into the gas stream/system (this should also be shown in the piping diagram);
- an explanation of the conditions that ensures low amounts of sulfur in the gas stream and supporting test results using appropriate H<sub>2</sub>S monitoring.

#### Chevron's Request

Chevron submitted supporting information with the AMP request. This information included a statement that the FWTP off-gas stream is generated from the Refinery's FWTP which consists of a foul water oxidizer, an ammonia stripper, a flash drum and various heat exchangers. Chevron also included a fuel gas system overview drawing indicating the FWTP off-gas and the sampling points for effluent water pH and temperature and FWTP off-gas H<sub>2</sub>S content. Chevron stated that there are no entry or crossover points which would allow sour gases to be combined with the FWTP off-gas that is combusted in the F-5201 and F-5202 boilers. Chevron stated that caustic is injected into the foul water to maintain the effluent pH at greater than or equal to 9. This minimum pH level and the medium temperature range will ensure that H<sub>2</sub>S will not be liberated into the FWTP off-gas. Chevron submitted fourteen consecutive daily sample results using Sensidyne tubes that indicate the H<sub>2</sub>S content of the FWTP off-gas stream never exceeded 0.75 ppm, the detection limit of the Sensidyne tubes, and during these 2 weeks the pH of the effluent was between 9 and 11 and the temperature of the effluent was in the range of 228-242°F. These results are expected to be representative.

Chevron proposed to sample the H<sub>2</sub>S content of the FWTP off-gas using Sensidyne tubes twice weekly for the first six months, then once per quarter for 6 quarters, then twice per year thereafter. If any of these sample results is greater than 81 ppm (one-half of the NSPS Subpart J limit) then Chevron will sample the FWTP off-gas on a daily basis for 7 days. If the average plus 3 standard deviations of these 7 samples is less than 81 ppm then Chevron will report the daily average effluent pH and the recovered off-gas sample results to EPA. If the average plus 3 standard deviations of these 7 samples is greater than or equal to 81 ppm then Chevron will notify EPA and test the off-gas stream daily for a two-week period followed by weekly sampling. The weekly sampling will continue until EPA approves a revised sampling schedule or withdraws approval of this AMP. Additionally, the pH and temperature of the FWTP effluent are both analyzed continuously.

Approval of Chevron's Alternative Monitoring Plan

EPA has reviewed Chevron's request for an AMP and has determined that it includes all of the required information. The FWTP off-gas at the Refinery is inherently low in H<sub>2</sub>S and Chevron has submitted fourteen consecutive days of sample results to support this conclusion. There are also no crossover or entry points that would allow for sour gas to be introduced into the FWTP off-gas stream. Therefore, the Administrator of the EPA, by authority duly-delegated to the undersigned, approves Chevron's request for an AMP.

If you have any questions regarding this approval please contact Charles Aldred, Air Enforcement Office, at (415) 972-3986 or [aldred.charles@epa.gov](mailto:aldred.charles@epa.gov).

Sincerely,



Douglas K. McDaniel  
Chief, Enforcement Office  
Air Division

cc: Wilfred Nagamine, Hawaii Department of Health



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
 REGION IX  
 75 Hawthorne Street  
 San Francisco, CA 94105

JAN 10 2007

Mr. David E. Rogers  
 Refinery Manager  
 Chevron Products Company  
 Hawaii Refinery  
 91-480 Malakole St.  
 Kapolei, HI 96707-1807

Chevron - Hawaii Refinery Date: 1-26-07  
 Hawaii Refinery Manager: TM Kovar X  
 Circulate: \_\_\_\_\_ Copies: \_\_\_\_\_  
 DGEN \_\_\_\_\_ BINL \_\_\_\_\_  
 MAAM X \_\_\_\_\_ CRCA \_\_\_\_\_  
 SCFR \_\_\_\_\_ JACX \_\_\_\_\_  
 MAHE \_\_\_\_\_ JWLE X \_\_\_\_\_  
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Dear Mr. Rogers:

On December 14, 2006, Chevron Products Company (Chevron) submitted to the United States Environmental Protection Agency (EPA) an Alternative Monitoring Plan (AMP) request for the off-gas stream from the Foul Water Treating Plant (FWTP), which is combusted in the boiler F-5203 at the Chevron Hawaii Refinery (Refinery). EPA approved an AMP on February 8, 2006 for the FWTP off-gas when it is combusted in boilers F-5201 and F-5202. The AMP proposes that the FWTP off-gas does not need to be continuously monitored for hydrogen sulfide (H<sub>2</sub>S) content; instead the pH of the FWTP effluent will be maintained at greater than or equal to 9 and the temperature of the FWTP effluent will be maintained at between 210 and 250°F. Samples of the FWTP off-gas will be collected at least twice per year and analyzed for H<sub>2</sub>S content with Sensidyne gas detector tubes. For the reasons proposed by Chevron and outlined below, EPA approves the requested AMP.

Regulatory Background

The Standards of Performance for New Stationary Sources (NSPS) Subpart J (Standards of Performance for Petroleum Refineries) at 40 C.F.R. § 60.104(a)(1) requires the owner or operator of a fuel gas combustion device at a petroleum refinery to burn no refinery fuel gas that contains H<sub>2</sub>S in excess of 230 milligrams per dry standard cubic meter (0.10 grain per dry standard cubic foot). This limit is equivalent to 160 parts per million (ppm) H<sub>2</sub>S. Pursuant to 40 C.F.R. § 60.105(a)(3), the owner or operator of a fuel gas combustion device subject to 40 C.F.R. § 60.104(a)(1) is required to install, calibrate, maintain, and operate a continuous monitoring system (CMS) to monitor and record the concentration by volume of sulfur dioxide emitted to the atmosphere. Alternatively, a CMS to monitor and record the H<sub>2</sub>S in fuel gases before being burned in any fuel gas combustion device may be used. Pursuant to 40 C.F.R. § 60.13(i), after receipt and consideration of written application, the Administrator may approve alternative procedures to any monitoring procedures or requirements of [Part 60].

The EPA issued guidance titled "Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas" (RFG Guidance). The RFG Guidance is divided into four subjects:



conditions for approval; data requirements; monitoring schedules for approved alternative plans; and general conditions for approved monitoring plans. Chevron's request for an AMP included the information required by the RFG Guidance:

- a description of the gas stream to be considered including submission of the appropriate piping diagrams indicating the boundaries of the gas streams/system;
- the affected fuel gas combustion device(s) to be considered;
- an identification of the proposed sampling point for the alternative monitoring;
- a statement that there are no sour gas crossover points into the gas stream/system (this should also be shown in the piping diagram);
- an explanation of the conditions that ensures low amounts of sulfur in the gas stream and supporting test results using appropriate H<sub>2</sub>S monitoring.

#### Chevron's Request

Chevron submitted supporting information with the AMP request. This information included a statement that the FWTP off-gas stream is generated from the Refinery's FWTP which consists of a foul water oxidizer, an ammonia stripper, a flash drum and various heat exchangers.

Chevron also included a fuel gas system overview drawing indicating the FWTP off-gas and the sampling points for effluent water pH and temperature and FWTP off-gas H<sub>2</sub>S content. Chevron stated that there are no entry or crossover points which would allow sour gases to be combined with the FWTP off-gas that is combusted in the F-5203 boiler. Chevron stated that caustic is injected into the foul water to maintain the effluent pH at greater than or equal to 9. This minimum pH level and the medium temperature range will ensure that H<sub>2</sub>S will not be liberated into the FWTP off-gas. Chevron submitted fourteen consecutive daily sample results using Sensidyne tubes that indicate the H<sub>2</sub>S content of the FWTP off-gas stream never exceeded 0.75 ppm, the detection limit of the Sensidyne tubes, and during these 2 weeks the pH of the effluent was between 9 and 11 and the temperature of the effluent was in the range of 228-240°F. These results are expected to be representative.

Chevron proposed to sample the H<sub>2</sub>S content of the FWTP off-gas using Sensidyne tubes twice weekly for the first six months, then once per quarter for 6 quarters, then twice per year thereafter. If any of these sample results is greater than 81 ppm (one-half of the NSPS Subpart J limit) then Chevron will sample the FWTP off-gas on a daily basis for 7 days. If the average plus 3 standard deviations of these 7 samples is less than 81 ppm then Chevron will report the daily average effluent pH and the recovered off-gas sample results to EPA. If the average plus 3 standard deviations of these 7 samples is greater than or equal to 81 ppm then Chevron will notify EPA and test the off-gas stream daily for a two-week period followed by weekly sampling.

The weekly sampling will continue until EPA approves a revised sampling schedule or withdraws approval of this AMP. Additionally, the pH and temperature of the FWTP effluent are both analyzed continuously.

Approval of Chevron's Alternative Monitoring Plan

EPA has reviewed Chevron's request for an AMP and has determined that it includes all of the required information. The FWTP off-gas at the Refinery is inherently low in H<sub>2</sub>S and Chevron has submitted fourteen consecutive days of sample results to support this conclusion. There are also no crossover or entry points that would allow for sour gas to be introduced into the FWTP off-gas stream. Therefore, the Administrator of the EPA, by authority duly-delegated to the undersigned, approves Chevron's request for an AMP.

If you have any questions regarding this approval please contact Charles Aldred, Air Enforcement Office, at (415) 972-3986 or [aldred.charles@epa.gov](mailto:aldred.charles@epa.gov).

Sincerely,



Douglas K. McDaniel  
Chief, Enforcement Office  
Air Division

cc: Wilfred Nagamine, Hawaii Department of Health



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
RESEARCH TRIANGLE PARK, NC 27711

DEC 14 2006

OFFICE OF  
AIR QUALITY PLANNING  
AND STANDARDS

**MEMORANDUM**

**SUBJECT:** ChevronTexaco Request to Use an Alternative Sulfur Oxides Test Method to Comply with Subpart J

**FROM:** Conniesue B. Oldham, Group Leader  
Measurement Technology Group, AQAD (E143-02)

*Robin R. Heyell for CBO*

**TO:** Charles Aldred  
Air Division, EPA Region 9

As requested in your November 16, 2006, correspondence, we have reviewed ChevronTexaco's proposal to use ASTM D4294-02 as an alternative to the methods referenced in 40 CFR 60.106(j) at their Kapaoloi, Hawaii refinery. Under 60.104(b)(3), fluid catalytic cracking units (FCCU) at applicable petroleum refineries may comply with the sulfur oxides standard by limiting the total sulfur content in their process fresh fuel to 0.30 percent or less by weight. One fresh feed sample must be collected per 8-hour period and analyzed by ASTM D129-64 (Reapproved 1978), ASTM D1552-83, ASTM D2622-87, or ASTM D1266-87 to compute daily and 7-day rolling averages.

ChevronTexaco asks to use ASTM D4294-02 as an alternative to the prescribed ASTM methods to determine the feed sulfur content. ASTM D4294-02 and D2622-87 are very similar methods with similar procedures that differ only in the way the analytical technique is applied. ASTM D4294-02 uses energy-dispersive X-ray fluorescence spectrometry and D2622-87 uses wavelength dispersive X-ray fluorescence spectrometry.

As of January 1, 2006, the ChevronTexaco facility became subject to 40 CFR Parts 80 and 86 which restrict the sulfur content of any gasoline blend produced at the refinery to 80 ppm or a yearly average of 30 ppm. ChevronTexaco intends to comply with these requirements by processing only low-sulfur feed in the FCCU. Sulfur data for this feed taken from August 2004 to the present show a yearly average sulfur content of 0.10 percent by weight and a maximum 7-day rolling average of 0.208 percent by weight. Currently, ChevronTexaco is required by their Title V permit to use ASTM D4294-02 to analyze the FCCU fresh feed. The refinery operators have experience using D4294-02, and ChevronTexaco believes this method is more appropriate for low-sulfur feed than the required ASTM methods.

In 2004, EPA approved a similar request by Chevron to use ASTM D4294-02 at its Pascagoula, Mississippi refinery. The approval letter is attached.

We believe ASTM D4294-02 and D2622-87 give comparable results. This, plus the current Title V requirement to use D4294-02, ChevronTexaco's shift to low sulfur feed, and the operator experience with D4294-02 makes D4294-02 an acceptable alternative to the methods required in 60.106(j). We, therefore, approve this request to use ASTM D4294-02 to measure feed sulfur content at the Kapolo'i refinery. In this approval, as in the 2004 approval, ChevronTexaco must adhere to the guidelines for minimizing interference effects listed in D4294-02. This is a site-specific method approval and applies only to the testing of FCCU fuels at ChevronTexaco's Kapolo'i, Hawaii refinery.

If you have questions or would like to discuss the matter further, please call Foston Curtis at (919) 541-1063, or you may e-mail him at [curtis.foston@epa.gov](mailto:curtis.foston@epa.gov).

Attachment

cc: Shaun Burke, OECA  
Foston Curtis (E143-02)  
John Kim, Region 9  
Wilfred Nagamini, HI DOH



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
RESEARCH TRIANGLE PARK, NC 27711

DEC 28 2004

OFFICE OF  
AIR QUALITY PLANNING  
AND STANDARDS

Rhonda Yoder  
Safety, Environmental & Health Manager  
Chevron Texaco Products Company  
El Segundo Refinery  
P.O. Box 1300  
Pascagoula, Mississippi 39568-1300

Dear Ms. Yoder:

As requested in your December 15, 2004 correspondence, we have reviewed Chevron's proposal to use ASTM D4294 as an alternative to ASTM D2622 as referenced in 40 CFR 60.106(j) at your Pascagoula, Mississippi refinery. Under 60.104(b)(3), fluid catalytic cracking units (FCCU) at applicable petroleum refineries may comply with the sulfur oxides standard by limiting the total sulfur content in their process fresh fuel to 0.30 percent or less by weight. One fresh feed sample must be collected per 8-hour period and analyzed by ASTM D129, ASTM D1552, ASTM D2622, or ASTM D1266.

ASTM D4294 and D2622 are very similar methods with similar procedures that differ in the way the analytical technique is applied. ASTM D4294 uses energy-dispersive X-ray fluorescence spectrometry and D2622 uses wavelength dispersive X-ray fluorescence spectrometry. We feel the two methods give comparable results and therefore approve your request to use ASTM D4294 as an alternative to ASTM D2622 for measuring sulfur in your process fresh fuel. In this approval, you must adhere to the guidelines for minimizing interference effects listed in D4294. This is a site-specific method approval and applies only to the testing of FCCU fuels at Chevron's Pascagoula, Mississippi refinery.

If you have questions or would like to discuss the matter further, please call Foston Curtis at (919) 541-1063, or you may e-mail him at [curtis.foston@epa.gov](mailto:curtis.foston@epa.gov).

Sincerely,

Conniesue B. Oldham, Ph.D, Group Leader  
Source Measurement Technology Group

cc: Foston Curtis (D205-02)  
David McNeal, Region 4



Jon Maurer  
Refinery Manager

Chevron Products Company  
Hawaii Refinery  
91-480 Malakole Street  
Kapolei HI 96707-1807  
Tel 808-682-5711  
Fax 808-682-2324  
JonMaurer@chevron.com

November 9, 2015

**CERTIFIED MAIL 7014 1820 0000 0357 0963  
RETURN RECEIPT REQUESTED**

Director, Air Division  
Mail Code AIR-1  
USEPA Region 9  
75 Hawthorne Street  
San Francisco, CA 94105

**Chevron Hawaii Refinery  
Request for an Exemption from H2S Monitoring under NSPS Ja**

Dear Mr. Hirai:

The Chevron Products Company ("Chevron") is hereby applying for an exemption from the H2S monitoring requirements pursuant to New Source Performance Standards (NSPS) 40 CFR 60 Subpart Ja §60.107a(b). On November 17, 2014, Chevron submitted a permit application for a Catalytic Oxidation ("CatOx") Unit to treat the off-gas from the refinery's Foul Water Treatment Plant ("FWTP") which is currently burned in boilers F-5201 and F-5202. The CatOx permit was issued on June 23, 2015, as an amendment to Covered Source Permit (CSP) 0088-01-C, Attachment II(A).

The off-gas stream from the FWTP is currently monitored pursuant to the NSPS J Alternative Monitoring Program ("AMP") approved by EPA in a letter dated February 8, 2006. Chevron is resubmitting this AMP information to demonstrate that this off-gas stream also meets the "inherently low in sulfur content" criteria of NSPS Ja §60.107a(a)(3)(iv). This information is also required to be submitted to the Hawaii Department of Health Clean Air Branch pursuant to Section D.24.b of Attachment II(A) of Chevron's CSP.

Attachments 1 through 3 contain additional information supporting this application:

- Attachment 1 – NSPS Ja §60.107a(b) Exemption Application Information
- Attachment 2 – Chevron AMP Request and Subsequent Approval Letter from EPA
- Attachment 3 – Relevant Sections of CSP 0088-01-C, Attachment II(A) for CatOx Unit

If you have any questions, or need additional information please contact Marcus Ruscio by phone at (808) 682-2282 or e-mail [mruscio@chevron.com](mailto:mruscio@chevron.com).

Sincerely,



mj  
Enclosures

Director, Air Division  
EPA Region 9  
November 9, 2015  
Page 2 of 2

cc: **CERTIFIED MAIL 7014 1820 0000 0357 0970**  
**RETURN RECEIPT REQUESTED**  
Mr. Nolan Hirai  
Manager, Clean Air Branch  
Environmental Management Division  
919 Ala Moana Boulevard  
Honolulu, Hawaii 96814

**ATTACHMENT 1**

**NSPS Ja §60.107a(b) Exemption Application Information**



CHEVRON HAWAII REFINERY  
H<sub>2</sub>S MONITORING EXEMPTION REQUEST PURSUANT TO NSPS SUBPART Ja  
(FOUL WATER TREATING PLANT OFF-GAS TO CATALYTIC OXIDATION UNIT)

Pursuant to §60.107a(a)(3)(iv), this attachment contains the information required by §60.107a(b)(1) to demonstrate the Foul Water Treatment Plant ("FWTP") off-gas is inherently low in sulfur:

**§60.107a(b)(1)(i) - A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;**

Foul water is generated from many different sources in the refinery and contains sulfides, mercaptans, phenols, and ammonia before it is treated at the Foul Water Treatment Plant (FWTP). The Fluidized Catalytic Cracking Unit generates the majority of foul water effluent from the separation of water from hydrocarbons in accumulators.

Foul water is routed from the process units through piping into the foul water tankage located in the Effluent Treatment Plant. It is then routed to the FWTP for treatment. The FWTP consists of a foul water oxidizer, ammonia stripper, a flash drum, and various heat exchangers. In the Foul Water Oxidizer, sulfides are chemically reacted with oxygen to form sulfates and thiosulfates. The oxidation reaction requires medium temperature (210-250°F), pressure (60-85 psig) and a pH of at least 9. These conditions keep the hydrogen sulfide (H<sub>2</sub>S) in solution and aid the downstream stripping process.

The heat for the oxidation reaction is provided by preheating the foul water feed by cross exchange with the NH<sub>3</sub> stripper bottoms and preheating with 40 psig steam. The exchanger is designed to heat the feed stream to 210°F with 40 psig steam or 250°F with 150 psig steam.

Caustic is injected to maintain a pH of the water in the range of 9-10. Maintaining a high pH keeps the dissolved H<sub>2</sub>S in solution and helps the steam stripping of ammonia and other dissolved gases (phenols). At low pH, 8.5 and under, sulfur may form in the oxidizer and exchangers. The caustic injection is adjusted to keep the treated water pH below 11. High pH water will kill the bacteria in the effluent plant's oxidation ponds.

Plant air, at 100 psig, is mixed with the foul water and caustic before entering the oxidizer. Air is added in direct proportion to the foul water rate (about 2 lbs. of oxygen in the air is added per lb of sulfide). The feed mixture enters the oxidizer at the bottom and flows upward through 20 perforated trays where mixing and reaction takes place. The column is pressurized at 65 psig, water packed and no vaporization occurs until the pressure is reduced in the flash pot.

The sulfides and mercaptans present in the foul water react with the oxygen in the air to form sulfate and thiosulfate salts which are entrained in the effluent and then routed to the effluent plant for further treatment. The concentration of sulfides is normally reduced from 2000 ppm to less than 1 ppm in the treated water. If the sulfides are not destroyed, the treated water from the FWTP appears black in color.

The oxidizer effluent is flashed across a pressure valve into V-5501 flash pot to 8 psig. Here, the remaining air, dissolved gases (some ammonia), light hydrocarbons, and steam are flashed. Since some residual hydrocarbons are present (even after weathering in the foul water tanks), and air has been added to the oxidizer, an explosion hazard could exist if the oxygen content in the off-gas is above 9%. To avoid this, the pressure in V-5501 flash pot is held below 10 psig and the temperature above 210°F. This ensures that enough steam flashes in the pot to hold the O<sub>2</sub> level below the design of 9%.

CHEVRON HAWAII REFINERY  
H<sub>2</sub>S MONITORING EXEMPTION REQUEST PURSUANT TO NSPS SUBPART Ja  
(FOUL WATER TREATING PLANT OFF-GAS TO CATALYTIC OXIDATION UNIT)

The flash pot also receives the NH<sub>3</sub> stripper, C-5510, overhead vapors. Currently, the total off-gas flows through a back pressure control valve and is then routed to boilers F-5201 and/or F-5202 for combustion. Moving forward, Chevron has proposed routing this stream to a Catalytic Oxidation ("CatOx") Unit for control (see Attachment 3).

**§60.107a(b)(1)(ii) - A statement that there are no crossover or entry points for sour gas (high H<sub>2</sub>S content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);**

The overhead vapor line from the foul water treatment plant to the proposed CatOx unit has no crossover points and there are no connections at which other gas streams with H<sub>2</sub>S can enter. A piping diagram is included at the end of this attachment.

**§60.107a(b)(1)(iii) - An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;**

The pH and temperature are indicating parameters that ensure H<sub>2</sub>S is kept in solution and does not drop out in downstream equipment. pH and temperature are continuously analyzed and appropriate alarms actuate when limits exceed allowable ranges.

Caustic is injected to maintain a pH of the foul water effluent in the range of 9-10. An online analyzer 55A205.pv monitors pH of the effluent to ensure the dissolved hydrogen sulfide stays in solution and helps the steam stripping of ammonia and other dissolved gases (phenols). Alarms activate when the pH is too low (7.5) or too high (12.0).

The oxidation reaction in the foul water oxidizer requires a medium temperature (210-250°F). The medium temperature also aids in keeping the hydrogen sulfide in solution. 55TC201.pv ensures that a medium temperature is maintained. The low temperature alarm activates at 210°F and the high temperature alarm at 250°F.

**§60.107a(b)(1)(iv) - The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppm H<sub>2</sub>S. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems;**

The information below was provided in Chevron's December 5, 2005 AMP request found in Attachment 2. Chevron performed initial sampling to determine the level of H<sub>2</sub>S in the off-gas stream. Since this stream normally flows continuously, sampling was completed once a day for fourteen consecutive days, from April 18 to May 1, 2005. The operator measured the foul water off-gas for H<sub>2</sub>S at a pressure transmitter. Sensidyne tubes were used to measure for H<sub>2</sub>S in the off-gas. The tubes are ranged from 0.75 ppm to 300 ppm; therefore 0.75 ppm is the lowest concentration that can be read. The sampling results are shown in table below. The 14 samples collected during the test period have H<sub>2</sub>S concentrations below the limit of detection, i.e. less than 0.75 ppm H<sub>2</sub>S, with a standard deviation of 0 ppm.

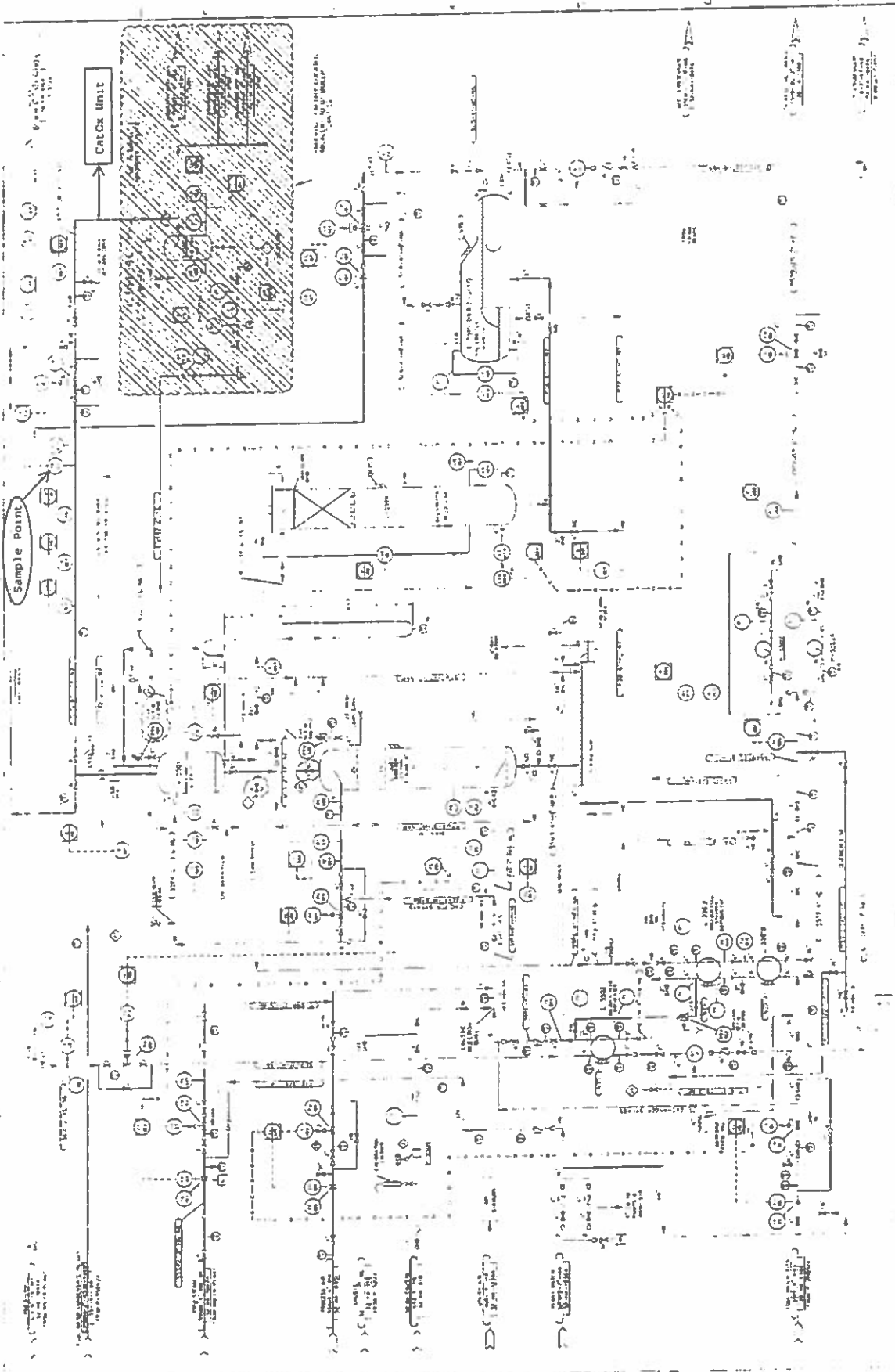
CHEVRON HAWAII REFINERY  
H2S MONITORING EXEMPTION REQUEST PURSUANT TO NSPS SUBPART Ja  
(FOUL WATER TREATING PLANT OFF-GAS TO CATALYTIC OXIDATION UNIT)

FOUL WATER TREATMENT PLANT OFF-GAS SAMPLING FOR H2S CONTENT			
DATE	Temp.*F	pH	H2S RESULTS
4/18/2005	234	10	< 0.75
4/19/2005	238	10	< 0.75
4/20/2005	234	11	< 0.75
4/21/2005	236	11	< 0.75
4/22/2005	234	9	< 0.75
4/23/2005	228	10	< 0.75
4/24/2005	240	11	< 0.75
4/25/2005	236	10	< 0.75
4/26/2005	235	10	< 0.75
4/27/2005	237	9	< 0.75
4/28/2005	234	9	< 0.75
4/29/2005	238	11	< 0.75
4/30/2005	234	11	< 0.75
5/1/2005	242	9	< 0.75

pH results are based on a daily average

**§60.107a(b)(1)(v) - A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of H2S concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare.**

The fourteen samples were collected for 14 consecutive days. During this time, operation of the FWTP was typical, stable, and continuous, and the pH was maintained above 9. Therefore, the sampling results are expected to be representative. Subsequent sampling of this stream since AMP was approved in 2006 is consistent with the original fourteen samples.



		Sulfur Refinery
PROJECT: Sulfur Water Treating Facility DRAWING NO: SW-100 DATE: 10/15/88		SHEET NO: 11A / 20
REVISIONS:		SCALE: AS SHOWN
APPROVED:		DRAWN:

UNIT: Sulfur Water Treating  
 DRAWING NO: SW-100  
 DATE: 10/15/88

**ATTACHMENT 2**

- 1) Chevron December 5, 2005 AMP Request**
- 2) EPA February 8, 2006 AMP Approval Letter**

Chevron Products Company  
Hawaii Refinery  
91-480 Malakole Street  
Kapolei, HI 96707-1807  
Tel 808 682 5711  
Fax 808 682 2324  
daverogers@Chevron.com

David E. Rogers  
Refinery Manager

December 5, 2005

**ChevronTexaco**

**CERTIFIED MAIL NO. 7002 1000 0005 0947 2425  
RETURN RECEIPT REQUESTED**

Ms. Debbie Jordan  
Director, Air Division  
US Environmental Protection Agency, Region 9  
75 Hawthorne Street  
San Francisco, CA 94105

**Request for EPA Approval of Alternative Monitoring Plan for Monitoring H2S in Fuel Gas  
Under NSPS Subpart J**

Dear Ms. Jordan:

Under the terms of the NSR Consent Decree between the United States and Chevron, Chevron's Hawaii Refinery will accept NSPS Subpart J (40 CFR Part 60) applicability to all fuel gas combustion devices which are not currently covered by under Subpart J. This submittal is being made pursuant to the schedule in Appendix D of the Consent Decree for the Hawaii Refinery's two boilers, F-5201 and F-5202.

Chevron requests your approval of the attached Alternative Monitoring Plan for the Foul Water Treating Plant (FWTP) off-gas stream. The plan was developed based on the US EPA Guidance Document, *Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas*.

Should you have any questions or require further information, please contact Sonni Escudro of our Environmental Staff at (808) 682-2372.

Sincerely,



SFE  
Attachments



cc: **CERTIFIED MAIL 7002 1000 0005 0947 2418**  
**RETURN RECEIPT REQUESTED**  
Director, Air Enforcement Division  
Office of Regulatory Enforcement  
c/o Matrix Environmental & Geotechnical Services  
120 Eagle Rock Avenue  
Suite 207  
East Hanover, NJ 07936  
Attn: Norma Eichlin

**CERTIFIED MAIL 7004 2890 0004 4202 5559**  
**RETURN RECEIPT REQUESTED**  
Director, Air Enforcement Division  
Office of Regulatory Enforcement  
U.S. Environmental Protection Agency  
Mail Code 2242-A  
1200 Pennsylvania Avenue, N.W.  
Washington D.C. 20460-0001

**CERTIFIED MAIL 7002 1000 0005 0947 2401**  
**RETURN RECEIPT REQUESTED**  
Chief  
Environmental Enforcement Section  
Environment and Natural Resources Division  
U.S. Department of Justice  
P.O. Box 7611, Ben Franklin Station  
Washington, DC 20044-7611  
Reference Case No. 90-5-2-1-07629

**CERTIFIED MAIL 7002 1000 0005 0947 2395**  
**RETURN RECEIPT REQUESTED**  
Region 9:  
Director  
Air Division  
Mail Code AIR-1  
USEPA Region 9  
75 Hawthorne Street  
San Francisco, CA 94105

**CERTIFIED MAIL 7002 1000 0005 0947 2388**  
**RETURN RECEIPT REQUESTED**  
Clean Air Branch  
Environmental Management Division  
Hawaii Department of Health  
P. O. Box 3378  
Honolulu, HI 96801-3378

Electronic copies to:  
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[jackson.james@epa.gov](mailto:jackson.james@epa.gov)  
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[JDonchin@Chevron.com](mailto:JDonchin@Chevron.com)  
[Steve.Carow@Chevron.com](mailto:Steve.Carow@Chevron.com)  
[Mike.Rockett@pillsburylaw.com](mailto:Mike.Rockett@pillsburylaw.com)



CHEVRON HAWAII REFINERY, PROPOSED ALTERNATIVE MONITORING PLAN  
UNDER NSPS SUBPART J (40 CFR PART 60) FOR FOUL WATER TREATING PLANT  
OFF-GAS TO F-5201 AND F-5202

**SECTION 1: REQUIRED INFORMATION**

**1.1 Describe the RFG and the affected fuel gas combustion device(s) to be considered for the AMP.**

Foul water is generated from many different sources in the refinery and contains sulfides, mercaptans, phenols, and ammonia before it is treated at the Foul Water Treatment Plant (FWTP). The Fluidized Catalytic Cracking Unit generates the majority of foul water effluent from the separation of water from hydrocarbons in accumulators.

Foul water is routed from the process units through piping into the foul water tankage located in the Effluent Treatment Plant. It is then routed to the FWTP for treatment. The FWTP consists of a foul water oxidizer, ammonia stripper, a flash drum, and various heat exchangers. In the Foul Water Oxidizer, sulfides are chemically reacted with oxygen to form harmless sulfates and thiosulfates. The oxidation reaction requires medium temperature (210-250°F), pressure (60-85 psig) and a pH of at least 9. These conditions keep the hydrogen sulfide (H<sub>2</sub>S) in solution and aid the downstream stripping process.

The heat for the oxidation reaction is provided by preheating the foul water feed by cross exchange with the NH<sub>3</sub> stripper bottoms and preheating with 40 psig steam. The exchanger is designed to heat the feed stream to 210°F with 40 psig steam or 250°F with 150 psig steam.

Caustic is injected to maintain a pH of the water in the range of 9-10. Maintaining a high pH keeps the dissolved H<sub>2</sub>S in solution and helps the steam stripping of ammonia and other dissolved gases (phenols). At low pH, 8.5 and under, sulfur may form in the oxidizer and exchangers. The caustic injection is adjusted to keep the treated water pH below 11. High pH water will kill the bacteria in the effluent plant's oxidation ponds.

Plant air, at 100 psig, is mixed with the foul water and caustic before entering the oxidizer. Air is added in direct proportion to the foul water rate (about 2 lbs. of oxygen in the air is added per lb of sulfide). The feed mixture enters the oxidizer at the bottom and flows upward through 20 perforated trays where mixing and reaction takes place. The column is pressurized at 65 psig, water packed and no vaporization occurs until the pressure is reduced in the flash pot.

The sulfides and mercaptans present in the foul water react with the oxygen in the air to form sulfate and thiosulfate salts which are entrained in the effluent and then routed to the effluent plant for further treatment. The concentration of sulfides is normally reduced from 2000 ppm to less than 1 ppm in the treated water. If the sulfides are not destroyed, the treated water from the FWTP appears black in color.

The oxidizer effluent is flashed across a pressure valve into V-5501 flash pot to 8 psig. Here, the remaining air, dissolved gases (some ammonia), light hydrocarbons, and steam are flashed. Since some residual hydrocarbons are present (even after weathering in the foul water tanks), and air has been added to the oxidizer, an explosion hazard could exist if the oxygen content in the off-gas is above 9%. To avoid this, the pressure in V-5501 flash pot is held below 10

CHEVRON HAWAII REFINERY, PROPOSED ALTERNATIVE MONITORING PLAN  
UNDER NSPS SUBPART J (40 CFR PART 60) FOR FOUL WATER TREATING PLANT  
OFF-GAS TO F-5201 AND F-5202

psig and the temperature above 210°F. This ensures that enough steam flashes in the pot to hold the O<sub>2</sub> level below the design of 9%.

The flash pot also receives the NH<sub>3</sub> stripper, C-5510, overhead vapors. The total off-gas flows through a back pressure control valve and is then routed to either F-5201 and F-5202 for combustion. The off-gas is burned at the tangential fired fuel burners along with refinery fuel gas and/or fuel oil. The refinery fuel gas is measured for H<sub>2</sub>S for NSPS Subpart J compliance with a NSPS-certified gas chromatograph.

The boilers that combust the overhead vapors from the FWTP are described in our Covered Source Permit as follows:

F5201-220 MMBtu/hr boiler  
F5202-160.8 MMBtu/hr boiler

1.2 Provide a statement and supporting piping diagram that demonstrates that the RFG stream does not have any crossover points at which other gas streams with H<sub>2</sub>S can enter.

The overhead vapor line from the foul water treating plant to the boilers has no crossover points and there are no connections at which other gas streams with H<sub>2</sub>S can enter. Piping diagram attached. [COMMENT: There is no diagram attached.]

1.3 Explain the conditions that ensure low concentrations of H<sub>2</sub>S in the RFG stream.

Caustic is injected to maintain a pH of the foul water effluent in the range of 9-10. An online analyzer 55A205.pv monitors pH of the effluent to ensure the dissolved hydrogen sulfide stays in solution and helps the steam stripping of ammonia and other dissolved gases (phenols). Alarms activate when the pH is too low (7.5) or too high (12.0).

The oxidation reaction in the foul water oxidizer requires a medium temperature (210-250°F). The medium temperature also aids in keeping the hydrogen sulfide in solution. 55TC201.pv ensures that a medium temperature is maintained. The low temperature alarm activates at 210°F and the high temperature alarm at 250°F.

1.4 Supporting Test Data

Chevron performed initial sampling to determine the level of H<sub>2</sub>S in the off-gas stream. Since this stream normally flows continuously, sampling was completed once a day for fourteen consecutive days, from April 18 to May 1, 2005. The operator measured the foul water off-gas for H<sub>2</sub>S at a pressure transmitter. Sensidyne tubes were used to measure for H<sub>2</sub>S in the off-gas. The tubes are ranged from 0.75ppm to 300ppm, therefore 0.75ppm is the lowest concentration that can be read. The sampling results are shown in Table 1.4. The 14 samples collected during the test period have H<sub>2</sub>S concentrations below the limit of detection, i.e. less than 0.75 ppm H<sub>2</sub>S, with a standard deviation of 0 ppm.

CHEVRON HAWAII REFINERY, PROPOSED ALTERNATIVE MONITORING PLAN  
 UNDER NSPS SUBPART J (40 CFR PART 60) FOR FOUL WATER TREATING PLANT  
 OFF-GAS TO F-5201 AND F-5202

TABLE 1.4

FOUL WATER TREATMENT PLANT OFF-GAS SAMPLING FOR H <sub>2</sub> S CONTENT			
DATE	Temp.*F	pH	H <sub>2</sub> S RESULTS
4/18/2005	234	10	< 0.75
4/19/2005	238	10	< 0.75
4/20/2005	234	11	< 0.75
4/21/2005	236	11	< 0.75
4/22/2005	234	9	< 0.75
4/23/2005	228	10	< 0.75
4/24/2005	240	11	< 0.75
4/25/2005	236	10	< 0.75
4/26/2005	235	10	< 0.75
4/27/2005	237	9	< 0.75
4/28/2005	234	9	< 0.75
4/29/2005	238	11	< 0.75
4/30/2005	234	11	< 0.75
5/1/2005	242	9	< 0.75

pH results are based on a daily average  
 TEST WAS DONE USING A SENSIDYNE GAS DETECTION PUMP WITH  
 SENSIDYNE TUBES RANGING FROM 0.75-300 PPM

**1.5 Stability and Representativeness**

Fourteen samples were collected for 14 consecutive days. During this time, operation of the FWTP was typical, stable, and continuous, and the pH was maintained above 9. Therefore, the sampling results are expected to be representative.

**1.6 Indicating Parameter**

The pH and temperature are indicating parameters that ensure H<sub>2</sub>S is kept in solution and does not drop out in downstream equipment. pH and temperature are continuously analyzed and appropriate alarms actuate when limits exceed allowable ranges.

**1.7 Variability and Monitoring Limit of Indicator**

If the pH indicator is not working or is taken out of service for maintenance, the foul water effluent will be monitored for pH two times within a 12 hour period. If the outage continues for more than a day, then the foul water off-gas will be monitored every 12 hour shift for H<sub>2</sub>S until the pH analyzer is brought online. The FWTP cannot operate without temperature indication and will require storing foul water in tankage and the shutdown of the FWTP for repair of the temperature indicator.

CHEVRON HAWAII REFINERY, PROPOSED ALTERNATIVE MONITORING PLAN  
UNDER NSPS SUBPART J (40 CFR PART 60) FOR FOUL WATER TREATING PLANT  
OFF-GAS TO F-5201 AND F-5202

**SECTION 2: PROPOSED ALTERNATIVE MONITORING PLAN PROCEDURES**

**2.1 Audits and Recordkeeping**

If requested by the agency, Chevron will conduct a test audit for the AMP. The audit shall consist of daily detector tube samples collected over a one-week period, for a total of seven (7) days.

**2.2 Description of Monitoring, Testing and Reporting Procedures**

The sampling proposed for the ongoing program is described below.

Step 1: Since the sampling results described in Section 1.4 above indicate the H<sub>2</sub>S concentration in the off-gas is non-detectable, Chevron proposes to monitor H<sub>2</sub>S in the off-gas stream pursuant to the following monitoring schedule:

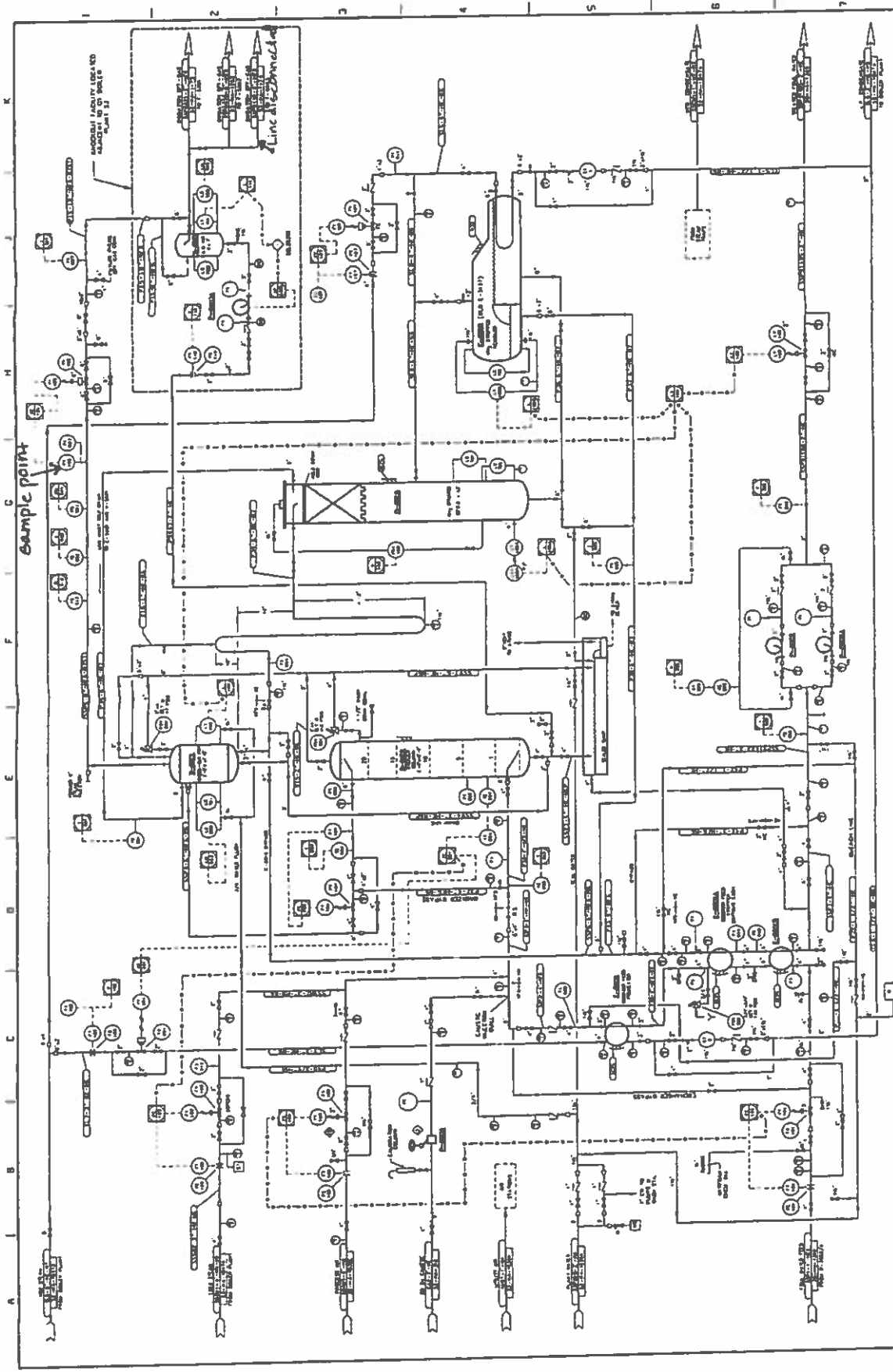
- twice a week for the first 3 months (26 samples). If any results are greater than 1 ppm, Chevron will continue sampling twice a week for an additional 3 months.
- once per quarter for 6 quarters (6 samples)
- twice per year thereafter, and
- when pH drops below 9 as described in section 1.7

H<sub>2</sub>S results will be reported semi-annually to EPA Region 9 and the Department of Health-Clean Air Branch within 30 days of the end of the respective 6-month period. The results will include calculation of the mean, the standard deviation, and the range of variability.

Step 2: If, at any time during the previous step, a single verified detector tube sample value is greater than or equal to 81 ppm H<sub>2</sub>S, the gas stream will be sampled with detector tubes on a daily basis for 7 days.

If the average detector tube result plus 3 standard deviations for those seven samples is less than 81 ppm, the daily average value of the parameter indicator and the recovered off-gas sample results shall be reported to the agency in the next scheduled report. Chevron will then resume monitoring in accordance with the schedule of Step 1. If the average plus 3 standard deviations for those 7 samples is greater than or equal to 81 ppm H<sub>2</sub>S, sampling shall follow the requirements of Step 3.

Step 3: If the average plus 3 standard deviations for those 7 samples is greater than or equal to 81 ppm H<sub>2</sub>S, Chevron will notify EPA within five business days following the last sample day. In the event of such an occurrence, Chevron shall test the off-gas stream daily for a two week period. After the two week period is complete, sampling will continue once per week, until the agency approves a revised sampling schedule.



**Process Flow Diagram**  
**SAFETY WATER SYSTEM FACILITIES**  
**SAFETY WATER SYSTEM**

**90-HA-2-18**

**Chemicon**  
 Hawaii Refinery

DATE	NOV 3 2005
BY	...
FOR	...
REVISION	...



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IX

75 Hawthorne Street

San Francisco, CA 94105-3901

FEB 08 2006

Mr. David E. Rogers  
Refinery Manager  
Chevron Products Company  
Hawaii Refinery  
91-480 Malakole St.  
Kapolei, HI 96707-1807

Dear Mr. Rogers:

On December 5, 2005, Chevron Products Company (Chevron) submitted to the United States Environmental Protection Agency (EPA) an Alternative Monitoring Plan (AMP) request for the off-gas stream from the Foul Water Treating Plant (FWTP), which is combusted in the boilers F-5201 and F-5202 at the Chevron Hawaii Refinery (Refinery). The AMP proposes that the FWTP off-gas does not need to be continuously monitored for hydrogen sulfide ( $H_2S$ ) content; instead the pH of the FWTP effluent will be maintained at greater than or equal to 9 and the temperature of the FWTP effluent will be maintained at between 210 and 250°F. Samples of the FWTP off-gas will be collected at least twice per year and analyzed for  $H_2S$  content with Sensidyne gas detector tubes. For the reasons proposed by Chevron and outlined below, the United States Environmental Protection Agency (EPA) approves the requested AMP.

Regulatory Background

The Standards of Performance for New Stationary Sources (NSPS) Subpart J (Standards of Performance for Petroleum Refineries) at 40 C.F.R. § 60.104(a)(1) requires the owner or operator of a fuel gas combustion device at a petroleum refinery to burn no refinery fuel gas that contains  $H_2S$  in excess of 230 milligrams per dry standard cubic meter (0.10 grain per dry standard cubic foot). This limit is equivalent to 160 parts per million (ppm)  $H_2S$ . Pursuant to 40 C.F.R. § 60.105(a)(3), the owner or operator of a fuel gas combustion device subject to 40 C.F.R. § 60.104(a)(1) is required to install, calibrate, maintain, and operate a continuous monitoring system (CMS) to monitor and record the concentration by volume of sulfur dioxide emitted to the atmosphere. Alternatively, a CMS to monitor and record the  $H_2S$  in fuel gases before being burned in any fuel gas combustion device may be used. Pursuant to 40 C.F.R. § 60.13(i), after receipt and consideration of written application, the Administrator may approve alternative procedures to any monitoring procedures or requirements of [Part 60].

The EPA issued guidance titled "Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas" (RFG Guidance). The RFG Guidance is divided into four subjects: conditions for approval; data requirements; monitoring schedules for approved alternative plans; and general conditions for approved monitoring plans. Chevron's request for an AMP included the information required by the RFG Guidance:

- a description of the gas stream to be considered including submission of the appropriate piping diagrams indicating the boundaries of the gas streams/system;
- the affected fuel gas combustion device(s) to be considered;
- an identification of the proposed sampling point for the alternative monitoring;
- a statement that there are no sour gas crossover points into the gas stream/system (this should also be shown in the piping diagram);
- an explanation of the conditions that ensures low amounts of sulfur in the gas stream and supporting test results using appropriate H<sub>2</sub>S monitoring.

#### Chevron's Request

Chevron submitted supporting information with the AMP request. This information included a statement that the FWTP off-gas stream is generated from the Refinery's FWTP which consists of a foul water oxidizer, an ammonia stripper, a flash drum and various heat exchangers. Chevron also included a fuel gas system overview drawing indicating the FWTP off-gas and the sampling points for effluent water pH and temperature and FWTP off-gas H<sub>2</sub>S content. Chevron stated that there are no entry or crossover points which would allow sour gases to be combined with the FWTP off-gas that is combusted in the F-5201 and F-5202 boilers. Chevron stated that caustic is injected into the foul water to maintain the effluent pH at greater than or equal to 9. This minimum pH level and the medium temperature range will ensure that H<sub>2</sub>S will not be liberated into the FWTP off-gas. Chevron submitted fourteen consecutive daily sample results using Sensidyne tubes that indicate the H<sub>2</sub>S content of the FWTP off-gas stream never exceeded 0.75 ppm, the detection limit of the Sensidyne tubes, and during these 2 weeks the pH of the effluent was between 9 and 11 and the temperature of the effluent was in the range of 228-242°F. These results are expected to be representative.

Chevron proposed to sample the H<sub>2</sub>S content of the FWTP off-gas using Sensidyne tubes twice weekly for the first six months, then once per quarter for 6 quarters, then twice per year thereafter. If any of these sample results is greater than 81 ppm (one-half of the NSPS Subpart J limit) then Chevron will sample the FWTP off-gas on a daily basis for 7 days. If the average plus 3 standard deviations of these 7 samples is less than 81 ppm then Chevron will report the daily average effluent pH and the recovered off-gas sample results to EPA. If the average plus 3 standard deviations of these 7 samples is greater than or equal to 81 ppm then Chevron will notify EPA and test the off-gas stream daily for a two-week period followed by weekly sampling. The weekly sampling will continue until EPA approves a revised sampling schedule or withdraws approval of this AMP. Additionally, the pH and temperature of the FWTP effluent are both analyzed continuously.

Approval of Chevron's Alternative Monitoring Plan

EPA has reviewed Chevron's request for an AMP and has determined that it includes all of the required information. The FWTP off-gas at the Refinery is inherently low in H<sub>2</sub>S and Chevron has submitted fourteen consecutive days of sample results to support this conclusion. There are also no crossover or entry points that would allow for sour gas to be introduced into the FWTP off-gas stream. Therefore, the Administrator of the EPA, by authority duly-delegated to the undersigned, approves Chevron's request for an AMP.

If you have any questions regarding this approval please contact Charles Aldred, Air Enforcement Office, at (415) 972-3986 or [aldred.charles@epa.gov](mailto:aldred.charles@epa.gov).

Sincerely,



Douglas K. McDaniel  
Chief, Enforcement Office  
Air Division

cc: Wilfred Nagamine, Hawaii Department of Health



**ATTACHMENT 3**

**Relevant Sections of CSP 0088-01-C, Attachment II(A)  
for CatOx Unit**

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.690)<sup>1</sup>

3. The FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, Alkylation Plant and Effluent Treatment Plant are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT):
    - i. Subpart A, General Provisions; and
    - ii. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11.60.1-174, 40 CFR §63.640)<sup>1</sup>

4. The storage and use of flammable substances in this facility is subject to the provisions of 40 CFR Part 68, Chemical Accident Prevention Provisions. The permittee shall comply with all applicable requirements, including the submittal of:
  - a. A compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR §68.10(a); or
  - b. As part of the compliance certification submitted pursuant to Attachment I, Standard Condition No. 28, a certification statement that the facility is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of the Risk Management Plan.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §68)<sup>1</sup>

- \*5. The Catalytic Oxidation Unit is subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, New Source Performance Standards (NSPS):
    - i. Subpart A, General Provisions; and
    - \*ii. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

23. For each sewer line subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for inspections when a problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.697)<sup>1</sup>

\* 24. Catalytic Oxidation Unit – H<sub>2</sub>S Monitoring

- a. The permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H<sub>2</sub>S in the offgas from the Foul Water Treatment Plant before being oxidized in the Catalytic Oxidation Unit.
- b. The permittee may apply for an exemption from the H<sub>2</sub>S monitoring requirements described above for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the H<sub>2</sub>S monitoring requirements described above until there are changes in operating conditions or stream composition.
  - i. The permittee shall submit to the Department and U.S. EPA Region 9 a written application for an exemption from monitoring. The application must contain the following information:
    - (1) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;
    - (2) A statement that there are no crossover or entry points for sour gas (high H<sub>2</sub>S content) to be introduced into the fuel gas stream/system;
    - (3) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;
    - (4) The supporting test results from sampling the fuel gas stream/system demonstrating that the sulfur content is less than five (5) ppm H<sub>2</sub>S; and
    - (5) A description of how the two (2) weeks of monitoring results compares to the typical range of H<sub>2</sub>S concentration expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare.
  - ii. The effective date of the exemption is the date of submission of the information required above.
  - iii. No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the permittee shall follow the procedures in 40 CFR §60.107a(b)(3).

Director, Air Division  
EPA Region 9  
November 9, 2015  
Page 1 of 1

bcc: Kristi Mitchum

Records File: A-8-2-15, NSPS Ja H2S Monitoring Exemption Request

Electronic Files:

Cover Letter - \\KAPHINTDATA1.KAPHI.CHEVRONTEXACO.NET\Share\Envr\titleV\Permit Modifications\Sig Mods\CatOx\H2S Monitoring Exemption Request\CatOx Exemption Request from H2S Monitoring Cover Letter.docx

Exemption Request Info:

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WWR 11/4/15  
MCP 11/4/15  
AET 11/6/15  
KAM 11/9/15

**Appendix G**  
**Current Version of Attachment II(I)**

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DAVID Y. IGE  
GOVERNOR OF HAWAII



VIRGINIA PRESSLER, M.D.  
DIRECTOR OF HEALTH

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

In reply, please refer to:  
File:

October 9, 2015

**CERTIFIED MAIL**  
**RETURN RECEIPT REQUESTED**  
(7009 2820 0001 6573 1870)

15-705E CAB  
File No. 0088-24

Mr. Jon Mauer  
Refinery Manager  
Chevron USA Products Company  
Hawaii Refinery  
91-480 Malakole Street  
Kapolei, Hawaii 96707-1807

Dear Mr. Mauer:


**SUBJECT: Amendment of Covered Source Permit (CSP) No. 0088-01-C  
Minor Modification Application No. 0088-24  
FCCU NO<sub>x</sub> Limits  
Chevron USA Products Company  
Petroleum Refinery  
Located At: 91-480 Malakole Street, Kapolei, Oahu  
Date of Expiration: June 27, 2011 (this date is to be revised upon issuance  
of the renewal for CSP No. 0088-01-C)**

In accordance with Hawaii Administrative Rules, Chapter 11-60.1, and pursuant to your application for a Minor Modification dated January 15, 2015; the Department of Health (herein after referred to as Department), hereby amends Covered Source Permit (CSP) No. 0088-01-C issued to Chevron USA Products Company. The amendment incorporates NO<sub>x</sub> limits in the existing covered source permit section for the fluid catalytic cracking unit (FCCU).

The enclosed amended Attachment II(I): Special Conditions for the Fluid Catalytic Cracking Unit (FCCU) supersedes the corresponding Attachment II(I) issued with CSP No. 0088-01-C dated February 22, 1999 and amended on January 22, 2002, April 16, 2002, March 3, 2003, June 28, 2006, April 24, 2007, August 13, 2007, November 8, 2007, July 22, 2008, September 11, 2009, November 4, 2009, April 22, 2013, September 30, 2014, and June 23, 2015. All other permit conditions issued with CSP No. 0088-01-C shall not be affected and shall remain valid.

If there are any questions regarding these matters, please contact Mr. Darin Lum of the Clean Air Branch at (808) 586-4200.

Sincerely,

  
STUART YAMADA, P.E., CHIEF  
Environmental Management Division

DL:dh

c: CAB Monitoring Section

**ATTACHMENT II(I): SPECIAL CONDITIONS  
COVERED SOURCE PERMIT NO. 0088-01-C  
FLUID CATALYTIC CRACKING UNIT (FCCU)**

**Amended Date: October 9, 2015**

**Expiration Date: June 27, 2011<sup>3</sup>**

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description.**

1. This portion of the Covered Source Permit encompasses the following equipment and associated appurtenances:
  - a. Catalyst transfer operations;
  - b. One (1) - Fluid Catalytic Cracking Unit (FCCU) which includes the Regenerator and Reactor:
    - i. Particulate Control Devices:
      - (1) Cyclone; and
      - (2) Electrostatic Precipitator (ESP), Manufacturer: Hamon Research Cottrell, Inc., Model no. 8883.
  - c. One (1) - 61 MMBtu/hr furnace identified as F-5300 equipped with Callidus Ultra Blue burners; and
  - d. One (1) - 52 MMBtu/hr FCC Startup Air Heater identified as F-5310, Manufacturer: John Zink, Model: Direct Fired Air Heater.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number, and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations.**

1. The FCCU is subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, New Source Performance Standards:
    - i. Subpart A, General Provisions; and
    - ii. Subpart J, Standards of Performance for Petroleum Refineries.

- b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories:
- i. Subpart A, General Provisions; and
  - ii. Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.1, 40 CFR §60.100, 40 CFR §63.1561)<sup>1</sup>

2. The FCC Startup Air Heater is subject to the provisions of the following federal regulations:  
40 CFR Part 60, New Source Performance Standards:

- a. Subpart A, General Provisions;
- b. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.1, 40 CFR §60.100a)<sup>1</sup>

### **Section C. Operational and Emissions Limitations.**

1. The F-5300 furnace shall be fired only on refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (160 ppmv).

(Auth.: HAR §11-60.1-3, § 11-60.1-38, §11-60.1-90, 40 CFR §60.104)<sup>1</sup>

2. The permittee shall take measures to control fugitive dust at all catalyst transfer operations. The Department at any time may require the permittee to further abate fugitive dust emissions if an inspection indicates poor or insufficient control.

(Auth.: HAR §11-60.1-3, §11-60.1-33, §11-60.1-90)

3. The permittee shall not cause the discharge of visible emissions of fugitive dust beyond the lot line of the property on which the emissions originate.

(Auth.: HAR §11-60.1-3, §11-60.1-33, §11-60.1-90)



4. The permittee shall maintain and operate the cyclone and electrostatic precipitator in a manner consistent with good air pollution control practices for minimizing emissions.
- (Auth.: HAR §11-60.1-3, §11-60.1-90)
5. The vacuum gas oil (VGO) processed by the FCCU shall not exceed the following feed rate and sulfur content limit:
- A maximum VGO feed rate of 22,000 bbls/day\*;
  - A maximum sulfur content of VGO of 0.30% by weight\*\*.

\* Based on a rolling 365-day average

\*\*Based on a rolling seven-day (7-day) average, applicable at all times, including periods of startup, shutdown, and malfunctions

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.104, 40 CFR §60.108)<sup>1</sup>

6. Emission Limits

The permittee shall not discharge or cause the discharge from the FCCU emissions in excess of the following:

- PM Emission Limit: 1.0 pounds of PM per 1000 pounds (1.0 kg/Mg or 2.0 lb/ton) of coke burn-off in the catalyst regenerator (3-hr average)\*\*.
- CO Emission Limit: 500 ppmvd @ 0% O<sub>2</sub> (1-hr average)\*\*.
- SO<sub>2</sub> Emission Limit: 25 ppmvd @ 0% O<sub>2</sub> (365-day rolling average)\* and 50 ppmvd @ 0% O<sub>2</sub> (7-day rolling average)\*\*.
- NO<sub>x</sub> Emission Limit: 50 ppmvd @ 0% O<sub>2</sub> (365-day rolling average)\* and 87.9 ppmvd @ 0% O<sub>2</sub> (7-day rolling average)\*\*.

\*Applicable at all times, including periods of startup, shutdown, and malfunctions

\*\*Applicable at all times, excluding periods of startup, shutdown, and malfunctions

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, 40 CFR §60.102, 40 CFR §60.103, 40 CFR §63.1564)<sup>1</sup>

7. Visible Emissions (VE)

- For any six (6) minute averaging period, the FCCU shall not exhibit visible emissions of twenty (20) percent opacity or greater, except as follows: during start-up, shutdown, or equipment breakdown, the FCCU may exhibit visible emissions greater than twenty (20) percent opacity but not exceeding sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minutes.

- b. For any six (6) minute averaging period, the F-5300 furnace shall not exhibit visible emissions of forty (40) percent opacity or greater, except as follows: during start-up, shutdown, or equipment breakdown, the F-5300 furnace 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) minutes.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-32, §11-60.1-90, SIP §11-60-24, 40 CFR §60.102, 40 CFR §63.1564)<sup>1,2</sup>

#### 8. Operation, Maintenance, and Monitoring Plan

The permittee must prepare and implement an operation, maintenance, and monitoring plan for the FCCU, air pollution control system and continuous monitoring system. The purpose of this plan is to detail the operation, maintenance, and monitoring procedures to follow.

- a. The plan shall be submitted to the Department for review and approval along with the notification of compliance status. Any changes to the plan must be submitted for review and approved by the Department.
- b. Each plan must include the following information:
  - i. Process and control device parameters to be monitored for the FCCU, along with established operating limits.
  - ii. Procedures for monitoring emissions and process and control device operating parameters for the FCCU.
  - iii. Procedures to determine the coke burn-rate and the volumetric flow rate (if you use process data rather than direct measurement).
  - iv. Procedures and analytical methods used to determine the equilibrium catalyst Ni concentration, the equilibrium catalyst Ni concentration monthly rolling average, and the hourly or hourly average Ni operating value.
  - v. Procedures to determine the gas flow rate for a catalytic cracking unit if you use the alternative procedure based on air flow rate and temperature.
  - vi. Monitoring schedule, including when you will monitor and when you will not monitor the FCCU (e.g., during the coke burn-off, regeneration process).
  - vii. Quality control plan for each continuous opacity monitoring system and continuous emission monitoring system used to meet an emission limit in 40 CFR Part 63, Subpart UUU. This plan must include procedures for calibrations, accuracy audits, and adjustments to the system needed to meet applicable requirements for the system.
  - viii. Maintenance schedule for each monitoring system and control device for the FCCU that is generally consistent with the manufacturer's instructions for routine and long-term maintenance.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §63.1574)<sup>1</sup>

9. Startup, Shutdown, and Malfunction Plan (SSMP)

- a. The permittee shall develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in 40 CFR §63.6(e)(3).
- b. During periods of startup, shutdown, and malfunction, the permittee must operate in accordance with the SSMP.
- c. The permittee must report each instance in which each emission limitation and each operating limitation was not met. This includes periods of startup, shutdown, and malfunction. The permittee shall also report each instance in which the work practice standards were not met. These instances are deviations from the emission limitations and work practices. These deviations must be reported according to the requirements in 40 CFR §63.1575.
- d. Consistent with 40 CFR §63.6(e) and 40 CFR §63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Department's satisfaction that you were operating in accordance with 40 CFR §63.6(e)(1). The SSMP must also include elements designed to minimize the frequency of such periods (i.e., root cause analysis). The Department will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in 40 CFR §63.6(e).

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §63.1570)<sup>1</sup>

10. FCC Startup Air Heater

- a. The startup air heater may be utilized for up to twenty-two (22) days per year at maximum duty and shall only combust an inherently low sulfur commercial-grade LPG gas with a sulfur content not to exceed thirty (30) ppmv.
- b. The startup air heater shall only combust gas that has a H<sub>2</sub>S content that does not exceed 162 ppmv determined hourly on a three-hour (3-hour) rolling average basis and sixty (60) ppmv determined daily on a 365 successive calendar day rolling average basis.

(Auth.: HAR §11-60.1-3, §11-60.1-38, §11-60.1-90, 40 CFR §60.102a(g)(1)(ii), §60.107a(a)(3)(ii))<sup>1</sup>

**Section D. Monitoring and Recordkeeping Requirements.**

1. All records, including support information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Support information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

2. Vacuum Gas Oil (VGO)

- a. The permittee shall monitor the feed rates (in barrels per day) of the VGO processed by the FCCU. Records shall be kept on a **rolling 365-day average basis**.
- b. Compliance with the maximum sulfur content limit for the fresh feed (VGO) is determined daily on a **rolling seven-day (7-day) average basis** using the following analytical methods and calculation procedures outlined below:
  - i. One fresh feed sample shall be collected once per eight-hour (8-hour) period.
  - ii. Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods:

ASTM D129-64, 78, or 95, ASTM D1552-83 or 95, ASTM D2622-87, 94 or 98, or ASTM D1266-87, 91, or 98. (These methods are incorporated by reference: see 40 CFR §60.17). The applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Department.

- iii. If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:
  - (1) Individual samples shall be collected once per eight-hour (8-hour) period for each separate fresh feed stream charged directly into the riser or reactor of the fluid catalytic cracking unit. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.
  - (2) Each fresh feed sample shall be analyzed separately using the methods specified in Special Condition No. D.2.b.ii of this Attachment.
  - (3) Fresh feed sulfur content shall be calculated for each 8-hour period using the following equation:

$$S_f = \sum_{i=1}^n S_i Q_i / Q_t$$

where:

$S_f$  = fresh feed sulfur content expressed in percent by weight of fresh feed.

$n$  = number of separate fresh feed streams charged directly to the riser or reactor of the fluid catalytic cracking unit.

$Q_t$  = total volumetric flow rate of fresh feed charged to the fluid catalytic cracking unit.

$S_i$  = fresh feed sulfur content expressed in percent by weight of fresh feed for the "ith" sampling location.

$Q_i$  = volumetric flow rate of fresh feed stream for the "ith" sampling location.

- iv. Calculate a seven-day (7-day) average (arithmetic mean) sulfur content of the fresh feed using all of the fresh feed sulfur content values obtained during seven (7) successive twenty-four-hour (24-hour) periods.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

3. Visible Emissions (VE)

- a. Except in those months where VE observations are conducted by a certified reader for the annual observations of the F-5300 furnace, the permittee shall conduct monthly (*calendar month*) VE observations for the F-5300 furnace in accordance with 40 CFR Part 60, Appendix A, Method 9 or by use of a Ringelmann Chart as provided. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals for the F-5300 furnace. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.
- b. The permittee shall conduct annually (*calendar year*) VE observations for the F-5300 furnace by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9. For the annual observations, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals for the F-5300 furnace. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.
- c. Upon written request and justification, the Department may waive the requirements for the annual VE observations. The waiver request is to be submitted prior to the required annual VE observations and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior VE observations indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous annual VE observations. The annual VE observations shall not be waived for more than two (2) consecutive years.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90; SIP §11-60-15, SIP §11-60-24)<sup>2</sup>

4. Continuous Emissions Monitoring System (CEMS) for CO

- a. The permittee shall install, operate and maintain a continuous emissions monitoring system (CEMS) for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions from the FCCU.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is 1,000 ppm CO.
  - ii. Performance evaluations for the CO CEMS shall be in accordance with 40 CFR §60.13 and §63.8. The CO CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 4, Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 10 shall be used in conducting any relative accuracy test audit (RATA).
  - iii. Cylinder Gas Audits (CGA) shall be conducted on a quarterly basis in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.

- iv. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105, 40 CFR §63.1572)<sup>1</sup>

**5. Continuous Emissions Monitoring System (CEMS) for H<sub>2</sub>S**

- a. The permittee shall operate and maintain a continuous emissions monitoring system (CEMS) for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
  - ii. All fuel gas combustion devices having a common source of fuel gas may be monitored at one (1) location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.
  - iii. Performance evaluations for the H<sub>2</sub>S CEMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 7, Specifications and Test Procedures for Hydrogen Sulfide Continuous Emissions Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11, 15, 15A, or 16, shall be used in conducting any relative accuracy test audit (RATA).
  - iv. Cylinder Gas Audits (CGA) shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.
  - v. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105)<sup>1</sup>

**6. Continuous Emissions Monitoring System (CEMS) for O<sub>2</sub>**

- a. The permittee shall install, operate and maintain a continuous emissions monitoring system (CEMS) for continuously monitoring and recording the concentration by volume (dry basis) of O<sub>2</sub> emissions from the FCCU.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is ten percent (10%) O<sub>2</sub>.
  - ii. Performance evaluations for the O<sub>2</sub> CEMS shall be in accordance with 40 CFR §60.13 and §63.8. The O<sub>2</sub> CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 3, Specifications and Test Procedures for O<sub>2</sub> and CO<sub>2</sub> Continuous Emission Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 3A or 3B shall be used in conducting any relative accuracy test audit (RATA).

- iii. Cylinder Gas Audits (CGA) shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2. In lieu of the audit points specified in 40 CFR Part 60, Appendix F, Section 5.1.2, the permittee may audit the O<sub>2</sub> CEMS at twenty to thirty percent (20-30%) and fifty to sixty percent (50-60%) of the actual O<sub>2</sub> CEMS span value.
- iv. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105, 40 CFR §63.1572)<sup>1</sup>

**7. Continuous Emissions Monitoring System (CEMS) for SO<sub>2</sub>**

- a. The permittee shall install, operate and maintain a continuous emissions monitoring system (CEMS) for continuously monitoring and recording the concentration by volume (dry basis) of SO<sub>2</sub> emissions from the FCCU.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is 100 ppm SO<sub>2</sub>.
  - ii. Performance evaluations for the SO<sub>2</sub> CEMS shall be in accordance with 40 CFR §60.13. The SO<sub>2</sub> CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 2, Specifications and Test Procedures for SO<sub>2</sub> and NO<sub>x</sub> Continuous Emission Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 6, 6A or 6B shall be used in conducting any relative accuracy test audit (RATA). In lieu of the requirements of 40 CFR Part 60, Appendix F, Sections 5.1.1, 5.1.3, and 5.1.4, the permittee must conduct either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) at least once every three (3) years. The permittee shall conduct a Cylinder Gas Audit (CGA) each calendar quarter during which a RAA or a RATA is not performed.
  - iii. Cylinder Gas Audits (CGA) shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.
  - iv. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

**8. Continuous Emissions Monitoring System (CEMS) for NO<sub>x</sub>**

- a. The permittee shall install, operate and maintain a continuous emissions monitoring system (CEMS) for continuously monitoring and recording the concentration by volume (dry basis) of NO<sub>x</sub> emissions from the FCCU.
- b. The CEMS shall meet the following requirements:

- i. Performance evaluations for the NO<sub>x</sub> CEMS shall be in accordance with 40 CFR §60.13. The NO<sub>x</sub> CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 2, Specifications and Test Procedures for SO<sub>2</sub> and NO<sub>x</sub> Continuous Emission Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, or 7E shall be used in conducting any relative accuracy test audit (RATA). In lieu of the requirements of 40 CFR Part 60, Appendix F, Sections 5.1.1, 5.1.3, and 5.1.4, the permittee must conduct either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) at least once every three (3) years. The permittee shall conduct a Cylinder Gas Audit (CGA) each calendar quarter during which a RAA or a RATA is not performed.
- ii. CGA shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2.
- iii. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

9. Continuous Opacity Monitoring System (COMS) for Opacity

The permittee shall install, operate and maintain a continuous opacity monitoring system (COMS) for continuously measuring and recording the opacity levels of stack emissions from the FCCU. The system shall meet U.S. EPA monitoring performance standards (40 CFR §60.13, 40 CFR §63.8 and 40 CFR Part 60, Appendix B, Performance Specification 1, Specifications and test procedures for opacity continuous emission monitoring systems in stationary sources). The instrument shall be spanned at sixty (60), seventy (70), or eighty (80) percent opacity. As specified in 40 CFR §63.8(c)(4)(i), each continuous opacity monitoring system must complete a minimum of one (1) cycle of sampling and analyzing for each successive ten-second (10-second) period and one (1) cycle of data recording for each successive Six-minute (6-minute) period.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105, 40 CFR §63.1572)<sup>1</sup>

10. The following records must be kept:

- a. A copy of each notification and report that was submitted to comply with 40 CFR Part 63, Subpart UUU, including all documentation supporting any initial notification or Notification of Compliance Status that was submitted, according to the requirements in 40 CFR §63.10(b)(2)(xiv).
- b. The records in 40 CFR §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.
- c. Records of performance tests, performance evaluations, and opacity and visible emission observations as required in 40 CFR §63.10(b)(2)(viii).
- d. For each continuous emission monitoring system and continuous opacity monitoring system:



- i. Records described in 40 CFR §63.10(b)(2)(vi) through (xi).
  - ii. Monitoring data for continuous opacity monitoring systems during a performance evaluation as required in 40 CFR §63.6(h)(7)(i) and (ii).
  - iii. Previous (i.e., superceded) versions of the performance evaluation plan as required in 40 CFR §63.8(d)(3).
  - iv. Requests for alternatives to the relative accuracy test for continuous emission monitoring systems as required in 40 CFR §63.8(f)(6)(i).
  - v. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.
- e. Records in 40 CFR §63.6(h) for visible emission observations.
  - f. A current copy of the operation, maintenance, and monitoring plan onsite and available for inspection. Also records to show continuous compliance with the procedures in the operation, maintenance, and monitoring plan.
  - g. Records of any changes that affect emission control system performance.
  - h. The average coke burn-off rate (Mg (tons) per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to 40 CFR §60.102, 40 CFR §60.103, or 40 CFR §60.104(b)(2).
  - i. Data obtained from the daily feed sulfur tests.
  - j. Each rolling seven-day (7-day) average compliance determination for sulfur content of the feed.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.105, 40 CFR §60.107, 40 CFR §63.1576)<sup>1</sup>

#### 11. FCC Startup Air Heater

- a. The permittee shall maintain records of the fuel gas exemption that applies to the combustion of commercial-grade LPG gas that is inherently low in sulfur content.
- b. The permittee shall maintain a record of the number of days of operation of the unit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, 40 CFR §60.108a(c)(5))<sup>1</sup>

### **Section E. Notification and Reporting Requirements.**

#### 1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit on an annual basis the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate** and **Annual Emissions Report Form: Fuel Consumption** or equivalent forms, shall be used in reporting the FCCU feed rate and the fuel consumption of Furnace F-5300, respectively.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions 16, 17 and 25, respectively. These notifications shall include, but not be limited to:
  - a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - c. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

#### 4. Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form**, pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall be submitted **within ninety (90) days after the end of each calendar year**, and shall be signed and dated by a responsible official. The compliance certification shall include at a minimum the following information:

- a. The identification of each term or condition of the permit that is the basis of the certification;
- b. The compliance status;
- c. Whether compliance was continuous or intermittent;
- d. The methods used for determining the compliance status of the source currently and over the reporting period;
- e. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the

- requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act; and
- f. Any additional information as required by the Department including information to determine compliance.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. The permittee shall submit **semi-annually** written reports to the Department for monitoring purposes. The permittee shall submit a signed statement certifying the accuracy and completeness of the information contained in the report. The reports for Special Conditions Nos. E.5.a, E.5.b and E.5.c. 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 the reports for Special Conditions Nos. E.5.d thru E.5.h shall be submitted **within thirty (30) 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. The Vacuum Gas Oil (VGO) data consisting of the following:

- i. The maximum VGO feed rate (bbls/day) processed by the FCCU on a rolling 365-day average basis;
- ii. The maximum sulfur content (% by weight) of the VGO on a rolling seven-day (7-day) average basis; and
- iii. Any VGO exceedances as determined by the required VGO monitoring. Each exceedance reported shall include the date the exceedance occurred and the possible reason for the exceedance.

The enclosed **Monitoring Report Form: Vacuum Gas Oil (VGO)** or an equivalent form, shall be used for reporting.

- b. Any opacity exceedances as determined by the required VE monitoring for the F-5300 furnace. 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 there were no exceedances for that semi-annual period.

The enclosed **Monitoring Report Form: Visible Emissions**, shall be used.

- c. Any deviations from permit requirements shall be clearly identified.
- d. Any seven-day (7-day) period during which the average sulfur content of the fresh feed exceeds 0.30 percent by weight. The fresh feed sulfur content, a rolling

- seven-day (7-day) average, shall be determined using the procedures specified in Special Condition No. D.2.b of this Attachment.
- e. For each seven-day (7-day) period during which an exceedance has occurred as defined in Special Condition No. E.5.d of this Attachment:
    - i. The date that the exceedance occurred;
    - ii. An explanation of the exceedance;
    - iii. Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and
    - iv. A description of the corrective action taken, if any.
  - f. For each eight-hour (8-hour) period in which a feed sulfur measurement required by Special Condition No. D.2.b of this Attachment was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Department.
  - g. Compliance Report

The compliance report must contain the following information:

- i. Company name and address.
- ii. Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.
- iii. Date of report and beginning and ending dates of the reporting period.
- iv. If there are no deviations from any emission limitations that applies and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations or work practice standards during the reporting period and that no continuous emission monitoring system or continuous opacity monitoring system was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.
- v. For each deviation from an emission limitation occurring at the FCCU where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the following information:
  - (1) The total operating time of the FCCU during the reporting period.
  - (2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable) as applicable, and the corrective action taken.
  - (3) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero (0) and span and other daily calibration checks).
  - (4) The date and time that each malfunction started and stopped.
  - (5) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was inoperative, except for zero (low-level) and high level checks.

- (6) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was out-of-control, including the information in 40 CFR §63.8(c)(8).
- (7) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.
- (8) A summary of the total duration of the deviation during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging period specified in the regulation for other types of emission limitations), and the total duration as a percent of the total source operating time during the reporting period.
- (9) A breakdown of the total duration of the deviations during the reporting period and into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.
- (10) A summary of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging time specified in the regulation for other types of standards), and the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system as a percent of the total source operating time during that reporting period.
- (11) A breakdown of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period into periods that are due to monitoring equipment malfunctions, non-monitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.
- (12) An identification of each HAP that was monitored at the FCCU.
- (13) A brief description of the process units.
- (14) The monitoring equipment manufacturer(s) and model number(s).
- (15) The date of the latest certification or audit for the continuous opacity monitoring system or continuous emission monitoring system.
- (16) A description of any change in the continuous emission monitoring system or continuous opacity monitoring system, processes, or controls since the last reporting period.
- (17) A copy of any performance test done during the reporting period on the FCCU. The report may be included in the next semiannual report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, the permittee must submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief process description; a simplified flow diagram showing affected processes, control equipment, and sampling point locations; sampling site data; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions during the test; record of preparation of

standards; record of calibrations; raw data sheets for field sampling; raw data sheets for field and laboratory analyses; documentation of calculations; and any other information required by the test method.

- (18) Any requested change in the applicability of an emission standard in the periodic report. The permittee must include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements.
- (19) When actions taken to respond are consistent with the startup, shutdown and malfunction plan, the permittee is not required to report these events in the semiannual compliance report and the reporting requirement in 40 CFR §63.6(e)(3)(iii) and 40 CFR §63.10(d)(5) do not apply.
- (20) When actions taken to respond are not consistent with the startup, shutdown and malfunction plan, the permittee must report these events and the response taken in the semiannual compliance report. In this case, the reporting requirements in 40 CFR §63.6(e)(3)(iv) and 40 CFR §63.10(d)(5) do not apply.

h. Excess Emissions Report

- i. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department and the U.S. EPA for every **semi-annual calendar period**. The report shall include the following information:
  - (1) The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period;
  - (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the FCCU and F-5300 furnace. The nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted;
  - (3) The date and time identifying each period during which the continuous emissions monitoring system was inoperative except for zero (0) and span checks. The nature of each system repair or adjustment shall be described; and
  - (4) The report shall so state if no excess emissions have occurred. Also, the report shall so state if the continuous emissions monitoring system operated properly during the period and was not subject to any repairs or adjustments except for zero (0) and span checks.
- ii. All reports shall be postmarked by the thirtieth (30<sup>th</sup>) day following the end of each **semi-annual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form shall also be submitted in addition to the excess emissions and monitoring systems performance report.

- iii. For purposes of reports under 40 CFR §60.7(c), periods of excess emissions for the FCCU and F-5300 furnace that shall be determined and reported are defined as follows:
- (1) Opacity. All one-hour (1-hour) periods that contain two or more 6-minute periods during which the average opacity, as measured by the continuous opacity monitoring system, exceeds twenty (20) percent.
  - (2) Carbon Monoxide. All one-hour (1-hour) periods during which the average CO concentration, as measured by the CO continuous monitoring system under 40 CFR §60.105(a)(2), exceeds 500 ppmvd @ 0% O<sub>2</sub>.
  - (3) H<sub>2</sub>S. All rolling 3-hour periods during which the average concentration of H<sub>2</sub>S in RFG, as measured by the H<sub>2</sub>S continuous emissions monitoring system, exceeds 230 mg/dscm (160 ppmv).
  - (4) Sulfur Dioxide. All rolling 365-day periods during which the average SO<sub>2</sub> concentration, as measured by the SO<sub>2</sub> continuous emissions monitoring system, exceeds twenty-five (25) ppmvd @ 0% O<sub>2</sub> and all rolling seven-day (7-day) periods during which the average SO<sub>2</sub> concentration, as measured by the SO<sub>2</sub> continuous emissions monitoring system, exceeds 50 ppmvd @ 0% O<sub>2</sub>.
  - (5) Nitrogen Oxides. All rolling 365-day periods during which the average NO<sub>x</sub> concentration, as measured by the NO<sub>x</sub> continuous emissions monitoring system, exceeds fifty (50) ppmvd @ 0% O<sub>2</sub> and all rolling seven-day (7-day) periods during which the average NO<sub>x</sub> concentration, as measured by the NO<sub>x</sub> continuous emissions monitoring system, exceeds 87.9 ppmvd @ 0% O<sub>2</sub>.
- iv. Excess emissions indicated by the continuous emissions monitoring systems shall be considered violations of the applicable emission and concentration limits for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-32, §11-60.1-90, SIP §11-60-24, 40 CFR §60.105, 40 CFR §60.107, 40 CFR §63.1575)<sup>1</sup>

6. At least **thirty (30) days** prior to the following events, the permittee shall notify the Department in writing of:
- a. Conducting a performance specification test on any of the CEMS (CO, SO<sub>2</sub>, NO<sub>x</sub>, O<sub>2</sub>, or H<sub>2</sub>S) or COMS (opacity).
  - b. Conducting a source performance test as required by this Attachment, Section F, Testing Requirements.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.105, 40 CFR §60.106)<sup>1</sup>

**Section F. Testing Requirements.**

1. The permittee shall conduct or cause to be conducted annual performance tests for the FCCU, except for the opacity testing specified in Attachment II(I), Special Condition No. F.3.d, which is only required to be conducted initially. Performance tests shall be conducted for carbon monoxide (CO) and particulate matter (PM). All performance tests shall be conducted at the maximum production rate of the FCCU and at the maximum VGO feed rate, or at other production rates as may be specified by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

2. Performance tests for the emissions of CO and PM shall be conducted in accordance with the test methods set forth in 40 CFR Part 60, Appendix A. Only the test methods specified below or U.S. EPA-approved equivalent methods with prior written approval from the Department shall be used.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

3. The permittee shall determine compliance with the particulate matter (PM) standards in 40 CFR §60.102(a) as follows:

- a. The emission rate (E) of PM shall be computed for each run using the following equation:

$$E = C_s Q_{sd} / K R_c$$

Where:

E = Emission rate of PM, kg/Mg (lb/ton) of coke burn-off.  
C<sub>s</sub> = Concentration of PM, gr/dscm (gr/dscf).  
Q<sub>sd</sub> = Volumetric flow rate of effluent gas, dscm/hr (dscf/hr).  
R<sub>c</sub> = Coke burn-off rate, Mg/hr (ton/hr) coke.  
K = Conversion factor, 1000 g/kg (7000 gr/lb).

- b. Method 5B or 5F is to be used to determine the particulate matter emissions and associated moisture content from affected facilities without wet FGD systems. The sampling time for each run shall be at least sixty (60) minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Department when process variables or other factors preclude sampling for at least sixty (60) minutes.

- c. The coke burn-off rate (R<sub>c</sub>) shall be computed for each run using the following equation:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) - (K_2 Q_a - K_3 Q_r) ((\%CO/2) + (\%CO_2 + \%O_2))$$

Where:

R<sub>c</sub> = Coke burn-off rate, Mg/hr (ton/hr)



$Q_r$  = Volumetric flow rate of exhaust gas from catalyst regenerator before entering the emission control system, dscm/min (dscf/min).

$Q_a$  = Volumetric flow rate of air to FCCU regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

%CO<sub>2</sub> = carbon dioxide concentration, percent by volume (dry basis).

%CO = carbon monoxide concentration, percent by volume (dry basis).

%O<sub>2</sub> = Oxygen concentration, percent by volume (dry basis).

$K_1$  = Material balance and conversion factor,  $2.982 \times 10^{-4}$  (Mg-min)/(hr-dscm-%)

[ $9.31 \times 10^{-6}$  (ton-min)/(hr-dscf-%)].

$K_2$  = Material balance and conversion factor,  $2.088 \times 10^{-3}$  (Mg-min)/(hr-dscm-%)

[ $6.52 \times 10^{-5}$  (ton-min)/(hr-dscf-%)].

$K_3$  = Material balance and conversion factor,  $9.94 \times 10^{-5}$  (Mg-min)/(hr-dscm-%)

[ $3.1 \times 10^{-6}$  (ton-min)/(hr-dscf-%)].

- i. Method 2 shall be used to determine the volumetric flow rate ( $Q_r$ ).
- ii. The emission correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine CO<sub>2</sub>, CO and O<sub>2</sub> concentrations.

d. Method 9 and the procedures of 40 CFR §60.11 shall be used to determine opacity.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

4. The permittee shall determine compliance with the CO standard in 40 CFR §60.103(a) by using the integrated sampling or continuous sampling technique of Method 10 to determine the CO concentration (dry basis). The sampling time for each run shall be sixty (60) minutes.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, 40 CFR §60.106)<sup>1</sup>

5. Each source performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>

6. The permittee shall provide sampling and testing facilities at its own expense. The tests shall be conducted at the operating capacities identified in Special Condition No. F.1 of this Attachment. The Department may monitor any of the required source performance tests.

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

7. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

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

8. **At least thirty (30) days prior to performing a test**, the permittee shall submit a written source performance test plan to the Department and U.S. EPA that describes the test date(s), test duration, test locations, test method, source operation, fuel consumption, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A source performance test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>

9. **Within sixty (60) days after completion of the source performance test**, the permittee shall submit to the Department and U.S. EPA, the test report which shall include the operating conditions of the FCCU at the time of the test, the analysis of the VGO, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>

#### **Section G. Agency Notifications.**

Any document (including reports) required to be submitted by this Covered Source permit shall be in accordance with Attachment I, Standard Condition No. 29.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

<sup>3</sup>This date is to be revised upon issuance of the renewal for CSP No. 0088-01-C.

**Appendix H**  
**Current Version of CSP 0088-03-C**

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NEIL ABERCROMBIE  
GOVERNOR OF HAWAII



LINDA ROSEN, M.D., M.P.H.  
DIRECTOR OF HEALTH

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

In reply, please refer to:  
File:

September 11, 2014

**CERTIFIED MAIL**  
**RETURN RECEIPT REQUESTED**  
(7010 3090 0002 5271 6940)

14-735E CAB  
File No. 0088-21

Mr. Alan Davis  
Refinery Manager  
Chevron USA Products Company  
Hawaii Refinery  
91-480 Malakole Street  
Kapolei, Hawaii 96707-1807

Dear Mr. Davis:

**Subject: Covered Source Permit (CSP) No. 0088-03-C**  
**Significant Modification Application No. 0088-21**  
**Chevron USA Products Company**  
**One (1) 350 kW Black Start Diesel Engine Generator**  
**Located At: 91-480 Malakole Street, Kapolei, Oahu**  
**Date of Expiration: September 10, 2019**

The subject covered source permit is issued in accordance with Hawaii Administrative Rules, Title 11, Chapter 60.1. The issuance of this permit is based on the plans, specifications, and information that you submitted as part of your significant modification application dated December 18, 2013, and revised application dated January 22, 2014.

The covered source permit is issued subject to the conditions/requirements set forth in the following Attachments:

Attachment I: Standard Conditions  
Attachment II: Special Conditions  
Attachment III: Annual Fee Requirements  
Attachment IV: Annual Emissions Reporting Requirements

The following forms are enclosed for your use and submittal as required:

Compliance Certification Form  
Monitoring Report Form: Opacity Exceedances  
Monitoring Report Form: Black Start Diesel Engine Generator Hours of Operation  
Monitoring Report Form: Black Start Diesel Engine Generator Fuel Certification  
Annual Emissions Report Form: Black Start Diesel Engine Generator

The following are enclosed for your use in monitoring visible emissions:

Visible Emissions Form Requirements, State of Hawaii  
Visible Emissions Form

Mr. Alan Davis  
September 11, 2014  
Page 2

This permit: (a) shall not in any manner affect the title of the premises upon which the equipment is to be located; (b) does not release the permittee from any liability for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment; and (c) in no manner implies or suggests that the Department of Health, Clean Air Branch (herein after referred to as Department), or its officers, agents, or employees, assumes any liability, directly or indirectly, for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment.

If you have any questions, please contact Mr. Darin Lum of the Clean Air Branch at (808) 586-4200.

Sincerely,



STUART YAMADA, P.E., CHIEF  
Environmental Management Division

DL:nn

Enclosures

c: CAB Monitoring Section

**ATTACHMENT I: STANDARD CONDITIONS  
COVERED SOURCE PERMIT NO. 0088-03-C**

**Issuance Date: September 11, 2014**

**Expiration Date: September 10, 2019**

This permit is granted in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and is subject to the following standard conditions:

1. Unless specifically identified, the terms and conditions contained in this permit are consistent with the applicable requirement, including form, on which each term or condition is based.

(Auth.: HAR §11-60.1-90)

2. This permit, or a copy thereof, shall be maintained at or near the source and shall be made available for inspection upon request. The permit shall not be willfully defaced, altered, forged, counterfeited, or falsified.

(Auth.: HAR §11-60.1-6; SIP §11-60-11)<sup>2</sup>

3. This permit is not transferable whether by operation of law or otherwise, from person to person, from place to place, or from one piece of equipment to another without the approval of the Department of Health, except as provided in HAR, Section 11-60.1-91.

(Auth.: HAR §11-60.1-7; SIP §11-60-9)<sup>2</sup>

4. A request for transfer from person to person shall be made on forms furnished by the Department.

(Auth.: HAR §11-60.1-7)

5. In the event of any changes in control or ownership of the facilities to be constructed or modified, this permit shall be binding on all subsequent owners and operators. The permittee shall notify the succeeding owner and operator of the existence of this permit and its conditions by letter, copies of which will be forwarded to the Department and the U.S. Environmental Protection Agency (EPA), Region 9.

(Auth.: HAR §11-60.1-5, §11-60.1-7, §11-60.1-94)

6. The facility covered by this permit shall be constructed and operated in accordance with the application, and any information submitted as part of the application, for the Covered Source Permit. There shall be no deviation unless additional or revised plans are submitted to and approved by the Department, and the permit is amended to allow such deviation.

(Auth.: HAR §11-60.1-2, §11-60.1-4, §11-60.1-82, §11-60.1-84, §11-60.1-90)

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**Attachment I**  
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7. This permit (a) does not release the permittee from compliance with other applicable statutes of the State of Hawaii, or with applicable local laws, regulations, or ordinances, and (b) shall not constitute, nor be construed to be an approval of the design of the covered source.

(Auth.: HAR §11-60.1-5, §11-60.1-82)

8. The permittee shall comply with all the terms and conditions of this permit. Any permit noncompliance constitutes a violation of HAR, Chapter 11-60.1 and the Clean Air Act and is grounds for enforcement action; for permit termination, suspension, reopening, or amendment; or for denial of a permit renewal application.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-19, §11-60.1-90)

9. If any term or condition of this permit becomes invalid as a result of a challenge to a portion of this permit, the other terms and conditions of this permit shall not be affected and shall remain valid.

(Auth.: HAR §11-60.1-90)

10. The permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the terms and conditions of this permit.

(Auth.: HAR §11-60.1-90)

11. This permit may be terminated, suspended, reopened, or amended for cause pursuant to HAR, Sections, 11-60.1-10 and 11-60.1-98, and Hawaii Revised Statutes (HRS), Chapter 342B-27, after affording the permittee an opportunity for a hearing in accordance with HRS, Chapter 91.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90, §11-60.1-98)

12. The filing of a request by the permittee for the termination, suspension, reopening, or amendment of this permit, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

(Auth.: HAR §11-60.1-90)

13. This permit does not convey any property rights of any sort, or any exclusive privilege.

(Auth.: HAR §11-60.1-90)

14. The permittee shall notify the Department and U.S. EPA, Region 9, in writing of the following dates:

**CSP No. 0088-03-C**

**Attachment I**

**Page 3 of 6**

**Issuance Date: September 11, 2014**

**Expiration Date: September 10, 2019**

- a. The **anticipated date of initial start-up** for each emission unit of a new source or significant modification not more than sixty (60) days or less than thirty (30) days prior to such date;
- b. The **actual date of construction commencement** within fifteen (15) days after such date; and
- c. The **actual date of start-up** within fifteen (15) days after such date.

(Auth.: HAR §11-60.1-90)

15. The permittee shall furnish, in a timely manner, any information or records requested in writing by the Department to determine whether cause exists for terminating, suspending, reopening, or amending this permit, or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Department copies of records required to be kept by the permittee. For information claimed to be confidential, the Director of Health may require the permittee to furnish such records not only to the Department but also directly to the U.S. EPA, Region 9, along with a claim of confidentiality.

(Auth.: HAR §11-60.1-14, §11-60.1-90)

16. The permittee shall notify the Department in writing, of the **intent to shut down air pollution control equipment for necessary scheduled maintenance** at least twenty-four (24) hours prior to the planned shutdown. The submittal of this notice shall not be a defense to an enforcement action. The notice shall include the following:
  - a. Identification of the specific equipment to be taken out of service, as well as its location and permit number;
  - b. The expected length of time that the air pollution control equipment will be out of service;
  - c. The nature and quantity of emissions of air pollutants likely to be emitted during the shutdown period;
  - d. Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period; and
  - e. The reasons why it would be impossible or impractical to shut down the source operation during the maintenance period.

(Auth.: HAR §11-60.1-15; SIP §11-60-16)<sup>2</sup>

17. **Except for emergencies which result in noncompliance with any technology-based emission limitation in accordance with HAR, Section 11-60.1-16.5, in the event any emission unit, air pollution control equipment, or related equipment malfunctions or breaks down in such a manner as to cause the emission of air pollutants in violation of HAR, Chapter 11-60.1 or this permit, the permittee shall immediately notify the Department of the malfunction or breakdown, unless the protection of personnel or public health or safety demands immediate attention to the malfunction or breakdown and makes**



such notification infeasible. In the latter case, the notice shall be provided as soon as practicable. Within five (5) working days of this initial notification, the permittee shall also submit, in writing, the following information:

- a. Identification of each affected emission point and each emission limit exceeded;
- b. Magnitude of each excess emission;
- c. Time and duration of each excess emission;
- d. Identity of the process or control equipment causing the excess emission;
- e. Cause and nature of each excess emission;
- f. Description of the steps taken to remedy the situation, prevent a recurrence, limit the excessive emissions, and assure that the malfunction or breakdown does not interfere with the attainment and maintenance of the National Ambient Air Quality Standards and state ambient air quality standards;
- g. Documentation that the equipment or process was at all times maintained and operated in a manner consistent with good practice for minimizing emissions; and
- h. A statement that the excess emissions are not part of a recurring pattern indicative of inadequate design, operation, or maintenance.

The submittal of these notices shall not be a defense to an enforcement action.

(Auth.: HAR §11-60.1-16; SIP §11-60-16)<sup>2</sup>

18. The permittee may request confidential treatment of any records in accordance with HAR, Section 11-60.1-14.

(Auth.: HAR §11-60.1-14, §11-60.1-90)

19. This permit shall become invalid with respect to the authorized construction if construction is not commenced as follows:

- a. Within eighteen (18) months after the permit takes effect, is discontinued for a period of eighteen (18) months or more, or is not completed within a reasonable time.
- b. For phased construction projects, each phase shall commence construction within eighteen (18) months of the projected and approved commencement dates in the permit. This provision shall be applicable only if the projected and approved commencement dates of each construction phase are defined in Attachment II, Special Conditions, of this permit.

(Auth.: HAR §11-60.1-9, §11-60.1-90)

20. The Department may extend the time periods specified in Standard Condition No. 19 upon a satisfactory showing that an extension is justified. Requests for an extension shall be submitted in writing to the Department.

(Auth.: HAR §11-60.1-9, §11-60.1-90)

21. The permittee shall submit fees in accordance with HAR, Chapter 11-60.1, Subchapter 6.

(Auth.: HAR §11-60.1-90)

22. All certifications shall be in accordance with HAR, Section 11-60.1-4.

(Auth.: HAR §11-60.1-4, HAR §11-60.1-90)

23. The permittee shall allow the Director of Health, the Regional Administrator for the U.S. EPA and/or an authorized representative, upon presentation of credentials or other documents required by law:

- a. To enter the premises where a source is located or emission-related activity is conducted, or where records must be kept under the conditions of this permit and inspect at reasonable times all facilities, equipment, including monitoring and air pollution control equipment, practices, operations, or records covered under the terms and conditions of this permit and request copies of records or copy records required by this permit; and
- b. To sample or monitor at reasonable times substances or parameters to ensure compliance with this permit or applicable requirements of HAR, Chapter 11-60.1.

(Auth.: HAR §11-60.1-11, §11-60.1-90)

24. Within thirty (30) days of permanent discontinuance of the construction, modification, relocation, or operation of a covered source covered by this permit, the discontinuance shall be reported in writing to the Department by a responsible official of the source.

(Auth.: HAR §11-60.1-8; SIP §11-60-10)<sup>2</sup>

25. Each permit renewal application shall be submitted to the Department and the U.S. EPA, Region 9, no less than twelve (12) months and no more than eighteen (18) months prior to the permit expiration date. The Director may allow a permit renewal application to be submitted no less than six (6) months prior to the permit expiration date, if the Director determines that there is reasonable justification.

(Auth.: HAR §11-60.1-101, 40 CFR §70.5(a)(1)(iii))<sup>1</sup>

26. The terms and conditions included in this permit, including any provision designed to limit a source's potential to emit, are federally enforceable unless such terms, conditions, or requirements are specifically designated as not federally enforceable.

(Auth.: HAR §11-60.1-93)

27. The compliance plan and compliance certification submittal requirements shall be in accordance with HAR, Sections 11-60.1-85 and 11-60.1-86. As specified in HAR,

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**Attachment I**  
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Section 11-60.1-86, the compliance certification shall be submitted to the Department and the U.S. EPA, Region 9, once per year, or more frequently as set by any applicable requirement.

(Auth.: HAR §11-60.1-90)

28. Any document (including reports) required to be submitted by this permit shall be certified as being true, accurate, and complete by a responsible official in accordance with HAR, Sections 11-60.1-1 and 11-60.1-4, and shall be mailed to the following address:

**Clean Air Branch  
Environmental Management Division  
Hawaii Department of Health  
919 Ala Moana Boulevard, Room 203  
Honolulu, HI 96814**

Upon request and as required by this permit, all correspondence to the State of Hawaii Department of Health associated with this Covered Source Permit shall have duplicate copies forwarded to:

**Chief  
Permits Office, (Attention: Air-3)  
Air Division  
U.S. Environmental Protection Agency  
Region 9  
75 Hawthorne Street  
San Francisco, CA 94105**

(Auth.: HAR §11-60.1-4, §11-60.1-90)

29. To determine compliance with submittal deadlines for time-sensitive documents, the postmark date of the document shall be used. If the document was hand-delivered, the date received ("stamped") at the Clean Air Branch shall be used to determine the submittal date.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT II: SPECIAL CONDITIONS  
COVERED SOURCE PERMIT NO. 0088-03-C**

**Issuance Date:** September 11, 2014

**Expiration Date:** September 10, 2019

In addition to the Standard Conditions of the Covered Source Permit, the following emissions unit(s) is subject to the Special Conditions listed below:

**Section A. Equipment Description**

1. This permit encompasses the following equipment and related appurtenances:

One (1) 350 kW (755 hp) Cummins Power Generation black start diesel engine generator, Model No. DFEG, (Tier 2 rated).

(Auth.: HAR §11-60.1-3)

2. An identification tag or name plate shall be displayed on the black start diesel engine generator to show model no., serial no., and manufacturer. The identification tag or name plate shall be permanently attached to the black start diesel engine generator in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The black start diesel engine generator is subject to the provisions of the following federal regulations:
  - a. 40 Code of Federal Regulations (CFR) Part 60, Standards of Performance for New Stationary Sources, Subpart A, General Provisions;
  - b. 40 CFR Part 60, Standards of Performance for New Stationary Sources, Subpart III, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines;
  - c. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards), Subpart A, General Provisions; and
  - d. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards), Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.
2. The permittee shall comply with all applicable provisions of these standards, including all emission limitations and all notification, testing, monitoring, and reporting requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.4200, §63.1, §63.6585)<sup>1</sup>

**Section C. Emission and Operational Limitations, and/or Standards**

1. The black start diesel engine generator shall meet the definition of an Emergency Stationary RICE as described in 40 CFR §60.4219 and 40 CFR §63.6675, and Black Start Engine as described in 40 CFR §63.6675. The black start diesel engine generator shall comply with the requirements specified in 40 CFR §60.4211(f) and 40 CFR §63.6640(f) with the following exceptions:
  - i. The total hours of operation (emergency operation, maintenance checks, and readiness testing) of the black start diesel engine generator shall not exceed 500 hours in any rolling twelve-month (12-month) period;
  - ii. The black start diesel engine generator may be operated for up to 100 hours per calendar year for maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine; and
  - iii. The black start diesel engine generator shall not operate or is not contractually obligated to be available for up to fifteen (15) hours per calendar year for the purposes specified in 40 CFR §63.6640(f)(2)(ii) and (iii).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.4211, §63.6590, §63.6600, §63.6640)<sup>1</sup>

2. Fuel Limits

The black start diesel engine generator shall be fired only on diesel no. 2 with a maximum sulfur content of 0.0015% by weight, and a minimum cetane index of forty (40), or a maximum aromatic content of thirty five (35) volume percent.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §60.4207, §63.6590)<sup>1</sup>

3. For any six (6) minute averaging period, the black start diesel engine generator shall not exhibit visible emissions of twenty (20) percent opacity or greater, except as follows: during start-up, shut-down, or equipment breakdown, the diesel engine generator may exhibit visible emissions not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minutes.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

4. The black start diesel engine generator shall be properly maintained and kept in good operating condition at all times with scheduled inspections and maintenance as recommended by the manufacturer; or as needed.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

**Section D. Monitoring and Recordkeeping Requirements**

**1. Hours of Operation**

- a. The permittee shall install, operate, and maintain a non-resetting hour meter on the black start diesel engine generator for the continuous and permanent recording of the total hours of operation of the black start diesel engine generator for the purpose of showing compliance with Special Condition No. C.1 of this Attachment.
- b. The non-resetting meter shall not allow the manual resetting or other manual adjustments of the meter readings. The installation of any new non-resetting meter or the replacement of any existing non-resetting meter shall be designed to accommodate a minimum of five (5) years of equipment operation, considering any operational limitations, before the meter returns to a zero reading.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, 40 CFR §60.4209)<sup>1</sup>

**2. The permittee shall maintain records on the following items:**

- a. The total hours of operation of the black start diesel engine generator on a monthly and rolling twelve-month (12-month) basis to demonstrate compliance with Special Condition No. C.1.i of this Attachment. Records of the hours of operation of the black start diesel engine generator should include the reason the black start diesel engine generator was in operation during that time. Monthly records shall include:
  - i. Date of meter reading;
  - ii. Meter reading at the beginning of each month;
  - iii. Total hours of operation for each month;
  - iv. Total hours of operation on a rolling twelve-month (12-month) basis;
  - v. Total hours of operation associated with maintenance checks and readiness testing to demonstrate compliance with Special Condition No. C.1.ii of this Attachment; and
  - vi. Total hours of operation associated with the purposes specified in 40 CFR §63.6640(f)(2)(ii) and (iii) to demonstrate compliance with Special Condition No. C.1.iii of this Attachment.
- b. Fuel delivery receipts showing the fuel type, sulfur content (percent by weight), cetane index or aromatic content (volume percent), date of delivery, and gallons of fuel delivered to the site for use in the black start diesel engine generator shall be maintained. Fuel sulfur content, cetane index, and aromatic content may be demonstrated by providing the supplier's fuel specification sheet for the type of fuel purchased and received; and
- c. Records on inspections, maintenance, and any repair work conducted on the black start diesel engine generator. At a minimum, these records shall include: the date of the inspection/work, name and title of personnel performing inspection/work, a short

description of the action and/or any such repair work, and a description of the part(s) inspected or repaired.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, 40 CFR §60.4211, §60.4214, §63.6655)<sup>1</sup>

3. Visible Emissions (VE)

The permittee shall conduct **monthly** (calendar month) VE observations for the black start diesel engine generator by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

4. All records, including support information, shall be maintained for at least **five (5) years** from the date of any required monitoring, recordkeeping, testing, or reporting. Support information includes all maintenance, inspection, repair records, and copies of all reports required by this permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representative upon request.

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

**Section E. Notification and Reporting Requirements**

1. Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Condition Nos. 14, 17, and 24, respectively:
- Anticipated date of initial start-up, actual date of construction commencement, and actual date of start-up;*
  - Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and*
  - Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.*

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

2. The permittee shall report within **five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions

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may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

### 3. Monitoring Reports

The permittee shall submit **semi-annually** the following written report to the Department for monitoring purposes. The report 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. The total operating hours of the black start diesel engine generator on a monthly and rolling twelve-month (12-month) basis. The enclosed **Monitoring Report Form: Black Start Diesel Engine Generator Hours of Operation**, shall be used for reporting;
- b. The type of fuel fired, maximum sulfur content (percent by weight), minimum cetane index and maximum aromatic content (volume percent). The enclosed **Monitoring Report Form: Black Start Diesel Engine Generator Fuel Certification**, shall be used for reporting; and
- c. Any opacity exceedances as determined by the required VE 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 are 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: Opacity Exceedances**, shall be used.

- d. Any deviations from permit requirements shall be clearly identified.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

### 4. Annual Emissions Reports

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit on an **annual basis** the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within **sixty (60) days after the end of each calendar year**. The enclosed **Annual Emissions Report Form: Black Start Diesel Engine Generator**, shall be used in reporting.



**CSP No. 0088-03-C**  
**Attachment II**  
**Page 6 of 7**  
**Issuance Date: September 11, 2014**  
**Expiration Date: September 10, 2019**

Upon the written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-114)

#### 5. Compliance Certification Form

During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR, Section 11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

- a. The identification of each term or condition of the permit that is the basis of the certification;
- b. The compliance status;
- c. Whether compliance was continuous or intermittent;
- d. The methods used for determining the compliance status of the source currently and over the reporting period;
- e. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
- f. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedances as defined in 40 CFR 64 occurred; and
- g. Any additional information as required by the Department including information to determine compliance.

The compliance certification shall be submitted **within sixty (60) days** after the end of each calendar year, and shall be signed and dated by a responsible official.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

#### 6. Initial Notification

The permittee shall submit to the Department and U.S. EPA Region 9, an initial notification of applicability within 120 days after initial startup of the black start diesel engine generator. The notification shall include the information in 40 CFR §63.9(b)(2)(i) through (v), and a

**CSP No. 0088-03-C**  
**Attachment II**  
**Page 7 of 7**  
**Issuance Date: September 11, 2014**  
**Expiration Date: September 10, 2019**

statement that the black start diesel engine generator has no additional requirements and an explanation of the basis of the exclusion.

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §60.4214, §63.6645)<sup>1</sup>

7. The permittee shall submit the serial number of the black start diesel engine generator to the Department within **five (5) working days** after initial startup of the black start diesel engine generator.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

#### **Section F. Agency Notification**

Any document (including reports) required to be submitted by this permit shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT III: ANNUAL FEE REQUIREMENTS  
COVERED SOURCE PERMIT NO. 0088-03-C**

**Issuance Date: September 11, 2014**

**Expiration Date: September 10, 2019**

The following requirements for the submittal of annual fees are established pursuant to Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control. Should HAR, Chapter 60.1 be revised such that the following requirements are in conflict with the provisions of HAR, Chapter 60.1, the permittee shall comply with the provisions of HAR, Chapter 60.1:

1. Annual fees shall be paid in full:
  - a. Within **sixty (60) days** after the end of each calendar year; and
  - b. Within **thirty (30) days** after the permanent discontinuance of the covered source.
2. The annual fees shall be determined and submitted in accordance with Hawaii Administrative Rules, Chapter 11-60.1, Subchapter 6.
3. The annual emissions data for which the annual fees are based shall accompany the submittal of any annual fees and be submitted on forms furnished by the Department of Health.
4. The annual fees and the emission data shall be mailed to:

**Clean Air Branch  
Environmental Management Division  
Hawaii Department of Health  
919 Ala Moana Boulevard, Room 203  
Honolulu, HI 96814**

**ATTACHMENT IV: ANNUAL EMISSIONS REPORTING REQUIREMENTS  
COVERED SOURCE PERMIT NO. 0088-03-C**

**Issuance Date: September 11, 2014**

**Expiration Date: September 10, 2019**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

1. Complete the attached form(s):

**Annual Emissions Report Form: Black Start Diesel Engine Generator**

2. The reporting period shall be from January 1 to December 31 of each year. All reports shall be submitted to the Department of Health within **sixty (60) days** after the end of each calendar year and shall be mailed to the following address:

**Clean Air Branch  
Environmental Management Division  
Hawaii Department of Health  
919 Ala Moana Boulevard, Room 203  
Honolulu, HI 96814**

3. The permittee shall retain the information submitted, including all emission calculations. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department of Health upon request.
4. Any information submitted to the Department of Health without a request for confidentiality shall be considered public record.
5. In accordance with HAR, Section 11-60.1-14, the permittee may request confidential treatment of specific information, including information concerning secret processes or methods of manufacture, by submitting a written request to the Director and clearly identifying the specific information that is to be accorded confidential treatment.

**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-03-C  
PAGE 1 OF \_\_\_\_**

**Issuance Date: September 11, 2014**

**Expiration Date: September 10, 2019**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following certification at least annually, or more frequently as requested by the Department.

(Make Copies of the Compliance Certification Form for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Company/Facility Name: \_\_\_\_\_

Responsible Official (Print): \_\_\_\_\_

Title: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-03-C  
(CONTINUED, PAGE 2 OF \_\_\_\_)**

Issuance Date: September 11, 2014

Expiration Date: September 10, 2019

The purpose of this form is to evaluate whether or not the facility was in compliance with the permit terms and conditions during the covered period. If there were any deviations to the permit terms and conditions during the covered period, the deviation(s) shall be certified as *intermittent compliance* for the particular permit term(s) or condition(s). Deviations include failure to monitor, record, report, or collect the minimum data required by the permit to show compliance. In the absence of any deviation, the particular permit term(s) or condition(s) may be certified as *continuous compliance*.

**Instructions:**

Please certify Sections A, B, and C below for continuous or intermittent compliance. Sections A and B are to be certified as a group of permit conditions. Section C shall be certified individually for each operational and emissions limit condition as listed in the Special Conditions section of the permit (list all applicable equipment for each condition). Any deviations shall also be listed individually and described in Section D. The facility may substitute its own generated form in verbatim for Sections C and D.

**A. Attachment I, Standard Conditions**

<u>Permit term/condition</u>	<u>Equipment</u>	<u>Compliance</u>
All standard conditions	All Equipment listed in the permit	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent

**B. Special Conditions - Monitoring, Recordkeeping, Reporting, Testing, and INSIG**

<u>Permit term/condition</u>	<u>Equipment</u>	<u>Compliance</u>
All monitoring conditions	All Equipment listed in the permit	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
All recordkeeping conditions	All Equipment listed in the permit	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
All reporting conditions	All Equipment listed in the permit	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
All testing conditions	All Equipment listed in the permit	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
All INSIG conditions	All Equipment listed in the permit	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent

**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-03-C  
(CONTINUED, PAGE \_\_\_\_ OF \_\_\_\_)**

Issuance Date: September 11, 2014

Expiration Date: September 10, 2019

**C. Special Conditions - Operational and Emissions Limitations**

Each permit term/condition shall be identified in chronological order using attachment and section numbers (e.g., Attachment II, B.1, Attachment IIA, Special Condition No. B.1.f, etc.). Each equipment shall be identified using the description stated in Section A of the Special Conditions (e.g., unit no., model no., serial no., etc.). Check all methods (as required by permit) used to determine the compliance status of the respective permit term/condition.

Permit term/condition	Equipment	Method	Compliance
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent

**(Make Additional Copies if Needed)**

**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-03-C  
(CONTINUED, PAGE \_\_\_ OF \_\_\_)**

**Issuance Date: September 11, 2014**

**Expiration Date: September 10, 2019**

**D. Deviations**

<u>Permit Term/ Condition</u>	<u>Equipment / Brief Summary of Deviation*</u>	<u>Deviation Period time (am/pm) &amp; date (mo/day/yr)</u>	<u>Date of Written Deviation Report to DOH (mo/day/yr)</u>
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	

\*Identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR 64 occurred.

**(Make Additional Copies if Needed)**





**MONITORING REPORT FORM  
BLACK START DIESEL ENGINE GENERATOR HOURS OF OPERATION  
COVERED SOURCE PERMIT NO. 0088-03-C**

**Issuance Date:** September 11, 2014

**Expiration Date:** September 10, 2019

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:  
(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Company/Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as horsepower, kilowatt, tons/hour, etc.)

Serial/ID Nos.: \_\_\_\_\_

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

Responsible Official (Print): \_\_\_\_\_

Title: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

MONTH	TOTAL HOURS OF OPERATION MONTHLY BASIS	TOTAL HOURS OF OPERATION ROLLING 12-MONTH BASIS
JANUARY		
FEBRUARY		
MARCH		
APRIL		
MAY		
JUNE		
JULY		
AUGUST		
SEPTEMBER		
OCTOBER		
NOVEMBER		
DECEMBER		

**MONITORING REPORT FORM  
BLACK START DIESEL ENGINE GENERATOR FUEL CERTIFICATION  
COVERED SOURCE PERMIT NO. 0088-03-C**

**Issuance Date:** September 11, 2014

**Expiration Date:** September 10, 2019

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Company/Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as horsepower, kilowatt, tons/hour, etc.)

Serial/ID Nos.: \_\_\_\_\_

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

Responsible Official (Print): \_\_\_\_\_

Title: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

TYPE OF FUEL FIRED	MAXIMUM SULFUR CONTENT (% BY WEIGHT)	MINIMUM CETANE INDEX	MAXIMUM AROMATIC CONTENT (VOLUME %)

**ANNUAL EMISSIONS REPORT FORM  
BLACK START DIESEL ENGINE GENERATOR  
COVERED SOURCE PERMIT NO. 0088-03-C**

**Issuance Date:** September 11, 2014

**Expiration Date:** September 10, 2019

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Company/Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as horsepower, kilowatt, tons/hour, etc.)

Serial/ID Nos.: \_\_\_\_\_

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

Responsible Official (Print): \_\_\_\_\_

Title: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

TYPE OF FUEL FIRED	ANNUAL FUEL CONSUMPTION (GALLONS/YEAR)	MAXIMUM SULFUR CONTENT (% BY WEIGHT)

**VISIBLE EMISSIONS FORM REQUIREMENTS  
STATE OF HAWAII  
COVERED SOURCE PERMIT NO. 0088-03-C**

**Issuance Date:** September 11, 2014

**Expiration Date:** September 10, 2019

The **Visible Emissions (VE) Form** shall be completed **monthly** (*each calendar month*) for each equipment subject to opacity limits in accordance with 40 CFR Part 60, Appendix A, Method 9. At least **annually** (*calendar year*), VE observation shall be conducted for each equipment subject to opacity limits by a certified reader in accordance with Method 9. The VE Form shall be completed as follows:

1. VE observations shall take place during the day only. The opacity shall be noted in five (5) percent increments (e.g., 25%).
2. Orient the sun within a 140 degree sector to your back. Provide a source layout sketch on the VE Form using the symbols as shown.
3. For VE observations of stacks, stand at least three (3) stack heights but not more than a quarter mile from the stack.
4. For VE observations of fugitive emissions from crushing and screening plants, stand at least 4.57 meters (15 feet) from the visible emissions source, but not more than a quarter mile from the visible emission source.
5. Two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals for each stack or emission point.
6. The six (6) minute average opacity reading shall be calculated for each observation.
7. If possible, the observations shall be performed as follows:
  - a. Read from where the line of sight is at right angles to the wind direction.
  - b. The line of sight shall not include more than one (1) plume at a time.
  - c. Read at the point in the plume with the greatest opacity (without condensed water vapor), ideally while the plume is no wider than the stack diameter.
  - d. Read the plume at fifteen (15) second intervals only. Do not read continuously.
  - e. The equipment shall be operating at the maximum permitted capacity.
8. If the equipment was shut-down for that period, briefly explain the reason for shut-down in the comment column.

The permittee shall retain the completed VE Forms for recordkeeping. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department of Health, or their representative upon request.

Any required initial and annual performance test performed in accordance with Method 9 by a certified reader shall satisfy the respective equipment's VE monitoring requirements for the month the performance test is performed.

**VISIBLE EMISSIONS FORM  
COVERED SOURCE PERMIT NO. 0088-03-C**

**Issuance Date: September 11, 2014**

**Expiration Date: September 10, 2019**

(Make Copies for Future Use for Each Stack or Emission Point)

Company/Facility Name: \_\_\_\_\_

For stacks, describe equipment and fuel: \_\_\_\_\_

For fugitive emissions from crushers and screens, describe:

Fugitive emission point: \_\_\_\_\_

Plant Production (tons/hr): \_\_\_\_\_

(During observation)

Stack **X**  
Sun ●  
Wind →

Draw North Arrow

**X** Emission Point

Observers Position

140

Sun Location Line

**Site Conditions:**

Emission point or stack height above ground (ft): \_\_\_\_\_

Emission point or stack distance from observer (ft): \_\_\_\_\_

Emission color (black or white): \_\_\_\_\_

Sky conditions (% cloud cover): \_\_\_\_\_

Wind speed (mph): \_\_\_\_\_

Temperature (EF): \_\_\_\_\_

Observer Name: \_\_\_\_\_

Certified? (Yes/No): \_\_\_\_\_

Observation Date and Start Time: \_\_\_\_\_

MINUTES	Seconds				COMMENTS
	0	15	30	45	
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

Observation Date and Start Time: \_\_\_\_\_

MINUTES	Seconds				COMMENTS
	0	15	30	45	
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

**Appendix I**  
**Current Version of Attachment II(A)**

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DAVID Y. IGE  
GOVERNOR OF HAWAII



VIRGINIA PRESSLER, M.D.  
DIRECTOR OF HEALTH

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

In reply, please refer to  
File:

November 2, 2015

**CERTIFIED MAIL**  
**RETURN RECEIPT REQUESTED**  
(7009 2820 0001 6573 2013)

15-761E CAB  
File No. 0088-23

Mr. Jon Mauer  
Refinery Manager  
Chevron USA Products Company  
Hawaii Refinery  
91-480 Malakole Street  
Kapolei, Hawaii 96707-1807

Dear Mr. Mauer:

**SUBJECT: Administrative Permit Amendment**  
**Covered Source Permit (CSP) No. 0088-01-C**  
**Chevron USA Products Company**  
**Petroleum Refinery - Catalytic Oxidation Unit**  
**Located At: 91-480 Malakole Street, Kapolei, Oahu**  
**Date of Expiration: June 27, 2011 (this date is to be revised upon issuance**  
**of the renewal for CSP No. 0088-01-C)**

The Department of Health, Clean Air Branch (herein referred to as Department), acknowledges receipt of your letter dated October 22, 2015, regarding an administrative permit amendment to the subject covered source permit. Pursuant to Hawaii Administrative Rules, Chapter 11-60.1, the Department hereby amends the subject covered source permit.

The enclosed amended Attachment II(A): Special Conditions for Miscellaneous Process Units and Source Operations shall supersede, in its entirety, the corresponding Attachment II(A) issued with CSP No. 0088-01-C on June 23, 2015. All other permit conditions issued with CSP No. 0088-01-C shall not be affected and shall remain valid. A receipt for the application filing fee of \$100.00 is enclosed.

If there are any questions regarding these matters, please contact Mr. Darin Lum of the Clean Air Branch at (808) 586-4200.

Sincerely,

A handwritten signature in cursive script, appearing to read "Stuart Yamada".

STUART YAMADA, P.E., CHIEF  
Environmental Management Division

DL:dh

c: CAB Monitoring Section



**ATTACHMENT II(A): SPECIAL CONDITIONS  
COVERED SOURCE PERMIT NO. 0088-01-C  
MISCELLANEOUS PROCESS UNITS AND SOURCE OPERATIONS**

**Amended Date: November 2, 2015**

**Expiration Date: June 27, 2011<sup>3</sup>**

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description.**

1. This portion of the Covered Source Permit encompasses the requirements for miscellaneous process units and/or source operations not included with the Special Conditions of Attachments II(B) through II(M).

(Auth.: HAR §11-60.1-3)

**Section B. Applicable Federal Regulations.**

1. The FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, and FCC Flare Vapor Recovery System are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, New Source Performance Standards (NSPS):
    - i. Subpart A, General Provisions; and
    - ii. Subpart GGG, Standards of Performance for Equipment Leaks in Petroleum Refineries.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing, and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.590)<sup>1</sup>

2. The Cogeneration Plant, Crude Unit Furnaces and Desalter, and FCC Flare Vapor Recovery System are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, New Source Performance Standards (NSPS):
    - i. Subpart A, General Provisions; and
    - ii. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.690)<sup>1</sup>

3. The FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, Alkylation Plant and Effluent Treatment Plant are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT):
    - i. Subpart A, General Provisions; and
    - ii. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.
  - b. The above regulations are not applicable to any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system that is intended to operate in organic hazardous air pollutant service, as defined in 40 CFR §63.641, for less than 300 hours during the calendar year.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11.60.1-174, 40 CFR §63.640)<sup>1</sup>

4. The storage and use of flammable substances in this facility is subject to the provisions of 40 CFR Part 68, Chemical Accident Prevention Provisions. The permittee shall comply with all applicable requirements, including the submittal of:
  - a. A compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR §68.10(a); or
  - b. As part of the compliance certification submitted pursuant to Attachment I, Standard Condition No. 28, a certification statement that the facility is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of the Risk Management Plan.

(Auth.: HAR §11-60.1-3, §11-60.1-90, 40 CFR §68)<sup>1</sup>

5. The Catalytic Oxidation Unit is subject to the provisions of the following federal regulations:
- a. 40 CFR Part 60, New Source Performance Standards (NSPS):
    - i. Subpart A, General Provisions; and
    - ii. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.100a)<sup>1</sup>

**Section C. Operational and Emission Limitations.**

1. All pumps and compressors handling volatile organic compounds having a Reid Vapor Pressure (RVP) of 1.5 pounds per square inch (psi) or greater which can be fitted with mechanical seals shall have mechanical seals or other equipment of equal efficiency for purposes of air pollution control as may be approved by the Department. Pumps and compressors not capable of being fitted with mechanical seals, such as reciprocating pumps, shall be fitted with the best sealing system available for air pollution control given the particular design of pump or compressor as may be approved by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-41, §11-60.1-90)

2. The permittee shall not cause or allow the emissions of gas streams containing volatile organic compounds from a vapor blowdown system unless these gases are burned by smokeless flares, or abated by an equally effective control device as approved by the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-42, §11-60.1-90)

3. Compressor

- a. Each compressor located at the FCC Unit, Crude Unit, LPG Refrigeration System, Cogeneration Plant and Liquid Fuel System, and FCC Flare Vapor Recovery System shall be equipped and operated with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in 40 CFR §60.482-1(c), 40 CFR §60.482-3(h) and 40 CFR §60.482-3(i).
- b. Each compressor seal system as required in Special Condition No. C.3.a of this attachment shall be as follows:

- i. Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or
  - ii. Equipped with a barrier fluid system that is connected by a closed vent system to a control device that complies with the requirements of 40 CFR §60.482-10; or
  - iii. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
- c. The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.
- d. A compressor is exempt from the requirements of Special Condition Nos. C.3.a and C.3.b of this attachment if it is equipped with a closed vent system capable of capturing and transporting any leakage from the seal to a control device that complies with the requirements of 40 CFR §60.482-10, except as provided in Special Condition No. C.3.e of this attachment.
- e. Any compressor that is designated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by methods specified in 40 CFR §60.485(c) and is tested for compliance initially upon designation, annually, and at other times requested by the Department is exempt from the requirements of Special Condition Nos. C.3.a through C.3.d, D.3.a and D.3.b of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

#### 4. Pressure Relief Devices in Gas/Vapor Service

- a. Except during pressure releases, each pressure relief device in gas/vapor service located at the FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, and FCC Flare Vapor Recovery System shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR §60.485(c).
- b. *After each pressure release*, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, **as soon as practicable**, but no later than five (5) calendar days *after the pressure release*, except as provided in Special Condition No. C.8 of this attachment.
- c. Any pressure relief device is exempt from the requirements of Special Condition No. C.4.a and C.4.b of this attachment if it is equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device that complies with the requirements of 40 CFR §60.482-10.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

**5. Open Ended Valves/Lines**

- a. Each open-ended valve or line at the FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, Blending and Shipping Area, Alkylation Plant and Effluent Treatment Plant shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR §60.482-1(c). The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.
- b. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.
- c. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with Special Condition No. C.5.a of this attachment at all other times.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

**6. Sampling Connection Systems**

- a. Each sampling connection system at the FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, Blending and Shipping Area, Alkylation Plant and Effluent Treatment Plant shall be equipped with a closed-purged, closed-loop, or closed-vent system, except as provided in 40 CFR §60.482-1(c).
- b. Each closed-purged, closed-loop, or closed-vent system shall comply with the following requirements:
  - i. Return the purged process fluid directly to the process line; or
  - ii. Collect and recycle the purged process fluid to a process; or
  - iii. Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of 40 CFR §60.482-10.
- c. In-situ sampling systems and sampling systems without purges are exempt from the requirements of Special Condition No. C.6.a and C.6.b of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

**7. Individual Drain Systems**

- a. Sewer drains located at the Cogeneration Plant, Crude Unit Furnaces and Desalter, and FCC Flare Vapor Recovery System shall be equipped with water seal controls.
- b. Junction boxes located at the Cogeneration Plant shall be equipped with a cover and may have an open vent pipe at least three (3) feet (90 cm) in length and shall not exceed four (4) inches (10.2 cm) in diameter.

- c. Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.
- d. Sewer lines located at the Cogeneration Plant, Crude Unit Furnaces and Desalter, and FCC Flare Vapor Recovery System shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.
- e. Refinery wastewater routed through new process drains and a new first common downstream junction box at the Cogeneration Plant either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

8. Delay of Repair

- a. Delay of repair of equipment for which leaks have been detected will be allowed if the repair is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.
- b. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.
- c. Delay of repair for valves will be allowed if:
  - i. The permittee demonstrates that emissions of purged material resulting from the immediate repair are greater than the fugitive emissions likely to result from the delay of repair; and
  - ii. When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with the requirements of 40 CFR §60.482-10.
- d. Delay of repair for pumps will be allowed if:
  - i. Repair requires the use of a dual mechanical seal system that includes a barrier fluid system; and
  - ii. Repair is completed as soon as practicable, but not later than six (6) months after the leak was detected.
- e. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than six (6) months after the first process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

9. Catalytic Oxidation Unit - Offgas

- a. The offgas from the Foul Water Treatment Plant shall be routed to the Catalytic Oxidation Unit at all times, except during periods of maintenance, in which the foul water shall be stored in permitted storage tanks.
- b. The permittee shall not oxidize in the Catalytic Oxidation Unit any offgas from the Foul Water Treatment Plant that contains H<sub>2</sub>S in excess of 162 ppmv determined hourly on a three-hour (3-hour) rolling average basis and H<sub>2</sub>S in excess of sixty (60) ppmv determined daily on a 365 successive calendar day rolling average basis.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.102a(g)(1)(ii))<sup>1</sup>

10. Catalytic Oxidation Unit – Visible Emissions

For any six (6) minute averaging period, the Catalytic Oxidation Unit shall not exhibit visible emissions of twenty (20) percent opacity or greater, except as follows: during start-up, shut-down, or equipment breakdown, the Catalytic Oxidation Unit may exhibit visible emissions not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minutes.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

11. Catalytic Oxidation Unit – Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the Catalytic Oxidation Unit emissions in excess of the following emission limits:

Pollutant	Emission Limits (lb/hr) <sup>1</sup>
NO <sub>x</sub>	7.0
CO	7.4
VOC	0.63

<sup>1</sup> Based on a 3-hr average

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

12. Foul Water Treatment Plant

The permittee shall maintain the pH of the Foul Water Treatment Plant effluent water greater than or equal to nine (9) and the temperature of the Foul Water Treatment Plant effluent water between 210 °F and 250 °F. The permittee shall also maintain the H<sub>2</sub>S concentration of the Foul Water Treatment Plant offgas less than five (5) ppm.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

**Section D. Monitoring and Recordkeeping Requirements.**

1. All records, including support information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Support information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be in a permanent form suitable for inspection and made available to the Department or their representatives upon request.

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

2. Pumps in Light Liquid Service

- a. Each pump in light liquid service at the FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, Blending and Shipping Area, Alkylation Plant, and Effluent Treatment Plant shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §60.485(b), except as provided in 40 CFR §60.482-1(c) and 40 CFR §60.482-2(d), (e) and (f).
- b. Each pump in light liquid service at the FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, Blending and Shipping Area, Alkylation Plant, and Effluent Treatment Plant shall be checked by visual inspection **each calendar week** for indications of liquids dripping from the pump seal.
- c. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
- d. If there are indications of liquids dripping from the pump seal, a leak is detected.
- e. When a leak is detected, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected**.
- f. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of Special Condition No. D.2.a of this attachment provided the requirements of 40 CFR §60.482-2(d)(1) through (6) are met.
- g. Any pump that is designated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of Special Condition Nos. D.2.a, D.2.b, D.2.e, and D.2.f of this attachment if the pump:
  - i. Has no externally actuated shaft penetrating the pump housing;
  - ii. Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in 40 CFR §60.485(c); and
  - iii. Is tested for compliance with Special Condition No. 2.g.ii of this attachment initially upon designation, annually, and at other times requested by the Department.



- h. If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a control device that complies with the requirements of 40 CFR §60.482-10, it is exempt from the requirements of Special Condition Nos. D.2.a through D.2.g of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

### 3. Compressors

- a. Each compressor barrier fluid system shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both. Each sensor shall be checked **daily** or shall be equipped with an audible alarm. If the sensor indicates failure of the seal system, the barrier system, or both, a leak is detected.
- b. When a leak is detected, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected**.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

### 4. Pressure Relief Devices in Gas/Vapor Service

**No later than five (5) calendar days after a pressure release**, the pressure relief device subject to the requirements of 40 CFR Part 60, Subpart GGG shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR §60.485(c).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

### 5. Valves in Light Liquid Service and in Gas/Vapor Service

- a. Each valve in light liquid service at the FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, Blending and Shipping Area, Alkylation Plant and Effluent Treatment Plant shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §60.485(b).
- b. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
- c. Any valve for which a leak is *not detected for two (2) successive months* may be monitored the **first month of every quarter**, beginning with the next quarter, *until a leak is detected*. *If a leak is detected*, the valve shall be monitored **monthly** until a leak is *not detected for two (2) successive months*.
- d. *When a leak is detected*, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8 of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected**.

- e. First attempts at repair include, but are not limited to, the following best practices where practicable:
  - i. Tightening of bonnet bolts;
  - ii. Replacement of bonnet bolts;
  - iii. Tightening of packing gland nuts; and
  - iv. Injection of lubricant into lubricated packing.
- f. Any valve that is designated, as described in 40 CFR §60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of Special Condition No. D.5.a of this attachment if the valve:
  - i. Has no external actuating mechanism in contact with the process fluid;
  - ii. Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR §60.485(c); and
  - iii. Is tested for compliance with the Special Condition No. D.5.f.ii of this attachment initially upon designation, annually, and at other times requested by the Department.
- g. Any valve that is designated, as described in 40 CFR §60.486(f)(1), as unsafe-to-monitor valve and satisfies the criteria outlined in 40 CFR §60.482-7(g) is exempt from the requirements of Special Condition No. D.5.a of this attachment.
- h. Any valve that is designated, as described in 40 CFR §60.486(f)(2), as difficult-to-monitor valve and satisfies the criteria outlined in 40 CFR §60.482-7(h) is exempt from the requirements of Special Condition No. D.5.a of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

- 6. Pumps and Valves in Heavy Liquid Service, Pressure Relief Devices in Light Liquid or Heavy Liquid Service, and Flanges and other Connectors
  - a. Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors at the FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, FCC Flare Vapor Recovery System, Blending and Shipping Area, Alkylation Plant and Effluent Treatment Plant shall be monitored **within five (5) days** by the method specified in 40 CFR §60.485(b) *if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method.*
  - b. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
  - c. *When a leak is detected*, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8 of this attachment. The first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected.**
  - d. First attempts at repair include, but are not limited to, the best practices described in Special Condition No. D.5.e of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

7. *When each leak is detected*, a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

8. The identification on a valve may be removed after it has been monitored for two (2) successive months as specified in Special Condition No. D.5.c of this attachment and no leak has been detected during those two (2) months. The identification on equipment except a valve may be removed after it has been repaired.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

9. *When each leak is detected*, the following information shall be recorded in a log and shall be kept for two (2) years in a readily accessible location:

- a. The instrument and operator identification numbers and the equipment identification number;
- b. The date the leak was detected and the dates of each attempt to repair the leak;
- c. Repair methods applied in each attempt to repair the leak;
- d. "Above 10,000" if the maximum instrument reading measured by the methods specified in 40 CFR §60.485(a) after each repair attempt is equal to or greater than 10,000 ppm;
- e. "Repair delayed" and the reason for the delay if a leak is not repaired within fifteen (15) calendar days after discovery of the leak;
- f. The signature of the permittee whose decision it was that repair could not be effected without a process shutdown;
- g. The expected date of successful repair of the leak if a leak is not repaired within fifteen (15) days;
- h. Dates of process unit shutdown that occur while the equipment is unrepaired; and
- i. The date of successful repair of the leak.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

10. The following information pertaining to all equipment subject to the requirements of 40 CFR Part 60, Subpart GGG, or 40 CFR Part 63, Subpart CC, shall be recorded in a log that is kept in a readily accessible location:

- a. A list of identification numbers for all equipment;
- b. A list of identification numbers for equipment that are designated for no detectable emissions which is signed by the permittee;
- c. A list of equipment identification numbers for pressure relief devices required to comply with the requirements of Special Condition No. C.4 of this attachment;
- d. The dates of each compliance test used to determine no detectable emissions:

- i. The background level measured during each compliance test; and
- ii. The maximum instrument reading measured at the equipment during each compliance test.

e. A list of identification numbers for equipment in vacuum service.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

11. The following information pertaining to all valves subject to the requirements of 40 CFR Part 60, Subpart GGG, or 40 CFR Part 63, Subpart CC, shall be recorded in a log that is kept in a readily accessible location:

- a. A list of identification numbers for valves that are designated as unsafe-to-monitor, an explanation for each valve stating why the valve is unsafe-to-monitor, and the plan for monitoring each valve; and
- b. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

12. The following information shall be recorded in a log that is kept in a readily accessible location:

- a. Design criterion based on design considerations and operating experience indicating the failure of the seal system, barrier fluid system, or both of each affected pump or compressor.
- b. Any changes to this criterion and the reasons for the changes.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

13. Each drain in active service at the Cogeneration Plant, Crude Unit Furnaces and Desalter, and FCC Flare Vapor Recovery System shall be checked by visual inspection or physical inspection **initially and monthly** thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

14. Except for out of service drains where a tightly sealed cap or plug is installed, each drain out of active service shall be checked by visual or physical inspection **initially and weekly** thereafter for indications of low water levels or other problems that could result in VOC emissions. Drains having tightly sealed caps or plugs shall be inspected **initially and semiannually** to ensure caps or plugs are in place and properly installed.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

15. *Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than twenty-four (24) hours after detection unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.*

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

16. Junction boxes located at the Cogeneration Plant shall be visually inspected **initially and semiannually** thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

17. *If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than fifteen (15) calendar days after the broken seal or gap is identified unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.*

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

18. The portion of each unburied sewer line located at the Cogeneration Plant and Crude Unit Furnaces and Desalter shall be visually inspected **initially and semiannually** for indication of cracks, gaps, or other problems that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

19. *Wherever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than fifteen (15) calendar days after identification unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.*

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

20. Before using any individual drain system installed in compliance with 40 CFR §60.692-2, the permittee shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of 40 CFR Part 60, Subpart QQQ not to be met. Points of inspection include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.696)<sup>1</sup>

21. For each individual drain systems subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions during the initial and periodic visual or physical inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.697)<sup>1</sup>

22. For junction boxes subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for each inspection when a broken seal, gap, or other problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.697)<sup>1</sup>

23. For each sewer line subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for inspections when a problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.697)<sup>1</sup>

24. Catalytic Oxidation Unit – H<sub>2</sub>S Monitoring

- a. The permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H<sub>2</sub>S in the offgas from the Foul Water Treatment Plant before being oxidized in the Catalytic Oxidation Unit.
- b. The permittee may apply for an exemption from the H<sub>2</sub>S monitoring requirements described above for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the H<sub>2</sub>S monitoring requirements described above until there are changes in operating conditions or stream composition.
  - i. The permittee shall submit to the Department and U.S. EPA Region 9 a written application for an exemption from monitoring. The application must contain the following information:
    - (1) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;
    - (2) A statement that there are no crossover or entry points for sour gas (high H<sub>2</sub>S content) to be introduced into the fuel gas stream/system;
    - (3) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;
    - (4) The supporting test results from sampling the fuel gas stream/system demonstrating that the sulfur content is less than five (5) ppm H<sub>2</sub>S; and

- (5) A description of how the two (2) weeks of monitoring results compares to the typical range of H<sub>2</sub>S concentration expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare.
- ii. The effective date of the exemption is the date of submission of the information required above.
- iii. No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the permittee shall follow the procedures in 40 CFR §60.107a(b)(3).
- c. The permittee shall keep records of the specific exemption determined to apply for each fuel stream that is exempted. The permittee shall keep a copy of the application as well as the letter from the Department and U.S. EPA, Region 9, granting approval of the application.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.107a(a)(2), §60.107a(b), §60.108a(c))<sup>1</sup>

25. Catalytic Oxidation Unit - Visible Emissions (VE)

The permittee shall conduct **monthly** (calendar month) VE observations for the Catalytic Oxidation Unit by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

26. Catalytic Oxidation Unit – Continuous Process Monitoring System for NO<sub>x</sub> and NH<sub>3</sub>

The permittee shall install, operate, calibrate, and maintain a continuous process monitoring system including one NO<sub>x</sub> analyzer and one NH<sub>3</sub> analyzer, for continuously monitoring and recording the NO<sub>x</sub> and NH<sub>3</sub> concentrations downstream of the Catalytic Oxidation Unit. The continuous process monitoring system must be in continuous operation whenever the Catalytic Oxidation Unit is in operation. The NH<sub>3</sub> concentration downstream of the Catalytic Oxidation Unit will be used to determine the CO and VOC concentrations downstream of the Catalytic Oxidation Unit using correlation factors for CO and VOC that are to be established during the source performance test specified in Special Condition No. F.3 of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

27. Foul Water Treatment Plant Monitoring and Recordkeeping

The permittee shall monitor the Foul Water Treatment Plant effluent water for pH and temperature on a daily basis. The permittee shall also monitor the Foul Water Treatment Plant offgas for H<sub>2</sub>S concentration using colorimetric indicator tubes at least twice per year and when the pH drops below nine (9). Records shall be kept of the effluent water pH and temperature and of the offgas H<sub>2</sub>S concentration.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

**Section E. Notification and Reporting Requirements.**

1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate** or equivalent form, shall be used in reporting fugitive emissions.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions 14, 16, 17, and 25, respectively. These notifications shall include, but not be limited to:

- a. Anticipated date of initial start-up, actual date of construction commencement, and actual date of start-up;
- b. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
- c. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- d. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)



3. The permittee shall report **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department of Health and EPA Region 9, **Compliance Certification Form**, pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall be submitted **within ninety (90) days after the end of each calendar year**, and shall be signed and dated by a responsible official. The compliance certification shall include, at a minimum, the following information:

- a. The identification of each term or condition of the permit that is the basis of the certification;
- b. The compliance status;
- c. Whether compliance was continuous or intermittent;
- d. The methods used for determining the compliance status of the source currently and over the reporting period;
- e. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act; and
- f. Any additional information as required by the Department including information to determine compliance.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. For valves, pumps and compressors subject to the requirements of 40 CFR Part 60, Subpart GGG, or 40 CFR Part 63, Subpart CC, the permittee shall submit **semiannual** reports to the Department. 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)**. The **initial** semiannual report shall include the following information:

- a. Process unit identification;
- b. Number of valves subject to the requirements of Special Condition No. D.5. of this attachment, excluding those valves designated for no detectable emissions under the provisions of Special Condition No. D.5.f of this attachment;
- c. Number of pumps subject to the requirements of Special Condition No. D.2. of this attachment, excluding those pumps designated for no detectable emissions under the provisions of Special Condition No. D.2.g of this attachment and those pumps complying with Special Condition No. D.2.h of this attachment; and
- d. Number of compressors subject to the requirements of Special Condition No. C.3. of this attachment, excluding those compressors designated for no detectable emissions under the provisions of Special Condition No. C.3.e of this attachment and those compressors complying with Special Condition No. C.3.d of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

6. All semiannual reports, required in Special Condition No. E.5 of this attachment, shall include the following information:

- a. Process unit identification;
- b. For each month during the semiannual reporting period;
  - i. Number of valves for which leaks were detected;
  - ii. Number of valves for which leaks were not repaired;
  - iii. Number of pumps for which leaks were detected;
  - iv. Number of pumps for which leaks were not repaired;
  - v. Number of compressors for which leaks were detected;
  - vi. Number of compressors for which leaks were not repaired; and
  - vii. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
- c. Dates of process unit shutdowns which occurred within the semiannual reporting period; and
- d. Revisions to items reported in the initial semiannual report if changes have occurred since the initial report or subsequent revisions to the initial report.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

7. The permittee shall submit to the Department within **sixty (60) days** after initial startup a certification that the equipment necessary to comply with 40 CFR Part 60, Subpart QQQ has been installed and that the required initial inspections or tests of process drains, sewer lines and junction boxes have been carried out in accordance with 40 CFR Part 60,

Subpart QQQ. Thereafter, the permittee shall submit **semiannually** a certification that all of the required inspections have been carried out in accordance with 40 CFR Part 60, Subpart QQQ.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.698)<sup>1</sup>

8. A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted **initially and semiannually** thereafter to the Department.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.698)<sup>1</sup>

9. If compliance with the provisions of 40 CFR Part 60, Subpart QQQ is delayed pursuant to 40 CFR §60.692-7, the notification required under 40 CFR §60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standard is technically impossible without a refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.698)<sup>1</sup>

10. Catalytic Oxidation Unit - Notifications

In accordance with 40 CFR §60.108a(b), the permittee shall notify the Department and U.S. EPA, Region 9, of the specific monitoring provisions of 40 CFR §60.107a with which the permittee intends to comply with for an emission limitation in 40 CFR §60.102a.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.108a(b))<sup>1</sup>

11. Catalytic Oxidation Unit - Monitoring Reports

The permittee shall submit **semi-annually** the following written report to the Department for monitoring purposes. The report 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 exceedances as determined by the required VE 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 are 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: Opacity Exceedances**, shall be used.

- b. Any deviations from permit requirements shall be clearly identified.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

**Section F. Testing Requirements**

1. **Within sixty (60) days after achieving the maximum production rate of the Catalytic Oxidation Unit, but not later than one-hundred eighty (180) days after initial startup of the Catalytic Oxidation Unit, the permittee shall conduct or cause to be conducted performance tests on the offgas from the Foul Water Treatment Plant to determine compliance with the hourly H<sub>2</sub>S limit in Special Condition No. C.9.b of this attachment.**

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161, 40 CFR §60.8, §60.104a)<sup>1</sup>

2. The performance tests shall be conducted and the results reported in accordance with the test method set forth in 40 CFR Part 60, Appendix A-5 and 40 CFR §60.8. Performance tests for the emissions of H<sub>2</sub>S shall be conducted using EPA Method 11 or U.S. EPA-approved equivalent methods, or alternative methods with prior written approval from the Department.

For Method 11, the sampling time and sample volume must be at least ten (10) minutes and 0.010 dscm (0.35 dscf). Two (2) samples of equal sampling time must be taken at about one-hour (1-hour) intervals. The arithmetic average of these two (2) samples constitutes a run. For most fuel gases, sampling times exceeding twenty (20) minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H<sub>2</sub>S may necessitate sampling for longer periods of time.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.104a(j))<sup>1</sup>

3. **Within sixty (60) days after achieving the maximum production rate of the Catalytic Oxidation Unit, but not later than one-hundred eighty (180) days after initial startup of the Catalytic Oxidation Unit and annually thereafter, the permittee shall conduct or cause to be conducted performance tests for nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), and volatile organic compounds (VOC) on the Catalytic Oxidation Unit outlet stack.**

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

4. Performance tests for the emissions of NO<sub>x</sub>, CO, and VOC shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A. The following test methods or U.S. EPA-approved equivalent methods, or alternative methods with prior written approval from the Department shall be used:
  - a. Performance tests for the emissions of NO<sub>x</sub> shall be conducted using 40 CFR Part 60 Methods 1-4 and 7.
  - b. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60 Methods 1-4 and 10.
  - c. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60 Methods 1-4 and 25A.

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

5. Each performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

6. The permittee shall provide sampling and testing facilities at its own expense. The Department may monitor any of the required performance tests.

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

7. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

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

8. **At least thirty (30) days prior to performing a test**, the permittee shall submit a written *performance test plan* to the Department and the U.S. EPA, Region 9, that describes the test date(s), test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A performance test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

9. **Within sixty (60) days after completion of the performance test**, the permittee shall submit to the Department and the U.S. EPA, Region 9, the test report which shall include the analysis of the offgas from the Foul Water Treatment Plant, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data. A similar test report for the performance tests on the Catalytic Oxidation Unit outlet stack shall also be submitted.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)<sup>1</sup>

10. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous performance test.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §60.8)<sup>1</sup>

**CSP No. 0088-01-C**  
**Attachment II(A)**  
**Page 22 of 22**  
**Amended Date: June 23, 2015**  
**Expiration Date: June 27, 2011<sup>3</sup>**

**Section G. Agency Notifications.**

1. Any document (including reports) required to be submitted by this Covered Source permit shall be in accordance with Attachment I, Standard Condition No. 29.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP. <sup>3</sup>This date is to be revised upon issuance of the renewal for CSP No. 0088-01-C.

**Appendix J**  
**Significant Modification Application for RICE**

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Jon Mauer  
Refinery Manager

Chevron Products Company  
Hawaii Refinery  
91-480 Malakole Street  
Kapolei HI 96707-1807  
Tel 808-682-5711  
Fax 808-682-2324  
JonMauer@chevron.com

April 30, 2015

**CERTIFIED MAIL 7014 1820 0000 0357 1113  
RETURN RECEIPT REQUESTED**

Mr. Nolan Hirai  
Manager, Clean Air Branch  
Environmental Management Division  
919 Ala Moana Boulevard  
Honolulu, Hawaii 96814

**Chevron Hawaii Refinery  
RICE Units – CSP 0088-01-C  
Permit Application for a Significant Modification**

Dear Mr. Hirai:

The Chevron Products Company is hereby applying for a Significant Modification to the Covered Source Permit (CSP) 0088-01-C, Attachment II(F) for three diesel-powered pumps. The pumps are subject to certain requirements of National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE) under 40 CFR 63 Subpart ZZZZ and New Source Performance Standard (NSPS) for Stationary Compression Ignition Internal Combustion Engines under 40 CFR 60 Subpart IIII.

Enclosed are three sets (1 original and 2 copies) of the applicable Significant Modification application forms for the Chevron Refinery. According to the State of Hawaii Department of Health (HDOH) Clean Air Branch, a CSP Significant Modification application requires the submittal of HDOH Forms S-1, S-6, C-1, C-2, and a compact disc (CD) containing the emissions modeling files.

Attachments A - C contain additional information supporting the application:

- Attachment A - Manufacturer's Information
- Attachment B - Emission Calculations
- Attachment C - Air Quality Assessment

Also enclosed is a \$1,000.00 check for the Significant Modification application fee.

If you have any questions, or need additional information please contact Marcus Ruscio by phone at (808) 682-2282 or e-mail [mruscio@chevron.com](mailto:mruscio@chevron.com).

Sincerely,

seb/mjr



Manager  
DOH - Clean Air Branch  
Environmental Management Division  
Page 2 of 2

Enclosures: HDOH Forms S-1, S-6 (includes Modeling Files CD), C-1, and C-2,  
Attachments A-C,  
Check for \$1,000.00

cc: **CERTIFIED MAIL 7014 1820 0000 0357 1106**  
**RETURN RECEIPT REQUESTED**  
Director, Air Division  
Mail Code AIR-1  
USEPA Region 9  
75 Hawthorne Street  
San Francisco, CA 94105

Chevron Products Company  
 A Division of Chevron U.S.A. Inc.  
 P.O. Box 9034  
 Concord CA 94524

CHECK DATE: 04/02/2015  
 CHECK NO: 0024086656  
 PAYEE REF: 0010508914  
 COMPANY NO: 0061  
 MAIL CODE: 11ECO



HAWAII STATE DEPT OF HEALTH  
 CLEAN AIR SPECIAL FUND COV  
 919 ALA MOANA BLVD RM 206  
 HONOLULU HI 968144912

ADDRESS INQUIRIES TO: P.O. Box 9034, Concord, CA 94524-1934  
 PHONE CONTACT: 925-827-7741 FAX CONTACT: 925-680-3534

INV DATE	INVOICE#	OUR REFERENCE#	GROSS AMT.	DISC AMT.	NET AMT.
03/30/2015	150330STA	0019010629	\$1,000.00	\$0.00	\$1,000.00
CSP# 0088-01-C PERMIT APPLICATION FEE					

DETACH AND RETAIN THIS STUB FOR YOUR RECORDS

CHECK# 0024086656 ATTACHED BELOW



Chevron Products Company  
 A Division of Chevron U.S.A. Inc.  
 P.O. Box 9034  
 Concord CA 94524

82-20  
 311

NO. 0024086656

04/02/2015

PAY TO  
 ORDER OF

HAWAII STATE DEPT OF HEALTH  
 CLEAN AIR SPECIAL FUND COV  
 919 ALA MOANA BLVD RM 206  
 HONOLULU HI 968144912

\*\*\*\*\*\$1,000.00

NOT VALID AFTER 1 YEAR

One thousand and 00/100 Dollars

*Chevron*

AUTHORIZED SIGNATURE

CITIBANK N.A., ONE PENN'S WAY, NEW CASTLE, DE 19720

1100 2008 1000012 110

## S-1: Standard Air Pollution Control Permit Application Form

(Covered Source Permit and Noncovered Source Permit)

State of Hawaii  
Department of Health  
Environmental Management Division  
Clean Air Branch  
P.O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: Chevron Products Company
2. Facility Name (if different from the Company): Chevron Hawaii Refinery
3. Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707  
 Phone Number: (808) 682-5711
4. Name of Owner/Owner's Agent: Jon Mauer  
 Title: Refinery Manager Phone: (808) 682-5711  
 Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707
5. Plant Site Manager/Other Contact: Jon Mauer  
 Title: Refinery Manager Phone: (808) 682-5711  
 Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707
6. Permit Application Basis: (Check all applicable categories.)  
 Initial Permit for a New Source       Initial Permit for an Existing Source  
 Renewal of Existing Permit       General Permit  
 Temporary Source       Transfer of Permit  
 Modification to a Covered Source: → Is Modification?  Significant     Minor     Uncertain  
 Modification to a Noncovered Source
7. If renewal or modification, include existing permit number: 0088-01-C
8. Does the Proposed Source require a County Special Management Area Permit?     Yes     No
9. Type of Source (Check One):     Covered Source       Covered and PSD Source  
     Noncovered Source       Uncertain
10. Standard Industrial Classification Code (SICC), if known: 2911

11. Proposed Equipment/Plant Location (e.g. street address): 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707  
 UTM Coordinates (meters): East: 592,190 North: 2,356,665  
 UTM Zone: 4 UTM Horizontal Datum:  Old Hawaiian  NAD-27  NAD-83
12. General Nature of Business: Petroleum Refining
13. Date of Planned Commencement of Construction or Modification: existing
14. Is any of the equipment to be leased to another individual or entity?  Yes  No
15. Type of Organization:  Corporation  Individual Owner  Partnership  
 Government Agency (Government Facility Code: \_\_\_\_\_)  
 Other: \_\_\_\_\_

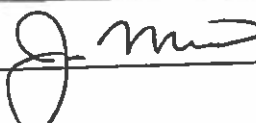
*Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR §11-60.1-64 & 11-60.1-84)*

**RESPONSIBLE OFFICIAL** (as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_  
 Title: Refinery Manager Phone: (808) 682-5711  
 Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official** (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Jon Mauer  
 (Signature):  Date: 4/30/15

<b>FOR AGENCY USE ONLY:</b>	
File/Application No.:	_____
Island:	_____
Date Received:	_____

Submit the following documents as part of your application:

- A. The **Emissions Units Table**, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:
1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SIC number. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirement of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
    - a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
    - b. Indicate the emission points that discharge together for any length of time.
    - c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.
  2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
    - a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO<sub>x</sub>), Sulfur Dioxide (SO<sub>2</sub>), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM<sub>10</sub>). Abbreviations may be used.
    - b. Include fugitive emissions.
    - c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
    - d. **Tons per year** is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.
  3. Describe **Stack Source Parameters**:
    - a. **Stack Height** is the height above the ground.
    - b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
    - c. **Flow Rate** is the actual, not the calculated, flow rate.
  4. Provide any additional information, if applicable, as follows:
    - a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
    - b. For a rectangular stack, indicate the length and width.
    - c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.
- B. A **process flow diagram** identifying all equipment used in the process, including the following:
1. Identify and describe each emission point.
  2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.
- C. A **facility location map**, drawn to a reasonable scale and showing the following:
1. The property involved and all structures on it. Identify property/fence lines plainly.
  2. Layout of the facility.
  3. Location and identification of the proposed emissions unit on the property.
  4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 100 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.
- D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Company Name: Chevron Products Company  
 Location: Kapolei

File No.: \_\_\_\_\_  
 Page 1 of 2

Make as many copies of this page as necessary)

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table

AIR POLLUTANT DATA				EMISSION POINTS				AIR POLLUTANT EMISSION RATE		UTM Zone Horizontal Datum		STACK SOURCE PARAMETERS					
Stack No	Unit No	Equipment Name/Description & SICC number	Equipment Date	AIR POLLUTANT	Regulated Hazardous Air Pollutant Name & CAS#	#/HR	Tons/ YR	Stack Height (mtrs)	Direction (width) °	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m³/s)	Temp (°K)	Capped (Y/N)			
Sand Filter Pump #1	Effluent Treating Plant	Sand Filter Pump Diesel Engine #1	2006 <sup>1</sup>	PMPM10		0.099	0.43	1.83	U	0.1	0.01	0.1	705	N			
				NOx		1.3	5.8										
				CO		1.6	7.2										
				VOC (NMHC)		1.3	5.8										
				SOx		0.0019	0.0085										
				HAPs		0.00092	0.0040										
				CO2e		230	1007										
Sand Filter Pump #2	Effluent Treating Plant	Sand Filter Pump Diesel Engine #2	2007 <sup>2</sup>	PMPM10		0.099	0.43	1.83	U	0.1	0.01	0.1	705	N			
				NOx		1.3	5.8										
				CO		1.6	7.2										
				VOC (NMHC)		1.3	5.8										
				Sox		0.0019	0.0085										
				HAPs		0.00092	0.0040										
				CO2e		0.099	0.43										

<sup>1</sup> Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27  
<sup>2</sup> Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal  
 \* Compliant with NSPS III 60.4208

Company Name: Chevron Products Company  
 Location: Kapolei

File No.: \_\_\_\_\_  
 Page 2 of 2

Make as many copies of this page as necessary

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table

Stack No	AIR POLLUTANT DATA			AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone Horizontal Datum	STACK SOURCE PARAMETERS						
	Unit No	Equipment Name/ Description & SICC number	Equipment Date		Regulated/ Hazardous Air Pollutant Name & CAS#	#/HR		Tons/ YR	Coordinates (mtrs)	Stack Height (mtrs)	Direction (width) <sup>a</sup>	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)
Transfer Pump	Effluent Treating Plant	Transfer pump	2010	PMPM10	0.099	0.43	East 592063 32 North 2356490 10	1.83	u	0.1	0.01	0.1	705	N
				NOx	1.3	5.8								
				CO	1.6	7.2								
				VOC (NMHC)	1.3	5.8								
				SOx	0.0019	0.0085								
				HAPs	0.00092	0.0040								
				CO2b	230	1007								

<sup>a</sup> Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

<sup>b</sup> Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal

**S-6: Application for a Significant Modification to a Covered Source**  
Sand Filter Pump #1

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail one (1) set directly to EPA at the following address:

Chief (Attention: AIR-3)  
 Permits Office, Air Division  
 U.S. Environmental Protection Agency  
 Region 9  
 75 Hawthorne Street  
 San Francisco, CA 94105

**I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:**

**A. Equipment Specifications:**

- |  |                                |
|--|--------------------------------|
| 1. <i>Maximum design capacity.</i>               | 200 hp                         |
| 2. <i>Fuel type.</i>                             | ULSD (Ultra Low Sulfur Diesel) |
| 3. <i>Fuel use.</i>                              | Continuous when operating      |
| 4. <i>Production capacity.</i>                   | Not Applicable                 |
| 5. <i>Production rates.</i>                      | Not Applicable                 |
| 6. <i>Raw materials.</i>                         | Not Applicable                 |
| 7. <i>Provide any manufacturer's literature.</i> | See Attachment A               |

**B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.**

The Sand Filter Pump #1, which includes a diesel-driven engine, routes treated wastewater in the refinery's Effluent Treating Plant through sand filters as needed for water quality compliance. Sand Filter Pump #1 operation alternates with Pump #2 during normal operation. Due to the portability of this unit, Pump #1 may be replaced with an equivalent unit as necessary while maintenance or reliability activities are performed on the pump.

1. *Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.*
  - a. Sand Filter Pump #1 is subject to NSPS Subpart IIII.
  - b. The fuel for this unit will be ULSD (Ultra Low Sulfur Diesel). The emissions associated with Pump #1 have been estimated and are provided in Attachment B.
  - c. The emissions have been estimated assuming a 100% operating factor.



2. List all *new insignificant* activities in accordance with HAR §11-60.1-82.

None

C. *Maximum Operating Schedule (to the extent needed to determine or regulate emissions):*

1. The maximum operating hours for emissions estimating are 24 hours per day
2. 8760 hours per year
3. Pump #1 operation alternates with Pump #2 during normal operation.

D. *Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:*

1. *Description of or reference to any applicable test methods for determining compliance with each applicable requirement.*
  - a. Sand Filter Pump #1 is subject to 40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE). This non-emergency RICE is subject to New Source Performance Standards (NSPS) of 40 CFR 60 Subpart IIII for Stationary Compression Ignition (CI) Internal Combustion Engines.
  - b. If replaced with an equivalent pump, the replacement unit will meet the requirements of 60.4208 for installation of previous model engines.

2. *Explanation of all proposed exemptions from any applicable requirements.*

No exemptions are proposed.

E. *Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.*

No operational limitations are proposed for Sand Filter Pump #1 operation. In normal operation, Pump #1 operation alternates with Pump #2, however, emissions are estimated assuming a 100 % operating factor. Due to the portability of this unit, Pump #1 may be replaced with an equivalent unit as necessary while maintenance or reliability activities are performed on the pump. The fuel for this unit will be ULSD (Ultra Low Sulfur Diesel). The emissions associated with Pump #1 have been estimated and are provided in Attachment B.

F. *Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable.*

Sand Filter Pump #1, which includes a diesel-driven engine, is installed and operational in the Effluent Treating Plant. The RICE in this service may be a leased or owned unit, and may be replaced by another RICE for maintenance or reliability activities.

G. *Provide detailed information to define permit terms and conditions for any proposed emissions trading within the facility in accordance with HAR §11-60.1-96.*

No emissions trading is proposed.

- H. For **significant** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards.

An assessment of the air quality impact of this significant modification is provided in Attachment C. The emission modeling results are included with this permit application in electronic form (CD).

The emissions modeled for assessment of the air quality impact are shown in Table 1 in Attachment C. The modeled emissions for CO and PM/PM10 are approximately 30% lower than the emissions in Form S-1, Emissions Table, however, the modeling results have sufficient margin below the NAAQS or SAAQS to demonstrate that Pump #1 will not cause or contribute to an exceedance.

- I. For **new** covered sources or **significant** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7.

1. Not Applicable. The proposed significant modification is not subject to the requirements of Subchapter 7 of HAR Chapter 11-60.1.

- J. Provide the following for compliance purposes:

1. A Compliance Plan, Form C-1.

See Attached Form C-1.

1. A Compliance Certification, Form C-2.

See Attached Form C-2.

- II. **Submit an application fee according to the Application Fee Schedule in the Instructions for Applying for an Air Pollution Control Permit.**

See attached fees.

- III. **Provide other information as follows:**

- A. As required by any applicable requirement or as requested and deemed necessary by the Director of Health (hereafter, Director) to make a decision on the application.
- B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

- IV. **The Director reserves the right to request the following information:**

- A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.
- B. Results of source emissions testing, ambient air quality monitoring, or both.

C. *Information on other available control technologies.*

V. **An application shall be determined to be complete only when all of the following have been complied with:**

- A. *All information required or requested in numbers I, III, and IV has been submitted.*
- B. *All documents requiring certification have been certified pursuant to HAR §11-60.1-4.*
- C. *All applicable fees have been submitted.*
- D. *The Director has certified that the application is complete.*

Information, certified documents, and fees required or requested in numbers I, III, and IV have been submitted with this application.

VI. **The Director shall not continue to act upon or consider an incomplete application.**

- A. The applicant shall be notified in writing whether the application is complete:
  - 1. For the requirements of subchapter 7, thirty days after receipt of the application.
  - 2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
  - 3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to VI.A.2 above, the application shall be deemed complete for the requirements of subchapter 5.
- B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. **After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.**

- A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.
- B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

- VIII. The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.
- IX. The Director shall provide for public notice, including the method by which a public hearing can be requested, and an opportunity for public comment on the draft significant modification to the covered source in accordance with HAR §11-60.1-99.
- X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.
- XI. Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

**S-6: Application for a Significant Modification to a Covered Source**  
Sand Filter Pump #2

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)  
 Permits Office, Air Division  
 U.S. Environmental Protection Agency  
 Region 9  
 75 Hawthorne Street  
 San Francisco, CA 94105

**I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:**

**A. Equipment Specifications:**

- |  |                                |
|--|--------------------------------|
| 1. <i>Maximum design capacity.</i>               | 200 hp                         |
| 2. <i>Fuel type.</i>                             | ULSD (Ultra Low Sulfur Diesel) |
| 3. <i>Fuel use.</i>                              | Continuous when operating      |
| 4. <i>Production capacity.</i>                   | Not Applicable                 |
| 5. <i>Production rates.</i>                      | Not Applicable                 |
| 6. <i>Raw materials.</i>                         | Not Applicable                 |
| 7. <i>Provide any manufacturer's literature.</i> | See Attachment A               |

**B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.**

The Sand Filter Pump #2, which includes a diesel-driven engine, routes treated wastewater in the refinery's Effluent Treating Plant through sand filters as needed for water quality compliance. Sand Filter Pump #2 operation alternates with Pump #1 during normal operation. Due to the portability of this unit, Pump #2 may be replaced with an equivalent unit as necessary while maintenance or reliability activities are performed on the pump.

1. *Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.*
  - a. Sand Filter Pump #2 is subject to NSPS Subpart IIII.
  - b. The fuel for this unit will be ULSD (Ultra Low Sulfur Diesel). The emissions associated with Pump #2 have been estimated and are provided in Attachment B.
  - c. The emissions have been estimated assuming a 100% operating factor.

2. List all new insignificant activities in accordance with HAR §11-60.1-82.

None

C. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. The maximum operating hours for emissions estimating are 24 hours per day
2. 8760 hours per year
3. Pump #2 operation alternates with Pump #1 during normal operation.

D. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement.
  - a. Sand Filter Pump #2 is subject to 40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE). This non-emergency RICE is subject to New Source Performance Standards (NSPS) of 40 CFR 60 Subpart IIII for Stationary Compression Ignition (CI) Internal Combustion Engines.
  - b. If replaced with an equivalent pump, the replacement unit will meet the requirements of 60.4208 for installation of previous model engines

2. Explanation of all proposed exemptions from any applicable requirements.

No exemptions are proposed.

E. Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

No operational limitations are proposed for Sand Filter Pump #2 operation. In normal operation, Pump #2 operation alternates with Pump #1, however, emissions are estimated assuming a 100 % operating factor. Due to the portability of this unit, Pump #2 may be replaced with an equivalent unit as necessary while maintenance or reliability activities are performed on the pump. The fuel for this unit will be ULSD (Ultra Low Sulfur Diesel). The emissions associated with Pump #2 have been estimated and are provided in Attachment B.

F. Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable.

Sand Filter Pump #2, which includes a diesel-driven engine, is currently installed and operational in the Effluent Treating Plant. The RICE in this service may be a leased or owned unit, and may be replaced by another RICE for maintenance or reliability activities.

G. Provide detailed information to define permit terms and conditions for any proposed emissions trading within the facility in accordance with HAR §11-60.1-96.

No emissions trading is proposed.

H. For significant modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air

*quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards.*

An assessment of the air quality impact of this significant modification is provided in Attachment C. The emission modeling results are included with this permit application in electronic form (CD).

The emissions modeled for assessment of the air quality impact are shown in Table 1 in Attachment C. The modeled emissions for CO and PM/PM10 are approximately 30% lower than the emissions in Form S-1, Emissions Table, however, the modeling results have sufficient margin below the NAAQS or SAAQS to demonstrate that Pump #2 will not cause or contribute to an exceedance.

- I. For **new** covered sources or **significant** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7.*

Not Applicable. The proposed significant modification is not subject to the requirements of Subchapter 7 of HAR Chapter 11-60.1.

- J. Provide the following for compliance purposes:*
- 1. A Compliance Plan, Form C-1.*

See Attached Form C-1.

- 3. A Compliance Certification, Form C-2.*

See Attached Form C-2.

- II. Submit an application fee according to the Application Fee Schedule in the Instructions for Applying for an Air Pollution Control Permit.**

*See attached fees.*

- III. Provide other information as follows:**

- A. As required by any applicable requirement or as requested and deemed necessary by the Director of Health (hereafter, Director) to make a decision on the application.*
- B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.*

- IV. The Director reserves the right to request the following information:**

- A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.*
- B. Results of source emissions testing, ambient air quality monitoring, or both.*

C. *Information on other available control technologies.*

V. **An application shall be determined to be complete only when all of the following have been complied with:**

A. *All information required or requested in numbers I, III, and IV has been submitted.*

B. *All documents requiring certification have been certified pursuant to HAR §11-60.1-4.*

C. *All applicable fees have been submitted.*

D. *The Director has certified that the application is complete.*

Information, certified documents, and fees required or requested in numbers I, III, and IV have been submitted with this application.

VI. **The Director shall not continue to act upon or consider an incomplete application.**

A. **The applicant shall be notified in writing whether the application is complete:**

1. **For the requirements of subchapter 7, thirty days after receipt of the application.**

2. **For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.**

3. **Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to VI.A.2 above, the application shall be deemed complete for the requirements of subchapter 5.**

B. **During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.**

VII. **After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.**

A. **Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.**

B. **Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.**

VIII. **The Director shall provide reasonable procedures and resources to complete the review of**



the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.

- IX. The Director shall provide for public notice, including the method by which a public hearing can be requested, and an opportunity for public comment on the draft significant modification to the covered source in accordance with HAR §11-60.1-99.
- X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.
- XI. Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

**S-6: Application for a Significant Modification to a Covered Source**  
Transfer Pump

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail one (1) set directly to EPA at the following address:

Chief (Attention: AIR-3)  
 Permits Office, Air Division  
 U.S. Environmental Protection Agency  
 Region 9  
 75 Hawthorne Street  
 San Francisco, CA 94105

**I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:**

**A. Equipment Specifications:**

- |  |                                |
|--|--------------------------------|
| 1. <i>Maximum design capacity.</i>               | 300 hp                         |
| 2. <i>Fuel type.</i>                             | ULSD (Ultra Low Sulfur Diesel) |
| 3. <i>Fuel use.</i>                              | Continuous when operating      |
| 4. <i>Production capacity.</i>                   | Not Applicable                 |
| 5. <i>Production rates.</i>                      | Not Applicable                 |
| 6. <i>Raw materials.</i>                         | Not Applicable                 |
| 7. <i>Provide any manufacturer's literature.</i> | See Attachment A               |

**B. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.**

The Transfer Pump routes skim oil and/or wastewater from the refinery's Effluent Treating Plant to tankage in the Blending & Shipping Area. Due to the portability of this unit, the Transfer Pump may be replaced with an equivalent unit as necessary while maintenance or reliability activities are performed on the pump.

**1 Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities planned by the owner or operator, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.**

- a. The Transfer Pump is subject to NSPS Subpart IIII.
- b. The fuel for this unit will be ULSD (Ultra Low Sulfur Diesel). The emissions associated with the Transfer Pump have been estimated and are provided in Attachment B.
- c. The emissions have been estimated assuming a 100% operating factor.

2 List all **new insignificant** activities in accordance with HAR §11-60.1-82.

None

C. *Maximum Operating Schedule (to the extent needed to determine or regulate emissions):*

1. The maximum operating hours for emissions estimating are 24 hours per day
2. 8760 hours per year
3. The transfer pump operates as need to transfer material from the ETP to tankage in the Blending & Shipping Area.

D. *Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:*

1. *Description of or reference to any applicable test methods for determining compliance with each applicable requirement.*
  - a. The Transfer Pump is subject to 40 CFR 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE). This non-emergency RICE is also subject to the New Source Performance Standards (NSPS) of 40 CFR 60 Subpart IIII for Stationary Compression Ignition (CI) Internal Combustion Engines.
  - b. If replaced with an equivalent pump, the replacement unit will meet the requirements of 60.4208 for installation of previous model engines.
2. *Explanation of all proposed exemptions from any applicable requirements.*

No exemptions are proposed.

E. *Identify and describe current operational limitations or work practices the source plans to implement that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.*

No operational limitations are proposed for the Transfer pump operation. In normal operation, the Transfer pump is utilized to transfer material to tankage in the Blending & Shipping Area as needed. Emissions are estimated assuming a 100 % operating factor. Due to the portability of this unit, the Transfer Pump may be replaced with an equivalent unit as necessary while maintenance or reliability activities are performed on the pump. The fuel for this unit will be ULSD (Ultra Low Sulfur Diesel). The emissions associated with the Transfer Pump have been estimated and are provided in Attachment B.

F. *Provide a detailed schedule for construction or modification of the proposed source, including any major milestones, if applicable.*

The Transfer Pump, which includes a diesel-driven engine, is currently installed and operational in the Effluent Treating Plant. The RICE in this service may be a leased or owned unit, and may be replaced by another RICE for maintenance or reliability activities.

G. *Provide detailed information to define permit terms and conditions for any proposed emissions trading within the facility in accordance with HAR §11-60.1-96.*

No emissions trading is proposed.

- H. For **significant modifications** which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards.

An assessment of the air quality impact of this significant modification is provided in Attachment C. The emission modeling results are included with this permit application in electronic form (CD).

The emissions modeled for assessment of the air quality impact are shown in Table 1 in Attachment C. The modeled emissions for CO and PM/PM10 are approximately 30% lower than the emissions in Form S-1, Emissions Table, however, the modeling results have sufficient margin below the NAAQS or SAAQS to demonstrate that the Transfer Pump will not cause or contribute to an exceedance.

- I. For **new covered sources** or **significant modifications** subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7.

1. Not Applicable. The proposed significant modification is not subject to the requirements of Subchapter 7 of HAR Chapter 11-60.1.

- J. Provide the following for compliance purposes:

1. A Compliance Plan, Form C-1.

See Attached Form C-1.

4. A Compliance Certification, Form C-2.

See Attached Form C-2.

- II. **Submit an application fee according to the Application Fee Schedule in the Instructions for Applying for an Air Pollution Control Permit.**

See attached fees.

- III. **Provide other information as follows:**

A. As required by any applicable requirement or as requested and deemed necessary by the Director of Health (hereafter, Director) to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

- IV. **The Director reserves the right to request the following information:**

A. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

B. *Results of source emissions testing, ambient air quality monitoring, or both.*

C. *Information on other available control technologies.*

V. **An application shall be determined to be complete only when all of the following have been complied with:**

A. *All information required or requested in numbers I, III, and IV has been submitted.*

B. *All documents requiring certification have been certified pursuant to HAR §11-60.1-4.*

C. *All applicable fees have been submitted.*

D. *The Director has certified that the application is complete.*

Information, certified documents, and fees required or requested in numbers I, III, and IV have been submitted with this application.

VI. **The Director shall not continue to act upon or consider an incomplete application.**

A. The applicant shall be notified in writing whether the application is complete:

1. For the requirements of subchapter 7, thirty days after receipt of the application.
2. For the requirements of HAR subchapter 5, sixty days after receipt of the application. For purposes of this paragraph, the date of receipt of an application for a new covered source or significant modification subject to the requirements of subchapter 7 shall be the date the application is determined to be complete for the requirements of subchapter 7.
3. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days after receipt of an application pursuant to VI.A.2 above, the application shall be deemed complete for the requirements of subchapter 5.

B. During the processing of an application that has been determined or deemed complete, if additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

VII. **After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application within eighteen months, except as provided in HAR §11-60.1-88 and (A) and (B) below.**

A. Upon program approval, within nine months for an application containing an early reduction demonstration pursuant to section 112(i)(5) of the Clean Air Act.

B. Within twelve months for a new covered source or significant modification subject to the requirements of subchapter 7.

- VIII. The Director shall provide reasonable procedures and resources to complete the review of the majority of the applications for a significant modification within nine months after receipt of a complete application. An application for significant modification shall be approved only if the Director determines that the significant modification will be in compliance with all applicable requirements.
- IX. The Director shall provide for public notice, including the method by which a public hearing can be requested, and an opportunity for public comment on the draft significant modification to the covered source in accordance with HAR §11-60.1-99.
- X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.
- XI. Each application for a significant modification, and the proposed Covered Source Permit reflecting the significant modification shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

**C-1: Compliance Plan**  
**Sand Filter Pump #1, Sand Filter Pump #2, and Transfer Pump**

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets of paper if necessary.

1. Compliance status with respect to all Applicable Requirements:

Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

- YES      {If YES, complete items a and c below}
- NO      {If NO, complete items a, b, and c below}

a. Identify all applicable requirement(s) for which compliance is achieved.  
National Emission Standards for Hazardous Air Pollutants (NESHAP) Subparts A and ZZZZ (40 CFR Part 63), New Source Performance Standards (NSPS) Subparts A and IIII (40 CFR Part 60), and General Compliance Provisions for Highway, Stationary, and NonRoad Programs Subpart A (40 CFR Part 1068), and Control of Emission for and In-Use NonRoad Compression-Ignition Engines (40 CFR Part 1039).

Provide a statement that the source is in compliance and will continue to comply with all such requirements. The Sand Filter Pump #1, Sand Filter Pump #2, and the Transfer Pump are in compliance with the applicable requirements stated above and will continue to comply with the applicable requirements as specified in this significant modification application.

b. Identify all applicable requirement(s) for which compliance is NOT achieved.  
Hawaii Administrative Rules Chapter 11-60.1 Subchapter 5, Covered Sources.

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

Provide a detailed Schedule of Compliance Schedule and a description of how the source will achieve compliance with all such applicable requirements.

<u>Description of Remedial Action</u>	<u>Expected Date of Completion</u>
<u>The submittal of this significant modification air permit application by the Chevron Hawaii Refinery is the remedial action to achieve compliance.</u>	<u>April 30, 2015</u>
_____	_____
_____	_____

c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to

These applicable requirements may take effect AFTER permit issuance:

<u>Applicable Requirement</u>	<u>Effective Date</u>	<u>Currently in Compliance?</u>
<u>No additional requirements.</u>	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____

If the source is not currently in compliance, provide a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

<u>Description of Proposed Action/Steps to Achieve Compliance</u>	<u>Expected Date of Achieving Compliance</u>
<u>Not Applicable</u>	_____
_____	_____
_____	_____
_____	_____

Provide a statement that the source on a timely basis will meet all these applicable requirements:

Not Applicable

\_\_\_\_\_

\_\_\_\_\_

\_\_\_\_\_

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of each remedial action and the expected date of completion:

<u>Description of Remedial Action and Explanation</u>	<u>Expected Date of Completion</u>
<u>Not Applicable</u>	_____
_____	_____
_____	_____
_____	_____

2. Compliance Progress Reports:

a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: N/A Beginning Date: \_\_\_\_\_  
(less than or equal to 6 months)

b. Date(s) that the Action described in (1)(b) was achieved:

<u>Remedial Action</u>	<u>Date Achieved</u>
<u>N/A</u>	_____
_____	_____
_____	_____
_____	_____



c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

N/A

**RESPONSIBLE OFFICIAL**

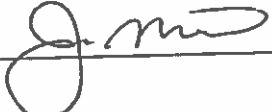
(as defined in HAR §11-60 1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_  
Title: Refinery Manager Phone: (808) 682-5711  
Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official**

(pursuant to HAR §11-60 1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Jon Mauer  
(Signature):  Date: 4/30/15

Facility Name: Chevron Hawaii Refinery

Location: Kapolei, HI

Permit Number: 0088-01-C

<b>FOR AGENCY USE ONLY</b>
File/Application No.: _____
Island: _____

File No.: \_\_\_\_\_

**C-2: Compliance Certification**  
**Sand Filter Pump #1, Sand Filter Pump #2, Transfer Pump**

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Complete as many copies of this form as needed. Use separate sheets of paper if necessary.

**RESPONSIBLE OFFICIAL**

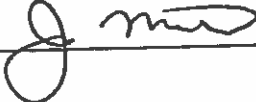
(as defined in HAR §11-60.1-1)

Name (Last): Mauer (First): Jon (MI): \_\_\_\_\_  
Title: Refinery Manager Phone: (808) 682-5711  
Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 36608

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Jon Mauer  
(Signature):  Date: 4/30/15

Facility Name: Chevron Hawaii Refinery  
Location: Kapolei, HI  
Permit Number: 0088-01-C

**FOR AGENCY USE ONLY**

File/Application No.: \_\_\_\_\_

Island: \_\_\_\_\_

Complete the following information for *each* applicable requirement that applies to *each* emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: Annual Beginning Date: 2015

2. Emissions Unit No./Description: Sand Filter Pump #1, Sand Filter Pump #2, and Transfer Pump

3. Identify the applicable requirement(s) that is/are the basis of this certification:

NESHAP Subpart A and ZZZZ [40CFR63.6590(a)(2) and (c)(7)]  
NSPS Subpart A and IIII [40 CFR 60.4205(b), 40 CFR 60.4211(a)]  
General Compliance Provisions for Subpart A (40 CFR 1068.1(4))  
Control of Emissions (40 CFR 1039.1(b), 40 CFR 1039.825)  
HAR 11-60.1 Subchapter 5

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?  
 YES  NO

b. If YES, will compliance be continuous or intermittent?  
 Continuous  Intermittent

c. If NO, explain:

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Chevron will keep records of the EPA certified engine by maintaining the certificate of conformity for each engine. Chevron will maintain a log of the type fuel utilized by each engine and record maintenance performed on each engine.

Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

Chevron recordkeeping and compliance assurance processes will be used for the certificates.  
Chevron will maintain a log of the type fuel used for each engine.  
Chevron will maintain records of maintenance performed on each engine in existing databases and recordkeeping processes.

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO Not Applicable

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

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- c. If NO, describe below which requirements will not be met:

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**ATTACHMENT A**  
**Manufacturer's Information**



## Model DV-150i

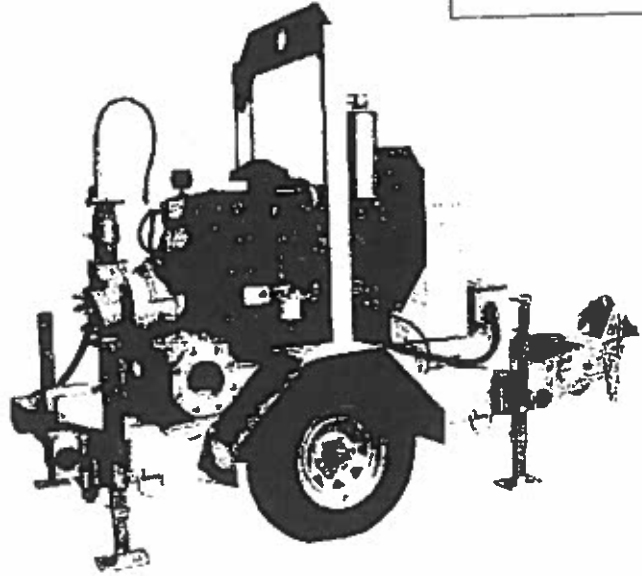
Size 6" X 6"

### Standard Features

- Hot Dip Galvanized Trailers and Skids
  - Radiator Enclosure
  - Battery Box
  - Wheels
- Zinc Plated Jacks
- Emissions Certified Engines
  - Perkins/Cat/John Deere
- DOT LED lights
- Electric Brakes with Safety breakaway
- Locking Battery Box

### Pump Features

- Solids-handling capabilities to 3" diameter maximum
- Continuous self-priming
- Runs dry unattended
- Suction lift up to 28 ft.
- Skid- or trailer-mounted
- Auto-start capable control panel
- Stainless Steel, CD4MCu and Chrome pump options

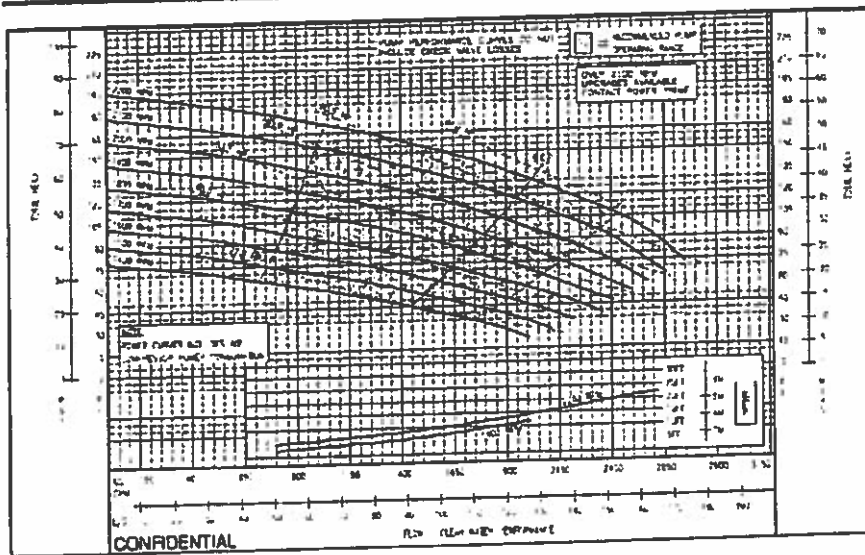


### Technical

- SAE-mounted
- 12 volt, electric start with control panel
- Skid- or trailer-mounted with optional lifting bale
- 24-hour minimum capacity fuel tank
- Compressor/Venturi automatic priming system
- Electric drive option available
- Sound attenuated option available
- Perkins Engine options: 1104C-44T for up to 2100rpm or 1104D-44TA for up to 2200rpm

### Material Specifications

- Standard Build - Ductile Iron volute, Stainless Steel open impellers and replaceable wear plates
- Pump Shaft  
431 Stainless Steel
- Mechanical Seal  
Solid silicon carbide mating faces  
Oil-bath lubrication for dry running
- Suction / discharge flanges ANSI 150# FF.



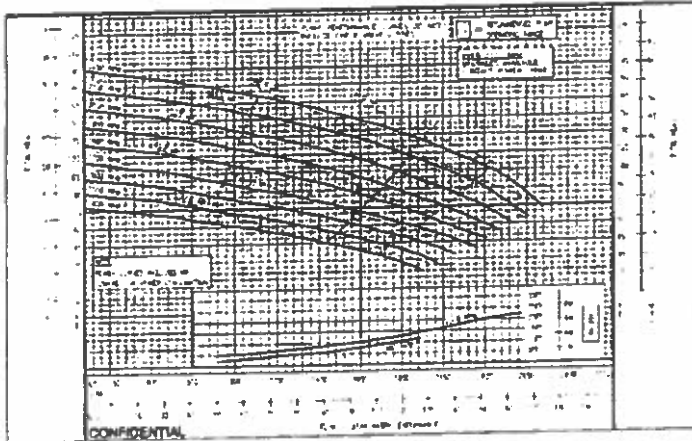
**Rain for Rent**  
 P.O. Box 2248  
 Bakersfield CA 93303  
 800-742-7246  
 661-393-1542  
 FAX 661-393-1542  
 www.rainforrent.com  
 info@rainforrent.com

Rain for Rent is a registered trademark of Western Oilfields Supply Company. Features and Specifications are subject to change without notice.



## DV-150i Technical Specifications

### Production Curve



### Performance Specs

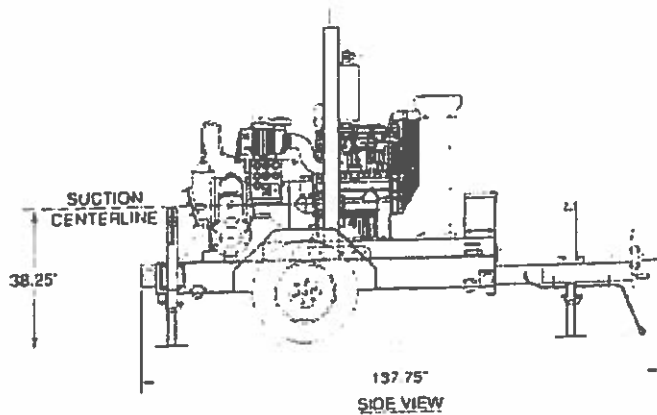
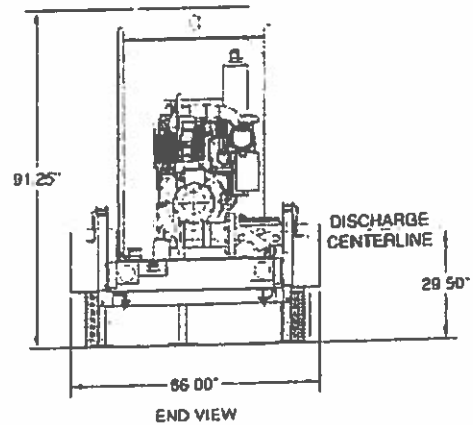
#### STANDARD 2 VANE IMPELLER

Minimum Operating Speed:	1400 rpm
Maximum Operating Speed:	2200 rpm
Maximum Head:	195 ft.
Maximum Flow:	2750 gpm

### Design Details

Pump Designation:	DV-150i
Pump Description:	Centrifugal end suction pump, single stage, volute type, 2-vane impeller
Solid Handling Size:	Up to 3.0 inches (77mm)
Operating Temperature:	MIN: -4°F (-20°C) MAX: +212°F (+100°C)

### Dimensions



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 800-742-7246  
 661-399-9124  
 FAX 661-393-1542  
 www.rainforrent.com  
 info@rainforrent.com

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 <b>AIR RESOURCES BOARD</b>	<b>PERKINS ENGINES COMPANY LTD.</b>	<b>EXECUTIVE ORDER U-R-022-0079</b> New Off-Road Compression-Ignition Engines

Pursuant to the authority vested in the Air Resources Board by Sections 43013, 43018, 43101, 43102, 43104 and 43105 of the Health and Safety Code; and

Pursuant to the authority vested in the undersigned by Sections 39515 and 39516 of the Health and Safety Code and Executive Order G-02-003;

**IT IS ORDERED AND RESOLVED:** That the following compression-ignition engine and emission control system produced by the manufacturer are certified as described below for use in off-road equipment. Production engines shall be in all material respects the same as those for which certification is granted.

MODEL YEAR	ENGINE FAMILY	DISPLACEMENT (liters)	FUEL TYPE	USEFUL LIFE (hours)
2006	6PKXL04.4RG1	4.4 & 3.3	Diesel	8000
<b>SPECIAL FEATURES &amp; EMISSION CONTROL SYSTEMS</b>			<b>TYPICAL EQUIPMENT APPLICATION</b>	
Direct Diesel Injection, Smoke Puff Limiter and Turbocharger			Tractor and Industrial Equipment	

The engine models and codes are attached.

The following are the exhaust certification standards (STD) and certification levels (CERT) for hydrocarbon (HC), oxides of nitrogen (NOx), or non-methane hydrocarbon plus oxides of nitrogen (NMHC+NOx), carbon monoxide (CO), and particulate matter (PM) in grams per kilowatt-hour (g/kw-hr), and the opacity-of-smoke certification standards and certification levels in percent (%) during acceleration (Accel), lugging (Lug), and the peak value from either mode (Peak) for this engine family (Title 13, California Code of Regulations, (13 CCR) Section 2423):

RATED POWER CLASS	EMISSION STANDARD CATEGORY		EXHAUST (g/kw-hr)					OPACITY (%)		
			HC	NOx	NMHC+NOx	CO	PM	ACCEL	LUG	PEAK
19 ≤ KW < 37	Tier 2	STD	N/A	N/A	7.5	5.5	0.60	20	15	50
37 ≤ KW < 75	Tier 2	STD	N/A	N/A	7.5	5.0	0.40	20	15	50
		CERT	-	-	6.6	0.8	0.30	7	3	10

**BE IT FURTHER RESOLVED:** That for the listed engine models, the manufacturer has submitted the information and materials to demonstrate certification compliance with 13 CCR Section 2424 (emission control labels), and 13 CCR Sections 2425 and 2426 (emission control system warranty).

Engines certified under this Executive Order must conform to all applicable California emission regulations.

This Executive Order is only granted to the engine family and model-year listed above. Engines in this family that are produced for any other model-year are not covered by this Executive Order.

Executed at El Monte, California on this 11<sup>TH</sup> day of January 2006.



Allen Lyons, Chief  
Mobile Source Operations Division



# Engine Model Summary Form

ATTACHMENT 1 OF 1

WR-022-0079

Manufacturer: Perkins Engines Peterborough Ltd  
 Engine category: Nonroad CI  
 EPA Engine Family: 8PKXL04.4RG1  
 Mfr. Family Name: 1104C-44T AND CATERPILLAR 3054  
 Process Code: New Submission

1.Engine Code	2.Engine Model	3.BHP@RPM (SAE Gross)	4.Fuel Rate: mm/stroke @ peak HP (for diesel only)	5.Fuel Rate: (bsh/yr) @ peak HP (for diesels only)	6.Torque @ RPM (ISEA Gross)	7.Fuel Rate: mm/stroke@peak torque	8.Fuel Rate: (lba/hr)@peak torque	9.Emission Control Devices Per SAE J1930
50 Sales								
1	2359/2100	99.9 @ 2100	83.5	38.7	306.0 lbf ft @	94.5	29.2	TC DDI
2	2359/2200	99.2 @ 2200	82.0	39.8	306.0 lbf ft @	94.5	29.2	TC DDI
3	2164/2200	91.9 @ 2200	73.0	35.5	286.0 lbf ft @	85.0	26.3	TC DDI
4	2165/2200	89.8 @ 2200	73.0	35.5	280.0 lbf ft @	85.0	26.3	TC DDI
5	2166/2000	98.6 @ 2000	83.0	36.7	304.0 lbf ft @	92.5	28.6	TC DDI
6	2166/2100	99.9 @ 2100	81.5	37.8	304.0 lbf ft @	92.5	28.6	TC DDI
7	2166/2200	99.9 @ 2200	80.0	38.9	304.0 lbf ft @	92.5	28.6	TC DDI
8	2166/2300	99.9 @ 2300	78.5	39.9	304.0 lbf ft @	92.5	28.6	TC DDI
9	2167/2000	96.6 @ 2000	83.0	36.7	298.0 lbf ft @	92.5	28.6	TC DDI
10	2167/2100	97.9 @ 2100	81.5	37.8	298.0 lbf ft @	92.5	28.6	TC DDI
11	2167/2200	97.2 @ 2200	80.0	38.9	298.0 lbf ft @	92.5	28.6	TC DDI
12	2167/2300	97.2 @ 2300	78.5	39.9	298.0 lbf ft @	92.5	28.6	TC DDI
13	2168/2200	99.9 @ 2200	78.0	36.9	274.0 lbf ft @	82.0	25.4	TC DDI
14	2168/2300	99.9 @ 2300	75.0	38.1	274.0 lbf ft @	82.0	25.4	TC DDI
15	2168/2400	99.9 @ 2400	74.0	38.2	274.0 lbf ft @	82.0	25.4	TC DDI
16	2169/2200	97.2 @ 2200	76.0	36.9	268.5 lbf ft @	82.0	25.4	TC DDI
17	2169/2400	97.2 @ 2400	74.0	39.2	268.5 lbf ft @	82.0	25.4	TC DDI
18	2230/2200	35.8 @ 2200	72.0	28.2	199.0 lbf ft @	80.0	18.6	TC DDI
19	2232/2200	41.0 @ 2200	81.0	29.5	214.6 lbf ft @	89.0	20.7	TC DDI
20	2442/1800	94.5 @ 1800	92.0	36.8	214.6 lbf ft @	89.0	20.7	TC DDI

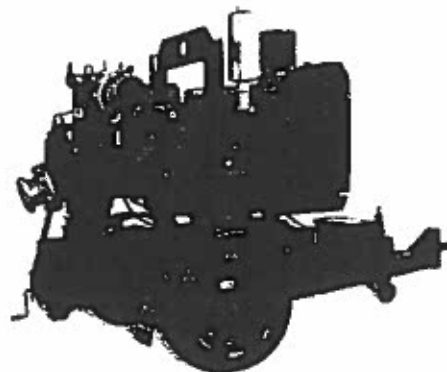
# CD150M Dri-Prime Pump

CD150M

The Godwin Dri-Prime CD150M pump offers flow rates to 2,277 USGPM and discharge heads to 154' (47m). Also it has the capability of handling solids up to 3" (75mm) in diameter.

The CD150M is able to prime to 28' (8.5 m) of suction lift from dry.

Indefinite dry-running is no problem due to the unique Godwin oil bath mechanical seal design. Solids handling, dry-running and portability make the CD150M the perfect choice for small dewatering and bypass applications. The standard model is mounted on a highway trailer, with a skid-mounted option.



## Features

- Simple maintenance normally limited to checking fluid levels.
- Close-coupled centrifugal pump with vacuum priming compressor mounted to a diesel engine. Also available in electric drive or as bare shaft pumpend.
- Extensive application flexibility. It will handle sewage, slurries and liquids with solids up to 3" in diameter.
- Continuously operated Godwin venturi air ejector priming device requiring no form of periodic adjustment or control.
- Dry-running heavy duty mechanical seal with abrasion-resistant interfaces.
- Also available in a Critically Silenced unit which drastically reduce noise levels of the pump.
- Standard engine John Deere 4045TF280. Also available with Caterpillar C4.4M-T.
- The volute & suction cover are made from cast iron bs1452:1990 grade 220 and the impeller is made from cast steel bs3100 a5 hardness to 200 hb brinell.

## Specifications

Suction connection	6" 125# ANSI B16.1
Delivery connection	6" 125# ANSI B16.1
Max capacity	2277 USGPM
Max head	154' (47m)
Max solids handling	3" (75mm)
Max impeller diameter	11" (280mm)
Max operating temp	176°F (80°C)
Max working pressure	69.6 psi (4.8 bar)
Max suction pressure	58.0 psi (4.0 bar)
Max casing pressure	104.4 psi (7.2 bar)
Max operating speed	2200 rpm

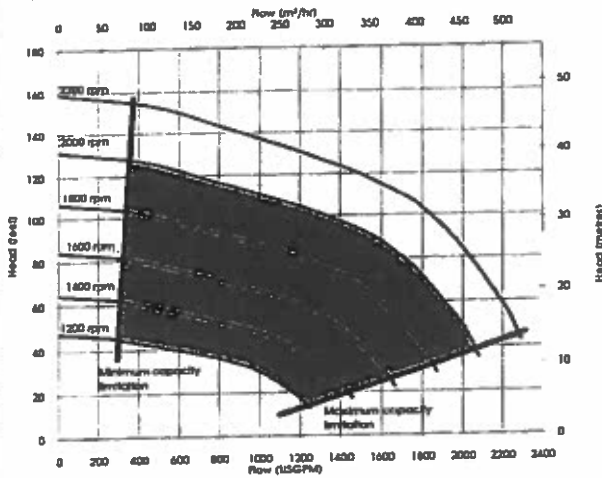
godwin   
a xylem brand

Reference number 95-1011-3000  
Date of issue August 25 2011  
Issue 1

Please contact Godwin for further details  
A typical picture of the pump is shown  
All information is approximate and for general guidance only

CD150M

### Performance Curve



### Materials

- Pump casing & suction cover: Cast iron BS1452:1990 grade 220
- Wearplates: Cast iron to BS1452 grade 220
- Pump shaft: Carbon steel BS970 080M40
- Impeller: Cast steel BS3100 A5 hardness to 200 HB Brinell
- Non-return valve body: Cast iron
- Mechanical seal faces: Silicon carbide vs silicon carbide

### Engine option 1

John Deere, 4045T280, 68.3 HP @ 2000 rpm  
Impeller diameter 11" (280 mm)

### Engine option 2

Caterpillar, C4.4M-T, 69.7 HP @ 2000 rpm  
Impeller diameter 11" (280 mm)

### Suction Lift Table

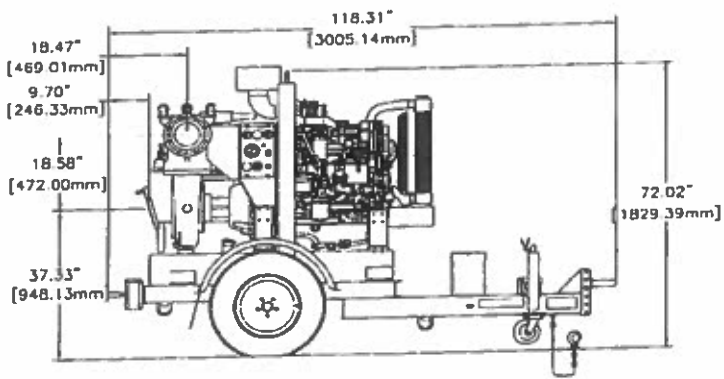
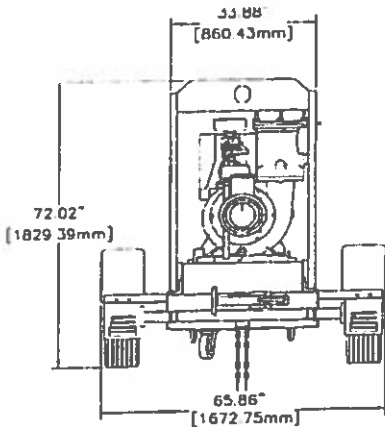
Total Suction Head (')	Total Delivery Head (')				
	23	36	49	66	112
9.8	2083	2008	1915	1739	550
15.1	2008	1964	1876	1655	440
20.0	1893	1849	1805	1611	374
24.9	1761	1717	1651	1567	-

### Suction Lift Table

Total Suction Head (')	Total Delivery Head (')				
	23	36	49	66	112
9.8	2083	2008	1915	1739	550
15.1	2008	1964	1876	1655	440
20.0	1893	1849	1805	1611	374
24.9	1761	1717	1651	1567	-

Fuel capacity (Full) 60 US Gal, (Usable) 60 US Gal  
Fuel consumption @ 2000 rpm BEP 3.4 US Gal/hr  
Weight: (Dry) 2,840 lbs, (Wet) 3,340 lbs  
Dimensions: (L) 118" x (W) 66" x (H) 72"

Fuel capacity (Full) 60 US Gal, (Usable) 60 US Gal  
Fuel consumption @ 2000 rpm BEP 3.4 US Gal/hr  
Weight: (Dry) 3,148 lbs, (Wet) 3,614 lbs  
Dimensions: (L) 118" x (W) 66" x (H) 72"



Performance data provided in tables is based on water tests at sea level and 68°F ambient  
All information is approximate and for general guidance only  
Please contact Godwin Pumps for further details  
Reference number: 95-1011-3000  
Date of issue: August 25, 2011  
Issue: 1

godwin   
a xylem brand

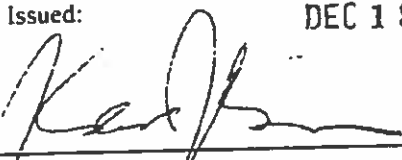
84 Floodgate Road | Bridgeport, NJ 08014 USA  
P: (856) 467-3636 | F: (856) 467-4841  
Sales@godwinpumps.com | godwinpumps.com

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
WASHINGTON, DC 20460

2007 Model Year Certificate of Conformity

Manufacturer: **JOHN DEERE POWER SYSTEMS OF DEERE AND COMPANY**  
Engine Family: **7JDXL04.5076**  
Certificate Number: **JDX-NRCI-07-33**  
Intended Service Class: **NR 4 (37-75)**  
Fuel Type: **DIESEL**  
FELs: g/kW-hr **NMHC+NOx: 6.5** **NOx: NA** **PM: 0.34**  
Effective Date: **12/18/2006**  
Date Issued: **DEC 18 2006**

  
\_\_\_\_\_  
Karl J. Simon, Acting Director  
Compliance and Innovative Strategies Division  
Office of Transportation and Air Quality

Pursuant to Section 213 of the Clean Air Act (42 U.S.C. section 7547) and 40 CFR Part 89, and subject to the terms and conditions prescribed in those provisions, this certificate of conformity is hereby issued with respect to the test engines which have been found to conform to applicable requirements and which represent the following nonroad engines, by engine family, more fully described in the documentation required by 40 CFR Part 89 and produced in the stated model year.

This certificate of conformity covers only those new nonroad compression-ignition engines which conform in all material respects to the design specifications that applied to those engines described in the documentation required by 40 CFR Part 89 and which are produced during the model year stated on this certificate of the said manufacturer, as defined in 40 CFR Part 89.

This certificate of conformity is conditional upon compliance of said manufacturer with the averaging, banking and trading provisions of 40 CFR Part 89, Subpart C. Failure to comply with these provisions may render this certificate void ab initio.

It is a term of this certificate that the manufacturer shall consent to all inspections described in 40 CFR 89.129-96 and 89.506-96 and authorized in a warrant or court order. Failure to comply with the requirements of such a warrant or court order may lead to revocation or suspension of this certificate for reasons specified in 40 CFR Part 89. It is also a term of this certificate that this certificate may be revoked or suspended or rendered void ab initio for other reasons specified in 40 CFR Part 89.

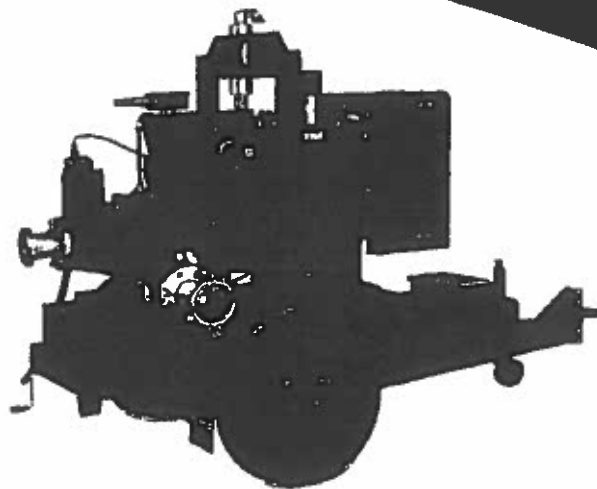
This certificate does not cover nonroad engines sold, offered for sale, or introduced, or delivered for introduction into commerce in the U.S. prior to the effective date of the certificate.

# CD103M Dri-Prime® Pump

The Godwin Dri-Prime CD103M pump offers flow rates to 1020 USGPM and has the capability of handling solids up to 3.0" in diameter.

The CD103M is able to automatically prime to 28' of suction lift from dry. Automatic or manual starting/stopping available through integral mounted control panel or optional wireless-remote access.

Indefinite dry-running is no problem due to the unique Godwin liquid bath mechanical seal design. Solids handling, dry-running, and portability make the CD103M the perfect choice for dewatering and bypass applications.



## Features and Benefits

- Simple maintenance normally limited to checking fluid levels and filters.
- Dri-Prime (continuously operated Venturi air ejector priming device) requiring no periodic adjustment. Optional compressor clutch available.
- Extensive application flexibility handling sewage, slurries, and liquids with solids up to 3.0" in diameter.
- Dry-running high pressure liquid bath mechanical seal with high abrasion resistant solid silicon carbide faces.
- Close-coupled centrifugal pump with Dri-Prime system coupled to a diesel engine or electric motor.
- All cast iron construction (stainless steel construction option available) with cast steel impeller.
- Also available in a critically silenced unit which reduces noise levels to less than 70 dBA at 30'.
- Standard engine Caterpillar C2.2T (IT4 Flex). Also available with John Deere 4024TF281 (IT4 Flex).

## Specifications

Suction connection	4" 150# ANSI B16.5
Delivery connection	4" 150# ANSI B16.5
Max capacity	1020 USGPM †
Max solids handling	3.0"
Max impeller diameter	10.1"
Max operating temp	176°F*
Max pressure	75 psi
Max suction pressure	58 psi
Max casing pressure	113 psi
Max operating speed	2200 rpm

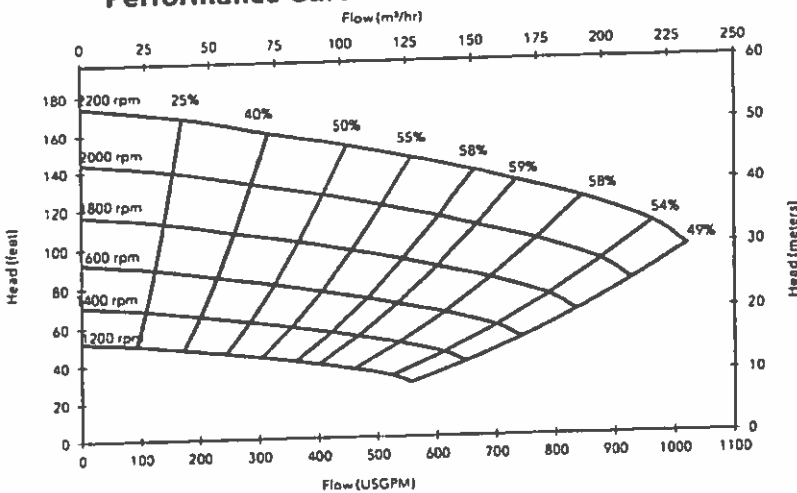
\* Please contact our office for applications in excess of 176°F.

† Larger diameter pipes may be required for maximum flows.

Please contact the factory or office for further details. A typical picture of the pump is shown. All information is approximate and for general guidance only.

godwin   
a xylem brand

### Performance Curve



### Engine option 1

Caterpillar C2.2T (IT4 Flex), 41 HP @ 2200 rpm

Impeller diameter 10 1"

Pump speed 2200 rpm

#### Suction Lift Table

Total Suction Head (feet)	Total Delivery Head (feet)				
	78	103	127	152	176
10	1022	915	646	350	-
15	996	834	538	215	-
20	888	753	431	-	-
25	807	646	269	-	-

Fuel capacity 60 US Gal

Max Fuel consumption @ 2200 rpm: 2.4 US Gal/hr

Max Fuel consumption @ 1800 rpm: 2.0 US Gal/hr

Weight (Dry): 2,240 lbs

Weight (Wet) 2,650 lbs

Dim. (L) 119" x (W) 66" x (H) 77"  
 Performance data provided in tables is based on water tests at sea level and 20°C ambient. All information is approximate and for general guidance only. Please contact the factory or office for further details.

### Materials

Pump casing & suction cover	Cast iron BS EN 1561 - 1997
Wearplates	Cast iron BS EN 1561 - 1997
Pump Shaft	Carbon steel BS 970 - 1991 817M40T
Impeller	Cast Steel BS3100 A5 Hardness to 200 HB Brinell
Non-return valve body	Cast iron BS EN 1561 - 1997
Mechanical seal	Silicon carbide face, Viton elastomers; Stainless steel body

### Engine option 2

John Deere 4024TF281 (IT4 Flex), 46 HP @ 2200 rpm

Impeller diameter 10 1"

Pump speed 2200 rpm

#### Suction Lift Table

Total Suction Head (feet)	Total Delivery Head (feet)				
	78	103	127	152	176
10	1022	915	646	350	-
15	996	834	538	215	-
20	888	753	431	-	-
25	807	646	269	-	-

Fuel capacity: 60 US Gal

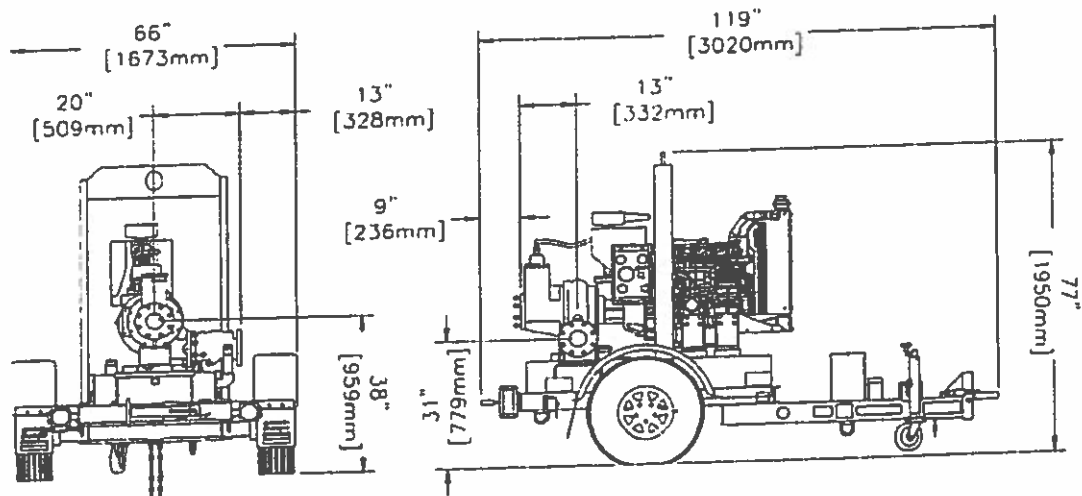
Max Fuel consumption @ 2200 rpm: 2.6 US Gal/hr

Max Fuel consumption @ 1800 rpm: 2.3 US Gal/hr

Weight (Dry): 2,400 lbs

Weight (Wet): 2,800 lbs

Dim. (L) 119" x (W) 66" x (H) 77"  
 Performance data provided in tables is based on water tests at sea level and 20°C ambient. All information is approximate and for general guidance only. Please contact the factory or office for further details.



**xylem**  
 Let's Solve Water

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Reference number 95-1008-3000  
 Date of issue February 26, 2014  
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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
OFFICE OF TRANSPORTATION AND AIR QUALITY  
WASHINGTON, DC 20460



CERTIFICATE OF CONFORMITY  
2010 MODEL YEAR

Manufacturer: **JOHN DEERE POWER SYSTEMS**  
Engine Family: **AJDXL02.4074**  
Certificate Number: **JDX-NRCI-10-06.1**  
Intended Service Class: **NR 3 (19-37)**  
Fuel Type: **DIESEL (LOW OR ULTRA-LOW SULFUR)**  
FELs: g/kW-hr **NMHC +NOx: N/A NOx: N/A PM: N/A**  
Effective Date: **12/16/2009**  
Date Issued: **12/16/2009**

Karl J. Simon, Director  
Compliance and Innovative Strategies Division  
Office of Transportation and Air Quality

Pursuant to Section 111 and Section 213 of the Clean Air Act (42 U.S.C. sections 7411 and 7547) and 40 CFR Part 60 and Part 1039, and subject to the terms and conditions prescribed in those provisions, this certificate of conformity is hereby issued with respect to the test engines which have been found to conform to applicable requirements and which represent the following stationary and nonroad engines, by engine family, more fully described in the documentation required by 40 CFR Part 60 and 1039, and produced in the stated model year.

This certificate of conformity covers only those new stationary and nonroad compression-ignition engines which conform in all material respects to the design specifications that applied to those engines described in the documentation required by 40 CFR Part 60 and 1039 and which are produced during the model year stated on this certificate of the said manufacturer, as defined in 40 CFR Part 60 and 1039.

It is a term of this certificate that the manufacturer shall consent to all inspections described in 40 CFR Part 1068 and authorized in a warrant or court order. Failure to comply with the requirements of such a warrant or court order may lead to a revocation or suspension of this certificate for reasons specified in 40 CFR Part 1039. It is also a term of this certificate that this certificate may be revoked or suspended or rendered void ab initio for other reasons specified in 40 CFR Part 1039.

This certificate does not cover stationary and nonroad engines sold, offered for sale, or introduced, or delivered for introduction, into commerce in the U.S. prior to the effective date of the certificate.

 <b>AIR RESOURCES BOARD</b>	<b>JOHN DEERE POWER SYSTEMS</b>	<b>EXECUTIVE ORDER U-R-004-0380</b> New Off-Road Compression-Ignition Engines

Pursuant to the authority vested in the Air Resources Board by Sections 43013, 43018, 43101, 43102, 43104 and 43105 of the Health and Safety Code; and

Pursuant to the authority vested in the undersigned by Sections 39515 and 39516 of the Health and Safety Code and Executive Order G-02-003;

**IT IS ORDERED AND RESOLVED:** That the following compression-ignition engines and emission control systems produced by the manufacturer are certified as described below for use in off-road equipment. Production engines shall be in all material respects the same as those for which certification is granted.

MODEL YEAR	ENGINE FAMILY	DISPLACEMENT (liters)	FUEL TYPE	USEFUL LIFE (hours)
2010	AJDXL02.4074	2.4	Diesel	5000
<b>SPECIAL FEATURES &amp; EMISSION CONTROL SYSTEMS</b>			<b>TYPICAL EQUIPMENT APPLICATION</b>	
Mechanical Diesel Injection, Turbo Charger, Smoke Puff Limiter			Loaders, Tractor, Pump, Compressor, Generator Set, Other Industrial Equipment	

The engine models and codes are attached.

The following are the exhaust certification standards (STD), or family emission limit(s) (FEL) as applicable, and certification levels (CERT) for hydrocarbon (HC), oxides of nitrogen (NOx), or non-methane hydrocarbon plus oxides of nitrogen (NMHC+NOx), carbon monoxide (CO), and particulate matter (PM) in grams per kilowatt-hour (g/kw-hr), and the opacity-of-smoke certification standards and certification levels in percent (%) during acceleration (Accel), lugging (Lug), and the peak value from either mode (Peak) for this engine family (Title 13, California Code of Regulations, (13 CCR) Section 2423):

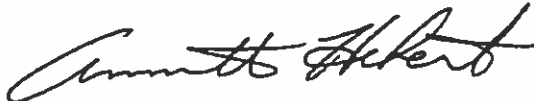
RATED POWER CLASS	EMISSION STANDARD CATEGORY		EXHAUST (g/kw-hr)					OPACITY (%)		
			HC	NOx	NMHC+NOx	CO	PM	ACCEL	LUG	PEAK
19 ≤ kW < 37	Tier 4 Interim	STD	N/A	N/A	7.5	5.5	0.30	20	15	50
		CERT	-	-	6.6	2.7	0.30	1	2	2

**BE IT FURTHER RESOLVED:** That for the listed engine models, the manufacturer has submitted the information and materials to demonstrate certification compliance with 13 CCR Section 2424 (emission control labels), and 13 CCR Sections 2425 and 2426 (emission control system warranty).

Engines certified under this Executive Order must conform to all applicable California emission regulations.

This Executive Order is only granted to the engine family and model-year listed above. Engines in this family that are produced for any other model-year are not covered by this Executive Order.

Executed at El Monte, California on this 28 day of December 2009.



Annette Hebert, Chief  
 Mobile Source Operations Division



Date: 12/08/2009

Attachment 1 of 1

Engine Model Summary Form

EO #: U-R-004-0380

Manufacturer: John Deere Power Systems  
Engine category: Nonroad CI  
EPA Engine Family: AJDXL02.4074  
Mtr Family Name: 250TB  
Process Code: New Submission

1.Engine Code	2.Engine Model	3.BHP@RPM (SAE Gross)	4.Fuel Rate mm/stroke @ peak HP (for diesel only)	5.Fuel Rate (ba/hr) @ peak HP (for diesels only)	6.Torque @ RPM (SEA Gross)	7.Fuel Rate mm/stroke@peak torque	8.Fuel Rate (ba/hr)@peak torque	9.Emission Control Device Per SAE J1930
4024TF270E	4024T	48.28@2400	37.80@2400	20.29@2400	148.39@1440	47.7@1440	15.44@1440	EM SPL DFI
4024TT012	4024T	48.28@2400	34.20@2400	18.48@2400	134.96@1440	43.2@1440	14.00@1440	EM SPL DFI
4024TF281A	4024T	48.28@2800	33.80@2800	21.26@2800	127.59@1880	40.5@1880	15.33@1880	EM SPL DFI
4024TF281B	4024T	48.28@1800	48.90@1800	19.82@1800	N/A	N/A	N/A	EM SPL DFI
4024TLV09	4024T	48.94@2400	34.20@2400	18.48@2400	134.96@1440	43.2@1440	14.00@1440	EM SPL DFI
4024TLV10	4024T	48.28@2400	34.20@2400	18.48@2400	134.96@1440	43.2@1440	14.00@1440	EM SPL DFI

TC

**ATTACHMENT B**  
**Emissions Calculations**

Source No.	Description	Equipment			Emissions															
		Fuel Type	Hrs of Operation	Max hp	Fuel (USDO) Consumption gal/hr	EF (lb/HP-hr)	NOx/MMHC (lb/hr)	SO2 (lb/hr)	CO (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	SO2 (lb/yr)	CO2e (lb/yr)	PM (lb/yr)	HAPs (lb/yr)					
3	Transfer Pump	Diesel	8760	200	9.2	Tier 3 Std	1.32	5.76	1.32	5.76	1.64	7.20	0.10	0.43	0.00195	0.01	230.00	1007.40	0.001	0.004
4	Sand Filter Pump #1	Diesel	8760	200	9.2	Tier 3 Std	1.32	5.76	1.32	5.76	1.64	7.20	0.10	0.43	0.00195	0.01	230.00	1007.40	0.001	0.004
5	Sand Filter Pump #2	Diesel	8760	200	9.2	Tier 3 Std	1.32	5.76	1.32	5.76	1.64	7.20	0.10	0.43	0.00195	0.01	230.00	1007.40	0.001	0.004

Sample Emissions Calculation - based on Emission Factor  
 NOx Emissions, lb/hr = Emission Factor, lb/hr-hp \* Max hp  
 NOx Emissions, tpy = Nox Emissions, lb/hr \* 24 hr/d \* 365 d/yr / 2000 lb/ton

Sample Emissions Calculation - based on fuel sulfur content  
 SOx Emissions, lb/hr = fuel consumption, gal/hr \* fuel density, lb/gal \* sulfur content, ppm / 10<sup>6</sup> \* MW SO<sub>x</sub> / MW sulfur

Emission Factors

EPA Exhaust Standards						
Tier	Model Year	MMHC (lb/HP-hr)	NOx (lb/HP-hr)	PM (lb/HP-hr)	CO (lb/HP-hr)	SO <sub>x</sub> (lb/HP-hr)
Tier 1	1998-2003	-	9.20	-	-	-
Tier 2	2004-2007	-	-	0.40	5.0	-
Tier 3	2008-2011	-	-	0.40	5.0	-
Tier 4	2012-2013	-	-	0.02	5.0	-
Tier 4	2014+	0.19	0.40	0.02	5.0	-

EPA Exhaust Standards						
Tier	Model Year	MMHC (lb/HP-hr)	NOx (lb/HP-hr)	PM (lb/HP-hr)	CO (lb/HP-hr)	SO <sub>x</sub> (lb/HP-hr)
Tier 1	1997-2002	-	9.2	-	-	-
Tier 2	2003-2006	-	-	0.30	5.0	-
Tier 3	2007-2011	-	-	0.30	5.0	-
Tier 4	2012-2013	-	-	0.02	5.0	-
Tier 4	2014+	0.19	0.40	0.02	5.0	-

EPA Exhaust Standards						
Tier	Model Year	MMHC (lb/HP-hr)	NOx (lb/HP-hr)	PM (lb/HP-hr)	CO (lb/HP-hr)	SO <sub>x</sub> (lb/HP-hr)
Tier 1	1996-2002	-	9.2	-	-	-
Tier 2	2003-2005	-	-	0.30	5.0	-
Tier 3	2006-2010	-	-	0.30	5.0	-
Tier 4	2011-2013	-	-	0.02	5.0	-
Tier 4	2014+	0.19	0.40	0.02	5.0	-

Compound	EF (lb/HP-hr)
Hexachlorobenzene (CAS#000071432)	0.000633
Benzene (CAS#0000071432)	6.531E-07
Toluene (CAS#000108883)	0.000408
Xylenes	0.000285
Propylene	0.00259
1,3-Butadiene (CAS#000105960)	0.000391
Formaldehyde (CAS#000050000)	0.00119
Acetaldehyde (CAS#000075070)	0.000787
Acrolein (CAS#000107028)	0.0000923
PAH Total	0.000188
Naphthalene (CAS# 000091203)	0.0000848
Anthracene (CAS# 000085091)	5.39E-08

Reference AP-42 Emission Factors, Table 3.1-2

7,000 lb/HP-hr was used to convert from lb/day to lb/yr as noted in AP-42

**ATTACHMENT C**

**Air Quality Impact Assessment  
with the National and State Ambient Air Quality Standards**

**NATIONAL AMBIENT AIR QUALITY STANDARDS MODELING  
ANALYSIS FOR THREE INTERNAL COMBUSTION ENGINES  
AT THE CHEVRON REFINERY  
IN KAPOLEI, HAWAII**



**Prepared for:  
Chevron Hawaii Refinery  
91-480 Malakole Street  
Kapolei, Hawaii 96707**

**Prepared by:  
RTP Environmental Associates, Inc.  
304A West Millbrook Road  
Raleigh, North Carolina 27609**

**April 2015**



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## 1.0 INTRODUCTION

An air quality dispersion modeling analysis has been conducted for emissions of criteria pollutants from three internal combustion engines at the Chevron Products Company (Chevron) facility in Kapolei, Hawaii. The analysis was conducted to evaluate the compliance status of the engines with respect to the National Ambient Air Quality Standards (NAAQS) or State Ambient Air Quality Standards (SAAQS) pursuant to HAR 11-60.1-83(a)(12) .

The results of the analysis demonstrate that the three engines will not cause or contribute to an exceedance of the NAAQS or SAAQS. The remainder of this document describes the modeling methodology and details the results of the analysis. The modeling conforms with the procedures specified in the Environmental Protection Agency's Guideline on Air Quality Models<sup>1</sup> as well as the New Source Review Workshop Manual (Draft)<sup>2</sup>.

<sup>1</sup> Guidelines on Air Quality Models, (Revised). EPA-450/2-78-027R, Appendix W of 40 CFR Part 51, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. August 1995.

<sup>2</sup> New Source Review Workshop Manual (Draft), U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, October 1990.





## 2.0 SITE DESCRIPTION

The Chevron Hawaii refinery is located within the Campbell Industrial Park at Kapolei, Ewa, Oahu, Hawaii. The approximate UTM coordinates of the refinery are 592,237 meters east and 2,356,775 meters north (UTM Zone 4, NAD 83). Figure 1 shows the general location of the refinery. Figure 2 shows the specific refinery location on a 7.5 minute USGS topographic map.

The Chevron Hawaii refinery is a covered source as defined at HAR § 60.1-1. The area surrounding the refinery is designated at 40 CFR § 81.312 as attainment or unclassifiable for all criteria pollutants.

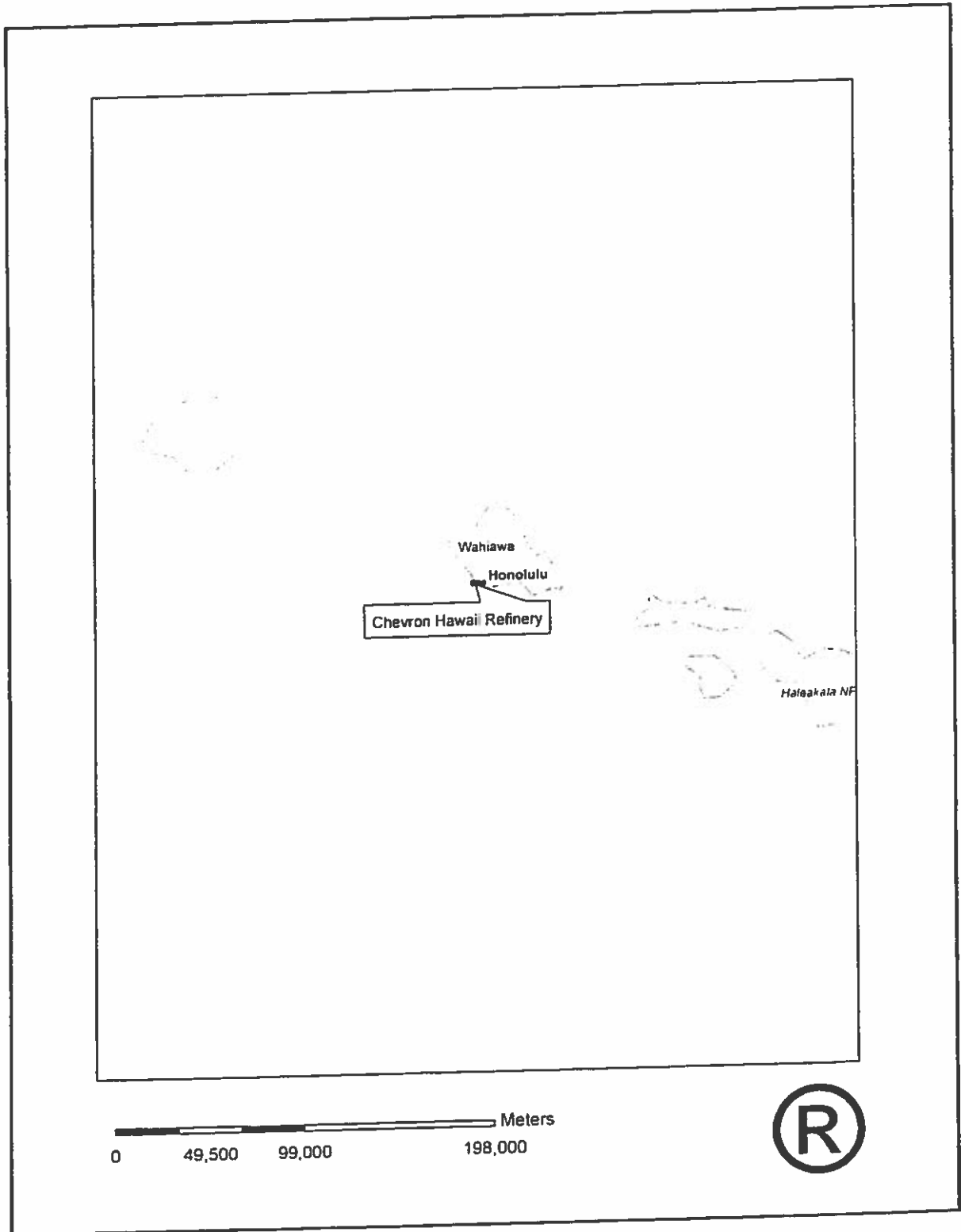


Figure 1. General Location of the Chevron Hawaii Refinery

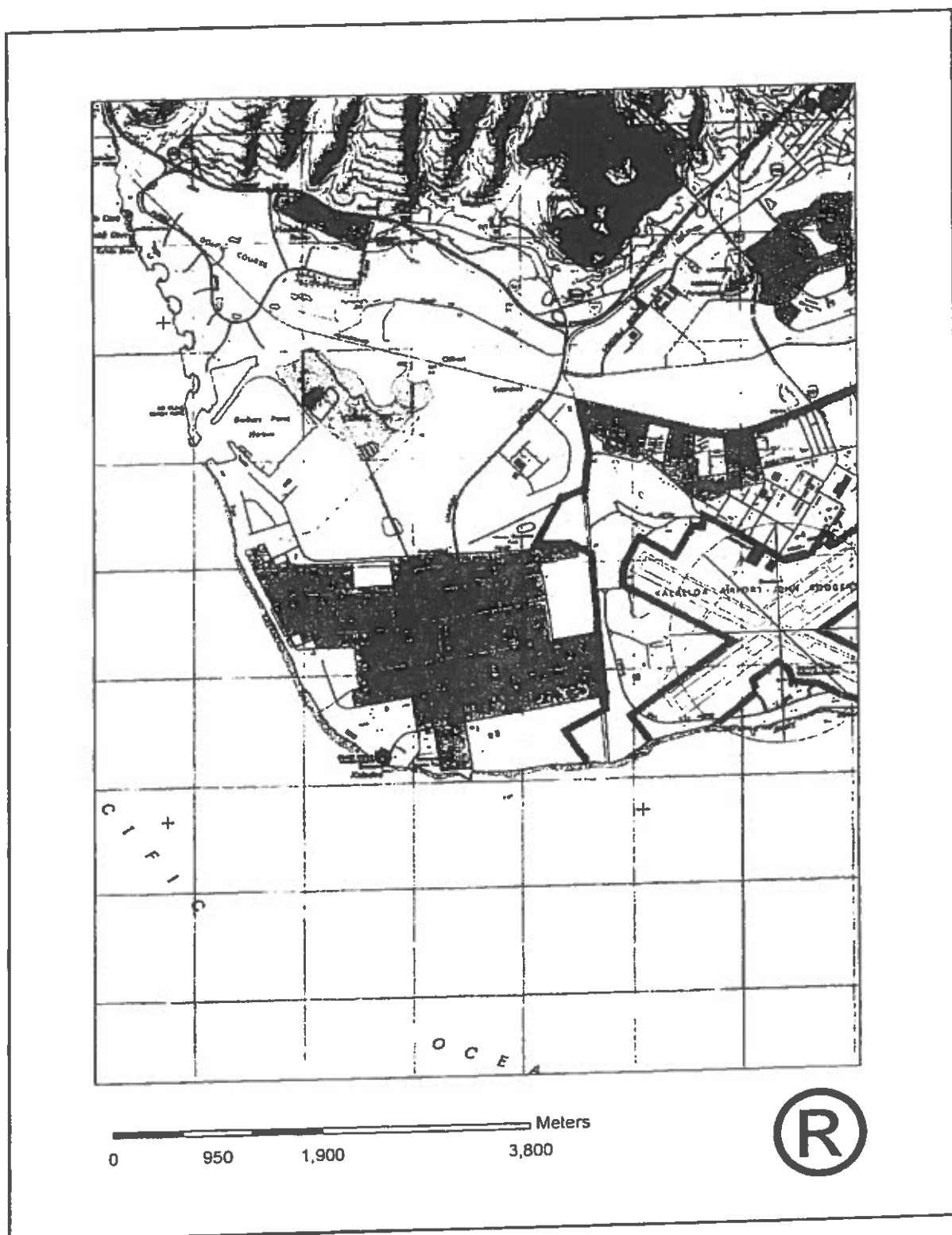


Figure 2. Specific Location of the Chevron Hawaii Refinery



### 3.0 MODEL SELECTION AND MODEL INPUT

#### 3.1 Model Selection

The latest version of the AMS/EPA Regulatory Model (AERMOD, Version 14134) was used to conduct the dispersion modeling analysis. The AERMOD system was used to calculate concentrations near the Chevron Hawaii refinery.

AERMOD is a Gaussian plume dispersion model that is based on planetary boundary layer principles for characterizing atmospheric stability. The model evaluates the non-Gaussian vertical behavior of plumes during convective conditions with the probability density function and the superposition of several Gaussian plumes. AERMOD is a modeling system with three components: AERMAP is the terrain preprocessor program, AERMET is the meteorological data preprocessor, and AERMOD includes the dispersion modeling algorithms.

AERMOD is the most appropriate model for calculating ambient concentrations near the Chevron Hawaii refinery based on the model's ability to incorporate multiple sources and source types. The model can also account for convective updrafts and downdrafts and meteorological data throughout the plume depth. The model also provides parameters required for use with up to date planetary boundary layer parameterization. The model also has the ability to incorporate building wake effects and to calculate concentrations within the cavity recirculation zone. All model options were selected as recommended in the EPA Guidelines on Air Quality Models.

#### 3.2 Land Use Analysis

The selection of the appropriate dispersion coefficients in the model is dependent on the land use within three kilometers of the refinery. The land use typing scheme of Auer was used to determine the proper land use classification.<sup>3</sup> It was determined that the

<sup>3</sup> Auer, Jr., A.H. "Correlation of Land Use and Cover with Meteorological Anomalies." Journal of Applied Meteorology, 17:636-643, 1978.



land use in the vicinity of the refinery is predominantly rural. Therefore, AERMOD was not run in the urban mode.

### **3.3 Good Engineering Practice Stack Height Analysis**

A Good Engineering Practice (GEP) stack height evaluation was conducted to determine if inclusion of building wake effects was required in the modeling analysis. Procedures used were in accordance with those described in the EPA Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations-Revised)<sup>4</sup>.

GEP formula stack height, as defined in 40 CFR 51, is expressed as  $GEP = H_b + 1.5L$ , where  $H_b$  is the building height and  $L$  is the lesser of the building height or maximum projected width. Building/structure locations were determined from refinery site plans. The structure locations and heights were input to the EPA's Building Profile Input Program (BPIP-PRIME) computer program to calculate the direction-specific building dimensions needed for AERMOD. The Chevron Hawaii refinery site plan is shown in Figure 3. A three dimensional rendering of the refinery is shown in Figure 4.

### **3.4 Meteorological Data Selection**

A five year data record (2008-2012) of hourly surface meteorological data from the Kalaeloa Airport (John Rodgers Field) and twice daily radiosonde sounding data from the Lihue upper air station were obtained from the National Climatic Data Center (NCDC) in Asheville, NC. The proximity of the Kalaeloa airport to the refinery (the airport is located 2km east of the refinery- please see Figure 2) ensures that the data are representative of the weather conditions that would affect dispersion and transport of refinery emissions. The Lihue upper air record is the most representative data set of this type available in Hawaii.

<sup>4</sup> Guideline for Determination of Good Engineering Practice Stack Height (Technical Support Document for Stack Height Regulations (Revised)). EPA-450/4-80-023R, U.S. Environmental Protection Agency, June 1985

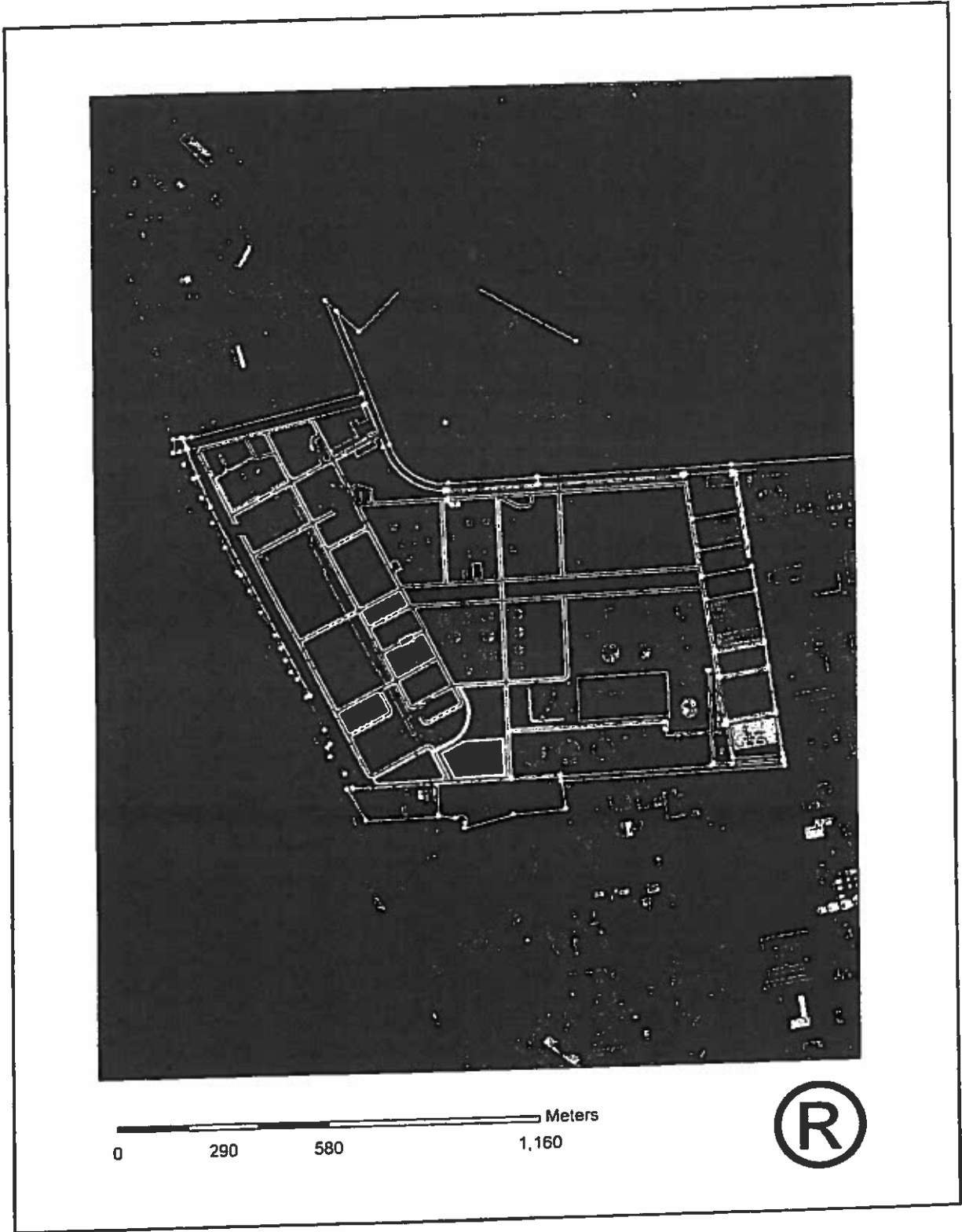


Figure 3. Chevron Refinery Plot Plan



Figure 4. Chevron Refinery Three Dimensional Plot Plan

### 3.5 Meteorological Data Processing

The meteorological data pre-processor AERMET (Version 12345) was used to develop meteorological data for the AERMOD modeling system. The AERMET software processes surface meteorological data and twice-daily upper air sounding data into the proper format using a three-stage process. The first stage extracts the data and administers several data quality checks. The second stage merges the data, and the third stage estimates the required boundary layer parameters and writes the data in a format readable by AERMOD.

The hourly surface measurements were augmented with 2-minute average wind speeds for each minute of the hour. The 2-minute average values at the Kalaeloa Airport were obtained and processed with the EPA's AERMINUTE program (Version 11059).

The AERMET meteorological processor requires estimates of the following surface characteristics: surface roughness length, albedo, and Bowen ratio. The surface roughness length is related to the height of obstacles to the wind flow. The surface roughness length influences the surface shear stress and is an important factor in calculating mechanical turbulence and stability. The albedo is the fraction of the total



incident solar radiation reflected by the surface back to space without absorption. The Bowen ratio is an indicator of surface moisture and is the ratio of the sensible heat flux to the latent heat flux. The albedo and Bowen ratio are used for determining the planetary boundary layer parameters for convective conditions due to the surface sensible heat flux. Estimates of Bowen ratio and surface roughness length were made using 2001 Land Cover Data and the Alaska Department of Environmental Conservation's Guidance, "How to Calculate the Geometric Mean Bowen Ratio and the Inverse-Distance Weighted Geometric Mean Surface Roughness Length in Alaska". This guidance was used because the EPA's AERSURFACE program could not be used to make estimates of Bowen ratio and surface roughness length due to the lack of USGS Land Cover data (NLCD92 data) for Hawaii (the NLCD92 data files are needed to run the AERSURFACE program). Surface characteristics were developed based upon eight sectors, by season, as shown in Figure 2.

### **3.6 Receptor Grid**

The receptor grid consisted of three cartesian grids. The first cartesian grid extended to approximately 5km from the fence in all directions. Receptors in this region were spaced at 100m intervals. The second grid extended to 10km. Receptor spacing in this region were 250m. The third grid extended to approximately 15km with a spacing of 500m. The grid was designed such that maximum refinery impacts fall within the 100m spacing of receptors. Receptors were also placed along the fenceline at 50m intervals.

Receptor elevations and hill height scale factors were calculated with AERMAP for each receptor location. The elevation data were obtained from the USGS 1/3 ARC Second National Elevation Data (NED) obtained from the USGS Seamless Server. The modeled near-field receptor grid is presented in Figure 5.

### **3.7 Modeled Stack Parameters and Emissions**

The stack parameter data and modeled maximum hourly emission rates are shown in Table 1. Each engine was modeled individually for comparison to the NAAQS.



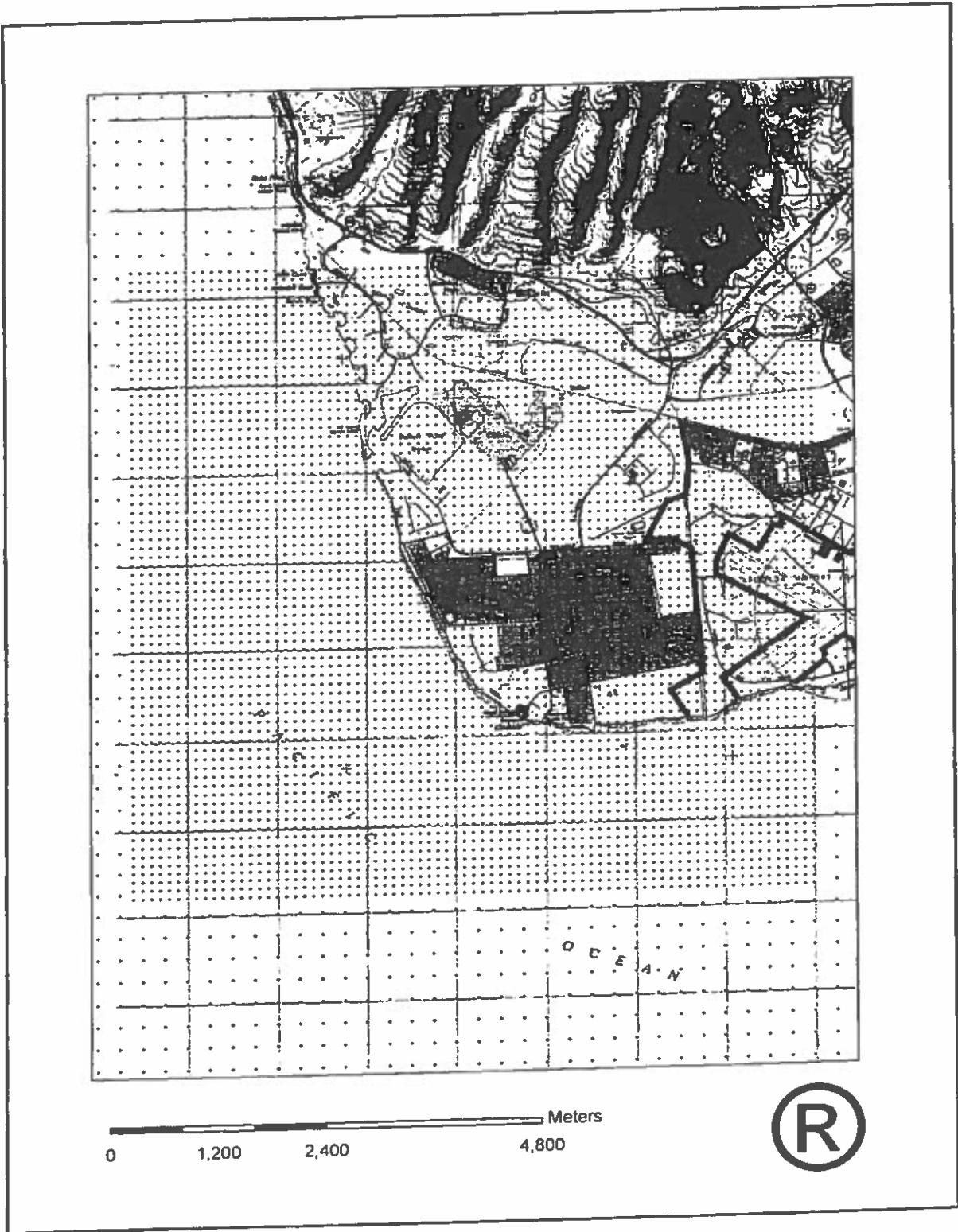


Figure 5. Chevron Near-Field Receptor Grid



Table 1. Chevron Modeled Input Data

Source ID	Source Description	Base		Stack		Exit		PM10 (lb/hr)	SO2 (lb/hr)	CO (lb/hr)	NO2 (lb/hr)
		Easting (X) (m)	Northing (Y) (m)	Elevation (ft)	Height (ft)	Temp (F)	Velocity (ft/sec)				
ICENG3	Oil Transfer - Godwin	592063.32	2356490.10	6.6	8.00	809	31.1	0.066	0.0019	1.151	1.316
ICENGA	Sand Filter - Godwin	592074.33	2356424.03	6.6	8.00	809	31.1	0.066	0.0019	1.151	1.316
ICENG5	Sand Filter - Godwin (New)	592074.33	2356424.03	6.6	8.00	809	31.1	0.066	0.0019	1.151	1.316



## 4.0 MODELING RESULTS

Demonstration of compliance with the NAAQS and SAAQS was assessed based. Compliance with the 1-hr SO<sub>2</sub> standard was conservatively assessed based upon the fourth highest value as modeled over five years of meteorological data, not on the form of the standard which is the 99<sup>th</sup> percentile (the fourth highest value) of the annual distribution of the daily maximum 1-hr values from the 5-year meteorological dataset. Compliance with the 1-hr NO<sub>2</sub> standard was assessed based upon the form of the standard which is the 98<sup>th</sup> percentile (the eighth highest value) of the annual distribution of the daily maximum 1-hr values from the 5-year meteorological dataset. Compliance with the 3-hour and 24-hour standards was based upon the form of the standard which is the highest second high value from each of the five years of meteorology. Compliance with the annual standards was based upon the highest value from the 5-year dataset. The EPA Tier 2 Ambient Ratio Method values for NO<sub>x</sub> to NO<sub>2</sub> conversion of 0.75 for the annual average and 0.80 for the 1-hour average were employed.

The results of the NAAQS/SAAQS analysis are presented in Table 2. As shown, the engines are compliant with the NAAQS/SAAQS.

### 4.1 Summary and Conclusions

Emissions from the three engines were evaluated in a dispersion modeling analysis. The modeling demonstrates that the ground level concentrations are below the levels designed to protect human health and welfare. The modeling input and output files are provided on the attached CD. Model summary results are presented in Attachment A. The summary results list the model file names associated with each phase of the analysis.<sup>5</sup>

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<sup>5</sup> As a general rule, the AERMOD input files have a ".dta" extension. The AERMOD output files have a ".lst" extension.



Table 2. Engine NAAQS/SAAQs Analysis Results

Pollutant	Averaging Period	Rank	Group	Modeled Concentration ( $\mu\text{g}/\text{m}^3$ ) <sup>a</sup>	Background Concentration ( $\mu\text{g}/\text{m}^3$ ) <sup>b</sup>	Total Concentration ( $\mu\text{g}/\text{m}^3$ )	Standard ( $\mu\text{g}/\text{m}^3$ )	Percent Standard	
PM10	24-hour	2ND	ICENG3	0.9	58.0	58.9	150.0	39.3%	
	Annual	1ST	ICENG3	0.2	16.3	16.5	50.0	32.9%	
	24-hour	2ND	ICENG4	0.9	58.0	58.9	150.0	39.3%	
	Annual	1ST	ICENG4	0.2	16.3	16.5	50.0	33.0%	
	24-hour	2ND	ICENG5	0.9	58.0	58.9	150.0	39.3%	
	Annual	1ST	ICENG5	0.2	16.3	16.5	50.0	33.0%	
	24-hour	2ND	ICENG3	0.9	9.9	10.8	35.0	30.8%	
	Annual	1ST	ICENG3	0.2	3.8	4.0	11.0	36.0%	
	24-hour	2ND	ICENG4	0.9	9.9	10.8	35.0	30.9%	
	Annual	1ST	ICENG4	0.2	3.8	4.0	11.0	36.2%	
PM2.5	24-hour	2ND	ICENG5	0.9	9.9	10.8	35.0	30.9%	
	Annual	1ST	ICENG5	0.2	3.8	4.0	11.0	36.2%	
	1-hour	4TH	ICENG3	0.1	47.0	47.1	196.0	24.0%	
	3-hour	2ND	ICENG3	0.1	28.5	28.5	1300.0	2.2%	
	24-hour	2ND	ICENG3	0.0	10.5	10.5	365.0	2.9%	
	Annual	1ST	ICENG3	0.0	7.5	7.5	80.0	9.4%	
	1-hour	4TH	ICENG4	0.1	47.0	47.1	196.0	24.0%	
	3-hour	2ND	ICENG4	0.1	28.5	28.5	1300.0	2.2%	
	24-hour	2ND	ICENG4	0.0	10.5	10.5	365.0	2.9%	
	Annual	1ST	ICENG4	0.0	7.5	7.5	80.0	9.4%	
SO <sub>2</sub>	1-hour	4TH	ICENG5	0.1	47.0	47.1	196.0	24.0%	
	3-hour	2ND	ICENG5	0.1	28.5	28.5	1300.0	2.2%	
	24-hour	2ND	ICENG5	0.0	10.5	10.5	365.0	2.9%	
	Annual	1ST	ICENG5	0.0	7.5	7.5	80.0	9.4%	
	1-hour	4TH	ICENG3	38.5	1714.3	1752.8	10000.0	17.5%	
	3-hour	2ND	ICENG3	25.8	1257.1	1282.9	5000.0	25.7%	
	24-hour	2ND	ICENG4	44.2	1714.3	1758.5	10000.0	17.6%	
	Annual	1ST	ICENG4	27.4	1257.1	1284.6	5000.0	25.7%	
	CO	1-hour	2ND	ICENG3	38.5	1714.3	1752.8	10000.0	17.5%
		3-hour	2ND	ICENG3	25.8	1257.1	1282.9	5000.0	25.7%
24-hour		2ND	ICENG4	44.2	1714.3	1758.5	10000.0	17.6%	
Annual		1ST	ICENG4	27.4	1257.1	1284.6	5000.0	25.7%	



Pollutant	Averaging Period	Rank	Group	Modeled Concentration ( $\mu\text{g}/\text{m}^3$ ) <sup>a</sup>	Background Concentration ( $\mu\text{g}/\text{m}^3$ ) <sup>b</sup>	Total Concentration ( $\mu\text{g}/\text{m}^3$ )	Standard ( $\mu\text{g}/\text{m}^3$ )	Percent Standard
NO <sub>2</sub>	1-hour	2ND	ICENG5	44.2	1714.3	1758.5	10000.0	17.6%
	8-hour	2ND	ICENG5	27.4	1257.1	1284.6	5000.0	25.7%
	1-hour	8TH	ICENG3	31.5	45.1	76.6	188.0	40.8%
	Annual	1ST	ICENG3	3.1	17.1	20.2	75.0	27.0%
	1-hour	8TH	ICENG4	33.4	45.1	78.5	188.0	41.7%
	Annual	1ST	ICENG4	3.5	17.1	20.6	75.0	27.5%
	1-hour	8TH	ICENG5	33.4	45.1	78.5	188.0	41.7%
	Annual	1ST	ICENG5	3.5	17.1	20.6	75.0	27.5%

<sup>a</sup>No off-site sources included.

<sup>b</sup>Background concentrations are from the Kapolei monitor (max value from 2010-2012).



**ATTACHMENT A**  
**Model Summary Results and Supporting Documentation**



Chevron Hawaii NAAQS Analysis Results

Pollutant	Average	Group	Rank	Model Conc. (ug/m3)	Background (ug/m3)	Total (ug/m3)	Total Standard (ug/m3)	% Standard
PM10	24-HR	ICENG3	2ND	0.9	58.0	58.9	150	39%
PM10	ANNUAL	ICENG3	1ST	0.2	16.3	16.5	50	33%
PM10	24-HR	ICENG4	2ND	0.9	58.0	58.9	150	39%
PM10	ANNUAL	ICENG4	1ST	0.2	16.3	16.5	50	33%
PM10	24-HR	ICENG5	2ND	0.9	58.0	58.9	150	39%
PM10	ANNUAL	ICENG5	1ST	0.2	16.3	16.5	50	33%
PM2.5	24-HR	ICENG3	2ND	0.9	9.9	10.8	35	31%
PM2.5	ANNUAL	ICENG3	1ST	0.2	3.8	4.0	11	36%
PM2.5	24-HR	ICENG4	2ND	0.9	9.9	10.8	35	31%
PM2.5	ANNUAL	ICENG4	1ST	0.2	3.8	4.0	11	36%
PM2.5	24-HR	ICENG5	2ND	0.9	9.9	10.8	35	31%
PM2.5	ANNUAL	ICENG5	1ST	0.2	3.8	4.0	11	36%
SO2	1-HR	ICENG3	4TH	0.1	47.0	47.1	196	24%
SO2	3-HR	ICENG3	2ND	0.1	28.5	28.5	1300	2%
SO2	24-HR	ICENG3	2ND	0.0	10.5	10.5	365	3%
SO2	Annual	ICENG3	1ST	0.0	7.5	7.5	80	9%
SO2	1-HR	ICENG4	4TH	0.1	47.0	47.1	196	24%
SO2	3-HR	ICENG4	2ND	0.1	28.5	28.5	1300	2%
SO2	24-HR	ICENG4	2ND	0.0	10.5	10.5	365	3%
SO2	Annual	ICENG4	1ST	0.0	7.5	7.5	80	9%
SO2	1-HR	ICENG5	4TH	0.1	47.0	47.1	196	24%
SO2	3-HR	ICENG5	2ND	0.1	28.5	28.5	1300	2%
SO2	24-HR	ICENG5	2ND	0.0	10.5	10.5	365	3%
SO2	Annual	ICENG5	1ST	0.0	7.5	7.5	80	9%
CO	1-HR	ICENG3	2ND	38.5	1714.3	1753	10000	18%
CO	8-HR	ICENG3	2ND	25.8	1257.1	1283	5000	26%
CO	1-HR	ICENG4	2ND	44.2	1714.3	1758	10000	18%
CO	8-HR	ICENG4	2ND	27.4	1257.1	1285	5000	26%
CO	1-HR	ICENG5	2ND	44.2	1714.3	1758	10000	18%
CO	8-HR	ICENG5	2ND	27.4	1257.1	1285	5000	26%
NO2	8TH-HIGHEST MAX DAILY 1-HR	ICENG3	1ST	31.5	45.1	76.6	188	41%
NOx	Annual	ICENG3	1ST	3.1	17.1	20.2	75	27%
NO2	8TH-HIGHEST MAX DAILY 1-HR	ICENG4	1ST	33.4	45.1	78.5	188	42%
NOx	Annual	ICENG4	1ST	3.5	17.1	20.6	75	27%
NO2	8TH-HIGHEST MAX DAILY 1-HR	ICENG5	1ST	33.4	45.1	78.5	188	42%
NOx	Annual	ICENG5	1ST	3.5	17.1	20.6	75	27%

Notes:

1. Background concentrations are from the Kapolei monitor (2010-2012)
2. No off-site sources included
3. Modeled 24-hr values for PM10 and PM2.5 are the high second high values. These values were conservatively used in lieu of the high 4th high for PM10 and the high eighth high for PM2.5
4. Modeled value for the 1-hr SO2 is the maximum 4th high value from the 5-yr meteorological dataset. This value was conservatively used in lieu of the 99% value of the maximum daily 1-hr concentrations
5. Modeled value for the 1-hr NO2 is the 98% value of the maximum daily 1-hr concentrations from the 5-yr dataset.
6. The 0.75 ARM was applied to the modeled annual NO2 concentration. The 0.50 ARM was applied to the modeled 1-hr concentrations.





# Appendix K

## Applicable Requirements for New Regulations

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## **Appendix K**

### **Applicable Requirements of New Regulations**

The following information is provided to comply with the requirements of §11-60.1-85(b)(2)(B) and §11-60.1-86(a)(1), as referenced in attached DOH form: Form C-2, Compliance Certification, #5.

## NSPS Ja

The most recent promulgation of the petroleum refinery New Source Performance Standard (NSPS) is contained within 40 CFR Part 60 Subpart Ja. The NSPS Ja rule, applying to Fluid Catalytic Cracking (FCC) Units, fuel gas combustion devices, and flares (as well as two process unit types that are not installed at the refinery: delayed coking units and sulfur recovery plants), was published on September 12, 2012. The final rule became effective November 13, 2012.

### Applicability

In §60.100a, the provisions of NSPS Ja, except for flares, apply to affected facilities that are constructed, modified or reconstructed after May 14, 2007. For flares, the provisions apply to flares which commence construction, modification or reconstruction after June 24, 2008.

Flares: Modifications were made to the Crude Flare and FCC Flare as defined in §60.100a(c) after June 24, 2008; therefore, the provisions of NSPS Ja apply to these flares.

FCC Startup Air Heater: The FCC Startup Air Heater is a fuel gas combustion device that was constructed after June 24, 2007; therefore, it is subject to NSPS Ja. The applicable requirements for this heater, permitted April 22, 2013 are in the amendment to Attachment II(I), included in Appendix G of this submittal.

The current permit amendment allows the monitoring exemption of NSPS Ja §60.107a(a)(3)(ii) because it combusts a commercial grade LPG that is considered inherently low in sulfur content fuel as defined in §60.107a(a)(3)(i-iv). This definition of fuels inherently low in sulfur content includes fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less.

The facility requests a proposed change for this heater to allow for combustion of fuel gas stream that meet a commercial grade product specification for sulfur content of 30 ppmv or less.

CatOx Unit: The Catalytic Oxidation Unit is a fuel gas combustion device that was constructed after June 24, 2007, and is therefore, subject to the provision of NSPS Ja. The applicable requirements for this heater, permitted November 2, 2015, are contained in the amended Attachment II(A).

## Applicable Requirements Summary for Crude Flare and FCC Flare

NSPS Ja		
Emission Limits or Standards	<p>162 ppmv H<sub>2</sub>S determined hourly on a 3-hour rolling average basis; 60 ppmv H<sub>2</sub>S on a 365 successive calendar day rolling average; 500 lbs SO<sub>2</sub> in a 24-hr period</p> <p>Process upset gases or fuel gas from relief valve leakage or other emergency malfunction are exempt from these limits.</p> <p>1. Flare Management Plan</p>	<p>§60.103a(h)</p> <p>§60.103a(b) and §60.103a(f)</p>
Monitoring	<p><u>Crude Flare</u> Crude Unit monitors H<sub>2</sub>S content with a CMS . The span value for the instrument is 300 ppmv H<sub>2</sub>S.</p> <p><u>FCC Flare</u> The FCC and Crude Flare systems are interconnected and allow a single FVRU to capture and redirect vent gases away from the flares. The Crude Flare gases are monitored as described above. The FCC Flare does not</p>	<p>Installed, operated and maintained per Performance Specification 7 of appendix B of 40 CFR 60</p> <p>Performance evaluations are conducted according to the requirements of to the requirements of §60.13(c) and Performance Specification 7 of appendix B to part 60.</p> <p>Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 is used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference-see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.</p> <p>The quality assurance procedures in appendix F to part 60 apply for the H<sub>2</sub>S monitor.</p>

	<p>receive routine or routinely intermittent streams. The FCC Flare combusts exempt streams from the NSPS J H<sub>2</sub>S limit (S/U, S/D, process upset, etc) and, therefore, does not require H<sub>2</sub>S monitoring.</p> <p><u>Both Crude and FCC Flares:</u> Flare gas header , C-6690 gas stream, and excess fuel gas line have flow meters. Total sulfur CMS with a span of 0-20%.</p>	§60.107a
Recordkeeping and Reporting	Notifications, recordkeeping and reporting requirements	§60.7 and §60.108a
Testing	Test methods and procedures	§60.104a(j)

**Recent NSPS J and Ja Changes:**

§60.104a(a) is revised to specify that a performance test for H<sub>2</sub>S is required for each flare that becomes subject to subpart Ja.

The flare flow sensor accuracy requirements in §60.107a(f)(1)(ii) have been revised to ±20 percent of the flow rate at velocities ranging from 0.1 to 1 feet per second and an accuracy of ±5 percent of the flow rate for velocities greater than 1 foot per second.

§60.105(b) is revised to add stain tube span requirements, where stain tube testing is allowed for low sulfur streams.

## Heater and Boiler MACT

Environmental Protection Agency's final decision on the issues for which it granted reconsideration on January 21, 2015 was published in the Federal Register on November 20, 2015

### Applicability

The refinery's process heaters and boilers, listed in DOH Form S-1, Standard Application Emissions Table and Tables 2-1 and 2-2, are existing units, except for F-5310, FCC Startup Air Heater. Existing units are defined as boilers or heaters that commenced construction or reconstruction on or before 6/4/2010 (Section 63.7490(b)). The compliance date for existing units is January 31, 2016. The FCC Startup Air Heater does not meet the definition of process heater in §63.7575, and is therefore not subject to this regulation.

MACT DDDDD		
Emission Limits or Standards	<p>For F-5303, F-5310, and F-5700 (<math>\geq 10</math> MMBTU per hour), the compliance requirements are work practice standards, including:</p> <ul style="list-style-type: none"> <li>• Annual tune-up</li> <li>• One-time energy assessment</li> </ul>	Table 3.3 of subpart
	<p>For F-5103, F-5153, F-5201 and F-5202, the compliance requirements are emission limits and work practice standards:</p> <ul style="list-style-type: none"> <li>• Emission limits for the following four pollutants:               <ol style="list-style-type: none"> <li>1. Mercury</li> <li>2. PM</li> <li>3. HCl</li> <li>4. CO</li> </ol> </li> <li>• Annual tune-up</li> <li>• One-time energy assessment</li> </ul>	Table 2 of subpart (non-continental) Table 4 of subpart
	<p>For F-5600 and F-6262 (<math>\leq 10</math> MMBTU per hour, but <math>\geq 5</math> MMBTU per hour), the compliance requirements are:</p> <ul style="list-style-type: none"> <li>• Tune-up every other year</li> <li>• One-time energy assessment</li> </ul>	Table 3.2 of subpart
	<p>For F-5930 and F-5950 (<math>\leq 5</math> MMBTU), the compliance requirements are:</p> <ul style="list-style-type: none"> <li>• Tune-up every five years</li> <li>• One-time energy assessment</li> </ul>	Table 3.1 of subpart

<b>Monitoring</b>	<b>F-5103, F-5153, F-5201 and F-5202</b>  <b>Fuel testing</b> <b>CMS for minimum oxygen level (30-day rolling avg)</b> <b>CPMS for operating load</b>	<b>Table 6 of this subpart</b>  <b>Table 8 of this subpart</b>
<b>Recordkeeping and Reporting</b>	<b>Notifications, recordkeeping and reporting requirements</b>	<b>§63.7545, §63.7555, §63.7 and 63.9</b>  <b>Table 9 of this subpart</b>
<b>Testing</b>	<b>Test methods and procedures</b>  <b>Crude Furnace and boilers: establish operating limits</b>	<b>Table 5 of subpart</b>  <b>Table 7 of subpart</b>

**Refinery MACT CC and UUU  
Changes from RSR**

The Petroleum Refinery Sector Risk and Technology Review (RSR) and New Source Performance Standards revision was published in the Federal Register on December 1, 2015. This review promulgates a revision to the Refinery MACT regulations CC and UUU, and NSPS Ja. The effective date for the rule changes is February 1, 2016.

The following information details the changes to the applicable requirements of the refinery MACT CC, MACT UUU and NSPS Ja regulations.

**Applicability and Compliance Schedule**

Applicability changes that impact the facility include the following in both subparts CC and UUU, unless otherwise specified:

- Emission standards in both subparts CC and UUU are now applicable at all times, eliminating the startup, shutdown and malfunction (SSM) excepts and Startup, Shutdown and Malfunction Plan (SSMP) requirements. Alternative standards are provided for certain startup, shutdown and maintenance operations. These changes in SSM emission limitations generally apply from February 1, 2016 for existing requirements.
- Exemption of emission points routed to the fuel gas system requires that on or after February 1, 2019, the flares receiving gas from that fuel gas system are subject to §63.670.
- The refinery Crude and FCC flares are used as control devices for Tanks 303 and 304; therefore, the flares will meet the applicable requirements of 40 CFR part 61, subpart FF and subpart G, or the requirements of §63.670.

The following summarizes the changes in subpart CC and subpart UUU by emission unit type.

MACT CC and UUU changes from RSR		
General Duty Provisions	Replaces previously applicable General Provisions general duty paragraphs (§63.63(1)(i) and (iii)).	§63.642(n) and §63.1571(c)
Miscellaneous Process Vents	The MPV requirements apply to episodic (such as startup and shutdown), process upset, and non-routine releases. Vents from on-stream analyzers will be included as MPV's after January 30, 2019. MPV's designated as Maintenance Vents will comply with the applicable requirements in paragraphs (c)(1) through (c)(3) of the subpart for each maintenance vent.	§63.643



	<p>After January 30, 2019, the Crude and FCC Flares will meet the monitoring requirements of §63.670 and §63.671, as a control device for MPV's. §63.11(b) applies until compliance with §63.670 is achieved.</p>	
Storage Vessels	<p>Group 1 storage vessel definition is expanded to include existing source storage vessels with capacities ≥20,000 gallons but &lt;40,000 gallons if the maximum true vapor pressure of the stored liquid is 1.9 psia or greater and to include storage tanks &gt;40,000 gallons if the maximum true vapor pressure is 0.75 psia or greater.</p> <p>New §63.660 replaces §63.646 as the applicable storage vessel requirements no later than April 29, 2016.</p>	<p>§63.641</p> <p>§63.660</p>
Equipment Leaks	No changes impact the facility	
Relief Devices	<p>New §63.648(j) supersedes the requirements for pressure relief devices in organic HAP service in §§60.482-4 and 63.165, as applicable. Per §63.648(j).</p> <p>Reporting requirements are contained in §63.655.</p>	§63.648(j)
Flares	<p>Crude and FCC flares, subject to subpart CC and §60.18, will meet the requirements of §63.670. In the interim, §63.11 flare requirements apply, with revision for the flares used to control storage vessels being imposed through subpart SS §63.987.</p> <p>Recordkeeping and reporting requirements are contained in §63.655.</p>	§63.640, §63.670
Fenceline Monitoring	Fenceline monitoring for benzene using EPA Methods 325A and B, and determination if an exceedance of the action level has occurred, root cause analysis (RCA) and corrective action requirements.	Per §63.658

<p>FCCU</p>	<p>The FCCU complies with the 1 lb PM/1000 lb coke burn compliance option (Option 2) and will meet an opacity limit established through a performance test, and monitoring contained in revised subpart UUU Table 2.</p> <p>PM performance testing requirements are contained in §63.1571.</p> <p>Per §63.1571(a)(6), a one-time hydrogen cyanide (HCN) performance test using EPA Method 320 is required by August 1, 2017. The Hawaii Refinery performed HCN testing between March 31, 2011 and February 1, 2016, and plans to request to submit the prior test data instead of performing a new HCN test is allowed. This request will be submitted by March 30, 2016 and the Administrator has 60 days to respond or the request is considered approved. CO concentrations and other FCCU operating information is required to be submitted along with the performance test results and report.</p>	<p>§63.1564 and 63.1565 and associated tables in this subpart</p> <p>§63.1571</p>
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## Site Remediation MACT

40 CFR Part 63 Subpart GGGGG – National Emission Standards for Hazardous Air Pollutants: Site Remediation

Chevron has reviewed its site remediation activities for applicability to the Site Remediation MACT. The site remediations conducted at the Refinery meet the conditions of 40 CFR 63.7881(c), therefore, the Refinery's site remediations are not subject to the requirements of the Site Remediation MACT, except for the recordkeeping requirements described in §63.7881(c)(2) to verify compliance with the Facility Wide, annual, 1 megagram (Mg) Exemption.



Chris P. Cavote  
Refinery Manager

0088-17  
HAND DELIVERED  
NOV 22 2011  
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November 22, 2011

Mr. Wilfred Nagamine  
Manager, Clean Air Branch  
Environmental Management Division  
919 Ala Moana Boulevard  
Honolulu, Hawaii 96814

**Chevron U.S.A. Inc., Hawaii Refinery  
Covered Source Permit No. 0088-02-C  
Application for Renewal**

Dear Mr. Nagamine:

The Chevron U.S.A. Inc., (Chevron), Hawaii Refinery is hereby applying for renewal of the referenced Covered Source Permit. As required by the S-3 application form, two sets (1 original and 1 copy) of the renewal application package are enclosed herewith and one set is being sent directly to Gerardo Rios, Chief of the Air Permits Office at U.S. EPA Region IX.

As previously discussed with Darin Lum of your staff, no additional application fee is being provided with this permit renewal application, as a renewal fee has already been paid to the Department in conjunction with Covered Source Permit No. 0088-01-C.

Chevron submitted the initial application for the referenced Covered Source Permit on May 25, 2006, with an update provided on August 15, 2006. During preparation of this renewal application, we became aware of errors in the 2006 permit application. Chevron with this application is promptly submitting supplementary facts and corrected information. Specifically:

- VOC emissions estimates for the miscellaneous equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206, including individual drain systems and equipment in VOC service, were not included in the permit application. Estimates of these emissions are provided in this application for renewal of Covered Source Permit No. 0088-02-C.
- Incorrect emission rates for boilers F-5205 and F-5206 and for the Acid Plant Combustion Chamber and Absorber, F6200ABS, were presented in Table 4-1 and included in the Air Quality Impact Analysis. Corrected emission rates for the boilers are presented in this application for renewal of Covered Source Permit No. 0088-02-C. The correct emission rates for F6200ABS were presented in the application for renewal of Covered Source Permit No. 0088-01-C, submitted to the Department on December 27, 2010.

In addition, as you will see in the compliance certification section, ambient monitoring conducted by the Department of Health indicates continuous compliance with the National and State Ambient Air Quality Standards. However, dispersion modeling, using conservative modeling parameters, conducted during preparation of this Covered Source Permit renewal application indicates the

Manager, Clean Air Branch  
Environmental Management Division  
Page 2 of 2

potential that certain emissions from the Chevron Hawaii Refinery could cause or contribute to exceedances of the listed standards. Although the compliance for these ambient standards is determined by actual monitoring data, because the initial results of the conservative modeling suggest a potential exceedance of the standards, Chevron is noting a potential noncompliance with the listed standards.

The Hawaii Refinery is initiating a review of the initial analysis for the Hybrid Energy Project and the pending Covered Source Permit renewal No. 0088-01-C. If any updates are necessary they will be promptly provided to the Department.

If you have any questions, or need additional information please call Sonni Escudro at (808) 682-2372.

Sincerely,

A handwritten signature in black ink, appearing to read "S. Escudro", with a horizontal line extending to the right from the end of the signature.

Enclosures (3)

cc: Chief, Permits Office, (Attention: Air-3)

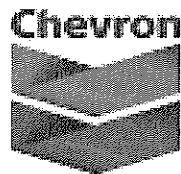
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# **Chevron Products Company**

## **Hawaii Refinery**



**Application for Renewal**  
**Covered Source Permit No. 0088-02-C**

**November 2011**

**Submitted to:**

**Hawaii Department of Health**  
**Clean Air Branch**  
**Honolulu, Hawaii**

**Prepared by:**



**RTP Environmental Associates, Inc.**  
**304-A West Millbrook Rd.**  
**Raleigh, NC 27609**

MA 17640

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# **Chapter 1. Introduction and Overview**

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## **1.1 Introduction**

The Hawaii Department of Health, Environmental Management Division, Clean Air Branch, issued Covered Source Permit No. 0088-02-C to the Chevron Products Company (“Chevron”) on May 23, 2007. This permit authorizes construction and operation of a Hybrid Energy Plant, comprising two steam boilers, a cogeneration turbine, and miscellaneous equipment, at the Chevron Hawaii Refinery located at Kapolei, Oahu, Hawaii.

This permit application is a request for renewal of Covered Source Permit No. 0088-02-C. This application is timely, pursuant to HAR § 11-60.1-101(b), because it is being submitted on or before the due date of November 22, 2011, as established by a May 20, 2011, letter from W.K. Nagamine of the Clean Air Branch to C.P. Cavote of Chevron.

## **1.2 Overview of Permit Application Content**

This permit application is complete, pursuant to HAR § 11-60.1-101(c), because it includes all information required by HAR § 11-60.1-101(a), all documents requiring certification have been certified pursuant to HAR § 11-60.1-4, and all applicable fees have been submitted. Specifically, a completed S-1: Standard Air Pollution Control Permit Application Form, is provided in this Section 1.2, and the remainder of this permit application package includes the information and documents required:

- As required by HAR § 11-60.1-101(a)(1), names and addresses are provided in the S-1 form in this Section 1.2;
- As required by HAR § 11-60.1-101(a)(2), and as referenced in section I.A of the S-3 application form, a certified statement regarding changes made to the covered source is provided in Section 1.3 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(2), and as referenced in section I.B of the S-3 application form, equipment specifications are provided in Section 2.1 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(2), and as referenced in section I.B of the S-3 application form, descriptions of fuels and fuel use are provided in Section 2.2 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(2), and as referenced in section I.D of the S-3 application form, information pertaining to typical operating schedules is provided in Section 2.3 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(2), specifications and drawings showing the design of the source and plant layout are provided in Section 2.4 herein;



- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(2), and as referenced in section I.C of the S-3 application form, the Standard Industrial Classification Code of the Chevron Hawaii Refinery is provided in the S-1 form in this Section 1.2;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(2), source category information is provided in Section 2.5 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(2), and as referenced in section I.C of the S-3 application form, information pertaining to alternative operating scenarios is provided in Section 2.6 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(3), and as referenced in section I.I of the S-3 application form, information pertaining to emissions trading within the facility is provided in Section 2.7 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(4), maximum emissions rates are provided provided in the S-1 form in this Section 1.2;
- As required by HAR § 11-60.1-101(a) and §§ 11-60.1-83(a)(4) and (a)(9), and as referenced in section I.C of the S-3 application form, emissions calculations and underlying assumptions are presented in Chapter 3 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(5), regulatory applicability is addressed in Chapter 4 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(5), information on stack parameters is presented in the S-1 form in this Section 1.2;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(6), and as referenced in section I.C of the S-3 application form, air pollution control equipment is discussed in Section 2.8 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(6), and as referenced in section I.C of the S-3 application form, compliance monitoring devices and activities are discussed in Section 2.9 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(7), and as referenced in section I.E of the S-3 application form, citations of applicable requirements are presented in Chapter 4 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(7), and as referenced in section I.E of the S-3 application form, test methods for determining compliance with applicable requirements are referenced in Chapter 4 herein;
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(8), and as referenced in section I.F of the S-3 application form, operational limitations and work practices affecting emissions are discussed in Sections 1.1 and 4.1 herein;
- As required by HAR § 11-60.1-83(a)(10), the construction schedule is described in Section 1.3 herein;
- Because no changes to source operations or emissions are proposed with this application for renewal of the Covered Source Permit, no ambient air quality impact assessment is required pursuant to HAR § 11-60.1-101(a) and § 11-60.1-83(a)(11);
- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(17), and as referenced in section I.E of the S-3 application form, exemptions from applicable requirements are discussed in Chapter 4 herein;

- As required by HAR § 11-60.1-101(a) and § 11-60.1-83(a)(18), and as referenced in section I.C of the S-3 application form, insignificant activities are discussed in Section 2.11 herein;
- As required by HAR § 11-60.1-101(a)(3), and as referenced in section I.J of the S-3 application form, a compliance plan is presented in Appendix A hereto;
- As required by HAR § 11-60.1-101(a)(4), and as referenced in section I.J of the S-3 application form, a compliance certification is presented in Appendix A hereto; and
- As required by HAR § 11-60.1-101(c)(3), and as referenced in section II of the S-3 application form, the application fee is presented in Section 1.4 herein.

**S-1: Standard Air Pollution Control Permit Application Form**  
(Covered Source Permit and Noncovered Source Permit)

State of Hawaii  
Department of Health  
Environmental Management Division  
Clean Air Branch  
P.O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: Chevron Products Company
2. Facility Name (if different from the Company): Chevron Hawaii Refinery
3. Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707  
Phone Number: (808) 682-5711
4. Name of Owner/Owner's Agent: Chris P. Cavote  
Title: Refinery Manager Phone: (808) 682-5711  
Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707
5. Plant Site Manager/Other Contact: Chris P. Cavote  
Title: Refinery Manager Phone: (808) 682-5711  
Mailing Address: 91-480 Malakole Street  
City: Kapolei State: HI Zip Code: 96707
6. Permit Application Basis: (Check all applicable categories.)  
 Initial Permit for a New Source       Initial Permit for an Existing Source  
 Renewal of Existing Permit       General Permit  
 Temporary Source       Transfer of Permit  
 Modification to a Covered Source: → Is Modification?     Significant     Minor     Uncertain  
 Modification to a Noncovered Source
7. If renewal or modification, include existing permit number: 0088-02-C
8. Does the Proposed Source require a County Special Management Area Permit?     Yes       No
9. Type of Source (Check One):     Covered Source       Covered and PSD Source  
 Noncovered Source       Uncertain
10. Standard Industrial Classification Code (SICC), if known: 2911

11. Proposed Equipment/Plant Location (e.g. street address): 91-480 Malakole Street

City: Kapolei State: HI Zip Code: 96707

UTM Coordinates (meters): East: 592,190 North: 2,356,665

UTM Zone: 4 UTM Horizontal Datum:  Old Hawaiian  NAD-27  NAD-83

12. General Nature of Business: Petroleum Refining

13. Date of Planned Commencement of Construction or Modification: n/a

14. Is **any** of the equipment to be leased to another individual or entity?  Yes  No

15. Type of Organization:  Corporation  Individual Owner  Partnership

Government Agency (Government Facility Code: \_\_\_\_\_)

Other: \_\_\_\_\_

*Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR §11-60.1-64 & 11-60.1-84)*

**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): Cavote (First): Chris (MI): P.

Title: Refinery Manager Phone: (808) 682-5711

Mailing Address: 91-480 Malakole Street

City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Chris P. Cavote

(Signature): 

Date: 11/22/11

**FOR AGENCY USE ONLY:**

File/Application No.: 0788-19

Island: OAHU

Date Received: 1/22/11

Company Name: Chevron Products Company

File No.: \_\_\_\_\_

Location: Kapolei

(Make as many copies of this page as necessary)

Page 1 of 4

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT				AIR POLLUTANT EMISSION RATE		UTM Coordinates		STACK SOURCE PARAMETERS					
Stack No.	Unit No.	Equipment Name/ Description & SICC number	Equipment Date	Regulated/ Hazardous Air Pollutant Name & CAS#	#/ HR	Tons/ YR	UTM Zone: <u>4</u>	Horizontal Datum: <u>NAD 83</u>	Stack Height (mtrs)	Direction (u/d/h) <sup>b</sup>	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)	Temp. (°K)	Capped (Y/N)		
F-5205		Foster Wheeler Boiler 1	2007	PM	24.75	103.8	East	591,796	24.99	up	0.91	19.3	12.4	449	N		
				PM-10	14.85	62.4	North	2,357,082									
				SO2	51.81	217.1	East										
				CO	7.92	34.6	North										
				NOx	31.68	134.5	East										
				VOC	0.50	2.1	North										
				Total HAP	0.14	0.6	East										
							North										
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<sup>a</sup> Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

<sup>b</sup> Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal

Company Name: Chevron Products Company

File No.: \_\_\_\_\_

Location: Kapolei

(Make as many copies of this page as necessary)

Page 2 of 4

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT				AIR POLLUTANT EMISSION RATE		UTM Zone: <u>4</u> Horizontal Datum: <u>NAD 83</u>		STACK SOURCE PARAMETERS					
Stack No.	Unit No.	Equipment Name/Description & SIC number	Equipment Date	Regulated/ Hazardous Air Pollutant Name & CAS#	# HR	Tons/ YR	Coordinates (mtrs)	Stack Height (mtrs)	Direction (width) <sup>b</sup>	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)	Temp. (°K)	Capped (Y/N)			
	F-5206	Foster Wheeler Boiler 2	2007	PM	24.75	103.8	East 591,780 North 2,357,074	24.99	up	0.91	19.3	12.4	449	N			
				PM-10	14.85	62.4	East										
				SO2	51.81	217.1	North										
				CO	7.92	34.6	East										
				NOx	31.68	134.5	North										
				VOC	0.50	2.1	East										
				Total HAP	0.14	0.6	North										
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\* Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

<sup>b</sup> Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal

Company Name: Chevron Products Company

File No.: \_\_\_\_\_

Location: Kapolei

(Make as many copies of this page as necessary)

Page 3 of 4

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum <sup>a</sup> NAD 83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/ Description & SIC number	Equipment Date	Regulated/ Hazardous Air Pollutant Name & CAS#	#/ HR	Tons/ YR	Coordinates (mtrs)	Stack Height (mtrs)	Direction (u/d/h) <sup>b</sup>	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)	Temp. (°K)	Capped (Y/N)		
	CTG-6704	Cogeneration Turbine with Duct Burner and HRSG	2007	PM	0.95	4.1	East 591,807 North 2,357,071 East	24.99	up	1.83	9.31	24.46	464	N		
				PM-10	0.95	4.1	North									
				SO2	2.33	10.2	East									
				CO	11.60	50.8	North									
				NOx	13.70	60.0	East									
				VOC	6.95	30.4	North									
				Total HAP	0.11	0.5	East									
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<sup>a</sup> Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

<sup>b</sup> Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal

Company Name: Chevron Products Company

File No.: \_\_\_\_\_

Location: Kapolei

(Make as many copies of this page as necessary)

Page 4 of 4

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

Stack No.	AIR POLLUTANT DATA: EMISSION POINTS			AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum <sup>a</sup> NAD 83	STACK SOURCE PARAMETERS							
	Unit No.	Equipment Name/ Description & SICC number	Equipment Date		Regulated/ Hazardous Air Pollutant Name & CAS#	#/ HR		Tons/ YR	Coordinates (mtrs)	Stack Height (mtrs)	Direction (width) <sup>b</sup>	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)	Temp. (° K)
		Drains (fugitive)	2007	VOC		0.32	East								
							North								
							East								
							North								
							East								
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<sup>a</sup> Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

<sup>b</sup> Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal



## 1.3 Statement of Changes to Covered Source

No construction and no changes to source operations, work practices, or equipment design are proposed in conjunction with this application for renewal of Covered Source Permit No. 0088-02-C.

An application for a significant modification of Covered Source Permit No. 0088-02-C is being submitted concurrently and under separate cover. That application requests changes to emission limits and other terms in the Covered Source Permit affecting steam boilers F-5205 and F-5206.<sup>1</sup> Changes to applicable requirements are anticipated as requested in that permit application. If the requested significant modification is granted, Chevron will not blend fuel oil in an attempt to meet the currently permitted PM/PM10 emission limit for these boilers.

Steam boilers F-5205 and F-5206 are shut down pending issuance of the modified Covered Source Permit. In addition, as discussed in more detail in Section 2.10 herein, boilers F-5201, F-5202 and F-5203 continue to operate pending issuance of the modified Covered Source Permit.

Other than shutting down boilers F-5205 and F-5206 before the end of their shakedown period and continuing to operate boilers F-5201, F-5202 and F-5203 as described above, no changes have been made in the design or operation of the covered source as proposed in the initial 2006 Covered Source Permit application for the Hybrid Energy Plant.

## 1.4 Application Fee

The Chevron Hawaii Refinery is a “major source,” as that term is defined at HAR § 11-60.1-1, and is a “toxic source” but not a “PSD source,” as those terms are defined at § 11-60.1-111. Therefore, pursuant to HAR § 11-60.1-113(b)(6)(B), the application fee for this covered source permit renewal is \$3,000.

As previously discussed with Darin Lum of your staff, no additional application fee is being provided with this permit renewal application, as a renewal fee has already been paid to the Department in conjunction with Covered Source Permit No. 0088-01-C.

---

<sup>1</sup> The pending application for a significant modification of Covered Source Permit No. 0088-02-C does not involve construction, but it does involve certain changes to source operations.

# Chapter 2. Source Information

---

This Chapter presents required information pertaining to the equipment at the Chevron Hawaii Refinery that is the subject of this application for covered source permit renewal.

## 2.1 Equipment Specifications

### 2.1.1 Cogeneration Unit

The cogeneration unit, CGT-6704, comprises a Solar Centaur 40 combustion turbine and a Split Dino Heat Recovery Steam Generator (“HRSG”). The heat input capacity of the combustion turbine is approximately 45.7 MMBtu/hour on a higher heating value (“HHV”) basis and its electrical generating capacity is approximately 3 MW. The total heat input capacity of the duct burners is approximately 49 MMBtu/hour on a HHV basis. The steam generation capacity of the HRSG is approximately 58,000 lbs/hour.

### 2.1.2 Steam Boilers

Each of the two Foster Wheeler steam boilers, F-5205 and F-5206, has a steam generation capacity of 78,000 lbs/hour and a heat input capacity of 99.0 MMBtu/hour on a HHV basis.

### 2.1.3 Miscellaneous Equipment

Covered Source Permit No. 0088-02-C authorizes construction and operation of “miscellaneous equipment associated with the cogeneration unit and boilers.” This includes individual drain systems, which are part of the refinery’s process wastewater collection system, and equipment (*i.e.*, valves, pressure relief devices, and connectors) in VOC service. As discussed in more detail in Section 4.1.3 herein, this miscellaneous equipment includes piping in VOC service which is part of an emissions unit for which operation is authorized by Covered Source Permit No. 0088-01-C.

## 2.2 Fuels and Fuel Use

### 2.2.1 Cogeneration Unit

The cogeneration unit, CGT-6704, includes a combustion turbine and an HRSG with duct burners. The combustion turbine will be fired with either refinery fuel gas or liquid naphtha and the duct burners will be fired with refinery fuel gas. The refinery fuel gas used in the cogeneration unit has a sulfur content of not more than 0.10 grains per dry standard cubic foot and a typical heat content of approximately 1300 Btu per standard cubic foot (HHV basis). The naphtha used in the combustion turbine has a sulfur content of not more than 0.03 percent by weight and a typical heat content of approximately 118,000 Btu per gallon (HHV basis).

## 2.2.2 Steam Boilers

The two steam boilers, F-5205 and F-5206, will be fired with low-sulfur fuel oil and refinery fuel gas. These fuels may be fired alone or may be fired simultaneously. The refinery fuel gas used in the boilers has a sulfur content of not more than 0.10 grains per dry standard cubic foot and a typical heat content of approximately 1300 Btu per standard cubic foot (HHV basis). The fuel oil used in the boilers has a sulfur content of not more than 0.5 percent by weight, based on a 30-day average, and a typical heat content of approximately 150,000 Btu per gallon (HHV basis).

## 2.3 Operating Schedule

The equipment at the Chevron Hawaii Refinery for which construction and operation are authorized by Covered Source Permit No. 0088-02-C operates or will operate up to 24 hours per day, 365 days per year.

## 2.4 Plot Plan

A plot plan showing the locations and configuration of the emissions units at the Chevron Hawaii Refinery is provided in Figure 2-1.

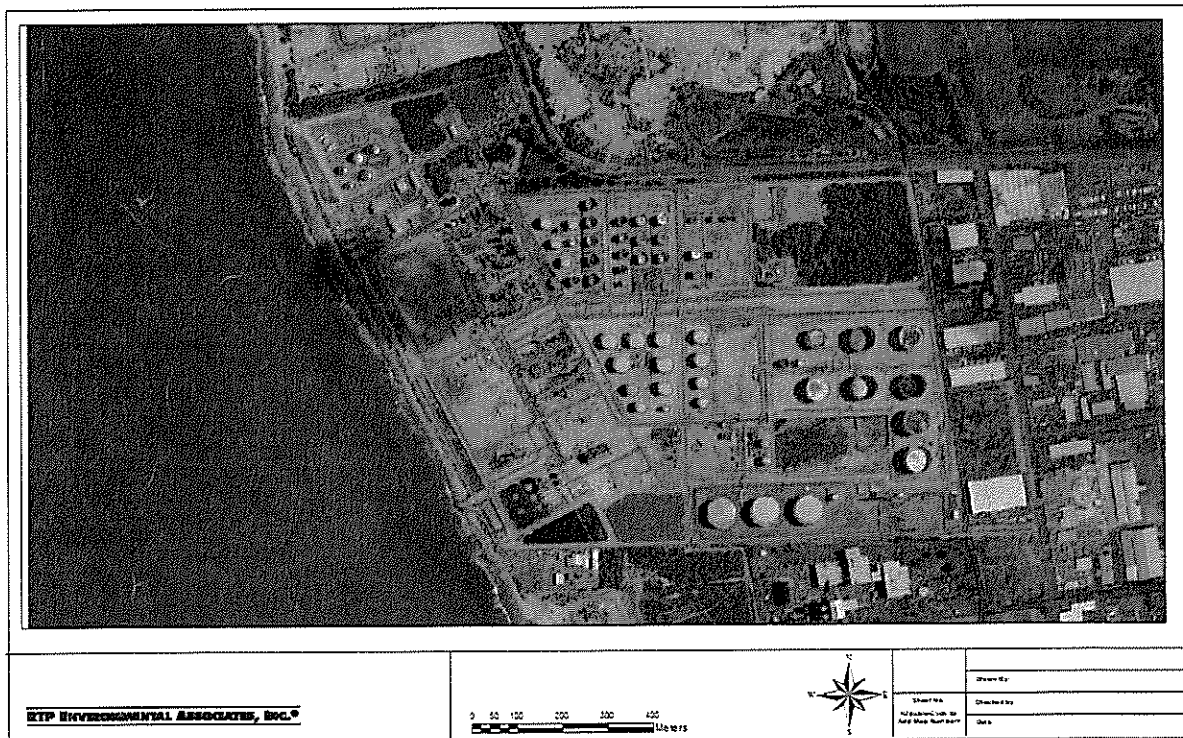


Figure 2-1. Chevron Hawaii Refinery Plot Plan

## **2.5 Source Category**

The source category list required by § 112(c)(1) of the federal Clean Air Act, as referenced in HAR § 11-60.1-171, was most recently revised by U.S. EPA on June 30, 2005. See, *70 Fed. Reg.* 37819. The equipment at the Chevron Hawaii Refinery for which construction and operation are authorized by Covered Source Permit No. 0088-02-C falls within three separate source categories.

### **2.5.1 Cogeneration Unit**

The cogeneration unit, CGT-6704, falls within the source category, “Combustion Turbines.”

### **2.5.2 Steam Boilers**

The two steam boilers, F-5205 and F-5206, fall within the source category, “Industrial/Commercial/Institutional Boilers and Process Heaters.”

### **2.5.3 Miscellaneous Equipment**

The miscellaneous equipment associated with cogeneration unit CGT-6704 and boilers F-5205 and F-5206 falls within the source category, “Petroleum Refineries — Other Sources Not Distinctly Listed.”

## **2.6 Alternative Operating Scenarios**

No alternative operating scenarios involving the equipment at the Chevron Hawaii Refinery for which construction and operation are authorized by Covered Source Permit No. 0088-02-C are proposed or anticipated.

## **2.7 Emissions Trading**

The Chevron Hawaii Refinery does not propose any emissions trading within the facility pursuant to HAR § 11-60.1-96.

## **2.8 Air Pollution Control Equipment**

### **2.8.1 Cogeneration Unit**

The combustion turbine is equipped with water injection for control of NO<sub>x</sub> emissions. The cogeneration unit, CGT-6704, is not equipped with any other air pollution control equipment as no other air pollution control equipment is required in order to comply with applicable requirements.

## **2.8.2 Steam Boilers**

The two steam boilers, F-5205 and F-5206, are not equipped with any air pollution control equipment as no air pollution control equipment is required in order to comply with applicable requirements.

## **2.8.3 Miscellaneous Equipment**

The miscellaneous equipment associated with cogeneration unit CGT-6704 and boilers F-5205 and F-5206 is not equipped with any air pollution control equipment as no air pollution control equipment is required in order to comply with applicable requirements.

# **2.9 Compliance Monitoring Devices and Activities**

## **2.9.1 Cogeneration Unit**

As required by Special Conditions D.1 through D.7 in Attachment II.A to Covered Source Permit No. 0088-02-C, the cogeneration unit, CGT-6704, is equipped with four monitoring devices:

- Non-resetting fuel meters for naphtha and refinery fuel gas fired in the combustion turbine and for refinery fuel gas fired in the duct burners;
- A continuous monitoring system for monitoring and recording the concentration of hydrogen sulfide in the refinery fuel gas being burned in the cogeneration unit;
- A continuous monitoring system to determine the ratio of water to fuel being fired in the combustion turbine; and
- A continuous emission monitoring system (“CEMS”) to measure and record the NO<sub>x</sub> and O<sub>2</sub> concentrations in the flue gas exhausted from the combustion turbine’s exhaust stack. In addition, samples of naphtha are collected from the fuel oil storage tank according to appendix D to 40 CFR part 75 and these samples are analyzed to determine sulfur content using methods specified in the permit, and monthly visible emissions observations are conducted using EPA Method 9 (in appendix A-4 to 40 CFR part 60).

## **2.9.2 Steam Boilers**

As required by Special Conditions D.1 through D.4 in Attachment II.B to Covered Source Permit No. 0088-02-C, the two steam boilers, F-5205 and F-5206, are equipped with non-resetting fuel meters for low-sulfur fuel oil and refinery fuel gas, continuous opacity monitoring systems, and continuous monitoring systems for continuously monitoring and recording the concentration of hydrogen sulfide in the refinery fuel gas being burned in the boilers. In addition, samples of low-sulfur fuel oil are collected from the fuel oil storage tank following each tank fill and each sample is analyzed to determine sulfur content.

## **2.9.3 Miscellaneous Equipment**

As required by Special Conditions D.1 through D.23 in Attachment II.C to Covered Source Permit No. 0088-02-C, leak detection and repair and equipment inspection programs are

implemented for miscellaneous equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 as required by 40 CFR part 60, subparts GGGa and QQQ.<sup>2</sup>

## 2.10 Retirement and Decommissioning of Existing Boilers

Special Condition C.1 in Attachment II.B to Covered Source Permit No. 0088-02-C requires the following:

*The existing three (3) boilers, Unit Nos. F-5201, F5202 and F5203, shall not be operated concurrently with the two (2) 99 MMBtu/hr boilers. The existing three (3) boilers, Unit Nos. F-5201, F-5202 and F-5203, shall be permanently shutdown within a one (1) year period after the startup of the two (2) 99 MMBtu/hr boilers.*

After determining during the shakedown period that the PM/PM10 emission limits applicable to boilers F-5205 and F-5206 are not achievable at all times, Chevron requested that the Department provide guidance concerning continued operation of boilers F-5201, F-5202 and F-5203. In an August 24, 2011, letter to the Refinery Manager, Mr. W.K. Nagamine, Clean Air Branch, stated the following:

2. Old Boiler Operation:

*In the existing covered source permit, Attachment II, Special Condition No. C.1, assumed that the old boilers would not be needed on a permanent basis after the new boilers were started up, certified and operational. However, due to the problems with meeting the PM/PM10 emission limit, the new boilers have been shut down after operating for just a few months.*

Therefore, after the conclusion of the shakedown period for the two (2) 99 MMBtu/hr boilers, the existing three (3) boilers, Unit Nos. F-5201, F-5202 and F-5203, shall not be operated concurrently with the two (2) 99 MMBtu/hr boilers. The existing three (3) boilers, Unit Nos. F-5201, F-5202 and F-5203, shall be permanently shutdown by no later than the end of the shakedown period for boilers, Unit Nos. F-5205 and F-5206.

## 2.11 Insignificant Activities

No new insignificant activities, pursuant to HAR § 11-60.1-82(e) to (g), are proposed in conjunction with this permit application.

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<sup>2</sup> See Section 4.1.3.1 herein for a discussion of applicability of 40 CFR part 60, subpart GGGa.

# Chapter 3. Emissions Calculations

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This Chapter presents emissions calculations for cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206. In addition, emissions calculations are presented for fugitive VOC emissions from miscellaneous equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206.

## 3.1 Cogeneration Unit

### 3.1.1 Assumptions

The emissions calculations for cogeneration unit CGT-6704 are based on the following assumptions:

- The combustion turbine has a heat input capacity of 45.7 MMBtu/hour (HHV basis).
- The duct burners have a heat input capacity of 48.9 MMBtu/hour (HHV basis).
- Emissions of VOC are based on the vendor guarantee of 6.95 lb/hr.
- Emissions of NO<sub>x</sub> are based on the vendor guarantee of 13.7 lb/hr.
- Emissions of filterable PM/PM10 are based on an emission factor of 0.01 lb/MMBtu.
- Emissions of CO are based on the 11.6 lb/hr emission limit in Attachment II.A to Covered Source Permit No. 0088-02-C.
- Emissions of SO<sub>2</sub> are based on fuel sulfur content of 0.10 grains per dry standard cubic foot in refinery fuel gas (as hydrogen sulfide) and 0.03 percent by weight in naphtha and fuel heat values of 1,300 Btu per standard cubic foot for refinery fuel gas and 20,700 Btu/lb for naphtha.

### 3.1.2 Annual VOC Emissions

Maximum annual emissions of VOC from the cogeneration unit are 30.4 tons/yr, calculated as follows.

$$E_{VOC,annual} = 6.95 \text{ lb/hr} \times 8,760 \text{ hr/yr} \div 2,000 \text{ lb/ton}$$
$$E_{VOC,annual} = 30.4 \text{ ton/yr}$$

### 3.1.3 Annual NO<sub>x</sub> Emissions

Maximum annual emissions of NO<sub>x</sub> from the cogeneration unit are 60.0 tons/yr, calculated as follows.

$$E_{NOx,annual} = 13.7 \text{ lb/hr} \times 8,760 \text{ hr/yr} \div 2,000 \text{ lb/ton}$$

$$E_{NOx,annual} = 60.0 \text{ ton/yr}$$

### 3.1.4 Hourly PM/PM10 Emissions

Maximum hourly emissions of PM/PM10 (filterable) from the cogeneration unit are 0.95 lb/hr, calculated as follows.

$$E_{PM,short} = \left( 45.7 \text{ MMBtu/hr} + 48.9 \text{ MMBtu/hr} \right) \times 0.01 \text{ lb/MMBtu}$$

$$E_{PM,short} = 0.95 \text{ lb/hr}$$

### 3.1.5 Annual PM/PM10 Emissions

Maximum annual emissions of PM/PM10 (filterable) from the cogeneration unit are 4.1 tons/yr, calculated as follows.

$$E_{PM,annual} = 0.95 \text{ lb/hr} \times 8,760 \text{ hr/yr} \div 2,000 \text{ lb/ton}$$

$$E_{PM,annual} = 4.1 \text{ ton/yr}$$

### 3.1.6 Annual CO Emissions

Maximum annual emissions of CO from the cogeneration unit are 50.8 tons/yr, calculated as follows.

$$E_{CO,annual} = 11.6 \text{ lb/hr} \times 8,760 \text{ hr/yr} \div 2,000 \text{ lb/ton}$$

$$E_{CO,annual} = 50.8 \text{ ton/yr}$$

### 3.1.7 Hourly SO<sub>2</sub> Emissions

Maximum hourly emissions of SO<sub>2</sub> from the cogeneration unit are 2.33 lb/hr, calculated as the sum of 1.32 lb/hr from burning naphtha in the combustion turbine and 1.01 lb/hr from burning refinery fuel gas in the duct burners, each of which is calculated as follows.

$$E_{SO2,naphtha} = \frac{0.03 \text{ lb S}}{100 \text{ lb fuel}} \times \frac{64.06 \text{ lb SO}_2}{32.06 \text{ lb S}} \div \frac{20,700 \text{ Btu}}{\text{lb fuel}}$$



$$EF_{SO_2, naphtha} = 0.0290 \text{ lb/MMBtu}$$

$$E_{SO_2, naphtha, short} = 45.7 \text{ MMBtu/hr} \times 0.0290 \text{ lb/MMBtu}$$

$$E_{SO_2, naphtha, short} = 1.32 \text{ lb/hr}$$

$$EF_{SO_2, RFG} = \frac{0.10 \text{ gr H}_2\text{S}}{\text{dscf fuel}} \times \frac{\text{lb H}_2\text{S}}{7,000 \text{ gr H}_2\text{S}} \times \frac{64.06 \text{ lb SO}_2}{34.08 \text{ lb H}_2\text{S}} \div \frac{1,300 \text{ Btu}}{\text{dscf fuel}}$$

$$EF_{SO_2, RFG} = 0.0207 \text{ lb/MMBtu}$$

$$E_{SO_2, RFG, short} = 48.9 \text{ MMBtu/hr} \times 0.0207 \text{ lb/MMBtu}$$

$$E_{SO_2, RFG, short} = 1.01 \text{ lb/hr}$$

$$E_{SO_2, short} = 1.32 \text{ lb/hr} + 1.01 \text{ lb/hr}$$

$$E_{SO_2, short} = 2.33 \text{ lb/hr}$$

### 3.1.8 Annual SO<sub>2</sub> Emissions

Maximum annual emissions of SO<sub>2</sub> from the cogeneration unit are 10.2 tons/yr, calculated as follows.

$$E_{SO_2, annual} = 2.33 \text{ lb/hr} \times 8,760 \text{ hr/yr} \div 2,000 \text{ lb/ton}$$

$$E_{SO_2, annual} = 10.2 \text{ ton/yr}$$

## 3.2 Steam Boilers

### 3.2.1 Assumptions

The emissions calculations for steam boilers F-5205 and F-5206 are based on the following assumptions:

- Each boiler has a heat input capacity of 99.0 MMBtu/hour on a higher heating value (“HHV”) basis.
- Emissions of VOC are based on the vendor guarantees of 0.005 lb per MMBtu heat input derived from combustion of fuel oil and 0.004 lb per MMBtu heat input derived from combustion of refinery fuel gas.
- Emissions of NO<sub>x</sub> are based on the vendor guarantee of 0.32 lb per MMBtu heat input derived from combustion of fuel oil and an emission factor of 0.1 lb per MMBtu heat input derived from combustion of refinery fuel gas.<sup>3</sup>
- Each boiler is subject to the following emission limits:
  - 0.08 lb CO per MMBtu heat input derived from combustion of fuel oil
  - 0.073 lb CO per MMBtu heat input derived from combustion of fuel oil
- Emissions of SO<sub>2</sub> are based on fuel sulfur content of 0.10 grains per dry standard cubic foot in refinery fuel gas (as hydrogen sulfide) and 0.5 percent by weight in fuel oil and fuel heat values of 1,300 Btu per standard cubic foot for refinery fuel gas and 150,000 Btu/gallon for fuel oil.
- The boilers will be subject to the following operational limit: Maximum heat input derived from fuel oil combustion in F-5205 and F-5206 (total for two boilers) shall not exceed 828,182 MMBtu per rolling 12-month time period.<sup>4</sup>
- Each boiler will be subject to the following emission limits:
  - 0.25 lb PM (filterable) per MMBtu heat input derived from combustion of fuel oil
  - 0.015 lb PM (filterable) per MMBtu heat input derived from combustion of refinery fuel gas
  - 0.15 lb PM10 (filterable) per MMBtu heat input derived from combustion of fuel oil
  - 0.015 lb PM10 (filterable) per MMBtu heat input derived from combustion of refinery fuel gas
  - When fuel oil and refinery fuel gas are combusted simultaneously, the applicable PM and PM10 emission limits will be prorated based on the percentage of heat input from each fuel.

### 3.2.2 Hourly VOC Emissions

Maximum hourly emissions of VOC from each boiler are 0.50 lb/hr, calculated as follows.

$$E_{VOC,short} = 99 \text{ MMBtu/hr} \times 0.005 \text{ lb/MMBtu}$$

<sup>3</sup> The NO<sub>x</sub> emission factor used for combustion of refinery fuel gas in boilers F-5205 and F-5206 is based on the results of preliminary testing conducted during the shakedown of the boilers. This factor is higher than the vendor guarantee of 0.042 lb per MMBtu heat input, which was the basis for the emissions calculations presented in the prior covered source permit application.

<sup>4</sup> As discussed in Section 1.3 herein, boilers F-5205 and F-5206 are currently shut down pending a significant modification to Covered Source Permit No. 0088-02-C. Emissions from the boilers currently are zero; the calculations and emission rates shown here are based on anticipated operation following receipt of the requested significant modification to the permit.

$$E_{VOC,short} = 0.50 \text{ lb/hr}$$

### 3.2.3 Annual VOC Emissions

Maximum annual emissions of VOC from each boiler are 2.1 tons/yr, calculated as follows.

$$HI_{total,annual} = 99 \text{ MMBtu/hr} \times 8,760 \text{ hr/yr}$$

$$HI_{total,annual} = 867,240 \text{ MMBtu/yr}$$

$$HI_{total,gas} = 867,240 \text{ MMBtu/yr} - 828,182 \text{ MMBtu/yr}$$

$$HI_{total,gas} = 39,058 \text{ MMBtu/yr}$$

$$E_{VOC,oil,annual} = 0.005 \text{ lb/MMBtu} \times 867,240 \text{ MMBtu/yr}$$

$$E_{VOC,oil,annual} = 4,141 \text{ lb/yr}$$

$$E_{VOC,gas,annual} = 0.004 \text{ lb/MMBtu} \times 39,058 \text{ MMBtu/yr}$$

$$E_{VOC,gas,annual} = 156 \text{ lb/yr}$$

$$E_{VOC,annual} = \left( 4,141 \text{ lb/yr} + 156 \text{ lb/yr} \right) \div 2,000 \text{ lb/ton}$$

$$E_{VOC,annual} = 2.1 \text{ ton/yr}$$

### 3.2.4 Hourly NO<sub>x</sub> Emissions

Maximum hourly emissions of NO<sub>x</sub> from each boiler are 31.7 lb/hr, calculated as follows.

$$E_{NOx,short} = 99 \text{ MMBtu/hr} \times 0.32 \text{ lb/MMBtu}$$

$$E_{NOx,short} = 31.7 \text{ lb/hr}$$

### 3.2.5 Annual NO<sub>x</sub> Emissions

Maximum annual emissions of NO<sub>x</sub> from each boiler are 134.5 tons/yr, calculated as follows.

$$E_{NOx,oil,annual} = 0.32 \text{ lb/MMBtu} \times 828,182 \text{ MMBtu/yr}$$

$$E_{NOx,oil,annual} = 265,018 \text{ lb/yr}$$

$$E_{NOx,gas,annual} = 0.10 \text{ lb/MMBtu} \times 39,058 \text{ MMBtu/yr}$$

$$E_{NOx,gas,annual} = 3,906 \text{ lb/yr}$$

$$E_{NOx,annual} = \left( 265,018 \text{ lb/yr} + 3,906 \text{ lb/yr} \right) \div 2,000 \text{ lb/ton}$$

$$E_{NOx,annual} = 134.5 \text{ ton/yr}$$

### 3.2.6 Hourly PM Emissions

Maximum hourly emissions of PM (filterable) from each boiler are 24.75 lb/hr, calculated as follows.

$$E_{PM,short} = 99 \text{ MMBtu/hr} \times 0.25 \text{ lb/MMBtu}$$

$$E_{PM,short} = 24.75 \text{ lb/hr}$$

### 3.2.7 Annual PM Emissions, Each Boiler

Maximum annual emissions of PM (filterable) from each boiler are 103.8 tons/yr, calculated as follows.

$$E_{PM,oil,annual} = 0.25 \text{ lb/MMBtu} \times 828,182 \text{ MMBtu/yr}$$

$$E_{PM,oil,annual} = 207,046 \text{ lb/yr}$$

$$E_{PM,gas,annual} = 0.015 \text{ lb/MMBtu} \times 39,058 \text{ MMBtu/yr}$$

$$E_{PM,gas,annual} = 586 \text{ lb/yr}$$

$$E_{PM,annual} = \left( 207,046 \text{ lb/yr} + 586 \text{ lb/yr} \right) \div 2,000 \text{ lb/ton}$$

$$E_{PM,annual} = 103.8 \text{ ton/yr}$$

### 3.2.8 Hourly PM10 Emissions

Maximum hourly emissions of PM10 (filterable) from each boiler are 14.85 lb/hr, calculated as follows.

$$E_{PM10,short} = 99 \text{ MMBtu/hr} \times 0.15 \text{ lb/MMBtu}$$

$$E_{PM10,short} = 14.85 \text{ lb/hr}$$

### 3.2.9 Annual PM10 Emissions, Each Boiler

Maximum annual emissions of PM10 (filterable) from each boiler are 62.4 tons/yr, calculated as follows.

$$E_{PM10,oil,annual} = 0.15 \text{ lb/MMBtu} \times 867,240 \text{ MMBtu/yr}$$

$$E_{PM10,oil,annual} = 124,227 \text{ lb/yr}$$

$$E_{PM10,gas,annual} = 0.015 \text{ lb/MMBtu} \times 39,058 \text{ MMBtu/yr}$$

$$E_{PM10,gas,annual} = 586 \text{ lb/yr}$$

$$E_{PM10,annual} = \left( 124,227 \text{ lb/yr} + 586 \text{ lb/yr} \right) \div 2,000 \text{ lb/ton}$$

$$E_{PM10,annual} = 62.4 \text{ ton/yr}$$

### 3.2.10 Hourly CO Emissions

Maximum hourly emissions of CO from each boiler are 7.92 lb/hr, calculated as follows.

$$E_{CO,short} = 99 \text{ MMBtu/hr} \times 0.08 \text{ lb/MMBtu}$$

$$E_{CO,short} = 7.92 \text{ lb/hr}$$

### 3.2.11 Annual CO Emissions

Maximum annual emissions of CO from each boiler are 34.6 tons/yr, calculated as follows.

$$E_{CO,oil,annual} = 0.08 \text{ lb/MMBtu} \times 867,240 \text{ MMBtu/yr}$$

$$E_{CO,oil,annual} = 66,255 \text{ lb/yr}$$

$$E_{CO,gas,annual} = 0.073 \text{ lb/MMBtu} \times 39,058 \text{ MMBtu/yr}$$

$$E_{CO,gas,annual} = 2,851 \text{ lb/yr}$$

$$E_{CO,annual} = \left( 66,255 \text{ lb/yr} + 2,851 \text{ lb/yr} \right) \div 2,000 \text{ lb/ton}$$

$$E_{CO,annual} = 34.6 \text{ ton/yr}$$

### 3.2.12 Hourly SO<sub>2</sub> Emissions

Maximum hourly emissions of SO<sub>2</sub> from each boiler are 51.8 lb/hr, calculated as follows (the emission factor equation is from AP-42 Section 1.3, Table 1.3-1, Sept. 1998 ed.):

$$EF_{SO_2,oil} = \frac{157 \times 0.5 \text{ lb}}{1000 \text{ gal}} \div \frac{0.15 \text{ MMBtu}}{\text{gal}}$$

$$EF_{SO_2,oil} = 0.523 \text{ lb/MMBtu}$$

$$E_{SO_2,oil,short} = 99 \text{ MMBtu/hr} \times 0.523 \text{ lb/MMBtu}$$

$$E_{SO_2,oil,short} = 51.8 \text{ lb/hr}$$

### 3.2.13 Annual SO<sub>2</sub> Emissions

Maximum annual emissions of SO<sub>2</sub> from each boiler are 217.1 tons/yr, calculated as follows (the SO<sub>2</sub> emission factor for refinery fuel gas is calculated as shown in Section 3.1.7 herein):

$$E_{SO_2, oil, annual} = 0.523 \text{ lb/MMBtu} \times 867,240 \text{ MMBtu/yr}$$

$$E_{SO_2, oil, annual} = 433,415 \text{ lb/yr}$$

$$E_{SO_2, gas, annual} = 0.0207 \text{ lb/MMBtu} \times 39,058 \text{ MMBtu/yr}$$

$$E_{SO_2, gas, annual} = 807 \text{ lb/yr}$$

$$E_{SO_2, annual} = \left( 433,415 \text{ lb/yr} + 807 \text{ lb/yr} \right) \div 2,000 \text{ lb/ton}$$

$$E_{SO_2, annual} = 217.1 \text{ ton/yr}$$

## 3.3 Miscellaneous Equipment

### 3.3.1 Assumptions

The miscellaneous equipment for which operation is authorized by Covered Source Permit No. 0088-02-C includes individual drain systems, which are part of the refinery's process wastewater collection system, and equipment (*i.e.*, valves, pressure relief devices, and connectors) in VOC service associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206.

Emissions calculations for individual drain systems are based on the following assumptions:

- Twenty-three (23) individual drain systems were installed in conjunction with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206.
- Uncontrolled VOC emissions from each drain are 1.54 lbs per day, based on the emission factor presented in AP-42 Section 5.1, Table 5.1-3 (Jan. 1995 ed.).
- A VOC control efficiency of 95 percent is achieved using the controls required by 40 CFR part 60, subpart QQQ, § 60.692-2, as discussed in Section 4.1.3.1 herein.

Equipment in VOC service associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 is part of the Cogen Plant (Area 67) process unit, operation of which is authorized under Covered Source Permit No. 0088-01-C. Estimates of VOC emissions presented in this Section 3.3 pertain only to the equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206, not to the entire emissions unit (*i.e.*, the collection of all

equipment in VOC service in the Cogen Plant. These emissions calculations are based on the following assumptions:

- Equipment in VOC service associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 includes the following components:
  - 326 valves in gas/vapor service
  - 6 valves in light liquid service
  - 44 valves in heavy liquid service
  - 940 flanges and other connectors
- VOC emissions from valves in heavy liquid service and from flanges and other connectors are based on the following emission factors from *Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017), U.S. EPA, November 1995, "Table 2-2: Refinery Average Emission Factors:"
  - 0.00051 lb/hr from each valve in heavy liquid service
  - 0.00055 lb/hr from each flange/connector
- VOC emissions from each valve in light liquid or gas/vapor service in the Cogen Plant, which is subject to the refinery's leak detection and repair program, are based on an emission factor of 0.016 lb/yr. This emission factor is based on past performance.

### 3.3.2 Annual VOC Emissions from Process Drains

Maximum annual emissions of VOC from each drain are 0.32 ton/yr, calculated as follows.

$$E_{VOC \text{ per drain}} = 1.54 \text{ lb/day} \times (1 - 0.95) \times 365 \text{ days/yr}$$

$$E_{VOC \text{ per drain}} = 28.1 \text{ lb/yr}$$

$$E_{VOC, \text{drains}} = \frac{28.1 \text{ lb/yr}}{\text{drain}} \times 23 \text{ drains} \div 2,000 \text{ lb/ton}$$

$$E_{VOC, \text{drains}} = 0.32 \text{ ton/yr}$$

### 3.3.3 Annual VOC Emissions from Equipment in VOC Service

Estimated annual emissions of VOC from equipment are 2.4 ton/yr, calculated as follows.

$$E_{VOC, HL \text{ valves}} = \frac{0.0051 \text{ lb/hr}}{\text{valve}} \times 44 \text{ valves} \times 8,760 \text{ hrs/yr}$$

$$E_{VOC, HL \text{ valves}} = 195.4 \text{ lb/yr}$$



$$E_{VOC,flanges} = \frac{0.0055 \text{ lb/hr}}{\text{flange}} \times 940 \text{ valves} \times 8,760 \text{ hrs/yr}$$

$$E_{VOC,flanges} = 4,538 \text{ lb/yr}$$

$$E_{VOC,LL/GV \text{ valves}} = \frac{0.016 \text{ lb/yr}}{\text{valve}} \times 332 \text{ valves}$$

$$E_{VOC,LL/GV \text{ valves}} = 5.3 \text{ lb/yr}$$

$$E_{VOC,equipment} = \frac{(195.4 \text{ lb/yr} + 4,538 \text{ lb/yr} + 5.3 \text{ lb/yr})}{2,000 \text{ lb/ton}}$$

$$E_{VOC,equipment} = 2.4 \text{ ton/yr}$$

# Chapter 4. Regulatory Applicability

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This Chapter presents citations and descriptions of applicable requirements affecting the cogeneration unit, CGT-6704, the steam boilers, F-5205 and F-5206, and miscellaneous equipment associated with this cogeneration unit and these boilers. In addition, a discussion of certain non-applicable regulations is provided.

## 4.1 Federal Emissions Standards

### 4.1.1 Cogeneration Unit

#### 4.1.1.1 40 CFR Part 60, Subparts A, J, and KKKK

As established by Special Condition B.1 in Attachment II.A to Covered Source Permit No. 0088-02-C, cogeneration unit CGT-6704 is subject to the provisions of three separate New Source Performance Standards (“NSPS”) regulations codified at 40 CFR part 60:

- The provisions of subpart A, “General Provisions,” apply to each affected facility under any NSPS rule in part 60. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions. Requirements applicable to the cogeneration unit are the performance standards for CEMS at 40 CFR § 60.13 (Special Condition D.4 in Attachment II.A to Covered Source Permit No. 0088-02-C), performance standards for the continuous monitoring system for hydrogen sulfide concentration in refinery fuel gas at § 60.13 (Special Condition D.5), notification requirements at § 60.7 (Special Condition E.1), and performance testing requirements at § 60.8 (Special Conditions F.1, F.2, F.3, F.6, and F.7).
- The cogeneration unit is a fuel gas combustion device subject to certain provisions of subpart J, “Standards of Performance for Petroleum Refineries.” Applicable requirements include the fuel gas hydrogen sulfide concentration limitation at 40 CFR § 60.104(a)(1) (Special Condition C.1 in Attachment II.A to Covered Source Permit No. 0088-02-C), fuel gas hydrogen sulfide concentration monitoring requirements at § 60.105(a) (Special Condition D.5), excess emissions reporting requirements in § 60.105(e) (Special Condition E.1), and performance testing requirements in § 60.106(e).
- The cogeneration unit includes a stationary combustion turbine subject to certain provisions of subpart KKKK, “Standards of Performance for Stationary Combustion Turbines.” Applicable requirements include the NO<sub>x</sub> emission standard at 40 CFR § 60.4320(a) (Special Condition C.2 in Attachment II.A to Covered Source Permit No. 0088-02-C), the SO<sub>2</sub> emission standard at § 60.4330(b) (Special Condition C.1.a), the general duty requirement at § 60.4333(a), requirements for operating NO<sub>x</sub> and O<sub>2</sub> CEMS at § 60.4335(b) and § 60.4345 (Special Condition D.4), requirements for monitoring the sulfur content of naphtha at § 60.4360 and § 60.4370 (Special Condition D.2), excess emissions reporting requirements in § 60.4375 (Special Condition E.1), and

performance testing requirements in § 60.4400, § 60.4405, and § 60.4415 (Special Conditions F.1 and F.2). Because Chevron has elected to comply with the requirements for operating NO<sub>x</sub> and O<sub>2</sub> CEMS in § 60.4335(b), the requirements for operating a continuous monitoring system to determine the ratio of water to fuel being fired (at § 60.4335(a)) and the requirement for maintaining the water injection rate above an established level (at § 60.4380(a)) do not apply to the cogeneration unit, CGT-6704.

#### 4.1.1.2 40 CFR Part 63, Subparts A and YYYY

As established by Special Condition B.2 in Attachment II.A to Covered Source Permit No. 0088-02-C, cogeneration unit CGT-6704 is subject to the provisions of two separate National Emissions Standards for Hazardous Air Pollutants (“NESHAP”) regulations codified at 40 CFR part 63:

- The provisions of subpart A apply to each affected source under any NESHAP rule in part 63. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions. Requirements applicable to the cogeneration unit are the operation and maintenance requirements at 40 CFR § 63.6(e) and § 63.8(c), recordkeeping and reporting requirements at 40 CFR § 63.10), and performance testing requirements at § 63.7 (Special Conditions F.1, F.2, F.3, F.6, F.7, and F.8 in Attachment II.A to Covered Source Permit No. 0088-02-C).
- The cogeneration unit includes a stationary combustion turbine subject to certain provisions of subpart YYYY, “National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.” Applicable requirements for the combustion turbine include the formaldehyde emission standard at 40 CFR § 63.6100 (Special Condition C.2 in Attachment II.A to Covered Source Permit No. 0088-02-C); the general duty requirement at § 63.6105; performance testing requirements at § 63.6115 and § 63.6120(a) through (d) (Special Conditions F.1 and F.2); petition requirements at § 63.6120(e) through (g); monitoring requirements at § 63.6125(b), § 63.6135, and § 63.6140; reporting requirements at § 63.6150; and recordkeeping requirements at § 63.6155 and § 63.6160.

#### 4.1.2 Steam Boilers

##### 4.1.2.1 40 CFR Part 60, Subparts A, Dc, and J

As established by Special Condition B.1.a in Attachment II.B to Covered Source Permit No. 0088-02-C, steam boilers F-5205 and F-5206 are subject to the provisions of three separate NSPS regulations codified at 40 CFR part 60:

- The provisions of subpart A apply to each affected facility under any NSPS rule in part 60. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions. Requirements applicable to steam boilers F-5205 and F-5206 are the performance standards for continuous opacity monitoring systems at 40 CFR § 60.13 (Special Condition D.3 in Attachment II.B to Covered Source Permit No. 0088-02-C), performance standards for continuous monitoring systems for hydrogen sulfide

concentration in refinery fuel gas at § 60.13 (Special Condition D.4), notification requirements at § 60.7 (Special Conditions E.1 and E.4), and performance testing requirements at § 60.8 (Special Conditions F.1, F.2, F.3, F.6, and F.7).

- Steam boilers F-5205 and F-5206 are steam generating units subject to certain provisions of subpart Dc, “Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.” Applicable requirements include the fuel sulfur limitation at 40 CFR § 60.42c(d) (Special Condition C.2 in Attachment II.B to Covered Source Permit No. 0088-02-C), fuel sampling requirements in § 60.46c(d) (Special Condition D.2), fuel consumption monitoring requirements in § 60.48c(g) (Special Condition D.1), excess emissions reporting requirements in § 60.48c(d) (Special Conditions E.1 and E.2), and performance testing requirements in § 60.44c(g) (Special Conditions F.1 and F.2). Pursuant to § 60.43c(e)(4), the boilers are exempt from the particulate matter limits at § 60.43c(c) and § 60.43c(e)(1), and therefore is not subject to the performance testing requirements for particulate matter emissions or opacity at § 60.45c.
- Steam boilers F-5205 and F-5206 are fuel gas combustion devices subject to certain provisions of subpart J, “Standards of Performance for Petroleum Refineries.” Applicable requirements include the fuel gas hydrogen sulfide concentration limitation at 40 CFR § 60.104(a)(1) (Special Condition C.2 in Attachment II.B to Covered Source Permit No. 0088-02-C), fuel gas hydrogen sulfide concentration monitoring requirements at § 60.105(a) (Special Condition D.4), excess emissions reporting requirements in § 60.105(e) (Special Condition E.1), and performance testing requirements in § 60.106(e).

#### 4.1.2.2 40 CFR Part 63, Subparts A and DDDDD

As established by Special Condition B.1.b in Attachment II.B to Covered Source Permit No. 0088-02-C, steam boilers F-5205 and F-5206 are subject to the provisions of two NESHAP regulations codified at 40 CFR part 63. Specifically, pursuant to 40 CFR § 63.7490, each of these boilers is an existing boiler under subpart DDDDD. However, pursuant to a final rule published by U.S. EPA on May 18, 2011 (*76 Fed. Reg. 28662*), the effective date of subpart DDDDD is stayed indefinitely. The provisions of 40 CFR part 63, subparts A and DDDDD, are therefore not applicable requirements at this time.

#### 4.1.3 Miscellaneous Equipment

##### 4.1.3.1 40 CFR Part 60, Subparts A, GGG, GGGa, and QQQ

As correctly indicated in Special Conditions B.1 and B.2 in Attachment II.C to Covered Source Permit No. 0088-02-C, the miscellaneous equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 is subject to the provisions of two NSPS regulations codified at 40 CFR part 60:

- The provisions of subpart A apply to each affected facility under any NSPS rule in part 60. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions. Requirements applicable to the miscellaneous equipment are the notification

requirements at 40 CFR § 60.7 (Special Condition E.9 in Attachment II.C to Covered Source Permit No. 0088-02-C).

- The miscellaneous equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 includes 23 individual drain systems that are associated with the refinery's process wastewater collection system and are subject to the provisions of subpart QQQ, "Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems." Applicable requirements for these individual drain systems include the equipment design standards and work practice requirements at 40 CFR § 60.692-2 and § 60.692-6 (Special Conditions C.7 and D.13 through D.19 in Attachment II.C to Covered Source Permit No. 0088-02-C), initial inspection requirements at § 60.696 (Special Condition D.20), recordkeeping requirements at § 60.697 (Special Conditions D.21 through D.23), and reporting requirements at § 60.698 (Special Conditions E.7 through E.9).

Although correct at the time of initial issuance of Covered Source Permit No. 0088-02-C, Special Condition B.1.b in Attachment II.C to Covered Source Permit No. 0088-02-C now incorrectly indicates that the miscellaneous equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 includes equipment in VOC service that is subject to subpart GGG, "Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006." The equipment in VOC service associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 is part of the Cogeneration Plant at the Hawaii refinery. Installation of this equipment commenced after November 7, 2006, and it constituted a modification of the Cogeneration Plant. Therefore, the equipment in VOC service in the Cogeneration Plant, including the equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206, is subject to subpart GGGa, "Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006."<sup>5</sup>

Throughout Attachment II.C to Covered Source Permit No. 0088-02-C, citations to the requirements of subpart GGG should be revised to reflect the applicable requirements of subpart GGGa or should be otherwise corrected. Specifically:

- Special Conditions C.3 and D.3 should be deleted, as there are no compressors associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206.
- Special Condition C.4 and D.4, pertaining to pressure relief devices in gas/vapor service, should be revised to reflect the applicable requirements of 40 CFR § 60.592a(a) and § 60.482-4a.
- Special Condition C.5, pertaining to open-ended valves and lines, should be revised to reflect the applicable requirements of 40 CFR § 60.592a(a) and § 60.482-6a.
- Special Condition C.6, pertaining to sampling connection systems, should be revised to reflect the applicable requirements of 40 CFR § 60.592a(a) and § 60.482-5a.

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<sup>5</sup> At the time of issuance of Covered Source Permit No. 0088-02-C in May 2007, the citation to subpart GGG was correct. In November 2006, EPA had proposed to make revisions to subpart GGG to make it more stringent. See, 71 *Fed. Reg.* 65302. In November 2007, EPA instead finalized those rule revisions as a new subpart GGGa. See, 72 *Fed. Reg.* 64860.

- Special Condition C.8, pertaining to delay of repair, should be revised to reflect the applicable requirements of 40 CFR § 60.592a(a) and § 60.482-9a.
- Special Condition D.2, pertaining to pumps in light liquid service, should be revised to reflect the applicable requirements of 40 CFR § 60.592a(a) and § 60.482-2a.
- Special Condition D.5, pertaining to valves in light liquid service and in gas/vapor service, should be revised to reflect the applicable requirements of 40 CFR § 60.592a(a) and § 60.482-7a.
- Special Condition D.6, pertaining to pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors, should be revised to reflect the applicable requirements of 40 CFR § 60.592a(a), § 60.593a(g), and § 60.482-8a.
- Special Conditions D.7 through D.12 should be revised to reflect the applicable recordkeeping requirements of 40 CFR § 60.592a(e) and § 60.486a.
- Special Conditions E.5 and E.6 should be revised to reflect the applicable reporting requirements of 40 CFR § 60.592a(e) and § 60.487a.

#### 4.1.3.2 40 CFR Part 63, Subparts A and CC

Special Condition B.3 in Attachment II.C to Covered Source Permit No. 0088-02-C incorrectly indicates that the equipment in VOC service associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 is subject to two NESHAP rules, subpart A and subpart CC. Pursuant to 40 CFR § 63.640(p)(2) in subpart CC, because the equipment in VOC service in the Cogeneration Plant is subject to the provisions of 40 CFR part 60, subpart GGGa, this equipment is no longer subject to the requirements of subpart CC. Because subpart CC does not apply, the general provisions in subpart A also do not apply.

## 4.2 Compliance Assurance Monitoring

### 4.2.1 Cogeneration Unit

The cogeneration unit, CGT-6704, is not subject to the provisions of the Compliance Assurance Monitoring (“CAM”) rule, 40 CFR part 64, for pollutants other than NO<sub>x</sub> because it does not use a “control device,” as that term is defined at 40 CFR § 64.1, for those pollutants. With respect to the NO<sub>x</sub> emissions standards in 40 CFR § 60.4325, the cogeneration unit is not subject to the provisions of the CAM rule because the emissions standards were proposed by U.S. EPA after November 15, 1990, pursuant to section 111 of the Clean Air Act and therefore are subject to the exemption provided by 40 CFR § 64.2(b)(1)(i). With respect to the NO<sub>x</sub> mass emissions limits imposed in Special Condition C.2 in Attachment II.A to Covered Source Permit No. 0088-02-C, the cogeneration unit is not subject to the provisions of the CAM rule because the permit specifies a “continuous compliance determination method,” as that term is defined at 40 CFR § 64.1, and the emission limits therefore are subject to the exemption provided by 40 CFR § 64.2(b)(1)(vi).

### 4.2.2 Steam Boilers

The two steam boilers, F-5205 and F-5206, are not subject to the provisions of the CAM rule because neither uses any “control devices,” as that term is defined at 40 CFR § 64.1.

### **4.2.3 Miscellaneous Equipment**

Miscellaneous equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 is not subject to the provisions of the CAM rule because none of the affected emissions units have pre-control device potential to emit above the applicable major source threshold of 100 tons per year.

## **4.3 Hawaii Administrative Rules**

### **4.3.1 HAR § 11-60.1-32: Visible Emissions**

This regulation limits the opacity of visible emissions from steam boilers F-5205 and F-5206 and cogeneration unit CGT-6704 to 20 percent, except during start-up, shutdown or equipment breakdowns, when the opacity may exceed 20 percent for a period aggregating not more than six minutes during any sixty minutes, but may not exceed 60 percent opacity. Compliance is determined using Method 9 (in appendix A-4 to 40 CFR part 60) and other EPA-approved methods.

### **4.3.2 HAR § 11-60.1-38: Sulfur Oxides from Fuel Combustion**

This regulation limits the sulfur content of fuel burned in steam boilers F-5205 and F-5206 and cogeneration unit CGT-6704 to 2 percent by weight. This limit is less stringent than the limits from NSPS subparts Dc, J, and KKKK, listed in Sections 4.1.1 and 4.1.2 herein.

## **Appendix A**

**Form C-1: Compliance Plan  
and  
Form C-2: Compliance Certification**



**C-1: Compliance Plan**

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets of paper if necessary.

1. Compliance status with respect to all Applicable Requirements:

Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

- YES     {If YES, complete items a and c below}
- NO        {If NO, complete items a, b, and c below}

a. Identify all applicable requirement(s) for which compliance is achieved.

All applicable requirements for steam boilers F-5205 and F-5206 other than Special Condition C.3 of Attachment II.B to Covered Source Permit No. 0088-02-C. See current permit and Sections 4.1.2 and 4.3 in this permit renewal application for a detailed list of applicable requirements for steam boilers F-5205 and F-5206.

All applicable requirements for cogeneration unit CGT-6704 except for the petition requirement at 40 CFR § 63.6120(e), discussed in (1)(b) below. See current permit and Sections 4.1.1 and 4.3 in this permit application for a detailed list of applicable requirements for cogeneration unit CGT-6704.

All applicable requirements for miscellaneous equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 except for 40 CFR part 60, subpart GGGa, discussed in (1)(b) below. See current permit and Section 4.1.3 in this permit application for detailed list of applicable requirements for the miscellaneous equipment.

All source-wide applicable requirements with the exception of the compliance certification requirement at Special Condition E.6 of Attachment II.A, Special Condition E.6 of Attachment II.B, and Special Condition E.4 of Attachment II.C to Covered Source Permit No. 0088-02-C and with the possible exception of the SO<sub>2</sub> State Ambient Air Quality Standards at HAR § 11-59-4(g), the SO<sub>2</sub> National Ambient Air Quality Standards at 40 CFR § 50.4, § 50.5, and § 50.17, and the NO<sub>x</sub> National Ambient Air Quality Standard at 40 CFR § 50.11, as discussed in (1)(b) below.

Provide a statement that the source is in compliance and will continue to comply with all such requirements.  
The source is in compliance and will continue to comply with all such requirements.

b. Identify all applicable requirement(s) for which compliance is NOT achieved.

(i) Special Condition C.3 of Attachment II.B to Covered Source Permit No. 0088-02-C sets an emission limit of 0.03 lb/MMBtu for PM/PM10 from the new boilers.

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(ii) 40 CFR part 63, subpart YYYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. Cogeneration unit CGT-6704 has met the compliance requirements for Subpart YYYYY as required by Covered Source Permit 0088-02-C, including the requirement (at 40 CFR § 63.6110(a)) to conduct an initial performance test, and the performance test demonstrated initial compliance with the formaldehyde emission limitation of 91 parts per billion by volume (at § 63.6100). Unit CGT-6704 includes a stationary combustion turbine that is not equipped with an oxidation catalyst. For combustion turbines that are not equipped with an oxidation catalyst, § 63.6120(e) of Subpart YYYYY requires the owner or operator to petition EPA either for approval of no additional operating limitations or for approval of operating parameters to be monitored during performance testing of the formaldehyde limit and continuously thereafter. Chevron discovered during the preparation of this Covered Source Permit renewal application that the Refinery did not comply with the petition requirement at § 63.6120(e) of Subpart YYYYY.

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(iii) 40 CFR part 60, subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006. The Cogeneration Plant at the Chevron Hawaii refinery is a process unit. The miscellaneous equipment in the Cogeneration Plant, operation of which is authorized by Covered Source Permit No. 0088-01-C, includes equipment in VOC service. Installation of miscellaneous equipment associated with cogeneration unit CGT-6704 and steam boilers F-5205 and F-5206 constituted a modification of the equipment in VOC service within the Cogeneration Plant. This modification commenced after November 7, 2006, triggering applicability of subpart GGGa. Chevron has been in compliance with the requirements of 40 CFR part 60, subpart GGG, as required by Covered Source Permit No. 0088-02-C, but Chevron discovered during the preparation of this Covered Source Permit renewal application that the equipment in VOC service in the Cogeneration Plant actually is subject to subpart GGGa, not subpart GGG, and is not in compliance with the requirements of subpart GGGa.

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(iv) Compliance certification requirement at Special Condition E.6 of Attachment II.A, Special Condition E.6 of Attachment II.B, and Special Condition E.4 of Attachment II.C to Covered Source Permit No. 0088-02-C.

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(v) SO<sub>2</sub> State Ambient Air Quality Standards at HAR § 11-59-4(g), SO<sub>2</sub> National Ambient Air Quality Standards at 40 CFR § 50.4, § 50.5, and § 50.17, and NO<sub>x</sub> National Ambient Air Quality Standard at 40 CFR § 50.11. Data collected by the ambient monitoring stations operated by the Department of Health, including at the Kapolei monitor approximately one mile north of the facility, indicates continuous compliance with the ambient air quality standards. These ambient monitoring stations use the reference methods prescribed by the applicable regulations and are the basis for determining compliance with the State and Federal standards. However, dispersion modeling, using conservative modeling parameters, conducted during preparation of this Covered Source Permit renewal application indicates that

certain emissions from the Chevron Hawaii Refinery could cause or contribute to potential exceedances of the listed standards. Although the compliance for these ambient standards is determined by actual monitoring data, because the initial results of the conservative modeling suggest a potential exceedance of the standards, Chevron is noting a potential noncompliance with the listed standards.

Provide a detailed Schedule of Compliance Schedule and a description of how the source will achieve compliance with all such applicable requirements.

<u>Description of Remedial Action</u>	<u>Expected Date of Completion</u>
<u>(i) This limit was found to be unachievable during the shakedown period. The boilers did not operate beyond the shakedown period. As agreed to with the Department, the boilers have been shut down and will remain so until the permit conditions are modified.</u>	<u>May 22, 2012</u>
<u>(ii) Chevron will submit the required petition to U.S. EPA. Chevron will comply with EPA's directive in response to the petition.</u>	<u>February 22, 2012 As required by the EPA directive</u>
<u>(iii) Chevron will achieve full compliance with the requirements of subpart GGGa for equipment in VOC service in the Cogeneration Plant.</u>	<u>February 22, 2012</u>
<u>(iv) Chevron will submit the required compliance certification for calendar year 2011.</u>	<u>March 30, 2012</u>
<u>(v) Chevron, in consultation with the Department, will provide to the Department a revised assessment of the ambient air quality impacts of the Hawaii refinery.</u>	<u>February 22, 2012</u>

c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to. These applicable requirements may take effect AFTER permit issuance:

<u>Applicable Requirement</u>	<u>Effective Date</u>	<u>Currently in Compliance?</u>
<u>40 CFR Part 63, subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters.</u>	<u>unknown</u>	<u>n/a</u>

If the source is not currently in compliance, provide a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

<u>Description of Proposed Action/Steps to Achieve Compliance</u>	<u>Expected Date of Achieving Compliance</u>
<u> </u>	<u> </u>
<u> </u>	<u> </u>
<u> </u>	<u> </u>

Provide a statement that the source on a timely basis will meet all these applicable requirements:

As established by Special Condition B.1.b in Attachment II.B to Covered Source Permit No. 0088-02-C, the two steam boilers, F-5205 and F-5206, are subject to the provisions of subpart DDDDD and, as a result, to the General Provisions in 40 CFR part 63, subpart A. In June 2007, subpart DDDDD was vacated in a judicial action. U.S. EPA subsequently initiated rulemaking to revise subpart DDDDD. Pursuant to 40 CFR § 63.7490 in the revised rule, boilers F-5205 and F-5206 are existing sources under subpart DDDDD. Pursuant to a final rule published by U.S. EPA on May 18, 2011 (76 Fed. Reg. 28662), the effective date of the revised subpart DDDDD is stayed indefinitely. If the stay is lifted, the source will timely meet all applicable requirements under subparts A and DDDDD.

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of each remedial action and the expected date of completion:

<u>Description of Remedial Action and Explanation</u>	<u>Expected Date of Completion</u>
_____	_____
_____	_____
_____	_____
_____	_____

2. Compliance Progress Reports:

a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal:     n/a     Beginning Date:       
(less than or equal to 6 months)

b. Date(s) that the Action described in (1)(b) was achieved:

<u>Remedial Action</u>	<u>Date Achieved</u>
n/a	

c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

n/a

**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): Cavote (First): Chris (MI): P.

Title: Refinery Manager Phone: (808) 682-5711

Mailing Address: 91-480 Malakole Street

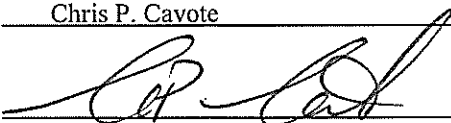
City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Chris P. Cavote

Signature:  Date: 11/21/11

Facility Name: Chevron Products Company

Location: Kapolei

Permit Number: 0088-02-C

<b>FOR AGENCY USE ONLY</b>
File/Application No.: _____
Island: _____
Date Received: _____

**C-2: Compliance Certification**

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Complete as many copies of this form as needed. Use separate sheets of paper if necessary.

**RESPONSIBLE OFFICIAL**

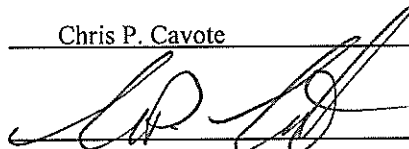
(as defined in HAR §11-60.1-1)

Name (Last): Cavote (First): Chris (MI): P.  
 Title: Refinery Manager Phone: (808) 682-5711  
 Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Chris P. CavoteSignature: Date: 11/22/11Facility Name: Chevron Products CompanyLocation: KapoleiPermit Number: 0088-02-C

FOR AGENCY USE ONLY

File/Application No.: \_\_\_\_\_

Island: \_\_\_\_\_

Date Received: \_\_\_\_\_

Complete the following information for **each** applicable requirement that applies to **each** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: annual Beginning Date: March 2008

2. Emissions Unit No./Description: Cogeneration Unit CGT-6704

3. Identify the applicable requirement(s) that is/are the basis of this certification:

All applicable requirements other than the petition requirement at 40 CFR § 63.6120(e). See Attachment II.A to current Covered Source Permit No. 0088-02-C and Sections 4.1.1 and 4.3 in this permit application for a detailed list of applicable requirements for cogeneration unit CGT-6704.

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

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5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Monitoring, recordkeeping, testing, and reporting as required in Attachment II.A to current Covered Source Permit No. 0088-02-C and as discussed in Sections 2.9.1, 4.1.1, and 4.3 in this permit application.

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Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See above.

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

As described in Sections 2.9.1 and 4.1.1.1 in this permit application, Chevron will comply with the monitoring and recordkeeping requirements in 40 CFR part 60, subpart KKKK. In addition, as noted in item (1) on the previous page, Chevron will submit annual compliance certifications. Cogeneration Unit CGT-6704 is not subject to the Compliance Assurance Monitoring Rule, 40 CFR part 64.

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- c. If NO, describe below which requirements will not be met:
- 
- 
- 
- 
- 
-



Complete the following information for *each* applicable requirement that applies to *each* emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: annual Beginning Date: March 2008

2. Emissions Unit No./Description: Cogeneration Unit CGT-6704

3. Identify the applicable requirement(s) that is/are the basis of this certification:

Unit CGT-6704 includes a stationary combustion turbine that is not equipped with an oxidation catalyst. For combustion turbines that are not equipped with an oxidation catalyst, 40 CFR § 63.6120(e) requires the owner or operator to petition EPA either for approval of no additional operating limitations or for approval of operating parameters to be monitored during performance testing of the formaldehyde limit and continuously thereafter.

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

Cogeneration unit CGT-6704 has met the compliance requirements for 40 CFR part 63, subpart YYYY, included in Attachment II.A to Covered Source Permit 0088-02-C. Chevron discovered during the preparation of this permit application that the Refinery did not comply with the petition requirement at 40 CFR § 63.6120(e).

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Following submission of the required petition, facility records will be used to determine compliance.

Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See above.

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

As noted in item (1) on the previous page, Chevron will submit annual compliance certifications.

Cogeneration Unit CGT-6704 is not subject to the Compliance Assurance Monitoring Rule, 40 CFR part 64.

- c. If NO, describe below which requirements will not be met:

The petition requirement at 40 CFR § 63.6120(e) is an enhanced monitoring requirement and, as discussed in item (4)(c) above, has not been met.

Complete the following information for **each** applicable requirement that applies to **each** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: annual Beginning Date: March 2008

2. Emissions Unit No./Description: Boilers F-5205 and F-5206

3. Identify the applicable requirement(s) that is/are the basis of this certification:

All applicable requirements other than Special Condition C.3 of Attachment II.B to Covered Source Permit No. 0088-02-C. See current permit and Sections 4.1.2 and 4.3 in this permit application for a detailed list of applicable requirements for steam boilers F-5205 and F-5206.

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

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5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Monitoring, recordkeeping, testing, and reporting as required in Attachment II.B to current Covered Source Permit No. 0088-02-C and as discussed in Sections 2.9.2, 4.1.2, and 4.3 in this permit application.

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Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See above.

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

As described in Sections 2.9.2 and 4.1.2.1 in this permit application, Chevron will comply with the monitoring and recordkeeping requirements in 40 CFR part 60, subpart Dc. In addition, as noted in item (1) on the previous page, Chevron will submit annual compliance certifications. Boilers F-5205 and F-5206 are not subject to the Compliance Assurance Monitoring Rule, 40 CFR part 64.

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- c. If NO, describe below which requirements will not be met:
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- 
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-

Complete the following information for *each* applicable requirement that applies to *each* emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: annual Beginning Date: March 2008

2. Emissions Unit No./Description: Boilers F-5205 and F-5206

3. Identify the applicable requirement(s) that is/are the basis of this certification:

Special Condition C.3 of Attachment II.B to Covered Source Permit No. 0088-02-C (PM/PM10 emission limit of 0.03 lb/MMBtu heat input).  
\_\_\_\_\_  
\_\_\_\_\_

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

This limit was determined during the shakedown period not to be continuously achievable. The boilers did not operate beyond the shakedown period. As agreed to with the Department, the boilers have been shut down and will remain so until the permit condition is modified.  
\_\_\_\_\_  
\_\_\_\_\_

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Performance testing, as required in Special Conditions F.1 through F.5 in Attachment II.B to current Covered Source Permit No. 0088-02-C, will be used to demonstrate compliance with the PM and PM10 emission limits.

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Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See above.

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES                       NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

As noted in item (1) on the previous page, Chevron will submit annual compliance certifications. Boilers F-5205 and F-5206 are not subject to the Compliance Assurance Monitoring Rule, 40 CFR part 64.

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- c. If NO, describe below which requirements will not be met:
- 
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-

Complete the following information for **each** applicable requirement that applies to **each** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: annual Beginning Date: March 2008

2. Emissions Unit No./Description: Miscellaneous equipment associated with cogeneration unit CGT-6704 and boilers F-5205 and F-5206

3. Identify the applicable requirement(s) that is/are the basis of this certification:

All applicable requirements other than 40 CFR part 60, subpart GGGa. See Attachment ILC to current Covered Source Permit No. 0088-02-C and Section 4.1.3 in this permit application for a detailed list of applicable requirements for the miscellaneous equipment associated with cogeneration unit CGT-6704 and boilers F-5205 and F-5206.

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

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5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Monitoring, recordkeeping, and reporting as required in Attachment II.C to current Covered Source Permit No. 0088-02-C and as discussed in Sections 2.9.3 and 4.1.3 in this permit application.

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Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See above.

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

As noted in item (1) on the previous page, Chevron will submit annual compliance certifications. The miscellaneous equipment associated with cogeneration unit CGT-6704 and boilers F-5205 and F-5206 is not subject to the Compliance Assurance Monitoring Rule, 40 CFR part 64.

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- c. If NO, describe below which requirements will not be met:
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- 
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- 
-



Complete the following information for **each** applicable requirement that applies to **each** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: annual Beginning Date: March 2008

2. Emissions Unit No./Description: Miscellaneous equipment associated with cogeneration unit CGT-6704  
and boilers F-5205 and F-5206

3. Identify the applicable requirement(s) that is/are the basis of this certification:

Requirements of 40 CFR part 60, subpart GGGa, as described in Section 4.1.3.1 in this permit application.  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

Installation of miscellaneous equipment associated with cogeneration unit CGT-6704 and steam boilers  
F-5205 and F-5206 constituted a modification of the equipment in VOC service within the Cogeneration  
Plant. This modification commenced after November 7, 2006, triggering applicability of subpart GGGa.  
Compliance with subpart GGGa has not been demonstrated.  
\_\_\_\_\_

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Monitoring, recordkeeping, and reporting, as described in Section 4.1.3.1 in this permit application, will be used to demonstrate compliance with the requirements of subpart GGGa.

Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See above.

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

As noted in item (1) on the previous page, Chevron will submit annual compliance certifications. The miscellaneous equipment associated with cogeneration unit CGT-6704 and boilers F-5205 and F-5206 is not subject to the Compliance Assurance Monitoring Rule, 40 CFR part 64.

- c. If NO, describe below which requirements will not be met:

The monitoring and recordkeeping requirements in 40 CFR part 60, subpart GGGa, are enhanced monitoring requirements and, as discussed in item (4)(c) above, have not been met.

Complete the following information for **each** applicable requirement that applies to **each** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:  
Frequency of Submittal: annual Beginning Date: March 2008

2. Emissions Unit No./Description: Sourcewide

3. Identify the applicable requirement(s) that is/are the basis of this certification:  
All source-wide applicable requirements other than the compliance certification requirement at Special Condition E.6 of Attachment II.A, Special Condition E.6 of Attachment II.B, and Special Condition E.4 of Attachment II.C to Covered Source Permit No. 0088-02-C, the SO<sub>2</sub> State Ambient Air Quality Standards at HAR § 11-59-4(g), the SO<sub>2</sub> National Ambient Air Quality Standards at 40 CFR § 50.4, § 50.5, and § 50.17, and the NO<sub>x</sub> National Ambient Air Quality Standard at 40 CFR § 50.11.

4. Compliance status:  
a. Will the emissions unit be in compliance with the identified applicable requirement(s)?  
 YES  NO  
b. If YES, will compliance be continuous or intermittent?  
 Continuous  Intermittent  
c. If NO, explain:  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Ambient monitoring conducted by the Department of Health, including at the Kapolei monitor approximately one mile north of the facility, with confirmatory dispersion modeling. Also, review of facility records.

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Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See above.

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

As noted in item (1) on the previous page, Chevron will submit annual compliance certifications.

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- c. If NO, describe below which requirements will not be met:
- 
- 
- 
- 
-

Complete the following information for **each** applicable requirement that applies to **each** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: annual Beginning Date: March 2008

2. Emissions Unit No./Description: Sourcewide

3. Identify the applicable requirement(s) that is/are the basis of this certification:

SO<sub>2</sub> State Ambient Air Quality Standards at HAR § 11-59-4(g), SO<sub>2</sub> National Ambient Air Quality Standards at 40 CFR § 50.4, § 50.5, and § 50.17, and NO<sub>x</sub> National Ambient Air Quality Standard at 40 CFR § 50.11.

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

See item (5) below.

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5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Ambient monitoring conducted by the Department of Health using the reference methods prescribed by the applicable regulations, including at the Kapolei monitor approximately one mile north of the facility, indicates continuous compliance. However, dispersion modeling, using conservative modeling parameters, conducted during preparation of this Covered Source Permit renewal application indicates the potential that certain emissions from the Chevron Hawaii Refinery could cause or contribute to exceedances of the listed ambient standards. Although the compliance for these ambient standards is determined by actual monitoring data, because the initial results of the conservative modeling suggest a potential exceedance of the standards, Chevron is noting a potential noncompliance with the listed standards.

Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See above.

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

As noted in item (1) on the previous page, Chevron will submit annual compliance certifications.

- c. If NO, describe below which requirements will not be met:

Complete the following information for *each* applicable requirement that applies to *each* emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: annual Beginning Date: March 2008

2. Emissions Unit No./Description: Sourcewide

3. Identify the applicable requirement(s) that is/are the basis of this certification:

Compliance certification requirement at Special Condition E.6 of Attachment II.A, Special Condition E.6 of Attachment II.B, and Special Condition E.4 of Attachment II.C to Covered Source Permit No. 0088-02-C.

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

During preparation of this Covered Source Permit renewal application, Chevron determined that compliance certifications under Covered Source Permit No. 0088-02-C had not been submitted for calendar years 2007-2010, as the equipment covered by this permit had not become operational.

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

Review of facility records.

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Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

See above.

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

- a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES                       NO

- b. If YES, identify the requirements and the provisions being taken to achieve compliance:

As noted in item (1) on the previous page, Chevron will submit annual compliance certifications.

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- c. If NO, describe below which requirements will not be met:

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RENEWAL APPLICATION  
COVERED SOURCE PERMIT (0088-01C)  
CHEVRON HAWAII REFINERY  
KAPOLEI, HAWAII

PREPARED FOR:

**STATE OF HAWAII  
DEPARTMENT OF HEALTH**

PREPARED BY:

**CHEVRON USA  
PRODUCTS COMPANY**

**DECEMBER 27, 2010**

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# 1. Introduction

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## 1.1 Application for Permit

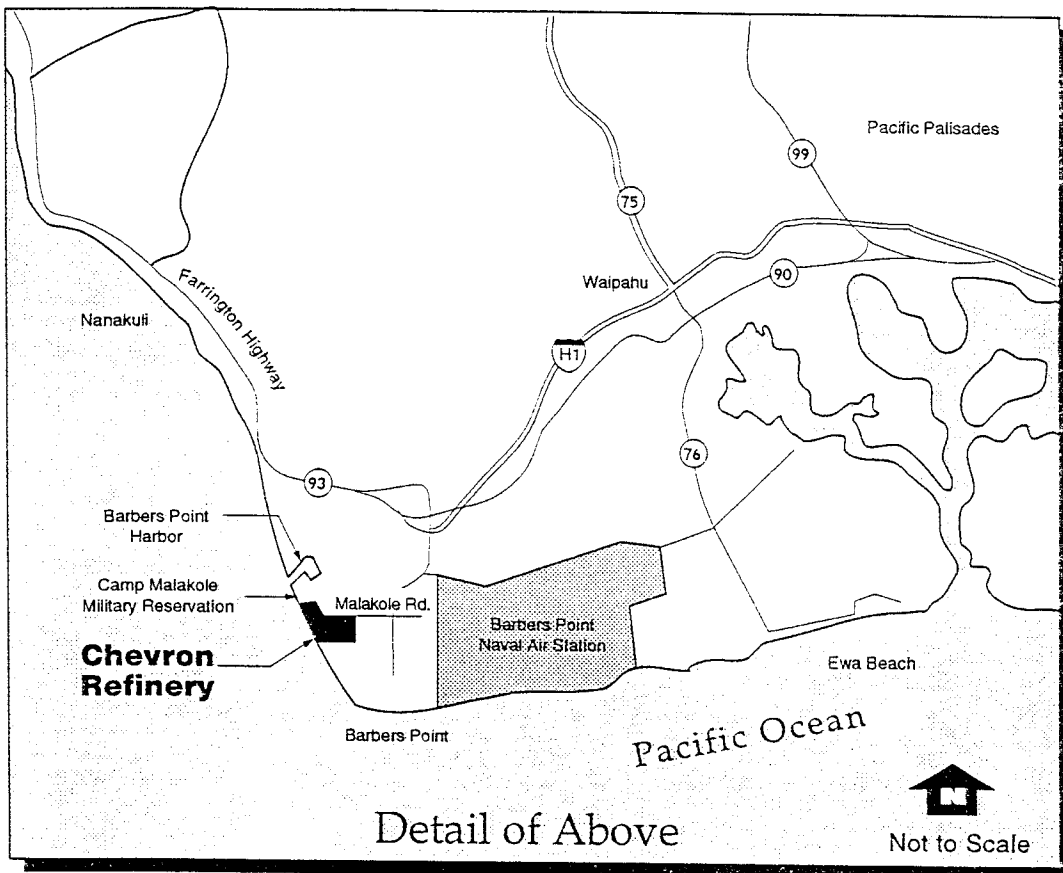
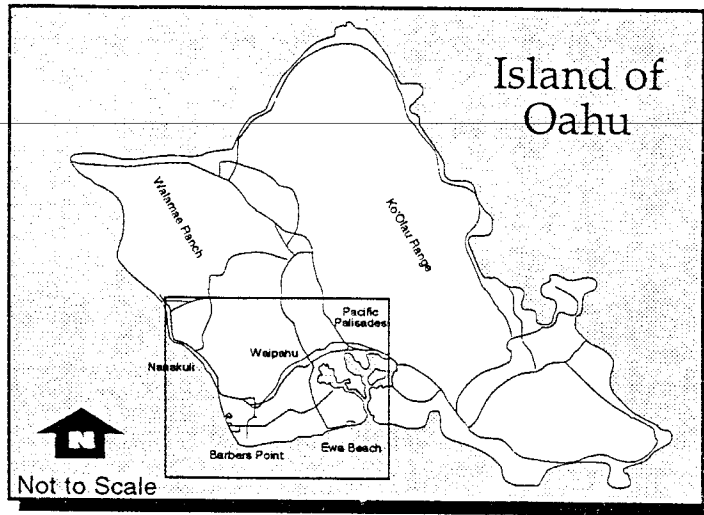
Chevron U.S.A. Products Company, a subsidiary of ChevronTexaco Corporation (Chevron) hereby makes application to the Hawaii Department of Health (DOH) Clean Air Branch for a renewal of Covered Source Permit No. 0088-01-C for the Chevron Hawaii Refinery located at Kapolei, Ewa, Oahu, Hawaii. The Hawaii Refinery began operation in 1960. In September 1994, Chevron filed an application for an initial Covered Source Permit. The Covered Source Permit was issued by DOH on February 22, 1999 and was valid through February 22, 2004. In August 2003, an application for a renewal of the Covered Source Permit was submitted to DOH. DOH issued six of the 13 Attachment II permits by process area throughout the 2007 calendar year which expire 27 June 2011. In August 2006, an application for significant modification was submitted for the Hybrid Energy Plant. DOH modified the covered source permits for those source categories impacted and issued those amendment permits on 23 May 2007 and expire 22 May 2012. This 2010 application is being submitted six months prior to covered source permit expiration date of 27 June 2011 to meet the permit shield requirements as allowed in §11-60.1-101 (5)(b). It is anticipated that this renewal will be for the timeframe from June 28, 2011 through June 27, 2016.

This renewal application is made pursuant to the regulations and requirements contained in the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1 (Air Pollution Control). According to these Rules, the Hawaii Refinery is classified as a major, covered source under the Hawaii permitting program. This document consists of the complete permit renewal application, including all the information required in Title 11, Chapter 60, Section 11-60.1-101 and the application forms provided by the DOH. Because Section 11-60.1-101 essentially requires permit renewal applications to contain the same types of information needed for initial permit applications, much of the data presented in this document is unchanged from material provided in the 2003 renewal application. This application, however, also includes the significant modifications requested in 2006 and identifies the facility changes that have occurred during the current permit time frame ( 2006 through 2011), as well as proposed facility and permit changes for the renewal permit time frame (2011 through 2016).

## 1.2 Facility Information

The Hawaii Refinery is operated by Chevron U.S.A. Products Company. The responsible official is the Refinery Manager. The contact for questions regarding this application is the Air Environmental Specialist, who may be reached at (808) 682-5711.

The refinery is located within the Campbell Industrial Park at Kapolei, Ewa, Oahu, Hawaii, as shown on Figure 1-1. The refinery property consists of 248 acres situated at 21°18'40" North latitude and 158°06'57" West longitude.



**SITE VICINITY MAP  
CHEVRONTEXACO HAWAII TITLE V RENEWAL**

DATE:

FIG. NO:

1-1

The refinery address is:

Chevron U.S.A. Products Company, Hawaii Refinery  
91-480 Malakole Street  
Kapolei, HI 96707

The zoning of the refinery property is I-2, Heavy Industrial.

## 1.3 Overview

This application package has been designed to respond to the requirements of the DOH operating permit program regulations, including the requirements of §11.60-101, Covered Source Renewal. This section (Section 1) contains introductory and applicant information, as well as a completed DOH application form. Section 2 presents background information and a technical description of the refinery and its processes and operations. The estimated maximum potential emissions of regulated pollutants from refinery processes are presented in Section 3, along with a list of insignificant activities, as required in the DOH rules. This section also contains requests to continue the current exemptions for selected small sources in accordance with §11-60.1-82(e) through (g).

Section 4 presents information showing that the dispersion modeling analysis presented in the original Title V permit application (and updated modeling that has been done in association with subsequent facility modifications) remains adequate to represent the refinery's maximum impacts to local air quality. Section 5 is an assessment of regulatory requirements applicable to refinery operations and the associated monitoring and reporting activities.

## 1.4 Application Forms

The Standard Permit Application Form, S-1 is included at the end of this section. The form has been completed and a directory indicating the locations within this application of specific items requested on Page 3 of the form is provided below. Responses to the substantive information requirements of Form S-3 are also provided below.

### 1.4.1 Form S-1

The following information is provided in response to the information requested on DOH Form S-1, page 3 of 4. The items listed below are numbered according to the section designations used on Form S-1.

#### A. Emission Units Table

1. Section 2 and 3 describes the types and locations of emissions.
  - 1.1. Unique numbers for plant sites and equipment unit identification are in Table 2.1. These plant area site numbers match the unit description used on the location map in Figure 2.1.
  - 1.2. Emission point identification is provided by equipment numbers in Figures 2.3 through 2.13. These Figures are consistent with the unique numbers for plant sites provided in Table 2.1.
  - 1.3. SIC number is in Section 2.1.

- 1.4. Emission points are identified and described in Sections 2.3.1 through 2.3.15
- 1.5. Emission points regulated and hazardous air pollutant data are provided in Section 3, Tables 3.1 through 3.13.
- 1.6. Equipment Date is provided as an attachment to the S-1 Forms below.
2. Emission rates are provided in Section 3
  - 2.1. Maximum facility emissions of regulated air pollutants are shown in Tables 3-12 and 3-13.
  - 2.2. Maximum pollutant emissions from the refinery processes are quantified in Section 3 of this application and summarized in Tables 3.1 through 3.11. Detailed emission calculations are presented in Appendix B.
  - 2.3. Fugitive emissions are quantified in Section 3, Tables 3.10 and 3.11. Detailed emission calculations are presented in Appendix B.
  - 2.4. Maximum potential emission rates expected are provided in pounds per hour or tons per year in Tables 3.1 through 3.13 with detailed emission calculations in Appendix B.
3. Stack parameter information has been included as an attachment to the S-1 Forms below.
4. Additional information
  - 4.1. Equipment units capable of using different fuels are listed in different rows in the attachment to the S-1 Forms below.
  - 4.2. All stacks provide a diameter as no rectangular stacks are currently on site.
  - 4.3. No stack parameters or height limitations were developed because of CAA Section 123. Stacks were all in existence prior to December 31, 1970.
- B. A process flow diagram of the Hawaii Refinery is shown in Figure 2-2 by plant site area number.
  - B.1 Emission points are identified and described in the Form S-1 section 1.1 and 1.2. Process Flow diagrams in detail by plant site area are provided in Figures 2.3 through 2.13. Equipment unit numbers are included where applicable.
  - B.2 Emission Points where air pollutants are released to the atmosphere are also included in Figures 2.3 through 2.13. Combustion release points, controlled vents and exhaust gas release points are labeled where applicable.
- C. The general facility location is shown in Figure 1.1.
  - C.1 The property involved, structures, property lines and fence lines are provided in Figure 2.1.
  - C.2 The layout of the facility is provided in Figure 2.1.
  - C.3 The approximate location of each emission unit is labeled by plant site area.
  - C.4 Location of the property is defined in Figure 1.1 providing major roads and key featured landmarks adjacent to the property. Location of equipment and adjacent streets are provided in Figure 2.1 by plant site areas.
- D. Facility changes and modifications are provided in Section 5.3.2.

### 1.4.2 Form S-3

The following information is provided in response to the information requested on DOH Form S-3. The items listed below are numbered according to the section designations used on Form S-3.

- I.A This application describes facility changes that have occurred since submittal of the 2003 Covered Source Permit renewal application and the associated applicable requirements.
- I.B Equipment specifications, including applicable maximum design capacity, fuel type, fuel use, production capacity, production rates, and raw materials, are presented in Sections 2.2 through 2.8 and Appendix B.
- I.C A description of all facility processes and products defined by Standard Industrial Code is provided in Section 2.3. No anticipated alternative operating scenarios are proposed. Pollution control equipment used in the refinery is described in Section 3.3. List of insignificant activities is provided in 3.5.
- I.D The operating schedule for the refinery is described in Section 2.7.
- I.E Applicable air quality regulatory requirements, as defined in §11-60.1-81, and the associated compliance monitoring and reporting requirements are presented in Section 5.
- I.F The basis for estimating maximum facility emissions is provided in Section 3, including equipment and/or operating limitations that affect maximum emissions.
- I.G As described in Section 4, air quality assessments of the refinery's impacts on local air quality have been conducted for the initial Covered Source Permit application and in connection with subsequent applications for modifications to refinery facilities. These previous assessments are adequate to demonstrate that the refinery does not cause applicable ambient air quality standards to be exceeded.
- I.H This application for permit renewal does not pertain to a new covered source or to a significant modification subject to the Prevention of Significant Deterioration provisions of Subchapter 7 of HAR Chapter 11-60.1, and is therefore not required to submit the analyses, assessments, monitoring and other applicable requirements of Subchapter 7.
- I.I Chevron does not propose to conduct any emissions trading among sources of the Hawaii Refinery.
- I.J A completed compliance plan, DOH Form C-1, and a compliance certification, Form C-2, are provided in Section 5 of this application.



**S-1: Standard Air Pollution Control Permit Application Form**  
(Covered Source Permit and Noncovered Source Permit)

State of Hawaii  
Department of Health  
Environmental Management Division  
Clean Air Branch  
P.O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: \_\_\_\_\_
2. Facility Name (if different from the Company): \_\_\_\_\_
3. Mailing Address: \_\_\_\_\_  
City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_  
Phone Number: \_\_\_\_\_
4. Name of Owner/Owner's Agent: \_\_\_\_\_  
Title: \_\_\_\_\_ Phone: \_\_\_\_\_  
Mailing Address: \_\_\_\_\_  
City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_
5. Plant Site Manager/Other Contact: \_\_\_\_\_  
Title: \_\_\_\_\_ Phone: \_\_\_\_\_  
Mailing Address: \_\_\_\_\_  
City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_
6. Permit Application Basis: (Check all applicable categories.)  
 Initial Permit for a New Source      Initial Permit for an Existing Source  
 Renewal of Existing Permit      General Permit  
 Temporary Source      Transfer of Permit  
 Modification to a Covered Source: ➔ Is Modification?     Significant     Minor     Uncertain  
 Modification to a Noncovered Source
7. If renewal or modification, include existing permit number: \_\_\_\_\_
8. Does the Proposed Source require a County Special Management Area Permit?     Yes      No
9. Type of Source (Check One):     Covered Source      Covered and PSD Source  
    Noncovered Source      Uncertain
10. Standard Industrial Classification Code (SICC), if known: \_\_\_\_\_

11. Proposed Equipment/Plant Location (e.g. street address): \_\_\_\_\_

City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_

UTM Coordinates (meters): East: \_\_\_\_\_ North: \_\_\_\_\_

UTM Zone: \_\_\_\_\_ UTM Horizontal Datum:  Old Hawaiian  NAD-27  NAD-83

12. General Nature of Business: \_\_\_\_\_

13. Date of Planned Commencement of Construction or Modification: \_\_\_\_\_

14. Is **any** of the equipment to be leased to another individual or entity?  Yes  No

15. Type of Organization:  Corporation  Individual Owner  Partnership

Government Agency (Government Facility Code: \_\_\_\_\_)

Other: \_\_\_\_\_

*Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR §11-60.1-64 & 11-60.1-84)*

**RESPONSIBLE OFFICIAL** (as defined in HAR §11-60.1-1)

Name (Last): \_\_\_\_\_ (First): \_\_\_\_\_ (MI): \_\_\_\_\_

Title: \_\_\_\_\_ Phone: \_\_\_\_\_

Mailing Address: \_\_\_\_\_

City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_

**Certification by Responsible Official** (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): \_\_\_\_\_

(Signature): \_\_\_\_\_ Date: \_\_\_\_\_

<b>FOR AGENCY USE ONLY:</b>
File/Application No.: _____
Island: _____
Date Received: _____

Submit the following documents as part of your application:

- A. The **Emissions Units Table**, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:
1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SICC number. Emission points shall be identified and described in sufficient detail to establish the basis for **fees** and applicability of requirement of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
    - a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
    - b. Indicate the emission points that discharge together for any length of time.
    - c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.
  2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
    - a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO<sub>x</sub>), Sulfur Dioxide (SO<sub>2</sub>), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM<sub>10</sub>). Abbreviations may be used.
    - b. Include fugitive emissions.
    - c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
    - d. **Tons per year** is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.
  3. Describe **Stack Source Parameters**:
    - a. **Stack Height** is the height above the ground.
    - b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
    - c. **Flow Rate** is the actual, not the calculated, flow rate.
  4. Provide any additional information, if applicable, as follows:
    - a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
    - b. For a rectangular stack, indicate the length and width.
    - c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.
- B. A **process flow diagram** identifying all equipment used in the process, including the following:
1. Identify and describe each emission point.
  2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.
- C. A **facility location map**, drawn to a reasonable scale and showing the following:
1. The property involved and all structures on it. Identify property/fence lines plainly.
  2. Layout of the facility.
  3. Location and identification of the proposed emissions unit on the property.
  4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 100 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.
- D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Company Name: \_\_\_\_\_

File No.: \_\_\_\_\_

Location: \_\_\_\_\_

(Make as many copies of this page as necessary)

Page 1 of 1

**EMISSIONS UNITS TABLE**

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: _____ Horizontal Datum <sup>a</sup> : _____		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/ Description & SICC number	Equipment Date	Regulated/ Hazardous Air Pollutant Name & CAS#	#/ HR	Tons/ YR	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h) <sup>b</sup>	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m <sup>3</sup> /s)	Temp. (° K)	Capped (Y/N)
		See Attached Spreadsheet					East								
								North							
							East								
							North								
							East								
							North								
							East								
							North								
							East								
							North								
							East								
							North								
							East								
							North								
							East								
							North								
							East								
							North								

<sup>a</sup> Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

<sup>b</sup> Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal

Form S-1  
Stack Information

Stack or Fugitive Point ID	Emission Release Emission Unit ID	Process ID No. (Fuel/Product/Material ID No.)	Emission Unit Description that is being exhausted (78 characters max.)	Equipment Date	Emission Release Code	If single process exhausts to multiple stacks, list % routed to each stack	UTM Easting (m) Horizontal-X	UTM Northing (m) Vertical-Y	Zone (4 or 5)	Datum (Old Hwn, NAD-27, or NAD-83)	Stack Ht (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (deg. F)	Stack Flow Rate (ACFS)	Horizontal Collection Method	Reference Point Code	Horizontal Accuracy Measure(m)
7	F5103	1	01 crude furnace	1961	02		592,053	2,356,683	4	NAD 83	141	4.9	40.8	350	777	027	106	500
7	F5103	2	01 crude furnace	1961	02		592,053	2,356,683	4	NAD 83	141	4.9	40.8	350	777	027	106	500
7	F5153	1	02 crude furnace	1961	02		592,053	2,356,683	4	NAD 83	141	4.9	40.8	350	777	027	106	500
7	F5153	2	02 crude furnace	1961	02		592,053	2,356,683	4	NAD 83	141	4.9	40.8	350	777	027	106	500
1	F5201	1	01 boiler	1961	02		591,888	2,356,981	4	NAD 83	125	9.2	19.7	500	1305	027	106	500
1	F5201	2	01 boiler	1961	02		591,888	2,356,981	4	NAD 83	125	9.2	19.7	500	1305	027	106	500
1	F5201	21	01 boiler	1961	02		591,888	2,356,981	4	NAD 83	125	9.2	19.7	500	1305	027	106	500
2	F5202	1	02 boiler	1961	02		591,884	2,356,989	4	NAD 83	125	5.6	36.1	370	882	027	106	500
2	F5202	2	02 boiler	1961	02		591,884	2,356,989	4	NAD 83	125	5.6	36.1	370	882	027	106	500
2	F5202	21	02 boiler	1961	02		591,884	2,356,989	4	NAD 83	125	5.6	36.1	370	882	027	106	500
3	F5203	1	03 boiler	1961	02		591,880	2,356,997	4	NAD 83	125	5.6	36.1	370	882	027	106	500
3	F5203	2	03 boiler	1961	02		591,880	2,356,997	4	NAD 83	125	5.6	36.1	370	882	027	106	500
3	F5203	21	03 boiler	1961	02		591,880	2,356,997	4	NAD 83	125	5.6	36.1	370	882	027	106	500
8	F5300	2	FCC Furnace	1961-62	02		591,896	2,356,928	4	NAD 83	140	5.6	22.3	712	545	027	106	500
9	F5930	2	Isom Furnace 01	1961-62	02		591,979	2,356,793	4	NAD 83	80	3.0	2.3	800	16	027	106	500
9	F5950	2	Isom Furnace 02	1961-62	02		591,979	2,356,793	4	NAD 83	80	3.0	2.3	800	16	027	106	500
10	F5700	2	H2 Manufac.	1960-62	02		592,058	2,356,642	4	NAD 83	125	5.9	6.2	500	171	027	106	500
11	F5600	2	Hydrogenation	1961-62	02		592,046	2,356,626	4	NAD 83	125	4.9	6.6	1510	125	027	106	500
12	F6200	2	Acid Plant CC	1961-62	02		591,907	2,356,434	4	NAD 83	123	3.0	9.7	175	68	027	106	500
13	F6262	2	Acid Pt Furnace		02		591,880	2,356,433	4	NAD 83	64	2.0	15.1	628	46	027	106	500
14	F6003	2	Asphalt Furnace		02		592,405	2,356,492	4	NAD 83	30	1.0	43.3	275	33	027	106	500
4	KC6701	2	01 cogen, combined cycle		02		591,824	2,357,038	4	NAD 83	70	3.9	68.6	399	835	027	106	500
4	KC6701	3	01 cogen, combined cycle		02		591,824	2,357,038	4	NAD 83	70	3.9	68.6	399	835	027	106	500
4	KS6701	2	01 cogen, simple cycle		02		591,824	2,357,038	4	NAD 83	70	3.9				027	106	500
4	KS6701	3	01 cogen, simple cycle		02		591,824	2,357,038	4	NAD 83	70	3.9				027	106	500
5	KC6702	2	02 cogen, combined cycle		02		591,819	2,357,047	4	NAD 83	70	3.9	68.6	399	835	027	106	500
5	KC6702	3	02 cogen, combined cycle		02		591,819	2,357,047	4	NAD 83	70	3.9	68.6	399	835	027	106	500
5	KS6702	2	02 cogen, simple cycle		02		591,819	2,357,047	4	NAD 83	70	3.9				027	106	500
5	KS6702	3	02 cogen, simple cycle		02		591,819	2,357,047	4	NAD 83	70	3.9				027	106	500
6	KC6703	2	03 cogen, combined cycle		02		591,814	2,357,057	4	NAD 83	70	3.9	68.6	399	835	027	106	500
6	KC6703	3	03 cogen, combined cycle		02		591,814	2,357,057	4	NAD 83	70	3.9	68.6	399	835	027	106	500
6	KS6703	2	03 cogen, simple cycle		02		591,814	2,357,057	4	NAD 83	70	3.9				027	106	500
6	KS6703	3	03 cogen, simple cycle		02		591,814	2,357,057	4	NAD 83	70	3.9				027	106	500
25	TkS104	11	Tk 104 External Floating Roof, Standing Loss		01		592,574	2,356,694	4	NAD 83	56	138				027	106	500
25	TkW104	11	Tk 104 External Floating Roof, Withdrawal Loss		01		592,574	2,356,694	4	NAD 83	56	138				027	106	500
26	TkS105	11	Tk 105 External Floating Roof, Standing Loss		01		592,675	2,356,692	4	NAD 83	61	176				027	106	500
26	TkW105	11	Tk 105 External Floating Roof, Withdrawal Loss		01		592,675	2,356,692	4	NAD 83	61	176				027	106	500
27	TkS106	11	Tk 106 External Floating Roof, Standing Loss		01		592,678	2,356,586	4	NAD 83	61	176				027	106	500
27	TkW106	11	Tk 106 External Floating Roof, Withdrawal Loss		01		592,678	2,356,586	4	NAD 83	61	176				027	106	500
28	TkS107	11	Tk 107 External Floating Roof, Standing Loss		01		592,782	2,356,695	4	NAD 83	55	176				027	106	500
28	TkW107	11	Tk 107 External Floating Roof, Withdrawal Loss		01		592,782	2,356,695	4	NAD 83	55	176				027	106	500
29	TkS108	11	Tk 108 External Floating Roof, Standing Loss		01		592,785	2,356,588	4	NAD 83	54	176				027	106	500

Form S-1  
Stack Information

Stack or Fugitive Emission Point ID	Emission Unit ID	Process ID No. (Fuel/Product/Material ID No.)	Emission Unit Description that is being exhausted (78 characters max.)	Equipment Date	Emission Release Code	If single process exhausts to multiple stacks, list % routed to each stack	UTM Easting (m) Horizontal-X	UTM Northing (m) Vertical-Y	Zone (4 or 5)	Datum (Old Hwn, NAD-27, or NAD-83)	Stack Ht (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (deg. F)	Stack Flow Rate (ACFS)	Horizontal Collection Method	Reference Point Code	Horizontal Accuracy Measure(m)
29	TkW108	11	Tk 108 External Floating Roof, Withdrawal Loss		01		592,785	2,356,588	4	NAD 83	54	176				027	106	500
30	TkS109	14	Tk 109 External Floating Roof, Standing Loss		01		592,577	2,356,582	4	NAD 83	61	176				027	106	500
30	TkW109	14	Tk 109 External Floating Roof, Withdrawal Loss		01		592,577	2,356,582	4	NAD 83	61	176				027	106	500
31	TkS110	11	Tk 110 External Floating Roof, Standing Loss		01		592,792	2,356,508	4	NAD 83	61	189				027	106	500
31	TkW110	11	Tk 110 External Floating Roof, Withdrawal Loss		01		592,792	2,356,508	4	NAD 83	61	189				027	106	500
32	TkS111	3	Tk 111 External Floating Roof, Standing Loss		01		592,793	2,356,427	4	NAD 83	61	189				027	106	500
32	TkW111	3	Tk 111 External Floating Roof, Withdrawal Loss		01		592,793	2,356,427	4	NAD 83	61	189				027	106	500
65	TkS113	11	Tk 113 External Floating Roof, Standing Loss		01		592,506	2,356,641	4	NAD 83	46	60				027	106	500
65	TkW113	11	Tk 113 External Floating Roof, Withdrawal Loss		01		592,506	2,356,641	4	NAD 83	46	60				027	106	500
33	TkS152	11	Tk 152 Vertical Fixed Roof, Breathing Loss		01		592,326	2,356,651	4	NAD 83	48	110				027	106	500
33	TkW152	11	Tk 152 Vertical Fixed Roof, Working Loss		01		592,326	2,356,651	4	NAD 83	48	110				027	106	500
35	TkS162	13	Tk 162 External Floating Roof, Standing Loss		01		592,185	2,356,658	4	NAD 83	29	34				027	106	500
35	TkW162	13	Tk 162 External Floating Roof, Withdrawal Loss		01		592,185	2,356,658	4	NAD 83	29	34				027	106	500
36	TkS163	13	Tk 163 External Floating Roof, Standing Loss		01		592,185	2,356,641	4	NAD 83	29	34				027	106	500
36	TkW163	13	Tk 163 External Floating Roof, Withdrawal Loss		01		592,185	2,356,641	4	NAD 83	29	34				027	106	500
37	TkS232	19	Tk 232 External Floating Roof, Standing Loss		01		592,360	2,356,884	4	NAD 83	45	55				027	106	500
37	TkW232	19	Tk 232 External Floating Roof, Withdrawal Loss		01		592,360	2,356,884	4	NAD 83	45	55				027	106	500
38	TkS233	19	Tk 233 External Floating Roof, Standing Loss		01		592,360	2,356,839	4	NAD 83	45	55				027	106	500
38	TkW233	19	Tk 233 External Floating Roof, Withdrawal Loss		01		592,360	2,356,839	4	NAD 83	45	55				027	106	500
39	TkS235	10	Tk 235 External Floating Roof, Standing Loss		01		592,316	2,356,838	4	NAD 83	45	55				027	106	500
39	TkW235	10	Tk 235 External Floating Roof, Withdrawal Loss		01		592,316	2,356,838	4	NAD 83	45	55				027	106	500
40	TkS236	14	Tk 236 External Floating Roof, Standing Loss		01		592,199	2,356,958	4	NAD 83	46	77				027	106	500
40	TkW236	14	Tk 236 External Floating Roof, Withdrawal Loss		01		592,199	2,356,958	4	NAD 83	46	77				027	106	500
41	TkS237	14	Tk 237 External Floating Roof, Standing Loss		01		592,244	2,356,960	4	NAD 83	46	77				027	106	500
41	TkW237	14	Tk 237 External Floating Roof, Withdrawal Loss		01		592,244	2,356,960	4	NAD 83	46	77				027	106	500
42	TkS249	10	Tk 249 Domed Ext. Floating Roof, Standing Loss		01		592,358	2,356,959	4	NAD 83	37	43				027	106	500
42	TkW249	10	Tk 249 Domed Ext. Floating Roof, Withdrawal Loss		01		592,358	2,356,959	4	NAD 83	37	43				027	106	500
43	TkS250	10	Tk 250 Domed External Floating Roof, Standing Loss		01		592,407	2,356,962	4	NAD 83	32	34				027	106	500
43	TkW250	10	Tk 250 Domed External Floating Roof, Withdrawal Loss		01		592,407	2,356,962	4	NAD 83	32	34				027	106	500
45	TkS252	15	Tk 252 External Floating Roof, Standing Loss		01		592,201	2,356,874	4	NAD 83	51	72				027	106	500
45	TkW252	15	Tk 252 External Floating Roof, Withdrawal Loss		01		592,201	2,356,874	4	NAD 83	51	72				027	106	500
46	TkS253	15	Tk 253 External Floating Roof, Standing Loss		01		592,247	2,356,875	4	NAD 83	52	72				027	106	500
46	TkW253	15	Tk 253 External Floating Roof, Withdrawal Loss		01		592,247	2,356,875	4	NAD 83	52	72				027	106	500
47	TkS254	14	Tk 254 External Floating Roof, Standing Loss		01		592,316	2,356,883	4	NAD 83	46	72				027	106	500
47	TkW254	14	Tk 254 External Floating Roof, Withdrawal Loss		01		592,316	2,356,883	4	NAD 83	46	72				027	106	500
48	TkS255	14	Tk 255 External Floating Roof, Standing Loss		01		592,201	2,356,917	4	NAD 83	46	77				027	106	500
48	TkW255	14	Tk 255 External Floating Roof, Withdrawal Loss		01		592,201	2,356,917	4	NAD 83	46	77				027	106	500
49	TkS256	14	Tk 256 External Floating Roof, Standing Loss		01		592,245	2,356,917	4	NAD 83	46	77				027	106	500
49	TkW256	14	Tk 256 External Floating Roof, Withdrawal Loss		01		592,245	2,356,917	4	NAD 83	46	77				027	106	500
50	TkS257	16	Tk 257 External Floating Roof, Standing Loss		01		592,157	2,356,958	4	NAD 83	46	67				027	106	500
50	TkW257	16	Tk 257 External Floating Roof, Withdrawal Loss		01		592,157	2,356,958	4	NAD 83	46	67				027	106	500
51	TkS258	17	Tk 258 External Floating Roof, Standing Loss		01		592,158	2,356,922	4	NAD 83	46	67				027	106	500
51	TkW258	17	Tk 258 External Floating Roof, Withdrawal Loss		01		592,158	2,356,922	4	NAD 83	46	67				027	106	500



Form S-1  
Stack Information

Stack or Fugitive Emission Point ID	Emission Unit ID	Process ID No. (Fuel/Product/Material ID No.)	Emission Unit Description that is being exhausted (78 characters max.)	Equipment Date	Emission Release Code	If single process exhausts to multiple stacks, list % routed to each stack	UTM Easting (m) Horizontal-X	UTM Northing (m) Vertical-Y	Zone (4 or 5)	Datum (Old Hwn, NAD-27, or NAD-83)	Stack Ht (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (deg. F)	Stack Flow Rate (ACFS)	Horizontal Collection Method	Reference Point Code	Horizontal Accuracy Measure(m)
52	TkS262	14	Tk 262 External Floating Roof, Standing Loss		01		592,159	2,356,886	4	NAD 83	46	67				027	106	500
52	TkW262	14	Tk 262 External Floating Roof, Withdrawal Loss		01		592,159	2,356,886	4	NAD 83	46	67				027	106	500
53	TkS263	20	Tk 263 External Floating Roof, Standing Loss		01		592,089	2,356,994	4	NAD 83	46	77				027	106	500
53	TkW263	20	Tk 263 External Floating Roof, Withdrawal Loss		01		592,089	2,356,994	4	NAD 83	46	77				027	106	500
54	TkS264	20	Tk 264 External Floating Roof, Standing Loss		01		592,091	2,356,956	4	NAD 83	49	77				027	106	500
54	TkW264	20	Tk 264 External Floating Roof, Withdrawal Loss		01		592,091	2,356,956	4	NAD 83	49	77				027	106	500
55	TkS265	20	Tk 265 External Floating Roof, Standing Loss		01		592,092	2,356,913	4	NAD 83	46	80				027	106	500
55	TkW265	20	Tk 265 External Floating Roof, Withdrawal Loss		01		592,092	2,356,913	4	NAD 83	46	80				027	106	500
56	TkS266	3	Tk 266 External Floating Roof, Standing Loss		01		592,093	2,356,872	4	NAD 83	46	80				027	106	500
56	TkW266	3	Tk 266 External Floating Roof, Withdrawal Loss		01		592,093	2,356,872	4	NAD 83	46	80				027	106	500
57	TkS267	20	Tk 267 External Floating Roof, Standing Loss		01		592,094	2,356,828	4	NAD 83	46	80				027	106	500
57	TkW267	20	Tk 267 External Floating Roof, Withdrawal Loss		01		592,094	2,356,828	4	NAD 83	46	80				027	106	500
58	TkS269	3	Tk 269 External Floating Roof, Standing Loss		01		592,050	2,356,913	4	NAD 83	46	60				027	106	500
58	TkW269	3	Tk 269 External Floating Roof, Withdrawal Loss		01		592,050	2,356,913	4	NAD 83	46	60				027	106	500
59	TkS271	20	Tk 271 External Floating Roof, Standing Loss		01		592,052	2,356,828	4	NAD 83	43	77				027	106	500
59	TkW271	20	Tk 271 External Floating Roof, Withdrawal Loss		01		592,052	2,356,828	4	NAD 83	43	77				027	106	500
66	TkS272	18	Tk 272 Vertical Fixed Roof, Breathing Loss		01		592,011	2,356,909	4	NAD 83	48	77				027	106	500
66	TkW272	18	Tk 272 Vertical Fixed Roof, Working Loss		01		592,011	2,356,909	4	NAD 83	48	77				027	106	500
60	TkS273	12	Tk 273 External Floating Roof, Standing Loss		01		592,159	2,356,852	4	NAD 83	45	55				027	106	500
60	TkW273	12	Tk 273 External Floating Roof, Withdrawal Loss		01		592,159	2,356,852	4	NAD 83	45	55				027	106	500
61	TkS274	18	Tk 274 Vertical Fixed Roof, Breathing Loss		01		591,989	2,356,957	4	NAD 83	48	87				027	106	500
61	TkW274	18	Tk 274 Vertical Fixed Roof, Working Loss		01		591,989	2,356,957	4	NAD 83	48	87				027	106	500
62	TkS275	3	Tk 275 External Floating Roof, Standing Loss		01		592,019	2,356,941	4	NAD 83	31	34				027	106	500
62	TkW275	3	Tk 275 External Floating Roof, Withdrawal Loss		01		592,019	2,356,941	4	NAD 83	31	34				027	106	500
63	TkS301	13	Tk 301 External Floating Roof, Standing Loss		01		591,965	2,356,392	4	NAD 83	38	42				027	106	500
63	TkW301	13	Tk 301 External Floating Roof, Withdrawal Loss		01		591,965	2,356,392	4	NAD 83	38	42				027	106	500
64	TkS302	13	Tk 302 External Floating Roof, Standing Loss		01		591,973	2,356,376	4	NAD 83	38	42				027	106	500
64	TkW302	13	Tk 302 External Floating Roof, Withdrawal Loss		01		591,973	2,356,376	4	NAD 83	38	42				027	106	500
15	M1	4	FCC precip	1961-62	02		591,894	2,356,970	4	NAD 83	125	4.9	107.0	550	2034	027	106	500
15	M1	22	FCC precip		02		591,894	2,356,970	4	NAD 83	125	4.9	107.0	550	2034	027	106	500
16	M2	5	Cooling Tower	1961-62	01		592,095	2,356,455	4	NAD 83	60	26.2	26.2	113	14201	027	106	500
17	M3	6	Acid Plant Absorber Stack	1961-62	02		591,907	2,356,434	4	NAD 83	123	3.0	9.7	175	68	027	106	500
18	M4	7	Catalyst Transfer		02		591,928	2,356,901	4	NAD 83						027	106	500
19	M5	8	Wastewater Treatment		01		591,675	2,357,127	4	NAD 83						027	106	500
19	M5	22	Wastewater Treatment		01		591,675	2,357,127	4	NAD 83						027	106	500
20	M6	9	Process Fugitives		01		591,675	2,357,127	4	NAD 83						027	106	500
21	M7	10	Load Rack		01		592,336	2,357,016	4	NAD 83						027	106	500
22	M8	9	FCC Flare	1961-62	02		592,141	2,356,378	4	NAD 83	157	0.6	65.6	1832	42.0	027	106	500
23	M9	9	Crude Flare	1961-62	02		592,207	2,356,412	4	NAD 83	155	0.2	65.6	1832	12.7	027	106	500
23	M9	22	Crude Flare	1961-62	02		592,207	2,356,412	4	NAD 83	155	0.2	65.6	1832	12.7	027	106	500

## 2. Facility Description

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This section presents information describing operations at the Hawaii Refinery, as required by HAR §11-60.1-83(a)(2). The refinery receives various crude oils delivered by marine tankers and produces a wide variety of products. Operations vary depending on the material being processed and the products being manufactured. Information on these operations, equipment, and fuels, and other project description details are provided below.

The initial Covered Source Permit application package for the Hawaii Refinery was submitted to DOH in 1994 and included then current process descriptions and identified specific equipment and/or process changes that were anticipated at that time. The updated process descriptions provided in Sections 2.4.1 through 2.4.15 for individual refinery units include information on the current status of the changes that were anticipated in 1994. Additionally, several modification projects may be implemented during the renewal period from 2010 through 2016, and these are summarized in the appropriate process descriptions as well. Many of these prospective changes are intended to optimize existing operations, and are not considered “modifications” pursuant to State or Federal requirements. The Hybrid Project is the only proposed significant modification and is addressed in Section 3.5.3. Applicable regulatory requirements that would be triggered by these proposed changes are discussed in Section 5.

### 2.1 Nature and Location of Facility

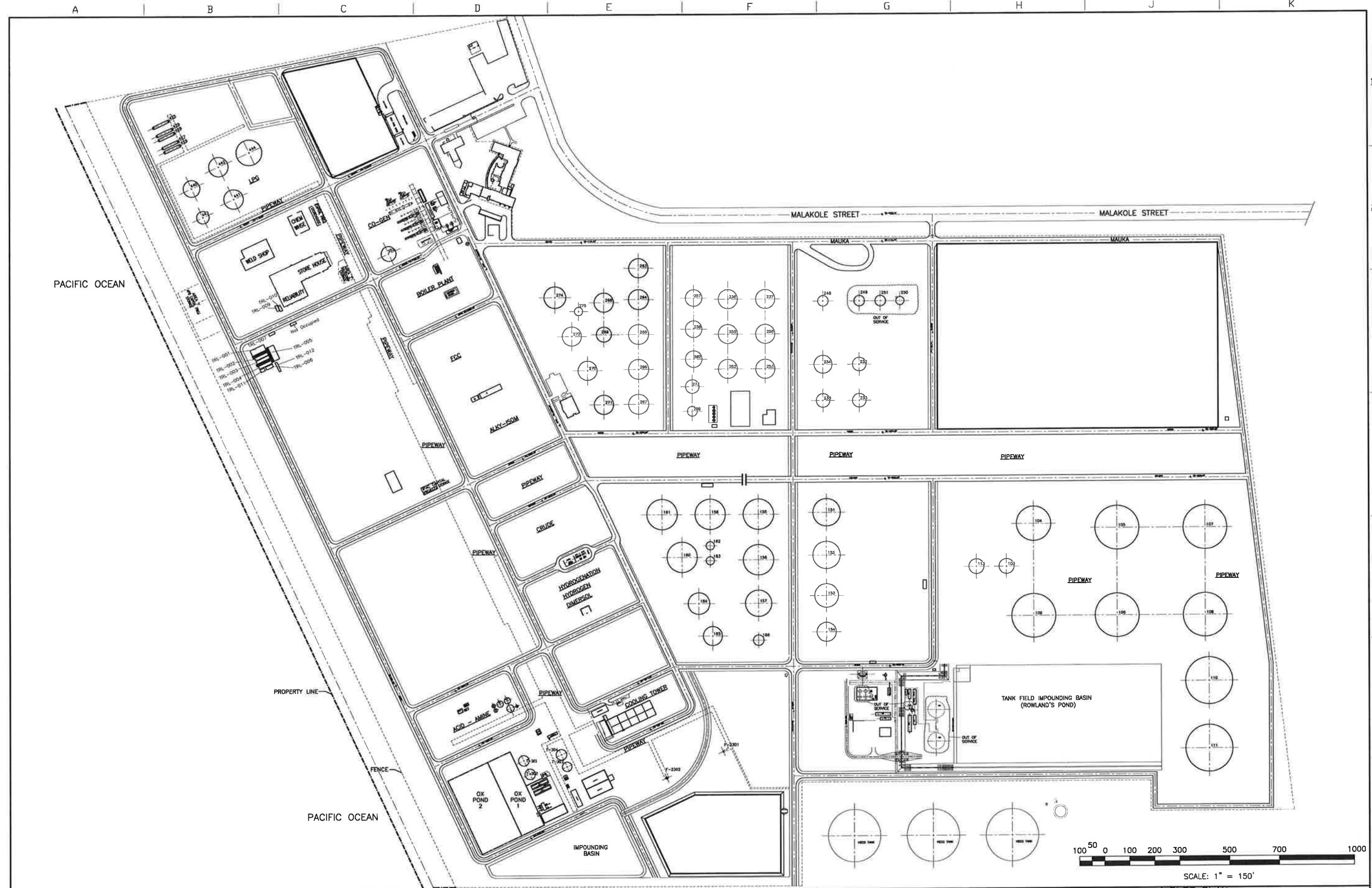
The Hawaii Refinery is an integrated petroleum refinery on the island of Oahu, Hawaii. Please refer to Section 1 for a description of the facility location. The Standard Industrial Classification Code (SICC) for the refinery is 2911. The North American Industrial Classification System (NAICS) Code is 324110. A facility plot plan is presented as Figure 2-1.

### 2.2 Overview of Petroleum Refining

Crude oils are complex mixtures of chemical compounds ranging from dissolved gases to compounds that are solids at room temperature. Almost all of these compounds, however, are composed of hydrogen and carbon (hydrocarbon compounds). Also included in crude oil are water and trace contaminants such as inorganic salts, metals, and sulphur compounds.

The steps by which crude oil is processed into numerous saleable products are known collectively as refining. Crude oils from various locations may have differing compounds and properties that affect specific refinery operations. The initial refining process separates crude oil into different fractions based on their respective boiling point ranges. Some of the lighter and intermediate fractions are blended into products. Heavier fractions may be further processed by cracking the large hydrocarbon molecules into smaller ones. The structures of some molecules may also be rearranged to provide the desired components.





REFERENCE DRAWINGS

NOTES

REVISIONS

SCALE	DATE	DR APPR	ENGR	APPROVE
SCALE 1" = 150'	DATE 28 APRIL 98 V.J.S. CK			



PLOT PLAN	HAWAII REFINERY
A	10-HA-1C

The basic steps used in refining crude oil feedstock at the Hawaii Refinery are as follows. First, crude oil is separated into several components using distillation methods. Heavier hydrocarbon compounds are further processed by cracking and subsequent combining or rearranging. Undesirable compounds containing sulfur, such as hydrogen sulfide or mercaptans, are removed or transformed to useful compounds. The various hydrocarbon components are blended together according to product specifications. For example, motor gasoline may include straight-run naphtha, cracked gasoline, reformate, alkylate and other components. Refinery operations also include auxiliary systems, such as hydrogen production, wastewater treating, acid production, and steam production.

## 2.3 Refinery Process Descriptions and Relationship to Marine Mooring Facility

The Hawaii Refinery is considered a major stationary source, and therefore is subject to the Title V permit program. A general process flow diagram for the refinery is presented in Figure 2-2. Marine tankers deliver crude oil from various locations to the Hawaii Refinery for processing. Marine vessel operations are exempted from the permitting requirements of the Hawaii program by HAR §11-60.1-82(d)(3). The marine mooring facility that services the refinery is approximately 1½ miles offshore and is not contiguous to the refinery. Accordingly, that facility operates under a separate Covered Source Permit, No. 0098-01-C. Chevron has submitted and received a separate permit renewal from DOH for the marine mooring facility.

### 2.3.1 Crude Unit

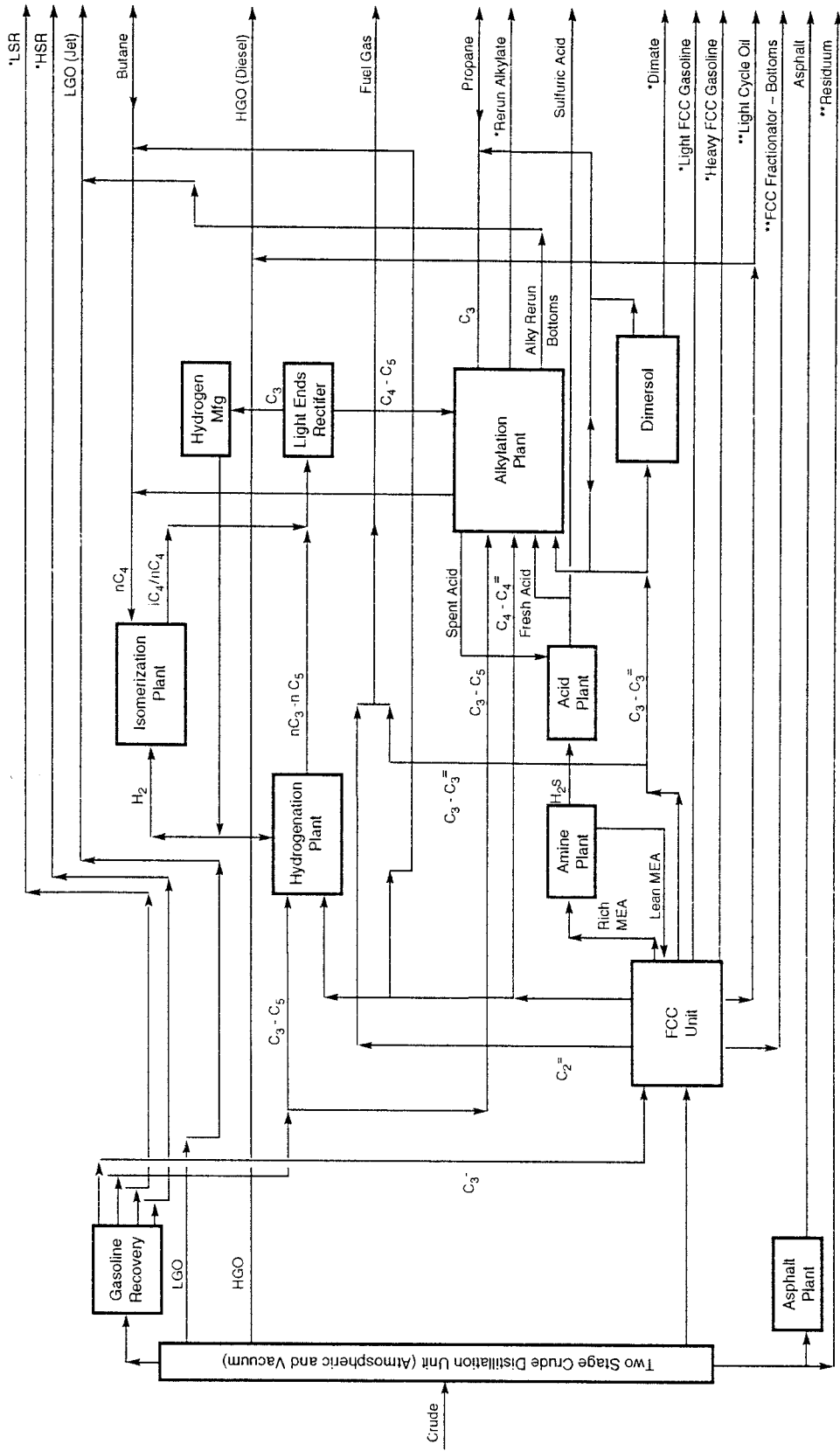
#### 2.3.1.1 Current Process

Crude oil processed at the refinery is transferred from tankers via pipeline to the blending and shipping area of the refinery, where it is placed in storage tanks. The crude oil is then pumped to the crude unit, where the refining process begins.

A simplified flow diagram of the crude distillation unit is presented as Figure 2-3. The crude feed enters the crude unit and is routed to the primary feed pump. This pump boosts the pressure of the feed to enable it to flow through the various heat exchangers and the desalter. The primary feed exchangers increase the temperature of the crude feed from approximately 100°F to about 300°F.

Crude oil frequently contains brine and inorganic salts from underground deposits. To minimize the fouling and corrosion of refining equipment, the crude is run through a desalter. The desalter reduces the velocity of the crude oil flow and, with the aid of electrical grids, separates additional water from the crude. Because most of the solids present are soluble in water, they leave the desalter with the water phase.

The crude oil out of the desalter is routed through a preheat exchanger to a flash drum to vaporize the light hydrocarbons and route them directly to the atmospheric column (bypassing the atmospheric furnace). The crude oil from the bottom of the flash drum is routed to the suction side of the crude booster pump, which pumps the oil through the secondary preheat train exchangers. The oil exiting the preheat exchangers is pumped through the atmospheric furnace into the atmospheric column, at a temperature of about 680°F.

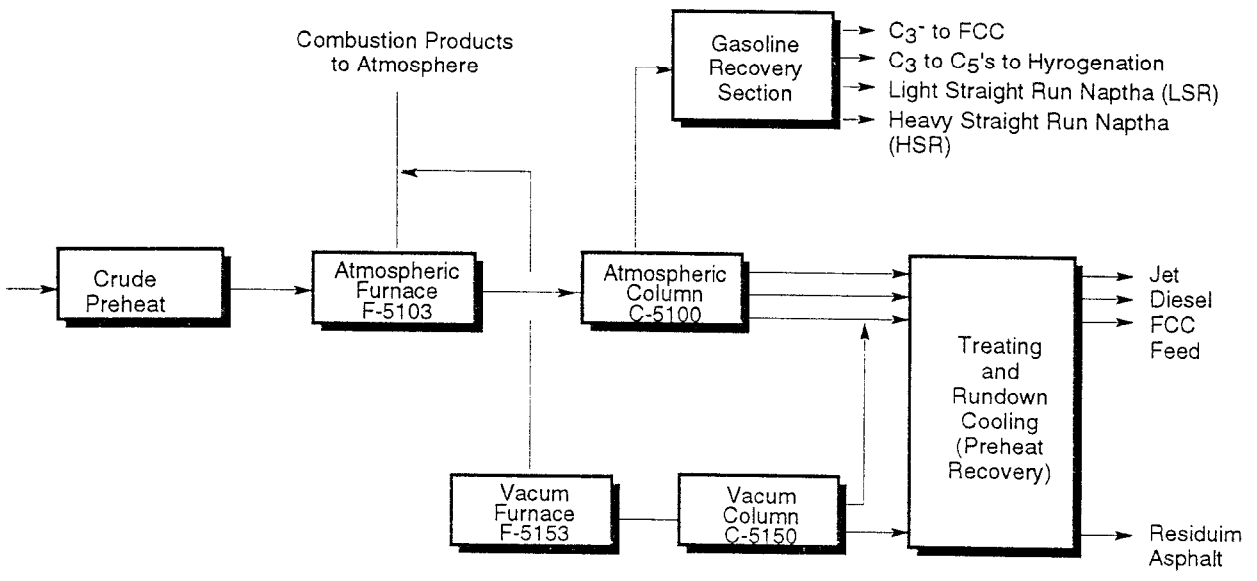


\* GASOLINE BLEND STOCKS  
 \*\* FUEL OIL BLEND STOCKS

HAWAII REFINERY GENERAL PROCESS FLOW  
 CHEVRONTExACO HAWAII TITLE V RENEWAL

DATE:

FIG. NO:  
 2-2



CRUDE UNIT SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE:

FIG. NO:

2-3

In the atmospheric column, the hot crude oil vaporizes and several product streams are drawn off, as follows:

- *Atmospheric overhead* – All material lighter than jet, which includes whole straight run naphtha and light ends such as methane, ethane, propane and butane
- *First side cut* – Normally commercial jet fuels (Jet A-40, Jet A-50, Jet JP-8)
- *Second side cut* – Not normally produced
- *Third side cut* – Low Sulfur Diesel fuel *Fourth side cut* – Atmospheric gas oil, which is fluid catalytic cracker (FCC) feed
- *Bottoms* – Feed to the vacuum column

The atmospheric tower bottoms product is routed through the vacuum furnace, where it is heated to approximately 790°F. Because products at lower pressure boil at lower temperatures, the vacuum column operates under vacuum to promote distillation of the heavy bottoms product without cracking of molecules. Two side product streams are both vacuum gas oil (VGO), which is used as a feed to the fluid catalytic cracker (FCC) unit. Residual product (residuum) is routed through exchangers to storage, where it is blended into fuel oil or a road asphalt base. Residuum may also be used as a feedstream to the FCC. Air pollutant emissions from the crude unit occur in the form of fugitive releases from piping components in gas and liquid service and as combustion products from the vacuum and atmospheric furnaces.

### 2.3.1.2 Future Process

Following is a description of potential crude unit alteration that may be implemented during the renewal period from 2011 through 2016. This change is primarily to optimize existing operations that may not require any modification to the current permit. The project consists of changing the fixed speed motors to variable speed motors for the forced draft fan and induced draft fan at the crude unit. This is an energy savings project that will optimize performance of the combustion process. The change would not increase the unit's operation beyond its original (permitted) capacity, although it could result in a slight increase in fuel combustion relative to operations in recent years.

## 2.3.2 Fluid Catalytic Cracker (FCC) Unit

### 2.3.2.1 Current Process

The purpose of the fluid catalytic cracker (FCC) unit is to convert material from the crude unit into gasoline blend components. Additionally, the FCC produces refinery fuel gas, propane and propylene, butane and butylene, light cycle oil and fractionator bottoms.

The conversion of the FCC feed to higher valued products is accomplished by “cracking” the heavier hydrocarbon molecules into lighter molecules by contacting the feed with an air-assisted circulating catalyst at relatively high temperature (980-1010°F). The process of cracking the molecules results in the formation of coke on the catalyst. This coke inhibits the cracking process, so it is burned off to restore catalyst activity. The heat of combustion of the coke is a major source of heat to maintain the needed reaction temperature. The flue gas

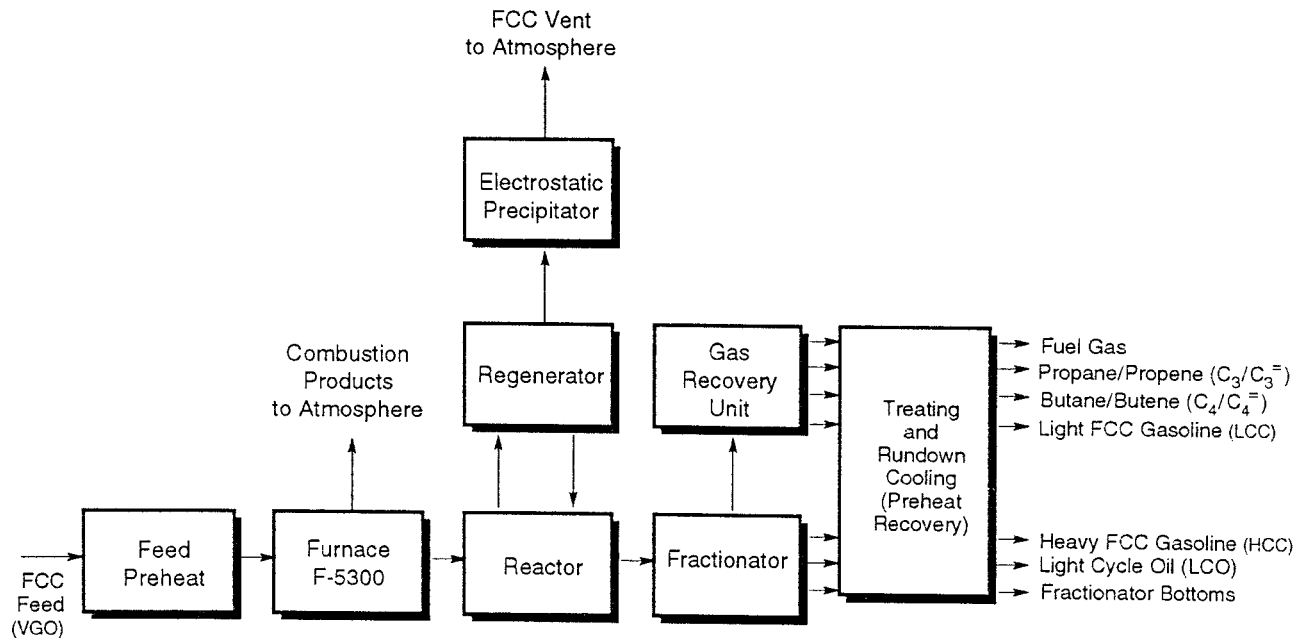
exiting the FCC is mixed with some particles of catalyst and routed through cyclones and an electrostatic precipitator to remove this particulate matter.

Products are routed to the fractionator and separated, as shown in Figure 2-4. The gas recovery unit separates gaseous products and includes removal of hydrogen sulfide. Products from the crude distillation towers and the FCC are treated by several other refinery process units, as discussed in the following subsections.

Since the initial covered source permit was issued, a low NO<sub>x</sub> burner has been installed on the FCC furnace that operates on RFG. This equipment change took place in 2008 and DOH was notified.

The refinery has been operating the FCC and regenerator with an electrostatic precipitator (ESP) since 1961. In 2002, the ESP was replaced, following application for and DOH approval of a minor modification to the existing Covered Source Permit. Emissions from the FCC and gas recovery unit consist of piping component fugitives, as well as PM<sub>10</sub> and combustion gases from the precipitator and FCC furnace.

In 2002, Chevron also applied for a permit modification to enable a FCC Revamp Project to modernize the technology of the FCC to current industry standards. The DOH issued a permit amendment to the Covered Source Permit for this project on March 3, 2003. The project included installation of a slide valve control to improve the ability of the operators to balance the operation of the catalyst reaction and regeneration vessels, as well as other upgrades. The project has resulted in improved reliability, ability to implement advanced controls, improved turndown capability/environmental performance, and better operational flexibility to process low sulfur feeds to meet the future low sulfur gasoline requirements.



FCC UNIT SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE:

FIG. NO:

2-4

The FCC Revamp Project application presented to DOH showed that the project would not cause an emission increase and therefore would not trigger any new federal New Source Performance Standards (NSPS) or the Prevention of Significant Deterioration (PSD) permitting process. The DOH processed the application as a major modification, because DOH added federally enforceable permit conditions to maintain emissions below PSD levels. Dispersion modeling was conducted that showed the project would have a negligibly small effect on local air quality. The project was completed in May 2003.

A Flare Vapor Recovery Compressor (FVR) has been added to the Miscellaneous Process Units and source operations. This equipment reduces the plant emissions from the FCCU although it is physically located in the Crude Unit area. PTE were not accounted for as fuel streams vary based on plant activity. As this equipment does not account for an increase in emissions it was not considered a significant modification.

Monitoring equipment for continuous measurement of opacity and CO emissions were installed and in operation to comply with MACT 'UUU' standards before April 2005. Additional CEMS and COMS were installed in 2005 and 2006 to monitor for NO<sub>x</sub>, SO<sub>2</sub> and O<sub>2</sub>.

### **2.3.2.2 Future Process**

A redesign of the air grid at the FCCU is currently being considered as a proposed change for 2013. The FCCU Regenerator currently has a "plate grid". The "plate grid" consists of a plate with holes in it, that allows air to come through to ensure fluidization and combustion in the bed. The "plate grid" is prone to mechanical stress and causes grid differential pressure problems which can lead to de-fluidization. Chevron is investigating a change in design to a "pipe grid" in which air flow through pipes and out nozzles. The new design of the pipe grid will ensure fluidization and allows improved turndown of feed rates.

## **2.3.3 Hydrogen Manufacturing Plant**

### **2.3.3.1 Current Process**

The purpose of the hydrogen plant is to convert butane, propane and the lighter hydrocarbons into hydrogen and carbon dioxide. The hydrogen is used in the hydrogenation, dimersol, and isomerization processes. The carbon dioxide generated in the unit is vented to the atmosphere. The hydrogen manufacturing process separates the hydrogen atoms from hydrocarbon molecules in a catalytic reforming furnace. The hydrogen unit emits fugitive emissions from piping components and combustion products from the furnace. A simplified flow diagram of the hydrogen plant is provided in Figure 2-5.

### **2.3.3.2 Future Process**

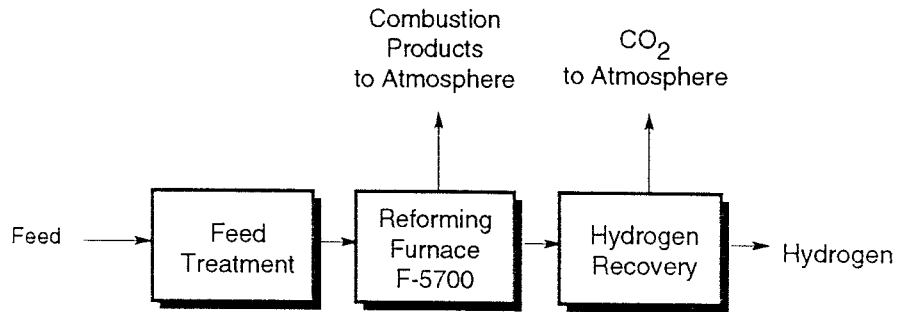
No changes have occurred in the Hydrogen Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.



## 2.3.4 Hydrogenation Plant

### 2.3.4.1 Current Process

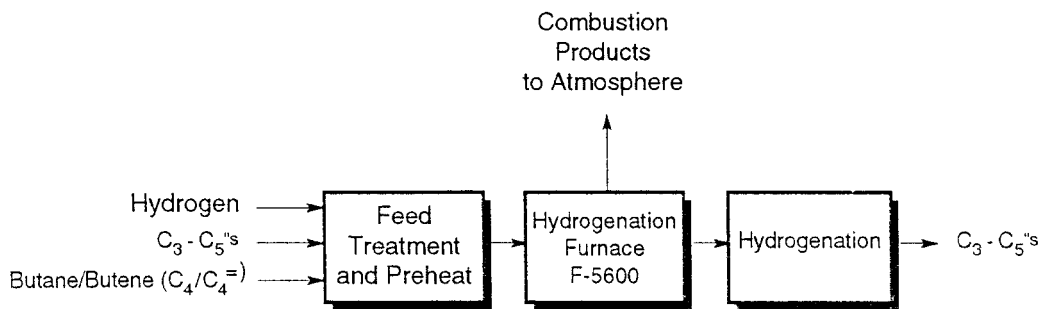
The hydrogenation plant saturates butene with hydrogen to form a saturated butane molecule. The butane is then fed to the isomerization process or used for gasoline blending. The hydrogenation process uses a fixed-bed reactor with a hydrogen rich atmosphere. The hydrogenation plant emits fugitive emissions from piping components and combustion emissions from the hydrogenation furnace. A simplified representation of the unit's process flow is shown in Figure 2-6.



HYDROGEN PLANT SIMPLIFIED  
PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE:

FIG. NO:  
2-5



HYDROGENATION PLANT SIMPLIFIED  
 PROCESS FLOW DIAGRAM  
 CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE:

FIG. NO:

2-6

### 2.3.4.2 Future Process

The Ultra Low Sulfur Diesel Project is being proposed at the refinery at this time. The project includes modifying the existing Hydrogenation Plant to allow it to process FCC Heavy Cat Crack, a gasoline blend component, and Crude Unit diesel in addition to the existing streams it processes today. The objectives of the modified plant will be the removal of sulfur and nitrogen from the feed streams. The project will require new pumps, vessels, piping, distillation columns and their associated equipment, and potentially a new reactor. No analysis of the proposed equipment changes has taken place at this time to understand the air quality impacts. The following proposed facility modification is described below for information purposes only. As further information on the project develops, the quantitative effects on emissions, if any, will be evaluated and applicable rules will be addressed on a case-by-case basis.

## 2.3.5 Dimersol Plant

### 2.3.5.1 Current Process

A Dimersol reactor and associated facilities were installed in 1987 as part of the gasoline manufacturing section to improve C3 handling within the refinery and to reduce flaring. The Dimersol plant converts propylene into dimate (hexene isomers), a gasoline blend component. The dimate is routed to a storage tank for blending. Propylene feed is supplied from the FCC unit and is converted in the Dimersol Reactor.

The Dimersol process is a closed-loop system that does not emit pollutants directly to the atmosphere. Fugitive piping component emissions, however, are released from the Dimersol Plant. A simplified process flow diagram for this unit is presented as Figure 2-7.

### 2.3.5.2 Future Process

No changes have occurred in the Dimersol Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

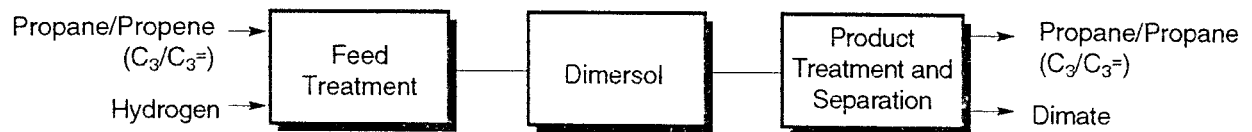
## 2.3.6 Isomerization

### 2.3.6.1 Current Process

The purpose of the Isomerization Plant is to convert normal butane into isobutane. Isobutane is required as one of the two feed components in the alkylation process. The isomerization process uses a fixed bed reactor with a catalyst of aluminum beads. The feed stream is dehydrated upstream of the isomerization process, as water will deactivate the catalyst. Combustion emissions from the isomerization furnace and fugitive emissions from piping components result from operation of the Isomerization Plant. The products of the isomerization process are fed to the Alkylation Plant. A simplified process flow diagram for this unit is presented as Figure 2-8.

### 2.3.6.2 Future Process

No changes have occurred in the Isomerization Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.



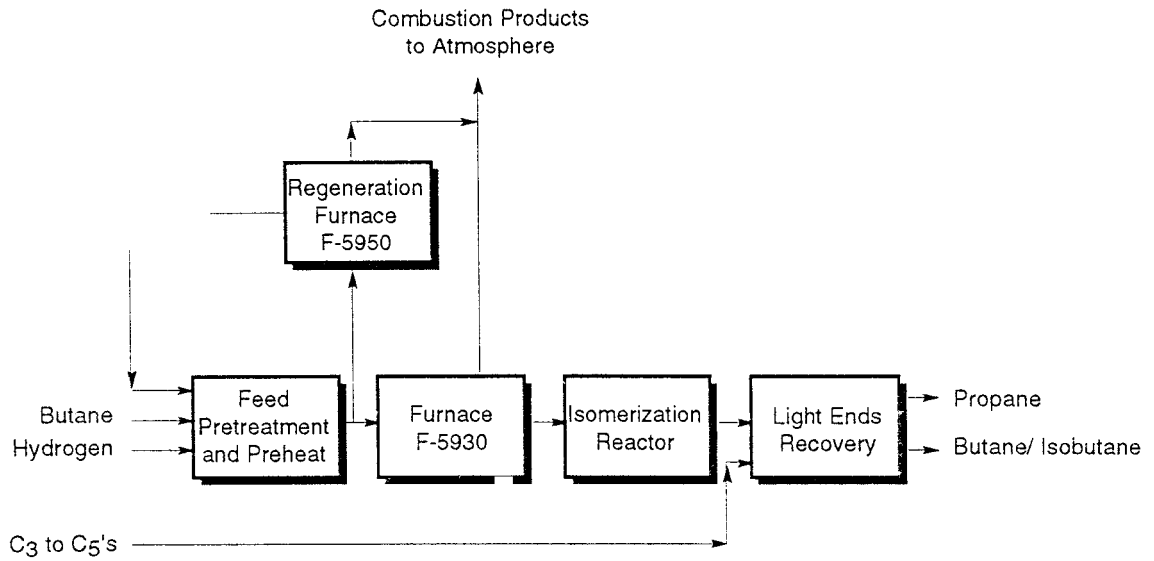
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DIMERSOL PLANT SIMPLIFIED  
 PROCESS FLOW DIAGRAM  
 CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE:

FIG. NO:

2-7



ISOMERIZATION PLANT SIMPLIFIED PROCESS FLOW  
 DIAGRAM [INCLUDING LIGHT ENDS RECTIFIER (LER)]  
 CHEVRONTXACO HAWAII TITLE V RENEWAL

DATE:

FIG. NO:

2-8

## 2.3.7 Alkylation

### 2.3.7.1 Current Process

The alkylation process joins the isobutane from the Isomerization Plant with propylene or butene to form alkylate, a gasoline-blending component. This reaction is catalyzed by high-concentration sulfuric acid. The reaction is exothermic and the heat of reaction is captured by heat exchangers. The alkylation process emits fugitive piping component emissions. A simplified process flow diagram for this unit is presented as Figure 2-9.

### 2.3.7.2 Future Process

No changes have occurred in the Alkylation Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

## 2.3.8 Acid Manufacturing

### 2.3.8.1 Current Process

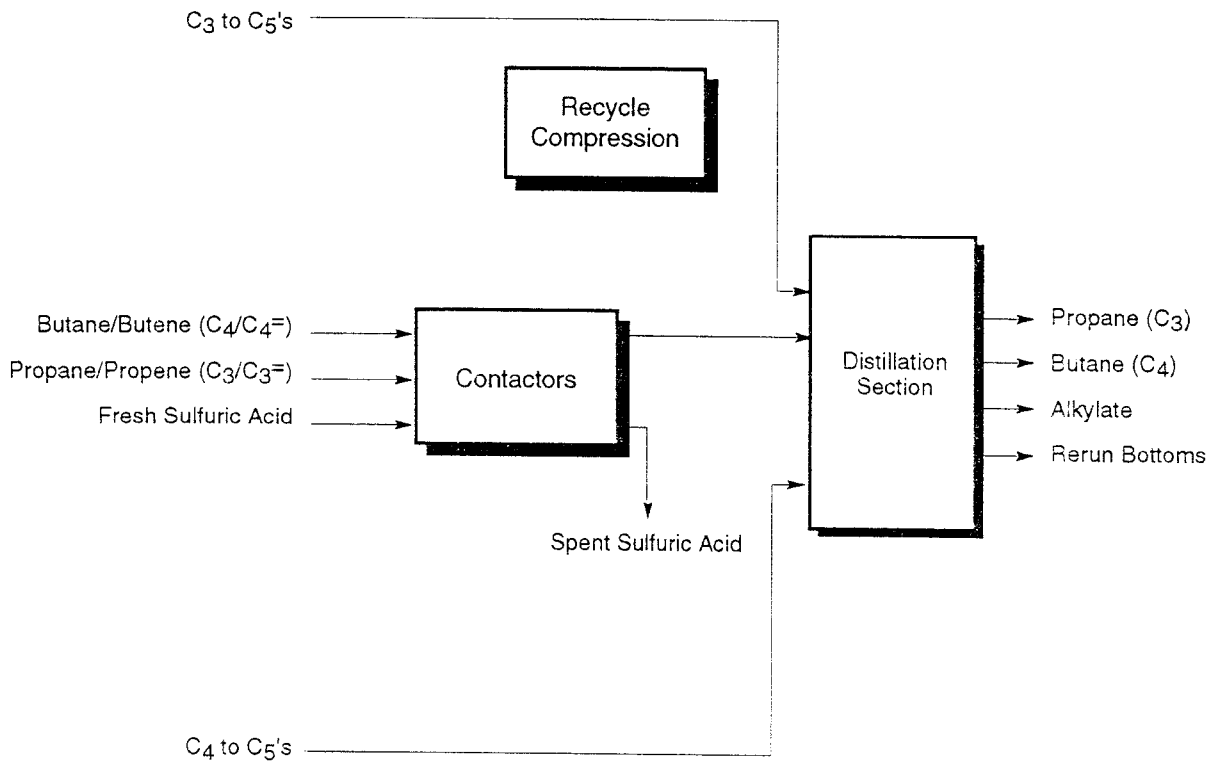
The Acid Manufacturing area of the Hawaii Refinery includes sulfuric acid manufacturing, acid storage, and amine processing facilities. The Amine Plant is an amine regeneration system used to recover hydrogen sulfide. The Acid Plant manufactures sulfuric acid from feedstocks available in the refinery.

The principal feeds are spent acid returned from the alkylation plant and H<sub>2</sub>S gas from the amine regeneration system. The Acid Plant produces acid by decomposition of spent acid and combustion of hydrogen sulfide gas to form sulfur dioxide (SO<sub>2</sub>). The SO<sub>2</sub> is then oxidized to form sulfur trioxide (SO<sub>3</sub>). Finally, the SO<sub>3</sub> is absorbed in a strong sulfuric acid solution to form sulfuric acid. Residual unconverted SO<sub>2</sub> is emitted from the absorber stack. Fugitive component emissions result from the acid and amine regeneration facilities. The acid plant combustion chamber and preheater emit combustion products. The combustion chamber exhaust passes through the plant and is emitted from the adsorbing tower stack. A simplified process flow diagram is presented as Figure 2-10.

A Caustic Scrubber Project was installed during 2003. The project entailed utilization of a caustic system to remove hydrogen sulfide from the acid gas feed stream during periods when the acid plant is shut down and all the acid plant gas is routed to the FCC unit flare. This change was implemented to improve process operations, rather than as an air pollution project.

### 2.3.8.2 Future Process

No changes have occurred in the Alkylation Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

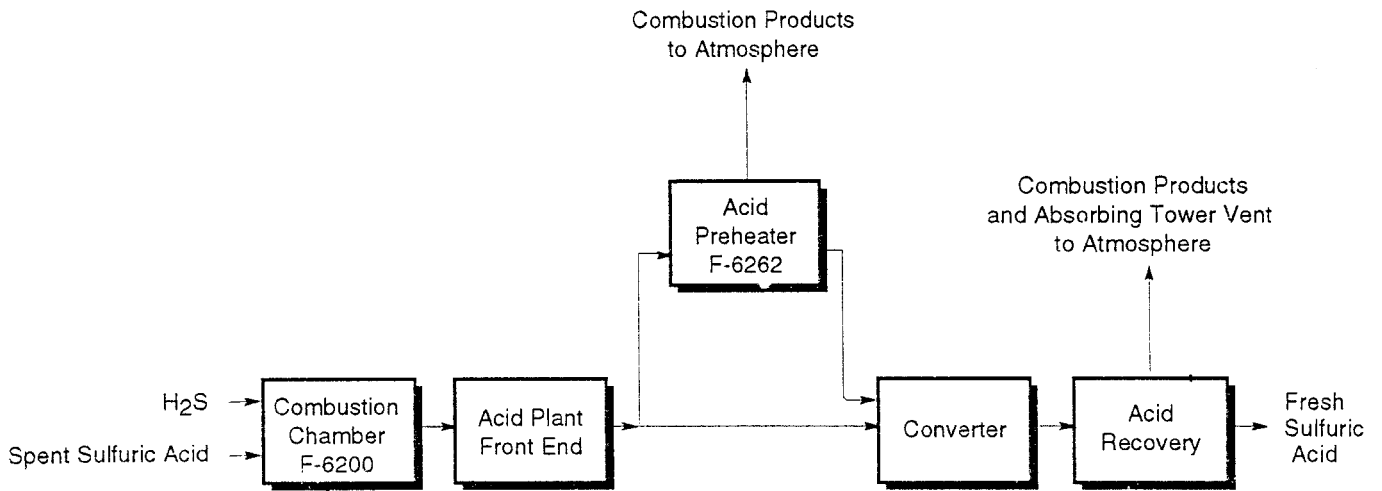


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ALKYLATION PLANT SIMPLIFIED  
 PROCESS FLOW DIAGRAM  
 CHEVRONTEXACO HAWAII TITLE V RENEWAL

	DATE:	FIG. NO:
		2-





ACID PLANT SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL

DATE:

FIG. NO:  
2-10

## **2.3.9 Boiler Plant**

### **2.3.9.1 Current Process**

Steam is critical to the refinery processes and 600-pound steam is used throughout the facility. Steam is supplied by three boilers in the Boiler Plant and three Cogeneration Plant turbines, each of which is equipped with a heat recovery steam generator (HRSG). The Boiler Plant consists of the three boilers and ancillary fuel supply systems. Both RFG and fuel oil are used as fuels in the boilers.

In April 2007, Chevron accepted 40 CFR 60 Subpart J, Standards of Performance for Petroleum Refineries, for the boilers and furnaces at the refinery.

### **2.3.9.2 Future Process**

The only change in this area being considered for implementation during the term of the renewed permit is the hybrid energy project that would replace the steam generation function of the three existing boilers with two new boilers and a new cogeneration plant (see Section 2.3.10). The proposed details of the hybrid energy project were provided to DOH on May 25, 2006 and updated on August 23, 2006 in the significant modification application available in Appendix E. These proposed equipment changes have been accounted for in the Covered Source Permit issued on May 23, 2007. Implementation of the hybrid energy project is slated for 2011.

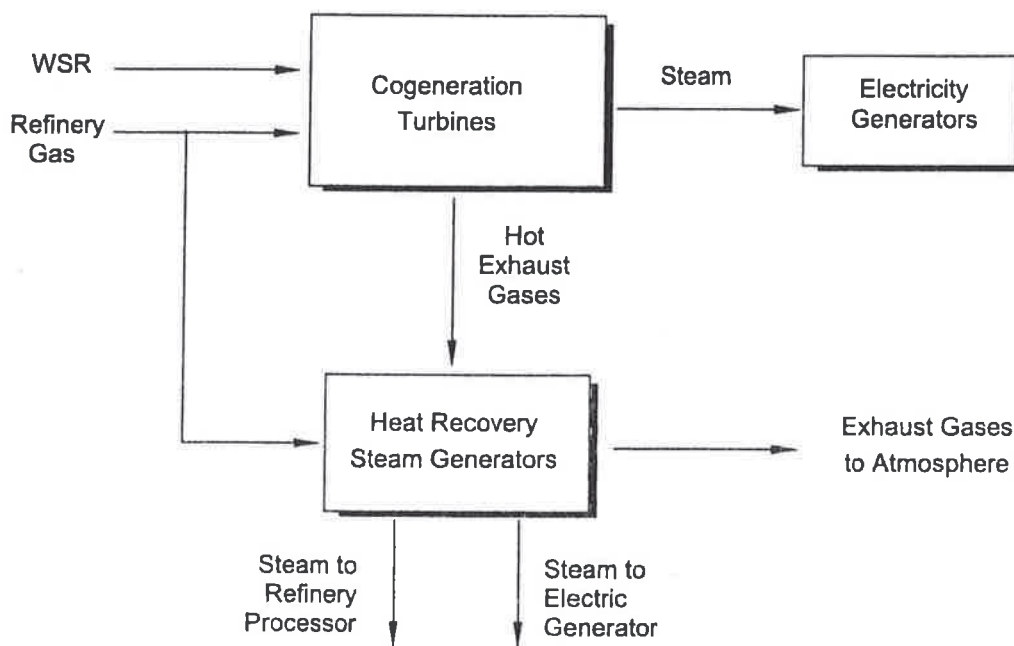
## **2.3.10 Cogeneration Plant**

### **2.3.10.1 Current Process**

This area includes three 40 MMBtu/hr gas turbines with Heat Recovery Steam Generators (HRSGs). These units are equipped with low-NO<sub>x</sub> burners and water injection for control of NO<sub>x</sub> emissions. Refinery fuel gas (RFG) and whole straight run naphtha (WSR) are used as fuels in the cogeneration turbines. Only RFG is combusted in the HRSGs. Fuel combustion products are emitted from these units. A process flow diagram for the Cogeneration Plant is provided in Figure 2-11.

### **2.3.10.2 Future Process**

The hybrid energy project was proposed to DOH in May 2006 to install one new 46 MMBTU/hr cogeneration turbine and a new Heat Recovery Steam Generator (HRSG). Controls and fuels used will be consistent with existing turbines. The modified Covered Source Permit accounting for this change in equipment was issued from DOH on May 23, 2007.



**COGENERATION PLANT  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRON HAWAII REFINERY**

	DATE:	FIG. NO: 2-11
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## 2.3.11 Blending and Shipping

### 2.3.11.1 Current Process

The blending and shipping area includes the refinery tank farm, LPG handling system and truck loading racks. Fugitive emissions from tanks and piping components are emitted from this process area, which contains no fuel-burning equipment.

The refinery tank farm consists of storage tanks for the following hydrocarbon liquids: crude oil, refinery products, blending components and recovered oil. The capacities, control equipment and types of service that have been assumed in postulating the maximum emission scenario for the refinery, including tank emissions, are described in Section 3.

Chevron has installed secondary seals or equivalent controls on storage tanks at the facility to meet 40 CFR 63 Subpart CC requirements. Tanks 249, 250 were changed to Domed External Floating Roof for storage of Aviation gasoline in December 2001. Tank 275 changed to Domed External Floating Roof in August 2006. Tanks 268, 270 and 272 contain Diesel fuel and do not have secondary seals installed.

The current Covered Source Permit allows the storage capacities of Storage Tanks 105 through 111 to be increased by 12 percent, provided that no new applicable requirement is triggered by such action and the seal requirements pursuant to 40 CFR Part 63, Subpart CC have been met. Since the issuance of the initial permit, Tanks 105, 106, 109, 110 and 111 have received course additions that increased their capacities by about 12 percent. Tanks 107 and 108 may be similarly expanded during the term of the renewed Covered Source Permit. Tanks 232, 235 and 253 had 1% increases in capacity. Tanks 237 and 271 had 3% increases. Tank 269 had a 5% increase in capacity. These smaller increases were not because of changes in the capacity of the tank itself. Rather, these capacities were changed from the safe oil height capacity to the maximum capacity of the tank as a conservative assumption for calculations.

Since the initial issuance of the Covered Source Permit some of the tanks have changed service type. Tank 109 went from Crude to Gasoline and those tanks storing LSR/HSR are now storing WSR.

All tank changes have been accounted for in the maximum emission calculations in Table 3.4 and 3.5. Detailed emission calculations are provided in Appendix B.

Typically, products from the refinery are shipped offsite via pipeline, and the truck loading rack is not used. If the pipeline is unavailable, the truck loading rack at the refinery will be used. Estimated loading volumes during such periods, based on the assumption that the refinery would need to meet the outer island fuel demands, are as follows:

- Motor gasoline – 20,000 barrels per day
- Aviation gasoline – 110 barrels per day
- Jet Fuel – 13,000 barrels per day
- Diesel – 10,000 barrels per day

### 2.3.11.2 Future Process

No additional changes to storage tanks are being considered for implementation during the term of the renewed permit.

## **2.3.12 Asphalt Plant**

### **2.3.12.1 Current Process**

The asphalt plant consists of tanks, pumps, a fired furnace and loading racks. In early 2008, the asphalt plant was taken out of operation and activity of associated equipment ceased. With the exception of the furnace, equipment has been altered to prevent operation. The furnace has not operated and has no plans during the renewal term of this permit to come back online. As the furnace is still capable of combusting fuel, potential to emit calculations were included in Section 3.

### **2.3.12.2 Future Process**

No operation of the asphalt plant equipment is expected through the permit renewal term.

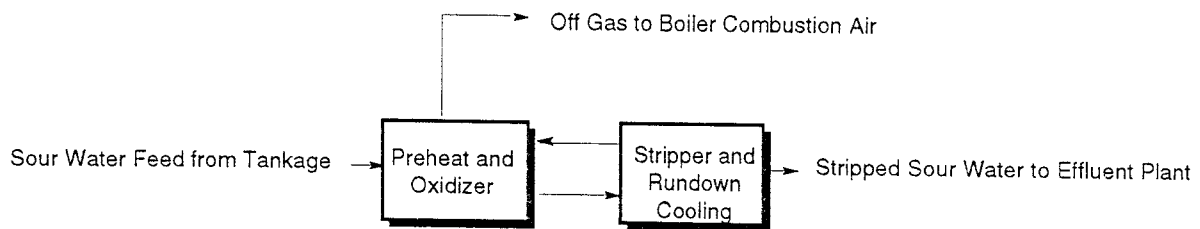
## **2.3.13 Effluent Treatment**

### **2.3.13.1 Current Process**

Wastewater consists of process area sampling waste, process (oily) wastewater, and stormwater waste. Wastewater containing ammonia, sulfides, and hydrocarbons is routed to the sour water tanks, then treated in the Foul Water Oxidizer and pumped to the wastewater treatment plant. Off-gas (primarily ammonia) from the Oxidizer is sent via the combustion air to one of the boilers. A simplified process flow diagram of the Foul Water Oxidizer is presented in Figure 2-12.

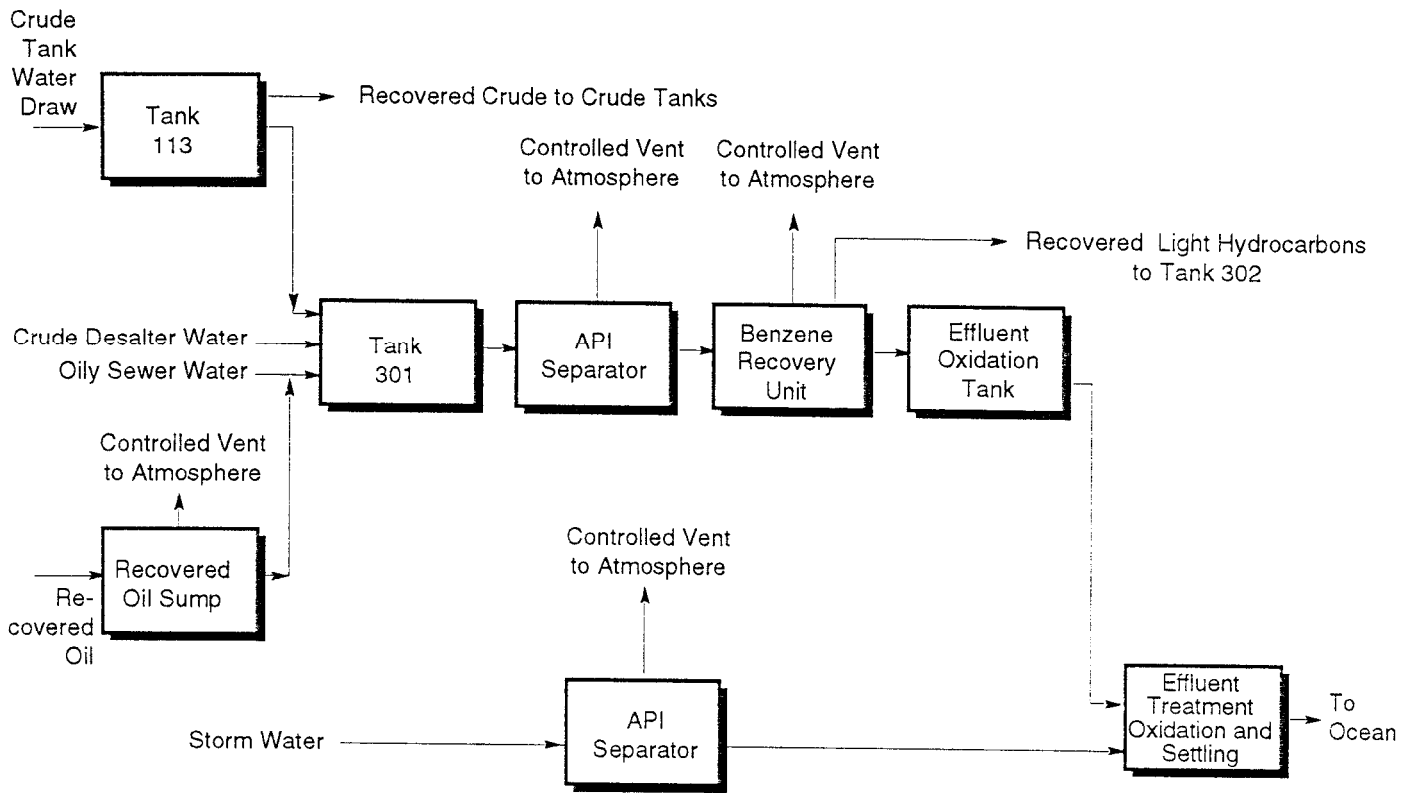
Wastewater not sent to the Foul Water Oxidizer (i.e., possibly containing hydrocarbons) is routed to the API separators, where oil is recovered and the resulting wastewater is treated. Treatment for process wastewater uses a nitrogen gas stripper for benzene control. Gaseous hydrocarbons from the nitrogen stripper are removed in a carbon adsorber. Both process wastewater and stormwater waste are then treated by aggressive biological oxidation in ponds. A simplified process flow diagram of the Effluent (Wastewater Treatment) Plant is presented in Figure 2-13. Minimal fugitive emissions result from the foul water and wastewater treatment plants.

The landfarm previously used to biodegrade hydrocarbon-contaminated soils ceased to receive such materials in July 1995, was capped in November 1997 and received formal closure from EPA in 1998. This facility is no longer in use, but ongoing activities include monthly inspections of the cap integrity and quarterly monitoring of permitted wells for BTEX and semi-volatiles. Groundwater monitoring in this area is to be included in the annual "plume-wide Groundwater Monitoring Program" submitted to DOH.



**FOUL WATER OXIDIZER**  
**SIMPLIFIED PROCESS FLOW DIAGRAM**  
**CHEVRONTEXACO HAWAII TITLE V RENEWAL**

	DATE:	FIG. NO:
		2-



**EFFLUENT PLANT  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRONTEXACO HAWAII TITLE V RENEWAL**

DATE:	FIG. NO: 2-
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### **2.3.13.2 Future Process**

Except for closure of the landfarm, no changes have occurred in the Effluent Treatment Area since the original Title V permit for the refinery was issued, and no future changes are under consideration at the time of this permit renewal application.

## **2.3.14 Flares**

### **2.3.14.1 Current Process**

Safety is a critical concern in refinery operation. In case of equipment failure or other malfunctions, systems are in place to protect the equipment from damage and the facility's workers from harm. The refinery has many safety systems, including two flares. During normal operations, the FCC Flare primarily combusts off-gases from the FCC Unit, Isomerization Plant, Alkylation Plant, Cogeneration Plant, Acid and Amine Plants, sour water tankage, and fuel gas system. The Crude Unit Flare serves the Crude Unit, Hydrogen Plant, Hydrogenation Plant and Dimersol Plant, LPG area, as well as the sour water tankage and has a CEMS. Each flare handles gases for their associated equipment units during shutdown. Historically, during Acid Plant shutdowns, the H<sub>2</sub>S stream to the plant was routed to the FCC Flare for destruction. However this no longer occurs because of the Caustic Scrubber project discussed below.

As described in Section 2.3.8, the Caustic Scrubber project has been implemented and will send acid gas streams through a caustic system for H<sub>2</sub>S removal before routing it to the flare when the Acid Plant is down, thus sharply reducing the SO<sub>2</sub> emissions of the refinery during Acid Plant downtime.

### **2.3.14.2 Future Process**

No future changes are under consideration at the time of this permit renewal application.

## **2.3.15 Cooling Tower**

### **2.3.15.1 Current Process**

The refinery employs an induced draft evaporative cooling tower to dissipate waste heat from several refinery processes. The cooling tower has ten cells.

### **2.3.15.2 Future Process**

No changes in the cooling system have been undertaken since issuance of the initial Title V permit for the Hawaii Refinery, and none are under consideration at the time of this permit renewal application.



## 2.4 Design and Production Rate and Capacity

As discussed above, the refinery consists of numerous interrelated process units. Table 2-1 presents design capacity and production capacity/rate information for the major refinery process units and equipment. Actual throughputs of the units will vary over time, depending on numerous variables; however, any one process or piece of equipment may operate at its design capacity periodically or for extended periods.

## 2.5 Fuels and Fuel Use

Combustion sources at the refinery are fueled primarily by RFG or refinery fuel oil. The cogeneration turbines may be fired on either RFG or whole straight run naphtha. Fuel types and fuel use rates for specific equipment unit are presented in Table 2-2. Fuel usage rates have been estimated based on equipment design heat rates and the estimated average lower heating value (LHV) of the applicable fuels. RFG has an estimated average lower heating value of approximately 1030 Btu per standard cubic foot. Whole straight run naphtha has an estimated average lower heating value of approximately 4758 MBTU/bbl.

Actual fuel heating values vary according to refinery operations. Fuel oil has an estimated average LHV of approximately 5.78 MMBtu per barrel. Fuel flow rates in the cogeneration turbines and HRSGs are limited by DOH permit conditions.

## 2.6 Raw Materials

The primary raw material used in the Hawaii Refinery is crude oil. The base operating scenario for the refinery is the processing of a wide variety of crude oils from various sources. Crude oil is processed at a maximum rate of approximately 65,000 barrels per day. A list of the raw materials used at the refinery is presented in Table 2-3.

## 2.7 Plant Layout and Operating Schedule

The plant layout is presented on Figure 2-1. The refinery operates 24 hours per day, 7 days per week, 52 weeks per year.

## 2.8 Equipment Specifications

The types of processes that are present at the Hawaii Refinery have been described above. There are literally hundreds of pieces of equipment in each process unit. Table 2-1 provided the design capacity for the major pieces of equipment and process units in the refinery. Detailed specifications for each piece of equipment have not been included in this application, because of the large number of equipment and component types.

**Table 2-1**  
**REFINERY DESIGN CAPACITY AND PRODUCTION RATE INFORMATION**

Plant Area	Unit	Equipment	Capacity
20	Storage	Storage tanks	(see Section 3)
23	Cooling tower	Cooling tower	750 mmbtu/hr
	Crude flare	Flare 2301	253 mlb gas/hr
	FCC flare	Flare 2302	1.85 mmlb gas/hr
36	Wastewater	API separators	1400 gal/min combined
51	Crude	Distillation towers	65,000 bbls per day
		Furnace 5103	151.5 mmbtu/hr
		Furnace 5153	62.5 mmbtu/hr
52/55	Boilers	Boiler 5201	220 mmbtu/hr
		Boiler 5202	160.8 mmbtu/hr
		Boiler 5203	160.8 mmbtu/hr
53	FCC	FCC unit	22,000 bbl per day
		Furnace 5300	61 mmbtu/hr
		Catalyst regenerator	266 mmbtu/hr
56	Hydrogenation Manufacturing Plant	Hydrogenation unit	3200 bbl/day
		Furnace 5600	9 mmbtu/hr
57	Hydrogen Plant	Hydrogen unit	2500 mscf/hr
		Furnace 5700	24.3 mmbtu/hr
58	Alkylation Plant	Alkylation unit	7500 bbl per day
59	Isomerization Plant	Isomerization unit	2500 bbl/day
		Furnace 5930	4 mmbtu/hr
		Furnace 5950	1.6 mmbtu/hr
60	Asphalt Plant	Asphalt plant	Storage for transfer
		Furnace 6003	5.7 mmbtu/hr
61/62	Amine/acid plant	Acid plant	110 ton acid/day
		Combustion chamber 6200	4.2 mscf/hr
		Furnace 6262	5.1 mmbtu/hr
66	Dimersol Plant	Dimersol plant	3000 bbl per day
67	Cogeneration	Turbine 6701	76 mmbtu/hr
		Turbine 6702	76 mmbtu/hr
		Turbine 6703	76 mmbtu/hr

**Table 2-2  
FUELS AND FUEL USE**

Area	Equipment	Fuel	Design Fuel Use
51	Furnace 5103 Furnace 5153	Fuel Oil/RFG with RFG Pilot	630 bbl/Day 260 bbl/Day
52/55	Boiler 5201 Boiler 5202 Boiler 5203	Fuel Oil and RFG	914 bbl/Day or 214 MSCF/Hr 668 bbl/Day or 156 MSCF/Hr 668 bbl/Day or 156 MSCF/Hr
53	Furnace 5300 FCC Stack	Fuel Oil and RFG Cat. Coke	254 bbl./Day or 60 MSCF/Hr 22,000 bbl/Day
56	Furnace 5600	RFG	9 MSCF/Hr
57	Furnace 5700	RFG	24 MSCF/Hr
59	Furnace 5930 Furnace 5950	RFG RFG	4 MSCF/Hr 1.6 MSCF/Hr
60	Furnace 6003	RFG	5.5 MSCF/Hr
61/62	Comb. Chamber 6200 Furnace 6262	RFG RFG	4.2 MSCF/Hr 4.95 MSCF/Hr
67	Turbine 6701, 6702, 6703 Turbine 6701, 6702, 6703 HRSG 6701, 6702, 6703	RFG Whole Straight Run Naphtha RFG	38.8 MSCF/Hr (Per Turbine) 192 bbl/Day (Per Turbine) 34 MSCF/Hr (Per HRSG)

**Table 2-3  
RAW MATERIALS**

Raw Material	Source
Crude oil	Tankers
Gasoline blending components (example: reformat)	Pipeline, made on site
Sulfuric acid	Made on site (may be imported)
Fuel oil components (example: low sulfur waxy residuum)	Pipeline, made on site
Other feed/blend stocks (example: vacuum gas oil)	Pipeline, made on site

## 2.9 Base Operating Scenarios

The base refinery operating scenario consists of the processing of crude oils in the process units and equipment, as indicated in the refinery description in Section 2.3. During normal operations, the refinery may process crude oils from a variety of sources and with various characteristics. Likewise, the refinery normally produces a wide range of intermediate and final products. Although each type of crude oil is processed in a similar manner, each requires specific refining techniques.

Therefore, the base operating scenario for this facility is the receiving and processing of various crude oils, without differentiating the make-up of the different crudes or the mix of refinery products generated. Maximum potential air pollutant emissions for this base scenario can be estimated by assuming operation of all equipment and process units at design capacity and the use of those raw materials and products that would produce the highest emissions. Estimation of these maximum potential emissions, which generally overestimate actual refinery emissions, is presented in Section 3.

## 2.10 Alternative Operating Scenarios

Alternative operating scenarios represent operational characteristics outside the range of normal operations. All operating scenarios for the Hawaii Refinery that are considered likely to occur have been incorporated within the base operating scenario, as described in the previous section. The maximum emissions scenario presented in Section 3 reflects the assumptions of refinery and process unit operations at maximum capacity, as well as the combination of raw materials and products that would correspond to the highest emissions of air pollutants among all the possible variations.

Therefore, there are no alternative operating scenarios, and it will not be necessary to implement inter-facility or process area emissions trading.

## 3. Emission Information

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This section provides information required in HAR §11-60.1-83(3), (4), (5), and (6). Maximum air pollutant emission estimates are presented for the base operating scenario, as described in Section 2. The following text explains the refinery emission inventory methods and summarizes the results. Detailed calculations of maximum criteria pollutant and HAPs emissions by source type are presented in Appendix B. It should be noted that the calculations of emissions presented in this report represent the maximum potential emissions from the refinery, which are greater than the actual emissions produced by refinery operations.

### 3.1 Inventory of Refinery Potential to Emit

The Chevron Hawaii Refinery includes several types of sources that have the potential to emit criteria air pollutants and hazardous air pollutants (HAPs). For purposes of developing the facility's emissions inventory, the refinery sources have been divided into the following eight categories:

- Point combustion sources
- Storage tanks
- Truck loading rack
- Process unit fugitives
- Cooling tower
- Wastewater treatment facilities
- Flaring
- Catalyst transfer operations at the FCC

#### 3.1.1 Point Combustion Sources

The point combustion sources at the refinery consist of boilers, furnaces, and turbines. Fuels used by these units consist primarily of RFG and fuel oil. The turbines may also be fueled by whole straight run naphtha. In order to estimate the Potential to Emit (PTE) for these units, maximum fuel use rates based on equipment design capacities were multiplied by appropriate emission factors, except for sources that have federally enforceable DOH permit limits on either their emission rates or fuel usage rates. Information on the fuel type, maximum fuel use, the origins of emission factors, and comments regarding the emission calculation methods for all point combustion sources are presented in Table 3-1. Emission factors and calculation spreadsheets are contained in Appendix B.

The primary source of emission factors used to quantify criteria pollutant and HAP emissions from combustion sources is EPA Publication AP-42 (EPA, 1985 et seq). Fuel use rates for the furnaces and boilers were derived from the design fuel heat input rate and the lower heating value of the fuel used in each unit. The refinery's fuel oil has a nominal lower heating value of 5.78 million Btu per barrel, whereas RFG has a nominal lower heating value of 1030 Btu per standard cubic foot. The actual heating values vary according to refinery operations.

**Table 3-1  
MAXIMUM EMISSION ESTIMATE BASIS FOR POINT COMBUSTION SOURCES**

Area	Equipment	Fuel	Maximum Fuel Use	Emissions Estimate Basis
23(Cooling towers, flares)	Flares	RFG	N/A	Emission Factors From AP-42 Section 5.1-1
51 (Crude Unit)	Furnace 5103 Furnace 5153	Fuel Oil Fuel Oil (gas pilots)	630 bbl/Day 260 bbl/Day	SO <sub>2</sub> , NO <sub>2</sub> , and CO Limited By Permit VOC , PM and HAP emission factors from AP-42 Section 1.3 (Oil) and Section 1.4 (Gas)
52/55 (Boiler Plant)	Boiler 5201 Boiler 5202 Boiler 5203	Fuel Oil and RFG	914 bbl/Day or 214 MSCF/Hr 668 bbl/Day or 156 MSCF/Hr 668 bbl/Day or 156 MSCF/Hr	Emission factors from AP-42 Section 1.3 (Oil) and Section 1.4 (Gas)
53 (FCCU)	Furnace 5300 FCC Stack	RFG Cat. Coke	60 MSCF/Hr 22,000 bbl/day	- Emission factors from AP-42 Sections 1.3 and 1.4 HAP emission factors for FCC stack from Chevron source emissions tests
56 (Hydrogenation Plant)	Furnace 5600	RFG	9 MSCF/Hr	Emission factors from AP-42 Section 1.4
57 (Hydrogen Manufacturing Plant)	Furnace 5700	RFG	24 MSCF/Hr	Emission factors from AP-42 Section 1.4
59 (Isomerization Plant)	Furnace 5930 Furnace 5950	RFG RFG	4 MSCF/Hr 1.6 MSCF/Hr	Emission factors from AP-42 Section 1.4
60 (Asphalt Plant)	Furnace 6003	RFG	5.5 MSCF/Hr	Emission factors from AP-42 Section 1.4
61/62 (Amine, Acid Plant)	Furnace 6262 Comb. Chamber F-6200 Acid Plant	RFG RFG	4.95 MSCF/Hr 8.5 Mmbtu/Hr (Max in 2002) 110 Ton Acid Production/Day	Emission factors from AP-42 Section 1.4
67 (Cogeneration Plant)	Turbine 6701, 6702, 6703 Turbine 6701, 6702, 6703 HRSG 6701, 6702, 6703	RFG WSR RFG	38.8 MSCF/Hr (Per Turbine) 192 bbl/Day (Per Turbine) 34 MSCF/Hr (Per HRSG)	Mass balance for SO <sub>2</sub> emissions NO <sub>2</sub> and CO fuel use limited by permit and factors from AP-42 Section 1.4 and 3.1 VOC and PM factors from AP-42 Section 3.1
Generators	Various Diesel Units	Diesel		Emission Factors from AP-42 Section 3.3

The particulate emissions from the FCC precipitator are conservatively assumed to be at the DOH prohibitory limit.

Emissions of SO<sub>2</sub>, NO<sub>x</sub> and CO from the Crude Unit and Cogeneration Plant were based on federally enforceable DOH permit limits. Consumption of RFG and whole straight run naphtha (WSR) in the cogeneration turbines is limited by federally enforceable DOH permit conditions. Crude unit furnaces 5103 and 5153 are currently permitted to combust RFG on only 12 of 36 burners. Maximum estimated emissions for these furnaces were obtained assuming that these units operate to the full limit of the permit conditions.

WSR sulfur content in the cogeneration units is no more than 0.03 percent, as allowed by the current Title V permit. Fuel oil burned in the boilers (5201, 5202, and 5203) and crude unit furnaces (5103 and 5153) may contain up to 0.5 percent sulfur and fuel gas up to 160ppmv sulfur. Hazardous Air Pollutant (HAP) emission factors were taken from the EPA AP-42 compilation or from Chevron source tests.

Chevron has had a number of diesel fueled generators that were previously identified as insignificant sources with a capacity of 200 brake horsepower (bhp) or lower. These units support maintenance activities and the Boiler Plant. An additional 335 bhp standby emergency generator is used at the cogeneration area during power and cogeneration failures. Maritime Security Requirements required the installation of three emergency generators; one at each gate entrance, and one at the firehouse. Other emergency generators include fire water pumps and light plant operations. As these units are all used on an intermittent basis for refinery plant maintenance and repairs an hour limitation of 1008 hours per year was used for emission calculations. This hour limitation was derived from the worst case plant maintenance scenario. Every five years, the refinery plant is taken offline to perform maintenance for up to 6 weeks. Worst case scenario for operating time was assumed to be 24 hours per day, 7 days a week for 6 weeks a year. The criteria and hazardous air pollutants were calculated using AP-42 emission factors.

Maximum potential criteria pollutant emissions for refinery point sources are presented in Table 3-2. HAP emissions from point sources are summarized in Table 3-3. Please note that these tables present the maximum emission rates. Thus, if fuel oil combustion results in higher emissions for a given pollutant than RFG, the use of fuel oil is assumed in calculating emissions. Additionally, it is unlikely – if not impossible – for all of the refinery processes to operate concurrently at their maximum potential emission rates for all pollutants.

### 3.1.2 Storage Tanks

Crude oil, intermediate products, blending components, and finished products are placed in storage tanks. The refinery stores different classes of material in designated tanks. For example, specific tanks may store motor gasoline or several of its blend components. These same tanks, however, would not store diesel fuel. To estimate emissions, each storage tank is classified according to the class of material it contains, based on similar characteristics. Data from a Year 2009 tank emission inventory were used as the basis for calculating the tanks' PTE. Because the maximum crude oil throughput for the refinery (65,000 bbl/day) is 24 percent higher than the crude oil throughput during 2009, the throughput quantities and turnovers for all tanks were increased by 24 percent over the values in the 2009 inventory data in order to estimate their corresponding maximum potential emissions.

The classes of regulated hydrocarbon materials stored at the refinery are as follows:

- Crude oil
- Motor gasoline and its blend components
- Aviation gas
- Jet fuel
- Heavy liquids
- Liquid propane gas (LPG)
- Recovered oil



**Table 3-2  
MAXIMUM CRITERIA POLLUTANT EMISSIONS FROM POINT SOURCES**

Sources	Pollutant Emission Rates (ton/yr)						Total Criteria Pollutant Emissions
	PM <sub>10</sub>	SO <sub>2</sub>	CO	NO <sub>2</sub>	VOC	Lead	
Boilers	134.78	1353.83	86.23	551.88	13.11	0.026	2140
Cogen Turbines	11.72	27.92	52.49	193.16	2.34	0.006	288
Crude Furnaces	44.49	481.99	74.99	302.88	5.11	0.010	909
FCC Furnace	2.00	7.10	22.08	13.14	1.45	0.000	46
Isomerization Furnaces	0.19	0.66	2.06	2.45	0.13	0.000	5
Hydrogenation & Hydrogen Plant Furnaces	1.10	3.91	12.14	14.45	0.79	0.000	32
Acid preheater & combustion chamber	0.43	1.54	4.80	5.71	0.31	0.000	13
Asphalt Furnace	0.18	0.65	2.02	2.41	0.13	0.000	5
FCC Stack	175.20	333.35	499.32	285.07	14.67	0.000	1308
Generators	5.5	5.1	16.7	77.6	6.2	-	111
<b>Totals</b>	<b>375.6</b>	<b>2216.1</b>	<b>772.8</b>	<b>1448.7</b>	<b>44.2</b>	<b>0.0</b>	<b>4857.5</b>

**Table 3-3  
MAXIMUM HAP EMISSIONS FROM POINT SOURCES**

<b>Number</b>	<b>Area Description</b>	<b>Benzene CAS# 71432 (Ton/Yr)</b>	<b>Naphthalene CAS# 91203 (Ton/Yr)</b>	<b>o-Xylene CAS# 95476 (Ton/Yr)</b>	<b>Ethylbenzene CAS# 100414 (Ton/Yr)</b>	<b>p-Xylene CAS# 106423 (Ton/Yr)</b>	<b>Ethylene Dibromide CAS# 106934 (Ton/Yr)</b>	<b>Ethylene Dichloride CAS# 107062 (Ton/Yr)</b>
52	Boiler	0.003	0.008	0.001	0.00			
67	Cogen	0.034	0.018					
51	Crude	0.001	0.006	0.001	0.00			
53	FCC	0.001	0.000					
59	Isom	0.000	0.000					
56	Hydrogenation							
57	Hydrogen Manufacturing	0.000	0.000					
62	Acid Plant CC and Preheater	0.000	0.000					
60	Asphalt Plant	0.000	0.000					
53	FCC Stack							
	Flare							
	Generators	0.00	0.00	0.00				
	<b>Total</b>	<b>0.040</b>	<b>0.032</b>	<b>0.002</b>	<b>0.001</b>	<b>0.000</b>	<b>0.000</b>	<b>0.000</b>

**Table 3-3 (continued)**  
**MAXIMUM HAP EMISSIONS FROM POINT SOURCES**

Number	Area Description	m-Xylene CAS# 108383 (Ton/Yr)	Toluene CAS# 108883 (Ton/Yr)	1,3-Butadiene CAS# 106990 (Ton/Yr)	n-Hexane CAS# 110543 (Ton/Yr)	Formaldehyde CAS# 50000 (Ton/Yr)	POM/PAH CAS# EDF047 (Ton/Yr)	Total HAPs Ton/Yr
52	Boiler Plant		0.046		1.230	0.349	0.298	1.935
67	Cogen Plant	0.033	0.067	0.008		0.506	0.021	0.688
51	Crude Unit		0.030		0.002	0.208	0.006	0.253
53	FCC Unit Furnace		0.001		0.473	0.020	0.000	0.494
59	Isomerization Plant		0.000		0.044	0.002	0.000	0.046
56	Hydrogenation Plant		0.000		0.071	0.003	0.000	0.074
57	Hydrogen Manufacturing Plant		0.000		0.189	0.008	0.000	0.198
62	Acid Plant CC and Preheater		0.000		0.103	0.004	0.000	0.107
60	Asphalt Point		0.000		0.043	0.002	0.000	0.045
53	FCC Stack					0.890		0.890
	Flare			0.002				0.002
	Generators		0.00	0.00		0.00	0.00	
	<b>Total</b>	<b>0.033</b>	<b>0.145</b>	<b>0.010</b>	<b>2.155</b>	<b>1.993</b>	<b>0.325</b>	<b>4.732</b>

To date, 33 external floating roof petroleum storage tanks have been fitted with secondary seals or domed roofs. Storage tank emissions were estimated using the EPA TANKS4.09d computer software package, with partial speciation (EPA, 2006). A list of each regulated tank in hydrocarbon service, its class of service, and estimated maximum total VOC emissions is provided in Table 3-4. A summary of maximum total HAP emissions by tank is presented in Table 3-5. Detailed emission reports for each tank, as generated by the TANKS4.09d emissions model, are presented in an accompanying document (Appendix B-2).

Storage tanks in LPG service are pressurized and have negligible emissions. Emissions from heavy liquids, specifically materials with vapor pressures less than 0.3 kPa (EPA, 1993a), are also excluded from this inventory. This exclusion is consistent with the December 15, 1993, "Model Permit for Leaking Sources" published by the EPA, and is discussed further in Section 3.6 of this application. For clarity, liquids having a vapor pressure less than 0.3 kPa will subsequently be referred to as insignificant heavy liquids. Section 3.6.10 contains justification for the exemption of these materials from the refining PTE inventory.

### 3.1.3 Truck Loading Rack

Typically, products are shipped from the refinery via pipeline. If Chevron were unable to use the pipeline (for example, in case of a shutdown for extended repairs), certain products would be loaded into trucks at the refinery truck loading rack. The current Covered Source Permit specifies the following maximum daily material loading rates:

- Motor gasoline – 7,300,000 barrels per any rolling 12-month period
- Aviation gasoline – 47,450 barrels per any rolling 12-month period
- Diesel – 2,920,000 barrels per any rolling 12-month period
- Jet Fuel – 438,000 barrels per any rolling 12-month period

Section 5.2 of AP-42 provides the following equation to estimate VOC emissions from loading activities:

$$L_L = 12.46 \text{ SPM}/T$$

Where:

- L = VOC Emissions, lb/1000 gal. liquid loaded
- S = Saturation factor (Chevron employs submerged loading)
- P = True vapor pressure, psia
- M = Molecular weight of vapors, lb/lb mole
- T = Temperature of material, °R

Estimated emissions and the parameter values used in the emission calculations are presented in Table 3-6. The PTE calculations assume that the maximum allowable quantities shown above for all fuels would be loaded during the year.

**Table 3-4  
MAXIMUM POTENTIAL VOC EMISSIONS FROM STORAGE TANKS**

Tank ID	Type of Tank	Service of Tank	Losses (lb/yr)	Losses (ton/yr)
Tk 104	External Floating Roof	Crude: Nanhi Group	5432.73	2.7
Tk 105	External Floating Roof	Crude: Tapis Group	8540.88	4.3
Tk 106	External Floating Roof	Crude: Tapis Group	8534.19	4.3
Tk 107	External Floating Roof	Crude: MinasGroup	5495.79	2.7
Tk 108	External Floating Roof	Crude: Widuri Group	8943.03	4.5
Tk 109	External Floating Roof	U/L	67697.10	33.8
Tk 110	External Floating Roof	Crude: Tapis Group	8751.16	4.4
Tk 111	External Floating Roof	WSR	39400.48	19.7
Tk 113	External Floating Roof	Rec Crude	14.99	0.0
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.00	0.0
Tk 162	External Floating Roof	Rec Oil	18448.29	9.2
Tk 163	External Floating Roof	Rec Oil	18448.29	9.2
Tk 232	External Floating Roof	HCC	2719.92	1.4
Tk 233	External Floating Roof	HCC	1876.24	0.9
Tk 235	External Floating Roof	Transmix	26156.81	13.1
Tk 236	External Floating Roof	U/L	56340.62	28.2
Tk 237	External Floating Roof	SUP	56291.42	28.1
Tk 249	External Floating Roof	Avgas	2580.58	1.3
Tk 250	External Floating Roof	Avgas	2114.93	1.1
Tk 252	External Floating Roof	LCC	61048.48	30.5
Tk 253	External Floating Roof	LCC	61050.45	30.5
Tk 254	External Floating Roof	U/L	55727.19	27.9
Tk 255	External Floating Roof	SUP	24360.42	12.2
Tk 256	External Floating Roof	U/L	56340.62	28.2
Tk 257	External Floating Roof	Dimate Gasoline	49414.54	24.7
Tk 258	External Floating Roof	Alkylate Gasoline	32763.93	16.4
Tk 262	External Floating Roof	SUP	55247.25	27.6
Tk 263	External Floating Roof	JetA	4276.30	2.1
Tk 264	External Floating Roof	JetA	4286.38	2.1
Tk 265	External Floating Roof	JetA	1790.07	0.9
Tk 266	External Floating Roof	WSR	32279.51	16.1
Tk 267	External Floating Roof	JetA	4377.14	2.2
Tk 268	External Floating Roof	Diesel	352.19	0.2
Tk 269	External Floating Roof	WSR	30980.76	15.5
Tk 270	External Floating Roof	Diesel	333.66	0.2
Tk 271	External Floating Roof	JetA or gasoline	1613.02	0.8
Tk 272	Vertical Fixed Roof	ULSD	2819.86	1.4
Tk 273	External Floating Roof	U/L	50696.68	25.3
Tk 274	Vertical Fixed Roof	ULSD	3599.85	1.8
Tk 275	External Floating Roof	WSR	651.43	0.3
Tk 301	External Floating Roof	Rec Oil	31994.08	16.0
Tk 302	External Floating Roof	Rec Oil	31994.08	16.0
Total Emissions for all Tanks:			935785.28	467.89

**Table 3-5  
MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank Id	Type of tank	Service of Tank	BENZENE	NAPHTHALENE	O-XYLENE	ETHYLBENZENE	P-XYLENE	ETHYLENE DIBROMIDE
			CAS# 71432	CAS# 91203	CAS# 95476	CAS# 100414	CAS# 106423	CAS# 106934
Tk 104	External Floating Roof	Crude: Nanhi Group	5.755	0.000	0.000	0.000	0.000	0.000
Tk 105	External Floating Roof	Crude: Tapis Group	20.587	0.000	0.000	0.000	0.000	0.000
Tk 106	External Floating Roof	Crude: Tapis Group	20.561	0.000	0.000	0.000	0.000	0.000
Tk 107	External Floating Roof	Crude: MinasGroup	7.039	0.000	0.000	0.000	0.000	0.000
Tk 108	External Floating Roof	Crude: Widuri Group	3.577	0.000	0.000	0.000	0.000	0.000
Tk 109	External Floating Roof	U/L	18.757	1.648	28.995	21.787	13.813	0.000
Tk 110	External Floating Roof	Crude: Tapis Group	21.151	0.000	0.000	0.000	0.000	0.000
Tk 111	External Floating Roof	WSR	276.453	0.000	13.750	0.000	153.662	0.000
Tk 113	External Floating Roof	Rec Crude	0.058	0.000	0.000	0.000	0.000	0.000
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.000	0.000	0.000	0.000	0.000	0.000
Tk 162	External Floating Roof	Rec Oil	16.908	0.516	5.535	2.532	1.584	0.041
Tk 163	External Floating Roof	Rec Oil	16.908	0.516	5.535	2.532	1.584	0.041
Tk 232	External Floating Roof	HCC	2.719	9.086	79.491	28.188	22.480	0.000
Tk 233	External Floating Roof	HCC	1.877	6.175	56.288	19.972	15.461	0.000
Tk 235	External Floating Roof	Transmix	0.000	0.000	0.000	0.000	0.000	6.592
Tk 236	External Floating Roof	U/L	15.551	0.949	22.582	17.330	10.303	0.000
Tk 237	External Floating Roof	SUP	15.502	0.421	5.329	2.063	1.488	0.000
Tk 249	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	0.000	0.650
Tk 250	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	0.000	0.533
Tk 252	External Floating Roof	LCC	119.869	0.000	17.497	19.281	11.086	0.000
Tk 253	External Floating Roof	LCC	119.884	0.000	17.522	19.301	11.112	0.000
Tk 254	External Floating Roof	U/L	15.380	0.922	22.275	17.110	10.142	0.000

**Table 3-5 (continued)**  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank Id	Type of tank	Service of Tank	BENZENE	NAPHTHALENE	O-XYLENE	ETHYLBENZENE	P-XYLENE	ETHYLENE DIBROMIDE
			CAS# 71432	CAS# 91203	CAS# 95476	CAS# 100414	CAS# 106423	CAS# 106934
Tk 255	External Floating Roof	SUP	6.593	0.192	2.228	0.865	0.673	0.000
Tk 256	External Floating Roof	U/L	15.551	0.949	22.582	17.330	10.303	0.000
Tk 257	External Floating Roof	Dimate Gasoline	0.000	0.000	0.000	0.000	0.000	0.000
Tk 258	External Floating Roof	Alkylate Gasoline	0.000	0.000	0.000	0.000	0.000	0.000
Tk 262	External Floating Roof	SUP	15.214	0.411	5.227	2.024	1.459	0.000
Tk 263	External Floating Roof	JetA	0.001	6.780	84.041	34.211	22.015	0.000
Tk 264	External Floating Roof	JetA	0.001	6.911	84.282	34.291	22.122	0.000
Tk 265	External Floating Roof	JetA	0.000	3.138	34.889	14.321	9.886	0.000
Tk 266	External Floating Roof	WSR	225.930	0.000	10.666	0.000	125.890	0.000
Tk 267	External Floating Roof	JetA	0.001	6.962	86.032	35.017	22.545	0.000
Tk 268	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000	0.000
Tk 269	External Floating Roof	WSR	216.778	0.000	10.169	0.000	120.825	0.000
Tk 270	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000	0.000
Tk 271	External Floating Roof	JetA or gasoline	0.000	3.022	31.971	12.904	8.393	0.000
Tk 272	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000	0.000
Tk 273	External Floating Roof	U/L	14.009	0.778	20.131	15.512	9.025	0.000
Tk 274	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000	0.000
Tk 275	External Floating Roof	WSR	4.928	0.000	0.600	0.000	2.541	0.000
Tk 301	External Floating Roof	Rec Oil	29.284	0.702	9.281	4.293	2.592	0.071
Tk 302	External Floating Roof	Rec Oil	29.284	0.702	9.281	4.293	2.592	0.071

**Table 3-5 (continued)**  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank Id	Type of tank	Service of Tank	ETHYLENE DICHLORIDE	M-XYLENE	TOLUENE	1,3- BUTADIENE	n-HEXANE	ANILINE
			CAS# 107062	CAS# 108383	CAS# 108883	CAS# 106990	CAS# 110543	CAS# 62533
Tk 104	External Floating Roof	Crude: Nanhi Group	0.000	0.000	0.000	0.000	0.000	0.500
Tk 105	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.000	0.083
Tk 106	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.000	0.082
Tk 107	External Floating Roof	Crude: MinasGroup	0.000	0.000	0.000	0.000	0.000	0.083
Tk 108	External Floating Roof	Crude: Widuri Group	0.000	0.000	0.000	0.000	0.000	0.068
Tk 109	External Floating Roof	U/L	0.000	67.644	371.837	0.000	393.641	0.032
Tk 110	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.000	0.088
Tk 111	External Floating Roof	WSR	0.000	30.985	249.063	0.000	801.791	0.247
Tk 113	External Floating Roof	Rec Crude	0.000	0.000	0.000	0.000	0.000	0.001
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.000	0.000	0.000	0.000	0.000	0.000
Tk 162	External Floating Roof	Rec Oil	0.000	83.897	17.654	0.000	1982.911	0.184
Tk 163	External Floating Roof	Rec Oil	0.000	83.897	17.654	0.000	1982.911	0.184
Tk 232	External Floating Roof	HCC	0.000	124.505	20.671	0.000	0.000	0.264
Tk 233	External Floating Roof	HCC	0.000	88.192	14.259	0.000	0.000	0.183
Tk 235	External Floating Roof	Transmix	1.887	0.062	0.000	0.000	5.371	0.000
Tk 236	External Floating Roof	U/L	0.000	53.359	304.608	0.000	326.995	0.062
Tk 237	External Floating Roof	SUP	0.000	8.818	8.110	0.000	326.335	0.062
Tk 249	External Floating Roof	Avgas	0.187	0.006	0.000	0.000	0.530	0.000
Tk 250	External Floating Roof	Avgas	0.152	0.005	0.000	0.000	0.434	0.000
Tk 252	External Floating Roof	LCC	0.000	51.943	371.903	0.000	202.587	0.062
Tk 253	External Floating Roof	LCC	0.000	52.005	372.049	0.000	202.603	0.062
Tk 254	External Floating Roof	U/L	0.000	52.661	301.100	0.000	323.411	0.062



**Table 3-5 (continued)**  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank Id	Type of tank	Service of Tank	ETHYLENE DICHLORIDE	M-XYLENE	TOLUENE	1,3- BUTADIENE	n-HEXANE	ANILINE
			CAS# 107062	CAS# 108383	CAS# 108883	CAS# 106990	CAS# 110543	CAS# 62533
Tk 255	External Floating Roof	SUP	0.000	3.692	3.424	0.000	139.292	0.062
Tk 256	External Floating Roof	U/L	0.000	53.359	304.608	0.000	326.995	0.062
Tk 257	External Floating Roof	Dimate Gasoline	0.000	0.000	0.000	0.000	0.000	0.000
Tk 258	External Floating Roof	Alkylate Gasoline	0.000	0.000	0.000	0.000	6.397	0.000
Tk 262	External Floating Roof	SUP	0.000	8.650	7.959	0.000	320.280	0.062
Tk 263	External Floating Roof	JetA	0.000	112.039	0.000	0.000	0.000	0.043
Tk 264	External Floating Roof	JetA	0.000	112.303	0.000	0.000	0.000	0.043
Tk 265	External Floating Roof	JetA	0.000	46.900	0.000	0.000	0.000	0.018
Tk 266	External Floating Roof	WSR	0.000	24.296	201.553	0.000	656.303	0.142
Tk 267	External Floating Roof	JetA	0.000	114.682	0.000	0.000	0.000	0.044
Tk 268	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000	0.000
Tk 269	External Floating Roof	WSR	0.000	23.195	193.163	0.000	629.836	0.130
Tk 270	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000	0.000
Tk 271	External Floating Roof	JetA or gasoline	0.000	42.262	0.000	0.000	0.000	0.016
Tk 272	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000	0.000
Tk 273	External Floating Roof	U/L	0.000	47.684	274.012	0.000	294.582	0.062
Tk 274	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000	0.000
Tk 275	External Floating Roof	WSR	0.000	1.191	5.682	0.000	13.639	0.062
Tk 301	External Floating Roof	Rec Oil	0.000	14.164	30.395	0.000	343.779	0.320
Tk 302	External Floating Roof	Rec Oil	0.000	14.164	30.395	0.000	343.779	0.320

**Table 3-5 (continued)**  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank Id	Type of tank	Service of Tank	CRESOL MIXTURE	PHENOL	STYRENE	METHANOL
			CAS# 1319773	CAS# 108952	CAS# 100425	CAS# 67561
Tk 104	External Floating Roof	Crude: Nanhi Group	7.606	0.499	0.000	0.000
Tk 105	External Floating Roof	Crude: Tapis Group	11.957	0.082	0.000	0.000
Tk 106	External Floating Roof	Crude: Tapis Group	11.948	0.080	0.000	0.000
Tk 107	External Floating Roof	Crude: MinasGroup	7.694	0.082	0.000	0.000
Tk 108	External Floating Roof	Crude: Widuri Group	12.520	0.064	0.000	0.000
Tk 109	External Floating Roof	U/L	0.000	0.062	0.000	0.000
Tk 110	External Floating Roof	Crude: Tapis Group	12.252	0.086	0.000	0.000
Tk 111	External Floating Roof	WSR	0.000	0.000	0.000	0.000
Tk 113	External Floating Roof	Rec Crude	0.021	0.001	0.000	0.000
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.000	0.000	0.000	0.000
Tk 162	External Floating Roof	Rec Oil	267.500	0.062	0.000	0.000
Tk 163	External Floating Roof	Rec Oil	267.500	0.062	0.000	0.000
Tk 232	External Floating Roof	HCC	0.000	0.062	0.000	0.000
Tk 233	External Floating Roof	HCC	0.000	0.062	0.000	0.000
Tk 235	External Floating Roof	Transmix	0.000	0.000	0.000	0.000
Tk 236	External Floating Roof	U/L	0.000	0.062	0.000	0.000
Tk 237	External Floating Roof	SUP	0.000	0.062	0.000	0.000
Tk 249	External Floating Roof	Avgas	0.000	0.000	0.000	0.000
Tk 250	External Floating Roof	Avgas	0.000	0.000	0.000	0.000
Tk 252	External Floating Roof	LCC	0.000	0.062	1.348	0.000
Tk 253	External Floating Roof	LCC	0.000	0.062	1.349	0.000
Tk 254	External Floating Roof	U/L	0.000	0.062	0.000	0.000

**Table 3-5 (continued)**  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank Id	Type of tank	Service of Tank	CRESOL MIXTURE	PHENOL	STYRENE	METHANOL
			CAS# 1319773	CAS# 108952	CAS# 100425	CAS# 67561
Tk 255	External Floating Roof	SUP	0.000	0.062	0.000	0.000
Tk 256	External Floating Roof	U/L	0.000	0.062	0.000	0.000
Tk 257	External Floating Roof	Dimate Gasoline	0.000	0.000	0.000	0.000
Tk 258	External Floating Roof	Alkylate Gasoline	0.000	0.000	0.000	0.000
Tk 262	External Floating Roof	SUP	0.000	0.062	0.000	0.000
Tk 263	External Floating Roof	JetA	4.276	0.336	0.000	0.000
Tk 264	External Floating Roof	JetA	4.286	0.346	0.000	0.000
Tk 265	External Floating Roof	JetA	1.790	0.148	0.000	0.000
Tk 266	External Floating Roof	WSR	0.000	0.000	0.000	0.000
Tk 267	External Floating Roof	JetA	4.377	0.345	0.000	0.000
Tk 268	External Floating Roof	Diesel	0.000	0.062	0.000	0.000
Tk 269	External Floating Roof	WSR	0.000	0.000	0.000	0.000
Tk 270	External Floating Roof	Diesel	0.000	0.062	0.000	0.000
Tk 271	External Floating Roof	JetA or gasoline	1.613	0.168	0.000	0.000
Tk 272	Vertical Fixed Roof	ULSD	0.000	0.410	0.000	0.000
Tk 273	External Floating Roof	U/L	0.000	0.062	0.000	0.000
Tk 274	Vertical Fixed Roof	ULSD	0.000	0.524	0.000	0.000
Tk 275	External Floating Roof	WSR	0.000	0.000	0.000	0.000
Tk 301	External Floating Roof	Rec Oil	463.914	0.069	0.000	0.000
Tk 302	External Floating Roof	Rec Oil	463.914	0.069	0.000	0.000

**Table 3-5 (continued)**  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank Id	Type of tank	Service of Tank	HCL	PERCHLOROETHYLENE	CYCLOHEXANE	BIPHENYL	2,2,4 TRIMETHYLPENTANE	CUMENE
			CAS# 7647010	CAS# 127184	CAS# 110827	CAS# 92524	CAS# 540841	CAS# 98828
Tk 104	External Floating Roof	Crude: Nanhi Group	0.000	0.000	0.000	0.000	0.520	0.502
Tk 105	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.314	0.104
Tk 106	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.314	0.104
Tk 107	External Floating Roof	Crude: MinasGroup	0.000	0.000	0.000	0.000	0.301	0.103
Tk 108	External Floating Roof	Crude: Widuri Group	0.000	0.000	0.000	0.000	0.744	0.131
Tk 109	External Floating Roof	U/L	0.000	0.000	82.349	0.000	49.536	0.120
Tk 110	External Floating Roof	Crude: Tapis Group	0.000	0.000	0.000	0.000	0.325	0.110
Tk 111	External Floating Roof	WSR	0.000	0.000	618.646	0.000	69.812	2.359
Tk 113	External Floating Roof	Rec Crude	0.000	0.000	0.000	0.000	0.001	0.001
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.000	0.000	0.000	0.000	0.000	0.000
Tk 162	External Floating Roof	Rec Oil	0.000	0.018	31.803	5.534	32.743	0.892
Tk 163	External Floating Roof	Rec Oil	0.000	0.018	31.803	5.534	32.743	0.892
Tk 232	External Floating Roof	HCC	0.000	0.000	0.000	0.000	0.000	0.122
Tk 233	External Floating Roof	HCC	0.000	0.000	0.000	0.000	0.000	0.086
Tk 235	External Floating Roof	Transmix	0.000	0.000	0.000	0.000	575.450	0.000
Tk 236	External Floating Roof	U/L	0.000	0.000	68.280	0.000	40.869	0.091
Tk 237	External Floating Roof	SUP	0.000	0.000	3.167	0.000	40.623	0.086
Tk 249	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	56.773	0.000
Tk 250	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	46.528	0.000
Tk 252	External Floating Roof	LCC	0.000	0.000	0.000	0.000	0.000	1.059
Tk 253	External Floating Roof	LCC	0.000	0.000	0.000	0.000	0.000	1.061
Tk 254	External Floating Roof	U/L	0.000	0.000	67.527	0.000	40.411	0.090

**Table 3-5 (continued)**  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank Id	Type of tank	Service of Tank	HCL	PERCHLOROETHYLENE	CYCLOHEXANE	BIPHENYL	2,2,4 TRIMETHYLPENTANE	CUMENE
			CAS# 7647010	CAS# 127184	CAS# 110827	CAS# 92524	CAS# 540841	CAS# 98828
Tk 255	External Floating Roof	SUP	0.000	0.000	1.348	0.000	17.235	0.062
Tk 256	External Floating Roof	U/L	0.000	0.000	68.280	0.000	40.869	0.091
Tk 257	External Floating Roof	Dimate Gasoline	0.000	0.000	0.000	0.000	0.000	0.000
Tk 258	External Floating Roof	Alkylate Gasoline	0.000	0.000	0.000	0.000	159.850	0.000
Tk 262	External Floating Roof	SUP	0.000	0.000	3.107	0.000	39.867	0.085
Tk 263	External Floating Roof	JetA	0.000	0.000	0.000	4.276	0.000	2.658
Tk 264	External Floating Roof	JetA	0.000	0.000	0.000	4.286	0.000	2.669
Tk 265	External Floating Roof	JetA	0.000	0.000	0.000	1.790	0.000	1.103
Tk 266	External Floating Roof	WSR	0.000	0.000	505.627	0.000	56.826	1.798
Tk 267	External Floating Roof	JetA	0.000	0.000	0.000	4.377	0.000	2.722
Tk 268	External Floating Roof	Diesel	0.000	0.000	0.000	0.141	0.000	0.000
Tk 269	External Floating Roof	WSR	0.000	0.000	485.151	0.000	54.498	1.710
Tk 270	External Floating Roof	Diesel	0.000	0.000	0.000	0.133	0.000	0.000
Tk 271	External Floating Roof	JetA or gasoline	0.000	0.000	0.000	1.613	0.000	1.023
Tk 272	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	1.128	0.000	0.000
Tk 273	External Floating Roof	U/L	0.000	0.000	61.506	0.000	36.794	0.082
Tk 274	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	1.440	0.000	0.000
Tk 275	External Floating Roof	WSR	0.000	0.000	11.001	0.000	1.386	0.124
Tk 301	External Floating Roof	Rec Oil	0.000	0.032	55.087	9.598	56.576	1.479
Tk 302	External Floating Roof	Rec Oil	0.000	0.032	55.087	9.598	56.576	1.479

**Table 3-5 (continued)**  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank Id	Type of tank	Service of Tank	O-TOLUIDINE	ACRYLAMIDE	PROPYLENE	1,2,4-TMBenzene	ETHYLENE
			CAS# 95534	CAS# 79061	CAS# 115071	CAS# 95636	CAS# 74851
Tk 104	External Floating Roof	Crude: Nanhi Group	0.543	0.000	0.054	0.000	0.000
Tk 105	External Floating Roof	Crude: Tapis Group	0.854	0.000	0.085	0.000	0.000
Tk 106	External Floating Roof	Crude: Tapis Group	0.853	0.000	0.085	0.000	0.000
Tk 107	External Floating Roof	Crude: MinasGroup	0.550	0.000	0.055	0.000	0.000
Tk 108	External Floating Roof	Crude: Widuri Group	0.894	0.000	0.089	0.000	0.000
Tk 109	External Floating Roof	U/L	6.770	0.068	0.000	11.747	0.000
Tk 110	External Floating Roof	Crude: Tapis Group	0.875	0.000	0.088	0.000	0.000
Tk 111	External Floating Roof	WSR	0.000	0.000	0.000	0.000	0.000
Tk 113	External Floating Roof	Rec Crude	0.001	0.000	0.000	0.000	0.000
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	0.000	0.000	0.000	0.000	0.000
Tk 162	External Floating Roof	Rec Oil	14.759	0.000	0.018	1.724	0.000
Tk 163	External Floating Roof	Rec Oil	14.759	0.000	0.018	1.724	0.000
Tk 232	External Floating Roof	HCC	27.199	0.000	0.000	27.354	0.000
Tk 233	External Floating Roof	HCC	18.762	0.000	0.000	19.266	0.000
Tk 235	External Floating Roof	Transmix	0.000	0.000	0.000	0.000	0.000
Tk 236	External Floating Roof	U/L	5.634	0.056	0.000	8.153	0.000
Tk 237	External Floating Roof	SUP	5.629	0.056	0.000	3.919	0.000
Tk 249	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	0.000
Tk 250	External Floating Roof	Avgas	0.000	0.000	0.000	0.000	0.000
Tk 252	External Floating Roof	LCC	0.000	0.000	0.000	0.445	0.000
Tk 253	External Floating Roof	LCC	0.000	0.000	0.000	0.446	0.000
Tk 254	External Floating Roof	U/L	5.573	0.056	0.000	8.000	0.000

**Table 3-5 (continued)**  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank Id	Type of tank	Service of Tank	O-TOLUIDINE	ACRYLAMIDE	PROPYLENE	1,2,4-TMBenzene	ETHYLENE
			CAS# 95534	CAS# 79061	CAS# 115071	CAS# 95636	CAS# 74851
Tk 255	External Floating Roof	SUP	2.436	0.024	0.000	1.628	0.000
Tk 256	External Floating Roof	U/L	5.634	0.056	0.000	8.153	0.000
Tk 257	External Floating Roof	Dimate Gasoline	0.000	0.000	0.062	0.000	0.000
Tk 258	External Floating Roof	Alkylate Gasoline	0.000	0.000	0.000	0.000	0.000
Tk 262	External Floating Roof	SUP	5.525	0.055	0.000	3.839	0.000
Tk 263	External Floating Roof	JetA	42.763	0.000	0.000	36.557	0.000
Tk 264	External Floating Roof	JetA	42.864	0.000	0.000	36.864	0.000
Tk 265	External Floating Roof	JetA	17.901	0.000	0.000	15.330	0.000
Tk 266	External Floating Roof	WSR	0.000	0.000	0.000	0.000	0.000
Tk 267	External Floating Roof	JetA	43.771	0.000	0.000	37.463	0.000
Tk 268	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000
Tk 269	External Floating Roof	WSR	0.000	0.000	0.000	0.000	0.000
Tk 270	External Floating Roof	Diesel	0.000	0.000	0.000	0.000	0.000
Tk 271	External Floating Roof	JetA or gasoline	16.130	0.000	0.000	14.807	0.000
Tk 272	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000
Tk 273	External Floating Roof	U/L	5.070	0.051	0.000	7.091	0.000
Tk 274	Vertical Fixed Roof	ULSD	0.000	0.000	0.000	0.000	0.000
Tk 275	External Floating Roof	WSR	0.000	0.000	0.000	0.000	0.000
Tk 301	External Floating Roof	Rec Oil	25.595	0.000	0.000	2.700	0.000
Tk 302	External Floating Roof	Rec Oil	25.595	0.000	0.000	2.700	0.000

**Table 3-6  
POTENTIAL EMISSIONS FROM REFINERY TRUCK LOADING RACK**

**(Note: emissions from this source normally do not occur and the indicated emissions represent an extremely conservative scenario in which the normal delivery of refinery products by pipeline is interrupted for a full year)**

Product Loaded	S	P	M	T	VOC Factor (lb/103 gal)	Throughput (103 gal/year)	VOC Emission (ton/yr)	Benzene tons/yr	Naphthalene tons/yr	o-Xylene tons/yr	Ethylbenzene tons/yr
Motor Gasoline	0.5	8.27	66	537	6.3	306600	970.75	4.8537	4.2713	13.6875	7.1835
Aviation Gas	0.5	5.22	60	537	3.6	1993	3.62	0.0000	0.0000	0.0000	0.0000
Diesel	0.5	0.0143	130	537	0.0	122640	1.32	0.0000	0.0000	0.0000	0.0000
Jet Fuel	0.5	0.205	130	537	0.3	183960	28.44	0.0000	0.3697	0.6797	0.2275

Product Loaded	p-Xylene tons/yr	Ethylene Dibromide tons/yr	Ethylene Dichloride tons/yr	m-Xylene tons/yr	Toluene tons/yr	1,3-Butadiene tons/yr	n-Hexane tons/yr	Aniline tons/yr	Cresol Mixture tons/yr
Motor Gasoline	10.1928	0.0000	0.0000	25.9189	42.6157	0.0000	13.0080	0.0971	0.0000
Aviation Gas	0.0000	0.0009	0.0000	0.0000	0.0000	0.0000	0.0011	0.0000	0.0000
Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0013
Jet Fuel	0.2986	0.0000	0.0000	0.7451	0.0000	0.0000	0.0000	0.0003	0.0284



**Table 3-6 (continued)**  
**POTENTIAL EMISSIONS FROM REFINERY TRUCK LOADING RACK**

Product Loaded	Phenol tons/yr	Styrene tons/yr	Methanol tons/yr	Nickel tons/yr	HCL tons/yr	Perchloroethylene tons/yr	Biphenyl tons/yr
Motor Gasoline	0.0971	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Aviation Gas	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Diesel	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0013
Jet Fuel	0.0284	0.0000	0.0000	0.0000	0.0000	0.0000	0.0284

Product Loaded	2,2,4 Trimethylpentane tons/yr	Cumene tons/yr	o-Toluidine tons/yr	Acrylamide tons/yr	Antimony Compounds tons/yr	Arsenic tons/yr	Cyanide Compounds tons/yr
Motor Gasoline	4.8537	0.0971	0.0971	0.0010	0.0000	0.0000	0.0000
Aviation Gas	0.0797	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Jet Fuel	0.0000	0.0284	0.2844	0.0000	0.0000	0.0000	0.0000

### 3.1.4 Process Unit Fugitives

As discussed in Section 2, the refinery incorporates numerous processes and storage facilities. These facilities are interconnected by piping, which uses tens of thousands of components such as valves, flanges, connectors, pumps, and compressors necessary for safe and efficient refinery operation. Fugitive emissions are defined as emissions that could not reasonably be expected to pass through a stack or vent. VOC emissions and emissions of the associated HAPs that occur due to leakage from piping components are defined as process fugitive emissions.

The estimation of process fugitive emissions was accomplished using published emission factors for specific components (e.g., valves, flanges, pumps, etc.) in a specific service (light liquid, heavy liquid, gas), and applying these factors to the total number of components in each process area. The refinery process areas are summarized in Table 3-7. The emission factors used for estimating total VOC emissions from components are presented in the EPA document "Protocol for Equipment Leak Estimates" (EPA, 1995). The fugitive emissions estimates were based on the Protocol's refinery average VOC emission factors, which are summarized in Table 3-8. Although a leak detection and repair (LDAR) program has been put in place within a number of refinery areas, non-LDAR emission factors are conservatively used to estimate the worst-case potential fugitive emissions from process units throughout the facility.

Calculation of fugitive emissions requires estimates of the total numbers of refinery components by type. In the original Covered Source Permit application, actual component counts for refinery process units were largely unavailable and the basis of the counts was the refinery Piping and Instrumentation Diagrams (P&IDs). Actual component counts obtained from implementation of the refinery LDAR program were used in this renewal application for those process areas where the LDAR program has been implemented. Component counts for the remaining refinery areas continue to rely on the data provided by the P&IDs.

The numbers of components by process area using non-LDAR emission factors are summarized in Table 3-9. Calculated VOC fugitive emissions by process area are summarized in Table 3-10. Detailed spreadsheets of component counts and emission estimates for individual components are provided on CD in Appendix B-3.

The above estimates reflect only streams in VOC service, which are defined as streams having a VOC content in excess of 10 percent by weight (EPA, 1995).

Pressure relief devices (PRV) that vent to a flare or control device are excluded from the fugitive emissions inventory because these emissions are controlled. As discussed previously, streams in insignificant liquid service (vapor pressure less than 0.3 kPa) have also been excluded from the inventory.

**Table 3-7**  
**REFINERY PROCESS AREAS**

<b>Area Number</b>	<b>Area Description</b>
20	LPG area and field piping Blending and shipping storage tanks
23	Relief systems/cooling towers
36	Waste water treatment Land treatment unit Foul water tanks
51	Crude unit
52/55	Boilers/foul water oxidizer
53/54	Fluid catalytic cracker unit
56	Hydrogenation plant
57	Hydrogen plant
58	Alkylation plant
59	Isomerization plant
60	Asphalt plant
61/62	Amine/acid plant
66	Dimersol plant
67	Cogeneration plant

**Table 3-8**  
**REFINERY AVERAGE PROCESS FUGITIVE VOC EMISSION FACTORS (\*)**

Equipment Type	Service <sup>1</sup>	Emission Factor (kg/hr/source)
Valves	G	0.0268
	LL	0.0109
	HL	0.00023
Pump Seals	G	0.2803**
	LL	0.114
	HL	0.021
Compressor Seals	G	0.636
PRVs	G	0.16
Connectors	ALL	0.00025
Open-ended Lines	ALL	0.0023
Sampling Connections	ALL	0.015

\* Obtained from Table 2-2 of EPA Document "Protocol for Equipment Leak Emission Estimates" 1995

\*\* No emission factor available for pump seals in gas service. Emission factor above reflects LL service for pump seals adjusted by the ratio of the gas to light liquid service emission factors for valves.

<sup>1</sup>G=Gas, LL=Light Liquid, HL=Heavy Liquid

**Table 3-9  
COMPONENT COUNTS BY REFINERY AREA**

<b>Area Number</b>	<b>Area Description</b>	<b>Service</b>	<b>Valves</b>	<b>Flanges</b>	<b>Pumps</b>	<b>Compressors</b>	<b>PRVS</b>
20	LPG area and field piping Blending and shipping storage tanks	All	2,421	11,432	58	4	32
23	Relief systems	All	53	220	0	0	0
36	Waste water treatment	All	246	335	12	0	2
51	Crude unit	All	1,403	6,558	29	1	4
52/55	Boilers/foul water oxidizer	All	103	181	0	0	0
53	Fluid catalytic cracker unit	All	1,908	2,452	33	0	12
56	Hydrogenation plant	All	422	812	1	2	4
57	Hydrogen plant	All	166	914	1	0	4
58	Alkylation plant	All	1,180	5,821	21	1	0
59	Isomerization plant	All	570	1,493	9	0	0
60	Asphalt plant	All	53	236	0	0	0
61/62	Amine/acid plant	All	12	49	0	0	0
66	Dimersol plant	All	974	1,272	21	0	12
67	Cogeneration plant	All	253	1,264	2	1	0
	<b>Total</b>	<b>All</b>	<b>9,765</b>	<b>33,039</b>	<b>187</b>	<b>9</b>	<b>71</b>

Note: For summary purposes, both connectors and fittings have been grouped under the category of flanges

**Table 3-10**  
**MAXIMUM FUGITIVE VOC EMISSIONS FROM**  
**FIELD PIPING COMPONENT LEAKS BY PROCESS AREA**

<b>Area Number</b>	<b>Area Description</b>	<b>VOC Emissions (Ton/Yr)</b>
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	438.3
23	Relief Systems	14.3
36	Waste Water Treatment Foul Water Tanks	1.6
51	Crude Unit	204.8
52/55	Boilers/Foul Water Oxidizer	27.1
53/54	Fluid Catalytic Cracker Unit	222.0
56	Hydrogenation Plant	71.5
57	Hydrogen Plant	34.4
58	Alkylation Plant	179.9
59	Isomerization Plant	107.9
60	Asphalt Plant	14.3
61/62	Amine/Acid Plant	3.3
66	Dimersol Plant	20.5
67	Cogeneration Plant	62.5
Total <sup>1</sup>		1402.2

<sup>1</sup>This value may be different from the sum on the counterparts due to rounding from truncation of insignificant digits.

The total VOC emissions estimated by means of the above methods served as the basis for estimating fugitive emissions of HAPs from the refinery process units. Each component, or group of components in the same service, was assigned a stream code that corresponds to a specific distribution of HAPs by weight. The stream compositions were developed by Chevron based on process engineering information, stream analyses or available literature. The total VOC emission estimate was then multiplied by the weight fractions for individual HAPs to estimate the corresponding species emissions.

Maximum estimated fugitive HAP emissions from process units are summarized in Table 3-11.

### 3.1.5 Wastewater and Foul Water Treatment

Wastewater and foul water treatment facilities process units are physically covered and controlled emission sources, excluding the downstream oxidizers after the Benzene Recovery Unit (BRU). AP-42 provides an emission factor of 0.2 pounds of VOC per thousand gallons of throughput for effluent treatment systems having control measures such as carbon adsorbers. The maximum capacity of the wastewater treatment system is 1,400 gallons per minute, yielding a maximum estimated VOC emission of 73.6 tons/year (147,200 lbs/year). HAP emissions are based on the VOC emissions and the speciation profile for recovered oil.

### 3.1.6 Cooling Tower

The primary source of VOC emissions from cooling towers is leakage from process equipment that results in organic liquids mixing with the cooling water. Chevron has a monitoring and maintenance program to minimize the occurrence of such leaks. Section 5.1 of AP-42 presents a VOC emission factor for cooling towers at refineries with a program to minimize leaks. This factor is 0.7 pounds of VOC per million gallons of water. The cooling tower at the Chevron Hawaii Refinery has a cooling water rate of 50,000 gallons per minute, resulting in an estimated VOC emission rate of 2.1 pounds per hour (9.2 tons per year).

### 3.1.7 Flaring

The refinery flares are necessary to control emissions from various equipment vents and to provide for safe operations in case of upset conditions or an emergency. Catastrophic upset condition gas rates are highly variable and difficult to predict; therefore, Chevron has primarily estimated emissions using AP-42 emission factors that are functions of the maximum refinery throughput. The flaring emission factors are based on an estimate of gas flaring rates as a function of refinery process rates. Note that the emissions are only provided as an estimate and that actual emissions may vary. Chevron attempts to minimize flaring events; however, in case of an emergency, flaring rates cannot be limited.

Table 5.1-1 of EPA document AP-42 provides the following refinery flaring emission factors (in pounds per thousand barrels of feed):

- Carbon monoxide - 4.3
- VOC - 0.8
- Nitrogen oxides - 18.9
- Sulfur oxides (as SO<sub>2</sub>) - 26.9

**Table 3-11**  
**MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS**

Number	Area Description	Benzene CAS# 71432 (ton/yr)	Naphthalene CAS# 91203 (ton/yr)	o-Xylene CAS# 95476 (ton/yr)	Ethylbenzene CAS# 100414 (ton/yr)	p-Xylene CAS# 106423 (ton/yr)	Ethylene Dibromide CAS# 106934 (ton/yr)	Ethylene Dichloride CAS# 107062 (ton/yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	0.82	1.40	3.32	1.25	1.71	0.45	0.27
23	Relief Systems	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Waste Water Treatment Unit	0.01	0.01	0.01	0.00	0.00	0.00	0.00
51	Crude Unit	1.15	0.23	0.75	0.18	0.33	0.00	0.00
52/55	Boilers/Foul Water Oxidizer	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	Fluid Catalytic Cracker Unit	0.87	0.61	1.81	0.91	1.30	0.00	0.00
56	Hydrogenation Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	Hydrogen Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Alkylation Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
59	Isomerization Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	Asphalt Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61/62	Amine/Acid Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Dimersol Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
67	Cogeneration Plant	0.271	0.000	0.000	0.000	0.000	0.000	0.000
	Process Fugitive Summary	3.13	2.26	5.89	2.34	3.35	0.45	0.27



**Table 3-11 (continued)**  
**MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS**

Number	Area Description	m-Xylene CAS# 108383 (ton/yr)	Toluene CAS# 108883 (ton/yr)	1,3-Butadiene CAS# 106990 (ton/yr)	n-Hexane CAS# 110543 (ton/yr)	Aniline CAS# 62533 (ton/yr)	Cresol Mixture CAS# 1319773 (ton/yr)	Phenol CAS# 108952 (ton/yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	4.63	4.60	0.30	1.21	0.02	0.16	0.10
23	Relief Systems	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Waste Water Treatment Unit	0.02	0.02	0.00	0.03	0.00	0.02	0.00
51	Crude Unit	1.22	2.57	0.02	3.50	0.01	0.05	0.01
52/55	Boilers/Foul Water Oxidizer	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	Fluid Catalytic Cracker Unit	3.33	5.19	0.25	0.37	0.02	0.00	0.01
56	Hydrogenation Plant	0.00	0.00	0.13	0.00	0.00	0.00	0.00
57	Hydrogen Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Alkylation Plant	0.00	0.00	0.05	0.01	0.00	0.00	0.00
59	Isomerization Plant	0.00	0.00	0.05	0.00	0.00	0.00	0.00
60	Asphalt Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61/62	Amine/Acid Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Dimersol Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
67	Cogeneration Plant	0.000	0.153	0.000	0.592	0.000	0.000	0.000
	Process Fugitive Summary	9.20	12.54	0.80	5.70	0.05	0.23	0.12

**Table 3-11 (continued)**  
**MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS**

Number	Area Description	Styrene CAS# 100425 (ton/yr)	Methanol CAS# 67561 (ton/yr)	Nickel CAS# 7440020 (ton/yr)	HCL CAS# 7647010 (ton/yr)	Perchloroethylene CAS# 127184 (ton/yr)	Biphenyl CAS# 92524 (ton/yr)	2,2,4 Trimethylpentane CAS# 540841 (ton/yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	0.02	0.03	0.00	0.00	0.00	0.09	0.44
23	Relief Systems	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Waste Water Treatment Unit	0.00	0.00	0.00	0.00	0.00	0.00	0.01
51	Crude Unit	0.00	0.00	0.00	0.00	0.00	0.01	0.55
52/55	Boilers/Foul Water Oxidizer	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	Fluid Catalytic Cracker Unit	0.04	0.00	0.00	0.00	0.00	0.01	0.00
56	Hydrogenation Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	Hydrogen Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Alkylation Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.40
59	Isomerization Plant	0.00	0.00	0.00	0.00	0.05	0.00	0.00
60	Asphalt Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61/62	Amine/Acid Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Dimersol Plant	0.00	0.00	0.34	0.00	0.00	0.00	0.00
67	Cogeneration Plant	0.000	0.000	0.000	0.000	0.000	0.000	0.104
	Process Fugitive Summary	0.07	0.03	0.34	0.00	0.05	0.11	1.51

**Table 3-11 (continued)**  
**MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS**

Number	Area Description	Cumene CAS# 98828 (ton/yr)	o-Toluidine CAS# 95534 (ton/yr)	Acrylamide CAS# 79061 (ton/yr)	Antimony Compounds CAS# ADQ500 (ton/yr)	Arsenic CAS# 7440382 (ton/yr)	Cyanide Compounds CAS# 1073 (ton/yr)	Total HAPs ton/yr
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	0.17	0.86	0.00	0.00	0.01	0.01	21.873
23	Relief Systems	0.00	0.00	0.00	0.00	0.00	0.00	0.003
36	Waste Water Treatment Unit	0.00	0.00	0.00	0.00	0.00	0.00	0.130
51	Crude Unit	0.08	0.09	0.00	0.00	0.01	0.01	10.794
52/55	Boilers/Foul Water Oxidizer	0.00	0.00	0.00	0.00	0.00	0.00	0.005
53	Fluid Catalytic Cracker Unit	0.04	0.18	0.00	0.00	0.02	0.02	14.976
56	Hydrogenation Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.143
57	Hydrogen Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.000
58	Alkylation Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.459
59	Isomerization Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.095
60	Asphalt Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.003
61/62	Amine/Acid Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.001
66	Dimersol Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.345
67	Cogeneration Plant	0.000	0.000	0.000	0.000	0.005	0.005	1.129
	Process Fugitive Summary	0.28	1.14	0.00	0.01	0.05	0.05	49.957

During normal operations, sulfur is stripped from the RFG in the acid plant (before it is flared). In the past when the acid plant was down, the sulfur was not removed from the acid plant gas stream, and additional SO<sub>2</sub> was produced by flaring. However, with the addition of the Caustic Scrubber, such high-SO<sub>2</sub> events will no longer occur. In addition the refinery has installed a flare vapor recovery system. This is described in Section 2.3.2.1.

Applying the AP-42 factors for CO, VOC, SO<sub>2</sub> and NO<sub>x</sub> to a rate of 65,000 bbl/day of crude oil feed, results in the following estimated emissions (tons per year) from both flares combined. This conservative approach to estimating flaring emissions was selected because of safety concerns associated with limiting the throughput to the flares. HAP emissions for the flare have not been quantified, because the flares combust a variety of process streams. Therefore, neither the specific HAPs present nor their quantities can be meaningfully determined.

- Carbon monoxide - 51.0 tons per year
- VOC - 9.5 tons per year
- Nitrogen oxides - 224.2 tons per year
- Sulfur dioxide - 319.1 tons per year

### 3.1.8 Catalyst Transfer Operations at the FCC

Operation of the FCC unit requires the removal and disposal of spent catalyst and the addition of fresh catalyst. Based on historical records, it is estimated that 77 tons per month of catalyst is disposed of and replaced with fresh catalyst. No emission factor was identified to address this specific catalyst handling activity. AP-42 (Section 8.23), however, provides factors for material transfer operations in the metallic minerals processing industry. The transfer of catalyst was assumed to be represented by the factor for material transfer (0.06 pounds of particulate per ton of material transferred [i.e., removal of spent catalyst plus replacement with new catalyst]). Using this factor results in an estimated particulate matter emission of .03 tons per year.

## 3.2 Summary

The refinery inventory of maximum potential criteria pollutant emissions is summarized in Table 3-12. The corresponding maximum potential HAP emissions are summarized in Table 3-13. These emissions reflect the estimation methods and assumptions for the individual source types described in Sections 3.1.1 through 3.1.8.

## 3.3 Identification of Control Devices

Emission control devices exist on the cogeneration turbines and compressor, the FCC stack, on many storage tanks, and the wastewater treatment system. The cogeneration turbines have low-NO<sub>x</sub> burners and water injection to reduce emissions of nitrogen oxides. This turbine control system is designed to limit NO<sub>x</sub> emissions to a level of no more than 67 and 69 parts per million on a volume basis at 15 percent O<sub>2</sub> for RFG and WSR fuels, respectively. The cogeneration compressor vents directly to the flare. The FCC Furnace has low-NO<sub>x</sub> burners to reduce emissions of nitrogen oxides.

**Table 3-12**  
**SUMMARY OF MAXIMUM POTENTIAL CRITERIA POLLUTANT EMISSIONS**  
**FROM THE CHEVRON HAWAII REFINERY**

Sources	Pollutant Emission Rates (ton/yr)						Total Criteria Pollutant Emissions
	PM10	SO <sub>2</sub>	CO	NO <sub>2</sub>	VOC	Lead	
Boilers	134.8	1353.8	86.2	551.9	13.1	0.0	2140
Cogen Turbines	11.7	27.9	52.5	193.2	2.3	0.0	288
Crude Furnaces	44.5	482.0	75.0	302.9	5.1	0.0	909
FCC Furnace	2.0	7.1	22.1	13.1	1.4	0.0	46
Isom Furnaces	0.2	0.7	2.1	2.5	0.1	0.0	5
H&H Furnaces	1.1	3.9	12.1	14.5	0.8	0.0	32
Acid preheater & combustion chamber	0.4	1.5	4.8	5.7	0.3	0.0	13
Asphalt Furnace	0.2	0.7	2.0	2.4	0.1	0.0	5
FCC Stack	175.2	333.3	499.3	285.1	14.7	0.0	1308
Generators	5.5	5.1	16.7	77.6	6.2	-	111
Cooling Tower	3.2	-	-	-	9.2	-	12
Acid plant absorber stack (*)	-	1405.3	-	-	-	-	1405
Catalyst transfer	0.0	-	-	-	-	-	0
Wastewater treatment	-	-	-	-	73.6	0.0	74
Loading Rack	-	-	-	-	1117.7	0.0	1118
Process Fugitives	-	-	-	-	1402.2	0.0	1404
Tanks	-	-	-	-	467.9	0.0	468
Marine loading	-	-	-	-	196.6	0.0	197
Refinery Flares	-	319.1	51.0	224.2	9.5	-	604
<b>Totals</b>	<b>378.9</b>	<b>3940.4</b>	<b>823.9</b>	<b>1672.9</b>	<b>3207.3</b>	<b>0.0</b>	<b>10024.8</b>

Notes: (\*) Criteria pollutant emissions from the acid preheater and combustion chamber are vented to the acid plant absorber stack. The listed SO<sub>2</sub> emissions from the acid plant absorber stack are only from acid production.

**Table 3-13**  
**SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY**

	BENZENE	NAPHTHALENE	O-XYLENE	ETHYLBENZENE	P-XYLENE	DIBROMIDE	DICHLORIDE	M-XYLENE	TOLUENE	1,3-BUTADIENE
	CAS# 71432	CAS# 91203	CAS# 95476	CAS# 100414	CAS# 106423	CAS# 106934	CAS# 107062	CAS# 108383	CAS# 108883	CAS# 106990
LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	0.82	1.40	3.32	1.25	1.71	0.45	0.27	4.63	4.60	0.30
RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE WATER TREATMENT LAND TREATMENT UNIT	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.02	0.02	0.00
CRUDE UNIT	1.15	0.23	0.75	0.18	0.33	0.00	0.00	1.22	2.57	0.02
BOILERS/FOUL WATER OXIDIZER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FLUID CATALYTIC CRACKER UNIT	0.87	0.61	1.81	0.91	1.30	0.00	0.00	3.33	5.19	0.25
HYDROGENATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13
HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALKYLATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05
ISOMERIZATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05
ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DIMERSOL PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COGENERATION PLANT	0.271	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.153	0.000

**Table 3-13 (continued)**  
**SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY**

	BENZENE	NAPHTHALENE	O-XYLENE	ETHYLBENZENE	P-XYLENE	DIBROMIDE	DICHLORIDE	M-XYLENE	TOLUENE	1,3-BUTADIENE
	CAS# 71432	CAS# 91203	CAS# 95476	CAS# 100414	CAS# 106423	CAS# 106934	CAS# 107062	CAS# 108383	CAS# 108883	CAS# 106990
BOILER POINT	0.003	0.008	0.001	0.00					0.046	
COGEN POINT	0.034	0.018						0.033	0.067	0.008
CRUDE POINT	0.001	0.006	0.001	0.00					0.030	
FCC POINT	0.001	0.000							0.001	
ISOM POINT	0.000	0.000							0.000	
H&H POINT	0.000	0.000							0.000	0.000
H&H POINT	0.000	0.000							0.000	0.000
ACID PLANT CC AND PREHEATER POINT	0.000	0.000							0.000	
ASPHALT POINT	0.000	0.000							0.000	
FCC STACK										
WASTEWATER	0.1398	0.3458	0.5887	0.1840	0.2796	0.0002	0.0000	0.7211	0.4709	0.0000
LOAD RACK	4.85	4.64	14.37	7.41	10.49	0.00	0.00	26.66	42.62	0.00
MARINE LOADING	4.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.32	0.00
FLARE										0.00
GENERATORS	0.00	0.00	0.00						0.00	0.00
HAPs Summary (ton/yr)	12.27	7.28	20.84	9.94	14.12	0.45	0.27	36.62	58.09	0.81

**Table 3-13 (continued)**  
**SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY**

	n-HEXANE	ANILINE	CRESOL MIXTURE	PHENOL	STYRENE	METHANOL	NICKEL	HCL	PERCHLORO ETHYLENE	BIPHENYL
	CAS# 110543	CAS# 62533	CAS# 1319773	CAS# 108952	CAS# 100425	CAS# 67561	CAS# 7440020	CAS# 7647010	CAS# 127184	CAS# 92524
LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	1.21	0.02	0.16	0.10	0.02	0.03	0.00	0.00	0.00	0.09
RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE WATER TREATMENT LAND TREATMENT UNIT	0.03	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CRUDE UNIT	3.50	0.01	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.01
BOILERS/FOUL WATER OXIDIZER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FLUID CATALYTIC CRACKER UNIT	0.37	0.02	0.00	0.01	0.04	0.00	0.00	0.00	0.00	0.01
HYDROGENATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALKYLATION PLANT	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ISOMERIZATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00
ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DIMERSOL PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.34	0.00	0.00	0.00
COGENERATION PLANT	0.592	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
BOILER POINT	1.230									
COGEN POINT										
CRUDE POINT	0.002									
FCC POINT	0.473									
ISOM POINT	0.044									
H&H POINT	0.071								0.000	0.000
H&H POINT	0.189								0.000	0.000
ACID PLANT CC AND PREHEATER POINT	0.103									
ASPHALT POINT	0.043									
FCC STACK										
WASTEWATER	1.0449	0.0007	1.0670	0.0589	0.0000	0.0000	0.0000	0.0000	0.0001	0.0221
LOAD RACK	13.01	0.10	0.03	0.13	0.00	0.00	0.00	0.00	0.00	0.03
MARINE LOADING	8.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FLARE										



**Table 3-13 (continued)**  
**SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY**

	n-HEXANE	ANILINE	CRESOL MIXTURE	PHENOL	STYRENE	METHANOL	NICKEL	HCL	PERCHLORO ETHYLENE	BIPHENYL
	CAS# 110543	CAS# 62533	CAS# 1319773	CAS# 108952	CAS# 100425	CAS# 67561	CAS# 7440020	CAS# 7647010	CAS# 127184	CAS# 92524
GENERATORS										
HAPs Summary (ton/yr)	30.90	0.14	1.33	0.30	0.07	0.03	0.34	0.00	0.05	0.17

**Table 3-13 (continued)**  
**SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY**

	2,2,4 TRIMETHYLPENTANE	CUMENE	O-TOLUIDINE	ACRYLAMIDE	ANTIMONY COMPOUNDS	ARSENIC	CYANIDE COMPOUNDS	Formaldehyde	POM/PAH
	CAS# 540841	CAS# 98828	CAS# 95534	CAS# 79061	CAS# ADQ500	CAS# 7440382	CAS# 1073	CAS# 50000	CAS# EDF047
LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	0.44	0.17	0.86	0.00	0.00	0.01	0.01		
RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
WASTE WATER TREATMENT LAND TREATMENT UNIT	0.01	0.00	0.00	0.00	0.00	0.00	0.00		
CRUDE UNIT	0.55	0.08	0.09	0.00	0.00	0.01	0.01		
BOILERS/FOUL WATER OXIDIZER	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
FLUID CATALYTIC CRACKER UNIT	0.00	0.04	0.18	0.00	0.00	0.02	0.02		
HYDROGENATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
ALKYLATION PLANT	0.40	0.00	0.00	0.00	0.00	0.00	0.00		
ISOMERIZATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
DIMERSOL PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
COGENERATION PLANT	0.104	0.000	0.000	0.000	0.000	0.005	0.005		
BOILER POINT								0.349	0.298
COGEN POINT								0.506	0.021
CRUDE POINT								0.208	0.006
FCC POINT								0.020	0.000
ISOM POINT								0.002	0.000
H&H POINT								0.003	0.000
H&H POINT								0.008	0.000
ACID PLANT CC AND PREHEATER POINT								0.004	0.000
ASPHALT POINT								0.002	0.000
FCC STACK								0.890	
WASTEWATER	0.5151	0.1251	0.0589	0.0000	0.0001	0.0001	0.0001		
LOAD RACK	4.93	0.13	0.38	0.00	0.00	0.00	0.00	0.00	0.00

**Table 3-13 (continued)**  
**SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY**

	2,2,4 TRIMETHYLPENTANE	CUMENE	O-TOLUIDINE	ACRYLAMIDE	ANTIMONY COMPOUNDS	ARSENIC	CYANIDE COMPOUNDS	Formaldehyde	POM/PAH
	CAS# 540841	CAS# 98828	CAS# 95534	CAS# 79061	CAS# ADQ500	CAS# 7440382	CAS# 1073	CAS# 50000	CAS# EDF047
MARINE LOADING	1.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FLARE									
GENERATORS								0.00	0.00
HAPs Summary (ton/yr)	8.53	0.54	1.58	0.00	0.01	0.05	0.05	1.99	0.32

Both flare stacks are also considered control devices because they are used to combust emissions from the venting of equipment that is regulated under NSPS and MACT requirements.

The FCC stack is routed through a cyclone and electrostatic precipitator (ESP). These devices remove particulate matter from the FCC flue gas. The removal efficiency of these controls ranges from 95 to more than 99 percent.

The wastewater treatment plant uses several devices to control emissions. The foul water tanks are vented to a flare and the foul water oxidizer is vented to the Boiler Plant boilers. The nitrogen strippers of the benzene recovery unit (BRU) remove hydrocarbons from the wastewater. These hydrocarbons are controlled by carbon absorbers and are subsequently sent to the recovered oil tankage. The BRU vents some nitrogen at the end of the adsorber regeneration. This vent is controlled by carbon canisters, as is the purge gas from the API separators. The recovered oil sump is connected to carbon canisters.

Secondary seals or equivalent (i.e., dome roofs) are installed on tanks subject to Subpart CC.

A detailed list of controls is provided in Appendix B.

### 3.4 Identification of Compliance Monitoring Devices

Chevron monitors numerous surrogate parameters that are used to estimate emissions from specific processes, and operates several monitors for compliance tracking. Usage of both fuel oil and RFG is monitored for each furnace and cogeneration turbine. For each storage tank, records are maintained on the material stored, its chemical properties, and the throughput of the tank.

Specific compliance monitors within the Hawaii Refinery consist of RFG H<sub>2</sub>S monitoring at the effluent from the gas treatment unit, NO<sub>x</sub> and O<sub>2</sub> monitors on the cogeneration turbine exhaust stacks, flare pilot light monitors, crude flare continuous emissions monitors, FCC monitors for SO<sub>2</sub>, NO<sub>x</sub> and O<sub>2</sub>. Additionally, at the BRU, control device outlet VOC content, regeneration steam flow, temperature, and duration of regeneration are monitored. Further information on compliance monitoring requirements is provided in Section 5 of this application.

Emissions trading between process areas or group designations is not proposed. Information regarding compliance monitoring and reporting for each source group within the refinery is presented in Section 5.

### 3.5 Insignificant Activities

The operating permit regulations (Section 11-60.1-82(d)(e)(f)(g)) exempt specific activities from permitting requirements, but requires that such activities be listed. The following activities are exempted under 11-60.1-82(f)(g):

- Numerous tanks storing organic liquids have a capacity of less than 40,000 gallons and are not subject to other requirements in Sections 111 and 112 of the Act. These tanks are summarized as follows:

Tank Number	Service	Capacity (gallons)
20TD1	Anti Icing Additive	11,340
20TD2	HCC	11,340
20TD3	Out of Service	11,340
20TD4	ULMidgrade	11,340
20TD6	Anti Icing Additive	8,148
2010	Aviation Lead	15,288
5198	Nalco 5300	8,068

### 3.6 Request for Additional Exemptions

Section 11-60.1-82(f)(7) allows the Director to exempt “other activities as determined on a case-by-case basis to be insignificant.” Petroleum refineries are complex facilities with numerous types and sizes of sources. Some of these sources are small and will have no significant impact on ambient air quality, are not covered by any applicable requirement, and were granted exemption status in the original Title V permit. Chevron requests that the Director again exempt the following sources from the requirements of 11-60.1-82:

1. *Meter stations, sampling points and filters.* These sources are present throughout the various process areas. Leakage from the connections and fittings associated with such equipment has been accounted for in the fugitive emissions estimates for each process unit. When sampling occurs or filters are changed, however, a small amount of VOC may be emitted. It is estimated that emissions are typically less than 10 pounds per occurrence. Inclusion of such equipment emissions and operations in the permit would impose a significant burden for monitoring and recordkeeping without significant air quality benefit. Chevron uses good engineering and operating practices to minimize emissions during these operations.
2. *Pump and tank degassing operations.* Occasionally, pumps in liquid service malfunction if a gas bubble is encountered in the fuel flow. The only practical method of returning the pump to operation is to vent the gas bubble, and prime the pump with liquid. Most pumps are tied into the flare relief system, so that such venting is controlled. Some pumps are not tied into the flare system, however, and must be vented to atmosphere in order to prime the pump with liquid. Pumps are vented only when degassing is required.

There are 98 tanks in hydrocarbon service at the refinery. Tank degassing is performed approximately once every 10 years to enable tank interiors to be inspected. Degassing may be done more frequently (three or four times in 10 years), however, if maintenance issues arise. Degassing operations consist of draining a tank to the minimum pump-out level. Vapors under the area of the floating roof are vented to the atmosphere. It is impossible to control these emissions using the flare because the tanks are not under pressure during degassing.

3. *Training fires.* The regulations exempt smoke generating equipment used in certified fire training facilities. Chevron requests DOH concurrence that this exemption also applies to open pit fires used by Chevron for fire training.
4. *Process upset vents.* Pressurized equipment such as the crude towers and FCC unit are equipped with relief vents that open only during malfunctions or severe process upset conditions. The frequency of such occurrences cannot be predicted, and the vents are critical for safe operation. Historically, venting episodes are rare. Chevron requests that emissions from upset vents be exempted. However, applicable NSPS, Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and National Emission Standards for Hazardous Air Pollutants (NESHAP) standards will be satisfied.
5. *Refinery gasoline pump.* A single service station style gasoline pump is located at the refinery, and is used to fill all gasoline-powered vehicles. Its typical monthly throughput is less than 2,000 gallons. Gasoline service station operations are exempted from permitting requirements and Chevron requests this exemption be extended to the single oline pump.
6. *Mercury.* The instrumentation repair shop and the laboratory periodically repair instruments and gauges that contain liquid mercury. Only small amounts of mercury are removed from such equipment and the mercury is in an unheated liquid state. The total inventory of mercury at the refinery is estimated to be less than 1 gallon. Insignificant emissions are expected from this activity.
7. *Oily sewer and stormwater vents.* Oily water and stormwater sewers exist beneath the refinery. The oily water sewer routes to an oil/water separator and contains minor amounts of oil mixed with water. Additionally, some trace amounts of oil may be present in the stormwater system. To prevent over-pressure, vent pipes 3 inches in diameter and less are placed along the sewer route. There are 76 of these vent pipes, plus six manholes with vent openings. These vent pipes are expected to have insignificant emissions.
8. *Maintenance and cleaning activities.* Routine maintenance and cleaning activities at the refinery use small amounts of commercial chemicals. These chemicals are delivered to the refinery in small containers or drums. Their use is expected to result in insignificant emissions.

Black Oil Tanks must be cleaned to remove accumulated sludge before inspection. It is estimated that approximately two tanks per year are cleaned. Insignificant emissions are expected from this activity.

Process unit shutdown and turnaround activities are performed infrequently as needed for maintenance. Typically, turnaround is performed every 2 to 4 years depending on the process unit. Process fluids are removed and displaced by water. The unit is drained and steamed. Steam is vented to the flares.

9. *Additives, promoters, passivators, and antifoam agents.* Various chemicals are used in the refinery operation to facilitate the refining process. Addition of these chemicals is not anticipated to materially change facility VOC or HAP emissions, and results in insignificant incremental emissions.

10. *Insignificant Heavy Liquids.* Chevron has reviewed applicable requirements for numerous source categories to determine the implication of developing an insignificant heavy liquids source category. Insignificant heavy liquids are hydrocarbon liquids that have a vapor pressure less than 0.3 kPa. In general, this includes diesel and the heavier hydrocarbon liquids.

Emission calculation equations and emission factors were reviewed to assess the impact of excluding insignificant heavy liquids from the refinery inventory. Fugitive and storage tank emissions factors for heavy liquids are one to two orders of magnitude less than those for light liquids.

11. *FCCU Baghouse.* Three baghouses (Flex-Kleen bin vent filter) are located on the electrostatic precipitator of the FCCU to capture potential fugitive dust emissions when the ESP hopper is emptied. The control efficiency of the baghouses is 99.9%. Operation of these three baghouses will meet the insignificant emissions rate of less than 2 tpy of a regulated pollutant.
12. *Storage of Regulated Pollutants not in VOC service.* Numerous onsite tanks store substances containing regulated pollutants. These tanks are not in VOC service, consistent with Subpart VV 40 CFR 60.481. In addition, these tanks are not in petroleum liquid service, consistent with Subpart K 40 CFR 60.111. Insignificant fugitive emissions result from these tanks, which are listed below:

Tank Number	Service	Capacity (gallons)
350	Refinery Fuel Oil	120,918
351	Refinery Fuel Oil	120,918
175	Out of Service	50,904
5211	25% Aqueous Ammonia	11,760
5481	Out of service	10,164
6673	Nickel Catalyst	5,418
5197	25% Aqueous Ammonia	120

13. *Storage of Spent Sulfuric Acid.* Spent sulfuric acid is stored in up to two tanks at the refinery. Sulfuric acid is not a regulated pollutant; however, spent acid may contain residual amounts of VOC. Insignificant emissions are anticipated from these tanks, which are numbered 62AP1 and 62AP3.
14. *Foul Water Offgas Treatment with Catalytic Oxidizer.* The foul water offgas with ammonia is currently going to the boilers for combustion. With the proposed installation of new boilers as described in the Hybrid Energy Plant Project, the addition of a skid mounted catalytic oxidizer is proposed to process the ammonia to nitrogen. The catalyst used is electrically heated and produces minimal NOx emissions. The NOx emission rate under normal operating conditions is .27 lb/hr or 1.18 tpy. This equipment unit is deemed insignificant as emissions are less than 2 tpy of a regulated air pollutant.
15. *Storage of Non-Regulated Pollutants.* The tanks shown in Table 3-15 contain non-regulated pollutants. These tanks are not subject to federal or state requirements. The list is provided to clarify the contents of all tanks at the refinery.

**Table 3-14  
NON-REGULATED POLLUTANT STORAGE TANKS\***

<b>Tank Number</b>	<b>Service</b>	<b>Roof Type</b>	<b>Capacity (bbls)</b>
305	Neutralized Water	Cone	24
306	Neutralized Water	Cone	72
62AP2	Sulfuric Acid	Cone	2,422
120	Gutwater	Cone	240
352	Raw Water	None	24,000
353	Condensate	Cone	253
354	Hot Line Reactor Bottoms Accumulator	Cone	810
381	Dirty Backwash Water Tank	Cone	758
382	De-ionized Water	Cone	274
AP-4	Regenerated MEA	Cone	504
AP-5	Regenerated MEA	Cone	504
AP-6	Caustic (25° Be)	Cone	280
2301	Sulfuric Acid	Cone	14
V-5182A&B	Caustic (25° Be & 5° Be)	Cone	242
5206	20° Be Caustic	Cone	179
5210	50° Be Caustic	Cone	1360
5390	Condensate	Cone	107
5480	Caustic	Cone	70
V-5486	Water	Cone	2
V-5897	Water	Cone	11
6646	Caustic	Cone	155
6658	Condensate	Cone	40
5311	Spent Catalyst (FCC)	Cone	4,000
5312	Catalyst Fines (FCC)	Cone	317
5313	Catalyst Fines (FCC)	Cone	317
5314	Fresh Catalyst (FCC)	Cone	60
5316	Fresh Catalyst (FCC)	Cone	1,128

\* Does not include Reverse Osmosis boiler water tank or caustic tank for Caustic Scrubber project.



## 4. Dispersion Modeling

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The initial Title V permit application for the Chevron Refinery included a dispersion modeling analysis that demonstrated that the facility's emissions would not cause or contribute to pollutant concentrations in excess of federal or Hawaii ambient standards. In recognition that the refinery's normal operations entail processing of a variety of crude oil feedstocks to produce numerous different products, the representation of emissions from the various sources was undertaken in a manner to ensure that the resulting pollutant concentration estimates would not be underestimated for any foreseeable operational condition of the refinery.

Accordingly, the dispersion modeling analysis to estimate maximum short-term impacts (24 hours or less) assumed that any source capable of using multiple fuels was operating with the fuel that would result in the highest potential emissions. Additionally, despite the actual intermittent operation of some sources, the emissions used for modeling were based on the worst-case assumption of continuous operation at maximum capacity for all hours of the year. This is an extremely conservative representation of emissions, especially for the annual averaging period.

Since the initial Covered Source Permit Application was submitted, Chevron has applied for several minor and major permit modifications to implement various refinery projects. In each such instance, DOH has made a decision as to whether additional dispersion modeling was required as part of the application to ensure that the proposed modification would not result in pollutant concentrations in excess of applicable ambient standards. These analyses have been conducted and submitted to DOH when required, and, in each case, have shown that compliance with the standards continues to be maintained.

Of the six proposed changes to existing conditions of the Covered Source Permit being requested in this application (Section 5.3.2), none would result in increased emissions or changes in the conditions of pollutant releases to the atmosphere that would justify remodeling for this renewal application.

- The request to implement the Hybrid Energy Project as submitted to DOH in Appendix E to include a new cogeneration turbine, HRSG and two new boilers are proposed equipment changes. Conditions for the construction of this equipment was granted by DOH on 23 May 2007. Air Dispersion Modeling for these equipment changes was accepted by DOH as complying with ambient air quality standards.
- The request to remove the Asphalt Plant and all associated equipment as it is no longer operational. This has resulted in a decrease in emissions.

Thus, it is Chevron's position that there is no reason to conduct additional dispersion modeling as part of this permit renewal package.

# 5. Applicable Requirements and Compliance

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## 5.1 Introduction

As required by HAR §11.60.1-83(a) and §11-60.1-86, this chapter presents information describing air quality requirements applicable to operations at the Chevron Hawaii Refinery and methods for monitoring compliance. The Chevron Hawaii Refinery was built and commenced operation in 1960. No changes triggering air quality requirements were implemented from 1960 through 1976. Several source modifications were implemented from 1976 through September 1994, and these changes were addressed when Chevron filed the application for the initial Title V Covered Source Permit in September 1994. On February 22, 1999 the State of Hawaii, Department of Health (DOH) Environmental Management Division issued the initial Title V Covered Sources Permit No. 0088-01-C to Chevron USA Products Company for the Hawaii Refinery. The Covered Source Permit issued by DOH addressed all applicable requirements and compliance monitoring for the facility, including modifications through 1994 and compliance with NESHAP Subpart CC, which was adopted between the times the application was submitted and the Covered Source Permit was issued.

The initial Covered Source Permit is incorporated by reference into this renewal application and a detailed analysis of requirements and compliance monitoring has not been reiterated. However, Section 5.2 contains a summary of the applicable requirements taken directly from the initial Title V Covered Source Permit Review Summary (File #0088-01) prepared by DOH to support issuance of the initial Covered Source Permit. Section 5.3.1 addresses applicable requirements and compliance for modifications or regulations that have been implemented since the time of initial Covered Source Permit issuance in 1999 through the current operations. Section 5.3.2 describes proposed facility changes and regulations that may take effect during the term of the permit renewal through 2016, including changes to the DOH insignificant source classifications. Section 5.4 addresses MACT applicability and Compliance Assurance Monitoring. Section 5.5 presents the required compliance forms pursuant to §11-60.1-86.

## 5.2 Initial Covered Source Permit Application Requirements

The initial permit application and resulting Title V Covered Source Permit along with any amendments since 1999 identified the facility applicable requirements, and the permit incorporated conditions to confirm compliance with these requirements. This section is a summary of the applicable rules and methods for monitoring compliance at the Chevron Hawaii Refinery, as required by §11-60.1-86. The following discussion was excerpted from the Covered Source Permit Review Summary prepared by DOH in support of the initial Covered Source Permit. This section is intended to be a comprehensive summary of applicable requirements and these requirements will also apply to the Renewed Covered Source Permit.

## 5.2.1 Applicable Federal Regulations

### 40 CFR 60: New Source Performance Standards (NSPS)

Subpart A: General Provisions (apply to all units that are subject to one or more of the following NSPS Subparts)

Subpart J: Standards of Performance for Petroleum Refineries (applies to the Crude Unit Furnaces, Asphalt Furnace, Acid Plant Preheater, FCC Flare, Crude Flare, Boilers, Hydrogenation Furnace, Hydrogen Furnace, Isomerization Furnaces and the Gas Turbines with Heat Recovery Steam Generators (HRSGs) in the Cogeneration Plant)

Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (applies to new Foster Wheeler Boilers)

Subpart GG: Standards of Performance for Stationary Gas Turbines (applies to the Gas Turbines with HRSGs in the Cogeneration Plant)

Subpart GGG: Standards of Performance for Equipment Leaks in Petroleum Refineries (applies to equipment -- valves, pumps, flanges, etc. -- in VOC/VOL service associated with the FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor, Boilers and Flares)

Subpart QQQ: Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems (applies to process drains and sewer lines associated with the Crude Unit Furnaces and Desalter, Cogeneration Plant, Boilers, FCC Flare Vapor Recovery System, and API Separators)

Subpart KKKK: Standards of Performance for Stationary Combustion Turbines (applies to new Solar Centaur combustion turbine/HRSG)

### 40 CFR Part 61: National Emission Standards for Hazardous Air Pollutants (NESHAP)

Subpart A: General Provisions (applicable to units that are subject to the following NESHAP Subpart):

Subpart FF: National Emission Standards for Hazardous Air Pollutants From Benzene Waste Operations (applies to the API Separators, Benzene Recovery Unit, Recovered Oil Sump, Skim Oil Tank, Wastewater Surge Tank, Recovered Oil Tank, and Crude Water Draw Tank)

### 40 CFR Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)

Subpart A: General Provisions (apply to units that are subject to the following Category-Specific NESHAP Subpart)

Subpart CC: National Emission Standards from Petroleum Refineries applies to streams in the FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, Boiler Plant, Alkylation Plant and Effluent Treatment Plant, all Group 1 and Group 2

petroleum storage tanks, flares, and the petroleum truck loading rack. Specifically, the equipment leak provisions of Subpart CC apply to streams in organic HAP service (at least 5% by weight total HAPs). These existing streams must comply with the equipment leak provisions in 40 CFR Part 60, Subpart VV. The processes at the Chevron Hawaii Refinery mentioned above must comply with Subpart VV for those streams in organic HAP service.

Subpart UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries (applies to FCCU)

Subpart YYYY: National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters (applies to new Foster Wheeler Boilers)

Compliance Dates: All noted units, except for the petroleum storage tanks and petroleum truck loading rack, have a compliance date on or before August 18, 1998. The Group 1 petroleum storage tanks (all storage tanks except for storage tanks 152, 263, 267 and 274) have a compliance date of August 18, 2005, or the next time the storage vessel is emptied or degassed after August 18, 1998. The petroleum truck loading rack is currently classified as a Group 2 gasoline loading rack, and must comply with Subpart CC upon classification as a Group 1 gasoline loading rack.

CFR Part 68: Chemical Accident Prevention Provisions (applies to the storage and use of flammable substances in the facility.)

### **Notes on Applicability**

Although the crude flare and FCC flare were constructed in 1959, prior to promulgation of NSPS requirements, these flares are now subject to NSPS Subpart GGG, 40 CFR 60.18, *General Pollution Control Requirements for Flares*, and 40 CFR 60.100, because both flares are used as control devices to comply with NSPS Subpart GGG.

Chevron requested in the initial Covered Source Permit application to increase the storage capacity of petroleum storage tanks Nos. 105, 106, 107, 108, 109, 110, and 111 by 12 percent over a five-year period. This increase in tank capacity was determined by DOH to result in a net decrease in tank emissions, due to fewer tank turnovers (tank filling and emptying operations). The secondary seals required by Subpart CC are being installed at the same times when the tank capacities are increased. Reconstruction and modification requirements under NSPS were deemed by DOH not to be triggered by these changes in tank capacity and seal configuration.

## **5.2.2 State Regulations**

The requirements governing sources of air contaminants in Hawaii are contained in Hawaii's Administrative Rules (HAR) Title 11, Department of Health Chapter 59 *Ambient Air Quality Standards*, and Chapter 60.1 - *Air Pollution Control*. Chapter 59 establishes the ambient air quality standards for the State of Hawaii and prohibits any person from contributing to a violation of these standards. Chapter 59 is applicable to the Chevron

refinery; consequently, compliance with the National Ambient Air Quality Standards is a state enforceable requirement. Chapter 60.1 establishes the air pollution permit program for the State of Hawaii, and contains many general and equipment-specific regulations. The following applicable requirements are addressed in the facility initial Covered Source Permit and will continue to apply to the renewed permit.

HAR Title 11, Chapter 59 – Ambient Air Quality Standards

HAR Title 11, Chapter 60.1 – Air Pollution Control

Subchapter 1: General Requirements

Subchapter 2: General Prohibitions

HAR 11-60.1-31: Applicability

HAR 11-60.1-32: Visible Emissions (applies to Crude Furnaces, Boilers, FCCU, Process Unit Furnaces, Asphalt Plant, Acid plant, and Cogeneration Plant)

HAR 11-60.1-33: Fugitive Dust (applies to FCCU catalyst transfer operations)

HAR 11-60.1-38: Sulfur Oxides from Fuel Combustion (Crude Furnaces, Boilers, FCCU, Process Unit Furnaces, Asphalt Plant, Acid Plant Preheater, and Cogeneration Plant)

HAR 11-60.1-39: Storage of Volatile Organic Compounds (applies to Petroleum Storage Tanks)

HAR 11-60.1-40: Volatile Organic Compound Water Separation (applies to API Separators)

HAR 11-60.1-41: Pump and Compressor Requirements (seal requirements apply to pumps and compressors handling VOC with a Reid vapor pressure greater than or equal to 1.5 psia in FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor)

HAR 11-60.1-42: Waste Gas Disposal (flare/abatement requirement for VOC vapor blowdown applies to equipment in FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor)

Subchapter 5: Covered Sources

Subchapter 6: Fees for Covered Sources, Noncovered Sources, and Agricultural Burning

Subchapter 8: Standards of Performance for Stationary Sources

HAR 11-60.1-161: New Source Performance Standards (apply to all units that are subject to one or more of the NSPS Subparts in 40 CFR 60, as noted above under Federal Requirements)

### Subchapter 9: Hazardous Air Pollutant Sources

HAR 11-60.1-174: Maximum Achievable Control Technology Standards (apply to units that are subject to the Category-Specific NESHAP in Subpart in 40 CFR 63 as noted above under Federal Requirements)

HAR 11-60.1-180: National Emission Standards for Hazardous Air Pollutants (apply to units that are subject to the NESHAP Subpart in 40 CFR 61 noted above under Federal Requirements)

Subchapter 7, Prevention of Significant Deterioration (PSD) was not applicable for the initial Covered Source Permit, because this facility was not a new major stationary source, nor did Chevron propose any major modifications to a major stationary source as defined in HAR 11-60.1-131. Applicability of PSD will need to be addressed on a project-by-project basis for future proposed facility modifications.

**BACT Requirements** – A Best Available Control Technology (BACT) analysis is required for new or modified sources that have the potential to cause a net increase of air emissions above specified significance levels as defined in HAR 11-60.1. The initial Covered Source Permit did not consider the facility to be a new source, nor were any modifications proposed that had the potential to cause a significant net increase in air emissions. Therefore, a BACT analysis was not required. Applicability of BACT requirements will need to be assessed on a project-by-project basis for all future proposed modifications to refinery facilities.

**Compliance Data System (CDS)** – CDS annual emissions reporting is applicable, because the Hawaii Refinery emits more than 100 tpy of PM, PM<sub>10</sub>, SO<sub>2</sub>, VOC, or NO<sub>x</sub>.

**National Emissions Data System (NEDS)** – NEDS annual emissions reporting is applicable to a number of sources within the refinery [except for the process unit furnaces (5600, 5700, 5930, and 5950), asphalt furnace, and cooling tower], since these are point sources within the facility that emit more than 25 tpy for PM, PM<sub>10</sub>, SO<sub>2</sub>, VOC, or NO<sub>x</sub> or more than 250 tpy of CO. The DOH also requires reporting of annual emissions for facilities that: (1) have total combined emissions of a single criteria pollutant equal to or exceeding 25 tpy; or (2) for which the sum of all hazardous air pollutants (HAPs) equals or exceeds 5 tpy.

**Compliance Assurance Monitoring (CAM)** – CAM was not applicable to the initial Covered Source Permit, because a complete Title V application was submitted before April 20, 1998. However, certain CAM requirements are applicable to this permit renewal, as discussed in Section 5.4.3.

#### ***Alternate Operating Scenarios:***

There were no alternate operating scenarios proposed in the initial covered source application for this facility, and none are requested in this application for permit renewal.

## 5.3 Applicable Requirements for Modifications

This section addresses facility operations, applicable requirements, and compliance issues for modifications to the Hawaii Refinery that have been implemented since the time of the initial Covered Source Permit issuance in 1999, or that may be implemented during the term of the renewed permit, which will extend into 2016. Section 5.3.1 identifies facility changes and requirements for the past permit term of 1999 through 2003. Future facility changes through the end of the renewed permit term in 2016 and the requirements potentially triggered by such changes are discussed in Section 5.3.2.

### 5.3.1 Facility Changes and Requirements: 1999 through 2010

The facility modifications that have already been implemented for the timeframe from 1999 through the submittal of this renewal application include the following:

1. The initial Covered Source Permit allowed tanks 105 through 111 to be modified to increase storage capacity by 12 percent. Tanks 105, 106, 109, 110, and 111 have been modified and secondary seals have been installed, as required by 40 CFR Part 63, Subpart CC. Tank numbers 107 and 108 have yet to be modified. DOH has determined that this increase in tank capacity will result in a net decrease in tank emissions due to fewer tank turnovers (tank filling and emptying). Due to the reduction in emissions and based on the cost to alter the tanks, DOH has previously determined that the change does not constitute a modification or reconstruction, and that the requirements of NSPS Subpart K are not triggered. Since the tanks have been modified, they have complied with the standards of 40 CFR Part 63, Subpart A, General Provisions and Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. The Subpart CC requirements applicable to these tanks are specified in the facility Covered Source Permit Attachment II(B), Section G, 40 CFR Part 63, Subpart CC Requirements. Additionally, these tanks must comply with the conditions specified in the facility Covered Source Permit, Attachment II(b), Section C through F. No additional amendments to the Covered Source Permit are necessary to accommodate this alteration.
2. Group 1 storage tanks at the first tank degassing and cleaning activity after August 18, 1998 or before August 18, 2005, whichever comes first, must comply with 40 CFR Part 63, Subpart CC. As of August 2003, 17 Group 1 storage tanks have been modified to date; the affected tank numbers are 105, 106, 109, 110, 111, 113, 162, 163, 232, 233, 237, 249, 250, 262, 271, 301 and 302. Secondary seals (or equivalent devices) will be installed on the remaining Group 1 storage tanks no later than August 18, 2005 and monitoring, notification, testing and recordkeeping as required by Subpart CC will be implemented. The Subpart CC requirements applicable to these tanks are specified in the facility Covered Source Permit Attachment II(B), Section G, 40 CFR Part 63, Subpart CC Requirements. Additionally, the tanks need to comply with the conditions specified in the facility Covered Source Permit Attachment II(B), Section C through F. No additional amendments or changes to the Covered Source Permit are required to allow for ongoing tank upgrades to achieve compliance with Part 63, Subpart CC.
3. The Chevron Hawaii Refinery applied for and obtained DOH approval for the installation of dome roofs on Tanks 249 and 250. This request was processed as a minor

modification, and the DOH issued an amendment to the Covered Source Permit on April 16, 2002 consisting of a replacement of Attachment II(B). The same request was also submitted for Tank 275 and DOH issued an amended Covered Source Permit on August 13, 2007. The revised Attachment IIB, which also reflects the changes described in Items 1 and 2 above is provided as Appendix C.

4. The Chevron Hawaii Refinery has applied for and received approval for a modification to the FCC unit. The FCC Revamp project consisted of installing a slide control valve to improve the ability to balance the operation of the catalyst reaction vessel and the catalyst regenerator vessel. The application presented to DOH for this change in equipment showed that the project would not cause an emission increase, and therefore would not trigger any new federal New Source Performance Standards (NSPS) or the Prevention of Significant Deterioration (PSD) permitting process. The DOH processed the application as a significant modification, because DOH added federally enforceable permit conditions to maintain emissions below PSD levels. Dispersion modeling showed that the project would have a negligible effect on local air quality. This modification resulted in an amendment to Covered Source Permit No. 0088-01-C Attachment II(I) on March 3, 2003. Construction of the modification was completed in May 2003.

The amendment requirements resulting from the FCC Revamp project were incorporated into the Covered Source Permit amended on 24 April 2007. The Chevron Hawaii Refinery installed an equivalent replacement electrostatic precipitator on the FCC regenerator exhaust in 2002. Chevron coordinated with DOH on the proposed replacement and obtained prior approval for the installation of the equipment. The equivalent replacement does not alter the description of permitted equipment or the applicable requirements currently contained in the Covered Source Permit.

### **5.3.2 Facility Changes for 2011 through 2016**

This section describes the proposed facility changes to be implemented during the renewal permit term from 2011 through 2016. It is requested that DOH process the proposed changes to current permit conditions as summarized below. Descriptions of several other proposed facility alterations that are currently less well developed are also provided for notification purposes only.

#### ***Proposed Condition Change 1***

The following proposed facility modification is described below for information purposes only. As further information on the project develops, the quantitative effects on emissions, if any, will be evaluated and applicable rules will be addressed on a case-by-case basis.

Fixed speed motors may be changed to variable speed motors for the forced draft fan and induced draft fan at the crude unit. This is an energy savings project that will optimize performance of the combustion process. The change would not increase the unit's operation beyond its original capacity, although it could result in a slight increase in fuel combustion relative to recent years. Emissions will remain below the limits specified in the current Operating Permit, Section IIG, Section C, Items 1 through 5. It is anticipated that this proposed modification may trigger New Source Review (NSR), but will not be subject to NSPS.



***Proposed Condition Change 2***

The Hybrid Energy Project as submitted to DOH in Appendix E is proposed for installation during the renewal permit period. This project includes the installation of a new cogeneration turbine, HRSG and two new boilers. This project also includes the shutdown of the three existing boilers causing no net increase in emissions. The amended Covered Source Permit for this modification was issued on 23 May 2007.

***Proposed Condition Change 3***

Storage tanks at the refinery plant are currently designated with a fuel service type. Under existing storage tanks covered source permit, Attachment II (B), Section E, Condition 5.a 'the permittee shall notify DOH 30 days prior to changing the VOC liquid stored in any of the storage tanks identified in Section A.1.a of this attachment'. A.1.a includes gasoline intermediates and finished products storage tanks. Chevron is requesting the removal of this condition E.5.a to provide flexibility to meet refinery operational needs.

***Proposed Condition Change 4***

A universal administrative change is requested to change all permit references of LSR or HSR over to WSR. LSR and HSR are no longer separated at the refinery. WSR is now used in refinery operations.

***Proposed Condition Change 5***

Remove the Asphalt Plant and all associated equipment units from permit as its operation has been cancelled from the refinery production activities.

***Proposed Condition Change 6***

The refinery operation contains a number of grandfathered equipment units that were installed prior to permit requirements. These units do not have operating limits or emission limits. Chevron is requesting that normal operation of grandfathered units be defined as described in this permit renewal application. This permit defines the operation and maintenance required according to manufacturer design specifications. These design specifications were used in the potential to emit calculations and are considered normal operation in this permit to operate. Emission releases from grandfathered units while operating under normal conditions are not reportable to meet CERCLA reporting guidelines if federally enforceable. Appendix A recommends proposed language for inclusion in permit.

## **5.4 MACT and CAM Requirements**

The Chevron Hawaii Refinery is a major source of hazardous air pollutants as described in Section 3 of this Covered Source Permit renewal application. As a major air toxic source, the refinery is potentially subject to MACT regulations that are codified under NESHAP. USEPA has adopted and proposed several MACT requirements over the past several years

that pertain to refinery operations. Section 5.4.1 addresses potential applicable MACT standards that have already been adopted, and identifies the associated applicable requirements for the Chevron Hawaii Refinery. Section 5.4.2 discusses the applicability of Compliance Assurance Monitoring requirements.

#### 5.4.1 Applicability of Adopted MACT Standards

The following MACT requirements have been adopted and finalized in the Code of Federal Regulations. Therefore, the determination of applicability of these requirements for the Covered Source Permit renewal can be considered final.

40 CFR 63, Subpart A, National Emission Standards for Hazardous Air Pollutants General Provisions. Subpart A contains general NESHAP definitions and notifications that are applicable to the Chevron Hawaii Refinery. These requirements are applicable to emission units that must comply with MACT standards. Compliance requirements for Subpart A were incorporated into the initial Covered Source Permit and are briefly addressed above in Section 5.2.

40 CFR 63, Subpart R, National Emission Standards for Hazardous Air Pollutants from Gasoline Distribution. The final Subpart R rule appeared in the Federal Register on 12/14/1994. Subpart R is applicable to the aviation gas storage tanks. For other storage tanks this is not an applicable requirement pursuant to 40 CFR 63.420(i), which exempts loading racks at refineries that are subject to Subpart CC. As specified in the current Covered Source Permit Attachment II(C), Section B, Condition 1, the Chevron Hawaii Refinery loading rack is subject to Subpart CC requirements and complies with the requirements contained in Attachment II(C). Therefore, Subpart R is not an applicable requirement.

40 CFR 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. The final Subpart CC rule appeared in the Federal Register August 18, 1995 and the date for compliance was 8/18/98. Subpart CC requires refineries to monitor and control emissions from tanks, process vents, piping components and wastewater operations. Compliance requirements for Subpart CC are applicable to the refinery. These requirements were incorporated into the initial Covered Source Permit, and are briefly addressed above in Section 5.2.

40 CFR 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries that occur at Catalytic Cracking Units, Catalytic Reforming Units and Sulphur Plants. The final Subpart UUU rule appeared in the Federal Register on April 11, 2002 and the date for compliance is April 11, 2005. Subpart UUU will apply to the FCC Unit at the Chevron Hawaii Refinery. The refinery does not have Catalytic Reforming Units or Sulphur Plants that are regulated under Subpart UUU. Subpart UUU limits emissions of metals and organic HAPs from FCC units. To demonstrate compliance with this MACT standard, particulate matter and nickel are used as surrogates for metals. Carbon monoxide (CO) is used as a surrogate for organic HAPs. Chevron chose to comply with the requirements of Option 2 in Subpart UUU. Under Option 2, the FCCU will need to meet emissions limits of 1 pound of PM<sub>10</sub> per 1,000 pounds of coke burned and 500 ppm CO. To demonstrate initial compliance, Chevron prepared a site-specific test plan and implemented a performance test to demonstrate that the facility complies with a PM<sub>10</sub> limit of 1 pound PM<sub>10</sub> per 1000 pounds of coke burned. During the performance test a site-specific opacity

limit was established. To demonstrate ongoing continuous compliance with the PM<sub>10</sub> limit a Continuous Opacity Monitor (COM) was installed to confirm that the site-specific opacity limit is achieved. Compliance with the CO limit will be demonstrated initially and continuously using a CO CEMS. The facility installed an opacity monitor and a CO CEMS to satisfy monitoring requirements by the April 11, 2005 deadline.

40 CFR 63, Subpart LLLLL, National Emission Standards for Hazardous Air Pollutants for Asphalt Processing and Asphalt Roof Manufacturing. The final Subpart LLLLL rule appeared in the Federal Register on April 29, 2003. The Chevron Hawaii Refinery no longer produces asphalt; therefore Subpart LLLLL is not an applicable requirement.

40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines appeared in the Federal Register on July 11, 2006. Generators operated at the refinery plant support maintenance activities, emergency backup power or are used in fire suppression. Those units that commenced installation after July 11, 2005 are applicable to this subpart.

40 CFR 63, Subpart GGGGG, National Emission Standards for Hazardous Air Pollutants for Site Remediation. Subpart GGGGG appeared in the Federal Register on October 8, 2003. The Chevron Hawaii Refinery no longer performs remediation onsite and, therefore, Subpart GGGGG is not anticipated to be applicable.

40 CFR 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines. Subpart ZZZZ appeared in the Federal Register on June 15, 2007. The compliance date for existing sources is three years after the rule is finalized or June 15 2010. Subpart ZZZZ applies to all internal combustion engines weather above or below 500 brake horsepower (bhp). Requirements for units over 500 bhp are detailed in this regulation. Requirements for units 500 bhp or less are regulated under 40 CFR 60 IIII or 40 CFR JJJJ. All of the internal combustion engines at the Hawaii Refinery are below this bhp rating, and therefore the requirements in this Subpart are not applicable.

40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters. Subpart DDDDD appeared in the Federal Register on September 13, 2004. The compliance date for existing sources is three years after the rule is finalized or September 13, 2007. The MACT was remanded on June 8, 2007 making the September 2007 compliance date no longer enforceable. The new Subpart DDDDD is scheduled to be promulgated in January 2011. The Hawaii Refinery boiler and furnace units that burn RFG or Natural Gas would be subject to these requirements.

40 CFR 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. Subpart YYYY appeared in the Federal Register on March 5, 2004. Compliance with the regulation for existing sources is proposed to be three years after the rule is finalized or March 5, 2007. The Hawaii Refinery cogeneration units 6701, 6702, and 6703 are existing diffusion flame stationary combustion sources. Based on the Federal Register, Vol. 68, No 9 subsection 63.6090 (b) Exceptions (3), existing diffusion flame turbines do not have to meet the requirements of this Subpart or Subpart A. The new Solar Centaur Cogeneration unit is applicable to Subpart YYYY.

## 5.4.2 Compliance Assurance Monitoring

Compliance Assurance Monitoring (CAM) requirements are codified in 40 CFR 64. These requirements are applicable to specific units of a facility on a pollutant-specific emissions basis. For these requirements to be applicable, all of the following three criteria must be met:

- The unit must use a control device to achieve compliance with emission standards
- The unit must be subject to an emission standard for the applicable regulated pollutant
- The unit pre-control device potential to emit must be greater than 100 tons per year

Pursuant to 64.2(b) the CAM applicability requirements do not apply to emissions limitations or standards that are proposed by EPA after November 1990 under Section 111 or 112 of the Clean Air Act. Simply stated, CAM is not applicable to units that are subject to NSPS, NESHAP, or MACT standards that were developed after 1990.

As stated in the preamble to the CAM rule, the rule does not apply to process fugitive emissions or tanks.

Most emission units at the Hawaii Refinery do not use control devices to comply with emissions standards, and therefore CAM is not applicable to these units. Specifically, furnaces, process heaters, flares, and the acid plant absorbing tower do not utilize control devices in order to satisfy emission standards. Based on the first of the three criteria presented above, CAM is not an applicable requirement for these units.

The FCC unit uses an electrostatic precipitator and a cyclone to meet applicable Hawaii rules 11-60.1-32 (opacity limits) and 11-60.1-38 (sulfur oxide emissions). The pre-control device PM<sub>10</sub> and SO<sub>2</sub> potential to emit are greater than 100 tons per year. However, the unit is subject to the MACT 40 CFR 63 Subpart UUU, which was promulgated after 1990, and therefore CAM is not applicable to PM<sub>10</sub> emissions from the FCC unit. The SO<sub>2</sub> emission limits in 11-60.1-38 are not incorporated into the Hawaii State Implementation Plan and, accordingly, do not constitute an “emission limit.” Therefore, CAM requirements are not applicable to the FCC unit.

The cogeneration units use low-NO<sub>x</sub> burners and water injection to reduce NO<sub>x</sub> emissions. Based on discussions in the preamble to 40 CFR 64, the low NO<sub>x</sub> burners are not considered a “control device” and do not trigger CAM applicability. Water injection is considered a control device and can trigger CAM requirements. The cogeneration units are subject to NSPS Subpart GG, which was promulgated prior to 1990 and contains an emissions standard for both NO<sub>x</sub> and SO<sub>x</sub>. However, the water injection is only used to control NO<sub>x</sub> emissions and there is no control device for SO<sub>x</sub> emissions. The NO<sub>x</sub> emissions with water injection are less than 100 tons per year per unit, although emissions without water injection would be anticipated to exceed the 100 ton per year threshold. Therefore, CAM is applicable to NO<sub>x</sub> emissions from the cogeneration units. The cogeneration units already utilize a CEMS to monitor NO<sub>x</sub> emissions, as required by the existing (initial) Covered Source Permit. Further, Attachment II(M), Section D, Condition 3 of this permit requires that the CEMS system meet EPA performance specification 40 CFR 60.13 and 40 CFR 60, Appendix B. Pursuant to CAM requirements contained in 40 CFR 64.4(b)(2) and 64.3(d)(2)(ii), a CEMS system is presumptively acceptable if it meets the requirements of Section 60.13 and Appendix B of part 60. Therefore, while CAM is applicable to the

cogeneration units, no additional or new monitoring is required. Chevron does need to meet the submittal requirements of 40 CFR 64.4 and these are addressed in Appendix D.

The Hybrid Energy Project will also trigger CAM requirements when the new cogeneration unit is installed. 40 CFR 60 Subpart KKKK and 40 CFR 63 Subpart YYYY will be applicable. Monitoring requirements as required by 40 CFR 64.4 will be met. Those monitoring systems are described in the Hybrid Energy Project significant modification application and Hybrid Energy Permit included in Appendix E.

CAM is not an applicable requirement for any other units within the Hawaii Refinery.

## 5.5 Compliance Forms

The facility complies with the applicable regulations, as identified in the attached Form C-1, pages 1-3, Compliance Plan. Chevron personnel have evaluated the applicable requirements, performed site inspections, reviewed monitoring data, and confirmed work practices to determine that the facility is in compliance. Continued adherence to these requirements will result in on-going compliance. The attached Form C-2, page 1, Compliance Certification verifies compliance with the applicable regulations. Monitoring, as required by applicable regulations, will be used to confirm continuing compliance. The information presented in this section is consistent with the information requested in the Form C-2, pages 2 and 3.

Chevron has previously demonstrated compliance with the NAAQS, based on maximum facility emissions of criteria pollutants and ambient dispersion modeling, which is discussed in Section 4 of this application. Note that verifying compliance with the NAAQS is a state requirement. The facility does not propose to adopt an emissions cap to avoid having to comply with any federal regulations. There are no applicable federal regulations that stipulate that an emissions cap must be placed on the facility.

### C-1: Compliance Plan

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets of paper if necessary.

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1. Compliance status with respect to all Applicable Requirements:

Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

YES      {If YES, complete items a and c below}

NO      {If NO, complete items a, b, and c below}

a. Identify all applicable requirement(s) for which compliance is achieved.

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Provide a statement that the source is in compliance and will continue to comply with all such requirements.

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b. Identify all applicable requirement(s) for which compliance is NOT achieved.

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Provide a detailed Schedule of Compliance Schedule and a description of how the source will achieve compliance with all such applicable requirements.

<u>Description of Remedial Action</u>	<u>Expected Date of Completion</u>
_____	_____
_____	_____
_____	_____
_____	_____

- c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to. These applicable requirements may take effect AFTER permit issuance:

<u>Applicable Requirement</u>	<u>Effective Date</u>	<u>Currently in Compliance?</u>
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____

If the source is not currently in compliance, provide a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

<u>Description of Proposed Action/Steps to Achieve Compliance</u>	<u>Expected Date of Achieving Compliance</u>
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____

Provide a statement that the source on a timely basis will meet all these applicable requirements:

\_\_\_\_\_

\_\_\_\_\_

\_\_\_\_\_

\_\_\_\_\_

\_\_\_\_\_

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of each remedial action and the expected date of completion:

<u>Description of Remedial Action and Explanation</u>	<u>Expected Date of Completion</u>
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____

2. Compliance Progress Reports:

- a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: \_\_\_\_\_  
(less than or equal to 6 months)

Beginning Date: \_\_\_\_\_

b. Date(s) that the Action described in (1)(b) was achieved:

<u>Remedial Action</u>	<u>Date Achieved</u>
_____	_____
_____	_____
_____	_____

c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

\_\_\_\_\_

\_\_\_\_\_

\_\_\_\_\_

**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): \_\_\_\_\_ (First): \_\_\_\_\_ (MI): \_\_\_\_\_

Title: \_\_\_\_\_ Phone: \_\_\_\_\_

Mailing Address: \_\_\_\_\_

City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): \_\_\_\_\_

(Signature): \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Location: \_\_\_\_\_

Permit Number: \_\_\_\_\_

FOR AGENCY USE ONLY	
File/Application No.:	_____
Island:	_____
Date Received:	_____



**C-2: Compliance Certification**

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Complete as many copies of this form as needed. Use separate sheets of paper if necessary.

**RESPONSIBLE OFFICIAL**

(as defined in HAR §11-60.1-1)

Name (Last): \_\_\_\_\_ (First): \_\_\_\_\_ (MI): \_\_\_\_\_

Title: \_\_\_\_\_ Phone: \_\_\_\_\_

Mailing Address: \_\_\_\_\_

City: \_\_\_\_\_ State: \_\_\_\_\_ Zip Code: \_\_\_\_\_

**Certification by Responsible Official**

(pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): \_\_\_\_\_

(Signature): \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Location: \_\_\_\_\_

Permit Number: \_\_\_\_\_

**FOR AGENCY USE ONLY**

File/Application No.: \_\_\_\_\_

Island: \_\_\_\_\_

Date Received: \_\_\_\_\_

Complete the following information for **each** applicable requirement that applies to **each** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the Director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: \_\_\_\_\_ Beginning Date: \_\_\_\_\_

2. Emissions Unit No./Description: \_\_\_\_\_

3. Identify the applicable requirement(s) that is/are the basis of this certification:

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4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

YES  NO

b. If YES, will compliance be continuous or intermittent?

Continuous  Intermittent

c. If NO, explain:

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5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

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Provide a detailed description of the methods used to determine compliance (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.):

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6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

b. If YES, identify the requirements and the provisions being taken to achieve compliance:

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c. If NO, describe below which requirements will not be met:

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**40 CFR Part 60 - Standards of Performance for New Stationary Sources**

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart A	(§§ 1 - 19) - General Provisions	Y	All Units	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart B	(§§ 20 - 29) - Adoption and Submittal of State Plans for Designated Facilities	N			
60	Subpart C	(§§ 30 - 31) - Emission Guidelines and Compliance Times	N			
60	Subpart C-b	(§§ 30 - 39) - Emissions Guidelines and Compliance Times for Large Municipal Waste Combustors that are Constructed on or Before September 20, 1994	N			
60	Subpart C-c	(§§ 30 - 36) - Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills	N			
60	Subpart C-d	(§§ 30 - 32) - Emissions Guidelines and Compliance Times for Sulfuric Acid Production Units	N			
60	Subpart C-e	(§§ 30 - 39) - Emission Guidelines and Compliance Times for Hospital/Medical/Infectious Waste Incinerators	N			
60	Subpart D	(§§ 40 - 46) - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971	N			
60	Subpart D-a	(§§ 40 - 52) - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978	N			
60	Subpart D-b	(§§ 40 - 49) - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	N			
60	Subpart D-c	(§§ 40 - 48) - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	Y		For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart E	(§§ 50 - 54) - Standards of Performance for Incinerators	N			
60	Subpart E-a	(§§ 50 - 59) - Standards of Performance for Municipal Waste Combustors for Which Construction is Commenced After December 20, 1989 and on or Before September 20, 1994	N			
60	Subpart E-b	(§§ 50 - 59) - Standards of Performance for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996	N			
60	Subpart E-c	(§§ 50 - 58) - Standards of Performance for Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	N			
60	Subpart F	(§§ 60 - 66) - Standards of Performance for Portland Cement Plants	N			
60	Subpart G	(§§ 70 - 74) - Standards of Performance for Nitric Acid Plants	N			
60	Subpart H	(§§ 80 - 85) - Standards of Performance for Sulfuric Acid Plants	N			
60	Subpart I	(§§ 90 - 93) - Standards of Performance for Hot Mix Asphalt Facilities	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart J	(§§ 100 - 109) - Standards of Performance for Petroleum Refineries	Y	All unit furnaces, Cogen turbines, the FCC, Flares	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart J-a	<a href="#">(§§ 100a - 109a) - STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER MAY 14, 2007</a>	N	Applies to FCCU, FCU, fuel gas combustion devices, flares, process heaters and sulfur recovery plants that begin construction after 14 May 2007.	Energy Project commenced construction on 15 Feb 2007.	New 24 June 2008, 73 FR 35867
60	Subpart K	(§§ 110 - 113) - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	N			
60	Subpart K-a	(§§ 110 - 115) - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	N			
60	Subpart K-b	(§§ 110 - 117) - 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	N			
60	Subpart L	(§§ 120 - 123) - Standards of Performance for Secondary Lead Smelters	N			
60	Subpart M	(§§ 130 - 133) - Standards of Performance for Secondary Brass and Bronze Production Plants	N			
60	Subpart N	(§§ 140 - 144) - Standards of Performance for Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	N			
60	Subpart N-a	(§§ 140 - 145) - Standards of Performance for Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	N			
60	Subpart O	(§§ 150 - 156) - Standards of Performance for Sewage Treatment Plants	N			
60	Subpart P	(§§ 160 - 166) - Standards of Performance for Primary Copper Smelters	N			
60	Subpart Q	(§§ 170 - 176) - Standards of Performance for Primary Zinc Smelters	N			
60	Subpart R	(§§ 180 - 186) - Standards of Performance for Primary Lead Smelters	N			
60	Subpart S	(§§ 190 - 195) - Standards of Performance for Primary Aluminum Reduction Plants	N			
60	Subpart T	(§§ 200 - 204) - Standards of Performance for the Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart U	(§§ 210 - 214) - Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants	N			
60	Subpart V	(§§ 220 - 224) - Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants	N			
60	Subpart W	(§§ 230 - 234) - Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants	N			
60	Subpart X	(§§ 240 - 244) - Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	N			
60	Subpart Y	(§§ 250 - 254) - Standards of Performance for Coal Preparation Plants	N			
60	Subpart Z	(§§ 260 - 266) - Standards of Performance for Ferroalloy Production Facilities	N			
60	Subpart AA	(§§ 270 - 276) - Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974, and on or Before August 17, 1983	N			
60	Subpart AA-a	(§§ 270 - 276) - Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 17, 1983	N			
60	Subpart BB	(§§ 280 - 285) - Standards of Performance for Kraft Pulp Mills	N			
60	Subpart CC	(§§ 290 - 296) - Standards of Performance for Glass Manufacturing Plants	N			
60	Subpart DD	(§§ 300 - 304) - Standards of Performance for Grain Elevators	N			
60	Subpart EE	(§§ 310 - 316) - Standards of Performance for Surface Coating of Metal Furniture	N			
60	Subpart GG	(§§ 330 - 335) - Standards of Performance for Stationary Gas Turbines	Y	Cogen	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart HH	(§§ 340 - 344) - Standards of Performance for Lime Manufacturing Plants	N			
60	Subpart KK	(§§ 370 - 374) - Standards of Performance for Lead-Acid Battery Manufacturing Plants	N			
60	Subpart LL	(§§ 380 - 386) - Standards of Performance for Metallic Mineral Processing Plants	N			
60	Subpart MM	(§§ 390 - 398) - Standards of Performance for Automobile and Light Duty Truck Surface Coating Operations	N			
60	Subpart NN	(§§ 400 - 404) - Standards of Performance for Phosphate Rock Plants	N			
60	Subpart PP	(§§ 420 - 424) - Standards of Performance for Ammonium Sulfate Manufacture	N			
60	Subpart QQ	(§§ 430 - 435) - Standards of Performance for the Graphic Arts Industry: Publication Rotogravure Printing	N			
60	Subpart RR	(§§ 440 - 447) - Standards of Performance for Pressure Sensitive Tape and Label Surface Coating Operations	N			
60	Subpart SS	(§§ 450 - 456) - Standards of Performance for Industrial Surface Coating: Large Appliances	N			
60	Subpart TT	(§§ 460 - 466) - Standards of Performance for Metal Coil Surface Coating	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart UU	(§§ 470 - 474) - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture	N			
60	Subpart VV	(§§ 480 - 489) - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JANUARY 5, 1981, AND ON OR BEFORE NOVEMBER 7, 2006	Y	pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart VV - a	<a href="#">(§§ 480a - 489a) - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER NOVEMBER 7, 2006</a>	Y	pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	New 16 Nov 2007, 72 FR 64883
60	Subpart WW	(§§ 490 - 496) - Standards of Performance for the Beverage Can Surface Coating Industry	N			
60	Subpart XX	(§§ 500 - 506) - Standards of Performance for Bulk Gasoline Terminals	N			
60	Subpart AAA	(§§ 530 - 539) - Standards of Performance for New Residential Wood Heaters	N			
60	Subpart BBB	(§§ 540 - 548) - Standards of Performance for the Rubber Tire Manufacturing Industry	N			
60	Subpart DDD	(§§ 560 - 566) - Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry	N			
60	Subpart FFF	(§§ 580 - 585) - Standards of Performance for Flexible Vinyl and Urethane Coating and Printing	N			
60	Subpart GGG	(§§ 590 - 593) - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JANUARY 4, 1983, AND ON OR BEFORE NOVEMBER 7, 2006	Y	Equipment Leaks at FCC, Crude, LPG, Dimersol, Cogen and Flares	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	

**40 CFR Part 60 - Standards of Performance for New Stationary Sources**

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart A	(§§ 1 - 19) - General Provisions	Y	All Units	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart B	(§§ 20 - 29) - Adoption and Submittal of State Plans for Designated Facilities	N			
60	Subpart C	(§§ 30 - 31) - Emission Guidelines and Compliance Times	N			
60	Subpart C-b	(§§ 30 - 39) - Emissions Guidelines and Compliance Times for Large Municipal Waste Combustors that are Constructed on or Before September 20, 1994	N			
60	Subpart C-c	(§§ 30 - 36) - Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills	N			
60	Subpart C-d	(§§ 30 - 32) - Emissions Guidelines and Compliance Times for Sulfuric Acid Production Units	N			
60	Subpart C-e	(§§ 30 - 39) - Emission Guidelines and Compliance Times for Hospital/Medical/Infectious Waste Incinerators	N			
60	Subpart D	(§§ 40 - 46) - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971	N			
60	Subpart D-a	(§§ 40 - 52) - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978	N			
60	Subpart D-b	(§§ 40 - 49) - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	N			
60	Subpart D-c	(§§ 40 - 48) - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	Y		For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart E	(§§ 50 - 54) - Standards of Performance for Incinerators	N			
60	Subpart E-a	(§§ 50 - 59) - Standards of Performance for Municipal Waste Combustors for Which Construction is Commenced After December 20, 1989 and on or Before September 20, 1994	N			
60	Subpart E-b	(§§ 50 - 59) - Standards of Performance for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996	N			
60	Subpart E-c	(§§ 50 - 58) - Standards of Performance for Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	N			
60	Subpart F	(§§ 60 - 66) - Standards of Performance for Portland Cement Plants	N			
60	Subpart G	(§§ 70 - 74) - Standards of Performance for Nitric Acid Plants	N			
60	Subpart H	(§§ 80 - 85) - Standards of Performance for Sulfuric Acid Plants	N			
60	Subpart I	(§§ 90 - 93) - Standards of Performance for Hot Mix Asphalt Facilities	N			



Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart J	(§§ 100 - 109) - Standards of Performance for Petroleum Refineries	Y	All unit furnaces, Cogen turbines, the FCC, Flares	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart J-a	<a href="#">(§§ 100a - 109a) - STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER MAY 14, 2007</a>	N	Applies to FCCU, FCU, fuel gas combustion devices, flares, process heaters and sulfur recovery plants that begin construction after 14 May 2007.	Energy Project commenced construction on 15 Feb 2007.	New 24 June 2008, 73 FR 35867
60	Subpart K	(§§ 110 - 113) - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	N			
60	Subpart K-a	(§§ 110 - 115) - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	N			
60	Subpart K-b	(§§ 110 - 117) - 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	N			
60	Subpart L	(§§ 120 - 123) - Standards of Performance for Secondary Lead Smelters	N			
60	Subpart M	(§§ 130 - 133) - Standards of Performance for Secondary Brass and Bronze Production Plants	N			
60	Subpart N	(§§ 140 - 144) - Standards of Performance for Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	N			
60	Subpart N-a	(§§ 140 - 145) - Standards of Performance for Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	N			
60	Subpart O	(§§ 150 - 156) - Standards of Performance for Sewage Treatment Plants	N			
60	Subpart P	(§§ 160 - 166) - Standards of Performance for Primary Copper Smelters	N			
60	Subpart Q	(§§ 170 - 176) - Standards of Performance for Primary Zinc Smelters	N			
60	Subpart R	(§§ 180 - 186) - Standards of Performance for Primary Lead Smelters	N			
60	Subpart S	(§§ 190 - 195) - Standards of Performance for Primary Aluminum Reduction Plants	N			
60	Subpart T	(§§ 200 - 204) - Standards of Performance for the Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart U	(§§ 210 - 214) - Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants	N			
60	Subpart V	(§§ 220 - 224) - Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants	N			
60	Subpart W	(§§ 230 - 234) - Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants	N			
60	Subpart X	(§§ 240 - 244) - Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	N			
60	Subpart Y	(§§ 250 - 254) - Standards of Performance for Coal Preparation Plants	N			
60	Subpart Z	(§§ 260 - 266) - Standards of Performance for Ferroalloy Production Facilities	N			
60	Subpart AA	(§§ 270 - 276) - Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974, and on or Before August 17, 1983	N			
60	Subpart AA-a	(§§ 270 - 276) - Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 17, 1983	N			
60	Subpart BB	(§§ 280 - 285) - Standards of Performance for Kraft Pulp Mills	N			
60	Subpart CC	(§§ 290 - 296) - Standards of Performance for Glass Manufacturing Plants	N			
60	Subpart DD	(§§ 300 - 304) - Standards of Performance for Grain Elevators	N			
60	Subpart EE	(§§ 310 - 316) - Standards of Performance for Surface Coating of Metal Furniture	N			
60	Subpart GG	(§§ 330 - 335) - Standards of Performance for Stationary Gas Turbines	Y	Cogen	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart HH	(§§ 340 - 344) - Standards of Performance for Lime Manufacturing Plants	N			
60	Subpart KK	(§§ 370 - 374) - Standards of Performance for Lead-Acid Battery Manufacturing Plants	N			
60	Subpart LL	(§§ 380 - 386) - Standards of Performance for Metallic Mineral Processing Plants	N			
60	Subpart MM	(§§ 390 - 398) - Standards of Performance for Automobile and Light Duty Truck Surface Coating Operations	N			
60	Subpart NN	(§§ 400 - 404) - Standards of Performance for Phosphate Rock Plants	N			
60	Subpart PP	(§§ 420 - 424) - Standards of Performance for Ammonium Sulfate Manufacture	N			
60	Subpart QQ	(§§ 430 - 435) - Standards of Performance for the Graphic Arts Industry: Publication Rotogravure Printing	N			
60	Subpart RR	(§§ 440 - 447) - Standards of Performance for Pressure Sensitive Tape and Label Surface Coating Operations	N			
60	Subpart SS	(§§ 450 - 456) - Standards of Performance for Industrial Surface Coating: Large Appliances	N			
60	Subpart TT	(§§ 460 - 466) - Standards of Performance for Metal Coil Surface Coating	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart UU	(§§ 470 - 474) - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture	N			
60	Subpart VV	(§§ 480 - 489) - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JANUARY 5, 1981, AND ON OR BEFORE NOVEMBER 7, 2006	Y	pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart VV - a	<a href="#">(§§ 480a - 489a) - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER NOVEMBER 7, 2006</a>	Y	pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	New 16 Nov 2007, 72 FR 64883
60	Subpart WW	(§§ 490 - 496) - Standards of Performance for the Beverage Can Surface Coating Industry	N			
60	Subpart XX	(§§ 500 - 506) - Standards of Performance for Bulk Gasoline Terminals	N			
60	Subpart AAA	(§§ 530 - 539) - Standards of Performance for New Residential Wood Heaters	N			
60	Subpart BBB	(§§ 540 - 548) - Standards of Performance for the Rubber Tire Manufacturing Industry	N			
60	Subpart DDD	(§§ 560 - 566) - Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry	N			
60	Subpart FFF	(§§ 580 - 585) - Standards of Performance for Flexible Vinyl and Urethane Coating and Printing	N			
60	Subpart GGG	(§§ 590 - 593) - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JANUARY 4, 1983, AND ON OR BEFORE NOVEMBER 7, 2006	Y	Equipment Leaks at FCC, Crude, LPG, Dimersol, Cogen and Flares	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart GGG - a	(§§ 590 - 593) - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER NOVEMBER 7, 2006	N		Facilities subject to subpart VV, subpart VVa, subpart GGG, or subpart KKK of this part are excluded from this subpart.	New 16 Nov 2007, 72 FR 64896
60	Subpart HHH	(§§ 600 - 604) - Standards of Performance for Synthetic Fiber Production Facilities	N			
60	Subpart III	(§§ 610 - 618) - Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	N			
60	Subpart JJJ	(§§ 620 - 625) - Standards of Performance for Petroleum Dry Cleaners	N			
60	Subpart KKK	(§§ 630 - 636) - Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.	N			
60	Subpart LLL	(§§ 640 - 648) - Standards of Performance for Onshore Natural Gas Processing: So2 Emissions	N			
60	Subpart NNN	(§§ 660 - 668) - Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	N			
60	Subpart OOO	(§§ 670 - 676) - Standards of Performance for Nonmetallic Mineral Processing Plants	N			
60	Subpart PPP	(§§ 680 - 685) - Standard of Performance for Wool Fiberglass Insulation Manufacturing Plants	N			
60	Subpart QQQ	(§§ 690 - 699) - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems	Y	VOC from wastewater systems at Crude furnaces and desalter, Cogen and API separators	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart RRR	(§§ 700 - 708) - Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	N			
60	Subpart SSS	(§§ 710 - 718) - Standards of Performance for Magnetic Tape Coating Facilities	N			
60	Subpart TTT	(§§ 720 - 726) - Standards of Performance for Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	N			
60	Subpart UUU	(§§ 730 - 737) - Standards of Performance for Calciners and Dryers in Mineral Industries	N			
60	Subpart VVV	(§§ 740 - 748) - Standards of Performance for Polymeric Coating of Supporting Substrates Facilities	N			
60	Subpart WWW	(§§ 750 - 759) - Standards of Performance for Municipal Solid Waste Landfills	N			
60	Subpart AAAA	(§§ 1000 - 1465) - Standards of Performance for Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart GGG - a	(§§ 590 - 593) - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER NOVEMBER 7, 2006	N		Facilities subject to subpart VV, subpart VVa, subpart GGG, or subpart KKK of this part are excluded from this subpart.	New 16 Nov 2007, 72 FR 64896
60	Subpart HHH	(§§ 600 - 604) - Standards of Performance for Synthetic Fiber Production Facilities	N			
60	Subpart III	(§§ 610 - 618) - Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	N			
60	Subpart JJJ	(§§ 620 - 625) - Standards of Performance for Petroleum Dry Cleaners	N			
60	Subpart KKK	(§§ 630 - 636) - Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.	N			
60	Subpart LLL	(§§ 640 - 648) - Standards of Performance for Onshore Natural Gas Processing: So2 Emissions	N			
60	Subpart NNN	(§§ 660 - 668) - Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	N			
60	Subpart OOO	(§§ 670 - 676) - Standards of Performance for Nonmetallic Mineral Processing Plants	N			
60	Subpart PPP	(§§ 680 - 685) - Standard of Performance for Wool Fiberglass Insulation Manufacturing Plants	N			
60	Subpart QQQ	(§§ 690 - 699) - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems	Y	VOC from wastewater systems at Crude furnaces and desalter, Cogen and API separators	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
60	Subpart RRR	(§§ 700 - 708) - Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	N			
60	Subpart SSS	(§§ 710 - 718) - Standards of Performance for Magnetic Tape Coating Facilities	N			
60	Subpart TTT	(§§ 720 - 726) - Standards of Performance for Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	N			
60	Subpart UUU	(§§ 730 - 737) - Standards of Performance for Calciners and Dryers in Mineral Industries	N			
60	Subpart VVV	(§§ 740 - 748) - Standards of Performance for Polymeric Coating of Supporting Substrates Facilities	N			
60	Subpart WWW	(§§ 750 - 759) - Standards of Performance for Municipal Solid Waste Landfills	N			
60	Subpart AAAA	(§§ 1000 - 1465) - Standards of Performance for Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	N			



Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
60	Subpart BBBB	(§§ 1500 - 1940) - Emission Guidelines and Compliance Times for Small Municipal Waste Combustion Units Constructed on or Before August 30, 1999	N			
60	Subpart CCCC	(§§ 2000 - 2265) - Standards of Performance for Commercial and Industrial Solid Waste Incineration Units for Which Construction is Commenced After November 30, 1999 or for Which Modification or Reconstruction is Commenced on or After June 1, 2001	N			
60	Subpart DDDD	(§§ 2500 - 2875) - Emissions Guidelines and Compliance Times for Commercial and Industrial Solid Waste Incineration Units that Commenced Construction on or Before November 30, 1999	N			
60	Subpart EEEE	(§§ 2880 - 2891) - Standards of Performance for Other Solid Waste Incineration Units for Which Construction Is Commenced After December 9, 2004, or for Which Modification or Reconstruction Is Commenced on or After June 16, 2006.	N			
60	Subpart FFFF	(§§ 2980 - 3078) - Emission Guidelines and Compliance Times for Other Solid Waste Incineration Units That Commenced Construction On or Before December 9, 2004	N			
60	Subpart HHHH	(§§ 4101 - 4176) - Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units	N			
60	Subpart IIII	<a href="#">(§§ 4200 - 4219) - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines</a>	Y	Generators and Fire Water Pumps installed after July 11, 2005	Applicable units: ICE of all sizes whether new or existing that commence installation after July 11, 2005. Monitor: non-resettlable hour meter, labeling requirement. Test Methods: EPA Methods 1, 1A, 3, 3A, 3B, 4, 5, 7E, 320. Recordkeeping: Maintenance, emission standards certification Reporting: Notification	New 11 July 2006, 71 FR 39172
60	Subpart JJJJ	<a href="#">(§§ 4230 - 4248) - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines</a>	N			New 18 Jan 2008, 73 FR 3591
60	Subpart KKKK	<a href="#">(§§ 4300 - 4420) - Standards of Performance for Stationary Combustion Turbines</a>	Y	Cogen	Applicable units: Peak load of 10 MMBTU/hr or greater. Monitor: Continous Monitoring System or CEMS for NOx. Total Sulfur Content. Test Method: Annual Performance Test in accordance with §60.8. EPA Methods 1, 2, 3A, 6, 6C, 8, 7E, 19, 20. Recordkeeping: usage, maintenance, emissions Reporting: Every 6 months in accordance with §60.7 ( c).	New 6 July 2006, 71 FR 38497
<b>Part 61 - National Emission Standards for Hazardous Air Pollutants</b>						

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
61	Subpart A	(§§ 1 - 19) - General Provisions	Y	All Units	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
61	Subpart B	(§§ 20 - 26) - National Emission Standards for Radon Emissions from Underground Uranium Mines	N			
61	Subpart C	(§§ 30 - 34) - National Emission Standard for Beryllium	N			
61	Subpart D	(§§ 40 - 44) - National Emission Standard for Beryllium Rocket Motor Firing	N			
61	Subpart E	(§§ 50 - 56) - National Emission Standard for Mercury	N			
61	Subpart F	(§§ 60 - 71) - National Emission Standard for Vinyl Chloride	N			
61	Subpart H	(§§ 90 - 97) - National Emission Standards for Emissions of Radionuclides Other Than Radon from Department of Energy Facilities	N			
61	Subpart I	(§§ 100 - 108) - National Emission Standards for Radionuclide Emissions from Federal Facilities Other Than Nuclear Regulatory Commission Licensees and Not Covered by Subpart H	N			
61	Subpart J	(§§ 110 - 112) - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene	N			
61	Subpart K	(§§ 120 - 127) - National Emission Standards for Radionuclide Emissions from Elemental Phosphorus Plants	N			
61	Subpart L	(§§ 130 - 139) - National Emission Standard for Benzene Emissions from Coke by-Product Recovery Plants	N			
61	Subpart M	(§§ 140 - 157) - National Emission Standard for Asbestos	Y		For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
61	Subpart N	(§§ 160 - 165) - National Emission Standard for Inorganic Arsenic Emissions from Glass Manufacturing Plants	N			
61	Subpart O	(§§ 170 - 177) - National Emission Standard for Inorganic Arsenic Emissions from Primary Copper Smelters	N			
61	Subpart P	(§§ 180 - 186) - National Emission Standard for Inorganic Arsenic Emissions from Arsenic Trioxide and Metallic Arsenic Production Facilities	N			
61	Subpart Q	(§§ 190 - 193) - National Emission Standards for Radon Emissions from Department of Energy Facilities	N			
61	Subpart R	(§§ 200 - 210) - National Emission Standards for Radon Emissions from Phosphogypsum Stacks	N			
61	Subpart T	(§§ 220 - 226) - National Emission Standards for Radon Emissions from the Disposal of Uranium Mill Tailings	N			
61	Subpart V	(§§ 240 - 247) - National Emission Standard for Equipment Leaks (Fugitive Emission Sources)	N			
61	Subpart W	(§§ 250 - 256) - National Emission Standards for Radon Emissions from Operating Mill Tailings	N			
61	Subpart Y	(§§ 270 - 277) - National Emission Standard for Benzene Emissions from Benzene Storage Vessels	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
61	Subpart BB	(§§ 300 - 306) - National Emission Standard for Benzene Emissions from Benzene Transfer Operations	N			
61	Subpart FF	(§§ 340 - 359) - National Emission Standard for Benzene Waste Operations	Y	API separators, BRU, recovered oil sump, skim oil tank, wastewater surge tank, recovers oil tank, and crude water draw tank	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
<b>Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories</b>						
63	Subpart A	(§§ 1 - 16) - General Provisions	Y	All Units	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
63	Subpart B	(§§ 40 - 56) - Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)	N			
63	Subpart C	(§§ 60 - 64) - List of Hazardous Air Pollutants, Petitions Process, Lesser Quantity Designations, Source Category List	N			
63	Subpart D	(§§ 70 - 81) - Regulations Governing Compliance Extensions for Early Reductions of Hazardous Air Pollutants	N			
63	Subpart E	(§§ 90 - 99) - Approval of State Programs and Delegation of Federal Authorities	N			
63	Subpart F	(§§ 100 - 107) - National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry	N			
63	Subpart G	(§§ 110 - 153) - National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater	N			
63	Subpart H	(§§ 160 - 183) - National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks	N			
63	Subpart I	(§§ 190 - 193) - National Emission Standards for Organic Hazardous Air Pollutants for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks	N			
63	Subpart J	(§§ 210 - 217) - National Emission Standards for Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production	N			
63	Subpart L	(§§ 300 - 313) - National Emission Standards for Coke Oven Batteries	N			
63	Subpart M	(§§ 320 - 326) - National Perchloroethylene Air Emission Standards for Dry Cleaning Facilities	N			
63	Subpart N	(§§ 340 - 348) - National Emission Standards for Chromium Emissions from Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks	N			
63	Subpart O	(§§ 360 - 368) - Ethylene Oxide Emissions Standards for Sterilization Facilities	N			



Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart Q	(§§ 400 - 407) - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers	N			
63	Subpart R	(§§ 420 - 429) - National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)	Y			
				<i>Avgas load rack</i>	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
63	Subpart S	(§§ 440 - 459) - National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry	N			
63	Subpart T	(§§ 460 - 470) - National Emission Standards for Halogenated Solvent Cleaning	N			
63	Subpart U	(§§ 480 - 507) - National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins	N			
63	Subpart W	(§§ 520 - 529) - National Emission Standards for Hazardous Air Pollutants for Epoxy Resins Production and Non-Nylon Polyamides Production	N			
63	Subpart X	(§§ 541 - 551) - National Emission Standards for Hazardous Air Pollutants from Secondary Lead Smelting	N			
63	Subpart Y	(§§ 560 - 569) - National Emission Standards for Marine Tank Vessel Loading Operations	N			
63	Subpart AA	(§§ 600 - 611) - National Emission Standards for Hazardous Air Pollutants from Phosphoric Acid Manufacturing Plants	N			
63	Subpart BB	(§§ 620 - 632) - National Emission Standards for Hazardous Air Pollutants from Phosphate Fertilizers Production Plants	N			
63	Subpart CC	(§§ 640 - 656) - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries	Y			
				FCCU, Crude Unit Furnace, B&S, Dimersol, Cogen, Liquid Fuel System, Alky, Effluent treatment plant, Group 1 tanks, Avgas load rack, heat exchangers	For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.	
63	Subpart DD	(§§ 680 - 698) - National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations	N			
63	Subpart EE	(§§ 701 - 708) - National Emission Standards for Magnetic Tape Manufacturing Operations	N			
63	Subpart GG	(§§ 741 - 759) - National Emission Standards for Aerospace Manufacturing and Rework Facilities	N			
63	Subpart HH	(§§ 760 - 778) - National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities	N			
63	Subpart II	(§§ 780 - 789) - National Emission Standards for Shipbuilding and Ship Repair (Surface Coating)	N			
63	Subpart JJ	(§§ 800 - 809) - National Emission Standards for Wood Furniture Manufacturing Operations	N			
63	Subpart KK	(§§ 820 - 832) - National Emission Standards for the Printing and Publishing Industry	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart LL	(§§ 840 - 854) - National Emission Standards for Hazardous Air Pollutants for Primary Aluminum Reduction Plants	N			
63	Subpart MM	(§§ 860 - 868) - National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills	N			
63	Subpart OO	(§§ 900 - 908) - National Emission Standards for Tanks-Level 1	N			
63	Subpart PP	(§§ 920 - 929) - National Emission Standards for Containers	N			
63	Subpart QQ	(§§ 940 - 949) - National Emission Standards for Surface Impoundments	N			
63	Subpart RR	(§§ 960 - 967) - National Emission Standards for Individual Drain Systems	N			
63	Subpart SS	(§§ 980 - 999) - National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process	N			
63	Subpart TT	(§§ 1000 - 1018) - National Emission Standards for Equipment Leaks-Control Level 1	N			
63	Subpart UU	(§§ 1019 - 1039) - National Emission Standards for Equipment Leaks-Control Level 2 Standards	N			
63	Subpart VV	(§§ 1040 - 1050) - National Emission Standards for Oil-Water Separators and Organic-Water Separators	N			
63	Subpart WW	(§§ 1060 - 1067) - National Emission Standards for Storage Vessels (Tanks)-Control Level 2	N			
63	Subpart XX	(§§ 1080 - 1097) - National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations	N			
63	Subpart YY	(§§ 1100 - 1114) - National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards	N			
63	Subpart CCC	(§§ 1155 - 1167) - National Emission Standards for Hazardous Air Pollutants for Steel Pickling-Hcl Process Facilities and Hydrochloric Acid Regeneration Plants	N			
63	Subpart DDD	(§§ 1175 - 1197) - National Emission Standards for Hazardous Air Pollutants for Mineral Wool Production	N			
63	Subpart EEE	(§§ 1200 - 1221) - National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors	N			
63	Subpart GGG	(§§ 1250 - 1261) - National Emission Standards for Pharmaceuticals Production	N			
63	Subpart HHH	(§§ 1270 - 1288) - National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities	N			
63	Subpart III	(§§ 1290 - 1309) - National Emission Standards for Hazardous Air Pollutants for Flexible Polyurethane Foam Production	N			
63	Subpart JJJ	(§§ 1310 - 1335) - National Emission Standards for Hazardous Air Pollutant Emissions: Group IV Polymers and Resins	N			
63	Subpart LLL	(§§ 1340 - 1359) - National Emission Standards for Hazardous Air Pollutants from the Portland Cement Manufacturing Industry	N			
63	Subpart MMM	(§§ 1360 - 1369) - National Emission Standards for Hazardous Air Pollutants for Pesticide Active Ingredient Production	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart NNN	(§§ 1380 - 1389) - National Emission Standards for Hazardous Air Pollutants for Wool Fiberglass Manufacturing	N			
63	Subpart OOO	(§§ 1400 - 1419) - National Emission Standards for Hazardous Air Pollutant Emissions: Manufacture of Amino/Phenolic Resins	N			
63	Subpart PPP	(§§ 1420 - 1439) - National Emission Standards for Hazardous Air Pollutant Emissions for Polyether Polyols Production	N			
63	Subpart QQQ	(§§ 1440 - 1459) - National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting	N			
63	Subpart RRR	(§§ 1500 - 1520) - National Emission Standards for Hazardous Air Pollutants for Secondary Aluminum Production	N			
63	Subpart TTT	(§§ 1541 - 1550) - National Emission Standards for Hazardous Air Pollutants for Primary Lead Smelting	N			
63	Subpart UUU	(§§ 1560 - 1579) - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units	Y	FCC		For applicable monitoring, recordkeeping, notification, reporting, and test methods required, see current covered source permit.
63	Subpart VVV	(§§ 1580 - 1595) - National Emission Standards for Hazardous Air Pollutants: Publicly Owned Treatment Works	N			
63	Subpart XXX	(§§ 1620 - 1662) - National Emission Standards for Hazardous Air Pollutants for Ferroalloys Production: Ferromanganese and Silicomanganese	N			
63	Subpart AAAA	(§§ 1930 - 1990) - National Emission Standards for Hazardous Air Pollutants: Municipal Solid Waste Landfills	N			
63	Subpart CCCC	(§§ 2130 - 2192) - National Emission Standards for Hazardous Air Pollutants: Manufacturing of Nutritional Yeast	N			
63	Subpart DDDD	(§§ 2230 - 2292) - National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products	N			
63	Subpart EEEE	(§§ 2330 - 2406) - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)	N			
63	Subpart FFFF	(§§ 2430 - 2550) - National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing	N			
63	Subpart GGGG	(§§ 2830 - 2872) - National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production	N			
63	Subpart HHHH	(§§ 2980 - 3005) - National Emission Standards for Hazardous Air Pollutants for Wet-Formed Fiberglass Mat Production	N			
63	Subpart IIII	(§§ 3080 - 3176) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Automobiles and Light-Duty Trucks	N			
63	Subpart JJJJ	(§§ 3280 - 3420) - National Emission Standards for Hazardous Air Pollutants: Paper and Other Web Coating	N			
63	Subpart KKKK	(§§ 3480 - 3561) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Metal Cans	N			
63	Subpart MMMM	(§§ 3880 - 3981) - National Emission Standards for Hazardous Air Pollutants for Surface Coating of Miscellaneous Metal Parts and Products	N			
63	Subpart NNNN	(§§ 4080 - 4181) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Large Appliances	N			

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart OOOO	(§§ 4280 - 4371) - National Emission Standards for Hazardous Air Pollutants: Printing, Coating, and Dyeing of Fabrics and Other Textiles	N			
63	Subpart PPPP	(§§ 4480 - 4581) - National Emission Standards for Hazardous Air Pollutants for Surface Coating of Plastic Parts and Products	N			
63	Subpart QQQQ	(§§ 4680 - 4781) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Wood Building Products	N			
63	Subpart RRRR	(§§ 4880 - 4981) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Metal Furniture	N			
63	Subpart SSSS	(§§ 5080 - 5201) - National Emission Standards for Hazardous Air Pollutants: Surface Coating of Metal Coil	N			
63	Subpart TTTT	(§§ 5280 - 5460) - National Emission Standards for Hazardous Air Pollutants for Leather Finishing Operations	N			
63	Subpart UUUU	(§§ 5480 - 5610) - National Emission Standards for Hazardous Air Pollutants for Cellulose Products Manufacturing	N			
63	Subpart VVVV	(§§ 5680 - 5779) - National Emission Standards for Hazardous Air Pollutants for Boat Manufacturing	N			
63	Subpart WWWW	(§§ 5780 - 5935) - National Emissions Standards for Hazardous Air Pollutants: Reinforced Plastic Composites Production	N			
63	Subpart XXXX	(§§ 5980 - 6015) - National Emissions Standards for Hazardous Air Pollutants: Rubber Tire Manufacturing	N			
63	Subpart YYYY	<a href="#">(§§ 6080 - 6175) - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines</a>	Y	Cogen	Applicable units: All Stationary Combustion Turbines Monitor: Fuel Used, Hours Used, Formaldehyde emissions, catalyst inlet temperature Test Methods: 1, 1A, 3A, 3B, 4 Recordkeeping: Maintenance, startup, shutdown and malfunction Reporting: Notification, Semi Annual Report, Annual Performance Testing	5 Mar 2004, 69 FR 10537

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart ZZZZ	<a href="#">( §§ 6580 - 6675 ) - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines</a>	Y	Generators and Fire Water Pumps	Applicable units: All engines are subject.  Please see attached RICE NESHAP tab for detailed requirements for the following applicable engine categories: -Engines installed after 12 Jun 2006 must meet requirements in 40 CFR 60 IIII and JJJJ. No other requirements from ZZZZ are applicable. -CI engines 100 hp or less and installed before 12 Jun 2006. -Non-emergency CI at or between 100 and 500 hp installed before 12 Jun 2006. -Emergency CI (including Fire Water Pumps) installed prior to 12 Jun 2006	15 Jun 2004, 69 FR 33506
63	Subpart AAAAA	( §§ 7080 - 7143 ) - National Emission Standards for Hazardous Air Pollutants for Lime Manufacturing Plants	N			
63	Subpart BBBB	( §§ 7180 - 7195 ) - National Emission Standards for Hazardous Air Pollutants for Semiconductor Manufacturing	N			
63	Subpart CCCCC	( §§ 7280 - 7352 ) - National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing, Quenching, and Battery Stacks	N			
63	Subpart DDDDD	( §§ 7480 - 7575 ) - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters	Y		Proposed Rule expected to be finalized in Jan 2011. Would impact all units using natural gas, fuel oil or refinery gas.	
63	Subpart EEEEE	( §§ 7680 - 7765 ) - National Emission Standards for Hazardous Air Pollutants for Iron and Steel Foundries	N			
63	Subpart FFFFF	( §§ 7780 - 7852 ) - National Emission Standards for Hazardous Air Pollutants for Integrated Iron and Steel Manufacturing Facilities	N			
63	Subpart GGGGG	<a href="#">( §§ 7880 - 7957 ) - National Emission Standards for Hazardous Air Pollutants: Site Remediation</a>	N			
63	Subpart HHHHH	( §§ 7980 - 8105 ) - National Emission Standards for Hazardous Air Pollutants: Miscellaneous Coating Manufacturing	N			
63	Subpart IIIII	( §§ 8180 - 8266 ) - National Emission Standards for Hazardous Air Pollutants: Mercury Emissions from Mercury Cell Chlor-Alkali Plants	N			
63	Subpart JJJJJ	( §§ 8380 - 8515 ) - National Emission Standards for Hazardous Air Pollutants for Brick and Structural Clay Products Manufacturing	N			
63	Subpart KKKKK	( §§ 8530 - 8665 ) - National Emission Standards for Hazardous Air Pollutants for Clay Ceramics Manufacturing	N			
63	Subpart LLLLL	( §§ 8680 - 8698 ) - National Emission Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing Manufacturing	N			



Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart MMMMM	(§§ 8780 - 8830) - National Emission Standards for Hazardous Air Pollutants: Flexible Polyurethane Foam Fabrication Operations	N			
63	Subpart NNNNN	(§§ 8980 - 9075) - National Emission Standards for Hazardous Air Pollutants: Hydrochloric Acid Production	N			
63	Subpart PPPPP	(§§ 9280 - 9375) - National Emission Standards for Hazardous Air Pollutants for Engine Test Cells/Stands	N			
63	Subpart QQQQQ	(§§ 9480 - 9571) - National Emission Standards for Hazardous Air Pollutants for Friction Materials Manufacturing Facilities	N			
63	Subpart RRRRR	(§§ 9580 - 9652) - National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing	N			
63	Subpart SSSSS	(§§ 9780 - 9824) - National Emission Standards for Hazardous Air Pollutants for Refractory Products Manufacturing	N			
63	Subpart TTTTT	(§§ 9880 - 9942) - National Emissions Standards for Hazardous Air Pollutants for Primary Magnesium Refining	N			
63	Subpart WWWW	(§§ 10382 - 10448) - National Emissions Standards for Hazardous Air Pollutants for Hospital Ethylene Oxide Sterilizers	N			New but assumed by Description that its not applicable
63	Subpart YYYYY	(§§ 10680 - 10692) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: ELECTRIC ARC FURNACE STEELMAKING FACILITIES	N			New but assumed by Description that its not applicable
63	Subpart ZZZZ	(§§ 10880 - 10906) - National Emissions Standards for Hazardous Air Pollutants FOR IRON AND STEEL FOUNDRIES AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart BBBBB	<a href="#">(§§ 11080 - 11100) - National Emissions Standards for Hazardous Air Pollutants FOR SOURCE CATEGORY: GASOLINE DISTRIBUTION BULK TERMINALS, BULK PLANTS, AND PIPELINE FACILITIES</a>	N			New 10 Jan 2008, 73 FR 1933 Not applicable if subject to 63 subpart R and CC, which Chevron is.
63	Subpart CCCCC	<a href="#">(§§ 11110 - 11132) - National Emissions Standards for Hazardous Air Pollutants FOR SOURCE CATEGORY: GASOLINE DISPENSING FACILITIES</a>	N			New but assumed by Description that its not applicable
63	Subpart DDDDD	(§§ 11140 - 11145) - National Emissions Standards for Hazardous Air Pollutants FOR POLYVINYL CHLORIDE AND COPOLYMERS PRODUCTION AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart EEEEE	(§§ 11146 - 11152) - National Emissions Standards for Hazardous Air Pollutants FOR PRIMARY COPPER SMELTING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart FFFFF	(§§ 11153 - 11159) - National Emissions Standards for Hazardous Air Pollutants FOR SECONDARY COPPER SMELTING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart GGGGG	(§§ 11160 - 11168) - National Emissions Standards for Hazardous Air Pollutants FOR PRIMARY NONFERROUS METALS AREA SOURCES-- ZINC, CADMIUM, AND BERYLLIUM	N			New but assumed by Description that its not applicable
63	Subpart HHHHH	(§§ 11169 - 11180) - National Emissions Standards for Hazardous Air Pollutants: PAINT STRIPPING AND MISCELLANEOUS SURFACE COATING OPERATIONS AT AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart LLLLL	(§§ 11393 - 11399) - National Emissions Standards for Hazardous Air Pollutants FOR ACRYLIC AND MODACRYLIC FIBERS PRODUCTION AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart MMMMM	(§§ 11400 - 11406) - National Emissions Standards for Hazardous Air Pollutants FOR CARBON BLACK PRODUCTION AREA SOURCES	N			New but assumed by Description that its not applicable

Part	Subpart	(Sections) Description	Applicable	Emission Units	Applicability Details	Notes
63	Subpart NNNNNN	(§§ 11407 - 11413) - National Emissions Standards for Hazardous Air Pollutants FOR CHEMICAL MANUFACTURING AREA SOURCES: CHROMIUM COMPOUNDS	N			New but assumed by Description that its not applicable
63	Subpart OOOOOO	(§§ 11414 - 11420) - National Emissions Standards for Hazardous Air Pollutants FOR FLEXIBLE POLYURETHANE FOAM PRODUCTION AND FABRICATION AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart PPPPPP	(§§ 11421 - 11427) - National Emissions Standards for Hazardous Air Pollutants FOR LEAD ACID BATTERY MANUFACTURING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart QQQQQQ	(§§ 11428 - 11434) - National Emissions Standards for Hazardous Air Pollutants FOR WOOD PRESERVING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart RRRRRR	(§§ 11435 - 11447) - National Emissions Standards for Hazardous Air Pollutants FOR CLAY CERAMICS MANUFACTURING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart SSSSSS	(§§ 11448 - 11460) - National Emissions Standards for Hazardous Air Pollutants FOR GLASS MANUFACTURING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart NNNNNN	(§§ 11407 - 11413) - National Emissions Standards for Hazardous Air Pollutants FOR CHEMICAL MANUFACTURING AREA SOURCES: CHROMIUM COMPOUNDS	N			New but assumed by Description that its not applicable
63	Subpart TTTTTT	(§§ 11462 - 11474) - National Emissions Standards for Hazardous Air Pollutants FOR SECONDARY NONFERROUS METALS PROCESSING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart VVVVVV	(§§ 11494 - 11503) - National Emissions Standards for Hazardous Air Pollutants FOR CHEMICAL MANUFACTURING AREA SOURCES	N			New but assumed by Description that its not applicable
63	Subpart WWWWWW	(§§ 11504 - 11513) - National Emissions Standards for Hazardous Air Pollutants: AREA SOURCE STANDARDS FOR PLATING AND POLISHING OPERATIONS	N			New but assumed by Description that its not applicable
63	Subpart XXXXXX	(§§ 11514 - 11523) - National Emissions Standards for Hazardous Air Pollutants AREA SOURCE STANDARDS FOR NINE METAL FABRICATION AND FINISHING SOURCE CATEGORIES	N			New but assumed by Description that its not applicable
63	Subpart YYYYYY	(§§ 11524 - 11543) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: FERROALLOYS PRODUCTION FACILITIES	N			New but assumed by Description that its not applicable
63	Subpart ZZZZZZ	(§§ 11544 - 11558) - National Emissions Standards for Hazardous Air Pollutants: AREA SOURCE STANDARDS FOR ALUMINUM, COPPER, AND OTHER NONFERROUS FOUNDRIES	N			New but assumed by Description that its not applicable
63	Subpart AAAAAA	<a href="#">(§§ 11559 - 11567) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: ASPHALT PROCESSING AND ASPHALT ROOFING MANUFACTURING</a>	N			New but assumed by Description that its not applicable
63	Subpart BBBBBB	(§§ 11579 - 11588) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: CHEMICAL PREPARATIONS INDUSTRY	N			New but assumed by Description that its not applicable
63	Subpart CCCCCC	(§§ 11599 - 11638) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: PAINTS AND ALLIED PRODUCTS MANUFACTURING	N			New but assumed by Description that its not applicable
63	Subpart DDDDDD	(§§ 11619 - 11638) - National Emissions Standards for Hazardous Air Pollutants FOR AREA SOURCES: PREPARED FEEDS MANUFACTURING	N			New but assumed by Description that its not applicable
	<b>Part 68 - Chemical Accident Prevention Provisions</b>		Y	All Units		

40 CFR part 63, subpart ZZZZ  
National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Summary of Requirements

Engine Category	Date Constructed	Emission Limitations	Operating Limitations	Fuel Requirements	Performance Tests	Monitoring, Installation, Collection, Operation and Maintenance Requirements	Initial Compliance	Continuous Compliance	Notification Requirements	Recordkeeping Requirements	Reporting Requirements	General Provisions (40 CFR part 63)
<b>Stationary RICE at Area Sources</b>												
<b>STEP 1a - Existing Area Sources</b>												
<b>Existing Stationary Engine ≤500 HP Located at Area Sources of HAP</b>												
Emergency CI	Before 6/12/2006	63.6603 Table 2d	No Requirements	No Requirements	No Requirements	63.6625(e), (f), (h)	No Requirements	63.6635 63.6640	No Requirements	63.6655	63.6650 (except 63.6650(g))	Yes
Non-Emergency CI 300<HP≤500	Before 6/12/2006	63.6603 Table 2d	No Requirements	>300 HP with displacement <30 l/cyl: 63.6604	63.6612 63.6615 63.6620 Table 4	63.6625(e), (h), (i) ≥300 HP: 63.6625(g)	63.6630	63.6635 63.6640	63.6645	63.6655 (except 63.6655(f))	63.6650 (except 63.6650(g))	Yes
Non-Emergency CI ≤300 HP	Before 6/12/2006	63.6603 Table 2d	No Requirements	No Requirements	No Requirements	63.6625(e), (h), (i)	No Requirements	63.6635 63.6640	No Requirements	63.6655 (except 63.6655(f))	63.6650 (except 63.6650(g))	Yes
SI 4SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
SI 2SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
SI 4SRB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
Landfill/Digester Gas	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
Residential/Commercial/Institutional Emergency	Before 6/12/2006	No Requirements										
<b>Existing Stationary Engine &gt;500 HP Located at Area Sources of HAP</b>												
Emergency CI	Before 6/12/2006	63.6603 Table 2d	No Requirements	No Requirements	No Requirements	63.6625(e), (f), (h)	No Requirements	63.6635 63.6640	No Requirements	63.6655	63.6650 (except 63.6650(g))	Yes
Non-Emergency CI	Before 6/12/2006	63.6603 Table 2d	63.6603 Table 2b	>300 HP with displacement <30 l/cyl: 63.6604	63.6610 63.6615 63.6620 Table 4	63.6625(g), (h)	63.6630	63.6635 63.6640	63.6645	63.6655 (except 63.6655(f))	63.6650 (except 63.6650(g))	Yes
SI 4SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
SI 2SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
SI 4SRB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
Landfill/Digester Gas	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)										
Residential/Commercial/Institutional Emergency	Before 6/12/2006	No Requirements										



40 CFR part 63, subpart ZZZZ  
National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Summary of Requirements

<b>Stationary RICE at Area Sources</b>		
<b>STEP 1b - New &amp; Reconstructed Area Sources</b>		
<b>New &amp; Reconstructed Stationary Engine ≤500 HP Located at Area Sources of HAP</b>		
Limited Use	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJJ (SI NSPS), as applicable.
Emergency	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJJ (SI NSPS), as applicable.
Non-Emergency CI	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS)
SI 4SLB	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)
SI 2SLB	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)
SI 4SRB	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)
Landfill/Digester Gas	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)
<b>New &amp; Reconstructed Stationary Engine &gt;500 HP Located at Area Sources of HAP</b>		
Limited Use	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJJ (SI NSPS), as applicable.
Emergency	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJJ (SI NSPS), as applicable.
Non-Emergency CI	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS)
SI 4SLB	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)
SI 2SLB	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)
SI 4SRB	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)
Landfill/Digester Gas	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)

40 CFR part 63, subpart ZZZZ  
National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Summary of Requirements

<b>Stationary RICE at Major Sources</b>														
<b>STEP 2(a)(i)</b>														
<b>Existing Stationary Engine ≤500 HP Located at Major Sources of HAP</b>														
Emergency CI	Before 6/12/2006	63.6602 2c	Table Table 2c	63.6602 Table 2c	No Requirements	No Requirements	63.6625(e), (f), (h)	No Requirements	63.6635 63.6640	No Requirements	63.6655	63.6650 (except 63.6650(g))	Yes	
Non-Emergency CI 100≤HP≤500	Before 6/12/2006	63.6602 2c	Table Table 2c	63.6602 Table 2c	>300 HP with displacement <30 l/cyl: 63.6604	63.6612 63.6620	63.6615 Table 4	63.6625(h), (i) HP: 63.6625(g) ≥300	63.6630	63.6635 63.6640	63.6645	63.6655 63.6655(f) (except 63.6650(g))	Yes	
CI <100 HP	Before 6/12/2006	63.6602 2c	Table Table 2c	63.6602 Table 2c	No Requirements	No Requirements	63.6625(h), (i)	No Requirements	63.6635 63.6640	No Requirements	63.6655 63.6655(f) (except 63.6650(g))	63.6650 (except 63.6650(g))	Yes	
SI 4SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)												
SI 2SLB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)												
SI 4SRB	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)												
Landfill/Digester Gas	Before 6/12/2006	No Requirements (Rule to be finalized Aug 2010)												
<b>STEP 2(a)(ii)</b>														
<b>Existing Stationary Engine &gt;500 HP Located at Major Sources of HAP</b>														
Limited Use	Before 12/19/2002	No Requirements												
Emergency CI	Before 12/19/2002	No Requirements												
Non-Emergency CI	Before 12/19/2002	63.6600(d) 2c	Table Table 2b	63.6600(d) Table 2b	>300 HP and <30 l/cyl: 63.6604	63.6610 63.6620	63.6615 Table 3	63.6625(a), (b), (h), (i) ≥300 HP: 63.6625(g)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
SI 4SLB	Before 12/19/2002	No Requirements												
SI 2SLB	Before 12/19/2002	No Requirements												
SI 4SRB	Before 12/19/2002	63.6600(a) Table 1a		63.6600(a) Table 1b	No Requirements	63.6610 63.6620	63.6615 Table 3	63.6625(a), (b), (h)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
Landfill/Digester Gas	Before 12/19/2002	No Requirements												

40 CFR part 63, subpart ZZZZ  
National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Summary of Requirements

Stationary RICE at Major Sources												
STEP 2(b)(i)												
New & Reconstructed Stationary Engine ≤500 HP Located at Major Sources of HAP												
Limited Use	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJJ (SI NSPS), as applicable.										
Emergency	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS) or subpart JJJJ (SI NSPS), as applicable.										
Non-Emergency CI	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart IIII (CI NSPS)										
SI 4SLB <250 HP	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)										
Non-Emergency SI 4SLB ≥250 HP	On or After 6/12/2006 and before 1/1/2008	No Requirements										
Non-Emergency SI 4SLB ≥250 HP	Manufactured on or after 1/1/2008	63.6601 Table 2a	63.6601 Table 2b	No Requirements	63.6611 63.6615 63.6620 Table 4	63.6625(h), (i)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
Emergency SI 4SLB ≥250 HP	Manufactured on or after 1/1/2008	No Requirements	No Requirements	No Requirements	No Requirements	63.6625(d)	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	Yes
SI 2SLB	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)										
SI 4SRB	On or After 6/12/06	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)										
Landfill/Digester Gas	On or After 6/12/2006	Engines are subject to 40 CFR part 60, subpart JJJJ (SI NSPS)										
STEP 2(b)(ii)												
New & Reconstructed Stationary Engine >500 HP Located at Major Sources of HAP												
Limited Use	On or After 12/19/02	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	63.6645(f)	No Requirements	No Requirements	No (except as specified in 63.6645(f))
Emergency	On or After 12/19/2002	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	No Requirements	63.6645(f)	No Requirements	No Requirements	No (except as specified in 63.6645(f))
CI	On or After 12/19/02	63.6600(b) Table 2a	63.6600(b) Table 2b	No Requirements	63.6610 63.6615 63.6620 Table 3 Table 4	63.6625(a), (b), (h)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
SI 4SLB	On or After 12/19/02	63.6600(b) Table 2a	63.6600(b) Table 2b	No Requirements	63.6610 63.6615 63.6620 Table 3 Table 4	63.6625(a), (b), (h)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
SI 2SLB	On or After 12/19/02	63.6600(b) Table 2a	63.6600(b) Table 2b	No Requirements	63.6610 63.6615 63.6620 Table 3 Table 4	63.6625(a), (b), (h)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
SI 4SRB	On or After 12/19/02	63.6600(a) Table 1a	63.6600(a) Table 1b	No Requirements	63.6610 63.6615 63.6620 Table 3 Table 4	63.6625(a), (b), (h)	63.6630	63.6635 63.6640	63.6645	63.6655	63.6650	Yes
Landfill/Digester Gas	On or After 12/19/02	No Requirements	No Requirements	No Requirements	No Requirements	≥10 percent of the gross heat input on an annual basis: 63.6625(c), (h)			≥10 percent of the gross heat input on an annual basis: 63.6645(f)	≥10 percent of the gross heat input on an annual basis: 63.6655(c)	≥10 percent of the gross heat input on an annual basis: 63.6650(g)	No (except as specified in 63.6645(f))

<sup>a</sup>Note that certain engines covered under 40 CFR part 63, subpart ZZZZ, may be subject to additional requirements under 40 CFR part 60, subparts IIII and JJJJ.

<sup>b</sup>For assistance in determining the potential to emit, please refer to <http://www.epa.gov/ttn/chief/ap42/index.html> or contact your EPA regional office or state permitting staff. To determine the potential to emit, you may use emission factors from <http://www.epa.gov/ttn/chief/ap42/ch03/index.html>, test data, or other published information.

**Abbreviations:**  
 CI-Compression Ignition  
 SI-Spark Ignition  
 4SLB-4 Stroke Lean Burn  
 2SLB-2 Stroke Lean Burn  
 4SRB-4 Stroke Rich Burn

Department of Hawaii  
Title 11 State Requirements

Hawaii State Requirements Title 11

REGULATION - NAME	APPLICABLE	EMISSION UNITS
Chapter 59 - Ambient Air Quality Standards	Y	
Chapter 60.1 - Air Pollution Control	Y	
<b>Subchapter 1 General Requirements</b>	Y	
§11-60.1-1 Definitions	Y	
§11-60.1-2 Prohibition of air pollution	Y	
§11-60.1-3 General conditions for considering applications		
§11-60.1-4 Certification	Y	
§11-60.1-5 Permit conditions		
§11-60.1-6 Holding of permit	Y	
§11-60.1-7 Transfer of permit		
§11-60.1-8 Reporting discontinuance	Y	
§11-60.1-9 Cancellation of a noncovered or covered source permit		
§11-60.1-10 Permit termination, suspension, reopening, and amendment	Y	
§11-60.1-11 Sampling, testing, and reporting methods	Y	
§11-60.1-12 Air quality models		
§11-60.1-13 Operations of monitoring stations		
§11-60.1-14 Public access to information	Y	
§11-60.1-15 Reporting of equipment shutdown	Y	
§11-60.1-16 Prompt reporting of deviations	Y	
§11-60.1-16.5 Emergency provision		
§11-60.1-17 Prevention of air pollution emergency episodes		
§11-60.1-18 Variances		
§11-60.1-19 Penalties and remedies	Y	
§11-60.1-20 Severability	Y	
<b>Subchapter 2 General Prohibitions</b>	Y	
§11-60.1-31 Applicability	Y	
§11-60.1-32 Visible emissions	Y	Crude Furnaces, Boilers, FCCU, Process Unit Furnaces, Asphalt Plant, Acid plant, and Cogeneration Plant
§11-60.1-33 Fugitive dust	Y	FCCU catalyst transfer operations

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§11-60.1-34 Motor vehicles		
§11-60.1-35 Incineration		
§11-60.1-36 Biomass fuel burning boilers		
§11-60.1-37 Process industries		
§11-60.1-38 Sulfur oxides from fuel combustion	Y	Crude Furnaces, Boilers, FCCU, Process Unit Furnaces, Asphalt Plant, Acid plant, and Cogeneration Plant
§11-60.1-39 Storage of volatile organic compounds	Y	Petroleum Storage Tanks
§11-60.1-40 Volatile organic compound water separation	Y	API Separators
§11-60.1-41 Pump and compressor requirements	Y	seal requirements apply to pumps and compressors handling VOC with a Reid vaport presser greater than or equal to 1.5 psia in FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor
§11-60.1-42 Waste gas disposal	Y	flare/abatement requirement for VOC vapor blowdown applies to equipment in FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor
<b>Subchapter 3 Open Burning</b>	<b>N</b>	
§11-60.1-51 Definitions		
§11-60.1-52 General provisions		
§11-60.1-53 Agricultural burning: permit requirement		
§11-60.1-54 Agricultural burning: applications		
§11-60.1-55 Agricultural burning: "no-burn" periods		
§11-60.1-56 Agricultural burning: recordkeeping and monitoring		
§11-60.1-57 Agricultural burning: action on application		
<b>Subchapter 4 Noncovered Sources</b>	<b>N</b>	
§11-60.1-61 Definitions		
§11-60.1-62 Applicability		
§11-60.1-63 Initial noncovered source permit application		

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§11-60.1-64 Duty to supplement or correct permit applications		
§11-60.1-65 Compliance plan		
§11-60.1-66 Transition into the noncovered source permit program		
§11-60.1-67 Permit term		
§11-60.1-68 Permit content		
§11-60.1-69 Temporary noncovered source permits		
§11-60.1-70 Noncovered source general permits		
§11-60.1-71 Transmission of information to the administrator		
§11-60.1-72 Permit reopening		
§11-60.1-73 Public participation		
§11-60.1-74 Noncovered source permit renewal applications		
§11-60.1-75 Administrative permit amendment		
§11-60.1-76 Applications for modifications		
<b>Subchapter 5 Covered Sources</b>	Y	
§11-60.1-81 Definitions	Y	
§11-60.1-82 Applicability	Y	
§11-60.1-83 Initial covered source permit application	Y	
§11-60.1-84 Duty to supplement or correct permit applications	Y	
§11-60.1-85 Compliance plan	Y	
§11-60.1-86 Compliance certification of covered sources	Y	
§11-60.1-87 Transition period		
§11-60.1-88 Action on applications submitted within one year of the effective date of this chapter		
§11-60.1-88.5 Permit action on insignificant activities		
§11-60.1-89 Permit term	Y	
§11-60.1-90 Permit content	Y	
§11-60.1-91 Temporary covered source permits		

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§11-60.1-92 Covered source general permits		
§11-60.1-93 Federally-enforceable permit terms and conditions		
§11-60.1-94 Transmission of information to the administrator		
§11-60.1-95 EPA oversight		
§11-60.1-96 Operational flexibility	Y	
§11-60.1-97 Repealed.		
§11-60.1-98 Permit reopening	Y	
§11-60.1-99 Public participation		
§11-60.1-100 Public petitions		
§11-60.1-101 Covered source permit renewal applications		
§11-60.1-102 Administrative permit amendment		
§11-60.1-103 Applications for minor modifications		
§11-60.1-104 Applications for significant modifications		
<b>Subchapter 6 Fees for Covered Sources, Noncovered Sources, and Agricultural Burning</b>	Y	
§11-60.1-111 Definitions		
§11-60.1-112 General fee provisions for covered sources	Y	
§11-60.1-113 Application fees for covered sources	Y	
§11-60.1-114 Annual fees for covered sources	Y	
§11-60.1-115 Basis of annual fees for covered sources		
§11-60.1-116 Repealed.		
§11-60.1-117 General fee provisions for noncovered sources		
§11-60.1-118 Application fees for noncovered sources		
§11-60.1-119 Annual fees for noncovered sources		
§11-60.1-120 Repealed.		

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§11-60.1-121 Application fees for agricultural burning permits		
<b>Subchapter 7 Prevention of Significant Deterioration Review</b>	N	was not applicable for the initial Covered Source Permit, because this facility was not a new major stationary source, nor did Chevron propose any major modifications to a major stationary source as defined in HAR 11-60.1-131. Applicability of PSD will need to be addressed on a project-by-project basis for future proposed facility modifications.
§11-60.1-131 Definitions	N	
§11-60.1-132 Source applicability	N	
§11-60.1-133 Exemptions	N	
§11-60.1-134 Ambient air increments	N	
§11-60.1-135 Ambient air ceilings	N	
§11-60.1-136 Restriction on area classifications	N	
§11-60.1-137 Exclusions from increment consumption	N	
§11-60.1-138 Redesignation	N	
§11-60.1-139 Stack heights	N	
§11-60.1-140 Control technology review	N	
§11-60.1-141 Source impact analysis	N	
§11-60.1-142 Air quality models	N	
§11-60.1-143 Air quality analysis	N	
§11-60.1-144 Source information	N	
§11-60.1-145 Additional impact analyses	N	
§11-60.1-146 Sources impacting Class I areas - additional requirements	N	
§11-60.1-147 Public participation	N	
§11-60.1-148 Source obligation	N	
§11-60.1-149 Innovative control technology	N	
§11-60.1-150 Permit rescission	N	
<b>Subchapter 8 Standards of Performance for Stationary Sources</b>	Y	
§11-60.1-161 New source performance standards	Y	all units that are subject to one or more of the NSPS Subparts in 40 CFR 60
§11-60.1-162 Repealed.		
§11-60.1-163 Federal plans		



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<b>Subchapter 9 Hazardous Air Pollutant Sources</b>	Y	
§11-60.1-171 Definitions		
§11-60.1-172 List of hazardous air pollutants		
§11-60.1-173 Applicability		
§11-60.1-174 Maximum achievable control technology (MACT) emission standards	Y	units that are subject to the Category-Specific NESHAP in Subpart in 40 CFR 63
§11-60.1-175 Equivalent maximum achievable control technology (MACT) limitation		
§11-60.1-176 Repealed.		
§11-60.1-177 Early reduction		
§11-60.1-178 Accidental releases		
§11-60.1-179 Ambient air concentrations of hazardous air pollutants		
§11-60.1-180 National emission standards for hazardous air pollutants	Y	units that are subject to the NESHAP Subpart in 40 CFR 61
<b>Subchapter 10 Field Citations</b>	Y	
§11-60.1-191 Purpose		
§11-60.1-192 Offer to settle; penalties		
§11-60.1-193 Acceptance or withdrawal of citation		
§11-60.1-194 Form of citation		

**Appendix A**  
**Proposed Language**

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**APPENDIX A**  
**Proposed Language**

I. Chevron seeks to include the following as a standard condition in Attachment I:

Emission releases from grandfathered units while operating under normal conditions are not reportable to meet CERCLA reporting guidelines if federally enforceable.

## **Appendix B**

### **Detailed Emission Calculations**

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**APPENDIX B**  
**Detailed Emission Calculations**

Appendix B	Detailed Potential to Emit Calculation Spreadsheets
Appendix B-2	TANKS4 Emission Model Runs for Chevron Hawaii Refinery (Separate Volume)
Appendix B-3	Detailed spreadsheets of component counts and emission estimates for individual components are provided on CD

**Appendix C**  
**Covered Source Permit Tanks**

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**ATTACHMENT II(B): SPECIAL CONDITIONS  
COVERED SOURCE PERMIT NO. 0088-01-C  
PETROLEUM STORAGE TANKS**

**Amended Date: August 13, 2007**

**Expiration Date: June 27, 2011**

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the Covered Source Permit encompasses the following equipment and associated appurtenances:
  - a. Twenty-Seven (27) Gasoline Intermediates and Finished Products Storage Tanks
    - i. One (1) - 272,000 bbl external floating roof storage tank identified as Tank 111;
    - ii. Two (2) - 19,200 bbl external floating roof storage tanks identified as Tanks 232 and 235;
    - iii. Two (2) - 19,000 bbl external floating roof storage tanks identified as Tanks 233 and 273;
    - iv. Four (4) - 38,000 bbl external floating roof storage tanks identified as Tanks 236, 237, 255, and 256;
    - v. One (1) - 9,500 bbl external floating roof storage tanks identified as Tank 251;
    - vi. One (1) - 37,000 bbl external floating roof storage tank identified as Tank 252;
    - vii. One (1) - 37,400 bbl external floating roof storage tank identified as Tank 253;
    - viii. One (1) - 33,000 bbl external floating roof storage tank identified as Tank 254;
    - ix. Three (3) - 29,000 bbl external floating roof storage tanks identified as Tanks 257, 258, and 262;
    - x. Three (3) - 41,000 bbl external floating roof storage tanks identified as Tanks 264, 265, and 266;
    - xi. One (1) - 23,000 bbl external floating roof storage tank identified as Tank 269;
    - xii. One (1) - 36,000 bbl external floating roof storage tank identified as Tank 271;
    - xiii. Two (2) - 4,700 bbl external floating roof storage tanks identified as Tanks 162 and 163;
    - xiv. One (1) - 235,000 bbl external floating roof storage tank identified as Tank 109;
    - xv. One (1) - 9,500 bbl external floating roof storage tank converted to an internal floating roof storage tank identified as Tank 249; and
    - xvi. Two (2) - 5,000 bbl external floating roof storage tanks converted to internal floating roof storage tanks identified as Tanks 250 and 275.
  - b. Eight (8) Crude Oil Storage Tanks
    - i. One (1) - 149,000 bbl external floating roof storage tank identified as Tank 104;
    - ii. Two (2) - 237,000 bbl external floating roof storage tanks identified as Tanks 105 and 107;
    - iii. Two (2) - 235,000 bbl external floating roof storage tanks identified as Tanks 106 and 108;

- iv. One (1) - 272,000 bbl external floating roof storage tank identified as Tank 110;
- v. One (1) - 23,000 bbl external floating roof storage tank identified as Tank 113; and
- vi. One (1) - 81,250 bbl vertical fixed roof storage tank identified as Tank 152.

c. Three (3) Jet Fuel Storage Tanks

- i. One (1) - 50,827 bbl vertical fixed roof storage tank identified as Tank 274;
- ii. One (1) - 38,000 bbl external floating roof storage tank identified as Tank 263; and
- iii. One (1) - 41,000 bbl external floating roof storage tank identified as Tank 267.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each tank. The identification tag or nameplate shall be attached to the tank in a conspicuous location. Information shall also be made available upon request that identifies the capacity, date of construction, serial number or I.D. number and manufacturer of each tank.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. Each of the storage tanks identified in Section A of this Attachment are subject to the provisions of the following federal regulations:
- a. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),
    - i. Subpart A, General Provisions; and
    - ii. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

For Group 1 storage tanks (all storage tanks except for Storage tanks 152, 263, 267, and 274), the permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements, at the first tank degassing and cleaning activity after August 18, 1998, or before August 18, 2005, whichever comes first. The major requirements of these standards are detailed in **Section G - 40 CFR Part 63, Subpart CC Requirements** of this Attachment. Group 1 storage tanks shall comply with Sections C through G below. Group 2 storage tanks (Storage tanks 152, 263, 267 and 274) shall comply with Sections C through F below.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174, 40 CFR §63.640, §63.646)<sup>1</sup>



**Section C. Operational and Emissions Limitations**

1. The true vapor pressure of the volatile organic liquid stored in each of the storage tanks identified in Special Condition A.1.a. of this Attachment shall not be greater than or equal to 11.0 pounds per square inch absolute (psia).  
  
(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)
2. The true vapor pressure of the volatile organic liquid stored in Storage Tanks 152 and 274 shall not be greater than or equal to 1.5 pounds per square inch absolute (psia).  
  
(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)
3. Storage tanks identified in Special Condition No. A.1.b. of this Attachment shall only store crude oil.  
  
(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)
4. Storage tanks identified in Special Condition No. A.1.c. of this Attachment shall only store jet fuel.  
  
(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)
5. Each storage tank identified in Section A of this Attachment, except for Storage Tanks 152 and 274, shall be equipped with a floating roof which will rest on the surface of the liquid contents and be equipped with a closure seal or seals to close the space between the roof edge and tank wall.  
  
(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)
6. All tank gauging and sampling devices for each of the storage tanks identified in Section A of this Attachment, except for Storage Tanks 152 and 274, shall be gas-tight except when tank gauging or sampling is taking place.  
  
(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)
7. Each storage tank identified in Section A of this Attachment shall be equipped with a permanent submerged fill pipe.  
  
(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)
8. The permittee may increase the storage capacities of Storage Tanks 105 through 111 by 12% to the capacities listed below, provided that no new applicable requirement is triggered by such action and the permittee has installed the seal requirements pursuant to 40 CFR

Part 63, Subpart CC. The permittee must obtain prior written approval of the Department of Health and must demonstrate that a modification or reconstruction under NSPS or a PSD review would not be triggered.

Storage Tanks 105 and 107 - 265,440 bbl  
Storage Tanks 106, 108 and 109 - 263,200 bbl  
Storage Tanks 110 and 111- 304,640 bbl

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

#### **Section D. Monitoring and Recordkeeping Requirements**

1. The permittee shall maintain a record of the volatile organic liquid stored, the period of storage, and the maximum true vapor pressure (psia) of that liquid for each storage tank identified in Section A of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

2. The permittee shall keep readily accessible records showing the dimensions of each storage tank identified in Section A of this Attachment and an analysis showing the capacity of the storage tank. This record shall be kept as long as the storage tank retains Group 1 or Group 2 status and is in operation. If a storage tank is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources, a record of any data, assumptions, and procedures used to make this determination shall be retained. The permittee shall use the Group 1 and Group 2 storage vessel definitions in 40 CFR §63.641.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; 40 CFR §63.646, §63.654)<sup>1</sup>

3. Records shall be retained for five (5) years in a permanent form suitable for inspection and made available to the Department of Health or their representatives upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; 40 CFR §63.646, §63.654)<sup>1</sup>

#### **Section E. Notification and Reporting Requirements**

1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons

per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due **within sixty (60) days** following the end of each calendar year. The enclosed **Annual Emissions Report Forms: External/Internal Floating Roof Petroleum Storage Tank, and Fixed Roof Petroleum Storage Tank** or equivalent forms, shall be used in reporting emissions.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions 16, 17, and 25, respectively. These notifications shall include, but not be limited to:
  - a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - c. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department of Health and EPA Region 9, the attached **Compliance Certification Form** pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall be submitted **within ninety (90) days after** the end of each calendar year, and shall be signed and dated by an authorized representative.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. The permittee shall notify the Department of Health at least **thirty (30) days** prior to:
  - a. Changing the volatile organic liquid stored in any of the storage tanks identified in Section A.1.a. of this Attachment; and
  - b. Increasing the storage capacity of Storage Tanks 105 thru 111 in accordance with Special Condition No. C.8. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

#### **Section F. Agency Notifications**

Any document (including reports) required to be submitted by this Covered Source permit shall be in accordance with Attachment I, Standard Condition No. 29.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

#### **Section G. 40 CFR Part 63, Subpart CC Requirements**

##### **1. Operational and Emission Limitations**

- a. Group 1 storage tanks consisting of an external floating roof converted to an internal floating roof (petroleum storage tanks 249, 250 and 275) shall comply with the provisions of 40 CFR §63.646 including the following:
  - i. The internal floating roof shall rest or float on the liquid surface inside a storage tank that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage tank is completely emptied and degassed or subsequently emptied and refilled. When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as soon as practical.
  - ii. The petroleum storage tanks shall be equipped with one of the following closure devices between the wall of the storage tank and the edge of the internal floating roof:

- (1) A foam or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal);
  - (2) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage tank and the edge of the internal floating roof. The lower seal may be vapor mounted, but both must be continuous; or
  - (3) A mechanical shoe seal.
- iii. If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.
  - iv. Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seals exceeds the manufacturer's recommended setting.
  - v. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.
- b. Group 1 storage tanks with an external floating roof (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271 and 273) shall comply with the provisions of 40 CFR §63.646 including the following:
- i. Each external floating roof shall be equipped with a primary seal and secondary seal to close the space between the wall of the storage tank and roof edge. The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. The primary and secondary seals shall completely cover the annular space between the edge of the floating roof and tank wall in a continuous fashion, except during the inspections required by Special Condition No. G.2.b. of this Attachment.
  - ii. The floating roof is to be floating on the liquid at all times (i.e., off the roof leg supports), except during initial fill until the floating roof is lifted off leg supports and during those intervals when the storage tank is completely emptied and degassed or when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the floating roof is resting on the leg supports shall be continuous and shall be accomplished as soon as practical.
  - iii. If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

- iv. Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seals exceeds the manufacturer's recommended setting.
- v. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.646)<sup>1</sup>

## 2. Monitoring and Recordkeeping Requirements

- a. For the Group 1 storage tanks consisting of an external floating roof converted to an internal floating roof (petroleum storage tanks 249, 250 and 275), the permittee shall demonstrate compliance by complying with the requirements of 40 CFR §63.120(a)(1) through (a)(7) including the following:
  - i. The permittee shall visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), according to the schedule specified below:
    - (1) For storage tanks equipped with a single-seal system, the permittee shall perform the inspections specified below:
      - (a) Visually inspect the internal floating roof and the seal through manholes and roof hatches on the fixed roof at least once every **twelve (12) months** after initial fill, or at least once every **twelve (12) months** after the compliance date specified in Special Condition No. B.1. of this Attachment; and
      - (b) Visually inspect the internal floating roof, the seal, gaskets, slotted membranes, and sleeve seals (if any) each time the storage tank is emptied and degassed, and at least once every **ten (10) years** after the compliance date specified in Special Condition No. B.1. of this Attachment.
    - (2) For storage tanks equipped with a double-seal system, the permittee shall perform either one of the inspections indicated below:
      - (a) Visually inspect the internal floating roof, the primary seal, the secondary seal, gaskets, slotted membranes, and sleeve seals (if any) each time the storage tank is emptied and degassed and at least once every **five (5) years** after the compliance date specified in Special Condition No. B.1. of this Attachment; **or**

- (b) Visually inspect the internal floating roof and the secondary seal through manholes and roof hatches on the fixed roof at least once every **twelve (12) months** after initial fill, or at least once every **twelve (12) months** after the compliance date specified in Special Condition No. B.1. of this Attachment, **and**
    - (c) Visually inspect the internal floating roof, the primary seal, the secondary seal, gaskets, slotted membranes, and sleeve seals (if any) each time the vessel is emptied and degassed and at least once every **ten (10) years** after the compliance date specified in Special Condition No. B.1. of this Attachment.
  - ii. If during the inspections required by Special Condition Nos. G.2.a.i.(1)(a) or G.2.a.i.(2)(b) of this Attachment, the internal floating roof is not resting on the surface of the liquid inside the storage tank and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached; or there are holes or tears in the seal fabric; or there are visible gaps between the seal and the wall of the storage tank, the permittee shall repair the items or empty and remove the storage tank from service within **forty-five (45) calendar days**. If a failure that is detected during inspections required by Special Condition Nos. G.2.a.i.(1)(a) or G.2.a.i.(2)(b) of this Attachment cannot be repaired within **forty-five (45) calendar days** and if the tank cannot be emptied within **forty-five (45) calendar days**, the permittee may utilize up to 2 extensions of up to **thirty (30)** additional calendar days each. Documentation of a decision to utilize an extension shall include a description of the failure, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the tank will be emptied as soon as practical.
  - iii. Except as provided in Special Condition No. G.2.a.iv. of this Attachment, for all the inspections required by Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a), and G.2.a.i.(2)(c) of this Attachment, the permittee shall notify the Department of Health in writing at least **thirty (30) calendar days** prior to the refilling of each storage tank to afford the Department of Health the opportunity to have an observer present.
  - iv. If the inspections required by Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a), and G.2.a.i.(2)(c) of this Attachment is not planned and the permittee could not have known about the inspection **thirty (30) calendar days** in advance of refilling the tank, the permittee shall notify the Department of Health at least **seven (7) calendar days** prior to the refilling of the storage tank. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, the notification including the written documentation may be made in writing and sent so that it is received by the Department of Health at least **seven (7) calendar days** prior to refilling.

- v. If during the inspections required by Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a), and G.2.a.i.(2)(c) of this Attachment, the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or the gaskets no longer close off the liquid surface from the atmosphere; or the slotted membrane has more than 10 percent open area, the permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage tank with organic HAP.
- b. For Group 1 storage tanks with external floating roofs (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271 and 273), the permittee shall demonstrate compliance by complying with the requirements of 40 CFR §63.120(b)(1) through (b)(10) including the following:
  - i. Except as provided in Special Condition No. G.2.b.vii. of this Attachment, the permittee shall determine the gap areas and maximum gap widths between the primary seal and the wall of the storage tank, and the secondary seal and the wall of the storage tank as follows:
    - (1) Within **ninety (90) calendar days** of installation of the secondary seal, inspection of both the primary and secondary seals; and
    - (2) At least **once every five (5) years** for the primary seal and at least **once per year** for the secondary seal thereafter.
  - ii. Except as provided in Special Condition No. G.2.b.vii. of this Attachment, the permittee shall determine gap widths and gap areas in the primary and secondary seals (seal gaps) individually by the procedures described below:
    - (1) Seal gaps, if any, shall be measured at one or more floating roof levels when the roof is not resting on the roof leg supports.
    - (2) Seal gaps, if any shall be measured around the entire circumference of the tank in each place where an 0.32 centimeter (1/8 inch) diameter uniform probe passes freely (without forcing or binding against the seal) between the seal and the wall of the storage tank. The circumferential distance of each such location shall also be measured.
    - (3) The total surface area of each gap described in Special Condition No. G.2.b.ii.(2) of this Attachment shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.



- iii. The permittee shall add the gap surface area of each gap location for the primary seal and divide the sum by the nominal diameter of the tank. The accumulated area of gaps between the tank wall and the primary seal shall not exceed 212 square centimeters per meter of tank diameter and the width of any portion of any gap shall not exceed 3.81 centimeters (1-1/2 inches).
- iv. The permittee shall add the gap surface area of each gap location for the secondary seal and divide the sum by the nominal diameter of the tank. The accumulated area of the gaps between the tank wall and the secondary seal shall not exceed 21.2 square centimeters per meter of tank diameter and the width of any portion of any gap shall not exceed 1.27 centimeters (1/2 inch). These seal gap requirements may be exceeded during the measurement of primary seal gaps as required by Special Condition No. G.2.b.i. of this Attachment.
- v. The primary seal shall meet the following requirements:
  - (1) Where a metallic shoe seal is in use, one end of the metallic shoe shall extend into the stored liquid and the other end shall extend a minimum vertical distance of 61 centimeters (24 inches) above the stored liquid surface.
  - (2) There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.
- vi. The secondary seal shall meet the following requirements:
  - (1) The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall, except as provided in Special Condition No. G.2.b.iv. of this Attachment.
  - (2) There shall be no holes, tears, or other openings in the seal or seal fabric.
- vii. If the permittee determines that it is unsafe to perform the seal gap measurements required in Special Condition No. G.2.b.i. of this Attachment or to inspect the tank to determine compliance with Special Condition No. G.2.b.v. and G.2.b.vi. of this Attachment because the floating roof appears to be structurally unsound and poses an imminent or potential danger to inspecting personnel, the permittee shall comply with one of the following:
  - (1) The permittee shall measure the seal gaps or inspect the storage tank no later than **thirty (30) calendar days** after the determination that the roof is unsafe, or
  - (2) The permittee shall empty and remove the storage tank from service no later than **forty-five (45) calendar days** after determining that the roof is unsafe. If the tank cannot be emptied within **forty-five (45) calendar days**, the permittee may utilize up to two extensions of up to **thirty (30) additional**

**calendar days** each. Documentation of a decision to utilize an extension shall include an explanation of why it was unsafe to perform the inspection or seal gap measurement, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the tank will be emptied as soon as practical.

viii. The permittee shall repair conditions that do not meet the requirements listed in Special Condition Nos. G.2.b.iii., G.2.b.iv., G.2.b.v. and G.2.b.vi. of this Attachment (i.e., failures), no later than **forty-five (45) calendar days** after identification, or shall empty and remove the storage tank from service no later than **forty-five (45) calendar days** after identification. If during seal gap measurements required in Special Condition No. G.2.b.i. of this Attachment or during inspections necessary to determine compliance with Special Condition Nos. G.2.b.v. and G.2.b.vi. of this Attachment a failure is detected that cannot be repaired within **forty-five (45) calendar days** and if the tank cannot be emptied within **forty-five (45) calendar days**, the permittee may utilize up to two extensions of up to **thirty (30) additional calendar days** each. Documentation of a decision to utilize an extension shall include a description of the failure, shall document that alternative storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the tank will be emptied as soon as practical.

ix. The permittee shall notify the Department of Health in writing **thirty (30) calendar days** in advance of any gap measurements to afford the Department of Health the opportunity to have an observer present.

x. The permittee shall visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the tank is emptied and degassed.

(1) If the external floating roof has defects; the primary seal has holes, tears or other openings in the seal or seal fabric; or the secondary seal has holes, tears or other openings in the seal or seal fabric; the permittee shall repair the items as necessary so that none of the conditions specified above exist before filling or refilling the storage tank with organic HAP.

(2) Except as provided below, for all the inspections required above, the permittee shall notify the Department of Health in writing as least **thirty (30) calendar days** prior to filling or refilling each storage tank with organic HAP to afford the Department of Health the opportunity to inspect the storage tank prior to refilling.

(3) If the inspections required above is not planned and the permittee could not have known about the inspection **thirty (30) calendar days** in advance of refilling the tank with organic HAP, the permittee shall notify the Department of Health at least **seven (7) calendar days** prior to refilling of the storage tank.

Take out of service → x.

Emergency Notification → (3)

Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent so that it is received by the Department of Health at least **seven (7) calendar days** prior to the refilling.

- c. For Group 1 storage tanks consisting of an external floating roof converted to an internal floating roofs (petroleum storage tanks 249, 250 and 275):
  - i. The permittee shall keep a record that each inspection required by Special Condition No. G.2.a. of this Attachment was performed.
- d. For Group 1 storage tanks with external floating roofs (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271 and 273):
  - i. The permittee shall keep records describing the results of the seal gap measurements made in accordance with Special Condition No. G.2.b. of this Attachment. The records shall include the date of the measurement, the raw data obtained in the measurement, and the calculations described in Special Condition Nos. G.2.b.iii. and G.2.b.iv. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.646)<sup>1</sup>

### 3. Notification and Reporting Requirements

- a. The permittee shall submit **semi-annually** written reports to the Department of Health. 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:
  - i. For Group 1 storage tanks consisting of an external floating roof converted to an internal floating roof (petroleum storage tanks 249, 250 and 275):
    - (1) Results of each inspection conducted in accordance with Special Condition No. G.2.a. of this Attachment in which a failure is detected in the control equipment. For storage tanks for which annual inspections are required under Special Condition Nos. G.2.a.i.(1)(a) and G.2.a.i.(2)(b) of this Attachment, the following specifications and requirements apply:
      - (a) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage tank and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears,

or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage tank.

- (b) Reports shall include the date of the inspection, identification of each storage tank in which a failure was detected, and a description of the failure. The report shall also describe the nature of and date the repair was made or the date the storage tank was emptied.
  - (c) If an extension is utilized in accordance with Special Condition No. G.2.a.ii. of this Attachment, the permittee shall, in the next semi-annual report, identify the tank; include the documentation specified in Special Condition No. G.2.a.ii. of this Attachment; and describe the date the storage tank was emptied and the nature of and date the repair was made.
- (2) For storage tanks for which inspections are required under Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a) or G.2.a.i.(2)(c) of this Attachment (i.e., internal inspections), the following specifications and requirements apply:
- (a) A failure is defined as any time in which the internal floating roof has defects; or the the primary seal has holes, tears, or other openings in the seal or seal fabric; or the secondary seal (if one has been installed) has holes, tears or other openings in the seal or the seal fabric; or, for a storage tank that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage tank that is part of a new source, the slotted membrane has more than a 10 percent open area.
  - (b) The report shall include the date of the inspection, identification of each storage tank in which a failure was detected, and a description of the failure. The report shall also describe the nature of and date the repair was made.
- ii. Group 1 storage tanks with external floating roofs (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271 and 273):
- (1) Documentation of the results of each seal gap measurement made in accordance with Special Condition No. G.2.b. of this Attachment in which the seal and seal gap requirements of Special Condition Nos. G.2.b.iii., G.2.b.iv., G.2.b.v. or G.2.b.vi. of this Attachment are not met. The documentation shall include the following information:

- (a) The date of the seal gap measurement;
  - (b) The raw data obtained in the seal gap measurement and the calculations described in Special Condition Nos. G.2.b.iii. and G.2.b.iv. of this Attachment;
  - (c) A description of any seal condition specified in Special Condition Nos. G.2.b.v. or G.2.b.vi. of this Attachment that is not met; and
  - (d) A description of the nature of and date the repair was made, or the date the storage tank was emptied.
- (2) If an extension is utilized in accordance with Special Condition Nos. G.2.b.vii. or G.2.b.viii. of this Attachment, the permittee shall, in the next semi-annual report, identify the tank; include the documentation specified in Special Condition Nos. G.2.b.vii. or G.2.b.viii. of this Attachment, as applicable; and describe the date the tank was emptied and the nature of and date the repair was made.
- (3) Documentation of any failures that are identified during the visual inspections required by Special Condition No. G.2.b.x. of this Attachment.
- (a) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears or other openings in the seal or the seal fabric.
  - (b) Documentation shall include the date of the inspection, identification of each storage tank in which a failure was detected, and a description of the failure. The nature of and the date the repair was made shall also be documented.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.654)<sup>1</sup>

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<sup>1</sup>The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**Appendix D**  
**40CFR 64.4 Submittal Requirements**

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**APPENDIX D**  
**40CFR 64.4 Submittal Requirements**

The Compliance Assurance Monitoring (CAM) requirements are applicable to the Chevron cogeneration units, identified as K-6701, K-6702 and K-6703. The units already have existing monitoring devices including, fuel oil and fuel gas non-resetting fuel meters, a continuous monitoring system to record the water-to-fuel ratio and a NO<sub>x</sub> Continuous Emission Monitoring system (CEMS) that serves all three cogeneration units sequentially. Requirements for the operation and maintenance of these systems are already addressed in the existing Covered Source Permit for the refinery. Based on review of 40 CFR 64.4(b)(1), it is anticipated that the NO<sub>x</sub> CEMS is presumptively acceptable to comply with CAM. However, the facility is still required under Section 64.4 Submittal Requirements to provide information to the Hawaii Department of Health and EPA on the monitoring equipment configuration and operation. Since this monitoring equipment has previously been reviewed by the DOH, a brief response to each of the submittal requirements specified in 40 CFR 64.4 is presented below.

64.4(a)(1) - The indicator to be monitored to demonstrate that the water injection control device is working properly is a NO<sub>x</sub> CEMS. This is an appropriate indicator as the concentration of NO<sub>x</sub> would increase and be detected by the CEMS in the event that the control device is not working properly.

64.4(a)(2) - The range of the NO<sub>x</sub> monitor is zero to 100 ppmv. The covered source maximum emissions limits are 67 and 69 ppmvd, depending on the fuel used by the cogeneration turbines. Chevron has previously submitted data to the Department of Health that indicates the typical value NO<sub>x</sub> emissions from the units are compliant with these limits. The range of the monitor is appropriate to demonstrate compliance under all process operating conditions.

64.4(a)(3) The performance criteria for the monitor are specified in 40 CFR 60.13 and 40 CFR 60 Appendix B. The Covered Source Permit already requires that the monitor be operated consistent with these criteria and specifies the frequency for monitoring.

64.4(a)(4) The performance criteria for the monitor is 40 CFR 60.13 and 40 CFR 60 Appendix B. The covered source permit already requires that the monitor be operated consistent with this criteria and specifies the frequency for monitoring.

64.4(b) No further justification for the proposed elements of the monitoring is required, since as specified in 64.4(b)(2) the monitoring is anticipated to be presumptively acceptable.

64.4 (c) The facility has previously provided to the Department of Health operating parameter data obtained during performance tests.

64.4(d) This requirement is not applicable, since operating data have previously been submitted.

64.4(e) The NO<sub>x</sub> CEMS has already been installed and therefore an implementation plan and schedule are not required.

64.4(f) This requirement is not applicable. The control devices are unique to each emission unit and are not a shared device.

64.49(g) This requirement is not applicable, since the emissions units are only controlled by one "control device" which consists of water injection. As noted in the preamble to the CAM rule low NO<sub>x</sub> burners are not a control device.



**Appendix E**  
**Hybrid Energy Project Application and Permit**

---

David E. Rogers  
Refinery Manager

**Chevron Products Company**  
Hawaii Refinery  
91-480 Malakole Street  
Kapolei HI 96707-1807  
Tel 808-682-5711  
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DaveRogers@chevron.com

May 25, 2006

Mr. Wilfred Nagamine  
Manager, Clean Air Branch  
Environmental Management Division  
919 Ala Moana Boulevard  
Honolulu, Hawaii 96814

**Chevron Hawaii Refinery**  
**Energy Project**  
**Permit Application for a Significant Modification**

Dear Mr. Nagamine:

The Chevron USA Products Company is hereby applying for a Significant Modification application for the Chevron Hawaii Refinery Proposed Energy Project - Hybrid. This proposed project will add 2 new boilers and a new combustion turbine that will have no material effect on the operations of emissions of any current refinery process. Neither will it cause any existing emission unit to operate outside the parameters of the facility's current operating permit.

Enclosed are three sets (1 original and 2 copies) of the applicable Significant Modification application package for the Chevron Hawaii Refinery. According to the State of Hawaii Department of Health (DOH) Clean Air Branch, a Covered Source Permit Significant Modification application requires the submittal of DOH forms S-1, C-1, and C-2. An explanation of the DOH forms included is as follows:

- ***S-1 - Standard Permit Application Form***  
The DOH Form S-1 provides the facility contact information. See Appendix A in package.
- ***S-6 - Application for a Significant Modification to a Covered Source***  
The DOH Form S-6 provides a clear description of new emission limits, as well as, new reporting monitoring and record keeping requirements. See Application package.
- ***C-1 - Compliance Plan***  
The DOH Form C-1 states that Chevron is in compliance with the applicable state and federal regulations. See Appendix C in package.

Manager, Clean Air Branch  
Environmental Management Division  
Page 2 of 2

- ***C-2 – Compliance Certificate***  
The DOH Certification Form is submitted for the new applicable requirements. See Appendix C in package.

Also enclosed is a \$3,000.00 check for the Significant Modification application fee. If you have any questions, or need additional information please call Helen Mary Wessel at (808) 682-2282.

Sincerely,

HMW

Enclosures: DOH Forms S-1, S-6, C-1, and C-2,  
Check for \$3,000.00

bcc: Marshall McCormick

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**Thomas M. (Tom) Kovar**  
Refinery Manager

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August 23, 2006

Mr. Wilfred Nagamine  
Manager, Clean Air Branch  
Environmental Management Division  
919 Ala Moana Boulevard  
Honolulu, Hawaii 96814

**Chevron Hawaii Refinery**  
**Energy Project - Hybrid**  
**Permit Application for a Significant Modification - Update**

Dear Mr. Nagamine:

The Chevron USA Products Company submitted an application for a Significant Modification application for the Chevron Hawaii Refinery Proposed Energy Project – Hybrid on May 25, 2006. Based on discussions with your office subsequent to that submittal, the original application has been updated to reflect those changes. The principal differences from the original application that are described in this Update include:

- A decision has been made to consider only new steam boilers provided by Foster Wheeler; therefore, all Rentech boiler option sections have been removed.
- Calculation of net emission changes resulting from the proposed modifications now takes into account contemporaneous emissions increases and decreases that have occurred in recent years at the Hawaii Refinery.
- The previous proposal to limit operation of the new boilers to an annual average duty of 70,000 lb/hour of steam per boiler has been eliminated due to the consideration of contemporaneous emissions.
- Dispersion modeling has been redone incorporating the one-year record of meteorological input data recommended for this application by DOH.

This proposed project remains the same (i.e., the addition of two new boilers and one new combustion turbine).

Enclosed are three sets (1 original and 2 copies) of the updated Significant Modification application package for the Chevron Hawaii Refinery. According to the State of Hawaii Department of Health (DOH) Clean Air Branch, a Covered Source Permit Significant Modification application requires the submittal of DOH forms S-1, C-1, and C-2. An explanation of the DOH forms included is as follows:

- **S-1 - Standard Permit Application Form**  
The DOH Form S-1 provides the facility contact information.  
See Appendix A in package.

Manager, Clean Air Branch  
Environmental Management Division  
August 23, 2006  
Page 2 of 2

- **S-6 - Application for a Significant Modification to a Covered Source**  
The DOH Form S-6 provides a clear description of new emission limits, as well as, new reporting monitoring and record keeping requirements. See Application package.
- **C-1 – Compliance Plan**  
The DOH Form C-1 states that Chevron is in compliance with the applicable state and federal regulations. See Appendix C in package.
- **C-2 – Compliance Certificate**  
The DOH Certification Form is submitted for the new applicable requirements. See Appendix C in package.

If you have any questions, or need additional information please call Helen Mary Wessel at (808) 682-2282.

Sincerely,

HMW

Enclosures

bcc: Marshall McCormick

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FINAL DRAFT

APPLICATION FOR SIGNIFICANT  
MODIFICATION TO A COVERED  
SOURCE PERMIT: CHEVRON HAWAII  
REFINERY PROPOSED ENERGY  
PROJECT

*Prepared for*

Hawaii Department of Health  
Clean Air Branch

*Prepared by*

Chevron Hawaii Refinery

May 11, 2006



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Appendix D	Modeling Input/Output Files (On Accompany Compact Disk)

## SECTION 1 INTRODUCTION

This is the Application of Chevron U.S.A. Products Company, a subsidiary of Chevron Corporation (Chevron), to the Hawaii Department of Health (DOH) Clean Air Branch for a significant modification to Covered Source Permit No. 0088-01-C for the Chevron Hawaii Refinery located at Kapolei, Oahu, Hawaii. The subject of this Application is a new Hybrid Energy Project within the refinery site that will provide steam and electricity in support of refinery operations. The term ‘hybrid’ is used because the proposed project includes two new steam boilers in addition to a new cogeneration turbine similar to the three units already operating at the Hawaii Refinery

The new cogeneration turbine will be a Solar Centaur unit with associated heat recovery steam generator (HRSG) that will be equipped for duct firing to further enhance steam generating capacity. As described more fully in Section 2.1, the design basis for the new steam boilers has been established, but a final decision on the specific boiler make and model has not been made at the time of this Application’s filing. Accordingly, complete information and analyses are provided for both of the remaining candidate boiler systems throughout this Application, so that the DOH permit review process can commence regardless of the final decision on this equipment.

Fuels for the new cogeneration unit and boilers will be supplied by existing refinery processes. Fuels for the cogeneration turbine will consist of a combination of refinery fuel gas (RFG) and liquid naphtha, although only RFG will be provided to the HRSG duct burner. The two new boilers will use a combination of RFG and low sulfur fuel oil (LSFO). The steam and electrical power production of the new equipment will allow retirement of three existing steam boilers within the refinery that currently also operate on RFG and LSFO. Replacement of these existing boilers will result in a net decrease in the annual emissions of sulfur dioxide (SO<sub>2</sub>). Net increases will occur in the emissions of NO<sub>x</sub>, CO and VOC and PM<sub>10</sub>, but the refinery will accept conditions limiting these increases to levels below the PSD major modification thresholds.

### 1.1 APPLICANT INFORMATION

The Hawaii Refinery is operated by Chevron U.S.A. Products Company. The responsible official is the Refinery Manager. The contact for questions regarding this Application is the Air Environmental Specialist, who may be reached at (808) 682-2282.

The refinery is located within the Campbell Industrial Park at Kapolei, Ewa, Oahu, Hawaii (see Figure 1-1). The refinery property consists of 248 acres situated at 21°18’40’’ North latitude and 158° 06’ 57’’ West longitude. A plot plan of the existing refinery is shown in Figure 1-2.

The refinery address is:

Chevron U.S.A. Products Company, Hawaii Refinery  
91-480 Malakole Street  
Kapolei, HI 96707

## 1.2 OVERVIEW OF PROPOSED PROJECT

The cogeneration element of the proposed Hybrid Energy Project will consist of a new Solar Centaur combustion turbine (CT) operating as a cogeneration plant to generate a power production capacity of approximately 3 megawatts (MW) and 58,000 pounds per hour of steam for use in refinery processes. The CT will be equipped with water injection and low-NO<sub>x</sub> burners designed to limit emissions of oxides of nitrogen (NO<sub>x</sub>). The thermal energy of fuel combusted by the turbine is converted to mechanical energy, which drives an electrical generator. The hot exhaust gases from the turbine are routed to a heat recovery steam generator (HRSG) which is essentially a boiler for supplemental steam production. The HRSG will include a section for supplemental steam production using duct firing to increase steam pressure. At full load the HRSG with duct firing will bring the combined steam generating capacity of the cogeneration unit to 58,000 lb/hour at 585 °F and 600 psig.

The two new steam boilers that will complete the Hybrid Energy Project will be designed to ensure an annual average steam generation capacity of 70,000 lb/hour each, with maximum capacity up to 77,000 lb/hour to meet additional short-term steam requirements throughout the refinery, when required. As of the date of this application, Chevron is still considering boilers meeting these requirements from two different vendors, Foster-Wheeler and Rentech. The maximum steam production for each vendor is 75,200 lb/hour for each Rentech boiler and 77,000 lb/hour for each Foster Wheeler boiler. The emissions guarantees offered by the two vendors are slightly different and the locations of the two boiler stacks on the refinery site would also be slightly different, depending on which boilers are ultimately selected. In order to expedite permitting, Chevron has decided to prepare this application to provide DOH with full information on the proposed project with either boiler option.

This Application seeks a permit that will allow:

- (1) Operation of the new turbine/HRSG train continuously at full load on either RFG or naphtha to produce 3 MW of electricity and 58,000 pounds of steam at any time, and
- (2) Operation of the two new boilers on a combination of RFG and LSFO to provide a combined full-time production of up to 140,000 lb of steam per hour and short-term maximum steam production of up to 154 lb/hour. Chevron will accept a condition limiting LSFO use in the two boilers to no more than 129,500 barrels per year if the Foster Wheeler boilers are selected, and no more than 101,000 barrels per year if the Rentech boilers are selected.

Information is provided in this application to demonstrate that operations at these levels, in combination with the retirement of the three existing steam boilers can be accomplished without resulting in a significant net emissions increase for any pollutant or a violation of any ambient air quality standard.

**Insert Figure 1-1  
Hawaii Refinery Location and Environs**

**Insert Figure 1-2**  
**Plot Plan of the Existing Hawaii Refinery**

The new cogeneration train and boilers will be located within the refinery adjacent to and north of the three existing cogeneration units, the operation of which will be unaffected by the proposed action. Electricity and steam generated by the new units will be used to support various refinery processes. The steam produced by these units will allow retirement of three existing boilers in the refinery Boiler Plant (Boilers F-5201, F-5202 and F-5203), representing a combined fuel input capacity of 541.6 MMBtu. This Application demonstrates that the replacement of uncontrolled older-vintage boilers with a modern, well-controlled cogeneration unit and new boilers will result in a net decrease in the annual emissions of SO<sub>2</sub> relative to pre-project operations and relatively small net annual emissions increases for other pollutants.

Other than the replacement of Boilers F-5201, F-5202 and F-5203, the proposed cogeneration project will have no material effect on the operations or emissions of any current refinery process, and will not cause any existing emission unit to operate outside the parameters of the facility's current Operating Permit.

### 1.3 JUSTIFICATION FOR SIGNIFICANT MODIFICATION APPLICATION

The applicant has determined that the proposed project constitutes a Significant Modification to the existing Operating Permit for the Chevron Refinery. The requirements governing permits for sources of air contaminants in Hawaii are contained in the Hawaii Administrative Rules (HAR) Title 11, Chapter 60.1 – Air Pollution Control. Section 11.60.1-81 defines a “Modification” as a physical change in or a change in the method of operation of a stationary source which requires a change to a permit. Modifications may be “minor” or “significant” A significant modification is a modification that does not qualify as a minor modification. A minor modification to a stationary source includes changes that:

- (1) Do not increase the emissions of any air pollutant above the permitted emission limits;
- (2) Do not result in or increase the emissions of any air pollutant not limited by permit to specified levels;
- (3) Do not violate any applicable requirement;
- (4) Do not involve significant changes to existing monitoring requirements or any relaxation or significant change to existing reporting or recordkeeping requirements in the permit;
- (5) Do not require or change a case-by-case determination of an emission limitation or other standard, a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;
- (6) Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement, and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject; and
- (7) Do not constitute a modification pursuant to any provision of Title I of the Clean Air Act.

Criteria (2), (3) and (6) are met by the proposed project, but Criteria (1), (4), (5) and (7) are not, based on the following reasoning:

- The project will increase total refinery emissions of some pollutants above the levels allowed in the current permit.
- The project will be subject to a new emission limit for formaldehyde pursuant to the recently promulgated turbine MACT standard (40 CFR 63 Subpart YYYY), which was not otherwise applicable to the Hawaii Refinery. This standard will entail new monitoring, recordkeeping and reporting requirements. The new cogeneration turbine will also be subject to the NO<sub>x</sub> and SO<sub>2</sub> emission requirements of a proposed New Source Performance Standard (NSPS) for combustion turbines, 40 CFR 60 Subpart KKKK. Although this standard has not yet been finalized, its date of applicability will be retroactive to include any combustion turbines with a peak power output of at least 1 MW that is constructed after February 18, 2005, which would include the proposed units at the Hawaii Refinery. In addition, the new boilers will be subject to the recently revised requirements pertaining to the applicable NSPS, 40 CFR 60 Subpart Dc.
- The project requires a new air quality impact analysis because emissions of certain pollutants will increase relative to historical levels and the locations and exhaust parameters of the stacks for the new units will be different from the old boilers they will replace.
- By resulting in a net emissions increase for some pollutants, the project would constitute a modification under Title 1 of the Clean Air Act.
- Since the project will not conform to four of the conditions for a Minor Modification in HAR §11.60.1-82, it is not a minor modification, and is instead a significant modification.

#### 1.4 ORGANIZATION OF THIS APPLICATION

A completed standard permitting form, DOH Form S-1 is provided in Appendix A to this Application. In accordance with the finding in Section 1.3 that the new Hybrid Energy Project will constitute a significant modification, this Application has been organized to provide all of the information requested under §11.60.1-104 and DOH Form S-6, *Application for a Significant Modification to a Covered Source*. Data items required for completion of Form S-6 are listed in Table 1-1 below with references to the locations within this Application where the corresponding information is provided.



**Table 1-1**  
**Key to Information Required by DOH Form S-6**

Item	Information Required for Significant Modification Application Pursuant to HAR §11.60.1-104	Location in Application
(1)	Applicant Information.	Section 1.1
(2)	Description of Significant Modification.	Sections 1.2, 1.3, 2
(3)	Description of nature, location, design capacity, production capacity, production rates, fuel use, raw materials and typical operating schedules and capacities needed to determine or regulate emissions.	Section 2
	Standard Industrial Classification Code	Section 2.1
(4)	Information to define permit terms and conditions for any proposed emissions trading within the facility.	N/A, see Section 5.3
(5)	Maximum emission rates, including fugitive emissions, of all regulated and hazardous air pollutants and all air pollutants for which the source is major from each emission unit related to the modification.	Section 3
	Supporting emissions calculations and assumptions.	Appendix B
(6)	Identification and description of all emission points in sufficient detail to establish the basis for fees and the applicability of DOH and federal requirements.	Sections 2, 3
	Information on stack parameters	Tables 4-2 and 4-3
(7)	Identification and detailed description of air pollution control equipment and compliance monitoring devices or activities and emissions before and after controls.	Sections 2, 3
(8)	Citation and description of all applicable requirements applicable compliance testing methods for each requirement.	Section 5
(9)	Operational limitations or work practices that affect emissions of regulated and hazardous pollutants.	Section 3.5
(10)	Calculations and assumptions providing basis for information under items (3), (5), (6), (7) and (9).	Appendix B
(11)	Detailed construction schedule.	Section 2.2
(12)	Assessment of ambient air quality impact of the covered source.	Section 4
(13)	Analyses, assessments, monitoring and other applications requirements of Subchapter 7, if applicable.	N/A
(14)	Results of risk assessment, if requested by DOH.	N/A
(15)	Results of source testing, if requested by DOH.	N/A
(16)	Information and associated analyses on other available control technologies.	N/A
(17)	Explanation of proposed exemptions from applicable requirements.	N/A, see Section 5.4
(18)	List of insignificant activities.	N/A, see Section 3.6
(19)	Compliance plan in accordance with §11.60.1-85.	Section 5.5, Appendix C
(20)	Source compliance certification in accordance with §11.60.1-86.	Section 5.5, Appendix C
(21)	Other information deemed necessary by DOH to review the application or to implement, enforce or determine the applicability of other applicable requirements.	N/A

## SECTION 2 PROJECT DESCRIPTION

This section presents an engineering description of the proposed modification to the Hawaii Refinery, including technical information regarding the proposed new equipment and the intended manner of its operation, as well as existing equipment that will be replaced by the new Hybrid Energy Project. The purpose of the proposed energy project will be to provide reliable steam and electricity needed for various refinery processes. Ultimately, the new plant will functionally replace the steam generation of three existing boilers in the Boiler Plant area of the refinery. The objective for this modification is to improve refinery reliability and efficiency, while improving environmental performance.

### 2.1 EQUIPMENT AND FUEL SPECIFICATIONS

The following subsections provide engineering information on project equipment and fuel specifications. Separate discussions are provided for the proposed cogeneration unit and the proposed steam boilers.

#### 2.1.1 New Cogeneration Unit

Electricity and steam will be generated by a new Solar Centaur 40 combustion turbine equipped with Solar's proprietary low-NO<sub>x</sub> burner system and water injection for NO<sub>x</sub> control. The maximum fuel energy input rate to the turbine at typical Oahu temperature and humidity conditions is approximately 45 MMBtu/hour. Either of two fuels produced by refinery processes will be used to fire the turbine, i.e., refinery fuel gas (RFG) or liquid naphtha (also referred to as "whole straight run" or WSR). Both fuels are currently used to fire the existing cogeneration units at the Hawaii Refinery. The approximate energy contents for these fuels (higher heating values) are 1300-1350 British Thermal Units per standard cubic foot (Btu/scf – higher heating value or HHV) for RFG and 4.96 MMBtu (HHV) per barrel for naphtha. Detailed fuel specifications are provided in Table 2-1 and 2-2 for RFG and naphtha, respectively.

The applicant proposes to operate the new cogeneration unit with no restrictions governing the amount of either fuel that can be used in any given year. Accordingly, the emissions data presented in Section 3 and the air quality impact analysis in Section 4 of this application represent the fuel usage scenarios that correspond to the maximum pollutant emissions and air quality impacts from this equipment.

Hot exhaust gases from the new combustion turbine will be sent to a Split Dino Heat Recovery Steam Generator (HRSG) unit to increase steam production. The duct burner for the new unit will be designed to combust only RFG and will have a rated capacity of approximately 49 MMBtu/hour. The intended mode of operation for the cogeneration unit will entail near full-load operation with duct firing on a near-full-time basis. Under these conditions, the new turbine/HRSG unit will be capable of continuously generating up to about 3 MW of electricity and up to 58,000 lb/hour of steam for use in refinery processes.

Detailed vendor equipment specifications, including emissions data, for the proposed combustion turbine, HRSG and duct burner, are provided in Appendix B.

This application proposes that the new turbine be permitted to burn either RFG or naphtha fuel for up to all hours of the year (8,760 hours). It is further proposed that duct firing with RFG be permitted in the

**Table 2-1**  
**Specifications for RFG Fuel Used in New Cogeneration**  
**Turbine and HRSG Duct Burner**

Component	RFG (% mol)
Hydrogen	9.3
Methane	28.9
Ethane	15.1
Ethylene	15.8
Propylene	9.9
Butanes	0.3
I-Butane	0.1
Propane	6.9
I-Butane	0.7
N-Butane	0.5
I-Pentane	0.1
Component	0.8
Nitrogen	11.6
Heating Content (Btu/scf) HHV	1303

**Table 2-2**  
**Specifications for Naphtha Fuels Used In New Cogeneration Turbine**

Component	Naphtha Composition
Sulfur, ppm	42
Chlorides, ppm	1
Paraffins, LV%	68.3
Olefins, LV%	1.1
Napthenes, LV%	26.43
Aromatics, LV%	5.4
Heating Content (Btu/gal) HHV	118,138

HRSG for operation up to 8,760 hours per year. No alternative operating scenarios are proposed, since the modeling analyses described in Section 4 demonstrate that the project will not cause or contribute to a violation of any ambient air quality standard for this worst-case emissions scenario.

The new gas turbine will be equipped with low-NO<sub>x</sub> burners and water injection. This combination of control measures will limit emissions of oxides of nitrogen (NO<sub>x</sub>) from the turbine to no more than 67 ppmvd at 15% O<sub>2</sub> for RFG fuel and 60 ppmvd at 15% O<sub>2</sub> for naphtha fuel. Duct firing will increase mass emissions of NO<sub>x</sub> for each train by about 24% with RFG fuel and by about 26% when naphtha fuel is used. The incremental effects of duct firing are much less for CO and VOC emissions. Quantitative emissions data are presented in Section 3.

### 2.1.2 New Steam Boilers

Two new boilers will provide an annual average steam generation capacity of 70,000 lb/hour each. Depending on the vendor, each boiler will have a maximum capacity of 75,200 lb/hour and 77,000 lb/hour for Rentech and Foster Wheeler boilers, respectively, to meet additional short-term steam requirements and fuel loads throughout the refinery, when required. The two new boilers in conjunction with the turbine/HRSG unit will replace three existing steam boilers.

As of the date of this application, Chevron is still considering boilers from two vendors, Foster-Wheeler and Rentech. Both vendors guarantee equipment that will provide the required steam capacity; however the emissions guarantees are different and the locations of the two boiler stacks on the refinery site would also be slightly different, depending on which of the two boilers is ultimately selected. Information on both vendors' boilers is detailed in this section.

Regardless of which equipment is ultimately selected, the two boilers will be operated at an annual capacity factor sufficient to produce a combined annual steam production rate of 140,000 lb per hour. In either case, a combination of LSFO and RFG will be used to fuel the new boilers. As described in Section 3, estimates of annual emission from the different boiler systems have been developed based on the maximum amounts of boiler fuel oil that could be used without causing the incremental emissions of the entire project to exceed the corresponding PSD significant emissions levels. Using this criterion results in the following proposed operating scenarios:

- The two new boilers will use approximately 101,000 barrels/year of LSFO if the Rentech boilers are selected, which amounts to about 39.4% of the annual boiler fuel stream. The remaining 60.6% of the fuel stream will be supplied by RFG.
- The Foster Wheeler boilers, which have lower guaranteed NO<sub>x</sub> emissions, could use up to 129,500 barrels per year, representing about 53.3% of the annual boiler fuel input energy, with the remaining 46.7% supplied by RFG.

Each boiler will be operated with an annual average fuel heat input rate of about 89,000 Btu/hour (HHV), and 94,000 Btu/hour (HHV) for Foster Wheeler and Rentech boilers respectively. This heat input rate for either boiler corresponds to 70,000 lb/hour steam at 12% flue gas recirculation and an average feedwater temperature of 250 °F. Each boiler will be capable of a maximum fuel energy input rate of 96.35 MMBtu/hour for Foster Wheeler and 99 MMBtu/hour for Rentech in order to provide additional short-term capacity to meet the refinery's steam generating needs. As further discussed in Section 3, although maximum, short term heat input rates differ depending on vendor, a maximum heat input rate of 99 MMBTU/hr/boiler for either vendor is conservatively assumed for purposes of estimating maximum short-term ( 1 to 24 hour average) boiler emissions in the dispersion modeling presented in Section 4 .

Fuel specifications for LSFO are provided in Table 2-3. Data for the RFG fuel were provided previously in Table 2-1. Both RFG and LSFO fuels are currently used as fuel for the three existing boilers. Based on the permit conditions for the existing boilers, the LSFO sulfur content is assumed to be as high as 0.45% (by weight) in this Application for all SO<sub>2</sub> emissions, estimates and in the dispersion modeling analyses described in Section 4. This provides a conservative representation of the proposed project's impacts on SO<sub>2</sub> levels, as recent fuel analyses indicate a considerably lower LSFO sulfur content of 0.34% (by wt), this conservative approach, based on historical data was taken for all emission estimates and modeling purposes.

**Table 2-3**  
**Specifications for LSFO Fuel Used in New Boilers**

	LSFO (BTU/lb)
<b>Component</b>	
N2 (% by Wt)	0.33%
Sulfur (% by wt)	0.34%
Ash (% by wt)	0.019%
Heat Content (HHV)	18,870

Plot plans showing the locations and configuration of the proposed new cogeneration unit and boilers within the Hawaii Refinery are provided in Figure 2-1a (Rentech boilers) and Figure 2-1b (Foster Wheeler boilers). Note that the boiler stack locations would be slightly different in the two scenarios. The existing three boilers that are also shown on the diagram will be completely removed after the new equipment is installed and operational.

The SIC Code for petroleum refineries is 2911.

## 2.2 PROJECT CONSTRUCTION SCHEDULE

A preliminary schedule for implementation of the proposed hybrid cogeneration project at the Hawaii Refinery with anticipated milestone dates is provided below in Table 2-4. The total duration of the construction effort is expected to be about 10 months. The new equipment will be installed adjacent to the existing cogeneration facilities in a location that is currently unoccupied. As indicated by the schedule, civil and site preparation work will take about 2 months. Installation of the major equipment, electrical and controls will occur over a period of slightly more than 3 months and testing and commissioning will require about the two additional months.

**Table 2-4  
Proposed Energy Project Construction Schedule**

	<u>Start Date</u>	<u>Finish Date</u>
Air Permit Received		February 14, 2007
Civil Site Work/Underground	February 15, 2007	April 25, 2007
Pipeway Supports	February 15, 2007	April 11, 2006
Install Cogen and Boilers	April 26, 2007	May 23, 2007
Electrical and Controls	May 24, 2007	August 1, 2007
Commissioning	August 2 2007	September 26, 2007
Commercial Operation		October, 2007

### 2.3 PROPOSED OPERATING SCHEDULE

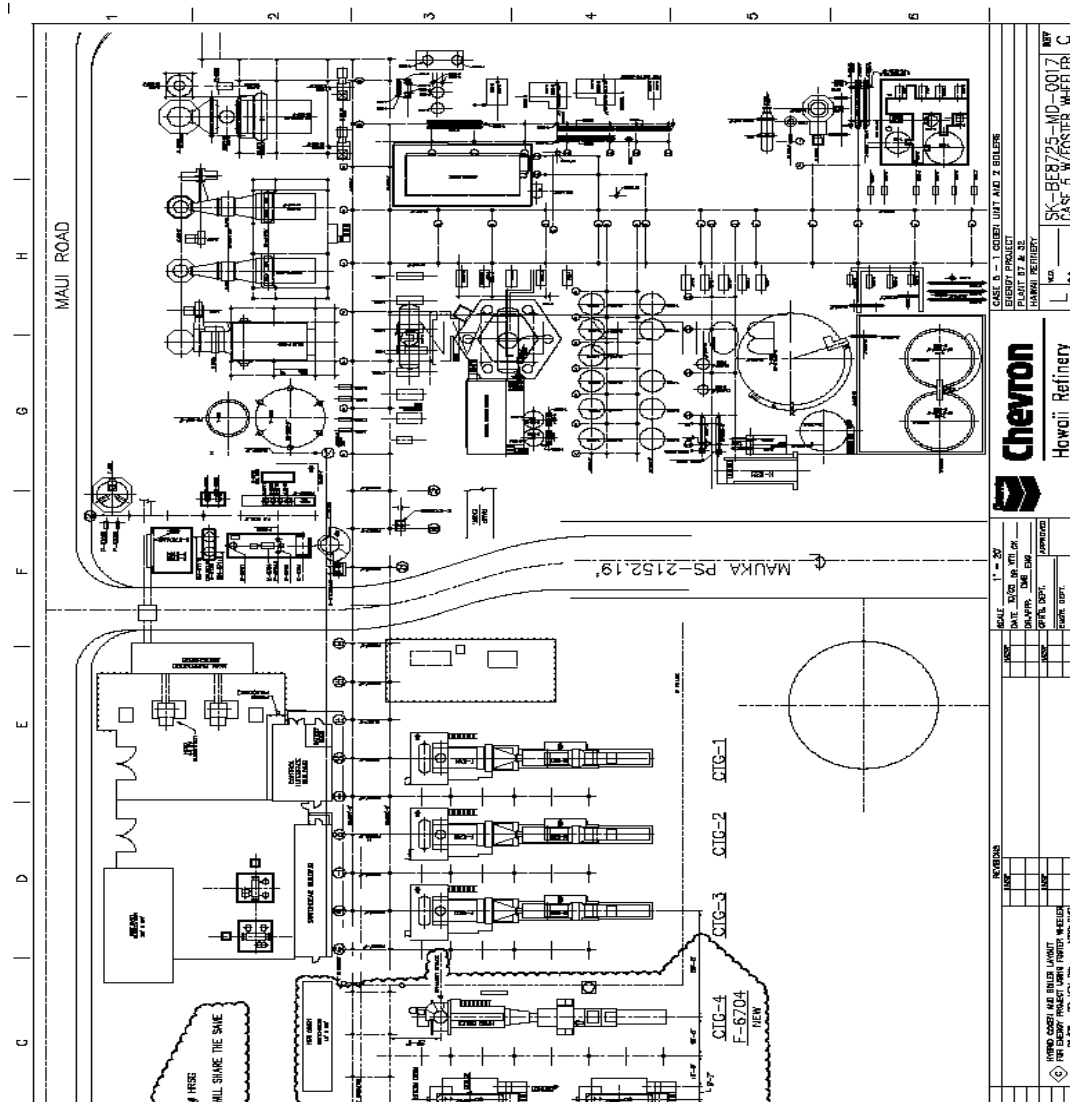
Operation of the proposed equipment will not be seasonal or irregular. Normal operation of the cogeneration plant will be continuous operation at near-full load for the turbine/HRSG train. The Hawaii Refinery seeks a permit to operate the new cogeneration turbine/HRSG train, including duct burner on either RFG or naphtha in the turbine and solely RFG in the duct burner, as well as the two boilers on either RFG or LSFO, for up to 24 hours of operation per day, 365 days per year. However, the applicant will accept permit conditions limiting the extent of boiler fuel oil usage and the average boiler firing rate.

### 2.4 RETIREMENT AND DECOMMISSIONING OF EXISTING BOILERS

The additional steam generation capacity that will be provided by the new equipment will enable the refinery to retire three existing boilers in the Boiler Plant. Accordingly, Boilers F-5201 (220 MMBtu/hour) and Boilers F-5202 and F-5203 (160.8 MMBtu/hour each) will be removed from service. These boilers are currently operating on either refinery fuel gas or fuel oil without emission controls. In practice, these existing boilers may remain as backup units for a period of up to one year, or until all required tests of the new equipment have been completed and safe, reliable operation of the new equipment has been demonstrated. However, these boilers will not be operated concurrently with the new equipment at any time before they are decommissioned.



**Figure 2-1b**  
**Plot Plan of Energy Project Site Arrangement with Foster Wheeler Steam Boilers**





## SECTION 3 PROJECT EMISSIONS ESTIMATES

This section describes the basis for estimating pollutant emissions from the proposed new equipment, as well as the net change in refinery air pollutant emissions that will result from implementation of the proposed project. Sections 3.1 and 3.2 present quantitative emissions data for the new cogeneration system and boilers, respectively. The reduction in emissions that will result from removal of the three retired boilers is estimated in Section 3.4. Appendix B contains vendor equipment specifications and data sheets, as well as spreadsheets showing the detailed calculation of mass emission rates for all pollutants.

### 3.1 EMISSIONS FROM NEW COGENERATION UNIT

Emissions that will result from operation of the new turbine/HRSG unit have been estimated using the best available information for each pollutant. Data provided by the vendors of the selected turbine and duct burner has been used to develop stack emission rates for oxides of nitrogen ( $\text{NO}_x$ ), carbon monoxide (CO) and volatile organic compounds (VOC). Emissions for sulfur dioxide ( $\text{SO}_2$ ) were estimated based on mass balance methods assuming the same fuel sulfur content limits that are specified in the current Operating Permit for the existing cogeneration turbines, i.e., 160 ppmv as hydrogen sulfide ( $\text{H}_2\text{S}$ ) for RFG and 0.03% sulfur by weight for (liquid) naphtha fuel. Emissions of particulate matter ( $\text{PM}_{10}$ ) from the new cogeneration turbine were estimated based on the maximum usage rates for both fuels and the emission factors for combustion turbine in the AP-42 *Compilation of Air Pollutant Emissions Factors*. Since no factors are available for turbines burning refinery gas or naphtha, these  $\text{PM}_{10}$  estimates relied on emission factors for natural gas and distillate oil fuel. The HRSG duct burner will be fueled exclusively with RFG, and the corresponding vendor emission factors were used with projected fuel usage rates to estimate emissions for all criteria pollutants.

#### 3.1.1 $\text{NO}_x$ , CO and VOC Emissions

Table 3-1 presents the estimated full-load exhaust concentrations and mass emission rates of  $\text{NO}_x$ , CO and VOC for the proposed turbine and duct burner of the new cogeneration plant. The first two parts of the table provide vendor emissions guarantees for the turbine and duct burner, respectively. The third part provides stack emissions data for the combined turbine and duct burner unit, as the emissions for the turbine/HRSG train will be exhausted from a common stack. The data in Table 3-1 represent emissions guarantees from the vendors of this equipment in both stack gas concentration units (parts per million by volume or ppmv) and mass emission rates (pounds per million Btu of fuel input energy, higher heating value or HHV basis). As described later in Section 3.3, source test results for the very similar existing cogeneration units burning the same fuels (RFG and naphtha) indicate that actual emissions of CO will be well below the level indicated by the conservative vendor emission factors. Accordingly, the Hawaii Refinery is willing to accept permit conditions to limit turbine/HRSG stack emissions of CO to values well below those shown in the last section of Table 3-1. The proposed maximum stack CO emission limit for the cogeneration turbine/HRSG is 14.9 lb/hour with either RFG or naphtha fuel (see Section 3.3).

**Table 3-1**  
**Vendor Guaranteed Emission Rates for Turbine/HRSG Train<sup>1</sup>**  
**Turbine Emissions**

Pollutant	Units	Refinery Gas Fuel	Naphtha Fuel
		Without Duct Firing	Without Duct Firing
NO <sub>x</sub> (as NO <sub>2</sub> )	lb/hr	11.06	10.15
CO	lb/hr	5.02	25.74
VOC <sup>2</sup>	lb/hr	1.44	5.90
NO <sub>x</sub> (as NO <sub>2</sub> )	ppmvdc	67.00	60.00
CO	ppmvdc	50.00	250.00
VOC <sup>2</sup>	ppmvdc	25.00	100.00

**Duct Burner Emissions**

Pollutant	Units	Refinery Gas Fuel
		With Duct Firing
Burner Duty	MMBtu/hr HHV	48.86
NO <sub>x</sub> (as NO <sub>2</sub> )	lb/MMBtu HHV	0.05
CO	lb/MMBtu HHV	0.05
VOC <sup>2</sup>	lb/MMBtu HHV	0.02
PM10	lb/MMBtu HHV	0.01
NO <sub>x</sub> (as NO <sub>2</sub> )	lb/hr	2.64
CO	lb/hr	2.64
VOC <sup>2</sup>	lb/hr	1.05
PM10	lb/hr	0.53

**Table 3-1 (continued)**  
**Vendor Guaranteed Emission Rates for Turbine/HRSG <sup>1</sup>**  
**Stack Emissions**

Pollutant	Units	Refinery Gas Fuel		Naphtha Fuel <sup>4</sup>	
		With Duct Firing	Without Duct Firing	With Duct Firing	Without Duct Firing
NO <sub>x</sub> (as NO <sub>2</sub> ) <sup>3</sup>	lb/hr	13.70	11.06	12.79	10.15
CO <sup>3</sup>	lb/hr	7.66	5.02	28.38	25.74 <sup>3</sup>
VOC <sup>2</sup>	lb/hr	2.49	1.44	6.95 <sup>3</sup>	5.90

<sup>1</sup> Emissions data shown in this table correspond to an ambient temperature of 75°F.

<sup>2</sup> VOC emissions shown in this table are the Unburned Hydrocarbons (UHC) data (as methane) provided by Deltak, which are conservatively assumed to be 100% VOC.

<sup>3</sup> The applicant wishes to replace the vendor-guaranteed maximum hourly emissions of CO with a value of 14.9 lb/hr, and will accept permit conditions limiting cogeneration CO emissions to this level which is approximately equivalent to a stack gas concentration of 60 ppmvd CO @ 15% O<sub>2</sub>.

<sup>4</sup> The duct burner will be run exclusively with RFG fuel. Stack emissions totals include duct firing at the maximum capacity of the burner with RFG.

Continuous, year-round operation for the proposed turbine with duct firing was assumed in developing total annual emissions for the proposed cogeneration plant.

### 3.1.2 SO<sub>x</sub> Emissions

Emissions of sulfur dioxide (SO<sub>2</sub>) from the turbine/HRSG train were estimated based on a mass balance calculation. Specifically, all of the sulfur contained in the fuels combusted by the gas turbine and duct burner is assumed to combine with oxygen to form SO<sub>2</sub>. Thus, the emissions for this pollutant are completely determined from knowledge of the quantity of fuel that will be used and its sulfur content on a mass basis. For the proposed cogeneration turbine and duct burner, we have assumed the same fuel sulfur contents that is specified in the Hawaii Refinery's current permit for the existing cogeneration units (i.e., 160 parts per million H<sub>2</sub>S by volume for refinery fuel gas and 0.03% sulfur by weight for naphtha fuel). This assumption leads to a conservative estimate of future SO<sub>2</sub> emissions, as the actual sulfur contents of these fuels in the Hawaii Refinery during recent years have been consistently lower than these levels. Maximum fuel flow rates provided by Solar Turbines were assumed for the gas turbine (45.70 MMBtu/hour for RFG and 44.88 MMBtu/hour for naphtha).

Maximum burner duty rates provided by Deltak were assumed (48.86 MMBtu/hour running exclusively on RFG) and the same RFG sulfur content limit of 160 parts per million H<sub>2</sub>S by volume provided the basis for calculating SO<sub>2</sub> emissions from the duct burner. Continuous year-round operation at the maximum fuel combustion rates for the turbine on naphtha fuel and duct burner on RFG were assumed to develop a theoretical maximum value for the annual SO<sub>2</sub> emissions from the new turbine/HRSG unit.

### 3.1.3 PM<sub>10</sub> Emissions

Estimates of particulate matter emissions from the proposed new combustion turbine were not provided by the turbine vendor. In addition, emission factors specifically applicable to these types of equipment burning RFG and naphtha fuels are not available in standard USEPA references, such as the AP-42 compilation. For these circumstances, PM<sub>10</sub> emissions for the new turbine have been estimated by means of the same approach that has been used by the Hawaii Refinery in annual emissions reports to DOH for the three existing cogeneration units. Specifically, AP-42 emission factors for gas turbines using natural gas and diesel fuels were used to quantify the expected emissions of PM<sub>10</sub> from the new turbine on RFG and naphtha fuels, respectively. Maximum fuel flow rates provided by Solar Turbines were assumed for the gas turbine (45.70 MMBtu/hour (HHV) for RFG and 44.88 MMBtu/hour (HHV) for naphtha).

The maximum duct burner duty rate (48.86 MMBtu/hour, HHV basis) and the burner PM<sub>10</sub> emission factor in pounds per million Btus provided by Deltak were multiplied to obtain the maximum hourly emission rates. Continuous year-round operation at the maximum combustion rates for the turbine/HRSG train was assumed. The highest of the calculated annual values, corresponding to the turbine on 100% naphtha fuel with duct firing on RFG has been used to provide a conservatively high estimate of annual PM<sub>10</sub> emissions from the new cogeneration train.

## 3.2 EMISSIONS FROM NEW BOILERS

Emissions that will result from operation of the two new boilers have been estimated using the best available information for each pollutant. Data provided by vendors of both boiler designs being considered (Foster-Wheeler and Rentech) have been used to develop separate emission rates for oxides of nitrogen (NO<sub>x</sub>), carbon monoxide (CO) and volatile organic compounds (VOC), and particulate matter (PM<sub>10</sub>). Emissions for sulfur dioxide (SO<sub>2</sub>) were estimated based on mass balance methods assuming a fuel sulfur content of 0.0031% by weight for RFG and 0.45% percent by weight for LSFO.

### 3.2.1 NO<sub>x</sub>, CO, VOC and PM<sub>10</sub> Emissions

Tables 3-2a and 3-2b present the estimated full-load operating data and emission factors of NO<sub>x</sub>, CO, PM<sub>10</sub> and VOC for the proposed boilers of both vendors being considered. The first table presents data provided by Foster-Wheeler for boilers generating 70,000lb/hr steam with 12% flue gas recirculation (FGR) and a boiler feedwater temperature of 250 °F. Emissions for this condition are based on the expected annual average boiler fuel mixture of 53.3% LSFO and 46.7% RFG. Accordingly, this condition corresponds to annual average emissions for each of the two new boilers. Also presented in Table 3-2a are the emissions for a possible worst-case short-term emission scenario corresponding to a maximum steam generation rate of 77,000 lb per hour per boiler, and 100% LSFO usage at a rate of 99 MMBtu/hour (HHV). Although data provided by the two boiler vendors specify different maximum short-term fuel energy input rates, a common value of 99 MMBtu/hr/boiler has been assumed for both boiler systems, since this is the maximum capacity specified to the vendors by Chevron. This worst-case condition could exist for limited periods when inadequate RFG supplies are available, and for this reason the hourly emission rates shown for this case were used in the dispersion modeling described in Section 4 for evaluation of ambient air quality impacts for averaging times of 1 to 24 hours.

The NO<sub>x</sub>, CO and VOC data in Table 3-2a correspond directly to vendor emissions guarantees. Note, however, that an emission factor of 0.03 lb/MMBtu has been used for estimating boiler particulate emissions for both the long-term average and short-term maximum emission scenarios in Table 3-2a. This value has been used in lieu of higher boiler vendor guarantees for this pollutant, because, as described in Section 5.1, the 0.03 lb/MMBtu limit is specified in the recently revised New Source Performance Standard (40 CFR 60 Subpart Dc), as well as the applicable boiler NESHAPS standard (40 CFR 63 Subpart DDDDD). Chevron recognizes that the boilers will be required to meet these federal standards, and, if necessary, will modify the boiler fuel stream by blending LSFO with a lighter fuel to ensure continuous compliance. However, since the final boiler design has not yet been selected, identification of the specific measures to accomplish this compliance is premature. Therefore in calculating project emissions and in the air quality modeling analyses presented in Section 5, an emission rate of 0.03 lb/MMBtu has been used for all boiler calculations, since this will clearly represent the upper limit of particulate emissions that can be permitted.

Table 3-2b presents similar vendor data for Rentech boilers. Emissions information are presented for both the planned annual average operating condition with a steam generation rate of 70,000 lb/hr/boiler of steam with 12% flue gas recirculation (FGR) when operating on either FGR or LSFO fuel. Because the guaranteed NO<sub>x</sub> emission rate for these boilers is somewhat higher than for the Foster Wheeler units, this average operating scenario for the Rentech boilers limits LSFO usage to just 39.4% on an annual basis in order to avoid an overall net project NO<sub>x</sub> emissions increase of 40 tons per year, which would trigger PSD review (see Section 3.5). Table 3-2b also presents information for the maximum short-term emission scenario, i.e., 75,200 lb/hr/boiler steam generation with a 99 MMBtu/hr/boiler fuel energy input rate on LSFO only.

**Table 3-2a**  
**Vendor Guaranteed Emission Rates Per Boiler<sup>1</sup>**  
**Foster Wheeler Data**

Steam Production Rate	Average Case - 70,000 lb steam per hour <sup>2</sup>		Maximum Case - 77,000 lb steam per hour <sup>3</sup>	
	% LSFO <sup>2</sup>	% RFG <sup>2</sup>	% LSFO <sup>3</sup>	% RFG
Fuel Mix	53.3 <sup>2</sup>	46.7 <sup>2</sup>	100	0
Fuel Energy Input Rate (MMBtu/hour)	87.6	89.5	96.35 <sup>3</sup>	-

Pollutant Emission Rate	lb/MMBTU	lb/MMBTU	lb/hr	lb/MMBTU	lb/hr
NO <sub>x</sub> (as NO <sub>2</sub> )	0.32	0.042	16.70	0.32	18.83
CO	0.08	0.073	6.8	0.08	7.61
PM <sub>10</sub> <sup>4</sup>	0.03	0.03	2.66	0.03	2.97
VOC <sup>2</sup>	0.005	0.004	0.38	0.005	0.495

<sup>1</sup> Emissions based on 12% flue gas recirculation and an expected boiler feedwater temperature of 250 °F

<sup>2</sup> Average annual boiler production rate and fuel mix

<sup>3</sup> Maximum short-term boiler production and fuel mix The value actually used for calculating mass emission rates and modeling is 99 MMBTU/hour.

<sup>4</sup> An emission rate of 0.03 lb/MMBTU for PM<sub>10</sub> has been used for all boiler calculations, since this will represent the upper limit of particulate emissions that can be permitted

**Table 3-2b**  
**Vendor Guaranteed Emission Rates Per Boiler<sup>1</sup>**  
**Rentech Data**

Steam Production Rate	Average Case - 70,000 lb steam per hour <sup>2</sup>		Maximum Case - 75,200 lb steam per hour <sup>3</sup>	
	% LSFO <sup>2</sup>	% RFG <sup>2</sup>	% LSFO <sup>3</sup>	% RFG
Fuel Mix	39.4 <sup>2</sup>	60.6 <sup>2</sup>	100	0
Fuel Energy Input Rate (MMBtu/hour)	92.35	94.77	99.0	-

Pollutant Emission Rate	lb/MMBTU	lb/MMBTU	lb/hr	lb/MMBTU	lb/hr
NO <sub>x</sub> (as NO <sub>2</sub> )	0.38	0.05	20.917	0.36	22.36
CO	0.06	0.037	4.59	0.06	4.88
PM <sub>10</sub> <sup>4</sup>	0.03	0.03	2.80	0.03	2.97
VOC <sup>2</sup>	0.005	0.004	0.42	0.005	0.449

<sup>1</sup> Emissions based on 12% flue gas recirculation and an expected boiler feedwater temperature of 250 °F

<sup>2</sup> Average annual boiler production rate and fuel mix

<sup>3</sup> Maximum short-term boiler production and fuel mix.

<sup>4</sup> An emission rate of 0.03 lb/MMBtu for PM<sub>10</sub> has been used for all boiler calculations, since this will represent the upper limit of particulate emissions that can be permitted

### 3.2.2 SO<sub>x</sub> Emissions

Emissions of sulfur dioxide (SO<sub>2</sub>) from the two boilers were estimated based on mass balance calculations. All of the sulfur contained in the fuels combusted by the boilers is assumed to combine with oxygen to form SO<sub>2</sub>. Thus, the emissions for this pollutant are completely determined from knowledge of the quantity of fuel that will be used and its sulfur content on a mass basis. For the proposed boilers, we have assumed the average LSO and RFG contents reported for the existing boilers during 2001-2002 (0.45% for LSFO and 0.0031% for RFG).

### 3.3 SUMMARY OF EMISSIONS FROM NEW EQUIPMENT

Table 3-3 lists the estimated maximum annual emissions for criteria pollutants from the proposed new cogeneration unit and boilers. Continuous operation of the turbine at maximum load on naphtha fuel (with full duct firing on RFG) is assumed in all emission calculations shown in this table, which also shows estimated annual emissions for both project configurations (either boilers from Foster Wheeler or Rentech). The case with the turbine operating at full load on naphtha fuel with duct firing at maximum duty on RFG and each of the new boilers operating at the fuel energy input corresponding to 70,000 lb steam production per hour with produces the highest total annual emissions for all pollutants. The worst-case annual emissions have been developed assuming up to 53.3% of the boiler fuel could be LSFO with Foster Wheeler equipment and 39.4% LSFO for the Rentech units. Accordingly, the discussion of the net emissions changes resulting from the proposed project in Section 3.5 will use the results for these project configurations.

Note that the emissions estimates for the turbine/HRSG train in Table 3-3 were derived primarily from vendor emissions guarantees, which reflect the general lack of historical data on emission characteristics of their equipment using the nonstandard fuels (RFG and naphtha) that are contemplated for the proposed turbine/HRSG unit. Because of this uncertainty, the turbine and HRSG vendors have provided very conservative estimates for the emissions of certain pollutants, especially CO. In an effort to understand the degree of overstatement that may be incorporated in the turbine/HRSG vendor guarantees for these pollutants, the applicant has reviewed data from recent source testing that has been conducted on the three existing cogeneration units at the refinery. While the existing turbines and HRSGs are not identical to the proposed unit, they are similarly sized, use the same two fuels and are equipped with duct firing. Thus the recent source test results should provide a valid basis for understanding the degree of conservatism that has been built into the vendor emissions guarantees for the new cogeneration unit. The highest CO emission rate recorded during the most recent tests conducted on the three existing cogeneration units was 27.8 ppmv @ 15% O<sub>2</sub> (approximately) 2.8 lb/hour).

The comparison with the available source test data indicates that CO emissions from the new units are likely to be well below the values guaranteed by the turbine vendor. Whereas the estimated exhaust gas concentration of CO for the new turbine on naphtha fuel is 250 ppmv at 15% O<sub>2</sub>, stack tests on the existing turbines, even with duct firing included, are consistently less than 30 ppmv for CO. The applicant does not wish to trigger the Prevention of Significant Deterioration requirements of Subchapter 7 of HAR because of the artificially high vendor data for CO shown in Tables 3-1. Accordingly, Chevron will

accept permit conditions limiting emissions from the gas turbine train to no more than 14.9 lb/hr of CO, which are still considerably higher than the emissions indicated by the source tests on the existing units. Based on the source testing results to date on the existing cogeneration units, actual emissions will likely be even lower than the values recommended here.

**Table 3-3**

**Estimated Combined Annual Emissions from New Turbine/HRSG Train and Two New Boilers for Two Candidate Project Configurations– Based on Vendor Emissions Guarantees and Applicant Proposed Limits for Turbine/HRSG CO Emissions**

Boiler Vendor <sup>1</sup>	Turbine/HRSG	Annual Emissions (tons per year)				
		NO <sub>x</sub>	CO	VOC	SO <sub>2</sub>	PM <sub>10</sub>
Foster Wheeler	100% load with duct firing	206.3	124.8	34.0	204.2	27.9
Rentech	100% load with duct firing	206.3	103.0	34.0	162.2	29.3

<sup>1</sup> Emissions incorporate proposed LFSO annual usage limits (53.3% for Foster Wheeler, 39.4% for Rentech), and proposed CO emission limits for the turbine/HRSG as described above.

### 3.4 EMISSION REDUCTIONS FROM RETIREMENT OF EXISTING BOILERS

The three boilers that will be retired upon successful commissioning of the new cogeneration plant are Boiler F-5201 (fuel input capacity of 220 MMBtu/hour) and Boilers F-5202 and F-5203 (160.8 MMBtu/hour each). These three boilers have operated at the refinery to provide process steam for many years using either RFG or fuel oil. Representative emission data and duty levels from 1996 and 1997 are used for comparison between the new proposed plant and the existing. An annual emissions inventory is reported to DOH by the refinery every year, and the data of the 1996 and 1997 inventories are the basis for estimating the actual emissions of criteria pollutants from the two affected boilers during those years. Per a change in the federal New Source program announced in the Federal Register December 31, 2002, baseline actual emissions can be represented with data from any consecutive 24-month period in the past ten years. The method for developing these estimates is presented below.

During 1996 and 1997, the Hawaii Refinery reported RFG and fuel oil usage by the three boilers in the Boiler Plant to DOH. The average annual fuel oil and RFG used by each of the three boilers is shown in Table 3-4. The average fuel oil and RFG sulfur contents recorded during recent years were 0.45% and 0.0031% by weight, respectively.



**Table 3-4**  
**Fuel Usage For Each Boiler During 1996-1997**

Boiler	Process Rate (MMBTU/hr)	Total Average Oil Used (bbl/yr)	Total Average Gas Used (MSCF/yr)
Boilers F-5201	220	61,825	307,709.16
Boilers F-5202	160.8	45,189	223,550.00
Boilers F-5203	160.8	45,189	223,550.00

With this information, calculation of historical pollutant emissions from the two boilers was straightforward using AP-42 boiler emission factors for oil (Tables 1.3-1, 1.3-2 and 1.3-3) and natural gas (Tables 1.4-1 and 1.4-2) fuels and summing to obtain emissions for both fuels combined. These calculations yield the estimated annual emission totals for the boilers that are shown in Table 3-5. The totals at the bottom of this table represent the estimated quantities of boiler emissions that will cease to occur as a result of the proposed hybrid energy project.

**Table 3-5**  
**Estimated Historical Emissions from Boilers in Hawaii Refinery Boiler Plant**

Boiler	Total Emissions from Boilers in 1996-1997 (TPY)				
	PM <sub>10</sub>	SO <sub>2</sub>	CO	NO <sub>x</sub>	VOC
F-5201	10.7	92.5	10.2	67.7	1.8
F-5202	7.8	67.6	7.4	49.4	1.3
F-5203	7.8	67.6	7.4	49.4	1.3
<b>TOTALS</b>	<b>26.4</b>	<b>227.8</b>	<b>25</b>	<b>166.4</b>	<b>4.5</b>

### 3.5 NET EMISSION CHANGE DUE TO PROPOSED PROJECT

Table 3-6 shows a calculation of the proposed project's net effect on annual refinery criteria pollutant emissions, based on the equipment and fuel scenario producing the highest annual emissions for the proposed new cogeneration equipment, and continuous normal operation of both boilers (with 53.3% LSFO use for the Foster Wheeler boilers and 39.4% LSFO for the Rentech boilers). The tabulated emission changes represent the maximum annual emissions due to the two new boilers, turbine, and HRSG (Table 3.3), assuming applicant proposed emission limits for CO on the turbine/HRSG unit, minus the estimated actual emissions from Boilers F-5201, F-5202 and F-5203 found in the last line of Table 3-5. Separate tabulations are provided for each of the candidate boiler systems. This table shows that by limiting the percentage use of LSFO in either of the candidate boiler configurations, the net emission increases for NO<sub>x</sub>, CO, PM<sub>10</sub> and VOC can be maintained below the corresponding PSD Significant Emissions Increase trigger levels, while net decreases in annual emissions will result for SO<sub>2</sub>.

**Table 3-6**  
**Estimated Maximum Net Emissions Changes Resulting from Implementation of Proposed Hybrid Cogeneration Project (tons per year) – Based on Vendor Emission Guarantees @ 70,000lb/hour Average Steam Production and Proposed Applicant Emission Limits**

Using New Boilers from FOSTER WHEELER @ 53.3% Oil Usage	Total Emissions from Boilers (TPY)				
	PM10	SO2	CO	NOx	VOC
New Turbine/HRSG (highest emissions regardless of fuel)	4.7	10.1	65.3	60.0	30.4
Old Boilers	26.4	227.8	25.0	166.4	4.5
Total Replacement Boilers	23.3	194.1	59.6	146.3	3.5
Difference = New Turbine/HRSG + Replacement Boiler - Old Boilers	1.6	-23.6	99.8	39.8	29.4
PSD significance levels	15	40	100	40	40
Greater than significance level?	no	no	no	no	no

Using New Boilers from RENTECH @ 39.4% Oil Usage	Total Emissions from Boilers (TPY)				
	PM10	SO2	CO	NOx	VOC
New Turbine/HRSG (highest emissions regardless of fuel)	4.7	10.1	65.3	60.0	30.4
Old Boilers	26.4	227.8	25.0	166.4	4.5
Total Replacement Boilers	24.7	152.1	37.7	146.3	3.6
Difference = New Turbine/HRSG + Replacement Boiler - Old Boilers	3.0	-65.6	78.0	39.8	29.5
PSD significance levels	15	40	100	40	40
Greater than significance level?	no	no	no	no	no

\*Net emissions changes were determined by subtracting total annual average 1996-1997 emissions due to Boilers F-5201, F-5202 and F-5203 (last row of Table 3-5) from the maximum potential annual emissions from the proposed hybrid cogeneration plant (two boilers plus turbine plus duct burner) in Table 3-3. Negative values indicate a net emissions decrease will result from the hybrid cogeneration project.

### 3.6 PROJECT HAP EMISSIONS

Project emissions of hazardous air pollutants were estimated using the same methodology that has been employed for several years in compiling the Hawaii Refinery's annual emissions inventories for submittal to DOH. We are unaware of any published emissions factors for HAPs from gas turbines or duct burners that are specific to either RFG or naphtha fuels, and the approach used in this Application therefore uses AP-42 HAP factors for natural gas and diesel fuel as the best available approximations. Emission factors for HAPs from boilers using fuel oil are available, but boiler factors specific to RFG are not specified; therefore AP-42 HAP factors for natural gas were used as the best available approximation.

Table 3-7a shows the estimated annual HAP emissions from the new turbine/HRSG and two new boilers, as well as the estimated emissions decreases that will occur as a result of the retirement of the three existing refinery boilers. Table 3-7b shows the net change in emissions resulting from both refinery modifications. Both tables show estimates including the boilers from the two candidate vendors.

Note that the toxic air pollutants emitted from the new boilers and cogeneration unit will be somewhat different depending on whether RFG or naphtha fuel combustion is assumed. According to Table 3-7, annual emissions are calculated assuming continuous normal operation of both boilers (with up to 53.3% LSFO use, and full load for the turbine/HRSG assuming applicant proposed emission limits for CO. It is important to recognize that Table 3-7 compares maximum potential to emit for the boilers and turbine/HRSG unit with actual historical operations for the boilers. In addition, the new turbine will actually use both naphtha and RFG.

Emissions of formaldehyde from the new turbine/HRSG were estimated based on the allowable stack concentration limit of 91 parts per billion (ppb) specified in the MACT standard for combustion turbines, 40 CFR 63 Subpart YYYY. Source testing conducted on the existing turbine/HRSG train showed that the new units should achieve compliance with this standard. Mass emission rates of formaldehyde corresponding to 91 ppb were estimated by scaling from the vendor data on criteria pollutant emissions in Table 3-1. The resulting values are about 435 lb/year for full-time operation on RFG fuel with duct firing and 439 lb/year for full-time operation on naphtha fuel with duct firing. The higher of these values is entered in turbine/HRSG columns in Table 3-7. Note that the source testing on the existing cogeneration units at the Hawaii Refinery showed that duct firing is actually quite effective in destroying formaldehyde to below detection levels. In addition, emissions tests during operation of the existing units on RFG fuel showed no detectable formaldehyde with or without duct firing. Given that the normal operating mode of the new cogeneration unit will be with duct firing for supplemental steam production and that RFG fuel will be used for a substantial fraction of annual hours, the estimates of formaldehyde emission presented here are almost surely overestimates.

The boiler MACT standard in 40 CFR 63 Subpart DDDDD imposes a limit of 0.0005 lb/MMBtu on hydrogen chloride (HCl) emissions for new boilers. No boiler emission factor for this HAP is provided in AP-42 for either oil or gas fuel firing, although the air toxics emission data base maintained by the California Air Resources Board does include a factor for boilers burning refinery gas. Accordingly the HCl emissions from the boilers on RFG have been included in Tables were estimated based on an assumed value of 0.0005 lb/MMBtu, since compliance with this standard is mandatory.

As demonstrated by the data in Tables 3-7a and 3-7b, the proposed project is expected to result in a net decrease in the total refinery emissions of HAPs. Emissions for individual compounds will increase, but none by more than a few hundred pounds per year.

## SECTION THREE

## Project Emissions Estimates

**Table 3-7a**  
**Estimated Emissions of Hazardous Air Pollutants from Proposed Hybrid Energy Project Sources**

Hazardous Air Pollutant	Maximum Potential Emissions for Turbine/HRSG Unit (lb/yr)		Maximum Potential Emissions for Boilers (lb/yr) Foster Wheeler		Maximum Potential Emissions for Boilers (lb/yr) Rentech		Retiring Boilers (lb/year)	
	RFG Fuel	Naphtha Fuel	RFG Firing	LSFO Firing	RFG Firing	LSFO Firing	RFG	LSFO
1,3-Butadiene	0.356	6.474	0	0	0	0	0	0
Acetaldehyde	33.134	17.120	0	0	0	0	0	0
Acrolein	5.301	2.739	0	0	0	0	0	0
Antimony	0	0	0	14.315	0	11.156	0	33.561
Arsenic	0	4.325	0.056	3.599	0.077	2.805	0.151	8.438
Benzene	9.940	26.759	0.590	0.584	0.811	0.455	1.585	1.368
Beryllium	0	0.122	0.003	0.076	0.005	0.059	0.009	0.178
Cadmium	0	1.887	0.309	1.085	0.425	0.846	0.830	2.544
Chromium	0	4.325	0.393	2.304	0.541	1.796	1.057	5.402
Cobalt	0	0	0.024	16.415	0.032	12.792	0.063	38.483
Dichlorobenzene	0	0	0.337	0	0.463	0	0.906	0
Ethylbenzene	26.507	13.696	0	0.173	0	0.135	0	0.407
Formaldehyde	435.481	438.743	21.075	89.983	28.958	70.123	56.611	210.953
Hexane	0	0	505.792	0	694.985	0	1358.656	0
Hydrochloric Acid			183		251			
Lead	0	5.504	0	4.117	0	3.209	0	9.653
Manganese	0	310.588	0.107	8.180	0.147	6.375	0.287	19.178
Mercury	0	0.472	0.073	0.308	0.100	0.240	0.196	0.722
Methyl Chloroform (1,1,1-)	0	0	0	0.644	0	0.501	0	1.509
Naphthalene	1.077	14.317	0.171	3.081	0.236	2.401	0.460	7.224
Nickel	0	1.808	0.590	230.410	0.811	179.557	1.585	540.168
PAH	1.822	16.668	0.02492	3.272	0.034	2.550	0.067	7.671
Phosphorus	0	0	0	25.795	0	20.102	0	60.473
Propylene oxide	24.022	12.412	0	0	0	0	0	0
Selenium	0	9.829	0.007	1.862	0.009	1.451	0.018	4.366
Toluene	107.685	55.642	0.955	16.906	1.313	13.175	2.566	39.634
Xylene	53.014	27.393	0	0.297	0	0.232	0	0.697
All HAPS	698.3	970.8	713.5	423.4	979.9	330.0	1425.0	992.6

**Table 3.7b**  
**Estimated Net Change in Hazardous Air Pollutant Emissions**  
**Due to Proposed Energy Project (lb/year)**

Hazardous Air Pollutant	Using Foster Wheeler Boilers	Using Rentech Boilers
	RFG Naphtha	RFG Naphtha
1,3-Butadiene	6.47	6.47
Acetaldehyde	17.12	17.12
Acrolein	2.74	2.74
Antimony	-19.25	-22.40
Arsenic	-0.61	-1.38
Benzene	24.98	25.07
Beryllium	0.01	0.00
Cadmium	-0.09	-0.22
Chromium	0.56	0.20
Cobalt	-22.11	-25.72
Dichlorobenzene	-0.57	-0.44
Ethylbenzene	13.46	13.43
Formaldehyde	282.24	270.26
Hexane	-852.86	-663.67
Hydrochloric acid	183	251
Lead	-0.03	-0.94
Manganese	299.41	297.64
Mercury	-0.07	-0.11
Methyl Chloroform (1,1,1-Trichloroethane)	-0.87	-1.01
Naphthalene	9.89	9.27
Nickel	-308.95	-359.58
PAH	12.23	11.51
Phosphorus	-34.68	-40.37
Propylene oxide	12.41	12.41
Selenium	7.31	6.91
Toluene	31.30	27.93
Xylene	26.99	26.93
ALL HAPS	-309.9	-134.9

\* Net emissions changes determined by subtracting total annual average 1996-1997 emissions due to Boilers F-5201, F-5202 and F-5203 from the maximum potential annual emissions from the proposed hybrid cogeneration plant (turbine plus duct burner and boilers). Negative values indicate a net emissions decrease will result from the cogeneration project.

### 3.7 OPERATIONAL LIMITATIONS OR WORK PRACTICES THAT REDUCE PROJECT EMISSIONS

As described previously, the Hawaii Refinery wishes to permit the new hybrid energy project to allow continuous, full-time operation of the new gas turbine at peak load with duct firing throughout the year. The use of LSFO in the boilers will not exceed applicant specified limits. Specifically, LSFO use will not exceed 53.3% of the annual new boiler fuel consumption (just over 129,500 barrels per year if the Foster Wheeler boilers are selected, and LSFO use will not exceed 39.4% of the annual new boiler fuel consumption (about 101,000 barrels per year) if Rentech boilers are selected.

Further, regardless of the boilers selected, both units will operate at an annual capacity factor below 100%, with an average value of 91% which is equivalent to 70,000 lb steam production per hour per boiler. The new turbine will be equipped with a low-NO<sub>x</sub> burner and water injection to limit emissions of NO<sub>x</sub> to the levels indicated in Section 3.1 (Table 3-1). These measures will prevent NO<sub>x</sub> emissions from exceeding the levels specified in the New Source Performance Standards for gas turbines in 40 CFR 60 Subpart GG. In addition, the proposed turbine/HRSG train will comply with the more stringent NO<sub>x</sub> and SO<sub>2</sub> emissions standards of the proposed new NSPS for combustion turbines in 40 CFR 60 Subpart KKKK.

Boiler emissions of PM<sub>10</sub> from the new boilers will be maintained in compliance with the 0.03 lb/MMBtu limit that is specified in both the NSPS (40 CFR 60 Subpart Db) and the NESHAP (40 CFR 63 Subpart DDDDD). If the initial source testing of these units indicates that worst-case operation on LSFO will not comply with this limit, then Chevron will determine a mixture of LSFO with lighter fuels that does comply.

### 3.8 INSIGNIFICANT ACTIVITIES

The proposed project will consist of the addition of a new turbine/HRSG train and two new boilers for electric power and steam generation and the retirement of three existing boilers that have previously provided steam for use in refinery processes. No other emissions sources within the refinery will be materially altered or operated differently as a result of the proposed cogeneration project. The project does not include any new insignificant activities as this term is defined in §11-60.1-82.

## SECTION 4 AIR QUALITY IMPACT ANALYSIS

Under DOH Rule §60.1-8104(a)(12), an application for a significant modification that will increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, must submit a modeling assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment should include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards (NAAQS) and state ambient air quality standards.

As described in Section 3.5, annual refinery emissions of NO<sub>x</sub>, PM<sub>10</sub>, CO and VOC are expected to increase when the proposed project is implemented. Thus, dispersion modeling is required as part of this application. Net emissions of SO<sub>2</sub> are expected to decrease, as the existing boilers F-5201, F-5202 and F-5203 are functionally replaced by the new turbine/HRSG train and new steam boilers. However, a decision was made to conduct modeling for all pollutants because the emissions from the new cogeneration turbine/HRSG and boilers will be released from stacks in different locations and with different dimensions and exhaust characteristics than those from the boilers they will replace.

For these reasons, Chevron has elected to conduct dispersion modeling in order to eliminate any question about the potential effects of the proposed project on ambient air quality near the refinery. Specifically, maximum concentrations due to Hawaii Refinery operations with the new equipment were estimated for all criteria pollutants and averaging times addressed in federal and Hawaii ambient air quality standards. Specifically, the modeling included all existing emission sources within the refinery (except the three retiring boilers) operating at their average levels during the two-year period 2001-2002, in addition to the new cogeneration unit and the two new boilers. The only existing refinery process that will be affected by the proposed cogeneration project is the Boiler Plant, since three boilers will be retired after the new cogeneration unit and new boilers come on-line. Accordingly, the existing Boiler Plant emissions sources were excluded from the total refinery emissions for the simulations to evaluate future maximum short-term and long-term impacts of the proposed energy project.

Presently, Chevron is deciding between two boiler manufacturers, Foster Wheeler and Rentech. In order that the permitting process can proceed before the final boiler selection has been made, the air quality dispersion modeling analysis described in this section was conducted to include both boiler types. Thus separate sets of simulations were made to obtain results for: (1) all other existing refinery sources, the new cogeneration unit and the Foster Wheeler boilers; and (2) all other existing refinery sources, the new cogeneration unit and the Rentech boilers.

Details of the methods, input data and assumptions used for this analysis and a description of the modeling results are provided in the following subsections. Model input/output files for these simulations are submitted on a compact disk accompanying this application.

### 4.1 MODEL SELECTION

The Industrial Source Complex Short Term 3 model (ISCST3) (US Environmental Protection Agency, Version 02035) (US EPA 1995, 2002) was selected for this evaluation of criteria pollutant impacts from the Hawaii Refinery operations. For many years, ISCST3, which uses a steady-state Gaussian representation of horizontal and vertical dispersion of airborne pollutant plumes, has served as the

workhorse dispersion model for regulatory review of new industrial facilities and modifications. Attributes of the model that were considered in its selection for this application include:

- Ability to simulate the effects of multiple sources within an industrial complex;
- Ability to simulate the effects of complex terrain within in the modeling domain;
- Ability to use a sequential record of hourly meteorological input data of any length;
- Flexibility with respect to the form and contents of model output information.

The “Regulatory Default” settings of the ISCST3 model were selected for the present evaluation. These include use of final plume rise, buoyancy-induced dispersion for hot sources, processing of calm wind data, default values for the assumed wind profile exponents and vertical potential temperature gradients for different atmospheric stability conditions (see Section 4.3).

#### 4.2 MODELING REPRESENTATION OF REFINERY EMISSIONS

As noted previously, refinery emissions during the period 2001-2002 have been determined to be the most representative of normal operations during the last five years. Accordingly, the average of the point source emissions data reported to DOH for these two years were used to represent existing refinery sources for the modeling analysis. These inventories represent the refinery’s best efforts to quantify *actual* current emissions of criteria pollutants by using actual (as opposed to worst-case or allowable) fuel usage amounts and sulfur contents, source test results and other data collected during these years. For each source, an average of the annual emission rates reported for 2001 and 2002 was used to obtain existing source emissions. Since the objective of the modeling will be to estimate the impacts of future operations with the proposed energy project, the three existing steam boilers that will be retired as part of the project were the only existing refinery point sources not included in the modeling inventory.

The other change in refinery operations and emissions resulting from the proposed energy project will be the addition of the new cogeneration gas turbine/HRSG train with duct firing and the two new steam boilers. Thus, the maximum short-term and long-term emissions from these sources, as described in Sections 3-1 and 3-2, were also included in the mode simulations. Tables 4-1 and 4-2 show the annual emission rates and stack parameters for all the sources included in the modeling simulations for the proposed project with the new turbine/HRSG and new boilers. Separate data are included for two Foster Wheeler and two Rentech boilers, since the final determination of boiler design has not been made as of the submittal date for this application.

The layout and stack parameters for the two new Foster Wheeler and Rentech boilers are somewhat different. Therefore they are set as separate sources in the ISCST3 model input data. The combined pollutant concentrations from the existing sources plus the new turbine/HRS with the two Foster Wheeler boilers was input as one source group (ALL+FW), and the existing sources plus the new turbine/HRSG with the two Rentech boilers were included in a source group called ALL+REN. Results are presented in Section 4.6 for the two boiler options.



### Plume Downwash Considerations

The proximity of stacks within the refinery to buildings, tanks and other large structures can induce a condition known as aerodynamic downwash, whereby plumes emitted from such stacks are drawn into low pressure zones in the lee of these wind obstacles, which can potentially cause relatively high ground-level pollutant concentrations close to the source location. To account for this effect, the location coordinates, horizontal dimensions and heights of significant structures within the Hawaii Refinery were determined by site personnel. These data were entered into the USEPA Building Profile Input Program (BPIP) to create a data file with the necessary information for downwash calculations involving the appropriate structures for different wind directions. This BPIP output file was then entered with the other inputs to ISCST3 to accomplish the simulation of plume downwash effects.

### Boiler Stack Considerations

The new Rentech boilers are equipped with rain caps on each boiler stack. The rain caps hinder the momentum of the exiting exhaust gas, essentially changing the outlet velocity from vertical to horizontal. In order to model these stacks properly, the vertical velocity is set to 0.001 m/sec making the plume rise due to momentum negligible. The stack diameter is also modified to account for a lower velocity while maintaining the stack gas volume flow. The stack height is reduced by 3 times the actual stack diameter and the ISCST3 model option to calculate stack tip downwash is turned off. This conservative approach would result in the plume remaining closer to the ground than for an uncapped stack and therefore results in higher pollutant concentrations closer to the source.

**Table 4-1  
Future Refinery Emissions of Modeled Pollutants with Proposed Energy Project**

Source ID	Source Description	Emissions (tons/year)			
		PM <sub>10</sub>	SO <sub>2</sub>	CO	NO <sub>x</sub>
CTG6704	New Turbine/HRSG Train	4.65*	10.08	65.7	56.07*
FWBOIL1	New Boiler (Foster Wheeler 1)	11.65	96.99	29.86	73.31
FWBOIL2	New Boiler (Foster Wheeler 2)	11.65	96.99	29.86	73.31
RENBOIL1	New Boiler (Rentech 1)	12.13	75.30	18.63	72.06
RENBOIL2	New Boiler (Rentech 2)	12.13	75.30	18.63	72.06
CTG6701	Existing Cogen Turbine	2.21	1.55	6.42	31.30
CTG6702	Existing Cogen Turbine	2.21	1.55	6.42	31.30
CTG6703	Existing Cogen Turbine	2.21	1.55	6.42	31.30
F5103	Crude Unit - Atmospheric Furnace	25.55	245.25	17.42	151.15
F5153	Crude Unit - Vacuum Furnace	6.43	101.16	7.20	78.77
F5300	FCC Furnace	0.38	0.24	4.07	4.83
F5600	Hydrogenation Furnace	0.03	0.03	0.31	0.38
F5700	Hydrogen Plant Furnace	0.28	0.17	2.92	3.48
F5930	Isomerization Furnace	0.07	0.03	0.76	0.90
F5950	Isomerization Furnace	0.03	0.02	0.31	0.37
F6003	Asphalt Plant Furnace	0.07	0.07	0.87	1.04
F6262	Acid Plant Furnace	0.14	0.10	1.43	1.67
F6200ABS	Acid Plant Combustion Chamber & Absorber	0.14	464.53	1.70	2.05
FCCPRECP	FCC Precipitator Stack	155.11	365.88	462	224.55
CRUFLARE	Crude Flare F2301	-	11.2	4.1	17.8
FCCFLARE	FCC Flare F2302	-	101.2	36.5	160.6
COOL1	Cooling Tower	0.24			
COOL2	Cooling Tower	0.24			
COOL3	Cooling Tower	0.24			
COOL4	Cooling Tower	0.24			
COOL5	Cooling Tower	0.24			
COOL6	Cooling Tower	0.24			
COOL7	Cooling Tower	0.24			
COOL8	Cooling Tower	0.24			
COOL9	Cooling Tower	0.24			
COOL10	Cooling Tower	0.24			

\* Emissions for new cogeneration unit are based on continuous, year-round at maximum fuel use rates for the turbine/HRSG train with full duct burning and naphtha fuel. Emissions for all existing sources are based on actual 2001-2002 fuel usage rates.

**Table 4-2**  
**Stack Parameters for Future Hawaii Refinery Emission**  
**Sources with Proposed Energy Project – Annual Average Emission Condition**

Source ID	Source Type	UTM East (m)	UTM North (m)	Base Elevation (m)	Stack Height (m)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
CTG6704	New Turbine/HRSG Train	591807	2357070	2.7	24.99	464.26	9.31	1.829
FWBOIL1	New Boiler (Foster Wheeler 1)	591796	2357082	2.7	24.99	449.26	17.65	0.905
FWBOIL2	New Boiler (Foster Wheeler 2)	591780	2357074	2.7	24.99	449.26	17.65	0.905
RENBOIL1	New Boiler (Rentech 1)	591796	2357076	2.7	22.28	446.48	0.001	62.2
RENBOIL2	New Boiler (Rentech 2)	591780	2357068	2.7	22.28	446.48	0.001	62.2
CTG6701	Existing Cogen Turbine	591824	2357038	2.53	21.34	477.05	20.9	1.2
CTG6702	Existing Cogen Turbine	591819	2357047	2.56	21.34	477.05	20.9	1.2
CTG6703	Existing Cogen Turbine	591814	2357057	2.71	21.34	477.05	20.9	1.2
F5103	Crude Unit - Atmospheric Furnace	592053	2356683	2.96	42.9	450	12.45	1.5
F5153	Crude Unit - Vacuum Furnace	592053	2356683	2.96	42.9	450	12.45	1.5
F5300	FCC Furnace	591896	2356928	2.74	42.8	651	6.8	1.7
F5600	Hydrogenation Furnace	592046	2356626	2.71	38.1	1094	2	1.5
F5700	Hydrogen Plant Furnace	592058	2356642	2.87	38.1	533	1.9	1.8
F5930	Isomerization Furnace	591979	2356793	2.83	24.4	700	0.7	0.9
F5950	Isomerization Furnace	591976	2356791	2.8	24.4	700	0.7	0.9
F6003	Asphalt Plant Furnace	592405	2356492	3.05	9.1	408	13.2	0.3
F6262	Acid Plant Furnace	591880	2356433	0.91	19.4	604	4.6	0.6
F6200ABS	Acid Plant Combustion Chamber & Absorber	591907	2356434	1.1	37.49	352.6	2.95	0.91
FCCPRECP	FCC Precipitator Stack	591894	2356970	2.87	38.2	561	32.6	1.5
CRUFLARE	Crude Flare F2301	592207	2356412	2.56	47.34	1273	20	0.059
FCCFLARE	FCC Flare F2302	592141	2356378	2.13	47.75	1273	20	0.195
COOL1	Cooling Tower	592075	2356445	2.26	18.36	318	8	8
COOL2	Cooling Tower	592080	2356436	2.26	18.36	318	8	8
COOL3	Cooling Tower	592085	2356450	2.35	18.36	318	8	8
COOL4	Cooling Tower	592089	2356441	2.35	18.36	318	8	8

**Table 4-2 (continued)**  
**Stack Parameters for Future Hawaii Refinery Emission**  
**Sources with Proposed Cogeneration Project**

Source ID	Source Type	UTM East (m)	UTM North (m)	Base Elevation (m)	Stack Height (m)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
COOL5	Cooling Tower	592095	2356455	2.41	18.36	318	8	8
COOL6	Cooling Tower	592099	2356446	2.41	18.36	318	8	8
COOL7	Cooling Tower	592105	2356459	2.5	18.36	318	8	8
COOL8	Cooling Tower	592109	2356451	2.47	18.36	318	8	8
COOL9	Cooling Tower	592114	2356464	2.59	18.36	318	8	8
COOL10	Cooling Tower	592119	2356456	2.53	18.36	318	8	8

### 4.3 METEOROLOGICAL INPUT DATA

A five year data record (1988-1992) of hourly surface meteorological data for the Barbers Point Naval Air Station was obtained from the Western Climatic Data Center and processed with twice daily radiosonde (weather balloon) sounding data for the Lihue upper air station for the same period by means of the PCRAMMET preprocessor program to create a continuous record of hourly parameter values suitable for operation of the ISCST3 model. The proximity of Barbers Point to the Hawaii Refinery ensures that these data are representative of the weather conditions that would affect dispersion and transport of refinery emissions. The Lihue upper air record is the most representative data set of this type that is available in Hawaii. The parameters that are input to the ISCST3 model for each hour of a modeling simulation include wind speed, wind direction, ambient temperature, atmospheric stability category and mixing height. Model simulations were made for all five years of the meteorological input data to ensure that the maximum potential impacts before and after commencement of cogeneration operations would not be underestimated.

### 4.4 BACKGROUND AIR QUALITY DATA

Recent air quality monitoring data collected at the DOH monitoring sites closest to the Hawaii Refinery were used to characterize existing air quality for purposes of this modeling analysis. Table 4-3 lists the highest and second highest criteria pollutant concentrations recorded during 2004 at the nearest monitoring stations for each pollutant. This is the latest year for which an annual DOH monitoring report has been published. This table also lists the applicable federal and Hawaii ambient air quality standards.

**Table 4-3  
Ambient Air Pollutant Concentrations Measured Locally in 2004**

Air Pollutant	Averaging Time <sup>a</sup>	Monitoring Station	Measured Concentration (µg/m <sup>3</sup> )		Standards (µg/m <sup>3</sup> )		
			1 <sup>st</sup> High	2 <sup>nd</sup> High	Hawaii State Standard <sup>b</sup>	Federal Primary Standard	Federal Secondary Standard
Carbon Monoxide, CO	1-hour	Kapolei	2,394	1,710	10,000	40,000	40,000
	8-hour	Kapolei	983	955	5,000	10,000	10,000
Nitrogen Dioxide, NO <sub>2</sub>	Annual	Kapolei	9	-	70	100	100
Particulate Matter less than 10µm, PM <sub>10</sub>	24-hour	Kapolei	53 <sup>c</sup>	41	150	150	150
	Annual	Kapolei	13	-	50	50	50
Particulate Matter less than 2.5µm, PM <sub>2.5</sub>	24-hour	Kapolei	7 <sup>d</sup>	6	-	65	65
	Annual	Kapolei	3	-	-	15	15
Ozone	1-hour	Sand Island	118	116	-	235	235
	8-hour	Sand Island	110	108	157	157	157
Sulfur Dioxide, SO <sub>2</sub>	3-hour	Kapolei	17	12	1,300	-	1,300
	24-hour	Kapolei	7	6	365	365	-
	Annual	Kapolei	1	-	80	80	-
Lead, Pb <sup>e</sup>	Calendar quarter	-	-	-	1.5	1.5	1.5
Hydrogen Sulfide, H <sub>2</sub> S	1-hour	Lava Tree	14	11	35	-	-

- a. All averaging times are based on block averages except for the 8-hour ozone standard, which is based on running 8-hour periods.
- b. Limiting concentrations specified for a calendar year or a calendar quarter shall not be exceeded. Limiting concentrations specified for 1-hour, 3-hour, 8-hour, and 24-hour periods shall not be exceeded more than once in a calendar year.
- c. 54 ug/m<sup>3</sup> was the highest 24-hour PM<sub>10</sub> value, including the New Year's fireworks event, but the value of 53 ug/m<sup>3</sup> is the reported valid value.
- d. 20 ug/m<sup>3</sup> was the value, including the New Year's fireworks event, but the value of 7 ug/m<sup>3</sup> is the reported valid value.
- e. Ambient air monitoring for lead was discontinued in October 1997 with EPA approval. Levels in the state were far below the federal standard since sampling began. With the elimination of lead in gasoline, measured levels were consistently zero or nearly zero.

**Note:** Data taken from 2004 Annual Summary Hawaii Air Quality Data  
<http://www.hawaii.gov/health/environmental/air/cab/cabmaps/pdf/databook2004.pdf>

As a means to ensure that pollutant impacts and compliance with ambient standards would be evaluated very conservatively, the highest measured pollutant concentration for each pollutant and averaging time was added to the maximum refinery contribution predicted by the model in order to estimate total concentrations for comparison with federal and Hawaii ambient standards. In other words, it has been assumed that the highest recorded concentration during an entire year represents the contribution of non-refinery sources at all times and receptor locations in all modeling simulations. In actuality the monitoring data, particularly at the Kapolei station, reflect some contribution of the existing refinery sources, with the result that these contributions are effectively double counted by this analysis, lending additional conservatism to the model results.

#### 4.5 MODEL RECEPTOR DATA

A grid of receptors, i.e., the array of geographical points at which the model was instructed to calculate pollutant concentrations extended from the property line of the refinery to a distance of 15 kilometers beyond the property line in all directions. Closer spacing of receptor locations was used near the facility to ensure that maximum concentrations would be detected, with decreasing receptor density at greater distances. The specific receptor spacing conventions used for all simulations described in this application were as follows:

- Receptors were placed on the refinery property line at intervals of 50 meters.
- From the refinery property line out to a distance of 1 kilometer beyond the perimeter, a spacing of 100 meters was used.
- For distances between 1 and 10 kilometer beyond the perimeter, the spacing was 500 meters.
- For distances between 10 kilometers and 15 kilometers beyond the perimeter, the spacing was 1,000 meters.
- Additional receptors were selected to coincide with locations of high elevation points in the nearby hills.

A file of digital terrain data for the refinery vicinity was obtained from the website of the State of Hawaii Office of Planning [<http://www.state.hi.us/dbedt/gis/scnctr.htm>], and this data set was processed to assign elevations to all model receptors.

#### 4.6 MODELING RESULTS

Table 4-4(a) and 4.4(b) list the maximum predicted pollutant concentrations due to refinery point source emissions for the proposed cogeneration project using Foster Wheeler and Rentech boilers respectively. These tables demonstrate that, even with the conservative assumptions used to represent background concentrations, the predicted pollutant concentrations in the refinery vicinity are compliant with federal and Hawaii ambient air quality standards for all pollutants. These results confirm that the proposed energy project will result in no appreciable adverse effect with respect to compliance with applicable air quality standards in the area surrounding the Hawaii Refinery.

The maximum CO concentration for both the 1-hour and 8-hour averaging time are predicted to be several hundred meters to the north and west of the project site. This result is consistent with the shift of emissions from the existing boilers to the new turbine/HRSG train and new boilerse, which are northwest of the boilers. Maximum concentrations for other pollutants are not expected to be as far away from the project site as CO. As described in Section 3.1.4, the assumed CO emissions for the new cogeneration unit probably incorporates a higher level of conservatism than those for the other pollutants, which is leading to the anomalous results with regard to the location of the modeled peak concentrations.

Electronic copies of all model input and output files for this air quality impact assessment are contained on a compact disk that is provided as Appendix D to this application. These files will allow DOH to review the modeling analysis in full detail.

**Table 4-4(a)**  
**Dispersion Modeling Results for Evaluation of Project Impacts to Air Quality**  
**Estimated Impacts of Refinery with Proposed New Equipment: 1 Turbine/HRSG & 2 Foster Wheeler Boilers**

Pollutant	Averaging Period	1988 Maximum Modeled Concentration			1989 Maximum Modeled Concentration			1990 Maximum Modeled Concentration			1991 Maximum Modeled Concentration			1992 Maximum Modeled Concentration			Maximum Modeled Concentration (µg/m³)	Measured Background Concentration (µg/m³)	Maximum Total Concentration (µg/m³)	Under NAAQS?	Under HAAQS?	NAAQS	HAAQS
		µg/m³	UTM X (m)	UTM Y (m)	µg/m³	UTM X (m)	UTM Y (m)	µg/m³	UTM X (m)	UTM Y (m)	µg/m³	UTM X (m)	UTM Y (m)	µg/m³	UTM X (m)	UTM Y (m)							
PM10	Annual	0.5	591,760	2,356,495	0.4	591,500	2,356,900	0.4	591,760	2,356,495	0.4	591,500	2,356,900	0.3	591,781	2,356,451	0.5	13	13.5	yes	yes	50	50
	24-hour	3.5	592,000	2,360,500	4.5	592,000	2,360,500	4.5	594,250	2,360,000	6.4	592,500	2,361,000	5.9	593,500	2,360,000	6.4	53	59.4	yes	yes	150	150
SO2	Annual	5.4	591,760	2,356,495	4.3	591,760	2,356,495	4.6	591,760	2,356,495	4.4	591,760	2,356,495	3.9	591,781	2,356,451	5.4	1	6.4	yes	yes	80	80
	24-hour	35.1	591,800	2,358,100	38.3	592,100	2,358,000	39.9	591,400	2,357,500	45.6	592,500	2,360,500	47.2	591,600	2,357,600	47.2	7	54.2	yes	yes	365	365
	3-hour	146.6	591,400	2,357,500	151.5	591,500	2,357,600	231.9	593,000	2,360,500	186.0	592,500	2,360,500	202.5	593,500	2,360,500	231.9	17	248.9	yes	yes	1,300	1,300
NO2	Annual	4.2	591,760	2,356,495	3.6	591,760	2,356,495	3.8	591,760	2,356,495	3.9	591,500	2,356,900	3.2	591,760	2,356,495	4.2	9	13.2	yes	yes	100	70
CO	8-hour	25.6	591,400	2,357,500	25.5	591,600	2,357,600	33.0	592,500	2,361,000	40.8	594,000	2,360,750	44.3	593,500	2,360,000	44.3	983	1,027.3	yes	yes	10,000	5,000
	1-hour	98.5	590,500	2,361,500	88.5	594,500	2,360,250	97.3	590,500	2,362,500	99.4	591,000	2,361,000	95.3	593,000	2,361,000	99.4	2,394	2,493.4	yes	yes	40,000	10,000

**Table 4-4(b)**  
**Dispersion Modeling Results for Evaluation of Project Impacts to Air Quality**  
**Estimated Impacts of Refinery with Proposed New Equipment: 1 Turbine/HRSG & 2 Rentech Boilers**

Pollutant	Averaging Period	1988 Maximum Modeled Concentration			1989 Maximum Modeled Concentration			1990 Maximum Modeled Concentration			1991 Maximum Modeled Concentration			1992 Maximum Modeled Concentration			Maximum Modeled Concentration (µg/m³)	Measured Background Concentration (µg/m³)	Maximum Total Concentration (µg/m³)	Under NAAQS?	Under HAAQS?	NAAQS	HAAQS
		µg/m³	UTM X (m)	UTM Y (m)	µg/m³	UTM X (m)	UTM Y (m)	µg/m³	UTM X (m)	UTM Y (m)	µg/m³	UTM X (m)	UTM Y (m)	µg/m³	UTM X (m)	UTM Y (m)							
PM10	Annual	1.5	591,500	2,356,900	1.4	591,500	2,356,900	1.4	591,500	2,356,900	1.6	591,500	2,356,900	1.1	591,500	2,356,900	1.6	13	14.6	yes	yes	50	50
	24-hour	5.1	591,800	2,357,600	5.4	591,800	2,357,500	6.4	591,500	2,357,400	6.5	591,500	2,356,900	7.1	591,600	2,357,500	7.1	53	60.1	yes	yes	150	150
SO2	Annual	9.8	591,500	2,356,900	9.2	591,500	2,356,900	9.1	591,500	2,356,900	10.7	591,500	2,356,900	7.6	591,500	2,356,900	10.7	1	11.7	yes	yes	80	80
	24-hour	77.7	591,500	2,356,900	80.6	591,800	2,357,400	92.3	591,500	2,357,400	99.4	591,500	2,356,900	102.6	591,600	2,357,500	102.6	7	109.6	yes	yes	365	365
	3-hour	308.6	591,800	2,357,400	317.3	591,600	2,357,400	321.4	591,600	2,357,300	329.6	591,600	2,357,300	383.9	592,000	2,357,600	383.9	17	400.9	yes	yes	1,300	1,300
NO2	Annual	10.0	591,500	2,356,900	9.4	591,500	2,356,900	9.2	591,500	2,356,900	10.9	591,500	2,356,900	7.8	591,500	2,356,900	10.9	9	19.9	yes	yes	100	70
CO	8-hour	31.1	591,500	2,357,400	29.6	591,600	2,357,500	35.9	591,500	2,357,400	39.4	594,000	2,360,750	46.6	593,500	2,360,000	46.6	983	1,029.6	yes	yes	10,000	5,000
	1-hour	107.9	590,500	2,361,500	85.6	594,500	2,360,250	103.7	590,500	2,362,500	91.8	592,500	2,361,000	92.3	593,000	2,361,000	107.9	2,394	2,501.9	yes	yes	40,000	10,000



# SECTION FIVE Project Compliance With Applicable Regulatory Requirements

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## SECTION 5 PROJECT COMPLIANCE WITH APPLICABLE REGULATORY REQUIREMENTS

The only material changes to the refinery equipment and operations that will result from implementation of the proposed cogeneration project will be the addition of a new Solar Centaur 40 gas turbine and the associated HRSG with duct burner as well as two new boilers and the elimination of three existing boilers in the facility's Boiler Plant. Accordingly, this section focuses on the regulatory requirements pertaining to these specific activities.

### 5.1 APPLICABLE FEDERAL REQUIREMENTS

Federal regulatory requirements that are applicable to the proposed cogeneration project addressed in this application are summarized below.

#### **40 CFR 60 New Source Performance Standards (NSPS)**

- Subpart A: General Provisions (applicable to the proposed cogeneration project because it is subject to one or more of the following NSPS Subparts and provides general guidance for compliance with those Subparts)
- Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (applicable to the two proposed new steam boilers and regulates the corresponding emissions of sulfur oxides, particulate matter and nitrogen oxides).
- Subpart J: Standards of Performance for Petroleum Refineries (applies to the proposed combustion turbine and HRSG of the new cogeneration plant, and regulates the corresponding emissions of sulfur oxides).
- Subpart GG: Standards of Performance for Stationary Gas Turbines (applies to the proposed combustion turbine and regulates the corresponding emissions of sulfur oxides and nitrogen oxides).
- Subpart GGG: Standards of Performance for Equipment Leaks in Petroleum Refineries (applies to equipment – compressors, valves, pumps, pressure relief devices, sampling connection system, open-ended valves or lines, and flanges or other connectors in gaseous or liquid service associated with the proposed cogeneration unit and boilers, and regulates VOC emissions from such equipment.)
- Subpart QQQ: Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (applies to process drains and sewer lines associated with the proposed cogeneration plant and boilers, and regulates VOC emissions from this equipment.)
- Subpart KKKK (proposed): US EPA recently published a proposed new NSPS for new stationary combustion turbines with a power generation capacity of at least 1 MW. This

## SECTION FIVE Project Compliance With Applicable Regulatory Requirements

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rule will limit the allowable NO<sub>x</sub> and SO<sub>2</sub> emission rates from turbines constructed after February 18, 2005 to levels below those specified in Subpart GG (see above). The Subpart KKKK emission standards may be modified from those presented in the proposed rule, but no information is currently available regarding the specific nature of any such changes.

Explanations of the specific requirements of these NSPS as they apply to the proposed cogeneration unit are provided in Table 5-1, including the detailed requirements of each Subpart with regard to emission controls, monitoring, test methods and procedures, and recordkeeping and reporting.

### **40 CFR 63 National Emissions Standards for Hazardous Air Pollutants (NESHAPS)**

- Subpart A: General Provisions (applicable to units that are subject to the following Category-Specific NESHAP Subparts and provides general guidance for compliance with those Subparts.)
- Subpart CC: National Emission Standards from Petroleum Refineries (applies to leaks from piping components at a refinery that is a major source of Hazardous Air Pollutants and emits one or more of the HAPs listed in Table 1 of this Subpart).
- Subpart YYYY: National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (applies to the new cogeneration turbine, but not to the HRSG or duct burner).
- Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters (applies to the emission of PM, hydrochloric acid and CO from new steam boilers)

Explanations of the specific requirements of these MACT standards as they apply to the proposed energy project are presented in Table 5-2, including particulars of the associated emission control requirements, as well as the associated monitoring, test methods and procedures and recordkeeping and reporting requirements of each Subpart

### **New Source Review**

Implementation of the federal New Source Review requirements for new sources and modifications in Hawaii has been delegated by US EPA to DOH. The DOH permitting requirements are contained in Hawaii Administrative Rules Title 11, Chapter 60.1, as described below.

## 5.2 APPLICABLE HAWAII ADMINISTRATIVE RULES (HAR)

### **Title 11, Chapter 59 - Ambient Air Quality Standards**

#### *HAR 11-59-4: Ambient air quality standards*

Establishes ambient air quality standards applicable in Hawaii.

# SECTION FIVE Project Compliance With Applicable Regulatory Requirements

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## ***Title 11, Chapter 60.1 - Air Pollution Control***

### **Subchapter 1: General Requirements**

### **Subchapter 2: General Prohibitions**

#### *HAR 11-60.1-31: Applicability*

Specifies that all covered and non-covered sources of air pollution are subject to the requirements of this subchapter and that the most stringent requirement will apply in the event of any conflict between federal or state laws, rules, or regulations and the requirements of this subchapter.

#### *HAR 11-60.1-32: Visible Emissions*

Paragraph (b) - Visible emission for stationary sources which commenced construction, modification, or relocation after March 20, 1972 may not be of a density equal to or darker than 20 % opacity, except during start-up, shutdown or equipment breakdowns, when the opacity may exceed 20% for a period aggregating not more than 6 minutes during any sixty minutes, but may not be darker than 60% opacity.

Paragraph (c) - Compliance with the requirements of Paragraph (b) must be determined pursuant to 40 CFR Part 60, Appendix A, Method 9 and other EPA approved methods.

Paragraph (d) - Emissions of uncombined water, such as water vapor, are exempt from the provisions of subsection (b) and do not constitute a violation of this section.

#### *HAR 11-60.1- 33: Fugitive Dust*

Paragraph (a) - A person is prohibited from causing visible fugitive dust to become airborne without taking reasonable precautions. Examples of reasonable precautions are cited in this rule.

Paragraph (b) - No person shall cause or permit the discharge of visible fugitive dust beyond the boundary of the property on which the fugitive dust originates.

#### *HAR 11-60.1-38: Sulfur Oxides from Fuel Combustion*

Paragraph (a) - Prohibits burning of any fuel containing in excess of two per cent sulfur by weight, except for fuel used in ocean-going vessels.

#### *HAR 11-60.1-41: Pump and Compressor Requirements*

All pumps and compressors handling volatile organic compounds with a Reid vapor pressure of 1.5 pounds per square inch or greater which can be fitted with mechanical seals must use mechanical seals or other equipment of equal efficiency for purposes of air pollution control as may be approved by DOH. Pumps and compressors not capable of being fitted with mechanical seals, such as reciprocating pumps, must be fitted with the best sealing system available for air

## SECTION FIVE Project Compliance With Applicable Regulatory Requirements

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pollution control, given the particular design of pump or compressor, as may be approved by the DOH.

### *HAR §11-60.1-42: Waste Gas Disposal*

Emissions of gas streams containing volatile organic compounds from a vapor blowdown system must be burned by smokeless flares, or abated by an equally effective method approved by DOH (may apply to cogeneration compressors).

### **Subchapter 5: Covered Sources**

This application has been designed to provide all of the information regarding the proposed cogeneration project that is required under this subpart, with emphasis on the applicable requirements, for a proposed significant modification to a covered source permit, as listed under HAR §11-60.1-104.

### **Subchapter 6: Fees for Covered Sources, Non-covered Sources, and Agricultural Burning**

*HAR §11-60.1-113* of this subchapter requires payment of application fees for permit applications pertaining to new covered sources or modifications and provides a schedule of fees for determining the requirement payment amounts. No application will be deemed complete unless the required application fee has been paid in full.

### **Subchapter 7: Prevention of Significant Deterioration (PSD)**

PSD is not applicable for the proposed cogeneration project because this facility is not a new major stationary source, nor does the project constitute a major modification to a major stationary source as defined in HAR 11-60.1-131.

### **Subchapter 8: Standards of Performance for Stationary Sources**

*HAR 11-60.1-161 - New Source Performance Standards* (apply to all units that are subject to one or more of the NSPS Subparts in 40 CFR 60, as noted in Section 5.1, Federal Requirements.)

### **Subchapter 9: Hazardous Air Pollutant Sources**

*HAR 11-60.1-174 - Maximum Achievable Control Technology Standards* (apply to all units that are subject to one or more of the Category-Specific NESHAPs in Subpart 40 CFR 63, as noted above in Section 5.1, Federal Requirements)

*HAR 11-60.1-180 - National Emission Standards for Hazardous Air Pollutants* (apply to units that are subject to the NESHAP Subpart in 40 CFR 61 noted above under Federal Requirements)

## 5.3 NO EMISSIONS TRADING PROPOSED

The Hawaii Refinery does not proposed any emissions trading in accordance with §11-60.1-96.

## **SECTION FIVE** Project Compliance With Applicable Regulatory Requirements

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### **5.4 NO PROPOSED EXEMPTIONS FROM APPLICABLE REQUIREMENTS**

The Hawaii Refinery does not propose any exemptions from the applicable requirements listed in Sections 5.1 and 5.2.

### **5.5 COMPLIANCE PLANS AND CERTIFICATIONS**

Completed DOH Forms C-1 (Compliance Plan) and C-2 (Compliance Certification) are provided in Appendix C to this application.

### **5.6 APPLICATION FEE**

A check in the amount of \$3,000 is provided with this application for payment of application fees, calculated according to the specifications in §11-60.1-113(b)(6)(F) for “A significant modification to a major toxics source resulting in an increase of emissions greater than or equal to forty tpy of any regulated air pollutant other than hazardous air pollutants, or an increase of emissions greater than or equal to one tpy of any hazardous air pollutant”

**Table 5-1  
Federal New Source Performance Standards Applicable to the Proposed Hawaii Refinery Energy Project**

Requirement	Basis for Applicability	Standards	Monitoring Requirements	Test Methods and Procedures	Reporting/Recordkeeping
<b>40 CFR 60: New Source Performance Standards (NSPS)</b>					
Subpart A, General Provisions, §§ 60.1-60.19.	Applies to units that are subject to one or more of the following NSPS Subparts.	Presents general guidance for complying with all of the other applicable NSPS subparts below, including definitions and units used in all subparts, general requirements for construction and modification plans, notifications and recordkeeping requirements related to construction and modification projects, general guidance on emissions quantification and performance testing for new sources or modifications, installation and operation of monitoring equipment, state authority to permit new sources and modifications, prohibitions against circumvention of requirements, general guidance on control device requirements, and general guidance on compliance with notification and reporting requirements. Detailed requirements for specific equipment are summarized in the applicable NSPS subparts below.			
Subpart Dc Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	Applies to each steam generating unit that commences construction after June 9, 1989, and that have a heat input capacity greater than or equal to 2.9 MW (10 MMBtu/hr), but less than 29 MW (100 MMBtu/hr)  Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart.	<p>Sulfur Oxides: Any affected facility burning oil may not emit gases that contain SO<sub>2</sub> in excess of 215 ng/J (0.50 lb/million Btu) heat input; or, as an alternative, may not combust oil shall that contains greater than 0.5 weight percent sulfur. If oil is burned with any other fuel, except coal, only the combustion of the oil is counted in evaluating compliance with the SO<sub>x</sub> emission limit.</p> <p>The above SO<sub>2</sub> emission limit and fuel oil sulfur limit apply at all times, including periods of startup, shutdown, and malfunction.</p> <p>Particulate Matter: Facilities burning oil with a heat input capacity of 8.7 MW (30 million Btu/hr) or greater may not emit gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.</p> <p>An affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater may not emit gases containing particulate matter emissions in excess of 13 ng/J (0.030 lb/MMBtu) heat input.</p> <p>The above PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.</p>	<p>Sulfur Oxides: Affected units subject to SO<sub>2</sub> emission limits under this subpart must install, calibrate, maintain, and operate a CEMS for measuring SO<sub>2</sub> concentrations and either oxygen or carbon dioxide concentrations at the outlet of the SO<sub>2</sub> control device (or the outlet of the steam generating unit if no SO<sub>2</sub> control device is used), and shall record the output of the system.</p> <p>Alternatively, an owner or operator may elect to determine the average SO<sub>2</sub> emission rate by sampling the fuel prior to combustion. Fuel sampling will be conducted by either: (1) daily oil samples collected in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19; or (2) oil samples may be collected from the fuel tank for each steam generating unit immediately after the tank is filled and before any oil is combusted.</p> <p>Particulate Matter: Affected units subject to the opacity standards under this subpart must, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system, except that Units that burn only oil that contains no more than 0.5 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 230 ng/J (0.54 lb/MMBtu) heat input or less are not required to conduct PM emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.</p>	<p>Sulfur Oxides: For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received.</p> <p>For affected facilities where the owner or operator seeks to demonstrate compliance with the SO<sub>2</sub> standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier.</p> <p>Particulate Matter: The owner or operator of an affected facility subject to the PM and/or opacity standards under this subpart shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods described in Methods 1,3 and 5, 5B or 17.</p> <p>Units that burn only oil containing no more than 0.5 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 230 ng/J (0.54 lb/MMBtu) heat input or less are not required to conduct emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.</p>	<p>The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:</p> <p>The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.</p> <p>If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.</p> <p>The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.</p> <p>The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits, fuel oil sulfur limits, or percent reduction requirements of this subpart shall submit reports demonstrating compliance with these limits and requirements..</p> <p>The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.43c shall keep records and submit reports, including the following information, as applicable.</p> <p>Calendar dates covered in the reporting period.</p> <p>Each 30-day average SO<sub>2</sub> emission rate (nj/J or lb/million Btu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.</p> <p>Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.</p> <p>If fuel supplier certification is used to demonstrate compliance, in addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.</p> <p>Fuel supplier certification for distillate oil shall include (1) the name of the oil supplier; and a statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c.</p> <p>The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The owner or operator of an affected facility that only burns very low sulfur fuel oil or other liquid or gaseous fuels with potential sulfur dioxide emissions rate of 140 ng/J (0.32 lb/MMBtu) heat input or less shall record and maintain records of the fuels combusted during each calendar month.</p> <p>All records required under this subpart shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.</p> <p>The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.</p>

**Table 5-1  
Federal New Source Performance Standards Applicable to the Proposed Hawaii Refinery Energy Project**

Requirement	Basis for Applicability	Standards	Monitoring Requirements	Test Methods and Procedures	Reporting/Recordkeeping
Subpart J: Standards of Performance for Petroleum Refineries. §§ 60.100-60.109.	Applies to fuel gas combustion devices, i.e., "any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.	Sulfur Oxides: May not burn fuel gas containing H <sub>2</sub> S in excess of 230 mg/dscm (0.10 gr/dscf).	<p>Requires use of an instrument for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in fuel gases before being burned in any fuel gas combustion device.</p> <p>The span value of this instrument is 425 mg/dscm H<sub>2</sub>S.</p> <p>Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the SO<sub>2</sub> emissions into the atmosphere from each of the combustion devices or the concentration of H<sub>2</sub>S in the fuel gas being burned.</p> <p>Performance and relative accuracy evaluations of SO<sub>2</sub> or H<sub>2</sub>S monitor are to be conducted per test methods and to accuracy standards specified in § 60.105.</p> <p>Excess emissions that shall be determined and reported for the fuel H<sub>2</sub>S instrument are defined as all rolling 3-hour periods during which the average concentration of H<sub>2</sub>S.</p>	<p>In conducting the performance tests required in §60.8 of Subpart A, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified below:</p> <p>Compliance with the H<sub>2</sub>S concentration standard to be determined by Method 11, 15, 15A, or 16.</p> <p>The gases entering the sampling train should be at near atmospheric pressure.</p> <p>The sample shall be drawn from a point near the centroid of the fuel gas line.</p> <p>For Method 11, the sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run.</p> <p>For Method 15 or 16, at least three injects over a 1-hour period shall constitute a run.</p> <p>For Method 15A, a 1-hour sample shall constitute a run.</p>	<p>For any periods for which SO<sub>x</sub> data are not available, the owner or operator shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.</p> <p>The owner or operator shall submit the reports required under this subpart to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.</p> <p>The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.</p>

**Table 5-1  
Federal New Source Performance Standards Applicable to the Proposed Hawaii Refinery Energy Project**

Requirement	Basis for Applicability	Standards	Monitoring Requirements	Test Methods and Procedures	Reporting/Recordkeeping
Subpart GG: Standards of Performance for Stationary Gas Turbines. §§ 60.330-60.335	Applies to stationary gas turbines which commence construction after October 3, 1977 with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.	<p>Oxides of Nitrogen: No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain NOx in excess of:</p> $\text{STD} = 0.0150 \cdot (14.4)/Y + F$ <p>where:</p> <p>STD = allowable ISO NOx emission concentration (% by volume at 15% oxygen and on a dry basis),</p> <p>Y = manufacturer's rated heat rate at peak load (joules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kj/ watt hr and</p> <p>F = NOx emission allowance for fuel-bound nitrogen as defined in this section.</p> <p>Sulfur Oxides: Must comply with one or the other of the following conditions</p> <p>Emit no gases which contain SO2 in excess of 0.015% by volume at 15% O2 on a dry basis; or</p> <p>Burn no fuel containing total sulfur in excess of 0.8% percent by weight (8000 ppmw).</p>	<p>Any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOx emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.</p> <p>Any new turbine constructed after October 3, 1977 but before July 8, 2004, and which uses water or steam injection to control NOx emissions may elect to meet either the above requirement for continuous water or steam to fuel ratio monitoring, or may instead use a NOx CEMS installed, certified, operated, maintained, and quality-assured as described in § 60.334 (b). The owner or operator of any stationary gas turbine subject to the provisions of this subpart:</p> <p>Shall monitor the total sulfur content of the fuel being fired in the turbine, using total sulfur methods described in §60.335(b)(10), or, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), alternate methods referenced in §60.17 may be used; and</p> <p>Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen. The nitrogen content shall be determined using methods described in §60.335(b)(9) or an approved alternative.</p> <p>The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:</p> <p>Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in relevant sections of Appendix D to 40 CFR Part 75. If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.</p> <p>Gaseous fuel. Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.</p> <p>Custom schedules. Notwithstanding the above requirements, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply.</p> <p>For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction.</p>	<p>The performance tests required in §60.8, shall be conducted using either</p> <p>EPA Method 20</p> <p>ASTM D6522-00 (incorporated by reference, see §60.17), or</p> <p>EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NOx concentration.</p> <p>Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.</p> <p>Other methods referenced in § 60.335(c).</p> <p>The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:</p> <p>For each run of the performance test, the mean nitrogen oxides emission concentration corrected to 15 percent O2 shall be corrected to ISO standard conditions using the equation. in § 60.335(b).</p> <p>The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest load actually achievable. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.</p> <p>NOx emissions for a combined cycle turbine system with duct burner may be measured after the duct burner rather than directly after the turbine, but still must meet the applicable NOx emission limit for the combustion turbine in §60.332.</p> <p>If water or steam injection is used to control NOx with no additional post-combustion NOx control and monitoring of the steam or water to fuel ratio is elected, then that monitoring system must be operated concurrently with each test run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NOx emission limit.</p> <p>If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in § 60.335(b)(7)) or as part of the initial performance test of the affected unit.</p>	<p>Must maintain on-site records of gaseous and liquid, fuel usage, water to fuel ratio and fuel sulfur contents.</p> <p>Must periodically determine the fuel sulfur content or fuel nitrogen content under this subpart.</p> <p>The owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction.</p> <p>All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.</p>



**Table 5-1  
Federal New Source Performance Standards Applicable to the Proposed Hawaii Refinery Energy Project**

Requirement	Basis for Applicability	Standards	Monitoring Requirements	Test Methods and Procedures	Reporting/Recordkeeping
Subpart GGG— Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, §§ 60.590 - 60.593.	<p>The provisions of this subpart apply to affected facilities in petroleum refineries.</p> <p>A compressor is an affected facility.</p> <p>The group of all the equipment (defined in §60.591) within a process unit is an affected facility.</p> <p>Any affected facility under paragraph (a) of this section that commences construction or modification after January 4, 1983, is subject to the requirements of this subpart.</p> <p>Equipment means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.</p>	<p>Each owner or operator subject to the provisions of this subpart shall comply with the standards of §§60.482-1 to 60.482-10 of 40 CFR 60 Subpart VV (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry) as soon as practicable, but no later than 180 days after initial startup.</p> <p>An owner or operator may elect to comply with the requirements of §§60.483-1 and 60.483-2.</p> <p>An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of §60.48.</p> <p>Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§60.486 and 60.487.</p>	<p>Each owner or operator subject to the provisions of this subpart shall comply with the test methods and procedures required under §60.485 of 40 CFR 60 Subpart VV, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry, except as provided in §60.593.</p>	<p>Facilities subject to the provisions of this subpart shall comply with the recordkeeping requirements contained in §60.486 of 40 CFR 60, Subpart VV, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry.</p>	<p>Facilities subject to the provisions of this subpart shall comply with the reporting requirements contained in §60.487 of 40 CFR 60, Subpart VV, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry.</p>

**Table 5-1  
Federal New Source Performance Standards Applicable to the Proposed Hawaii Refinery Energy Project**

Requirement	Basis for Applicability	Standards	Monitoring Requirements	Test Methods and Procedures	Reporting/Recordkeeping
Subpart QQQ, Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems, §§ 60.690-60.699.	<p>Applicable to drains associated with the new cogeneration project.</p> <p>The provisions of this subpart apply to affected facilities located in petroleum refineries for which construction, modification, or reconstruction is commenced after May 4, 1987.</p> <p>An individual drain system is a separate affected facility.</p> <p>The construction or installation of a new individual drain system shall constitute a modification to an affected facility and a new individual drain system shall be limited to all process drains and the first common junction box.</p>	<p>Each owner or operator subject to the provisions of this subpart shall comply with the following requirements.</p> <p>Each drain shall be equipped with water seal controls.</p> <p>Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls and could result in VOC emissions.</p> <p>Alternatively, if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed.</p> <p>Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in §60.692-6.</p> <p>Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.</p> <p>Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.</p> <p>Junction boxes shall be visually inspected initially and semiannually thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.</p> <p>If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in §60.692-6.</p> <p>Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in §60.692-6.</p> <p>Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.</p>	<p>Compliance with the requirements §§60.692-1 to 60.692-5 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.696.</p> <p>Where a flare is used for VOC emission reduction, the owner or operator will comply with the monitoring requirements of 40 CFR60.18(f)(2).</p> <p>Where a VOC recovery device other than a carbon absorber is used to meet the requirements of §§60.692-5(a), the owner or operator will provide the administrator with information describing the operation of the control device and the process parameter(s) that would indicate proper operation and maintenance of the device.</p>	None applicable for proposed cogeneration plant.	<p>Each owner or operator of a facility subject to the provisions of this subpart shall comply with the following recordkeeping requirements. All records shall be retained for a period of 2 years after being recorded, unless otherwise noted.</p> <p>For individual drain systems subject to §60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.</p> <p>For junction boxes subject to §60.692-2, the location, date, and corrective action shall be recorded for inspections required by §60.692-2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.</p> <p>Recordkeeping requirements associated with repair of emission points are listed below:</p> <p>If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.</p> <p>The reason for the delay as specified in §60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.</p> <p>The signature of the owner or operator (or designee) whose decision it was that repair could not be affected without refinery or process shutdown shall be recorded.</p> <p>The date of successful repair or corrective action shall be recorded.</p> <p>Other information that must be maintained under this subpart is listed below:</p> <p>A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location, including detailed schematics, and piping and instrumentation diagrams; the dates and descriptions of any changes in the design specifications.</p> <p>An owner or operator electing to comply with the provisions of §60.693 shall notify the Administrator of the alternative standard selected in the report required in §60.7.</p> <p>Each owner or operator of a facility subject to this subpart shall submit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards.</p> <p>Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.</p> <p>A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to the Administrator.</p> <p>If compliance with the provisions of this subpart is delayed pursuant to §60.692-7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.</p>

**Table 5-2**  
**MACT Standards Applicable to the Proposed Hawaii Refinery Energy Project**

Requirement	Basis for Applicability	Standards	Monitoring Requirements	Test Methods and Procedures	Reporting/Recordkeeping
<b>40 CFR Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)</b>					
Subpart A: General Provisions, §§ 63.1-63.16	Applies to units that are subject to the following Category-Specific NESHAP Subparts	Presents general guidance for complying with all of the other applicable NSPS subparts below, including definitions and units, prohibition against circumvention, preconstruction review and notification requirements pertaining to hazardous air pollutants, general requirements for compliance and maintenance, performance testing, monitoring, notification, recordkeeping, reporting and control devices. Detailed requirements for specific equipment are summarized in the applicable MACT subparts below.			

**Table 5-2**  
**MACT Standards Applicable to the Proposed Hawaii Refinery Energy Project**

Requirement	Basis for Applicability	Standards	Monitoring Requirements	Test Methods and Procedures	Reporting/Recordkeeping
Subpart CC: National Emission Standards From Petroleum Refineries, §§ 63.640-63.655	Applies to leaks from piping components at a refinery that is a major source of Hazardous Air Pollutants and emits one or more of the HAPs listed in Table 1 of this Subpart. This subpart potentially applies to the new cogeneration plant's compressor(s) and liquid fuel system. Emissions associated with refinery gas fuel systems are exempted.	<p>Pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, or instrumentation systems that are added to an existing source are subject to the equipment leak standards for existing sources in §63.648.</p> <p>Performance tests and compliance determinations shall be conducted only according to the schedule and procedures specified in this subpart.</p> <p>A source subject to the requirements of this subpart shall control emissions of organic HAPs to the allowable level represented by the equation in §63.642(g).</p> <p>A source subject to the provisions of this subpart shall comply with the provisions of 40 CFR part 60 subpart VV and §63.648(b), or alternatively, the requirements of §§63.161 through 63.169, 63.171, 63.172, 63.175, 63.176, 63.177, 63.179, and 63.180 of subpart H, except as specified below.</p> <p>For purposes of compliance with this section, the provisions of 40 CFR 60, subpart VV apply only to equipment in organic HAP service, as defined in this subpart.</p> <p>Calculation of percentage leaking equipment components for subpart VV of 40 CFR part 60 may be done on a process unit basis or a source-wide basis.</p> <p>Upon startup of new sources, the owner or operator shall comply with §63.163(a)(1)(ii) of subpart H of this part for light liquid pumps and §63.168(a)(1)(ii) of subpart H of this part for gas/vapor and light liquid valves.</p> <p>Upon startup of new sources, the owner or operator shall comply with §63.163(a)(1)(ii) of subpart H of this part for light liquid pumps and §63.168(a)(1)(ii) of subpart H of this part for gas/vapor and light liquid valves.</p>	<p>Monitoring data must meet the test methods and procedures specified in §60.485(b) of 40 CFR part 60, subpart VV or §63.180(b)(1) through (b)(5) of subpart H of this part except for minor departures.</p> <p>The monitoring frequency for valves depends on whether the facility elects to monitor connectors as well.</p>	<p>Performance tests shall be conducted according to the provisions of §63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process.</p> <p>The instrument readings that define a leak for light liquid pumps subject to §63.163 of subpart H of this part and gas/vapor and light liquid valves subject to §63.168 of subpart H of this part are: 10,000 ppm, 5000 ppm and 2,000 ppm for Phase I, II, III equipment, respectively.</p> <p>Connectors in gas/vapor service or light liquid service are subject to the requirements for connectors in heavy liquid service in §63.169 of subpart H. The leak definition for valves, connectors, and instrumentation systems subject to §63.169 is 1,000 parts per million.</p>	<p>Reports that are required for affected equipment under this subpart include:</p> <p>The Notification of Compliance Status report as required by §63.654(f) for the emission points that were added or changed;</p> <p>Periodic Reports and other reports as required by §63.654 (g) and (h);</p> <p>Reports and notifications required by sections of 40 CFR 63 Subpart A that are applicable to this subpart, as identified in table 6 of this subpart.</p> <p>Reports and notifications required by §63.182, or 40 CFR 60.487.</p> <p>Reports required by §61.357 of subpart FF;</p> <p>Reports and notifications required by §63.428 (b), (c), (g)(1), and (h)(1) through (h)(3) of 40 CFR 63 Subpart R.</p> <p>Reports and notifications required by §63.567 of 40 CFR 63 subpart Y.</p> <p>The owner or operator of a source subject to this subpart must maintain all records and keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in this subpart. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours.</p> <p>Each owner or operator subject to the equipment leaks standards in §63.648 shall comply with the following recordkeeping and reporting provisions:</p> <p>Sections 60.486 and 60.487 of subpart VV of part 60 except as specified in paragraph (d)(1)(i) of this section; or §§63.181 and 63.182 of subpart H of this part except for §§63.182(b), (c)(2), and (c)(4).</p> <p>The signature of the owner or operator (or designate) whose decision it was that a repair could not be effected without a process shutdown is not required to be recorded. Instead, the name of the person whose decision it was that a repair could not be effected without a process shutdown shall be recorded and retained for 2 years.</p> <p>The Notification of Compliance Status report required by §63.182(c) of subpart H and the initial semiannual report required by §60.487(b) of 40 CFR part 60, subpart VV shall be submitted within 150 days of the compliance date specified in §63.640(h); the requirements of subpart H of this part are summarized in table 3 of this subpart.</p> <p>An owner or operator must keep a list of identification numbers for valves that are designated as leakless per §63.648(c)(10).</p> <p>An owner or operator must identify, either by list or location (area or refining process unit), equipment in organic HAP service less than 300 hours per year within refining process units subject to this subpart.</p> <p>An owner or operator must keep a list of reciprocating pumps and compressors determined to be exempt from seal requirements as per §§63.648 (f) and (i).</p> <p>The owner or operator of a source subject to this subpart shall submit Periodic Reports no later than 60 days after the end of each 6-month period when any of the compliance exceptions specified in paragraphs (g)(1) through (g)(6) of this section occur. The first 6-month period shall begin on the date the Notification of Compliance Status report is required to be submitted. A Periodic Report is not required if none of the compliance exceptions specified in paragraphs (g)(1) through (g)(6) of this section occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emissions averages, as provided in paragraph (g)(8) of this section. An owner or operator may submit reports required by other regulations in place of or as part of the Periodic Report required by this paragraph if the reports contain the information required by paragraphs (g)(1) through (g)(8) of this section.</p> <p>Other reports shall be submitted as specified in subpart A of this part as follows:</p> <p>Reports of startup, shutdown, and malfunction required by §63.10(d)(5).</p> <p>Records and reports of startup, shutdown, and malfunction are not required if they pertain solely to Group 2 emission points, as defined in §63.641.</p>

**Table 5-2**  
**MACT Standards Applicable to the Proposed Hawaii Refinery Energy Project**

Requirement	Basis for Applicability	Standards	Monitoring Requirements	Test Methods and Procedures	Reporting/Recordkeeping
Subpart YYYY: National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, §§ 63.6080-63.6175	<p>Applies to any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions.</p> <p>The Hawaii Refinery is a major source of HAPs.</p> <p>The definition of new stationary combustion turbine in this subpart applies to the proposed cogeneration turbines, because their construction will commence after January 14, 2003.</p> <p>The proposed turbine will not be any of the combustion turbine types exempted by §63.6090(b).</p> <p>Per § 63.6092, duct burners and waste heat recovery units are considered steam generating units and are not covered by subpart YYYY.</p>	<p>A new stationary combustion turbine which is a lean premix oil-fired stationary combustion turbine or a diffusion flame oil-fired stationary combustion turbine must comply with the emissions limitations and operating limitations in this subpart upon startup.</p> <p>Each new stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart, must comply with the emission limitations of 91 ppbvd or less at 15% oxygen.</p> <p>The owner or operator of a combustion turbine subject to this subpart must:</p> <p>operate within the above emission limitations and operating limitations at all times except during startup, shutdown, and malfunctions, and operate and maintain the combustion turbine, oxidation catalyst emission control device or other air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.</p> <p>Performance tests to demonstrate initial compliance demonstrations with the formaldehyde emission limit must be conducted within 180 calendar days after startup.</p> <p>Subsequent performance tests must be performed on an annual basis</p>	<p>Requirements for Performance Tests and Initial Compliance Demonstrations are specified in Table 3 of this subpart, including all required test methods and sampling conditions.</p> <p>Each performance test must be conducted according to the requirements of the General Provisions at §63.7(e)(1) of Subpart A and under the specific conditions in Table 2 of this subpart. Each test must include three separate test runs and each test run must last at least 1 hour. Performance tests must be conducted at 100 percent load plus or minus 10 percent.</p> <p>The operator of a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and uses an oxidation catalyst must monitor the catalyst inlet temperature on a continuous basis in order to comply with the operating limitations.</p> <p>Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), all parametric monitoring required under this subpart must be conducted at all times the stationary combustion turbine is operating.</p> <p>In some cases, it may be difficult to separately monitor emissions from the turbine and duct burner, so sources are allowed to meet the required emission limitations with their duct burners in operation</p>	<p>- The test methods applicable this subpart are:</p> <p>Stack formaldehyde concentration by Method 320 of 40 CFR 63, Appendix A or ASTM D6348-03, or another method approved by EPA.</p> <p>Sampling port and traverse points by Method 1 or 1a of 40 CFR 60, Appendix A.</p> <p>Oxygen concentration at the sampling port by Method 3a or 3b of 40 CFR 60, Appendix A.</p> <p>Moisture at the sampling port location for purposes of corrected formaldehyde concentration to a dry basis by Method 4 of 40 CFR 60, Appendix A or Method 320 of 40 CFR 603 Appendix A.</p>	<p>Sources subject to this subpart must meet the notification requirements in §63.6145 according to the schedule in §63.6145 and in 40 CFR Part 63, subpart A.</p> <p>The owner or operator of a combustion turbine subject to this subpart must keep the following records:</p> <p>A copy of each notification and report that was submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status.</p> <p>Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii) of Subpart A.</p> <p>Records of the occurrence and duration of each startup, shutdown, or malfunction.</p> <p>Records of the occurrence and duration of each malfunction of the air pollution control equipment, if applicable.</p> <p>Records of all maintenance on the air pollution control equipment.</p> <p>The operator of a stationary combustion turbine that is subject to the formaldehyde emission limitation is required to report the unit's compliance status semiannually according to the requirements of §63.6150.</p> <p>Each instance in which an affected unit did not meet an emission limitation or operating limitation must be reported. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements of §63.6150.</p> <p>The owner or operator of a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report containing the following information:</p> <p>Company name and address.</p> <p>Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.</p> <p>Date of report and beginning and ending dates of the reporting period.</p> <p>Information on the cause, duration and corrective action taken for each deviation from an emission limitation,</p>

**Table 5-2**  
**MACT Standards Applicable to the Proposed Hawaii Refinery Energy Project**

Requirement	Basis for Applicability	Standards	Monitoring Requirements	Test Methods and Procedures	Reporting/Recordkeeping
Subpart DDDDD: : National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters	<p>Applies to new, reconstructed or existing industrial commercial and institutional boilers and process heaters within a subcategory located at a major source of HAPs.</p> <p>The Hawaii Refinery is a major source of HAPs.</p> <p>The proposed Energy Project boilers will belong to the Large Liquid Fuel category, because they will be watertube boilers that do not burn any solid fuel and will burn any liquid fuel either alone or in combination with gaseous fuels, have a rated capacity greater than 10 MMBtu/hour heat input and have an annual capacity factor of greater than 10 percent.</p>	<p>Emission limits and work practice standards applicable to new or reconstructed Large Liquid Fuel boilers are subject to the following requirements:</p> <p>Particulate matter: 0.03 lb/MMBtu heat input</p> <p>Hydrogen Chloride: 0.0009 lb/MMBtu heat input</p> <p>Carbon Monoxide: 400 ppm by volume on a dry basis corrected to 3% O<sub>2</sub> (3-run average for units less than 100 MMBtu/hr)</p> <p>New boilers with particulate matter limits must maintain opacity to less than or equal to 10 percent opacity (1- hour block average).</p>	<p>New boilers rated at less than 100 MMBtu/hour with particulate matter limits must install, operate, certify and maintain a continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of 40 CFR 63.7525.</p> <p>New boilers with hydrogen chloride emission limits must maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to § 63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride.</p> <p>New boilers rated at least than 100 MMBtu/hour with CO emission limits must conduct initial and annual source testing to demonstrate compliance with such limits.</p>	<p>Method 5 or 17 for particulate matter emissions testing.</p> <p>SW-846-9520 or ASTM E776-87 for determining hydrogen chloride emissions from fuel analysis testing</p> <p>Method 10. 10A, or 10 B in Appendix A to 40 CFR Part 60.for Carbon Monoxide stack testing</p>	<p>Semiannual compliance reports, including the following information, as applicable.</p> <p>Company name and address</p> <p>.Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.</p> <p>Date of report and beginning and ending dates of the reporting period.</p> <p>The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.</p> <p>A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.</p> <p>A signed statement indicating no new types of fuel were burned. Or, if a new type of fuel, was burned, a calculation must be submitted of HCl emission rate using Equation 9 of §63.7530 that demonstrates that the affected unit is still meeting the emission limit for HCl emissions.</p> <p>Information on any startup, shutdown, or malfunction during the reporting period and confirmation that actions consistent with the startup/shutdown/malfunction plan were taken.</p> <p>If there are no deviations from any applicable emission limits or operating limits and no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period is required.</p> <p>If there were no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out of control during the reporting period is required..</p> <p>A startup, shutdown or malfunction report for each instance of an unplanned startup, shutdown or malfunction during which an applicable emission limit was exceeded – to be reported by telephone or fax within two working days and to be reported in writing within 7 days of the end of the event unless other arrangements have been made with the permitting authority.</p>

## SECTION 6 REFERENCES

U.S. Environmental Protection Agency, 1995 User's Guide for the Industrial Source Complex (ISC3) Dispersion Models, Office of Air Quality Planning and Standards, Emissions, Monitoring and Analysis Division, Research Triangle Park, North Carolina, September 1995.

U.S. Environmental Protection Agency, 2002 Industrial Source Complex Short-Term Model, Version 02035, February 4, 2002 on <http://www.epa.gov/ttn/scram>.





**STANDARD PERMIT APPLICATION FORM**

HAWAII DEPARTMENT OF HEALTH  
 ENVIRONMENTAL MANAGEMENT DIVISION  
 CLEAN AIR BRANCH

P.O. Box 3378 · Honolulu, HI 96801-3378 · Phone: (808) 586-4200

1. Company Name: **Chevron USA Products Company, a Division of ChevronTexaco Corp.**
2. Facility Name (if different from the Company): **Chevron Hawaii Refinery**
3. Mailing Address: **91-480 Malakole Street**  
 City: **Kapolei** State: **HI** Zip Code: **96707**  
 Phone Number: **(808) 682-5711**
4. Name of Owner/Owner's Agent: **David E. Rogers**  
 Title: **Refinery Manager** Phone: **(808) 682-5711**  
 Mailing Address: **91-480 Malakole Street**  
 City: **Kapolei** State: **HI** Zip Code: **96707**
5. Plant Site Manager/Other Contact: **David E. Rogers**  
 Title: **Refinery Manager** Phone: **(808) 682-5711**  
 Mailing Address: **91-480 Malakole Street**  
 City: **Kapolei** State: **HI** Zip Code: **96707**
6. Permit Application Basis: (Check One.)  
 Initial Permit for a New Source       Initial Permit for an Existing Source  
 Renewal of Existing Permit       General Permit  
 Temporary Source      Transfer of Permit  
 Modification: ==>> Is Modification?       Significant  Minor  Uncertain
7. If renewal or modification, include existing permit number: **CSP No. 0088-01-C**
8. Does the Proposed Source require a County Special Management Area Permit?       Yes  No
9. Type of Source (Check One):       Covered Source       Covered and PSD Source  
 Noncovered Source       Uncertain
10. Standard Industrial Classification Code (SICC), if known: **2911**

11. Proposed Equipment/Plant Location: **Chevron Hawaii Refinery**  
 City: **Kapolei** State: **Hi** Zip Code: **96707**  
 UTM Coordinates: **East-591,657 meters/ North-2,357,127 meters**
12. General Nature of Business: **Petroleum Refining**
13. Date of Planned Commencement of Construction or Modification: **February, 2007**
14. Is **any** of the equipment to be leased to another individual or entity?  Yes  No
15. Type of Organization:  Corporation  Individual Owner  Partnership  
 Government Agency (Government Facility Code) \_\_\_\_\_  
 Other: \_\_\_\_\_

*Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the non-covered source permit or release of a draft covered source permit. (§11-60.1-6)*

**RESPONSIBLE OFFICIAL**

(as defined in §11-60.1-1):

Name (Last): **Rogers** (First): **David** (MI): **E.**  
 Title: **Refinery Manager** Phone: **(808) 682-5711**  
 Mailing Address: **91-480 Malakole Street**  
 City: **Kapolei** State: **HI** Zip Code: **96707**

**CERTIFICATION by Responsible Official**

(pursuant to §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution control, and any permit issued thereof.

NAME (Print/Type): **David E. Rogers**  
 (Signature): \_\_\_\_\_ Date: \_\_\_\_\_

<p><b>FOR AGENCY USE ONLY:</b>          File/Application No.: _____          Island: _____          Date Received: _____</p>
--

**Fill in the *Emissions Units Table* as completely as possible. Use separate sheets of paper as applicable. General instructions are provided below:**

1. *Identify each emission point with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SIC Code. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirement of Chapter 60.1. Example of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations are O.K.*
  - a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service Number (CAS#).
  - b. Indicate the emission points that discharge together for any length of time.
2. *Provide a process flow diagram identifying all equipment used in the process, including the following:*
  - a. Emission points.
  - b. Locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.
3. *Describe all points of emissions identified in number 2 above.*
4. *Maximum emission rates shall be in such terms as necessary to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:*
  - a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO<sub>x</sub>), Sulfur Dioxide (SO<sub>2</sub>), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM<sub>10</sub>). Abbreviations are O.K.
  - b. Include fugitive emissions.
  - c. Pounds per hour (#/HR) is the maximum potential emission rate expected by applicant.
  - d. Tons per year is annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.
5. *Provide a facility location map, drawn to a reasonable scale and showing the following:*
  - a. The property involved and all structures on it. Identify property/fence lines plainly.
  - b. Layout of the facility.
  - c. Location and identification of the proposed emissions unit on the property.
  - d. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 325 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.
6. *Supply additional information as follows, if applicable:*
  - a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the Equipment Description.
  - b. For a rectangular stack, indicate the length and width.
  - c. Any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Act.

COMPANY NAME: Chevron USA Product Company, Hawaii Refinery

LOCATION: Kapolei

COMPANY NAME: Chevron USA Product Company, Hawaii Refinery

LOCATION: Kapolei

File No.:

PAGE 1 OF 1

File No.:

PAGE 1 OF 1

**EMISSIONS UNITS TABLE**

REVIEW OF APPLICATIONS AND ISSUANCE OF PERMITS WILL BE EXPEDITED BY SUPPLYING ALL NECESSARY INFORMATION ON THIS TABLE.

STACK NO.	UNIT NO.	EQUIPMENT NAME/DESCRIPTION and SIC Code	EQUIP. DATE (1)	REGULATED/HAZARDOUS AIR POLLUTANT NAME (CAS#)	#/HR.	TONS/YR.	ZONE	EAST (mtrs)	NORTH (mtrs)	HEIGHT ABOVE GROUND (mtrs)	DIRECT (2)	INSIDE DIA. (mtrs)	VEL. (m/s)	ACTUAL FLOW RATE (m <sup>3</sup> /s)	TEMP. (° K)
	CTG/HRSG	Cogeneration Turbine with HRSG and Duct Firing		PM10	1.06	4.66		591807	2357071	24.99	Up	1.8	9.31	24.46	464.26
				SO2	2.3	10.08									
				CO	15	65.70									
				NOx	12.8	60.0									
				VOC	6.95	30.4									
				Total HAPS		0.83									
	RENBOIL1	Rentech Boiler1		PM10	2.77	12.3		591796	2357076	22.28	Up*	62.2*	0.001*	2.79	446
				SO2	17.19	75.3									
				CO	4.25	18.6									
				NOx	16.45	72.06									
				VOC	0.37	1.62									
				Total HAPS		0.66									

STACK NO.	UNIT NO.	EQUIPMENT NAME/DESCRIPTION and SIC Code	EQUIP. DATE (1)	REGULATED/HAZARDOUS AIR POLLUTANT NAME (CAS#)	#/HR.	TONS/YR.	ZONE	EAST (mtrs)	NORTH (mtrs)	HEIGHT ABOVE GROUND (mtrs)	DIRECT. (2)	INSIDE DIA. (mtrs)	VEL. (m/s)	ACTUAL FLOW RATE (m³/s)	TEMP. (° K)
	RENBOIL2	Rentech Boiler2		PM10		12.3		591780	2357068	22.28	Up*	62.2*	0.001*	2.79	446
				SO2											
				CO											
				NOx											
				VOC											
				Total HAPS		0.66									
	FWBOIL1	Foster Wheeler Boiler1		PM10	2.66	11.7		591796	2357082	24.99	Up	0.905	17.65	11.35	449
				SO2	22.14	96.99									
				CO	6.82	30									
				NOx	16.74	73.31									
				VOC	0.44	1.93									
				Total HAPS		0.57									
	FWBOIL2	Foster Wheeler Boiler1		PM10	2.66	11.7		591780	2357074	24.99	Up	0.905	17.65	11.35	449
				SO2	22.14	96.99									
				CO	6.82	30.0									
				NOx	16.74	73.31									
				VOC	0.44	1.93									
				Total HAPS		0.97									

(1) Date of Equipment Construction, Reconstruction, or Modification. Provide supporting documentation.

(2) Exit direction of stack emissions: up, down, or horizontal.

\* Rentech stack emission is physically vertical however due to rain caps, stack parameters have been altered as reflected.

# APPENDIX B

## Vendor Equipment Specifications and Supporting Emissions Calculations

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# APPENDIX C

Completed DOH Forms C-1 (Compliance Plan) and  
C-2 (Compliance Certification)

---

**COMPLIANCE PLAN**

The Responsible Official shall submit a Compliance Plan with the following permit applications, and at such other times as requested by the director.

- Initial Noncovered Source Permit Application
- Initial Covered Source Permit Application
- Temporary Noncovered Source Permit Application
- Temporary Covered Source Permit Application
- General Noncovered Source Permit Application
- General Covered Source Permit Application
- Application for a Noncovered Source
- Application for a Covered Source Permit Renewal
- Application for a Modification to a Covered Source
- Application for a Significant Modification to a Covered Source

1. Compliance status with respect to all Applicable Requirements:

Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

YES            {If YES, complete items a and c below }

NO                {If NO, complete items a-c below }

a. Identify all applicable requirement(s) for which compliance is achieved:

*Please refer to Section 5 of Significant Modification Application.*

\_\_\_\_\_

Provide a statement that the source is in compliance and will continue to comply with all such requirements.

*The source is in compliance and will continue to comply with all such requirements.*

\_\_\_\_\_

\_\_\_\_\_

b. Identify all applicable requirement(s) for which compliance is NOT achieved:

*None*

\_\_\_\_\_



Provide a detailed Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements. Use separate sheets of paper, if necessary.

Description of Remedial Action

Expected Date of Completion

*Not applicable*

*Not applicable*

- c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to. These applicable requirements may be in effect AFTER permit issuance:

Effective  
Applicable Requirement

Date

Currently in  
Compliance?

*Will be compliant with 40 CFR 60 Subpart KKKK, Performance Standards for Combustion Turbines, from the commencement of new cogeneration plant operations. The NSPS has been proposed, but is not yet in effect. However, combustion turbines for which construction commences after February 18, 2005 will be subject to the eventual final rule.*

If the source is not currently in compliance, submit a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

Description of  
Proposed Action/Steps  
to Achieve Compliance

Expected Date  
of Achieving  
Compliance

*Will install monitoring equipment and perform testing, as required to demonstrate compliance with 40 CFR 60 Subparts GG and KKKK and 40 CFR 63 Subpart YYYY, and will be compliant with these requirements from the commencement of operations for the new cogeneration plant*

Provide a statement that the source on a timely basis will meet all these applicable requirements.

*The source on a timely basis will meet all applicable requirements.*

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of all remedial actions and the expected dates of completion.

Description of Remedial Action

Expected Date of Completion

*Not applicable*

2. Compliance Progress Reports:

a. If a compliance plan is being submitted to remedy a violation, complete the following information:

*Not applicable*

Frequency of Submittal:

Beginning Date:  
(less than or equal to 6 months)

\_\_\_\_\_

b. Date(s) that the Action described in (1)(b) was achieved:

Remedial Action

Date Achieved

*Not applicable*

\_\_\_\_\_

\_\_\_\_\_

c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

*Not applicable*

\_\_\_\_\_

***Certification of Compliance with all Applicable Requirements:***

This certification must be signed by a Responsible Official. Applications without a signed certification will be deemed incomplete.

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): **David E. Rogers, Refinery Manager**

(Signature): \_\_\_\_\_ Date: \_\_\_\_\_

File No.: \_\_\_\_\_

## **COMPLIANCE CERTIFICATION**

The Responsible Official shall submit a Compliance Certification with the following covered source permit applications, and at such other times as requested by the director.

- Initial Covered Source Permit Application;
- Temporary Covered Source Permit Application;
- General Covered Source Permit Application;
- Application for a Covered Source Permit Renewal; and
- Application for a Significant Modification to a Covered Source.

COMPLETE & SUBMIT THIS COVER PAGE AND SECTION A OF THIS FORM.

---

### ***Certification of Compliance with all Applicable Requirements:***

This certification must be signed by a Responsible Official. Applications without a signed certification will be deemed incomplete.

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution control, and any permit issued thereof.

Name (Print/Type): **David E. Rogers, Refinery Manager** \_\_\_\_\_

(Signature): \_\_\_\_\_ Date: \_\_\_\_\_

Complete the following information for **each** applicable requirement and/or term or condition of the permit that applies to **each** emissions unit at the source. Also include any additional information as required by the director. The compliance certification may reference information contained in a previous compliance certification submittal to the director, provided such referenced information is certified as being current and still applicable. **[Need to check information required by this form more thoroughly]**

**A. For compliance certifications submitted with any covered source permit application.**

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: **Annual** Beginning Date: \_\_\_\_\_

2. Emissions Unit No./Description: \_\_\_\_\_

3. Identify the applicable requirement(s) that is/are the basis of this certification: \_\_\_\_\_

**Please refer to Section 5 of Significant Modification Application**

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

**YES**       NO

b. If YES, will compliance be continuous or intermittent?

**Continuous**       Intermittent

c. If NO, explain.

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

5. The methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

**Please refer to the current Covered Source Permit and Section 5 of the Significant Modification Application**

\_\_\_\_\_  
\_\_\_\_\_  
\_\_\_\_\_

Provide a detailed description of the methods used to determine compliance: (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.)

---

**Please refer to the current Covered Source Permit and Section 5 of the Significant Modification Application**

---

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES

NO

b. If YES, identify the requirements and the provisions being taken to achieve compliance:

---

***A continuous emissions monitoring system (CEMS) for NO<sub>x</sub> will be installed on the stacks of the cogeneration combustion turbines/HRSGs pursuant to 40 CFR 60 Subpart GG (water injection control measure). The CEMS is required to meet EPA performance specifications in 40 CFR 60.13 and 40 CFR 60, Appendix B, as well as the submittal requirements of 40 CFR 64.4.***

---

c. If NO, describe below which requirements will not be met:

---

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---

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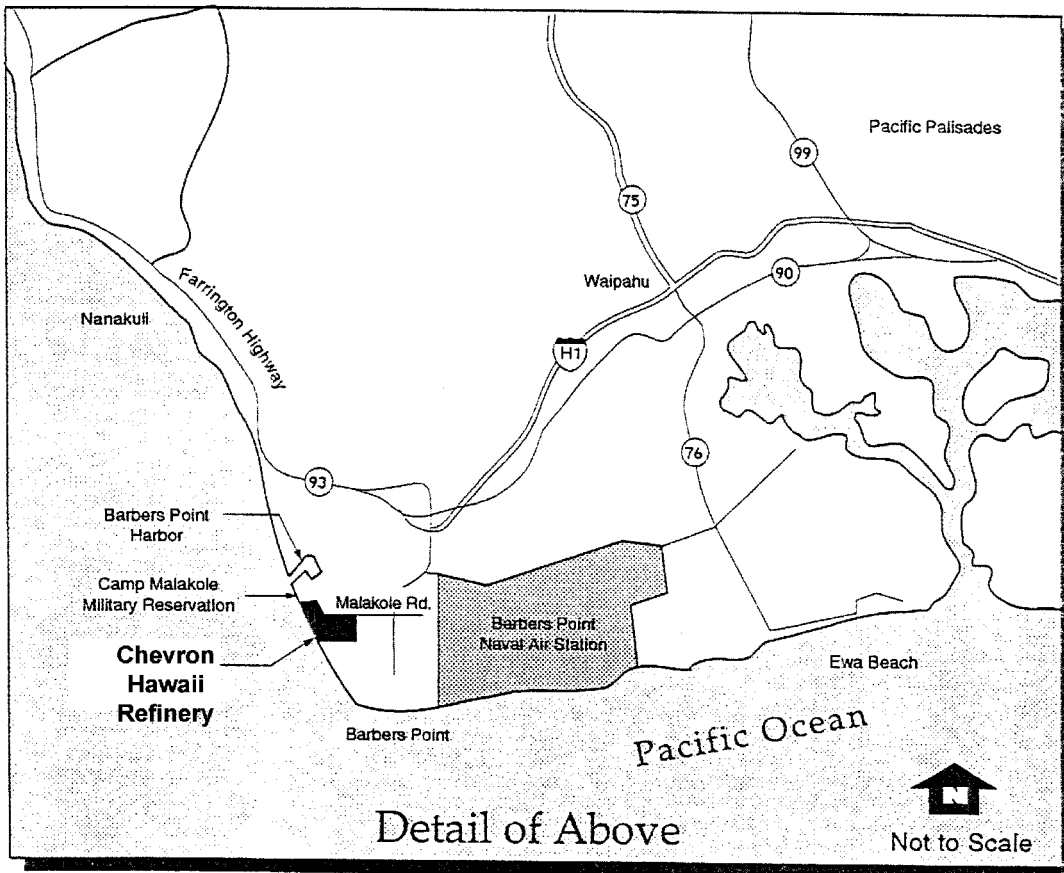
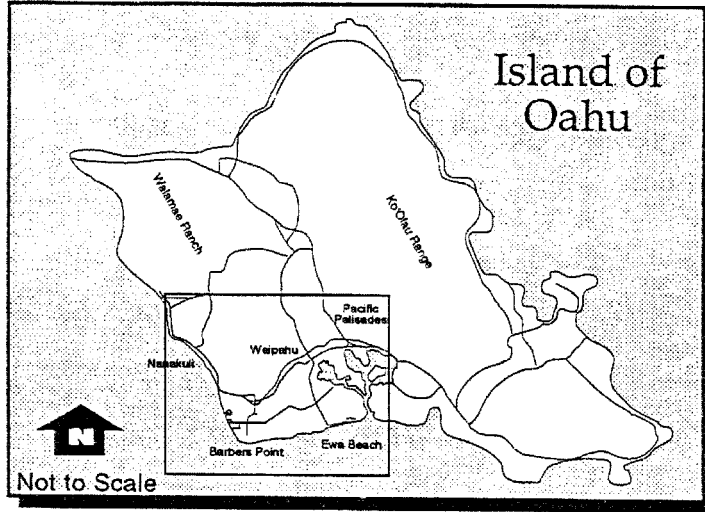
**FOR AGENCY USE ONLY:**

File/Application No.: \_\_\_\_\_

Island: \_\_\_\_\_

Date Received: \_\_\_\_\_





SITE VICINITY MAP  
CHEVRON HAWAII REFINERY

**URS**

CHECKED BY:

DATE: MAY 2003

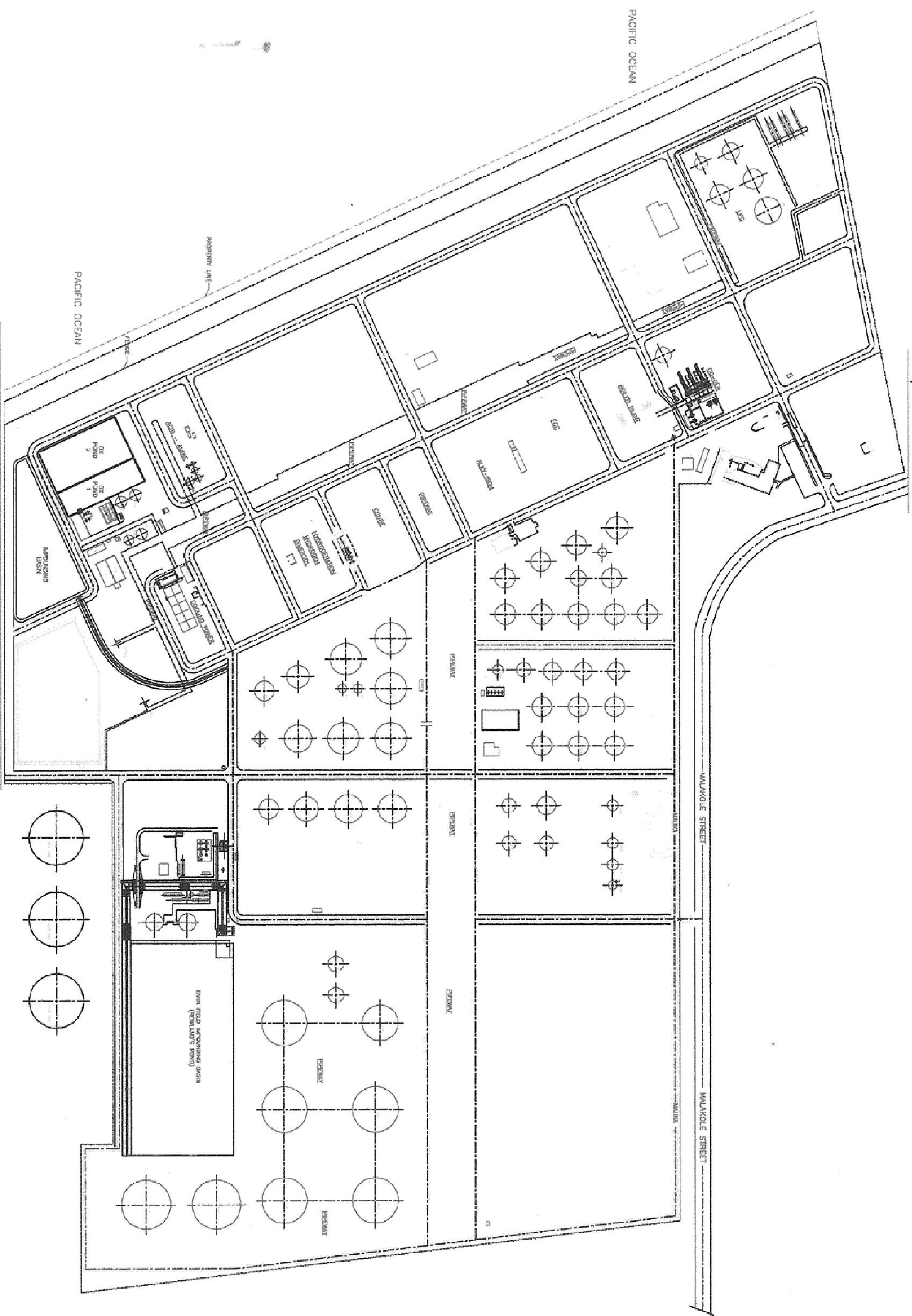
FIG. NO:

PM: JL


PROJ. NO: 27654009.01000

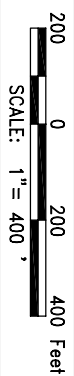
1-1





**PLOT PLAN**  
**CHEVRON HAWAII REFINERY**





<b>UPRS</b>	CHECKED BY: _____	DATE: 5-20-03	FIG. NO: <b>1-2</b>
	CHECKED BY: PM: JL	PROJ. NO: 27654009.01000	

# PERFORMANCE AND DATA

16 February 2006 No.: 9452

## **2.1.2 Performance Guarantee**

Subject to the conditions as listed in Section 2.1.1 (Performance Guarantee Basis) of this proposal, Deltak makes the following performance guarantees. Should the conditions listed in Section 2.1.1 change, the performance guarantees listed below shall change accordingly. The performance test procedure to determine whether the guarantees have been met must be mutually agreed upon at least 90 days prior to running the test. This test must be run within the first 3 months of operation with the HRSG in a clean and like new condition.

### **Liquid Naphtha (LSR) Fueled Gas Turbine / Refinery Fuel Gas (RFG) Fired HRSG System:**

1. The boiler will generate 57,889 pounds per hour of 585°F ( $\pm 10^\circ\text{F}$ ) superheated steam at 600 psig at the non-return valve outlet.
2. The total gas-side system pressure drop, from the turbine exhaust outlet expansion joint to the stack exit, when operating at the above conditions, will not exceed 6 inches W.C.
3. The duct burner heat release at this operating point is 44.6 MMBtu/Hr (LHV).
4. The water carryover from the steam drum will not exceed 0.016%.

# PERFORMANCE AND DATA

## 16 February 2006 No.: 9452

Sheet 2 of 2

Purchaser: ANVIL CORP		Date:			Des: SBE	
For: CHEVRON		Type: Split Dino 4F5-2012-2008-SE			Proj:	
Plant Site: KAPOLEI, HAWAII		Drawing No:			Drawn:	
Purchasers Reference: BE8725		Deltak Ref: 9452			Est:	
Centaur 40 (LSR) ZERO BLOWDOWN, 250°F FEED WATER TEMPERATURE						
UNIT		BOILER #1	CO/SCR SPOOL	BOILER #2	ECONOMIZER	OUTLET STACK
<b>HEATING SIDE DATA:</b>						
Fluid		TEG	TEG	TEG	TEG	TEG
Fouling factor	hr-ft <sup>2</sup> ·°F/Btu	0.0020		0.0020	0.0020	
Flow rate	lb/hr	147579	147579	147579	147579	147579
Design pressure	inH2Og	20	20	20	20	
Pressure drop	inH2O	3.3	0	1.0	0.3	0
Inlet temperature	°F	1750	752	752	547	376
Outlet temperature	°F	752	752	547	376	
Temperature drop (rise)	°F	998	0	205	171	
Ave. Spec. heat	Btu/lbm·°F	0.290		0.269	0.262	
Heat released	MBtu/hr	42.73		8.13	6.63	
Suppl fuel (Ave. RFG)	lb/hr					
Efficiency	%	99.0		99.0	99.0	
Flow Pattern					COUNTER	
<b>COOLING SIDE DATA:</b>						
Fluid		SAT. STEAM		SAT. STEAM	WATER	
Fouling factor	hr-ft <sup>2</sup> ·°F/Btu	0.0010		0.0010	0.0010	
Flow rate	lb/hr	48639		9250	57889	
Design pressure	psig	700		700	775	
Inlet pressure	psig	630		630	715	
Outlet pressure	psig	630		630	628	
Pressure drop	psi	0		0	87	
Design temperature	°F	720		600	530	
Inlet temperature	°F	494		494	250	
Outlet temperature	°F	494		494	360	
Temperature rise (drop)	°F	0		0	110	
Ave. Spec heat	Btu/lbm·°F					
Heat absorbed	MBtu/hr	42.30		8.04	6.56	
Cont. blow-down	%					
<b>EQUIPMENT DATA:</b>						
Heating surface	ft <sup>2</sup>	7465		8557	8399	
Tube diameter X min thkns	in	2.00 x .105		2.00 x .105	2.00 x .105	
Tube length (nominal)	ft	7.2		9.1	7.8	
Tube material		SA-178A		SA-178A	SA-178A	
Sections / Circuits		20		20	28 / 2	
Spacing transv to flow	in	4.50		4.50	4.50	
No. in direction of flow		12		8	8	
Spacing in dir. of flow	in	4.50		4.50	4.50	
Tube Arrangement		Staggered		Staggered	Inline	
Fin type		*5/32" SEG		5/32" SEG	5/32" SEG	
Fin #/in. X height X thkns	in	*		5.0x.75x.05	4.0x.75x.05	
Fin material		409SS		CS	CS	
Drum/Hdr number X diameter	in	48/30		2 X 24	2 X 4	
Drum/Hdr length (nominal)	ft					
Drum/Hdr material		SA-516-70		SA-516-70	SA-106B	
Steam purity	TDS, PPM					

\* 2 ROWS BARE TUBES, 2 ROWS 5.0x.625x.05, 8 ROWS 5.0x.75x.05

# DESCRIPTION

16 February 2006 No.: 9452

## Ductwork

A complete set of ductwork is included as shown. This includes inlet ducting from the gas turbine outlet to the HRSG, firing duct, and a duct for future installation of catalyst (by others.) The attached insulation and casing schedule lists the materials of construction.

## Expansion Joints

Two (2) flat-belt assembled expansion joints with composite fabric are included. The expansion joint connected to Boiler #1 will be designed for 800°F and 20" W.C. pressure complete with 7 ga. carbon steel liner / baffle and ceramic insulation pillow. The joint between the boiler and economizer modules is designed for 600°F and 20" W.C. pressure complete with carbon steel liner. Sketches of typical expansion joint cross-sections are included for reference.

## Controls – Not Included

A boiler control panel is not included. The boiler controls, including boiler safety features, firing rate control and three-element drum level/feed water control are to be provided by others. A separate Burner Management System panel is included as described in the Duct Burner description.

## Interconnecting Piping

One complete set of piping for interconnecting the various heat recovery steam generator sections is included. Piping 2-1/2" and larger will be supplied prefabricated in reasonable shipping and handling lengths. The piping will be left unpainted. Field connections will be flanged joints. Installation and insulation of this piping will be done in the field by others.

## Main Outlet Stack

A 6-ft. diameter carbon steel main outlet stack to 82 feet above grade is included. Ports for EPA emissions testing and a CEMS probe are included.

## Walkways and Ladders

Walkways and ladders providing access to the steam drum ends, along the length of the steam drum, the economizer upper header area, and to the main stack sampling platform are included, as shown in the Walkway Layout drawings.

## Duct Burner – John Zink Company

One burner system for firing refinery fuel gas with a maximum heat release of 48.7 MMBtu/Hr Net LHV for gas turbine exhaust, including fuel piping skid and flame safety system designed in accordance with NFPA 85 for single burner operation is included. The burner is capable of 10:1 turndown. The entire system is suitable for Class 1, Division 2, Group B/C/D hazardous location. The proposed system includes:

- I. Burner Assembly mounted in a rigid steel frame and internally insulated to include the following:

# DESCRIPTION

**16 February 2006 No.: 9452**

- A.) Two (2) auxiliary air blowers providing cooling air for the igniters, sight glasses and scanners; motors, pressure transmitter, pressure gauge, outlet check valves and inlet filters/silencers (shipped skid mounted, motor starters by others)

## IV. Supply by Others

- A.) Any equipment required for process operation and not specifically listed in I through III
- B.) Wiring between burner assembly and piping skid
- C.) Wiring and instrument tubing between loose shipped instruments and control panel
- D.) Wiring to scanner cooling air blower
- E.) Fuel supply piping to piping skid
- F.) Wiring between control panel and customer control system
- G.) Piping between burner assembly and piping skid
- H.) Electrical supply to control panel

## V. Notes

- A.) All wiring will be in accordance with the NEC except where specifically noted elsewhere

## VI. Burner Emissions

At maximum burner duty:

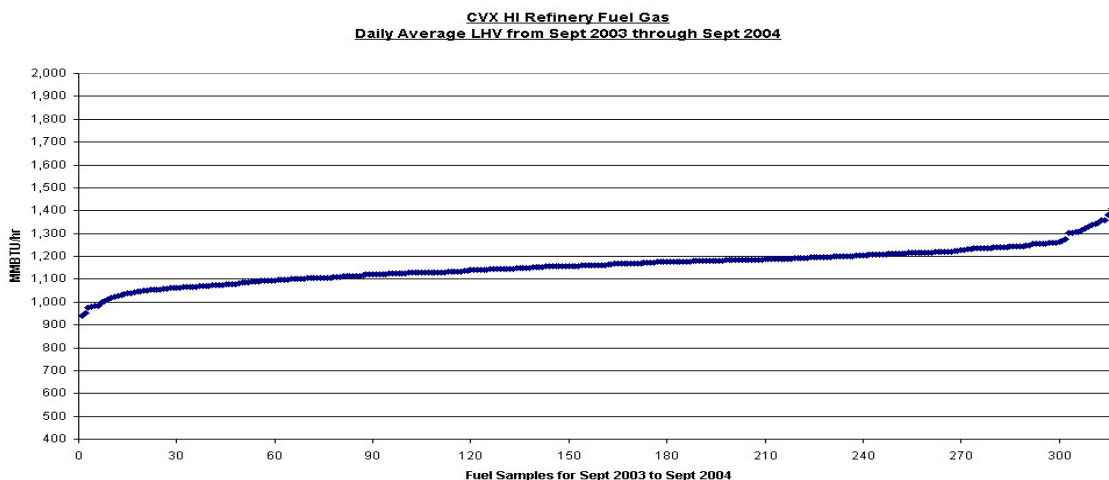
	lb/mmBTU [HHV]	lb/hr
$\Delta\text{NO}_x$ (as $\text{NO}_2$ )	0.05	2.64
$\Delta\text{CO}$	0.05	2.64
$\Delta\text{VOC}$ (non-methane, non-ethane, as $\text{CH}_4$ )	0.02	1.05
$\Delta\text{PM-10}$ (front half only)	0.01	0.53

Any sulfur contained in the fuel will pass through the burner in equilibrium and will be converted to  $\text{SO}_x$ . Emissions over the burner turndown range are guaranteed to not exceed the above mass-per-unit-time amounts.

**6.8 Fuel Properties**

**6.8.1 Refinery Fuel Gas**

The following plot shows the range of measured RFG BTU/SCF content for an entire year. As shown, the actual measured minimum is at 940 BTU/SCF, and the actual measured maximum is above 1,835 BTU/SCF.



For design purposes it will be assumed that the average heating content of RFG will be 1,200 BTU/SCF with the low at 1,000 BTU/SCF and the high at 1,350 BTU/SCF.

Compositions of the RFG low, average, and high BTU values are shown in the following chart.

<b>Typical Refinery Fuel Gas (RFG) Composition</b>			
<b>Component</b>	<b>Lower BTU RFG % Mol</b>	<b>Average BTU RFG % Mol</b>	<b>Higher BTU RFG % Mol</b>
Hydrogen	11.3	9.3	6.8
Methane	30.7	28.9	28.8
Ethane	16.5	15.1	14.8
Ethylene	16.7	15.8	15.9
Propylene	4.4	9.9	16.5
Butenes	0.3	0.3	0.0
I-Butene	0.1	0.1	0.1
Propane	2.4	6.9	5.7
I-Butane	0.2	0.7	2.7
N-Butane	0.0	0.5	0.4
I-Pentane	0.0	0.1	0.0
CO	0.9	0.8	0.8
Nitrogen	16.5	11.6	7.5
Heating Content BTU/SCF HHV	1,091	1,303	1,461
Heating Content BTU/SCF LHV	1,000	1,200	1,350
Maximum Hydrogen 20 Mole%			
Maximum Nitrogen 20 Mole%			
Maximum H2S 100 ppm			

**6.8.2 Liquid Naphtha Fuel (also called LSR)**

Following is a table showing the variability of the naphtha fuel:

<b>Typical Naphtha (LSR) Composition</b>	<b>Lightest Naphtha</b>	<b>Average Naphtha</b>	<b>Heaviest Naphtha</b>
API Gravity @ 60°F	68.8	66.6	64.7
S. G. @ 60 °F	0.706	0.714	0.721
IBP D-86	98	95	95
5%	124		130
10%	136	143	142
30%	168	170	178
50%	195	195	203
70%	220		226
90%	250	257	258
EP	288	321	317
<b>Ranges of Qualities</b>			
Vapor Pressure	10.5	8.0	7.5
Sulfur, ppm	1	42	98
Chlorides, ppm		1.0	
Paraffins, LV%		68.3	
Olefins, LV%	0.2	1.1	2.2
Napthenes, LV%		26.43	
Aromatics, LV%	4.4	5.4	6.5
<b>Contaminates</b>			
Heavy Metals Mercury ppbw	45 will be < 5.0 ppb	70 will be < 5 ppb	90 will be < 5 ppb

**6.8.3 Low Sulfur Fuel Oil (LSFO)**

Following is a table showing typical LFSO data:

<b>Description</b>	<b>Unit of Measure</b>	<b>Value</b>	<b>Specification</b>
Viscosity at 212F, Average	cSt	25.61	20.4 – 96.5
Total Sulfur	weight %	0.34	Max 0.50
Flash, Pensky-Marten	°F	230	Min 150
Sediment & Water - Fuel Oil	Vol%	0.10	Max 0.50
API Gravity, Anton Parr		16.6	12.0 – 24.0
Nitrogen	weight %	0.33	Max 0.50
Pour Point	°F	90	Max 125
Ash	weight %	0.019	Max 0.05
Heat of Combustion, Gross	MM Btu/bbl	6.321	

Notes

- 1) Flash point shall be at least 50 °F above pour point or 150 °F.
- 2) Data based upon a 6/24/05 Certificate of Analysis.

**6.8.4 Refinery Fuel Gas, Propane, Butane, and LSFO Fuel**

The following table shows the heating and economic values of RFG, LSFO, liquid naphtha, propane and butane:

<b>Heating Values</b>	<b>HHV</b>	<b>LHV</b>	<b>Value 2006</b>
Refinery Fuel Gas	1,303 BTU/SCF	1,200 BTU/SCF	\$8.35/MMBTU LHV
LSFO	~150,945 BTU/gal	~142,746 BTU/gal	\$8.35/MMBTU LHV
Liquid Naphtha	118,138 BTU/gal	110,061 BTU/gal	\$12.27/MMBTU LHV
Propane	90,962 BTU/gal	83,687 BTU/gal	\$14.75/MMBTU LHV

**6.9 Minimizing Disruptions Caused by Fluctuations in RFG**

The FCC Unit is the primary producer of refinery fuel gas. The annual average production rate is ~240 MMBTU/hr and currently varies on a daily basis of about ±40 MMBTU/hr. Ongoing projects are planned to reduce this swing to about ±20 MMBTU/hr. It also varies on a minute-to-minute basis by about ±15 MMBTU/hr. The RFG feeds various heaters and is also consumed by CTGs and HRSGs.

As production of RFG increases above the balanced average the excess RFG needs to be routed per one of the following options:

- Vented to the flare (not a desirable option)
- Consumed by a CTG or an HRSG producing an excess of 600# steam
- Consumed by a new Boiler and a reduction of burning liquid fuel to maintain the steam balance.

Since venting to the flare is undesirable and it is assumed that the CTGs are normally fully loaded, the new Boilers need to be designed to take the up-rate swings of the RFG. Also, since producing excess steam is a costly fuel-wasting option, the most desirable option is to design Boilers to downswing a liquid fuel load to compensate for the upswing in the RFG fuel load.

As RFG production decreases below the balanced average, one or a combination of the following actions must take place to maintain the required steam production:

- Additional LSFO must be fired in the crude furnace to displace RFG.
- Propane must be vaporized to supplement the RFG.
- Additional naphtha must be burned in the CTGs to displace RFG.
- Additional LSFO must be burned in the new Boilers to displace RFG.

Putting RFG fuel guns in the crude furnace is an option but it requires operator intervention and takes place in increments of 5 MMBTU/hr per gas gun. This option will only be used for gross periodic adjustments.



**Emission Data for Foster Wheeler**

**100% LSFO @ 250 BFW and 12% FGR**

Steam Production - lb/hr	70,000	77,000
Stack Exit Velocity - ft/s	58.3	65.2
Boiler Stack Temperature - (F)	348.0	361.0
Heat Input - mmBtu/hr	87.6	96.35
NOx - lb/mmBtu	0.32	0.32
PM 10 - lb/mmBtu	0.05	0.05

Note:

PM10 based on 0.019 wt% ash in the LSFO

0.33 wt% N2 in the LSFO

0.34 wt% Sulfur in the LSFO

**100% RFG @ 250 BFW and 12% FGR**

Steam Production - lb/hr	70,000	75,600
Stack Exit Velocity - ft/s	57.9	63.4
Boiler Stack Temperature - (F)	350.0	354.0
Heat Input - mmBtu/hr	89.5	96.85
NOx - lb/mmBtu	0.042	0.042
PM 10 - lb/mmBtu	0.01	0.01

Note:

PM10 based on 0.019 wt% ash in the LSFO

0.33 wt% N2 in the LSFO

0.34 wt% Sulfur in the LSFO

As provided by Chevron via email titled: FW:Emissions Numbers - Foster Wheeler"  
 From John Timmer (Chevron) to John Lague (URS Corp), May 03, 2006

Emission Data for Rentech

100% LSFO @ 250 BFW and 12% FGR

Steam Production - lb/hr	70,000	75,200
Stack Exit Velocity - ft/s	70.0	76.0
Boiler Stack Temperature - (F)	344.0	351.0
Heat Input - mmBtu/hr	92.35	99.00
NOx - lb/mmBtu	0.38	0.38
PM 10 - lb/mmBtu	0.045	0.045

Note:

PM10 based on 0.019 wt% ash in the LSFO

0.33 wt% N2 in the LSFO

0.34 wt% Sulfur in the LSFO

100% RFG @ 250 BFW and 18% FGR

Steam Production - lb/hr	70,000	73,045
Stack Exit Velocity - ft/s	62.0	
Boiler Stack Temperature - (F)	344.0	351.0 *
Heat Input - mmBtu/hr	94.77	99.0
NOx - lb/mmBtu	0.05	
PM 10 - lb/mmBtu	0.01	

Note:

PM10 based on 0.019 wt% ash in the LSFO

0.33 wt% N2 in the LSFO

0.34 wt% Sulfur in the LSFO

\* Temperatures as given by John Timmer 04/27/06

As provided by Chevron via email titled: RE:Updated Boiler Emissions Numbers"

From John Timmer (Chevron) to Michael Dyer (Anvil Corp), May 02, 2006

**Packaged Burner Bid  
For Chevron Products Company  
Located in Kapolei, Oahu, Hawaii**

A Proposal From  
Coen Company, Incorporated  
To  
Rentech Boiler Systems, Inc.  
Attn: Mrs. Beth Circle

**RENTECH**  
Boiler Systems, Inc.



April 2, 2006

Coen Proposal Number: 06-20-0074, Revision A.

April 2, 2006

Rentech Boiler Systems, Inc.  
5025 E. Business 20  
Abilene, TX 79601

Attention: Mrs. Beth Circle

Reference: The Chevron Products Company project, located in Kapolei, Oahu, Hawaii.

Coen Proposal No: 06-20-0074, Revision A.

Dear Mrs. Circle:

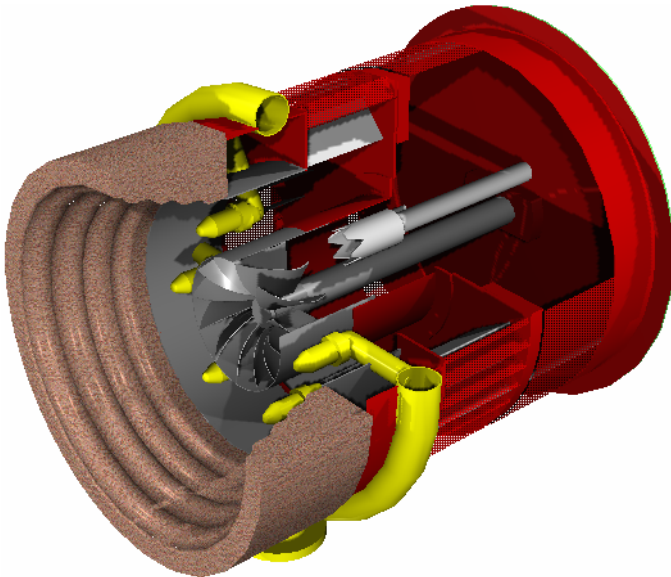
We are pleased to submit the enclosed proposal in response to your inquiry.

## 1.0 Overview

The DAF is Coen's most versatile low NO<sub>x</sub> burner with extensive flame shaping capability. The louvers, located in the annulus zone of the burner, give control of air spin to optimize flame conditions and emission levels. Here are the DAF burner highlights:

- Over 900 units in operation
- Two air zones for control
- Flame shaping capability

The "DAF" Burner



## 2.0 Detailed Scope

### 2.1 Burner Equipment for each Unit

#### Windbox (Qty: 1)

The windbox houses the burner and damper and is constructed of carbon steel, 1/4" thickness on the sides and 1/4" thickness on the front. The windbox is to be seal welded to the boiler front plate and is of sufficient size to provide air cooling to a major portion of the boiler front plate.

#### DAF Burner (Qty: 1)

The DAF "Distributed Air Flow" burner is a multi-staged low NOx burner. The burner consists of two separate air zones. The primary air stream establishes a strong central recirculating zone directly downstream of the isokinetic spinner. This provides stability throughout the burner firing range and adds to the burner's NOx reduction capabilities. The secondary air zone will employ adjustable swirl, which is used to shape the burner flame and to optimize NOx levels.

#### Throat Tile Pieces (Qty: 1)

Throat, preformed refractory tiles supplied loose for field installation by others. The tile tub is not included.

#### Refinery Gas Igniter (Qty: 1)

The igniter is electrically ignited and is interruptible per NFPA Class III requirements. The pilot electrode is sparked by a 6000 Volt transformer.

#### Igniter Refinery Gas Train (Qty: 1)

The igniter gas train, in ANSI 300# class construction, is fully assembled, wired and mounted on the fuel piping skid with the following components:

- One inlet manual shutoff valve, FLG steel body.
- One supply Y type strainer, FLG steel body.
- One pressure regulating valve, FLG steel body.
- Two automatic safety shutoff valves, FLG steel body, pneumatic ball type with 24 VDC actuating solenoid valves, Jamesbury.
- One igniter pressure gauge with block valve, 4-1/2" Ashcroft.
- One igniter flex hose, stainless steel.

#### Cane Spud Type Refinery Gas Burner (Qty: 1)

Axial cane spud type gas burner consisting of stainless steel spuds located around the periphery of the burner to uniformly distribute gas to the entire burner cross section. Each of the spuds will be connected by a carbon steel cane pipe to the gas ring header. The gas ring header is located outside and in front of the burner front plate. The individual cane spuds are fitted with manual isolation valves to allow for on-line cane element maintenance cleaning.

#### Main Refinery Gas Train (Qty: 1)

The main natural gas train, in ANSI 300# class construction, is fully assembled, wired and mounted on the fuel piping skid with the following components:

- One Hamer Line Blind valve, model BW, by R&M Energy Systems.
- One supply manual isolation valve, cast iron body.
- One supply pressure regulating valve, self contained, FLG steel body.
- One fuel flow meter, orifice plate assembly with differential pressure flow transmitter with 3-valve manifold, Daniels and Honeywell (4/20 mA output signal).
- One supply pressure gauge with calibration manifold, 4-1/2" Ashcroft
- Two BMS low pressure transmitters with block valves, Honeywell Smart type (4/20 mA output signal).
- Two automatic safety shutoff valves with proof of closed position switch, FLG steel body, pneumatic ball type with 24 VDC actuating solenoid valves, Jamesbury.
- Two safety shutoff valve leak test valves.
- Two BMS high pressure transmitters with calibration manifold, Honeywell Smart type (4/20 mA output signal).
- One fuel flow control valve with positioner and proof of low fire position switch, FLG steel body, Fisher model 667-ED globe style, with model DVC6010 positioner (4/20 mA drive signal).
- One burner pressure gauge with block valve, 4-1/2" Ashcroft
- One burner manual shutoff valve, FLG steel body.

#### Main Refinery Fuel Oil Gun (Qty: 1)

The main refinery fuel oil gun is an inside mix, steam atomizing type which fits into a socket assembly. This socket assembly is mounted on the center guidepipe and is designed to easily pull the gun out for cleaning. This socket assembly includes a blowout device which permits steam to be purged through the oil gun passages so that it may be removed without leaking or dripping oil. The system is complete with guide pipe, oil hose, steam hose, and vise/wrench set

#### Auxiliary Refinery Fuel Oil Gun (Qty: 1)

The auxiliary refinery fuel oil gun is an inside mix, steam atomizing type which fits into a socket assembly. This socket assembly and guidepipe are mounted adjacent to and in parallel to main refinery fuel oil gun. The purpose of the auxiliary gun is to allow for on-line maintenance cleaning of the main oil gun at any firing rate between 35% and 100% load. This socket assembly includes a blowout device which permits steam to be purged through the oil gun passages so that it may be removed without leaking or dripping oil. The system is complete with guide pipe, oil hose, and steam hose.

Note that a total of three oil guns are included for the following purposes. Note that operator action is needed at the burner front for oil gun changing.

- The first two guns are for the main guidepipe for oil only firing, or for gas and oil combination firing, and the second oil gun is a spare.

- The third oil gun is for the auxiliary guidepipe for on-line cleaning of the main oil gun, either with or without gas combination firing.

#### Refinery Fuel Oil Train (Qty: 1)

The refinery fuel oil train, in ANSI 300# class construction, is assembled, wired, and mounted on the fuel piping rack with the following components:

- One Hamer Line Blind valve, model BW, by R&M Energy Systems.
- One supply manual isolation valve, FLG steel body.
- One supply Y type strainer, FLG steel body.
- One pressure regulating valve, FLG steel body, Fisher model 95H.
- One supply pressure gauge with block valve, 4-1/2" Ashcroft.
- One supply temperature gauge with thermowell, 5" dial type, Ashcroft.
- Two BMS low pressure transmitters with calibration manifold, Honeywell Smart type (4/20 mA output signal).
- Two BMS high/low oil temperature transmitters, Honeywell Smart type (4/20 mA output signal).
- One fuel flow meter, vortex type with flow transmitter, Fisher (4/20 mA output signal).
- Two automatic safety shutoff valves with proof of closed position switch, FLG steel body, pneumatic ball type with 24 VDC actuating solenoid valves, Jamesbury.
- Two safety shutoff valve leak drain test valves.
- One fuel flow control valve with positioner and proof of low fire position switch, FLG steel body, Fisher model 667-EZ globe style, with model DVC6010 positioner (4/20 mA drive signal).
- One burner pressure gauge with block valve, 4-1/2" Ashcroft
- One burner manual shutoff valve, FLG steel body.

#### Refinery Fuel Oil Atomizing Steam Train (Qty: 1)

The atomizing steam train, in ANSI 300# class construction, is assembled, wired, and mounted on the windbox front with the following components:

- One supply manual isolation valve, FLG cast steel body.
- One supply Y type strainer, FLG cast steel body.
- One supply pressure gauge with block valve, 4-1/2" Ashcroft.
- Two BMS low pressure transmitters, Honeywell Smart type (4/20 mA output signal).
- One steam-to-oil atomizing media differential control valve, FLG cast steel body.
- Two BMS low steam flow transmitters, Honeywell Smart type (4/20 mA output signal).
- One condensate drain assembly with the following components; Y type strainer, and steam trap, FLG cast steel body.
- One automatic safety shutoff valve, FLG steel body, pneumatic ball type with 24 VDC actuating solenoid valve, Jamesbury.
- One burner manual shutoff valve, FLG cast steel body.

### Fuel Piping Skid (Qty: 1)

The burner fuel piping is mounted on a skid assembly with the following equipment.

- The duplex boiler/burner utility purge/cooling air blowers.
- The local lite off panel.
- The igniter gas piping train.
- The main gas piping train.
- The fuel oil piping train.
- The atomizing steam piping train.
- Instrument air header & tubing, with the following components.
- One supply manual valve, stainless steel body
- Two BMS low instrument air pressure transmitters with calibration manifold, Honeywell Smart type (4/20 mA output signal).
- One each SST root valve and SST tubing to each pneumatic burner valve.

### Local Lite Off Panel (Qty: 1)

Included is a local lite off and wiring termination panel, mounted on the fuel piping skid, measuring approximately 60" high x 20 " wide x 8" deep. The following door-mounted components will be mounted and wired for status indication and operator interface.

#### Indicating Lights

1. Common Limits Satisfied
2. Fuel Gas Limits Satisfied
3. Fuel Gas Limits Satisfied
4. Purge In Progressing
5. Purge Complete
6. Flame On #1
7. Flame On #2
8. Flame On #3
9. Ignition On
10. Gas Fuel Valve Open
11. Oil Fuel Valve Open
12. Burner Problem

#### Pushbutton & Meters

1. Purge Start
2. Gas Start
3. Oil Start
4. Gas Stop
5. Oil Stop
6. Alarm/Trip Acknowledge
7. Emergency Stop Pull-Button with Guard
8. Flame Scanner #1 Intensity Meter
9. Flame Scanner #2 Intensity Meter
10. Flame Scanner #3 Intensity Meter



### Local Lite Off Panel Features

1. Panel is Nema 4X stainless steel construction.
2. Panel is fitted with a Z-purge for the hazardous area rating.
3. Wiring Terminals to and from the burner valves are fused.

### Flame Scanners (Qty: 3)

Included is three Coen model DFS-2000-MB flame scanners, with one each 120 VAC to 24 VDC power supplies. Each flame scanner is self checking. Each flame scanners operated continuously in both the UV and IR light spectrums for superior flame sighting. Note that these scanners are immune from welding X-ray on nearby equipment. The flame scanners will provide the BMS with a digital flame - no flame signal. The Coen supplied power supplies will provide the following additional signals; 4/20 mA flame intensity signal for DCS indication, 0 to 10 Volt flame intensity signal for physical flame meter indication.

### Boiler/Burner Utility Purge/Cooling Air (Qty: 1)

Included is a duplex blower assembly, mounted on the fuel piping skid, with the below outlined scope of supply, for the below outlined services

#### Scope of Supply:

- Duplex or two 100% regenerative blowers, Rotron brand, model DR505. The service rating is 140 SCFM air flow at 20" wc.
- One each motor, 2 horsepower size, General Electric brand, to operate from 460V/3PH/60HZ power supply.
- Manual isolation valve on the air discharge.

#### Scope of Services:

- Purge/cooling air for the flame scanners.
- Purge/cooling air for the furnace rear wall site ports.
- Purge/cooling air for the boiler and economizer soot blowers.

### BMS Logic Documents (Qty: 1)

Included is the BMS Sequence of Operation text document, and the Boolean Logic diagrams, in accordance with NFPA 85 Chapter 5. The Sequence of Operation and Boolean Logic diagrams will include recommended procedure for safe and proper operation of the Coen burner, burner elements, fans, valves, flame scanners, scanner cooling air and any other applicable items for this project. The Sequence of Operation will also refer to all electrical control cabinets supplied for this project, their location, and functions available from each cabinet. The sequence will verbally describe proper purge, safe ignition of pilot and main fuel and proper shutdown procedures. The sequence will address proper relight procedure for the burner, and effect of any air fan failure, etc. This document will include "DO" and "DO NOT" where applicable for safe system operation and will include effect and remedy of uncontrolled trip and recommended procedure for a controlled shutdown. The sequence or electrical drawings supplied by Coen will include the power requirements; type of power required and detailed description of any special handling requirements. Included are provisions for two evolutions of document

review and approval. Additional review and approval evolutions are not included and can be supplied as a priced addition.

With the above Sequence of Operation text document, the following documentation and services are not included by Coen and are to be by others:

- Review of documents/data generated and supplied by others for purpose of verifying its correctness, safety aspect of configuration or program and adherence to codes, specifications and standards.
- Review of documents/data generated and supplied by others to verify its compatibility with Coen supplied electrical equipment to meet load and power requirements.
- Ladder logic diagram, Cause and Effect Diagram, or Block logic diagram.
- Verification of proper functionality and programming of the BMS within the end customer's DCS. Note that Coen recommends that a Coen factory trained field service person is contracted to verify proper functionality of the implemented logic, before start-up of the burner equipment. These services are available on a per diem basis or as a fixed priced addition. Please advise if a fixed price addition is needed. Without these services, Coen takes exception to any responsibility and/or liability for proper functionality of the implemented logic.
- Development and implementation of any DCS graphics.

#### Additional Features (Qty: 1)

The proposed burner system included the following additional features:

- Burner equipment is suitable for installation within a hazardous area in accordance with NFPA 70 Article 501 Class 1 Division 2 Groups C & D.
- ISA data sheets and an instrument index will be provided.
- All valves and instruments are fitted with an identification tag.
- All wiring is run through rigid galvanized steel conduit.
- All wiring is fitted with identification labels at both ends.
- All burner control wiring is type XHHW-2, 14 AWG size.
- Export packing for the fuel piping skid.
- Mil test reports or material certificates are included for burner valves and fuel piping.
- PMI is included for the applicable burner components.

#### Burner Operational Capabilities (Qty: 1)

The proposed burner will operate as follows:

- Refinery fuel gas only, from 100% to 10% load.
- Refinery fuel oil only, from 100% to 13% load
- Refinery fuel gas and refinery fuel oil together on a continuous basis, from 100% to 25% load. Note that all turndown ranges are from the maximum 99.0 mmbtu/hr.
- During plant upset conditions or dead start conditions, if vaporized propane or butane are used at the main refinery gas, then three of the six main burner

gas cane elements can be closed off for burner operation. The three cane gas elements can be open back up once the regular refinery gas is supplied.

- When combination firing gas and oil together, should one of the fuels have a fuel only trip, than the boiler and burner will remain is service, provided the input of the tripped fuel is not greater than approximately 30% of the total burner input. NFPA 85 does not dictate the maximum input of a tripped fuel in order to avoid a boiler trip; therefore this must be defined by industry standard practices and the ability of the burner. During partial loss of input by the trip of one fuel, the burner can tolerate a maximum instantaneous excess air level of approximately 80%, which corresponds to a trip of 30% of the total burner input. The maximum of 30% input is an estimation, and the actual value will be determined during start up.

### 2.3 Items Not Included In our Proposal

The following items are NOT included in this burner proposal and are to be provided by the boiler supplier or by others.

- Steam pressure reducing and relief valves station at the steam drum, to provide burner atomizing steam at 150 psig / saturated conditions.
- Interconnecting piping from the burner’s fuel piping skid to the individual burner connections.
- Interconnecting purge/cooling air piping from the burner’s fuel piping skid to the following components; flame scanners, boiler rear wall site ports, and boiler/economizer soot blowers.
- Thermal insulation for the atomizing steam piping and for the refinery fuel oil piping.
- BTU analyzer or calorimeter for the refinery fuel gas.
- Supply of burner atomizing steam from the 150 psig / saturated steam header.

### 2.4 Paint and Finish

Coen surface preparation and painting will be as follows:

	<u>Preparation</u>	<u>Primer</u>	<u>Finish</u>
External Steel	SSPC-SP6	Inorganic Zinc	Coen Green, Alkyd Enamel
Piping/Fittings	SSPC-SP6	Inorganic Zinc	Coen Green, Alkyd Enamel
Electrical Panels	---Manufacturers Standard--		
Instruments	---Manufacturers Standard--		
Conduit	---Manufacturers Standard—		

## 3.0 Design Conditions

### 3.1 Boiler Information

Number of boilers .....	2
Number of burners per boiler.....	1
Boiler manufacturer .....	Rentech Boiler
Boiler designation .....	D type
Furnace dimensions: Width inside water tubes (feet).....	6.83
Height (feet).....	10.7

Length (feet).....	30.0
Length for flame (feet).....	25.0
Boiler HHV BTU input, Gas / Oil .....	99.00 / 99.00
Boiler stack height (feet).....	82
Location .....	Outdoor
Economizer used.....	Yes

### 3.2 Electrical & Utilities

Fan electrical characteristics (v/hz/ph) .....	460/60/3
Panel electrical characteristics (v/hz/ph) .....	120/60/1
Instrument air supply (clean, dry, and oil-free) .....	60 to 100 psig

### 3.3 Codes

Area classification.....	Hazardous
NEMA class rating, control panels and instruments.....	NEMA 4X
Code requirements .....	NFPA 85
Piping requirements, fuel and steam service.....	ANSI B31.3, Steel Flanged
Insurance requirements .....	None

### 3.4 Combustion Air and FGR

Combustion air temperature, design (°F).....	75
Air humidity, design (%) .....	70
Plant elevation (FASL) .....	15
Combustion air pre-heat.....	No
Flue Gas Recirculation (FGR) Data	
FGR type.....	Induced
FGR temperature (°F), Gas / Oil.....	336 / 350

### 3.5 Fuels

Main fuel.....	Refinery Fuel Gas
Main fuel.....	Refinery Fuel Oil
Ignition fuel.....	Refinery Fuel Gas

#### Refinery Fuel Gas Details:

Higher heating value (btu/scf) .....	1,000 to 1,350
Specific gravity .....	0.61 to 0.54
Supply pressure (psig) .....	40

#### Refinery Fuel Oil Details:

Higher heating value (btu/lb).....	18,870
Supply viscosity needed (SSU).....	100 to 200
Supply temperature (°F).....	As needed
Supply pressure (psig) .....	185

#### Atomizing Steam Details:

Supply conditions .....	Saturated & dry
Supply pressure needed (psig) .....	150

## 4.0 Burner Performance and Guarantees

### 4.1 Burner Performance

Burner pressure drop ("w.c.), at 70,000 pph steam, Gas / Oil .....6.2 / 5.7  
 Burner pressure drop ("w.c.), at the 99.0 mmbtu/hr, Gas / Oil.....7.2 / 6.5  
 Burner excess air at high fire, Gas / Oil .....15% / 15%  
 FGR levels, Gas / Oil / Gas & Oil together .....18% / 12% / 12%  
 Boiler turndown based on 99.0 mmbtu/hr, Gas / Oil / Gas & Oil together  
 10:1 / 8:1 / 4:1

### 4.2 Burner Emission Guarantees

Emission Type / Fuel Type	Refinery Fuel Gas	Refinery Fuel Oil	50% Gas & 50% oil
NOx level (lbm/mmbtu – ppm)	0.050 - 42	0.460 - 360	0.260 - 210
CO level (lbm/mmbtu – ppm)	0.037 - 50	0.060 - 80	0.115 - 150
VOC level (lbm/mmbtu – ppm)	0.004 - 10	0.005 - 10	0.005 - 10
SOx level (lbm/mmbtu – ppm)	0.011 - 6.6	0.541 - 298	0.276 - 160
Particulate level (lbm/mmbtu)	0.010	0.070	0.040

Note that the above table shows the maximum NOx levels on oil or oil and gas firing, based on the maximum fuel bound nitrogen level of 0.50% by weight.

The below table shows the NOx levels on refinery fuel oil with variable nitrogen content.

Fuel Type	Oil Nitrogen Level	Refinery Fuel Oil	50% Gas & 50% oil
NOx level (lbm/mmbtu – ppm)	0.25% weight	0.330 - 260	0.200 - 160
NOx level (lbm/mmbtu – ppm)	0.33% weight	0.380 - 300	0.220 - 178
NOx level (lbm/mmbtu – ppm)	0.45% weight	0.440 - 345	0.250 - 200
NOx level (lbm/mmbtu – ppm)	0.50% weight	0.460 - 360	0.260 - 210

#### Notations to the above emissions:

1. All emissions on refinery fuel gas only firing, or for oil only firing, are from 25% to 100% of high fire load of 99.0 mmbtu/hr.
2. All emissions on combination gas and oil firing are from 25% to 100% of high fire load of 99.0 mmbtu/hr.
3. All emission are based on fuel HHV.
4. Emissions in the units of ppm are referenced to 3.0% dry stack oxygen.

5. Coen guarantees the stack CO emissions to be not greater than 50 or 80 or 150 ppm provided any furnace leakage does not contribute greater than 20 ppm of CO to the total CO emissions. If the stack CO emissions exceed the guarantee level, Coen will work with the customer/user to reduce the emissions to the guarantee level. This guarantee is based on; 1) operating with 15% excess air at high fire; 2) 25.0 feet minimum furnace length to the convection pass opening or superheater; 3) the furnace to convection back division wall is of gas tight membrane construction, 4) seals at the furnace front wall and drums are fully gas tight, and 4) the customer providing sampling ports for measuring the CO emissions at the rear of the furnace.
6. All emissions on oil firing are based on the following parameters; a variable fuel bound nitrogen level as outlined above, ash content of not greater than 0.05% by weight, sulfur content of not greater than 0.5% by weight, a sediment and water content of not greater than 0.50% by volume, and a Conradson Carbon content of not greater than 4.0% by weight.
7. Particulate emission on oil firing is based on the use of EPA test method #5 with a filter box temperature of 320°F(1.6% conversion of SO<sub>3</sub>), and 2% conversion of BS&W to particulate matter.

## 5.0 Options

As an option, Coen proposes to supply the boiler control system logic, to be implemented into the end customer's DCS. This option will provide the following documents and notations. Coen proposes to supply the boiler control system SAMA Logic Diagrams and the Control Operating Narrative, for the below outlined control loops. The proposed documents will include recommended procedure for safe and proper control of the Coen burner equipment, fans, valves, instruments and any other applicable items for this project. The Control Operating Narrative will also refer to all instruments and control elements supplied for this project, their location, and functions. The narrative will verbally describe proper operation of each device for proper control.

- For fully metered cross limited combustion control with excess stack oxygen trim, and fuel totalizing logic.
- Three element steam drum level feedwater control.
- Superheated steam atemporation temperature control.
- Furnace pressure draft control

With the above boiler control system documents, the following documentation and services are not included by Coen and are to be by others:

- Review of documents/data generated and supplied by others for purpose of verifying its correctness, control aspect of configuration or program and adherence to codes, specifications and standards.
- Review of documents/data generated and supplied by others to verify its compatibility with Coen supplied electrical equipment to meet load and power requirements.
- Verification of proper functionality and programming of the logic that is implemented into the end customer's DCS.
- Development and implementation of any DCS graphics.

As a specified option, Coen proposes to supply the complete BMS-3000 Triconex Tricon TMR burner management system. This option includes the below outlined functions, and system design, scope of supply and sequence of events.

BMS-3000 Triconex Tricon TMR Burner Management System (Qty: 1)

BMS-3000 Triconex Tricon TMR burner management system, comprised of the back-panel master logic assembly, measuring approximately 60" high x 60" wide, and supplied loose to be insert mounted inside of Chevron's existing remote indoor control console. The master logic back-panel will house the Triconex industrial duty programmable logic controllers, power conditioner, circuit breakers, fuses, isolation relays, master fuel trip relay, wiring and wire way, terminals, and all other equipment as required by the scope of the system proposed herein. The design and system supply will be as outlined below.

System Design, Scope of Supply, and Sequence of Events:

- System is designed in accordance with NFPA 85, Chapter 5.
- Control architecture is 3oo2 voting for flame scanners, and 2oo2 voting for critical safety shut down processor transmitters.
- All critical inputs such as F.D. fan running, gas pressure not low, etc. and other critical interlocks connected as discrete inputs to the system will be periodically checked for correct operation. All outputs connection to critical to fuel valves will be continuously checked for correct operation. In the event any failure is detected in the critical output, a master fuel trip (MFT) will result. CPU is continuously checked for correct operation by using an external watchdog timer.
- The BMS will include one Master Fuel Trip (MFT) relay. The MFT controls all power to the fuel valves and ignition transformer. The relay will be hardwired independent of the processor and I/O modules, providing a completely independent trip path. An Emergency trip pushbutton will be hardwired to the MFT relay.
- The system design will be failsafe, de-energized to trip.
- Coen will specify the exact part numbers for the Triconex hardware (PLCs, I/O cards, power supplies, and HIM communications module), and the operating license software.
- Chevron will then purchase the Triconex hardware and software, and free issue this equipment to Coen. Note that the warranty for the Triconex hardware is to be born by Chevron.
- Coen will mount the Triconex hardware, and all other components needed for a complete BMS (power conditioner, circuit breakers, fuses, isolation relays, master fuel trip relay, wiring and wire way, and terminals) onto a back-panel to form the remote master logic assembly. Sizing of the back-panel will be coordinated with Chevron's existing indoor control console.
- Coen will develop and down load the PLC operating program.
- The back-panel remote master logic assembly will be constructed and inspected in accordance with UL-508.

- The back-panel remote master logic assembly will interface with and will drive all of the devices on and which are wired to the local lite off panel on the burner's fuel piping skid.
- Coen will develop and submit a burner factory acceptance test (FAT) procedure for customer review.
- Coen will conduct a comprehensive FAT which will include the back-panel remote master logic assembly wired to the local lite off panel on the burner's fuel piping skid.
- The comprehensive FAT will be witnessed by Chevron of their local inspector.
- The back-panel remote master logic assembly will interface with Chevron's Honeywell TDC-3000 DCS by way of the Modbus HIM communications module.
- Chevron will program the BMS graphic displays and BMS interface actions into the Honeywell TDC-3000 DCS.

The following system alarm and first out trip indications are for graphic display in Chevron's Honeywell TDC-3000 DCS:

- Low Fuel Oil Pressure Trip
- Low Atomizing Steam Pressure Trip
- Low Atomizing Steam Flow Trip
- Low Fuel Gas Pressure Trip
- High Fuel Gas Pressure Trip
- F.D. Fan Starter Interlock Trip
- Low Combustion Air Pressure Trip
- Purge Limits Open Trip
- Light Off Limits Open Trip
- Critical Input Failure Trip
- Critical Output Failure Trip
- Scanner #1 Failure Alarm
- Scanner #2 Failure Alarm
- Scanner #3 Failure Alarm
- Flame Failure Trip
- Low Instrument Air Pressure Trip
- High High Boiler Steam Pressure Trip
- High Furnace Pressure Trip.
- System Damper Malfunction Trip

The following status indications and operator interface items are for graphic display in Chevron's Honeywell TDC-3000 DCS:

- Common Limits Satisfied
- Fuel Gas Limits Satisfied
- Fuel Oil Limits Satisfied
- Purge In Progressing
- Purge Complete
- Flame On, Scanner #1



- Flame On, Scanner #2
- Flame On, Scanner #3
- Ignition On
- Gas Fuel Valve Open
- Oil Fuel Valve Open
- Burner Problem
- Purge Start Pushbutton
- Gas Start Pushbutton
- Oil Start Pushbutton
- Gas Stop Pushbutton
- Oil Stop Pushbutton
- Emergency Stop Pull-button

Proposed BMS-3000 Triconex system includes the following documentation:

- Sequence Of Operation test document.
- Boolean Logic diagrams.
- Electrical I/O Schematic Wiring Diagram.
- Back-Panel Arrangement Drawing.
- BMS Bill Of Material.
- Hard copy of the Operating Program on 3-1/2" floppy disk.
- User's Manual for Triconex TMR equipment.
- Factory acceptance test procedure.

## Anti-Pulsation Design Requirements For Fan & Ductwork

### I. FAN AND DUCTWORK

- A. All remote fans with rating greater than 10" w.c. static pressure at any point in their operating range must have inlet vane dampers which are modulated with firing rate. Check with fan supplier to make sure inlet vane dampers are included.
- B. For remote fans with rating greater than 10" w.c. static pressure and where turndown greater than 5 to 1 is required, a discharge damper in addition to the inlet vane damper will be required, except as clarified in Item C below.
- C. Use the following chart to determine turndown attainable with the use of an inlet vane damper only. Note, the inlet vane damper must provide repeatable air flow control.

<b>Turndown with Remote Fan Inlet Vanes</b>								
<b>Burner</b>	<b>CPF, CPF/LN, DAF, DAZ, SAZ, Delta NOx</b>				<b>QLN</b>			
	Gas		Oil		Gas		Oil	
Burner turndown	10:1	8:1	8:1	6:1	10:1	8:1	8:1	6:1
Inlet vane damper turndown of combustion air flow	6:1	5:1	6:1	5:1	7.5:1	6:1	7.5:1	6:1
Maximum excess air as firing rate decreases	100%				55%			

- D. If turndown less than 5 to 1 is acceptable, an inlet vane damper alone may be adequate for fans with rating greater than 10" w.c. static pressure. The inlet vane damper must be properly selected and sized to achieve the required air control for turndown.
- E. Marginal inlet vane dampers can contribute to increased CO levels, instability at turndown, or reduced turndown.
- F. All ductwork must have splitters in expansions to reduce the included angle to less than 12 degrees. An adjustable splitter vane is further recommended immediately upstream of the windbox, to allow field adjustment of combustion air distribution within the ductwork.
- G. Turning vanes must be provided for all turns (ref. "Fan Engineering", Buffalo Forge Company).
- H. Adequate ductwork gage and/or stiffening is required to provide a natural frequency above 30 hz (i.e., appropriate to duct wall area).
- I. Install an isolation joint between forced draft air supply duct and Coen windbox inlet to impede the transmission of mechanical vibrations and mechanical forces.
- J. Avoid sharp duct turns. A properly designed straight section is recommended at windbox entrance.
- K. Avoid oversizing fans which limits damper travel over the firing range.
- L. Fans, fan inlet boxes and ducting can cause vibration or rumbling. The inlet ducting should be designed to prevent vortex shedding, and splitter plates should be incorporated in inlet boxes to prevent vortexes. Fans with inlet vane dampers should incorporate dorsal fins behind the vanes or vane tabs on each vane to break up vortexes.

### II. DISCHARGE DAMPER

- A. A "purge proving switch" and "low fire proving switch" are always required.
- B. A "purge limit switch" is required when not mounted on the inlet vane damper and 100 hp fan motor and electric damper actuator is used (see note 3 below).

### **III. INLET VANE DAMPER**

- A. A "purge proving switch" is always required.
- B. A "low fire proving switch" is required if the inlet vane damper is used as the primary air control, as opposed to differential control.
- C. A "purge limit switch" is required to limit the damper open position when an electric damper drive is used and the fan motor is 100 hp or greater. A full damper may overload the fan motor.
- D. When a variable frequency drive (VFD) is used to vary the combustion air speed, an inlet or discharge damper is required to prevent air pulsations at lower firing rates. This damper must be characterized to maintain a minimum of 15-20% of maximum fan output (not less than 2" w.c.) pressure across the fan.

### **IV. GENERAL NOTES**

- A. These recommendations are aids only. Coen Company, generally, is not familiar with jobsite design and layout of fans and ducts. However, Coen will comment on design of this equipment if sufficient details and drawings accompany such a request.
- B. The materials discussed within this document may not be furnished by Coen Company. See quotation for items supplied.
- C. When Coen provides a loose switch for any function, mounting brackets, actuating cams, and field wiring are by others.
- D. Position switches are to be actuated off the damper drive levers. Optional locations can be within power units or on switch and cam assemblies mounted on the drive jackshafts.

### **V. PERFORMANCE NOTES**

- A. To achieve good burner performance, good air distribution is required at the windbox inlet. This is especially critical when low excess air, low NOX or low CO is required. The combustion air at the windbox inlet must have a flat velocity profile, with all velocities no more than +15% from the average.
- B. Coen burner systems are often put into service in systems where Coen does not have total system design responsibility. Such system configurations (especially remote fan combustion air ductwork designs, fan sizing, heat recovery flue gas ductwork, and stack configurations) can cause flow instabilities and pressure fluctuations to occur which result in excessive ductwork, furnace wall, fan or heat recovery equipment vibration.

It is recognized that it is often more practical to modify the combustion system than it is to make other more drastic, field modifications to solve vibration/pulsation problems. While Coen Company will participate in reducing or eliminating these flow instabilities through burner modifications and/or other recommended system changes, this work will be performed at prevailing per diem service rates and all material and labor required for equipment modifications will be at the buyer's expense.



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# *Direct Fired Packaged Boilers. . .*

*Proposal to*

*Anvil Corporation  
Bellingham, Washington*

*For*

*The Supply of Two (2)  
Fired Packaged Boilers  
With Auxiliary Equipment*

*At*

*Chevron Hawaii Refinery  
Kapolei, Hawaii*

*RENTECH Proposal No. DTB-BC-1106-1*

TO: Anvil Corporation  
1675 West Bakerview Road  
Bellingham, WA 98226

April 9, 2006

ATTN: Mr. Michael Dyer

SUBJ: Your RFQ No. A1534-C

RENTECH Proposal No.: DTB-BC-1106-1

In accordance with your request, we are pleased to furnish our revised firm proposal for:

Two (2) 70,000 lb/hr "D" STYLE PACKAGED WATERTUBE BOILER with BURNER, SUPERHEATER, ECONOMIZER, FAN, LADDERS, PLATFORMS, and TRIM

to be designed and built in accordance with the requirements of Section I of the ASME Boiler and Pressure Vessel Code and described in the following pages.

Revisions include:

- Superheater tube material is SA-213-T11
- Single stage superheater in lieu of two stages
- Furnace 8" wider
- Diamond Power sootblowers
- BMS Boolean logic added
- Fuel piping material certification included
- Burner PMI added
- Fuel and atomizing steam train piping changed from 150# to 300#
- Main fuel gas and fuel oil Hamer blinds added
- Redundant blowers added to supply air to flame scanners, sight ports, and sootblowers
- Fan is by Chicago Blower
- Turbine is by Dresser

Page No.

4.....	Technical Discussion
5-7 .....	Scope of Supply
8-10 .....	Comments & Exceptions to Specifications
11-20 .....	Description
21-28 .....	Process Summary Sheets
29.....	Mechanical Design Data
30-31 .....	Boiler Trim
32-33 .....	Pricing Information
Attachment I.....	Coen Company Burner Proposal
Attachment II .....	User List
Attachment III.....	API 560 Comments

Thank you for your interest in doing business with **RENTECH BOILER SYSTEMS, INC.** We look forward to providing a prompt response to all of your questions, attention to all details, and top quality boilers. Please don't hesitate to contact me if you have any questions.

Sincerely,

Beth Circle  
Senior Sales Engineer

cc AHM Associates, Inc.  
Enright & Associates, Inc.

## **TECHNICAL DISCUSSION**

RENTECH is proposing two boilers designed to generate 70,000 lb/hr of superheated steam at 600 psig and 625°F with a maximum heat input of 99 mmBTU/hr. The boilers are designed to fire refinery gas alone or in combination with low sulfur refinery fuel oil. The boilers will be a fully shop assembled “D-Type” watertube package boiler with separate packaged economizers. Please refer to the data sheets for performance at the design conditions.

The boilers will be designed with complete membrane wall construction of the furnace, including the front wall. This design minimizes the need for refractory and refractory seals, even in the corners. By minimizing the refractory, faster start-ups are possible since the slow ramp-up time required to sustain the refractory at a constant temperature is not necessary. Of course, the absence of refractory rules out the possibility for cracking and crumbling problems that traditionally are associated with refractory in boilers. The water-cooled front and rear walls also allow the furnace to operate at a lower temperature, which helps to reduce the formation of NO<sub>x</sub>.

The proposed boiler has been carefully designed for your specific application with regard to:

- 100% membrane wall construction to reduce emissions and eliminate the long-term maintenance costs associated with refractory and firebrick and minimize startup time
- Conservative steam drum sizing
- Steam drum internals
- Convection superheater in lieu of radiant superheater to eliminate the problems associated with radiant superheaters

**SCOPE OF SUPPLY**

Supply		ITEM	Installation	
Rentech	Buyer		Rentech	Buyer
X		Package "D" Type Boiler, membrane wall construction		X
Not Required		Boiler (field) assembly		
X		Boiler hydrostatic test (shop)		
X		Superheater, single stage, convection type	X	
X		Downstream desuperheater (variable orifice type)		X
Option		Sweetwater condenser		X
X		COEN DAF Low NO <sub>x</sub> Burner	X	
X		Refinery gas train (rack mounted)		X
X		Low sulfur fuel oil train (rack mounted)		X
X		Pilot fuel train (rack mounted)		X
X		Atomizing steam train (windbox mounted)	X	
	X	BTU analyzer (refinery gas)		X
	X	Interconnecting piping to windbox		X
X		BMS logic and local light off panel		X
Option		Burner Management System (BMS)		X
	X	Triconex PLC	X	
X		SAMA logic for fully metered cross limited combustion control with O <sub>2</sub> trim and fuel totalizing logic, three element drum level control, superheated steam temperature control, and draft control		X
		Configuration of DCS		X
X		Floor mounted forced draft fan		X
X		Inlet silencer		X
X		Silencer support steel		X
X		Motor drive (inverter duty) (One boiler only)		X
	X	Variable frequency drive		X
	X	Motor controls and starter		X
X		Coupling		X
X		Turbine drive (One boiler only)		X
Option		Speed reducing gear (one boiler only)		X
X		Lube system		X
X		Base plates for drivers		X
X		Dampers		X
Not Furnished		Steam coil airheater		
X		Fresh air ductwork from inlet silencer to windbox	X	



Supply		ITEM	Installation	
Rentech	Buyer		Rentech	Buyer
Not Furnished		Bentley Nevada System		
X		Boiler Outlet (Economizer Inlet) Transition		X
X		Economizer (Factory Assembled)		X
X		Economizer Outlet Transition		X
X		FGR dampers, ductwork, and supports		X
X		Expansion joints in flue gas ductwork supplied		X
		Insulation and lagging:		
X		Boiler insulation and lagging	X	
Not Furnished		Windbox		
X		Economizer insulation and lagging	X	
X		Flue gas duct insulation and lagging	X	
Not Furnished		FGR ductwork		
	X	Insulation and lagging for drum heads		X
	X	Insulation and lagging of interconnecting Piping		X
Not Furnished		Provision for future SCR		
Not Furnished		SCR system		
X		Individual stacks, extending to 82' above grade		X
X		Stack draft control damper, expansion joint, and draft controls		X
		Ladders and platforms, galvanized, with no welds required, to provide access to:		
X		Burner/windbox		X
X		Steam drum		X
X		Observation ports		X
X		Economizer		X
X		Stack testing platform		X
X		Inlet silencer		X
X		Support steel for equipment supplied (galvanized)		X
X		Piping from feedwater control valve station to boiler outlet		X
	X	Piping external of terminal points		X
X		Boiler trim, including safety relief valves, shipped loose		X
X		O <sub>2</sub> analyzer, shipped loose		X
X		Sootblowers in boiler and economizer		X
X		Motor starters and manual pushbuttons		X
X		Automatic sequencing controller		X
X		Valves and piping		X
Not Furnished		Safety valve silencers		

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X		Safety valve vent stacks, extending to 7’ above platform height		X
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Supply		ITEM	Installation	
Rentech	Buyer		Rentech	Buyer
	X	Deaerator		X
	X	Boiler feedwater pumps		X
	X	Chemical feed system		X
	X	Blow down tank(s)		X
X		Sample cooler system		X
X		Seal air system		X
	X	Foundation, anchor bolts, concrete, grout		X
	X	Slide plates, bearing plates, and shim plates		X
	X	Freight from Abilene, Texas to the jobsite		
	X	Unloading boiler and auxiliary equipment at Jobsite		
	X	Boil-Out chemicals, including disposal		
	X	Interconnecting wiring or cabling, all instrument and scanner cooling/purge air tubing		X
	X	Electrical Power Supply and Lighting Protection		
	X	Heat tracing, freeze protection		X
	X	Spare Parts – Start up		
	X	Operational spare parts		
	X	Installation Consultant (Per Diem)		
	X	Start-Up Service		
	X	Class Room Training		
	X	Field Testing Labor, Equipment and Consumables		
X		Documentation		
X		Operation & Maintenance Manuals (6 hardcopy, 1 electronic)		
X		Two year warranty, after acceptance, of boiler pressure parts		
X		Five year warranty, after acceptance, of furnace, including the front wall		
Not Furnished		Letter(s) of Credit		

## **COMMENTS & EXCEPTIONS TO SPECIFICATIONS**

The following documents are applicable to this project. Comments and exceptions to their requirements are listed below.

Water Tube Package Boiler Specification Revision C  
Design and Fabrication of Steam Generators UT-S-SG-001  
Design and Fabrication of Steam Generators Addendum to UT-S-SG-001  
Design and Fabrication of Steam Generator Data Sheet U-2M9S1  
Process Design Basis Revision B  
Refractory Linings for Vessels, Lines, and Equipment GEMS I-5M  
General Purpose Steam Turbines (API 611) GEMS P-6M  
Centrifugal Fan Data Sheet  
Squirrel Cage Induction Motors Up To & Including 500 HP DRI-SU-1824-O  
Data Sheet for Squirrel Cage Induction Motor Up To & Including 500 HP DRI-DS-1824  
Appendix A – Noise Control UT-S-NC-001  
General Purpose Steam Turbines (API611) GEMS P-6M6  
General Purpose Steam Turbines (API 611) Addendum to P-6M  
Data Sheet General Purpose Steam Turbine Driver  
Drawing 98-9350 Special Purpose Turbine Gland Sealing and Leak-Off Systems  
Instrumentation for Packaged Equipment ICM-EG-4929-A  
Design of Electrical Systems and Equipment GEMS L-1D21  
List of Acceptable Manufacturers for Electrical Equipment  
List of Acceptable Manufacturers for Instrumentation  
External Coatings COM-EG-4743-C  
Carbon Steel Piping Fabrication PIM-EG-2505-K  
Stainless Steel Piping Fabrication PIM-SU-4770-B  
Positive Material Identification of Equipment and Piping for Maintenance and Capital Projects  
Structural Design Criteria CIV-SU-5009-F  
Thermal Insulation for Hot Lines, Vessels, and Equipment IRM-EG-1381-K  
800 Cranes, Rigging, and Lifting  
Products and Services Agreement  
Anvil Corporation Vendor Drawing and Data Requirements for Engineered Equipment

### Water Tube Package Boiler Specification Revision C:

- 2.1.2 Sootblowers consist of a combination of six rotary and one retractable in the boiler, and four rotaries in the economizer.
- 3.3 In the event of a conflict between the applicable codes and standards, RENTECH will identify on which code or standard their proposal is based.
- 4.3.5 The FD fan does not have enough static differential to use for flame scanner cooling/purge air. Air will be supplied from separate blowers.
- 4.4.8.2 The economizer has been designed with two sootblower lanes, which is one lane every 10 rows. Two rotary sootblowers will be installed in each lane.
- 4.4.9.5 The stacks are supported above the economizer. Consequently, the low spot for the drain will be in the boiler outlet (economizer inlet) transition directly below the stack.
- 4.4.9.6 The stack clean out door will be located in the economizer outlet transition to provide

- better access.
- 4.4.10.2 The proposed burner systems is in accordance with SIL2 requirements insofar as those requirements are defined in the project specifications. Participation in any SIL assessments or HAZOP reviews can be supplied on a per diem basis.
- 4.4.10.5 The Coen flame scanners proposed are not subject to x-ray interference, so a scanner bypass switch is not required or included.
- 4.5.2.c Test block for the fan is based on the mixed temperature of the combustion air and FGR, not 25°F above ambient.
- 4.9 Sootblowers consist of a combination of six rotary and one retractable in the boiler, and four rotaries in the economizer.
- 4.10.4 Instrument air is available at 60 - 100 psig so the actuator is not oversized.
- 4.12.2 The complete boiler system with fan, economizer, and stack is not skid mounted.
- 5.3.14 Dresser Rand standard Positive Material Identification (PMI) will be performed on the turbine. No PMI is included on the optional gearbox.

Design and Fabrication of Steam Generators UT-S-SG-001:

- 2.2 The drawings listed in the section were not included with the RFQ.
- 2.3 In the event of a conflict between the applicable codes and standards, RENTECH will identify on which code or standard their proposal is based.
- 4.17 Furnace floor tubes are sloped 7.5° and are membrane construction, so refractory is not required or included.
- 9.4 The economizer tube supports are lattice type to allow some bypass of hot flue gasses over the return bends and headers. The return bends are not located in the main gas path.
- 12.7 Motor service factor is 1.15 on sine wave power and 1.0 on inverter power (VFD).
- 12.10 Fan speed is 1,780 rpm.
- 12.12 Because of the FGR mixing box, the inlet silencer cannot be supported from the fan housing. Silencer support steel is included.
- 17.2 The stack height is 82' as specified on Data Sheet U-2M9S1.
- 20.2 Lighting is not included.

Design and Fabrication of Steam Generators Addendum to UT-S-SG-001:

- 2.1.13 CIV-SU-398-N Fabrication of Structural and Miscellaneous Steel was not included with the RFQ.
- 4.5 The cross sectional heat release rate is 1,237,000 BTU/ft<sup>2</sup>hr at a firing rate of 99 mmBTU/hr.
- 6.12 Emission excursions may occur during on line cleaning of the main oil gun while the load has been shifted to the auxiliary oil gun.
- 8.7 The entire boiler enclosure is membrane wall construction, including the portion beside the superheater. Utilizing all membrane construction allows all of the boiler walls to operate at the same temperature, and expand equally. Using hard casing in the superheater section would result in uneven thermal expansion, and could produce gas leaks.
- 9.3 The economizer has been designed for counter current flow, and the direction of water flow is generally downward. Even when the entering feedwater is 285°F, the minimum temperature differential between the drum and economizer outlet is over 100°F.
- 11.3 Excess air is 15% for gas firing.
- 12.1 The fan has not been quoted to API 673 because API 673 data sheets were not provided. Comments to API 560 Section 11 (Centrifugal Fans and Drivers for Fired Heater Systems)

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are included as Attachment III to this proposal.

Centrifugal Fan Data Sheet:

- A pressure test will not be performed.

Instrumentation for Packaged Equipment ICM-EG-4929-A:

8.4 The PLC in the optional BMS is Triconex, not Texas Instruments.

**GUARANTEED CENTAUR 40 GENERATOR SET PERFORMANCE****PERFORMANCE CONDITIONS**

The following site conditions were utilized to develop heat rate and power output guarantees:

Altitude	25 feet ASL
Ambient Temperature	75°F
Relative Humidity	70%
Inlet Pressure Drop	4" H <sub>2</sub> O
Exhaust Pressure Drop	10" H <sub>2</sub> O
Turbine Operating Level	100% Continuous Duty
Water Injection Ratio	0.30

**HEAT RATE AND POWER OUTPUT**

Refinery gas as defined on Page 9 of "Process Design Basis, January 18,2006"

Heat Rate @ Full Load	13,720 Btu/kWe-Hr (LHV)
Output Power at Generator	3,068 kWe
Terminals - Full Load	

Naptha as defined on Page 10 of "Process Design Basis, January 18,2006"

Heat Rate @ Full Load	13,923 Btu/kWe-Hr (LHV)
Output Power at Generator	3,003 kWe
Terminals - Full Load	

**EMISSIONS OUTPUT GUARANTEES****OPERATING ON REFINERY GAS**

Ambient Temperature range	Greater than 0°F
ppmv corrected to 15% O <sub>2</sub> Dry, steady state operation	
Water to fuel ratio cannot be guaranteed	
NO <sub>x</sub>	67 ppmv between 80 and 100% load
CO	50 ppmv between 95 and 100% load
	200 ppmv between 80 and 95% load
UHC	25 ppmv between 80 and 100% load

## OPERATING ON NAPHTHA LIQUID FUEL

Ambient Temperature range	Greater than 0°F
ppmv corrected to 15% O <sub>2</sub> Dry, steady state operation	
NO <sub>x</sub>	60 ppmv between 80 and 100% load
CO	250 ppmv between 95 and 100% load
	305 ppmv between 80 and 95% load
UHC	100 ppmv between 80 and 100% load

## NEAR FIELD NOISE DATA

NEAR FIELD – 85 dba as an average 3 ft from package at a height of 5 ft as measured at points spaced 5-10 ft apart around the enclosure when installed in a free field. These sound levels are exclusive of piping, other equipment, reflected sound or contributing site conditions.

### **NOTE 1:**

1. All Standard warranty conditions (i.e. engine warranty) apply
2. Intake air quality shall meet ES 9-98.
3. These fuels have been approved for use based on the data provided in the Process Design Basis (ie.g gas constituents and heating values) , However, the Buyer must also adhering to other relevant requirements in ES 9-98 not shown in fuel analysis. Specifically, particulate and dew point requirements, and liquid fuel handling recommendations.

fi

**From:** Warne, Ross H. [mailto:rwarne@anvilcorp.com]  
**Sent:** Thursday, April 13, 2006 7:57 AM  
**To:** Timmer, John  
**Cc:** Wines, Darin A.; Thompson, Gerry; Bennett, Dennis M.  
**Subject:** RE: Boiler Vendor Action Items for emissions modeling

Hi John,

[REDACTED]

Info we have

The stacks are 82 feet high, and both sellers are quoting a 36" diameter stack, I don't have the thickness but our spec calls for a minimum of thickness requirement of 3/16" with 1/8" CA so they should be 5/16" on the top course which is what would determine the exit velocity. I can confirm if necessary.

[REDACTED]

[REDACTED]

[REDACTED]

Thanks

*Ross Warne*

*Anvil Corporation*

[REDACTED]

Anvil Corporation Website [www.anvilcorp.com](http://www.anvilcorp.com)



## Boilers Long Term (Average) Scenario

	Foster Wheeler	Rentech
Percent Oil	53.30%	39.80%
Percent RFG	46.70%	60.20%

	Foster Wheeler	Rentech
Boiler Steam Production (lb/hr)	70,000	70,000
Boiler Heat Input - LSFO (mmbtu/hr)	87.6	92.35
Boiler Heat Input - RFG (mmbtu/hr)	89.5	94.77
Boiler Feedwater (F)	250	250
Boiler FGR	12%	12%
Boiler Stack Exit Velocity (ft/s)	57.9	62.0
Boiler Stack Temperature (F)	349	344

Boiler Stack Height	82 feet
Boiler Diameter	36 inches
Boiler Stack Thickness	0.1875 inches
INSIDE Stack Diameter	35.625 inches

984 Inches

### References

May 03 email from Jtimmer/May 02 email from Jtimmer  
 May 03 email from Jtimmer/May 02 email from Jtimmer  
 May 03 email from Jtimmer/May 02 email from Jtimmer  
 May 03 email from Jtimmer/May 02 email from Jtimmer  
 May 03 email from Jtimmer/May 02 email from Jtimmer  
 May 03 email from Jtimmer/May 02 email from Jtimmer  
 May 03 email from Jtimmer/May 02 email from Jtimmer

April 13 email from Ross Warne  
 April 13 email from Ross Warne  
 April 13 email from Ross Warne  
 April 13 email from Ross Warne

Emission Factors (lb/MMBtu)	* weighted factors based on spreadsheet operating at 70,000lb/hr; 53.3% oil, 47.7%RFG with new heat Input and assumed PM10 emission of 0.03				
	PM10	SO2	CO	NOX	VOC
Rentech	0.03	0.186	0.046	0.178	0.004
Foster Wheeler	0.03	0.25	0.077	0.189	0.005

\* note that commented values correspond to Rentech operated at 54.2% oil. Emission Factors shown are those given when operated at 60% oil. Emission Calculations uses 54.2 % in order to achieve PSD. Modeling uses factors as given by operating at 60% oil.

## Modeled Annual Emission Rate (lb/hour) for Two 60,000 lb steam /hr Boilers (combined emissions of two boilers)

	PM10	SO2	CO	NOX	VOC
Rentech	5.54	34.35	8.50	32.88	0.74
Foster Wheeler	5.31	44.24	13.63	33.45	0.88
<b>Emission Rate in g/s per boiler</b>					
	<b>g/s</b>				
Rentech	0.349	2.166	0.536	2.073	0.047
Foster Wheeler	0.335	2.790	0.859	2.109	0.056

## Short Term Scenario

Percent Oil in Boilers 100%  
 Percent RFG in Boilers 0%

	Foster Wheeler	Rentech
Boiler Steam Production (lb/hr)	77,000	75,200
Boiler Heat Input (mmbtu/hr)	96.35	99
Boiler Heat Input Used to calc emissions (mmbtu/hr)	99	99
Boiler Feedwater (F)	250	250
Boiler FGR	12%	12.00%
Boiler Stack Exit Velocity (ft/s)	65.2	76.0
Boiler Stack Temperature (F)	361	351

Boiler Stack Height	82	feet
Boiler Diameter	36	inches
Boiler Stack Thickness	0.1875	inches
ACTUAL Stack Diameter	35.625	inches

984 Inches

## References

May 03 email from Jtimmer/May 02 email from Jtimmer  
 May 03 email from Jtimmer/May 02 email from Jtimmer

May 03 email from Jtimmer/May 02 email from Jtimmer  
 May 03 email from Jtimmer/May 02 email from Jtimmer  
 May 03 email from Jtimmer/May 02 email from Jtimmer  
 May 03 email from Jtimmer/May 02 email from Jtimmer

April 13 email from Ross Warne  
 April 13 email from Ross Warne  
 April 13 email from Ross Warne  
 April 13 email from Ross Warne

## Emission Factors (lb/MMBtu)

	PM10	SO2	CO	NOX	VOC
Rentech*	0.03	0.471	0.06	0.38	0.005
Foster Wheeler	0.03	0.471	0.08	0.32	0.005

\* Rentech Proposal No. DTB-BC-1106-1, April 9, 2006

## Modeled Maximum Hourly Emission Rate for Two Boilers @ 99MMBTU/hr

	PM10	SO2	CO	NOX	VOC
Rentech (lbs/hr)	5.94	93.26	11.88	75.24	0.99
Foster Wheeler (lbs/hr)	5.94	93.26	15.84	63.36	0.99
<b>Emission Rate in g/s per boiler</b>					
	<b>g/s</b>				
Rentech	0.375	5.880	0.749	4.744	0.062
Foster Wheeler	0.375	5.880	0.999	3.995	0.062

<b>Turbine/HRSG Hourly Emissions</b>	<b>PM10</b>	<b>SO2</b>	<b>CO</b>	<b>NOX</b>	<b>VOC</b>
Based on Vendor Given Data (lb/hr)	1.06	2.30	28.38	12.79	6.95
Based on overriding CO and VOC emission data (lb/hr)	1.06	2.30	14.90	12.79	6.95
Based on overriding CO and VOC emission data (g/s)	0.134	0.290	1.879	1.613	0.876

\* sum of the HRSG + Turbine emissions

### **Turbine/HRSG Unit**

Turbine/HRSG Exhaust Gas Temperature (F)	376
Turbine /HRSG Exit Flow Rate (lb/hr)	147,579
Turbine/HRSG Outlet Stack Diameter (ft)	6
Turbine/HRSG Outlet Stack Height (ft)	82

**Info from Deltak Performance & Data February 16, 2006 Proposal No. 9451**

### **HRSG**

Info from Deltak 02/16/06 RFG only 58,000lb/hr

Emission Factors (based on HHV)		lb/MMBTU	lb/hr
Nox		0.05	2.64
CO		0.05	2.64
VOC		0.02	1.05
PM10		0.01	0.53

Heat Input (HHV) (mmbtu/hr) 48.86

Heat Released (LHV)	45 MMBTU/hr	CONVERT TO -->	48.86 MMBTU/hr	*Note that this is the heat release at operating conditions
Fuel Fired in HRSG	RFG	HHV		

**Info from Deltak Performance & Data February 16, 2006 Proposal No. 9452**

### **Turbine**

Info from Deltak 02/16/06

Naphtha & RFG

Turbine Heat Input 44.88 \* using only naphtha as a worst case scenario

Emission Factors*	Naphtha		RFG		Override Values for Both Turbine & HRSG	
	ppmv	lb/hr	ppmv	lb/hr	lb/hr	
Nox	60	10.15	67	11.06		
CO (95-100% load)	250	25.74	50	5.02	16.6	
(80-95% load)	305		200			
UHC	100	5.9	25	1.44		

\* at 15%O<sub>2</sub>

Naphtha Heat Rate (LHV)	13,923 BTU/kWe-Hr	CONVERT TO -->	41.81 MMBTU/hr	CONVERT TO -->	44.88 MMBTU/hr
Output Power at Generator	3,003 kWe	MMBTU/hr		HHV	
RFG Heat Rate (LHV)	13,720 BTU/kWe-Hr	CONVERT TO -->	42.09 MMBTU/hr	CONVERT TO -->	45.70 MMBTU/hr
Output Power at Generator	3,068 kWe	MMBTU/hr		HHV	

**Info from Solar Turbines Guaranteed Centaur 40 Generator Set Performance**





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

In reply, please refer to:  
File:

May 23, 2007

**CERTIFIED MAIL**  
**RETURN RECEIPT REQUESTED**  
(7006 0100 0004 9701 1901)

07-452 E CAB  
File No. 0088-11

Mr. Thomas M. Kovar  
Refinery Manager  
Chevron USA Products Company  
Hawaii Refinery  
91-480 Malakole Street  
Kapolei, Hawaii 96707-1807

Hawaii Refinery Manager: **TM Kovar**   
Circulate: 5-23-07  
Copies:   
DGEN \_\_\_\_\_ BINL \_\_\_\_\_  
MAAM  \_\_\_\_\_ CRCA \_\_\_\_\_  
SCFR \_\_\_\_\_ JACX \_\_\_\_\_  
MAHE \_\_\_\_\_ JWLE   
RHDR \_\_\_\_\_  
Original to: HMWE  
Return to: \_\_\_\_\_  
File: CDA Handle: \_\_\_\_\_

Dear Mr. Kovar:

**Subject: Covered Source Permit (CSP) No. 0088-02-C**  
**Significant Modification Application No. 0088-11**  
**Chevron USA Products Company**  
**Hybrid Energy Plant**  
**Located at 91-480 Malakole Street, Kapolei, Oahu**  
**Date of Expiration: May 22, 2012**

The subject Covered Source Permit is issued in accordance with Hawaii Administrative Rules, Title 11, Chapter 60.1. The issuance of this permit is based on the plans, specifications, and information submitted as part of your significant modification application dated May 25, 2006, and additional information dated August 23, 2006. A receipt for the application fee of \$3000.00 is enclosed.

The Covered Source Permit is issued subject to the conditions/requirements set forth in the following Attachments:

- Attachment I: Standard Conditions
- Attachment IIA: Special Conditions - Cogeneration Unit
- Attachment IIB: Special Conditions - Boilers
- Attachment IIC: Special Conditions - Miscellaneous Equipment
- Attachment III: Annual Fee Requirements
- Attachment IV: Annual Emission Reporting Requirements

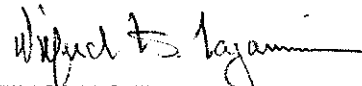
Mr. Thomas M. Kovar  
May 23, 2007  
Page 2

The following forms are enclosed for your use and submittal as required:

Compliance Certification Form  
Annual Emissions Report Form: Fuel Consumption  
Annual Emissions Report Form: Refinery Equipment - Process Rate  
Monitoring Report Form: Fuel Certification  
Monitoring Report Form: Visible Emissions  
Visible Emissions Observation Form Requirements with the following enclosures:  
a. Visible Emissions Observation Form  
b. Ringelmann Chart  
Excess Emission and Monitoring System Performance Summary Report

This permit, (a) shall not in any manner affect the title of the premises upon which the equipment is to be located; (b) does not release the permittee from any liability for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment, and in no manner implies or suggests that the Department of Health, or its officers, agents, or employees, assumes any liability, directly or indirectly, for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment.

Sincerely,



FOR THOMAS E. ARIZUMI, P.E., CHIEF  
Environmental Management Division

DL:se  
Enclosures

c: CAB Monitoring Section

**ATTACHMENT I: STANDARD CONDITIONS  
COVERED SOURCE PERMIT NO. 0088-02-C**

**Issuance Date: May 23, 2007**

**Expiration Date: May 22, 2012**

This permit is granted in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and is subject to the following standard conditions:

1. Unless specifically identified, the terms and conditions contained in this permit are consistent with the applicable requirement, including form, on which each term or condition is based.

(Auth.: HAR §11-60.1-90)

2. This permit, or a copy thereof, shall be maintained at or near the source and shall be made available for inspection upon request. The permit shall not be willfully defaced, altered, forged, counterfeited, or falsified.

(Auth.: HAR §11-60.1-6; SIP §11-60-11)<sup>2</sup>

3. This permit is not transferable whether by operation of law or otherwise, from person to person, from place to place, or from one piece of equipment to another without the approval of the Department of Health, except as provided in HAR, Section 11-60.1-91.

(Auth.: HAR §11-60.1-7; SIP §11-60-9)<sup>2</sup>

4. A request for transfer from person to person shall be made on forms furnished by the Department of Health.

(Auth.: HAR §11-60.1-7)

5. In the event of any changes in control or ownership of the facilities to be constructed or modified, this permit shall be binding on all subsequent owners and operators. The permittee shall notify the succeeding owner and operator of the existence of this permit and its conditions by letter, copies of which will be forwarded to the Department of Health and the U.S. Environmental Protection Agency (EPA), Region 9.

(Auth.: HAR §11-60.1-5, §11-60.1-7, §11-60.1-94)

6. The facility covered by this permit shall be constructed and operated in accordance with the application, and any information submitted as part of the application, for the Covered Source Permit. There shall be no deviation unless additional or revised plans are submitted to and approved by the Department of Health, and the permit is amended to allow such deviation.

(Auth.: HAR §11-60.1-2, §11-60.1-4, §11-60.1-82, §11-60.1-84, §11-60.1-90)

7. This permit (a) does not release the permittee from compliance with other applicable statutes of the State of Hawaii, or with applicable local laws, regulations, or ordinances, and (b) shall not constitute, nor be construed to be an approval of the design of the covered source.

(Auth.: HAR §11-60.1-5, §11-60.1-82)

8. The permittee shall comply with all the terms and conditions of this permit. Any permit noncompliance constitutes a violation of HAR, Chapter 11-60.1 and the Clean Air Act and is grounds for enforcement action; for permit termination, suspension, reopening, or amendment; or for denial of a permit renewal application.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-19, §11-60.1-90)

9. If any term or condition of this permit becomes invalid as a result of a challenge to a portion of this permit, the other terms and conditions of this permit shall not be affected and shall remain valid.

(Auth.: HAR §11-60.1-90)

10. The permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the terms and conditions of this permit.

(Auth.: HAR §11-60.1-90)

11. This permit may be terminated, suspended, reopened, or amended for cause pursuant to HAR, Sections 11-60.1-10 and 11-60.1-98, and Hawaii Revised Statutes (HRS), Chapter 342B-27, after affording the permittee an opportunity for a hearing in accordance with HRS, Chapter 91.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90, §11-60.1-98)

12. The filing of a request by the permittee for the termination, suspension, reopening, or amendment of this permit, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

(Auth.: HAR §11-60.1-90)

13. This permit does not convey any property rights of any sort, or any exclusive privilege.

(Auth.: HAR §11-60.1-90)



14. The permittee shall notify the Department of Health and U.S. EPA Region 9 in writing of the following dates:

- a. The **anticipated date of initial start-up** for each emission unit of a new source or significant modification not more than sixty (60) days or less than thirty (30) days prior to such date;
- b. The **actual date of construction commencement** within fifteen (15) days after such date; and
- c. The **actual date of start-up** within fifteen (15) days after such date.

(Auth.: HAR §11-60.1-90)

15. The permittee shall furnish, in a timely manner, any information or records requested in writing by the Department of Health to determine whether cause exists for terminating, suspending, reopening, or amending this permit, or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Department of Health copies of records required to be kept by the permittee. For information claimed to be confidential, the Director of Health may require the permittee to furnish such records not only to the Department of Health but also directly to the U.S. EPA Region 9 along with a claim of confidentiality.

(Auth.: HAR §11-60.1-14, §11-60.1-90)

16. The permittee shall notify the Department of Health in writing, of the **intent to shut down air pollution control equipment for necessary scheduled maintenance** at least twenty-four (24) hours prior to the planned shutdown. The submittal of this notice shall not be a defense to an enforcement action. The notice shall include the following:

- a. Identification of the specific equipment to be taken out of service, as well as its location and permit number;
- b. The expected length of time that the air pollution control equipment will be out of service;
- c. The nature and quantity of emissions of air pollutants likely to be emitted during the shutdown period;
- d. Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period; and
- e. The reasons why it would be impossible or impractical to shut down the source operation during the maintenance period.

(Auth.: HAR §11-60.1-15; SIP §11-60-16)<sup>2</sup>

17. Except for emergencies which result in noncompliance with any technology-based emission limitation in accordance with HAR, Section 11-60.1-16.5, in the event any emission unit, air pollution control equipment, or related equipment malfunctions or breaks down in such a manner as to cause the emission of air pollutants in violation of HAR, Chapter 11-60.1 or this permit, the permittee shall immediately notify the Department of Health of the malfunction or breakdown, unless the protection of personnel or public health or safety demands immediate attention to the malfunction or breakdown and makes such notification infeasible. In the latter case, the notice shall be provided as soon as practicable. Within five (5) working days of this initial notification, the permittee shall also submit, in writing, the following information:
- a. Identification of each affected emission point and each emission limit exceeded;
  - b. Magnitude of each excess emission;
  - c. Time and duration of each excess emission;
  - d. Identity of the process or control equipment causing each excess emission;
  - e. Cause and nature of each excess emission;
  - f. Description of the steps taken to remedy the situation, prevent a recurrence, limit the excessive emissions, and assure that the malfunction or breakdown does not interfere with the attainment and maintenance of the National Ambient Air Quality Standards and state ambient air quality standards;
  - g. Documentation that the equipment or process was at all times maintained and operated in a manner consistent with good practice for minimizing emissions; and
  - h. A statement that the excess emissions are not part of a recurring pattern indicative of inadequate design, operation, or maintenance.

The submittal of these notices shall not be a defense to an enforcement action.

(Auth.: HAR §11-60.1-16; SIP §11-60-16)<sup>2</sup>

18. The permittee may request confidential treatment of any records in accordance with HAR Section 11-60.1-14.

(Auth.: HAR §11-60.1-14, §11-60.1-90)

19. This permit shall become invalid with respect to the authorized construction if construction is not commenced as follows:

- a. Construction shall be commenced within eighteen (18) months after the permit takes effect, shall not be discontinued for a period of eighteen (18) months or more, and shall be completed within a reasonable time.

- b. For phased construction projects, each phase shall commence construction within eighteen (18) months of the projected and approved commencement dates in the permit. This provision shall be applicable only if the projected and approved commencement dates of each construction phase are defined in Attachment II, Special Conditions of this permit.

(Auth.: HAR §11-60.1-9, §11-60.1-90)

20. The Department of Health may extend the time periods specified in Standard Condition No. 19 upon a satisfactory showing that an extension is justified. Requests for an extension shall be submitted in writing to the Department of Health.

(Auth.: HAR §11-60.1-9, §11-60.1-90)

21. The permittee shall submit fees in accordance with HAR, Chapter 11-60.1, Subchapter 6.

(Auth.: HAR §11-60.1-90)

22. All certifications shall be in accordance with HAR, Section 11-60.1-4.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

23. The permittee shall allow the Director of Health, the Regional Administrator for the U.S. EPA and/or an authorized representative, upon presentation of credentials or other documents required by law:

- a. To enter the premises where a source is located or emission-related activity is conducted, or where records must be kept under the conditions of this permit and inspect at reasonable times all facilities, equipment, including monitoring and air pollution control equipment, practices, operations, or records covered under the terms and conditions of this permit and request copies of records or copy records required by this permit; and
- b. To sample or monitor at reasonable times substances or parameters to assure compliance with this permit or applicable requirements of HAR, Chapter 11-60.1.

(Auth.: HAR §11-60.1-11, §11-60.1-90)

24. Within thirty (30) days of **permanent discontinuance of the construction, modification, relocation, or operation of the facility covered by this permit**, the discontinuance shall be reported in writing to the Department of Health by a responsible official of the source.

(Auth.: HAR §11-60.1-8; SIP §11-60-10)<sup>2</sup>

25. Each permit renewal application shall be submitted to the Department of Health and the U.S. EPA Region 9 no less than twelve (12) months and no more than eighteen (18) months prior to the permit expiration date. The Department of Health may allow a permit renewal application to be submitted no less than six (6) months prior to the permit expiration date, if the Department of Health determines that there is reasonable justification.

(Auth.: HAR §11-60.1-101, 40 CFR §70.5 (a)(1)(iii))<sup>1</sup>

26. The terms and conditions included in this permit, including any provision designed to limit a source's potential to emit, are federally enforceable unless such terms, conditions, or requirements are specifically designated as not federally enforceable.

(Auth.: HAR §11-60.1-93)

27. The compliance plan and compliance certification submittal requirements shall be in accordance with HAR, Sections 11-60.1-85 and 11-60.1-86. As specified in HAR, Section 11-60.1-86, the compliance certification shall be submitted to the Department of Health and the U.S. EPA Region 9 once per year, or more frequently as set by any applicable requirement.

(Auth.: HAR §11-60.1-90)

28. **Any document (including reports) required to be submitted by this permit shall be certified as being true, accurate, and complete by a responsible official in accordance with HAR, Sections 11-60.1-1 and 11-60.1-4, and shall be mailed to the following address:**

**Clean Air Branch  
Environmental Management Division  
Hawaii Department of Health  
P.O. Box 3378  
Honolulu, HI 96801-3378**

**CSP No. 0088-02-C**  
**Attachment I**  
**Page 7 of 7**  
**Issuance Date: May 23, 2007**  
**Expiration Date: May 22, 2012**

**Upon request and as required by this permit, all correspondence to the State of Hawaii Department of Health associated with this Covered Source Permit shall have duplicate copies forwarded to:**

**Chief  
Permits Office, (Attention: Air-3)  
Air Division  
U.S. Environmental Protection Agency  
Region 9  
75 Hawthorne Street  
San Francisco, CA 94105**

(Auth.: HAR §11-60.1-4, §11-60.1-90)

29. To determine compliance with submittal deadlines for time-sensitive documents, the postmark date of the document shall be used. If the document was hand-delivered, the date received ("stamped") at the Clean Air Branch shall be used to determine the submittal date.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

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<sup>1</sup> The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup> The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT IIA: SPECIAL CONDITIONS**  
**COVERED SOURCE PERMIT NO. 0088-02-C**  
**COGENERATION UNIT**

**Issuance Date: May 23, 2007**

**Expiration Date: May 22, 2012**

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility.

**Section A. Equipment Description**

1. This portion of the Covered Source Permit encompasses the following equipment and associated appurtenances:

One (1) Cogeneration Unit consisting of the following:

- a. One (1) 46 MMBtu/hr combustion turbine, Solar Centaur 40, model no. 40-4701, serial no. 5157C;
- b. One (1) heat recovery steam generator (HRSG) with one (1) 49 MMBtu/hr duct burner, John Zink Company; and
- c. For NO<sub>x</sub> control, the combustion turbine is equipped with water injection and low NO<sub>x</sub> burners.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial number or I.D. number and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The combustion turbine/HRSG is subject to the provisions of the following federal regulations:

40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS),

- a. Subpart A, General Provisions;
- b. Subpart J, Standards of Performance for Petroleum Refineries; and
- c. Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.100, §60.4305)<sup>1</sup>

2. The combustion turbine is subject to the provisions of the following federal regulations:

40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),

- a. Subpart A, General Provisions; and
- b. Subpart YYYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.6085)<sup>1</sup>

3. The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

### **Section C. Operational and Emission Limitations**

1. Allowable Fuels

- a. The combustion turbine shall be fired only on naphtha with a sulfur content not to exceed 0.03% by weight or refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (160 ppmv);
- b. The HRSG duct burner shall be fired only on refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (160 ppmv).

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-38, §11-60.1-90, §11-60.1-161; 40 CFR §60.4330, §60.4365)<sup>1</sup>

2. Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the combustion turbine emissions in excess of the following emission limits while fired on naphtha or RFG:

**Maximum Emission Limits**

Pollutant	Fired on Naphtha		Fired on RFG	
	HRSG Duct Burner on	HRSG Duct Burner off	HRSG Duct Burner on	HRSG Duct Burner off
NO <sub>x</sub> (as NO <sub>2</sub> )	12.79 lb/hr	10.15 lb/hr 60 ppmvd @ 15% O <sub>2</sub>	13.70 lb/hr	11.06 lb/hr 67 ppmvd @ 15% O <sub>2</sub>
CO	11.6 lb/hr 60 ppmvd @ 15% O <sub>2</sub>	11.6 lb/hr 60 ppmvd @ 15% O <sub>2</sub>	7.66 lb/hr	5.02 lb/hr 50 ppmvd @ 15% O <sub>2</sub>
Formaldehyde		91 ppbvd @ 15% O <sub>2</sub>		91 ppbvd @ 15% O <sub>2</sub>

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; §11-60.1-174, 40 CFR §60.4325, §60.6100)<sup>1</sup>

3. Air Pollution Controls

The permittee shall continuously operate and maintain the following air pollution controls to meet the emission limits as specified in Special Condition No. C.2. of this Attachment. The following controls shall be fully operational upon startup, except as noted:

- a. Water injection in the combustion turbine shall be at a minimum rate of 0.5 pound of water per 1.0 pound of fuel or greater. The water injection system shall be fully operational immediately after the combustion turbine is brought up to 1.0 MW load, and shall continue to operate until the combustion turbine drops below 1.0 MW load.
- b. Low NO<sub>x</sub> burner system in the combustion turbine.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161, 40 CFR §60.4335)<sup>1</sup>

4. Visible Emissions (V.E.)

For any six (6) minute averaging period, the combustion turbine/HRSG shall not exhibit visible emissions of twenty (20) percent opacity or greater, except as follows. During start-up, shutdown, or equipment breakdown, the combustion turbine may exhibit visible emissions greater than twenty (20) percent opacity but not exceeding sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minutes.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)<sup>2</sup>

5. Provided that no new applicable requirement is triggered by such action, the permittee may perform a complete overhaul of the combustion turbine, subject to the written notification to and prior approval of the Department of Health. The permittee must demonstrate that a modification or reconstruction under NSPS or a PSD review would not be triggered. Complete overhaul for the combustion turbine shall be performed as necessary based on performance indicators for the unit, or as needed based on



consultation with the manufacturer. Overhaul entails the removal of the combustion turbine from service, and the replacement of the combustion turbine with an identical unit consisting of the same make and model number as the original permitted unit. Each replacement unit shall comply with all applicable requirements of the original permitted unit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

6. The combustion turbine/HRSG shall be properly maintained and kept in good operating condition at all times. The permittee shall follow a regular maintenance schedule, as recommended by the manufacturer or as needed, to ensure proper operation of the combustion turbine/HRSG.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

#### **Section D. Monitoring and Recordkeeping Requirements**

1. Fuel Consumption Monitoring

The permittee shall install, operate and maintain non-resetting fuel meters for the continuous measurement and recording of the amount of naphtha and RFG fired in the combustion turbine and the amount of RFG fired in the HRSG duct burner. Records shall be kept on an annual basis for the purpose of annual emissions reporting.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-114)

2. Naphtha Sulfur Content Monitoring

The sulfur content of the naphtha shall be sampled according to the frequency described in Sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D of 40 CFR Part 75 (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with the naphtha already in the intended storage tank.

The sulfur content of the naphtha shall be tested in accordance with American Society for Testing and Materials (ASTM) method D129, or alternatively methods D1266, D1552, D2622, D4294, or D5453. Records of the naphtha sulfur content shall be kept.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.4360, §60.4370, §60.4415)<sup>1</sup>

3. Continuous Monitoring System for Water to Fuel Ratio

The permittee shall install, operate and maintain a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the combustion turbine. The water to fuel monitor/recorder shall be accurate to within  $\pm 5$  percent. The continuous monitoring system shall be used to determine compliance with Special Condition No. C.3.a. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.4335)<sup>1</sup>

4. Continuous Emissions Monitoring System (CEMS) for NO<sub>x</sub>

The permittee shall install, operate and maintain a continuous emission monitoring system (CEMS) to measure and record the NO<sub>x</sub> and CO<sub>2</sub> or O<sub>2</sub> concentrations in the flue gas exhausted from the combustion turbine's exhaust stack. If a CO<sub>2</sub> CEMS is used, 40 CFR 60, Appendix A, Method 20, Equations 20.2 and 20.5 shall be used. The system shall meet EPA performance specifications (40 CFR §60.13 and 40 CFR 60, Appendix B and Appendix F).

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.4335)<sup>1</sup>

5. Continuous Emissions Monitoring System (CEMS) for H<sub>2</sub>S.

- a. The permittee shall install, operate and maintain a continuous emissions monitoring system (CEMS) for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned in the combustion turbine/HRSG.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
  - ii. All fuel gas combustion devices, including the combustion turbine with duct burner, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.
  - iii. Performance evaluations for the H<sub>2</sub>S CEMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 7, Specifications and Test Procedures for Hydrogen Sulfide Continuous Emissions Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11 shall be used in conducting any relative accuracy test audit (RATA).
  - iv. Cylinder Gas Audits (CGS) shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2

- v. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.105)<sup>1</sup>

6. Continuous Opacity Monitoring System (COMS)

The Department of Health may at any time require the permittee to install, operate, and maintain a continuous opacity monitoring system (COMS) for the continuous measurement and recording of the opacity of stack emissions, if it is determined that the visible emissions are in excess of the applicable standard. The system shall meet EPA monitoring performance standards (40 CFR §60.13 and 40 CFR 60, Appendix B, Performance Specifications).

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

7. Visible Emissions (V.E.)

- a. The permittee shall conduct **monthly** (*calendar month*) V.E. observations for each equipment subject to opacity limitations in accordance with 40 CFR Part 60, Appendix A, Method 9 or by use of a Ringelmann Chart as provided. For each period, two (2) observations shall be taken at fifteen (15) second intervals for six (6) consecutive minutes for each equipment. Records shall be completed and maintained in accordance with the *Visible Emissions Form Requirements*.
- b. The permittee shall conduct **annually** (*calendar year*) V.E. observations for each equipment subject to opacity limits by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9. For each period, two (2) observations shall be taken at fifteen (15) second intervals for six (6) consecutive minutes for each equipment. Records shall be completed and maintained in accordance with the *Visible Emissions Form Requirements*.
- c. Upon written request and justification, the Department of Health may waive the requirements for the **annual** V.E. observations. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous **annual** V.E. observations. The annual V.E. observations shall not be waived for more than two consecutive years.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90, SIP §11-60-24)<sup>2</sup>

8. Inspection, Maintenance and Repair Log

An inspection, maintenance and repair log shall be maintained for the combustion turbine/HRSG. Replacement of parts and repairs to the combustion turbine/HRSG shall be documented. At a minimum, the following records shall be maintained:

- a. The date of the inspection/repair;
- b. A description of the findings or any maintenance or repair work performed; and
- c. The name and title of the inspector.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

9. All records, including support information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Support information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be in a permanent form suitable for inspection and made available to the Department of Health or their representatives upon request.

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

**Section E. Notification and Reporting Requirements**

1. Excess Emissions Reporting

- a. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department of Health and the U.S. EPA Region 9 every **semiannual calendar period**. The report shall include the following information:
  - i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.
  - ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the combustion turbine/HRSG. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted, shall also be reported.
  - iii. The date and time identifying each period during which the continuous emissions monitoring system was inoperative except for zero and span checks. The nature of each system repair or adjustment shall be described.

- iv. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the continuous emissions monitoring system operated properly during the period and was not subject to any repairs or adjustments except zero and span checks.
- b. All reports shall be postmarked by the 30th day following the end of each **semiannual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form or an equivalent form shall also be submitted in addition to the excess emissions and monitoring systems performance report.
- c. Excess emissions shall be defined as follows:
  - i. Any operating period in which the 4-hour rolling average NO<sub>x</sub> emission rate, as measured by the NO<sub>x</sub> continuous emissions monitoring system, exceeds the emission limits set forth in Special Condition No. C.2. of this Attachment; or
  - ii. Any operating period in which the 4-hour rolling average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with the emission limits set forth in Special Condition No. C.2. of this Attachment; or
  - iii. Any rolling 3-hour period during which the average concentration of H<sub>2</sub>S in RFG, as measured by the H<sub>2</sub>S continuous emissions monitoring system, exceeds 230 mg/dscm (160 ppmv); or
  - iv. Any opacity measurements, as measured by the continuous opacity monitoring system (COMS)(if required to be installed), exceeding the opacity limits and corresponding averaging times set forth in Special Condition No. C.4. of this Attachment.
- d. Excess emissions indicated by the continuous monitoring systems shall be considered violations of the applicable emission limit for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7, §60.105, §60.4380)<sup>1</sup>

## 2. Semiannual Reporting

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

- a. Any opacity exceedances 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 semiannual period.

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

- b. The sulfur content of the naphtha. The enclosed **Monitoring Form: Fuel Certification** or an equivalent form shall be used;
- c. 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)<sup>2</sup>

### 3. Annual Emissions Reporting

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: - Fuel Consumption** or an equivalent form shall be used in reporting fuel usage.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

4. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Condition Nos. 14, 16, 17 and 24, respectively. These notifications shall include, but not be limited to:
  - a. Anticipated date of initial startup, actual date of construction commencement, and actual date of startup of the combustion turbine/HRSG;
  - b. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - c. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and

- d. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

5. Deviations

The permittee shall report (in writing) **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

6. Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department of Health and U.S. EPA Region 9, the attached **Compliance Certification Form**, pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall be submitted **within ninety (90) days after** the end of each calendar year, and shall be signed and dated by a responsible official. The compliance certification shall include at a minimum, the following information:

- a. The identification of each term or condition of the permit that is the basis of the certification;
- b. The compliance status;
- c. Whether compliance was continuous or intermittent;
- d. The methods used for determining the compliance status of the source currently and over the reporting period;
- e. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act; and
- f. Any additional information as required by the Department of Health including information to determine compliance.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

7. Combustion Turbine Overhaul

- a. The permittee shall submit overhaul notifications to the Department of Health for approval at least **thirty (30) days** or such lesser time as designated and approved by the Department of Health, *prior to turbine overhaul*. The notification shall at a minimum include:
  - i. List the combustion turbine to be overhauled. Identify turbine number, make, model, size, serial number, estimated hours of service, and reason for overhaul;
  - ii. Planned dates the combustion turbine will be placed out of service and the replacement unit in service;
  - iii. List the replacement combustion turbine for the overhauled unit. Identify make, model, size, and serial number; and
  - iv. Any additional information as requested by the Department of Health.
- b. Within **fifteen (15) days of the complete turbine overhaul**, the permittee shall notify the Department of Health in writing of the actual completion date, and any problems incurred during the overhaul.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

**Section F. Testing Requirements**

1. **Within sixty (60) days after** achieving the maximum production rate of the combustion turbine, **but not later than one-hundred eighty (180) days after** initial startup of the combustion turbine and annually thereafter, the permittee shall conduct or cause to be conducted performance tests on the combustion turbine while fired on naphtha and also RFG. Performance tests shall be conducted for nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), volatile organic compounds (VOC), and formaldehyde. All performance tests shall be conducted at the maximum operating capacity of the combustion turbine with the HRSG duct burner on and off, or at other operating loads as may be specified by the Department of Health.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.8, §60.4400, §63.7, §63.6110, §63.6115, §63.6120)<sup>1</sup>

2. The source performance tests shall be conducted and the results reported in accordance with the tests methods set forth in 40 CFR Part 60, Appendix A, 40 CFR Part 63, Appendix A, 40 CFR §60.8 and 40 CFR §63.7. The following test methods or U.S. EPA-approved equivalent methods, or alternative methods with prior written approval from the Department of Health, shall be used:



- a. Performance tests for the emissions of NO<sub>x</sub> shall be conducted using EPA Method 1 to 4 and 7E or 20;
- b. Performance tests for the emissions of CO shall be conducted using EPA Methods 1 to 4 and 10;
- c. Performance tests for the emissions of VOC shall be conducted using EPA Methods 1 to 4 and 25; and
- d. Performance tests for the emissions of formaldehyde shall be conducted using EPA Method 320 or ASTM D6348-03.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174, 40 CFR §60.8, §60.4400, §63.7, §63.6110, §63.6120)<sup>1</sup>

3. Each source performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>

4. The permittee shall provide sampling and testing facilities at its own expense. The tests shall be conducted at the operating capacities identified in Special Condition No. F.1 of this Attachment. The Department of Health may monitor any of the required source performance tests.

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

5. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department of Health before the tests.

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

6. **At least thirty (30) days prior to performing a test**, the permittee shall submit a written *source performance test plan* to the Department of Health and the U.S. EPA Region 9 that describes the test date(s), test duration, test locations, test methods, source operation, fuel consumption, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A source performance test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>

7. **Within sixty (60) days after completion of the source performance test**, the permittee shall submit to the Department of Health and the U.S. EPA Region 9, the test report which shall include the operating conditions of the combustion turbine/HRSG at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174, 40 CFR §60.8; 40 CFR §63.7)<sup>1</sup>

8. Upon written request and justification by the permittee, the Department of Health may waive the requirement for a specific annual source performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous source performance test.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174, 40 CFR §63.7)<sup>1</sup>

9. Upon the Department of Health's request, or if a significant change or performance deficiency occurs with the CEMS, performance tests for the H<sub>2</sub>S levels in the RFG shall be conducted and results reported in accordance with the instructions and test methods set forth in 40 CFR §60.106, and Appendix A, Method 11.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.106)<sup>1</sup>

### **Section G. Agency Notifications**

Any document (including reports) required to be submitted by this Covered Source permit shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup> The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup> The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT IIB: SPECIAL CONDITIONS**  
**COVERED SOURCE PERMIT NO. 0088-02-C**  
**BOILERS**

**Issuance Date: May 23, 2007**

**Expiration Date: May 22, 2012**

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility:

**Section A. Equipment Description**

1. This portion of the Covered Source Permit encompasses the following equipment and associated appurtenances:

Two (2) 99 MMBtu/hr boilers, Foster Wheeler, model no. AG-5060, serial nos. 7414, National Board No. 585 and 7415, National Board No. 586.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on the boilers which identifies the model number, serial number or I.D. number and manufacturer. The identification tag or nameplate shall be attached to the equipment in a conspicuous location.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

**Section B. Applicable Federal Regulations**

1. The boilers are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS),
    - i. Subpart A, General Provisions;
    - ii. Subpart J, Standards of Performance for Petroleum Refineries; and
    - iii. Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.
  - b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),
    - i. Subpart A, General Provisions; and
    - ii. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.40c, §60.100, §63.1, §63.7480)<sup>1</sup>

- The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

**Section C. Operational and Emissions Limitations**

- The existing three (3) boilers, Unit Nos. F-5201, F5202 and F5203, shall not be operated concurrently with the two (2) 99 MMBtu/hr boilers. The existing three (3) boilers, Unit Nos. F-5201, F-5202 and F-5203, shall be permanently shutdown within a one (1) year period after the startup of the two (2) 99 MMBtu/hr boilers.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

- Allowable Fuels

The boilers shall be fired only on low sulfur fuel oil (LSFO) with a maximum sulfur content not to exceed 0.5% by weight (30-day rolling average) or refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (160 ppmv). The LSFO sulfur limit shall apply at all times, including periods of startup, shutdown, and malfunction.

(Auth.: HAR §11-60.1-3, §11-60.1-38, §11-60.1-90, §11-60.1-161, 40 CFR §60.42c, §60.104)<sup>1</sup>

- Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the boilers any gases that contain carbon monoxide, particulate matter/PM<sub>10</sub>, and hydrogen chloride emissions in excess of the limits specified below while fired on LSFO or RFG. The particulate matter/PM<sub>10</sub> limit shall apply at all times, except during periods of startup, shutdown, and malfunction.

**Maximum Emission Limits for each Boiler**

Pollutant	Fired on LSFO	Fired on RFG
CO	0.08 lb/MMBtu 400 ppmvd @ 3% O <sub>2</sub>	0.073 lb/MMBtu 400 ppmvd @ 3% O <sub>2</sub>
PM/PM <sub>10</sub>	0.03 lb/MMBtu	0.03 lb/MMBtu
Hydrogen Chloride	0.0005 lb/MMBtu	0.0005 lb/MMBtu

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.43c, §63.7500)<sup>1</sup>

4. Visible Emissions (V.E.)

- a. The permittee shall not cause the discharge into the atmosphere emissions from the boilers exhibiting an opacity of twenty (20) percent or greater (6-minute average), except for one 6-minute period per hour of not more than twenty-seven (27) percent opacity. The opacity limit shall apply at all times, except during periods of startup, shutdown, and malfunction.
- b. The permittee shall not cause the discharge into the atmosphere emissions from the boilers exhibiting an opacity of ten (10) percent or greater (1-hour block average).

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.43c, §63.7530, SIP §11-60-24)<sup>1,2</sup>

5. The boilers shall be properly maintained and kept in good operating condition at all times. The permittee shall follow a regular maintenance schedule, as recommended by the manufacturer or as needed, to ensure proper operation of the boilers.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

**Section D. Monitoring and Recordkeeping Requirements**

1. Fuel Consumption

The permittee shall install, operate, and maintain non-resetting fuel meters for the continuous measurement and recording of the amount of LSFO and RFG fired in each boiler. Daily, monthly and annual records of the fuel consumption of each fuel for each boiler shall be maintained.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-114, 40 CFR §60.48c)<sup>1</sup>

2. LSFO Sulfur Content Monitoring

Oil samples may be collected from the fuel tank for each boiler immediately after the fuel tank is filled and before any oil is combusted. The permittee shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight

percent sulfur, the permittee shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.46c)<sup>1</sup>

3. Continuous Opacity Monitoring System (COMS)

- a. The permittee shall install, calibrate, operate, and maintain a continuous opacity monitoring system (COMS) for the measurement and recording of the opacity of stack emissions from each boiler.
- b. The systems shall meet the U.S. EPA monitoring performance standards of 40 CFR Part 60, Sections 60.13 and 63.8, and 40 CFR Part 60, Appendix B, Performance Specification 1. The span value of the opacity COMS shall be between 60 and 80 percent.
- c. All 6-minute average opacity readings shall be recorded in percent.

Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.13, §60.47c, §63.8, §63.7525)<sup>1</sup>

4. Continuous Emissions Monitoring System (CEMS) for H<sub>2</sub>S.

- a. The permittee shall install, operate and maintain a continuous emissions monitoring system (CEMS) for continuously monitoring and recording the concentration (dry basis) of H<sub>2</sub>S in the RFG before being burned in the boilers.
- b. The CEMS shall meet the following requirements:
  - i. The span value for the CEMS is 425 mg/dscm (300 ppmv) H<sub>2</sub>S.
  - ii. All fuel gas combustion devices, including the boilers, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H<sub>2</sub>S in the RFG being burned.
  - iii. Performance evaluations for the H<sub>2</sub>S CEMS shall be in accordance with 40 CFR §60.13. The H<sub>2</sub>S CEMS shall meet 40 CFR Part 6, Appendix B, Performance Specification 7, Specifications and Test Procedures for Hydrogen Sulfide Continuous Emissions Monitoring Systems in Stationary Sources; and Appendix F, Quality Assurance Procedures. 40 CFR Part 60, Appendix A, Method 11, shall be used in conducting any relative accuracy test audit (RATA).
  - iv. Cylinder Gas Audits (CGS) shall be conducted in accordance with 40 CFR Part 60, Appendix F, Section 5.1.2

- v. Calibration Drift (CD) assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.105)<sup>1</sup>

5. Inspection, Maintenance and Repair Log

An inspection, maintenance and repair log shall be maintained for the boilers. Replacement of parts and repairs to the boilers shall be documented. At a minimum, the following records shall be maintained:

- a. The date of the inspection/repair;
- b. A description of the findings or any maintenance or repair work performed; and
- c. The name and title of the inspector.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

6. All records, including support information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Support information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be in a permanent form suitable for inspection and made available to the Department of Health or their representatives upon request.

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

**Section E. Notification and Reporting Requirements**

1. Excess Emissions Reporting

- a. The permittee shall submit an excess emissions and monitoring systems performance report pursuant to 40 CFR §60.7(c) to the Department of Health and the U.S. EPA Region 9 every **semiannual calendar period**. The report shall include the following information:
  - i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions, and corrective actions taken.
  - ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the boiler(s). The nature and cause of any malfunction (if known), and the corrective actions taken or preventative measures adopted, shall also be reported.

- iii. The date and time identifying each period during which the continuous emissions monitoring system was inoperative except for zero and span checks. The nature of each system repair or adjustment shall be described.
  - iv. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the continuous emissions monitoring system operated properly during the period and was not subject to any repairs or adjustments except for zero and span checks.
- b. All reports shall be postmarked by the 30<sup>th</sup> day following the end of the **semiannual calendar period**. The enclosed **Excess Emissions and Monitoring System Performance Summary Report** form or an equivalent form shall also be submitted in addition to the excess emissions and monitoring systems performance report.
- c. Excess emissions shall be defined as follows:
- i. Any opacity measurements, as measured by the continuous opacity monitoring system (COMS), exceeding the opacity limits and corresponding averaging times set forth in Special Condition No. C.4 of this Attachment, or
  - ii. Any rolling 3-hr period during which the average concentration of H<sub>2</sub>S in RFG, as measured by the continuous emissions monitoring system, exceeds 230 mg/dscm (160 ppmv).
- d. Excess emissions indicated by the continuous monitoring systems shall be considered violations of the applicable emission limit for the purposes of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7, §60.48c, §60.105)

## 2. Semiannual Reporting

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

- a. LSFO sulfur content
  - i. Calendar dates covered in the reporting period;
  - ii. Each 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period, reasons for



noncompliance with the emission standards, and a description of corrective actions taken;

- iii. The enclosed **Monitoring Report Form: Fuel Certification** or an equivalent form shall be used;
- b. Any deviations from permit requirements shall be clearly identified.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90, §11-60.1-161; 40 CFR §60.48c)<sup>1</sup>

### 3. Annual Emissions Reporting

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Fuel Consumption** or an equivalent form shall be used in reporting fuel usage.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

### 4. Notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Condition Nos. 14, 17 and 24, respectively. These notifications shall include, but not be limited to:

- a. Date of construction commencement, anticipated date of initial startup, and actual date of startup. The notification shall include:
  - i. The design heat input capacity of the boilers and identification of fuels to be combusted in the boilers;
  - ii. The anticipated annual capacity factor based on all fuels fired and based on each individual fuel fired.
- b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- c. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; §11-60.1-161, 40 CFR §60.48c)<sup>1</sup>

5. Deviations

The permittee shall report (in writing) **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

6. Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department of Health and U.S. EPA Region 9, the attached **Compliance Certification Form**, pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall be submitted **within ninety (90) days after** the end of each calendar year, and shall be signed and dated by a responsible official. The compliance certification shall include at a minimum, the following information:

- a. The identification of each term or condition of the permit that is the basis of the certification;
- b. The compliance status;
- c. Whether compliance was continuous or intermittent;
- d. The methods used for determining the compliance status of the source currently and over the reporting period;
- e. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act; and
- f. Any additional information as required by the Department of Health including information to determine compliance.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

7. The permittee shall notify the Department of Health in writing of the permanent shutdown of the existing three (3) boilers, Unit Nos. F-5201, F-5202 and F-5203, **within five (5) days** of the shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

**Section F. Testing Requirements**

1. **Within sixty (60) days** after achieving the maximum production rate of the boilers **but not later than one-hundred eighty (180) day after** the initial start-up of the boilers and annually thereafter, the permittee shall conduct or cause to be conducted performance tests on the boilers. The performance tests shall be conducted for sulfur content, particulate matter/PM<sub>10</sub>, carbon monoxide, hydrogen chloride, and opacity while firing on LSFO and RFG. All performance tests shall be conducted at the maximum operating capacity of the boilers, or at other operating loads as may be specified by the Department of Health.

(Auth.: HAR §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174, 40 CFR §60.8, §60.44c, §60.45c, §63.7, §63.7520)<sup>1</sup>

2. The source performance tests shall be conducted and the results reported in accordance with the tests methods set forth in 40 CFR Part 60, Appendix A, 40 CFR Part 63, Appendix A, 40 CFR §60.8 and 40 CFR §63.7. The following test methods or U.S. EPA-approved equivalent methods, or alternative methods with prior written approval from the Department of Health, shall be used:

- a. The permittee shall demonstrate compliance with the LSFO sulfur limits based on shipment fuel sampling. The initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the boilers to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the permittee shall sample the oil in the fuel tank after each new shipment of oil is received, as described in Special Condition No. D.2. of this Attachment.

The sulfur content of the LSFO shall be tested in accordance with the most current American Society for Testing and Materials (ASTM) methods. ASTM Method D4294-03 is a suitable alternative to Method D129-00 for determining the sulfur content;

- b. Performance tests for the emissions of particulate matter/PM<sub>10</sub> shall be conducted using EPA Methods 1 to 4, 5 or 17, and 19;
- c. Performance tests for the emissions of CO shall be conducted using EPA Methods 1 to 4 and 10, 10A, or 10B;
- d. The permittee shall demonstrate compliance with the hydrogen chloride emission limit specified in Special Condition No. C.3 of this Attachment through fuel analyses according to 40 CFR §63.7521 and follow the procedures of 40 CFR §63.7530(d)(1) through (d)(5). The chlorine concentration shall be measured using the testing procedures specified in SW-846-9520 or ASTM Method E776-87;

- e. Performance tests for determining the opacity of stack emissions shall be conducted using the procedures of 40 CFR Part 60, Appendix A, Method 9.

(Auth.: HAR §11-60.1-11, §11-60.1-90, §11-60.1-161; §11-60.1-174, 40 CFR §60.8, §60.44c, §60.45c, §63.7, §63.7510, §63.7515, §63.7520, §63.7521, §63.7530)<sup>1</sup>

3. Each source performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with the applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8, 40 CFR §63.7)<sup>1</sup>

4. The permittee shall provide sampling and testing facilities at its own expense. The tests shall be conducted at the operating capacities identified in Special Condition No. F.1 of this Attachment. The Department of Health may monitor any of the required source performance tests.

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

5. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department of Health before the tests.

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

6. **At least thirty (30) days prior to performing a test**, the permittee shall submit a written source performance test plan to the Department of Health and the U.S. EPA Region 9 that describes the test date(s), test duration, test locations, test methods, source operation, fuel consumption, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A source performance test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8, 40 CFR §63.7)<sup>1</sup>

7. **Within sixty (60) days after completion of the source performance test**, the permittee shall submit to the Department of Health and the U.S. EPA Region 9, the test report which shall include the operating conditions of the boilers at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174, 40 CFR §60.8, 40 CFR §63.7)<sup>1</sup>

8. Upon written request and justification by the permittee, the Department of Health may waive the requirement for a specific annual source performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous source performance test.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174, 40 CFR §63.7)<sup>1</sup>

9. For the source performance testing of PM/PM<sub>10</sub> and hydrogen chloride, the requirements of 40 CFR §63.7515 shall apply:
- a. Performance testing may be waived for two (2) consecutive years if for at least three (3) consecutive years compliance with the emission limit can be shown. The performance testing must be conducted during the third year and no more than thirty-six (36) months after the previous performance test.
  - b. If the emission limits are continually met, the performance tests may be conducted every third year, but each performance test must be conducted no more than thirty-six (36) months after the previous performance test.
  - c. If a performance test shows noncompliance with an emission limit, the performance test must be conducted annually for that pollutant until all performance tests over a three (3) year period show compliance.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174, 40 CFR §63.7515)<sup>1</sup>

### **Section G. Agency Notifications**

Any document (including reports) required to be submitted by this Covered Source permit shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup> The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup> The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT IIC: SPECIAL CONDITIONS  
COVERED SOURCE PERMIT NO. 0088-02-C  
MISCELLANEOUS EQUIPMENT**

**Issuance Date:** May 23, 2007

**Expiration Date:** May 22, 2012

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility:

**Section A. Equipment Description**

This portion of the Covered Source Permit encompasses the requirements for miscellaneous equipment associated with the cogeneration unit and boilers.

(Auth.: HAR §11-60.1-3)

**Section B. Applicable Federal Regulations**

1. All valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and flanges or other connectors *in VOC service* as defined in §60.481 of 40 CFR Part 60, Subpart VV, are subject to the provisions of the following federal regulations:

40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS),

- a. Subpart A, General Provisions; and
- b. Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.590)<sup>1</sup>

2. All individual drain systems, as defined in §60.691 of 40 CFR Part 60, Subpart QQQ, and for which construction, modification, or reconstruction is commenced after May 4, 1987, are subject to the provisions of the following federal regulations:

40 CFR Part 60, Standards of Performance for New Stationary Source (NSPS),

- a. Subpart A, General Provisions; and
- b. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.690)<sup>1</sup>

3. All pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, or instrumentation systems *in organic hazardous air pollutant service*, as defined in §63.641 of 40 CFR Part 63, Subpart CC, are subject to the provisions of the following federal regulations:

40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),

- a. Subpart A, General Provisions; and
- b. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174, 40 CFR §63.1, §63.640)<sup>1</sup>

4. The permittee shall comply with all applicable requirements of the standards listed above, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

### **Section C. Operational and Emission Limitations**

1. All pumps and compressors handling volatile organic compounds having a Reid Vapor Pressure (RVP) of 1.5 pounds per square inch (psi) or greater which can be fitted with mechanical seals shall have mechanical seals or other equipment of equal efficiency for purposes of air pollution control as may be approved by the Department of Health. Pumps and compressors not capable of being fitted with mechanical seals, such as reciprocating pumps, shall be fitted with the best sealing system available for air pollution control given the particular design of pump or compressor as may be approved by the Department of Health.

(Auth.: HAR §11-60.1-3, §11-60.1-41, §11-60.1-90)

2. The permittee shall not cause or allow the emissions of gas streams containing volatile organic compounds from a vapor blowdown system unless these gases are burned by smokeless flares, or abated by an equally effective control device as approved by the Department of Health.

(Auth.: HAR §11-60.1-3, §11-60.1-42, §11-60.1-90)

3. Compressor

- a. Each compressor shall be equipped and operated with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in 40 CFR §60.482-1(c), 40 CFR §60.482-3(h) and 40 CFR §60.482-3(i).

- b. Each compressor seal system as required in Special Condition No. C.3.a. of this Attachment shall be as follows:
  - i. Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or
  - ii. Equipped with a barrier fluid system that is connected by a closed vent system to a control device that complies with the requirements of 40 CFR §60.482-10.
  - iii. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
- c. The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.
- d. A compressor is exempt from the requirements of Special Condition No. C.3.a. and C.3.b. of this Attachment if it is equipped with a closed vent system capable of capturing and transporting any leakage from the seal to a control device that complies with the requirements of 40 CFR §60.482-10, except as provided in Special Condition No. C.3.e. of this Attachment.
- e. Any compressor that is designated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by methods specified in 40 CFR §60.485(c) and is tested for compliance initially upon designation, annually, and at other times requested by the Department of Health is exempt from the requirements of Special Condition Nos. C.3.a. through C.3.d., D.3.a. and D.3.b. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

#### 4. Pressure Relief Devices in Gas/Vapor Service

- a. Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR §60.485(c).
- b. *After each pressure release*, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, **as soon as practicable**, but no later than 5 calendar days *after the pressure release*, except as provided in Special Condition No. C.8. of this Attachment.
- c. Any pressure relief device is exempt from the requirements of Special Condition No. C.4.a. and C.4.b. of this Attachment if it is equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief



device to a control device that complies with the requirements of 40 CFR §60.482-10.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

**5. Open Ended Valves/Lines**

- a. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR §60.482-1(c). The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.
- b. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.
- c. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with Special Condition No. C.5.a. of this Attachment at all other times.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

**6. Sampling Connection Systems**

- a. Each sampling connection system shall be equipped with a closed-purged, closed-loop, or closed-vent system, except as provided in 40 CFR §60.482-1(c).
- b. Each closed-purged, closed-loop, or closed-vent system shall comply with the following requirements:
  - i. Return the purged process fluid directly to the process line; or
  - ii. Collect and recycle the purged process fluid to a process; or
  - iii. Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of 40 CFR §60.482-10.
  - iv. In situ sampling systems and sampling systems without purges are exempt from the requirements of Special Condition No. C.6.a. and C.6.b. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

**7. Individual Drain Systems**

- a. Sewer drains shall be equipped with water seal controls.

- b. Junction boxes shall be equipped with a cover and may have an open vent pipe at least 3 feet (90 cm) in length and shall not exceed 4 inches (10.2 cm) in diameter.
- c. Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.
- d. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.
- e. Refinery wastewater routed through new process drains and a new first common downstream junction box either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

#### 8. Delay of Repair

- a. Delay of repair of equipment for which leaks have been detected will be allowed if the repair is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.
- b. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.
- c. Delay of repair for valves will be allowed if:
  - i. The permittee demonstrates that emissions of purged material resulting from the immediate repair are greater than the fugitive emissions likely to result from the delay of repair, and
  - ii. When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with the requirements of 40 CFR §60.482-10.
- d. Delay of repair for pumps will be allowed if:
  - i. Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and
  - ii. Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.
- e. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair

beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

#### **Section D. Monitoring and Recordkeeping Requirements**

1. All records, including support information, shall be maintained at the facility for at least five (5) years from the date of the monitoring samples, measurements, tests, reports, or application. Support information includes all calibration and maintenance records and copies of all reports required by the permit. These records shall be in a permanent form suitable for inspection and made available to the Department of Health or their representatives upon request.

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

#### **2. Pumps in Light Liquid Service**

- a. Each pump in light liquid service shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §60.485(b), except as provided in 40 CFR §60.482-1(c) and 40 CFR §60.482-2(d), (e) and (f).
- b. Each pump in light liquid service shall be checked by visual inspection **each calendar week** for indications of liquids dripping from the pump seal.
- c. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
- d. If there are indications of liquids dripping from the pump seal, a leak is detected.
- e. When a leak is detected, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8. of this Attachment. A first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected**.
- f. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of Special Condition No. D.2.a. of this Attachment provided the requirements of 40 CFR §60.482-2(d)(1) through (6) are met.
- g. Any pump that is designated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the

requirements of Special Condition Nos. D.2.a., D.2. b., D.2.e., and D.2.f. of this Attachment if the pump:

- i. Has no externally actuated shaft penetrating the pump housing;
  - ii. Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in 40 CFR §60.485(c); and
  - iii. Is tested for compliance with Special Condition No. 2.g.ii. of this Attachment initially upon designation, annually, and at other times requested by the Department of Health.
- h. If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a control device that complies with the requirements of 40 CFR §60.482-10, it is exempt from the requirements of Special Condition Nos. D.2.a. through D.2.g. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

### 3. Compressors

- a. Each compressor barrier fluid system shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both. Each sensor shall be checked **daily** or shall be equipped with an audible alarm. If the sensor indicates failure of the seal system, the barrier system, or both, a leak is detected.
- b. When a leak is detected, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8. of this Attachment. A first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected**.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

### 4. Pressure Relief Devices in Gas/Vapor Service

**No later than five (5) calendar days after a pressure release**, the pressure relief device subject to the requirements of 40 CFR Part 60, Subpart GGG shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR §60.485(c).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592)<sup>1</sup>

5. Valves in Light Liquid Service and in Gas/Vapor Service
- a. Each valve in light liquid service shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §60.485(b).
  - b. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
  - c. Any valve for which a leak is *not detected for 2 successive months* may be monitored the **first month of every quarter**, beginning with the next quarter, *until a leak is detected*. *If a leak is detected*, the valve shall be monitored **monthly** until a leak is *not detected for 2 successive months*.
  - d. *When a leak is detected*, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8. of this Attachment. A first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected**.
  - e. First attempts at repair include, but are not limited to, the following best practices where practicable:
    - i. Tightening of bonnet bolts;
    - ii. Replacement of bonnet bolts;
    - iii. Tightening of packing gland nuts; and
    - iv. Injection of lubricant into lubricated packing.
  - f. Any valve that is designated, as described in 40 CFR §60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of Special Condition No. D.5.a. of this Attachment if the valve:
    - i. Has no external actuating mechanism in contact with the process fluid;
    - ii. Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR §60.485(c); and
    - iii. Is tested for compliance with the Special Condition No. D.5.f.ii. of this Attachment initially upon designation, annually, and at other times requested by the Department of Health.
  - g. Any valve that is designated, as described in 40 CFR §60.486(f)(1), as unsafe-to-monitor valve and satisfies the criteria outlined in 40 CFR §60.482-7(g) is exempt from the requirements of Special Condition No. D.5.a. of this Attachment.

- h. Any valve that is designated, as described in 40 CFR §60.486(f)(2), as difficult-to-monitor valve and satisfies the criteria outlined in 40 CFR §60.482-7(h) is exempt from the requirements of Special Condition No. D.5.a. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

6. Pumps and Valves in Heavy Liquid Service, Pressure Relief Devices in Light Liquid or Heavy Liquid Service, and Flanges and other Connectors

- a. Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors shall be monitored **within five (5) days** by the method specified in 40 CFR §60.485(b) *if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method.*
- b. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
- c. *When a leak is detected*, it shall be repaired **as soon as practicable, but not later than fifteen (15) calendar days after it is detected**, except as provided in Special Condition No. C.8. of this Attachment. The first attempt at repair shall be made **no later than five (5) calendar days after each leak is detected.**
- d. First attempts at repair include, but are not limited to, the best practices described in Special Condition No. D.5.e. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

7. *When each leak is detected*, a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

8. The identification on a valve may be removed after it has been monitored for two (2) successive months as specified in Special Condition No. D.5.c. of this Attachment and no leak has been detected during those 2 months. The identification on equipment except a valve may be removed after it has been repaired.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

9. *When each leak is detected*, the following information shall be recorded in a log and shall be kept for 5 years in a readily accessible location:

- a. The instrument and operator identification numbers and the equipment identification number;
- b. The date the leak was detected and the dates of each attempt to repair the leak;
- c. Repair methods applied in each attempt to repair the leak;

- d. "Above 10,000" if the maximum instrument reading measured by the methods specified in 40 CFR §60.485(a) after each repair attempt is equal to or greater than 10,000 ppm;
- e. "Repair delayed" and the reason for the delay if a leak is not repaired within fifteen (15) calendar days after discovery of the leak;
- f. The signature of the permittee whose decision it was that repair could not be effected without a process shutdown;
- g. The expected date of successful repair of the leak if a leak is not repaired within fifteen (15) days;
- h. Dates of process unit shutdown that occur while the equipment is unrepaired;  
and
- i. The date of successful repair of the leak.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

10. The following information pertaining to all equipment subject to the requirements of 40 CFR Part 60, Subpart GGG, or 40 CFR Part 63, Subpart CC, shall be recorded in a log that is kept in a readily accessible location:

- a. A list of identification numbers for all equipment;
- b. A list of identification numbers for equipment that is designated for no detectable emissions which is signed by the permittee;
- c. A list of equipment identification numbers for pressure relief devices required to comply with the requirements of Special Condition No. C.4. of this Attachment;
- d. The dates of each compliance test used to determine no detectable emissions;  
and
  - i. The background level measured during each compliance test; and
  - ii. The maximum instrument reading measured at the equipment during each compliance test;
- e. A list of identification numbers for equipment in vacuum service.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

11. The following information pertaining to all valves subject to the requirements of 40 CFR Part 60, Subpart GGG, or 40 CFR Part 63, Subpart CC, shall be recorded in a log that is kept in a readily accessible location:

- a. A list of identification numbers for valves that are designated as unsafe-to-monitor, an explanation for each valve stating why the valve is unsafe-to-monitor, and the plan for monitoring each valve; and
- b. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

12. The following information shall be recorded in a log that is kept in a readily accessible location:

- a. Design criterion based on design considerations and operating experience indicating the failure of the seal system, barrier fluid system, or both of each affected pump or compressor.
- b. Any changes to this criterion and the reasons for the changes.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

13. Each drain in active service shall be checked by visual inspection or physical inspection **initially and monthly** thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

14. Except for out of service drains where a tightly sealed cap or plug is installed, each drain out of active service shall be checked by visual or physical inspection **initially and weekly** thereafter for indications of low water levels or other problems that could result in VOC emissions. Drains having tightly sealed caps or plugs shall be inspected initially and semiannually to ensure caps or plugs are in place and properly installed.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

15. *Whenever low water levels or missing or improperly installed caps or plugs are identified*, water shall be added or first efforts at repair shall be made **as soon as practicable**, but not later than twenty-hour (24) hours after detection unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2, §60.692-6)<sup>1</sup>



16. Junction boxes shall be visually inspected **initially and semiannually** thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

17. *If a broken seal or gap is identified*, first effort at repair shall be made **as soon as practicable, but not later than fifteen (15) calendar days** after the broken seal or gap is identified unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

18. The portion of each unburied sewer line shall be visually inspected **initially and semiannually** for indication of cracks, gaps, or other problems that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2)<sup>1</sup>

19. *Wherever cracks, gaps, or other problems are detected*, repairs shall be made **as soon as practicable, but not later than fifteen (15) calendar days** after identification unless it is determined to be technically impossible without a complete or partial refinery or process unit shutdown. In such instances, repair shall occur before the end of the next refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.692-2, §60.692-6)<sup>1</sup>

20. Before using any individual drain system installed in compliance with 40 CFR §60.692-2, the permittee shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of 40 CFR Part 60, Subpart QQQ not to be met. Points of inspection include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.696)<sup>1</sup>

21. For each individual drain systems subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions during the initial and periodic visual or physical inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.697)<sup>1</sup>

22. For junction boxes subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for each inspection when a broken seal, gap, or other problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.697)<sup>1</sup>

23. For each sewer line subject to the requirements of 40 CFR §60.692-2, the location, date, and corrective action shall be recorded for inspections when a problem is identified that could result in VOC emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.697)<sup>1</sup>

### **Section E. Notification and Reporting Requirements**

#### 1. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within **sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Form: Refinery Equipment - Process Rate** or equivalent form, shall be used in reporting fugitive emissions.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Condition Nos. 14, 16, 17 and 25, respectively. These notifications shall include, but not be limited to:

- a. Anticipated date of initial startup, actual date of construction commencement, and actual date of startup;
- b. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
- c. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- d. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report (in writing) **within five (5) working days** any deviations from permit requirements including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department of Health and U.S. EPA Region 9, the attached **Compliance Certification Form**, pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall be submitted **within ninety (90) days after** the end of each calendar year, and shall be signed and dated by a responsible official. The compliance certification shall include at a minimum, the following information:

- a. The identification of each term or condition of the permit that is the basis of the certification;
- b. The compliance status;
- c. Whether compliance was continuous or intermittent;
- d. The methods used for determining the compliance status of the source currently and over the reporting period;
- e. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act; and
- f. Any additional information as required by the Department of Health including information to determine compliance.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. The permittee shall submit for valves, pumps and compressors subject to the requirements of 40 CFR Part 60, Subpart GGG, or 40 CFR Part 63, Subpart CC, **semiannual** reports to the Department of Health beginning six months after the initial start-up date. The reports shall be submitted within **sixty (60) days after the end of each semiannual calendar period (January 1 to June 30 and July 1 to December 31)**. The **initial** semiannual report shall include the following information:

- a. Process unit identification;
- b. Number of valves subject to the requirements of Special Condition No. D.5. of this Attachment, excluding those valves designated for no detectable emissions under the provisions of Special Condition No. D.5.f. of this Attachment;
- c. Number of pumps subject to the requirements of Special Condition No. D.2. of this Attachment, excluding those pumps designated for no detectable emissions under the provisions of Special Condition No. D.2.g. of this Attachment and those pumps complying with Special Condition No. D.2.h. of this Attachment; and
- d. Number of compressors subject to the requirements of Special Condition No. C.3. of this Attachment, excluding those compressors designated for no detectable emissions under the provisions of Special Condition No. C.3.e. of this Attachment and those compressors complying with Special Condition No. C.3.d. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>

6. All semiannual reports, required in Special Condition No. E.5. of this Attachment, shall include the following information:
    - a. Process unit identification;
    - b. For each month during the semiannual reporting period,
      - i. Number of valves for which leaks were detected,
      - ii. Number of valves for which leaks were not repaired,
      - iii. Number of pumps for which leaks were detected,
      - iv. Number of pumps for which leaks were not repaired,
      - v. Number of compressors for which leaks were detected,
      - vi. Number of compressors for which leaks were not repaired, and
      - vii. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
    - c. Dates of process unit shutdowns which occurred within the semiannual reporting period; and
    - d. Revisions to items reported in the initial semiannual report if changes have occurred since the initial report or subsequent revisions to the initial report.
- (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.592, §63.648)<sup>1</sup>
7. The permittee shall submit to the Department of Health within **sixty (60) days** after initial startup a certification that the equipment necessary to comply with 40 CFR Part 60, Subpart QQQ has been installed and that the required initial inspections or tests of

process drains, sewer lines and junction boxes have been carried out in accordance with 40 CFR Part 60, Subpart QQQ. Thereafter, the permittee shall submit **semiannually** a certification that all of the required inspections have been carried out in accordance with 40 CFR Part 60, Subpart QQQ.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.698)<sup>1</sup>

8. A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted **initially and semiannually** thereafter to the Department of Health.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.698)<sup>1</sup>

9. If compliance with the provisions of 40 CFR Part 60, Subpart QQQ is delayed pursuant to 40 CFR §60.692-7, the notification required under 40 CFR §60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standard is technically impossible without a refinery or process unit shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, 40 CFR §60.698)<sup>1</sup>

#### **Section F. Agency Notifications**

Any document (including reports) required to be submitted by this Covered Source permit shall be in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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- 1 The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.
- 2 The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

**ATTACHMENT III: ANNUAL FEE REQUIREMENTS  
COVERED SOURCE PERMIT NO. 0088-02-C**

**Issuance Date: May 23, 2007**

**Expiration Date: May 22, 2012**

The following requirements for the submittal of annual fees are established pursuant to Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control. Should HAR, Chapter 60.1 be revised such that the following requirements are in conflict with the provisions of HAR, Chapter 60.1, the permittee shall comply with the provisions of HAR, Chapter 60.1:

1. Annual fees shall be paid in full:
  - a. **Within sixty (60) days** after the end of each calendar year; and
  - b. **Within thirty (30) days** after the permanent discontinuance of the covered source.
2. The annual fees shall be determined and submitted in accordance with Hawaii Administrative Rules, Chapter 11-60.1, Subchapter 6.
3. The annual emissions data for which the annual fees are based shall accompany the submittal of any annual fees and submitted on forms furnished by the Department of Health.
4. The annual fees and the emission data shall be mailed to:

**Clean Air Branch  
Environmental Management Division  
Hawaii Department of Health  
P.O. Box 3378  
Honolulu, HI 96801-3378**

**ATTACHMENT IV: ANNUAL EMISSIONS REPORTING REQUIREMENTS  
COVERED SOURCE PERMIT NO. 0088-02-C**

**Issuance Date: May 23, 2007**

**Expiration Date: May 22, 2012**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions:

1. Complete the attached forms:

**Annual Emissions Report Form: Fuel Consumption**

**Annual Emissions Report Form: Refinery Equipment - Process Rate**

2. The reporting period shall be from January 1 to December 31 of each year. All reports shall be submitted to the Department of Health within **sixty (60) days** after the end of each calendar year and shall be mailed to the following address:

**Clean Air Branch  
Environmental Management Division  
Hawaii Department of Health  
P.O. Box 3378  
Honolulu, HI 96801-3378**

3. The permittee shall retain the information submitted, including all emission calculations. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department of Health upon request.
4. Any information submitted to the Department of Health without a request for confidentiality shall be considered public record.
5. In accordance with HAR, Section 11-60.1-14, the permittee may request confidential treatment of specific information including information concerning secret processes or methods of manufacturing, by submitting a written request to the Department of Health and clearly identifying the specific information that is to be accorded confidential treatment.

**COMPLIANCE CERTIFICATION FORM**  
**COVERED SOURCE PERMIT NO. 0088-02-C**  
**PAGE 1 OF \_\_\_\_**

**Issuance Date:** May 23, 2007

**Expiration Date:** May 22, 2012

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following certification at least annually, or more frequently as requested by the Department:

(Make Copies of the Compliance Certification Form for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Company/Facility Name: \_\_\_\_\_

Responsible Official (Print): \_\_\_\_\_

Title: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.



**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-02-C  
(CONTINUED, PAGE \_\_\_ OF \_\_\_)**

Issuance Date: May 23, 2007

Expiration Date: May 22, 2012

The purpose of this form is to evaluate whether or not the facility was in compliance with the permit terms and conditions during the covered period. If there were any deviations to the permit terms and conditions during the covered period, the deviation(s) shall be certified as *intermittent compliance* for the particular permit term(s) or condition(s). Deviations include failure to monitor, record, report, or collect the minimum data required by the permit to show compliance. In the absence of any deviation, the particular permit term(s) or condition(s) may be certified as *continuous compliance*.

**Instructions:**

Please certify Sections A, B, and C below for continuous or intermittent compliance. Sections A and B are to be certified as a group of permit conditions. Section C shall be certified individually for each operational and emissions limit condition as listed in the Special Conditions section of the permit (list all applicable equipment for each condition). Any deviations shall also be listed individually and described in Section D. The facility may substitute their own generated form in verbatim for Sections C and D.

**A. Attachment I, Standard Conditions**

<u>Permit term/condition</u> All standard conditions	<u>Equipment(s)</u> All Equipment(s) listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
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**B. Special Conditions - Monitoring, Recordkeeping, Reporting, Testing, and INSIG**

<u>Permit term/condition</u> All monitoring conditions	<u>Equipment(s)</u> All Equipment(s) listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
<u>Permit term/condition</u> All recordkeeping conditions	<u>Equipment(s)</u> All Equipment(s) listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
<u>Permit term/condition</u> All reporting conditions	<u>Equipment(s)</u> All Equipment(s) listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
<u>Permit term/condition</u> All testing conditions	<u>Equipment(s)</u> All Equipment(s) listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
<u>Permit term/condition</u> All INSIG conditions	<u>Equipment(s)</u> All Equipment(s) listed in the permit	<u>Compliance</u> <input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent

**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-02-C  
(CONTINUED, PAGE \_\_\_\_ OF \_\_\_\_)**

Issuance Date: May 23, 2007

Expiration Date: May 22, 2012

**C. Special Conditions - Operational and Emissions Limitations**

Each permit term/condition shall be identified in chronological order using attachment and section numbers (e.g., Attachment II, B.1, Attachment IIA, Special Condition No. B.1.f, etc.). Each equipment shall be identified using the description stated in Section A of the Special Conditions (e.g., unit no., model no., serial no., etc.). Check all methods (as required by permit ) to show compliance for the respective permit term/condition.

Permit term/condition	Equipment(s)	Method	Compliance
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
		<input type="checkbox"/> monitoring <input type="checkbox"/> recordkeeping <input type="checkbox"/> reporting <input type="checkbox"/> testing <input type="checkbox"/> none of the above	<input type="checkbox"/> Continuous <input type="checkbox"/> Intermittent
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**(Make Additional Copies if Needed)**

**COMPLIANCE CERTIFICATION FORM  
COVERED SOURCE PERMIT NO. 0088-02-C  
(CONTINUED, PAGE \_\_\_ OF \_\_\_)**

**Issuance Date: May 23, 2007**

**Expiration Date: May 22, 2012**

**D. Deviations**

<u>Permit Term/ Condition</u>	<u>Equipment(s) / Brief Summary of Deviation</u>	<u>Deviation Period time (am/pm) &amp; date (mo/day/yr)</u>	<u>Date of Written Deviation Report to DOH (mo/day/yr)</u>
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	
		Beginning:  Ending:	

**(Make Additional Copies if Needed)**

**ANNUAL EMISSIONS REPORT FORM  
FUEL CONSUMPTION  
COVERED SOURCE PERMIT NO. 0088-02-C**

**Issuance Date:** May 23, 2007

**Expiration Date:** May 22, 2012

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions:

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as Horsepower, kilowatt, tons/hour, Btu/hr, etc.)

Serial/ID No.: \_\_\_\_\_

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

Responsible Official (PRINT): \_\_\_\_\_

TITLE: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

Equipment	Type of Fuel Fired	Annual Fuel Use (gallons/yr or ft <sup>3</sup> /yr)	Sulfur Content (% by weight)	H <sub>2</sub> S Content (ppm)
Combustion Turbine	Naphtha			N/A
Combustion Turbine	RFG		N/A	
Duct Burner	RFG		N/A	
Boiler No. 1	LSFO			N/A
Boiler No. 1	RFG		N/A	
Boiler No. 2	LSFO			N/A
Boiler No. 2	RFG		N/A	

**ANNUAL EMISSIONS REPORT FORM  
REFINERY EQUIPMENT – PROCESS RATE  
COVERED SOURCE PERMIT NO. 0088-02-C**

**Issuance Date:** May 23, 2007

**Expiration Date:** May 22, 2012

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions:

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as Horsepower, kilowatt, tons/hour, Btu/hr, etc.)

Serial/ID No.: \_\_\_\_\_

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

Responsible Official (PRINT): \_\_\_\_\_

TITLE: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

EMISSION SOURCE <sup>1</sup>	ANNUAL PROCESS RATE <sup>2</sup>	NOTES

<sup>1</sup> Specify emission source. For example, list FCCU, cooling tower, oil/water separator, valves, flanges, compressor seals, etc.

<sup>2</sup> Specify annual process rate. For example, list bbls refinery feed/yr, gallons cooling water/yr, gallons wastewater/yr, etc.

**MONITORING REPORT FORM  
FUEL CERTIFICATION  
COVERED SOURCE PERMIT NO. 0088-02-C**

**Issuance Date:** May 23, 2007

**Expiration Date:** May 22, 2012

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

For Period: \_\_\_\_\_ Date: \_\_\_\_\_

Facility Name: \_\_\_\_\_

Equipment Location: \_\_\_\_\_

Equipment Description: \_\_\_\_\_

Equipment Capacity/Rating (specify units): \_\_\_\_\_  
(Units such as Horsepower, kilowatt, tons/hour, Btu/hr, etc.)

Serial/ID No.: \_\_\_\_\_

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

Responsible Official (PRINT): \_\_\_\_\_

TITLE: \_\_\_\_\_

Responsible Official (Signature): \_\_\_\_\_

Equipment	Fuel	Sulfur Content (% by weight) <sup>1</sup>	Reason(s) for Noncompliance	Description of Corrective Actions Taken
Combustion Turbine	Naphtha			
Boilers	LSFO	(30-day average)		

<sup>1</sup> Report the highest sulfur content during the reporting period.

**EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE  
SUMMARY REPORT  
COVERED SOURCE PERMIT NO. 0088-02-C  
(PAGE 1 OF 2)**

**Issuance Date:** May 23, 2007

**Expiration Date:** May 22, 2012

(Make Copies for Future Use)

Facility Name: \_\_\_\_\_  
Equipment Location: \_\_\_\_\_  
Equipment Description: \_\_\_\_\_

**Pollutant Monitored:**

From: Date \_\_\_\_\_ Time \_\_\_\_\_  
To: Date \_\_\_\_\_ Time \_\_\_\_\_  
Emission Limit: \_\_\_\_\_

Date of Last CEMS Certification/Audit ..... \_\_\_\_\_  
**Total Source Operating Time** ..... \_\_\_\_\_

**EMISSION DATA SUMMARY**

1. Duration (Hours/Periods) of Excess Emissions in Reporting Period due to:
  - a. Start-Up/Shutdown..... \_\_\_\_\_
  - b. Cleaning/Soot Blowing..... \_\_\_\_\_
  - c. Control Equipment Failure..... \_\_\_\_\_
  - d. Process Problems..... \_\_\_\_\_
  - e. Other Known Causes..... \_\_\_\_\_
  - f. Unknown Causes..... \_\_\_\_\_
  - g. Fuel Problems..... \_\_\_\_\_
- Number of incidents of excess emissions..... \_\_\_\_\_
2. Total Duration of Excess Emissions..... \_\_\_\_\_
3. Total Duration of Excess Emissions  
(% of Total Source Operating Time)..... \_\_\_\_\_

**CEMS PERFORMANCE SUMMARY**

1. CEMS Downtime (Hours/Periods) in Reporting Period Due to:
  - a. Monitor Equipment Malfunctions..... \_\_\_\_\_
  - b. Non-Monitor Equipment Malfunctions..... \_\_\_\_\_
  - c. Quality Assurance Calibration..... \_\_\_\_\_
  - d. Other Known Causes..... \_\_\_\_\_
  - e. Unknown Causes..... \_\_\_\_\_
- Number of incidents of monitor downtime..... \_\_\_\_\_
2. Total CEMS Downtime..... \_\_\_\_\_
3. Total CEMS Downtime  
(% of Total Source Operating Time)..... \_\_\_\_\_

**EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE  
SUMMARY REPORT  
COVERED SOURCE PERMIT NO. 0088-02-C  
(CONTINUED, PAGE 2 OF 2)**

**Issuance Date: May 23, 2007**

**Expiration Date: May 22, 2012**

**CERTIFICATION by Responsible Official**

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

NAME (Print/Type): \_\_\_\_\_

Title: \_\_\_\_\_

(Signature): \_\_\_\_\_





**VISIBLE EMISSIONS FORM REQUIREMENTS  
STATE OF HAWAII  
COVERED SOURCE PERMIT NO. 0088-02-C**

**Issuance Date: May 23, 2007**

**Expiration Date: May 22, 2012**

The **Visible Emissions (V.E.) Form** shall be completed **monthly** (*each calendar month*) for each equipment subject to opacity limits in accordance with 40 CFR Part 60, Appendix A, Method 9 or use of a Ringelmann Chart as provided. At least **annually** (*calendar year*), V.E. observation shall be conducted for each equipment subject to opacity limits by a certified reader in accordance with Method 9. The V.E. Form shall be completed as follows:

1. Visible emissions observations shall take place during the day only and shall be compared to the Ringelmann Chart provided. The opacity shall be noted in five (5) percent increments (e.g., 25%).
2. Orient the sun within a 140 degree sector to your back. Provide a source layout sketch on the V.E. Form using the symbols as shown.
3. Stand at least three (3) stack heights, but not more than a quarter mile from the stack.
4. Two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals for each stack or emission point.
5. The six (6) minute average opacity reading shall be calculated for each observation.
6. If possible, the observations shall be performed as follows:
  - a. Read from where the line of sight is at right angles to the wind direction.
  - b. The line of sight shall not include more than one (1) plume at a time.
  - c. Read at the point in the plume with the greatest opacity (without condensed water vapor), ideally while the plume is no wider than the stack diameter.
  - d. Read the plume at fifteen (15) second intervals only. Do not read continuously.
  - e. The equipment shall be operating at the maximum permitted capacity.
7. If the equipment was shut-down for that period, briefly explain the reason for shut-down in the comment column.

The permittee shall retain the completed V.E. Forms for recordkeeping. These records shall be in a permanent form suitable for inspection, retained for a minimum of five years, and made available to the Department of Health, or their representative upon request.

Any required initial and annual performance test performed in accordance with Method 9 by a certified reader shall satisfy the respective equipment's V.E. monitoring requirements for the month the performance test is performed.

**VISIBLE EMISSIONS FORM  
COVERED SOURCE PERMIT NO. 0088-02-C**

**Issuance Date:** May 23, 2007

**Expiration Date:** May 22, 2012

(Make Copies for Future Use for Each Stack or Emission Point)

Permit No.: \_\_\_\_\_

Company Name: \_\_\_\_\_

Equipment and Fuel: \_\_\_\_\_

**Site Conditions:**

Stack height above ground (ft): \_\_\_\_\_

Stack distance from observer (ft): \_\_\_\_\_

Emission color (black or white): \_\_\_\_\_

Sky conditions (% cloud cover): \_\_\_\_\_

Wind speed (mph): \_\_\_\_\_

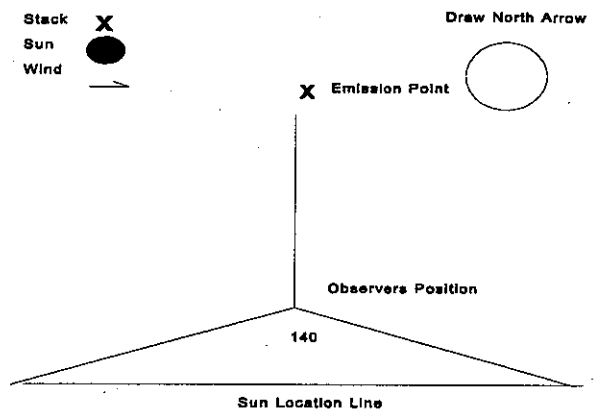
Temperature (°F): \_\_\_\_\_

Observer Name: \_\_\_\_\_

Certified? (Yes/No): \_\_\_\_\_

Observation Date and Start Time: \_\_\_\_\_

Method of Observation (Ringelmann Chart or Method 9): \_\_\_\_\_



SECONDS	0	15	30	45	COMMENTS
MINUTES					
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

Observation Date and Start Time: \_\_\_\_\_

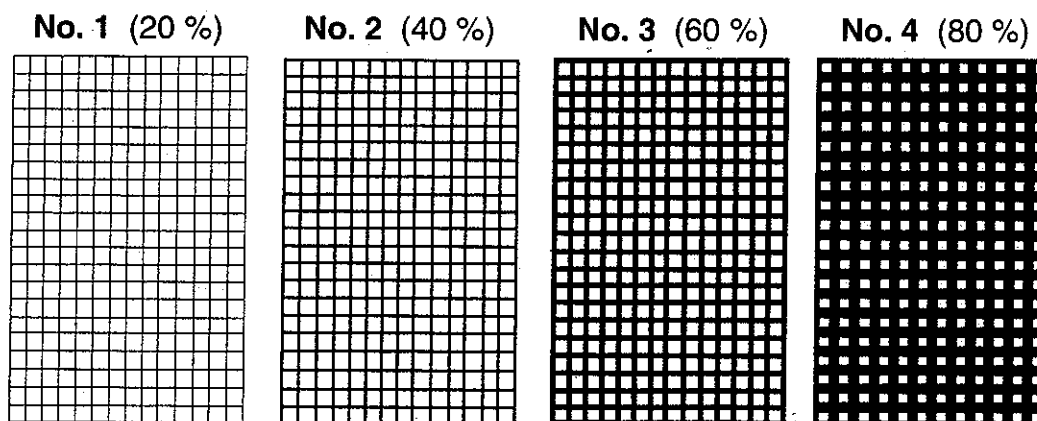
Method of Observation (Ringelmann Chart or Method 9): \_\_\_\_\_

SECONDS	0	15	30	45	COMMENTS
MINUTES					
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

## The Ringelmann Chart

In the late 1800's in Paris, France, Professor Maximilian Ringelmann developed the **Ringelmann Chart** to measure the combustion efficiency of coal-fired boilers. The shade of the smoke plume shows how well a boiler is operating - the poorer its combustion efficiency, the more unburned carbon particles in the smoke and the darker the plume.

Professor Ringelmann's chart established four measured shades of gray between white, valued at zero, and black, at five. These specific shades of gray, Ringelmann No. 1 to Ringelmann No. 4, can be accurately reproduced by placing a grid of black lines of a given width and spacing on a white background. Viewed from a distance, the grid lines and background merge into the shades of gray, to be compared to the shade of the smoke plume.



Ringelmann Chart (not to scale)

## Regulating Visible Emissions

The Ringelmann Chart became one of the first tools used to measure visible emissions. Introduced into the United States in 1897, it was soon accepted as the standard measure of smoke density and was used by engineers for power plant testing and smokeless combustion studies. In 1910, the Chart was officially adopted as part of the Smoke Ordinance for Boston, Mass.

Many city, state, and federal regulations now set smoke density limits based on the Ringelmann Smoke Chart. Although not originally designed as a regulatory tool to control air pollution, it gives good practical results when used by well-trained observers.

AUG 1 2003

0088-07

# URS

RENEWAL APPLICATION  
COVERED SOURCE PERMIT (0088-01C)

CHEVRON HAWAII REFINERY  
KAPOLEI, HAWAII

PREPARED FOR:

**STATE OF HAWAII**  
**DEPARTMENT OF HEALTH**

PREPARED BY:

**CHEVRON USA**  
**PRODUCTS COMPANY**

**JULY 29, 2003**

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**1.1 APPLICATION FOR PERMIT**

Chevron U.S.A. Products Company, a subsidiary of ChevronTexaco Corporation (Chevron) hereby makes application to the Hawaii Department of Health (DOH) Clean Air Branch for a renewal of Covered Source Permit No. 0088-01-C for the Chevron Hawaii Refinery located at Kapolei, Ewa, Oahu, Hawaii. The Hawaii Refinery began operation in 1960. In September 1994, Chevron filed an application for an initial Covered Source Permit. The Covered Source Permit was issued by DOH on February 22, 1999 and is valid through February 22, 2004. It is anticipated that this renewal will be for the timeframe from February 23, 2004 through February 22, 2009.

This renewal application is made pursuant to the regulations and requirements contained in the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1 (Air Pollution Control). According to these Rules, the Hawaii Refinery is classified as a major, covered source under the Hawaii permitting program. This document consists of the complete permit renewal application, including all the information required in Title 11, Chapter 60, Section 11-60.1-101 and the application forms provided by the DOH. Because Section 11-60.1-101 essentially requires permit renewal applications to contain the same types of information needed for initial permit applications, much of the data presented in this document is unchanged from material provided in the original application. This application, however, also identifies the facility changes that have occurred during the current permit time frame (1999 through 2004), as well as proposed facility and permit changes for the renewal permit time frame (2004 through 2009).

**1.2 FACILITY INFORMATION**

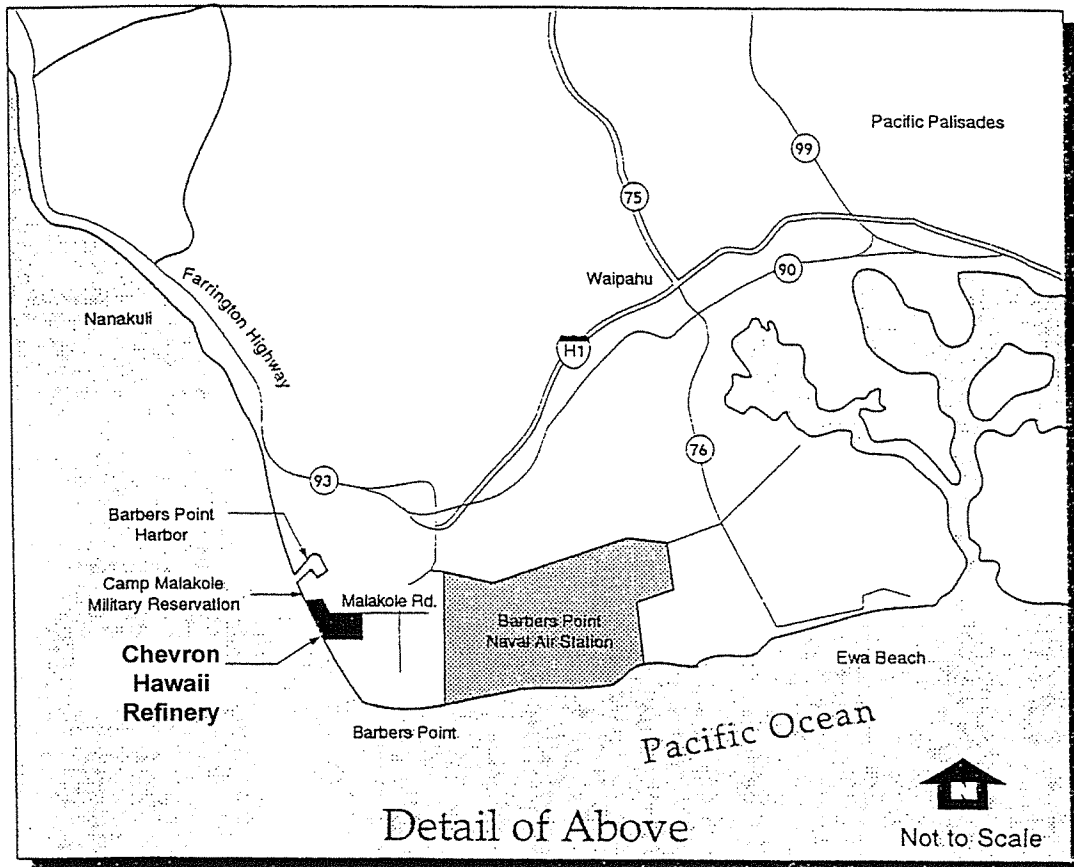
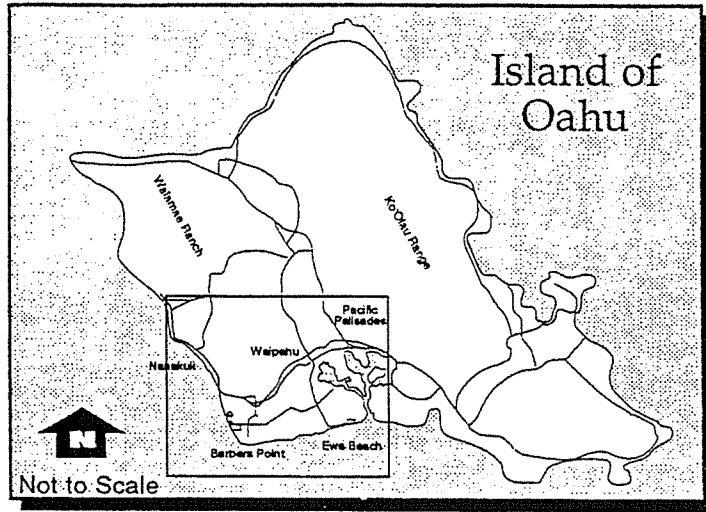
The Hawaii Refinery is operated by Chevron U.S.A. Products Company. The responsible official is the Refinery Manager. The contact for questions regarding this application is the Air Environmental Specialist, who may be reached at (808) 682-5711.

The refinery is located within the Campbell Industrial Park at Kapolei, Ewa, Oahu, Hawaii, as shown on Figure 1-1. The refinery property consists of 248 acres situated at 21°18'40" North latitude and 158°06'57" West longitude.

The refinery address is:

Chevron U.S.A. Products Company, Hawaii Refinery  
91-480 Malakole Street  
Kapolei, HI 96707

The zoning of the refinery property is I-2, Heavy Industrial.



SITE VICINITY MAP  
CHEVRON HAWAII REFINERY

**URS**

CHECKED BY:

DATE: MAY 2003

FIG. NO:

PM: JL

PROJ. NO: 27653013.01000

1-1

### **1.3 OVERVIEW**

This application package has been designed to respond to the requirements of the DOH operating permit program regulations, including the requirements of §11.60-101, Covered Source Renewal. This section (Section 1) contains introductory and applicant information, as well as a completed DOH application form. Section 2 presents background information and a technical description of the refinery and its processes and operations. The estimated maximum potential emissions of regulated pollutants from refinery processes are presented in Section 3, along with a list of insignificant activities, as required in the DOH rules. This section also contains requests to continue the current exemptions for selected small sources in accordance with §11-60.1-82(e) through (g).

Section 4 presents information showing that the dispersion modeling analysis presented in the original Title V permit application (and updated modeling that has been done in association with subsequent facility modifications) remains adequate to represent the refinery's maximum impacts to local air quality. Section 5 is an assessment of regulatory requirements applicable to refinery operations and the associated monitoring and reporting activities.

### **1.4 APPLICATION FORMS**

The Standard Permit Application Form, S-1 is included at the end of this section. The form has been completed and a directory indicating the locations within this application of specific items requested on Page 3 of the form is provided below. Responses to the substantive information requirements of Form S-3 are also provided below.

#### **1.4.1 Form S-1**

The following information is provided in response to the information requested on DOH Form S-1, page 3 of 4. The items listed below are numbered according to the section designations used on Form S-1.

1. Maximum pollutant emissions from the refinery processes are quantified in Section 3 of this application. Detailed emission calculations are presented in Appendix B.
2. A process flow diagram of the Hawaii Refinery is shown in Figure 2-2.
3. Section 3 describes the types and locations of emissions.
4. Maximum facility emissions of regulated air pollutants are shown in Tables 3-12 and 3-13.
5. The facility location is shown in Figure 1-1.
6. Stack parameter information is not presented in this renewal application form, because of the very large number of individual source within the Hawaii Refinery. Note that point sources and the associated stack parameters and emission rates were presented in Tables 1 and 2 of the Covered Source Permit Review Summary - File #0088- 01. Section 3 of this Covered Source Permit renewal application presents current Potential to Emit data for criteria pollutants and HAPs emitted by all refinery sources.

**1.4.2 Form S-3**

The following information is provided in response to the information requested on DOH Form S-3. The items listed below are numbered according to the section designations used on Form S-3.

- I.A Chevron certifies that this application accurately describes facility changes that have occurred since submittal of the initial Covered Source Permit application and the associated applicable requirements.
- I.B Equipment specifications, including applicable maximum design capacity, fuel type, fuel use, production capacity, production rates, and raw materials, are presented in Sections 2.2 through 2.8.
- I.C A description of all facility processes and products defined by Standard Industrial Code is provided in Section 2.3. No anticipated alternative operating scenarios are proposed. Pollution control equipment used in the refinery is described in Section 3.3.
- I.D The operating schedule for the refinery is described in Section 2.7.
- I.E Applicable air quality regulatory requirements, as defined in §11-60.1-82, and the associated compliance monitoring and reporting requirements are presented in Section 5.
- I.F The basis for estimating maximum facility emissions is provided in Section 3, including equipment and/or operating limitations that affect maximum emissions.
- I.G As described in Section 4, air quality assessments of the refinery's impacts on local air quality have been conducted for the initial Covered Source Permit application and in connection with subsequent applications for modifications to refinery facilities. These previous assessments are adequate to demonstrate that the refinery does not cause applicable ambient air quality standards to be exceeded.
- I.H As described in Section 4, air quality assessments of the refinery's impacts on local air quality have been conducted for the initial Covered Source Permit application and in connection with subsequent applications for modifications to refinery facilities. These previous assessments are adequate to demonstrate that the current refinery and future facility modifications that are currently being considered will not cause applicable ambient air quality standards to be exceeded.
- I.I This application for permit renewal does not pertain to a new covered source or to a significant modification subject to the Prevention of Significant Deterioration provisions of Subchapter 7 of HAR Chapter 11-60.1, and is therefore not required to submit the analyses, assessments, monitoring and other applicable requirements of Subchapter 7.
- I.J Chevron does not propose to conduct any emissions trading among sources of the Hawaii Refinery.
- I.K A completed compliance plan, DOH Form C-1, and a compliance certification, Form C-2, are provided in Section 5 of this application.

File/Application No.: \_\_\_\_\_

**STANDARD PERMIT APPLICATION FORM**

HAWAII DEPARTMENT OF HEALTH  
 ENVIRONMENTAL MANAGEMENT DIVISION  
 CLEAN AIR BRANCH  
 P.O. Box 3378 · Honolulu, HI 96801-3378 · Phone: (808) 586-4200

1. Company Name: Chevron USA Products Company, a Division of ChevronTexaco Corp.
2. Facility Name (if different from the Company): Chevron Hawaii Refinery
3. Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707  
 Phone Number: (808) 682-5711
4. Name of Owner/Owner's Agent: Martha A. Gilles  
 Title: Refinery Manager Phone: (808) 682-5711  
 Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707
5. Plant Site Manager/Other Contact: Martha A. Gilles  
 Title: Refinery Manager Phone: (808) 682-5711  
 Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707
6. Permit Application Basis: (Check One.)
- |  |  |
|--|--|
| <input type="checkbox"/> Initial Permit for a New Source       | <input type="checkbox"/> Initial Permit for an Existing Source   |
| <input checked="" type="checkbox"/> Renewal of Existing Permit | <input type="checkbox"/> General Permit  |
| <input type="checkbox"/> Temporary Source                      | Transfer of Permit   |
| <input type="checkbox"/> Modification: ==> Is Modification?    | <input type="checkbox"/> Significant <input type="checkbox"/> Minor <input type="checkbox"/> Uncertain |
7. If renewal or modification, include existing permit number: CSP No. 0088-01-C
8. Does the Proposed Source require a County Special Management Area Permit?  Yes  No
9. Type of Source (Check One):  Covered Source  Covered and PSD Source  
 Noncovered Source  Uncertain
10. Standard Industrial Classification Code (SICC), if known: 2911

11. Proposed Equipment/Plant Location: Chevron Hawaii Refinery  
 City: Kapolei State: Hi Zip Code: 96707  
 UTM Coordinates: East-591,657 meters/ North-2,357,127 meters
12. General Nature of Business: Petroleum Refining
13. Date of Planned Commencement of Construction or Modification: N/A
14. Is *any* of the equipment to be leased to another individual or entity?  Yes  No
15. Type of Organization:  Corporation  Individual Owner  Partnership  
 Government Agency (Government Facility Code: \_\_\_\_\_)  
 Other: \_\_\_\_\_

*Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the non-covered source permit or release of a draft covered source permit.* (§11-60.1-64 & 11-60.1-84)

**RESPONSIBLE OFFICIAL**

(as defined in §11-60.1-1):

Name (Last): Gilles (First): Martha (MI): A.  
 Title: Refinery Manager Phone: (808) 682-5711  
 Mailing Address: 91-480 Malakole Street  
 City: Kapolei State: HI Zip Code: 96707

**CERTIFICATION by Responsible Official**

(pursuant to §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution control, and any permit issued thereof.

NAME (Print/Type): Martha A. Gilles  
 (Signature): *MA Gilles* Date: 8/1/03

<p><b>FOR AGENCY USE ONLY:</b>          File/Application No.: _____          Island: _____          Date Received: _____</p>
--

Fill in the *Emissions Units Table* as completely as possible. Use separate sheets of paper as applicable. General instructions are provided below:

1. *Identify each emission point with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SIC Code. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirement of Chapter 60.1. Example of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations are O.K.*
  - a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service Number (CAS#).
  - b. Indicate the emission points that discharge together for any length of time.
2. *Provide a process flow diagram identifying all equipment used in the process, including the following:*
  - a. Emission points.
  - b. Locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.
3. *Describe all points of emissions identified in number 2 above.*
4. *Maximum emission rates shall be in such terms as necessary to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:*
  - a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO<sub>x</sub>), Sulfur Dioxide (SO<sub>2</sub>), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM<sub>10</sub>). Abbreviations are O.K.
  - b. Include fugitive emissions.
  - c. Pounds per hour (#/HR) is the maximum potential emission rate expected by applicant.
  - d. Tons per year is annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.
5. *Provide a facility location map, drawn to a reasonable scale and showing the following:*
  - a. The property involved and all structures on it. Identify property/fence lines plainly.
  - b. Layout of the facility.
  - c. Location and identification of the proposed emissions unit on the property.
  - d. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 325 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.
6. *Supply additional information as follows, if applicable:*
  - a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the Equipment Description.
  - b. For a rectangular stack, indicate the length and width.
  - c. Any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Act.

LOCATION: Kapolei

(Note: Stack data for point sources within the Chevron Hawaii Refinery are presented in Tables 1 and 2 of the DOH Covered Source Permit Review Summary - File #0088- 01. Current criteria pollutant and HAP Potential to Emit data for each process area of the Refinery are presented in Section 3 of this Covered Source Renewal Application.)

**EMISSIONS UNITS TABLE**

REVIEW OF APPLICATIONS AND ISSUANCE OF PERMITS WILL BE EXPEDITED BY SUPPLYING ALL NECESSARY INFORMATION ON THIS TABLE.

AIR POLLUTANT DATA: EMISSION POINTS			AIR POLLUTANT EMISSION RATE			UTM COORDINATES			STACK SOURCE PARAMETERS						
STACK NO.	UNIT NO.	EQUIPMENT NAME/DESCRIPTION and SIC Code	EQUIP. DATE (1)	REGULATED/HAZARDOUS AIR POLLUTANT NAME (CAS#)	#/HR.	TONS/YR.	ZONE	EAST (mtrs)	NORTH (mtrs)	HEIGHT ABOVE GROUND (mtrs)	DIRECT. (2)	INSIDE DIA. (mtrs)	VEL. (m/s)	ACTUAL FLOW RATE (m <sup>3</sup> /s)	TEMP (°K)

(1) Date of Equipment Construction, Reconstruction, or Modification. Provide supporting documentation.  
 (2) Exit direction of stack emissions: up, down, or horizontal.



This section presents information describing operations at the Hawaii Refinery, as required by HAR §11-60.1-83(a)(2). The refinery receives various crude oils delivered by marine tankers and produces a wide variety of products. Operations vary depending on the material being processed and the products being manufactured. Information on these operations, equipment, and fuels, and other project description details are provided below.

The initial Covered Source Permit application package for the Hawaii Refinery was submitted to DOH in 1994 and included then-current process descriptions and identified specific equipment and/or process changes that were anticipated at that time. The updated process descriptions provided in Sections 2.4.1 through 2.4.15 for individual refinery units include information on the current status of the changes that were anticipated in 1994. Additionally, several modification projects may be implemented during the renewal period from 2004 through 2009, and these are summarized in the appropriate process descriptions as well. Many of these prospective changes are intended to optimize existing operations, and are not considered “modifications” pursuant to State or Federal requirements. Applicable regulatory requirements that would be triggered by these proposed changes are discussed in Section 5.

## **2.1 NATURE AND LOCATION OF FACILITY**

The Hawaii Refinery is an integrated petroleum refinery on the island of Oahu, Hawaii. Please refer to Section 1 for a description of the facility location. The Standard Industrial Classification Code (SICC) for the refinery is 2911. A facility plot plan is presented as Figure 2-1.

## **2.2 OVERVIEW OF PETROLEUM REFINING**

Crude oils are complex mixtures of chemical compounds ranging from dissolved gases to compounds that are solids at room temperature. Almost all of these compounds, however, are composed of hydrogen and carbon (hydrocarbon compounds). Also included in crude oil are water and trace contaminants such as inorganic salts, metals, and sulphur compounds.

The steps by which crude oil is processed into numerous saleable products are known collectively as refining. Crude oils from various locations may have differing compounds and properties that affect specific refinery operations. The initial refining process separates crude oil into different fractions based on their respective boiling point ranges. Some of the lighter and intermediate fractions are blended into products. Heavier fractions may be further processed by cracking the large hydrocarbon molecules into smaller ones. The structures of some molecules may also be rearranged to provide the desired components.

The basic steps used in refining crude oil feedstock at the Hawaii Refinery are as follows. First, crude oil is separated into several components using distillation methods. Heavier hydrocarbon compounds are further processed by cracking and subsequent combining or rearranging. Undesirable compounds containing sulfur, such as hydrogen sulfide or mercaptans, are removed or transformed to useful compounds. The various hydrocarbon components are blended together according to product specifications. For example, motor gasoline may include straight-run naphtha, cracked gasoline, reformate, alkylate and other components. Refinery operations also include auxiliary systems, such as hydrogen production, wastewater treating, acid production, and steam production.



## **2.3 REFINERY PROCESS DESCRIPTIONS AND RELATIONSHIP TO MARINE MOORING FACILITY**

The Hawaii Refinery is considered a major stationary source, and therefore is subject to the Title V permit program. A general process flow diagram for the refinery is presented in Figure 2-2. Marine tankers deliver crude oil from various locations to the Hawaii Refinery for processing. Marine vessel operations are exempted from the permitting requirements of the Hawaii program by HAR §11-60.1-82(g)(7). The marine mooring facility that services the refinery is approximately 1½ miles offshore and is not contiguous to the refinery. Accordingly, that facility operates under a separate Covered Source Permit, No. 0098-01-C. Chevron is submitting a separate permit renewal application to DOH for the marine mooring facility.

### **2.3.1 Crude Unit**

#### **2.3.1.1 Current Process**

Crude oil processed at the refinery is transferred from tankers via pipeline to the blending and shipping area of the refinery, where it is placed in storage tanks. The crude oil is then pumped to the crude unit, where the refining process begins.

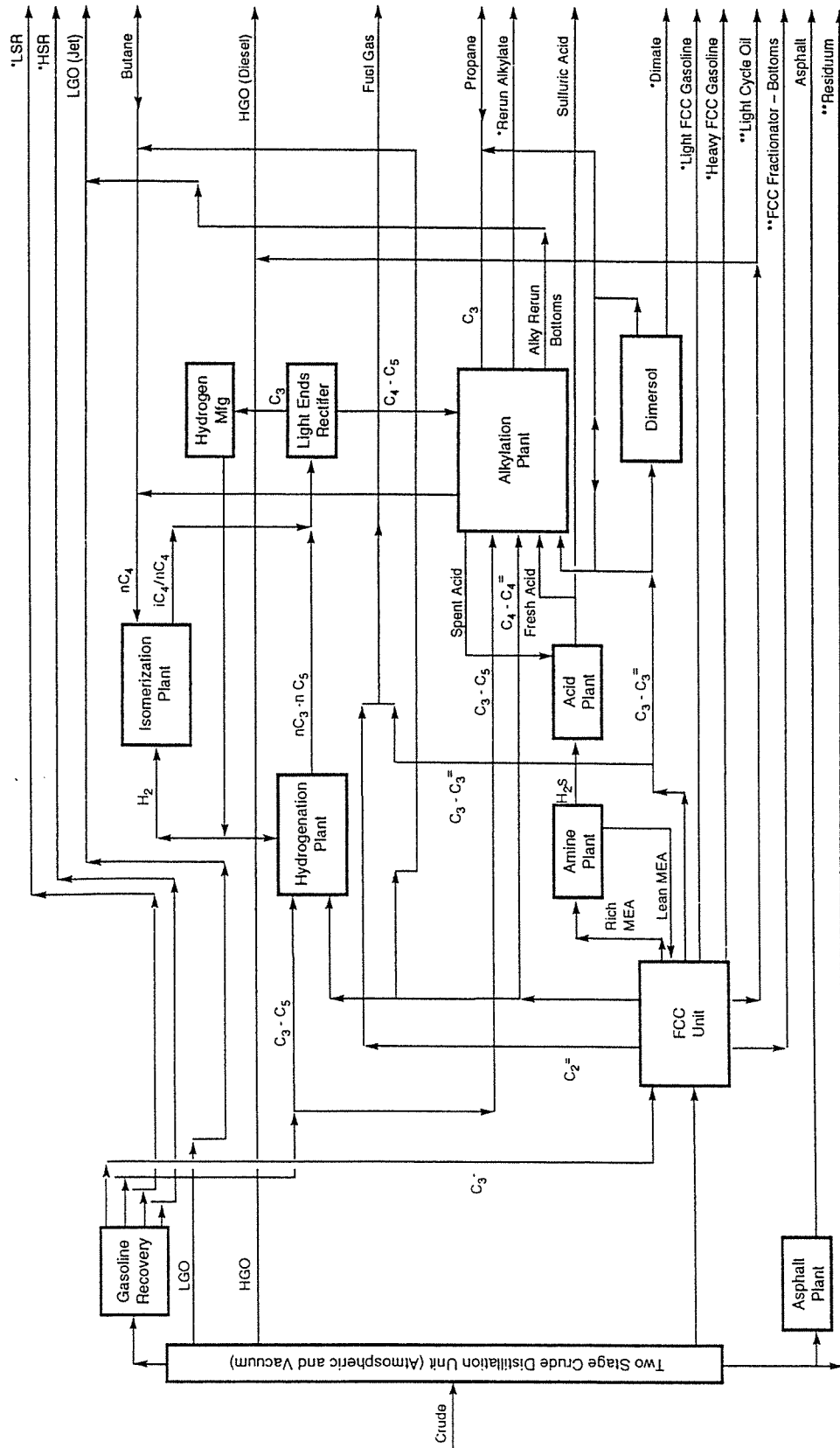
A simplified flow diagram of the crude distillation unit is presented as Figure 2-3. The crude feed enters the crude unit and is routed to the primary feed pump. This pump boosts the pressure of the feed to enable it to flow through the various heat exchangers and the desalter. The primary feed exchangers increase the temperature of the crude feed from approximately 100°F to about 300°F.

Crude oil frequently contains brine and inorganic salts from underground deposits. To minimize the fouling and corrosion of refining equipment, the crude is run through a desalter. The desalter reduces the velocity of the crude oil flow and, with the aid of electrical grids, separates additional water from the crude. Because most of the solids present are soluble in water, they leave the desalter with the water phase.

The crude oil out of the desalter is routed through a preheat exchanger to a flash drum to vaporize the light hydrocarbons and route them directly to the atmospheric column (bypassing the atmospheric furnace). The crude oil from the bottom of the flash drum is routed to the suction side of the crude booster pump, which pumps the oil through the secondary preheat train exchangers. The oil exiting the preheat exchangers is pumped through the atmospheric furnace into the atmospheric column, at a temperature of about 680°F.

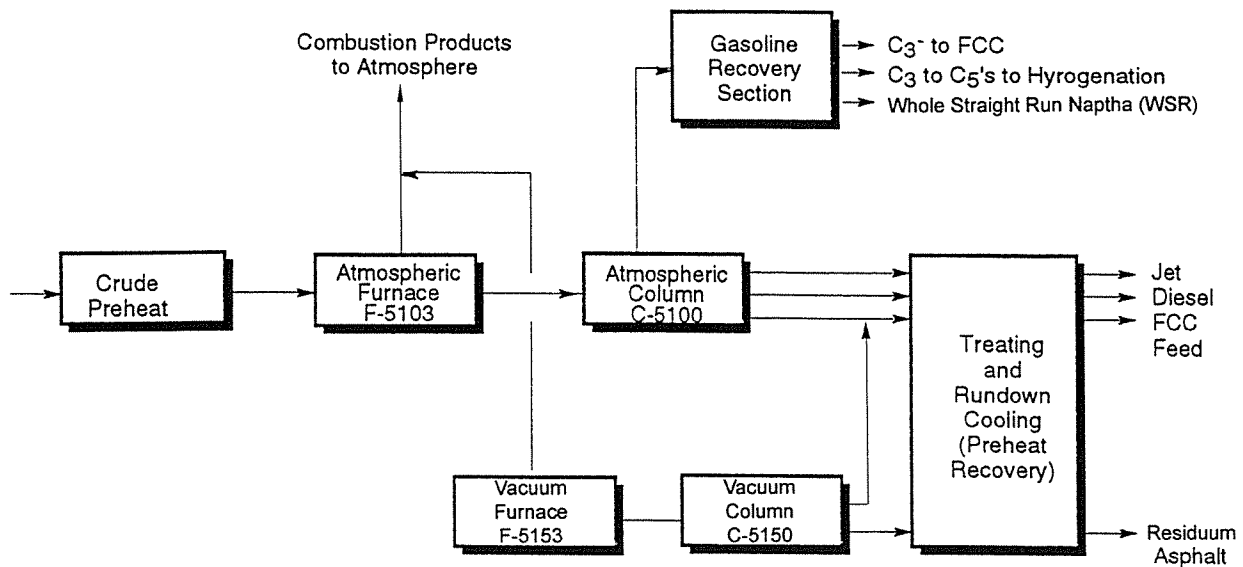
In the atmospheric column, the hot crude oil vaporizes and several product streams are drawn off, as follows:

- *Atmospheric overhead* – All material lighter than jet, which includes whole straight run naphtha and light ends such as methane, ethane, propane and butane
- *First side cut* – Normally commercial jet fuels (Jet A-40, Jet A-50, Jet JP-8)
- *Second side cut* – Not normally produced
- *Third side cut* – Diesel fuel (low sulfur and high sulfur)
- *Fourth side cut* – Atmospheric gas oil, which is fluid catalytic cracker (FCC) feed



\* GASOLINE BLEND STOCKS  
 \*\* FUEL OIL BLEND STOCKS

<b>CHEVRON HAWAII REFINERY GENERAL PROCESS FLOW DIAGRAM</b>			
<b>URS</b>	CHECKED BY:	DATE: MAY 2003	FIG. NO:
	PM: JL	PROJ. NO: 27653013.01000	2-2



**CRUDE UNIT  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRON HAWAII REFINERY**

**URS**

CHECKED BY:

DATE: MAY 2003

FIG. NO:

PM: JL

PROJ. NO: 27653013.01000

2-3

- *Bottoms* – Feed to the vacuum column

The atmospheric tower bottoms product is routed through the vacuum furnace, where it is heated to approximately 790°F. Because products at lower pressure boil at lower temperatures, the vacuum column operates under vacuum to promote distillation of the heavy bottoms product without cracking of molecules. Two side product streams are both vacuum gas oil (VGO), which is used as a feed to the fluid catalytic cracker (FCC) unit. Residual product (residuum) is routed through exchangers to storage, where it is blended into fuel oil or a road asphalt base. Residuum may also be used as a feedstream to the FCC. Air pollutant emissions from the crude unit occur in the form of fugitive releases from piping components in gas and liquid service and as combustion products from the vacuum and atmospheric furnaces.

A replacement crude jet stripper that was proposed to be installed during the current permit period, 1999 through 2004, and listed in the initial Covered Source Permit application as a possible future project in the Crude Unit has not been installed, and this project is no longer planned for implementation.

### 2.3.1.2 Future Process

Several projects at the crude unit may be implemented during the renewal period from 2004 through 2009. These are primarily changes to optimize existing operations that may not require any modification to the current permit. Following is a description of potential crude unit alterations that are currently under consideration.

- **Change fixed speed motors to variable speed motors for the forced draft fan and induced draft fan at the crude unit.** This is an energy savings project that will optimize performance of the combustion process. The change would not increase the unit's operation beyond its original (permitted) capacity, although it could result in a slight increase in fuel combustion relative to operations in recent years.
- **Change-out tubes in the convection section of the crude unit furnace.** This project would correct a configuration design problem with the current tubes, which become coated and cannot be adequately cleaned by soot blowing. The project would not change the design throughput limit of this furnace and would not cause an increase in the potential to emit. Installation is planned for 2008.
- **Add diesel draw to the vacuum column.** This would be a change in piping off the column and would only add a few piping components. Installation could occur by 2005.
- **Optimize whole straight run naphtha overhead of the crude unit.** This would essentially be a change in pipe size to optimize the crude unit's production for certain crudes that are used to make naphtha. No change to the unit's fuel use rate would result from such a modification, which is considered to have a low probability of being implemented in the next several years.

- **Change out 24 burners to allow the combustion of fuel oil and/or refinery gas in the atmospheric and vacuum crude furnaces.** The subject burners currently only combust fuel oil. This change is expected to reduce emissions of most pollutants. The timing for this project is uncertain.

### 2.3.2 Fluid Catalytic Cracker (FCC) Unit

#### 2.3.2.1 Current Process

The purpose of the fluid catalytic cracker (FCC) unit is to convert material from the crude unit into gasoline blend components. Additionally, the FCC produces refinery fuel gas, propane and propylene, butane and butylene, light cycle oil and fractionator bottoms.

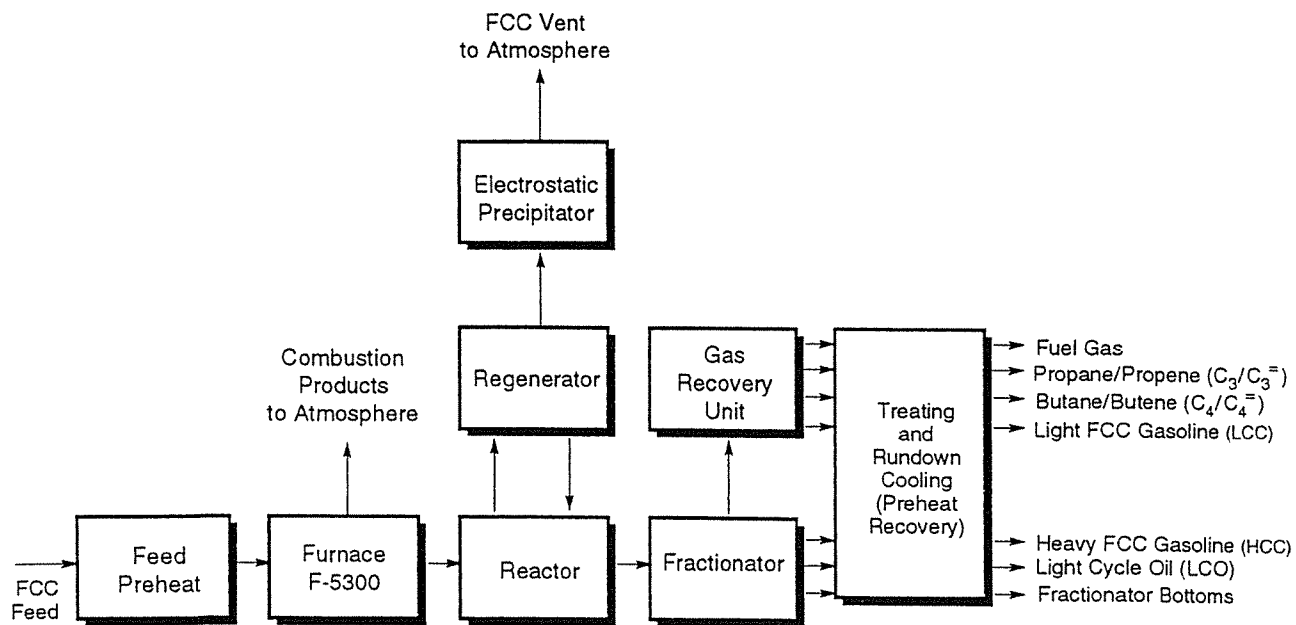
The conversion of the FCC feed to higher valued products is accomplished by “cracking” the heavier hydrocarbon molecules into lighter molecules by contacting the feed with an air-assisted circulating catalyst at relatively high temperature (980-1010°F). The process of cracking the molecules results in the formation of coke on the catalyst. This coke inhibits the cracking process, so it is burned off to restore catalyst activity. The heat of combustion of the coke is a major source of heat to maintain the needed reaction temperature. The flue gas exiting the FCC is mixed with some particles of catalyst and routed through cyclones and an electrostatic precipitator to remove this particulate matter.

Products are routed to the fractionator and separated, as shown in Figure 2-4. The gas recovery unit separates gaseous products and includes removal of hydrogen sulfide. Products from the crude distillation towers and the FCC are treated by several other refinery process units, as discussed in the following subsections.

The initial Covered Source Permit application identified a proposed FCC feed riser as a potential future project to improve FCC reactor temperature control and cracker performance. This modification was not implemented, having been superseded by the Revamp Project discussed below.

The refinery has been operating the FCC and regenerator with an electrostatic precipitator (ESP) since 1961. In 2002, the ESP was replaced, following application for and DOH approval of a minor modification to the existing Covered Source Permit. Emissions from the FCC and gas recovery unit consist of piping component fugitives, as well as PM<sub>10</sub> and combustion gases from the precipitator and FCC furnace.

In 2002, Chevron also applied for a permit modification to enable a FCC Revamp Project to modernize the technology of the FCC to current industry standards. The DOH issued a permit amendment to the Covered Source Permit for this project on March 3, 2003. The project included installation of a slide valve control to improve the ability of the operators to balance the operation of the catalyst reaction and regeneration vessels, as well as other upgrades. The project has resulted in improved reliability, ability to implement advanced controls, improved turndown capability/environmental performance, and better operational flexibility to process low sulfur feeds to meet the future low sulfur gasoline requirements.



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FCC UNIT  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRON HAWAII REFINERY

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DATE: MAY 2003

FIG. NO:

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PROJ. NO: 27653013.01000

2-4



The FCC Revamp Project application presented to DOH showed that the project would not cause an emission increase and therefore would not trigger any new federal New Source Performance Standards (NSPS) or the Prevention of Significant Deterioration (PSD) permitting process. The DOH processed the application as a major modification, because DOH added federally enforceable permit conditions to maintain emissions below PSD levels. Dispersion modeling was conducted that showed the project would have a negligibly small effect on local air quality. The project was completed in May 2003.

### **2.3.2.2 Future Process**

No further substantive process changes to the FCC unit are under consideration at the time of this permit renewal application. However, monitoring equipment for continuous measurement of opacity and CO emissions will be installed in this unit to comply with MACT standards before April 1, 2005.

## **2.3.3 Hydrogen Manufacturing Plant**

### **2.3.3.1 Current Process**

The purpose of the hydrogen plant is to convert butane, propane and the lighter hydrocarbons into hydrogen and carbon dioxide. The hydrogen is used in the hydrogenation, dimersol, and isomerization processes. The carbon dioxide generated in the unit is vented to the atmosphere. The hydrogen manufacturing process separates the hydrogen atoms from hydrocarbon molecules in a catalytic reforming furnace. The hydrogen unit emits fugitive emissions from piping components and combustion products from the furnace. A simplified flow diagram of the hydrogen plant is provided in Figure 2-5.

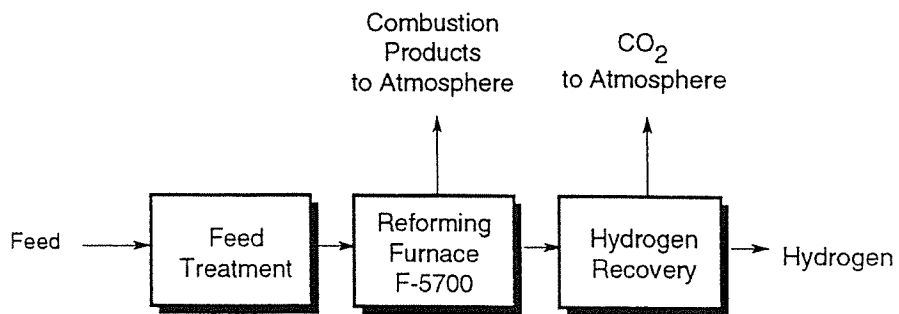
### **2.3.3.2 Future Process**

No changes have occurred in the Hydrogen Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

## **2.3.4 Hydrogenation Plant**

### **2.3.4.1 Current Process**

The hydrogenation plant saturates butene with hydrogen to form a saturated butane molecule. The butane is then fed to the isomerization process or used for gasoline blending. The hydrogenation process uses a fixed-bed reactor with a hydrogen rich atmosphere. The hydrogenation plant emits fugitive emissions from piping components and combustion emissions from the hydrogenation furnace. A simplified representation of the unit's process flow is shown in Figure 2-6.



HYDROGEN PLANT  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRON HAWAII REFINERY

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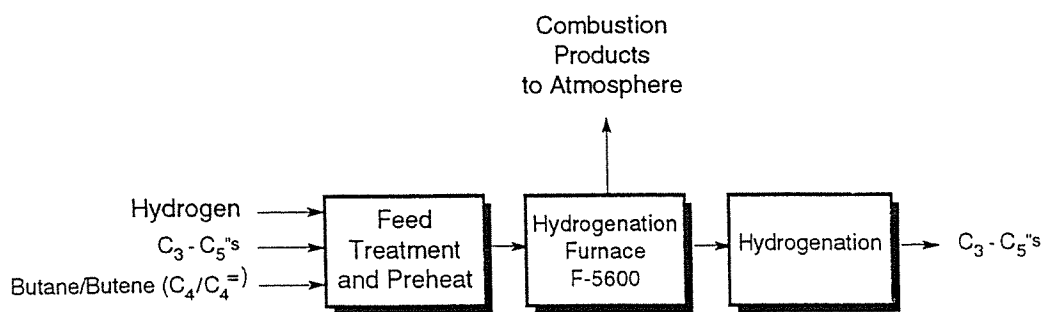
DATE: MAY 2003

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2-5



HYDROGENATION PLANT  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRON HAWAII REFINERY

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DATE: MAY 2003

FIG. NO:

PM: JL

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2-6

**2.3.4.2 Future Process**

No changes have occurred in the Hydrogenation Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

**2.3.5 Dimersol Plant****2.3.5.1 Current Process**

A Dimersol reactor and associated facilities were installed in 1987 as part of the gasoline manufacturing section to improve C3 handling within the refinery and to reduce flaring. The Dimersol plant converts propylene into dimate (hexene isomers), a gasoline blend component. The dimate is routed to a storage tank for blending. Propylene feed is supplied from the FCC unit and is converted in the Dimersol Reactor.

The Dimersol process is a closed-loop system that does not emit pollutants directly to the atmosphere. Fugitive piping component emissions, however, are released from the Dimersol Plant. A simplified process flow diagram for this unit is presented as Figure 2-7.

**2.3.5.2 Future Process**

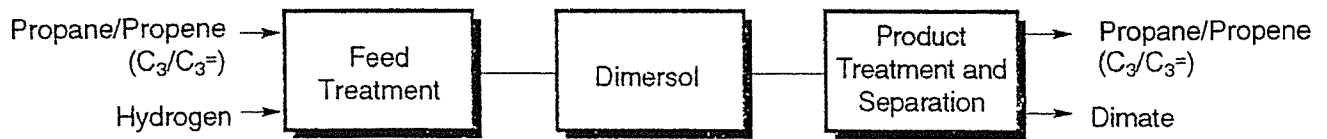
No changes have occurred in the Dimersol Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

**2.3.6 Isomerization****2.3.6.1 Current Process**

The purpose of the Isomerization Plant is to convert normal butane into isobutane. Isobutane is required as one of the two feed components in the alkylation process. The isomerization process uses a fixed bed reactor with a catalyst of aluminum beads. The feed stream is dehydrated upstream of the isomerization process, as water will deactivate the catalyst. Combustion emissions from the isomerization furnace and fugitive emissions from piping components result from operation of the Isomerization Plant. The products of the isomerization process are fed to the Alkylation Plant. A simplified process flow diagram for this unit is presented as Figure 2-8.

**2.3.6.2 Future Process**

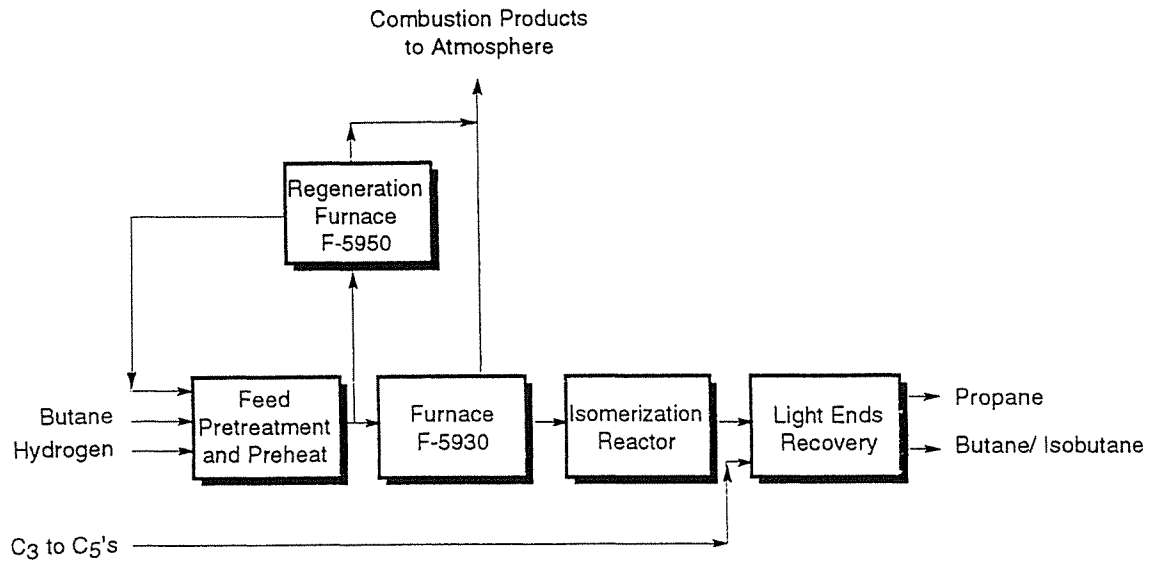
No changes have occurred in the Isomerization Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.



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DIMERSOL PLANT  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRON HAWAII REFINERY

<b>URS</b>	CHECKED BY:	DATE: MAY 2003	FIG. NO: 2-7
	PM: JL	PROJ. NO: 27653013.01000	



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<b>ISOMERIZATION PLANT</b> <b>SIMPLIFIED PROCESS FLOW DIAGRAM</b> <b>[INCLUDING LIGHT ENDS RECTIFIER (LER)]</b> <b>CHEVRON HAWAII REFINERY</b>			
<b>URS</b>	CHECKED BY:	DATE: MAY 2003	FIG. NO:
	PM: JL	PROJ. NO: 27653013.01000	2-8

### **2.3.7 Alkylation**

#### **2.3.7.1 Current Process**

The alkylation process joins the isobutane from the Isomerization Plant with propylene or butene to form alkylate, a gasoline-blending component. This reaction is catalyzed by high-concentration sulfuric acid. The reaction is exothermic and the heat of reaction is captured by heat exchangers. The alkylation process emits fugitive piping component emissions. A simplified process flow diagram for this unit is presented as Figure 2-9.

#### **2.3.7.2 Future Process**

No changes have occurred in the Alkylation Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

### **2.3.8 Acid Manufacturing**

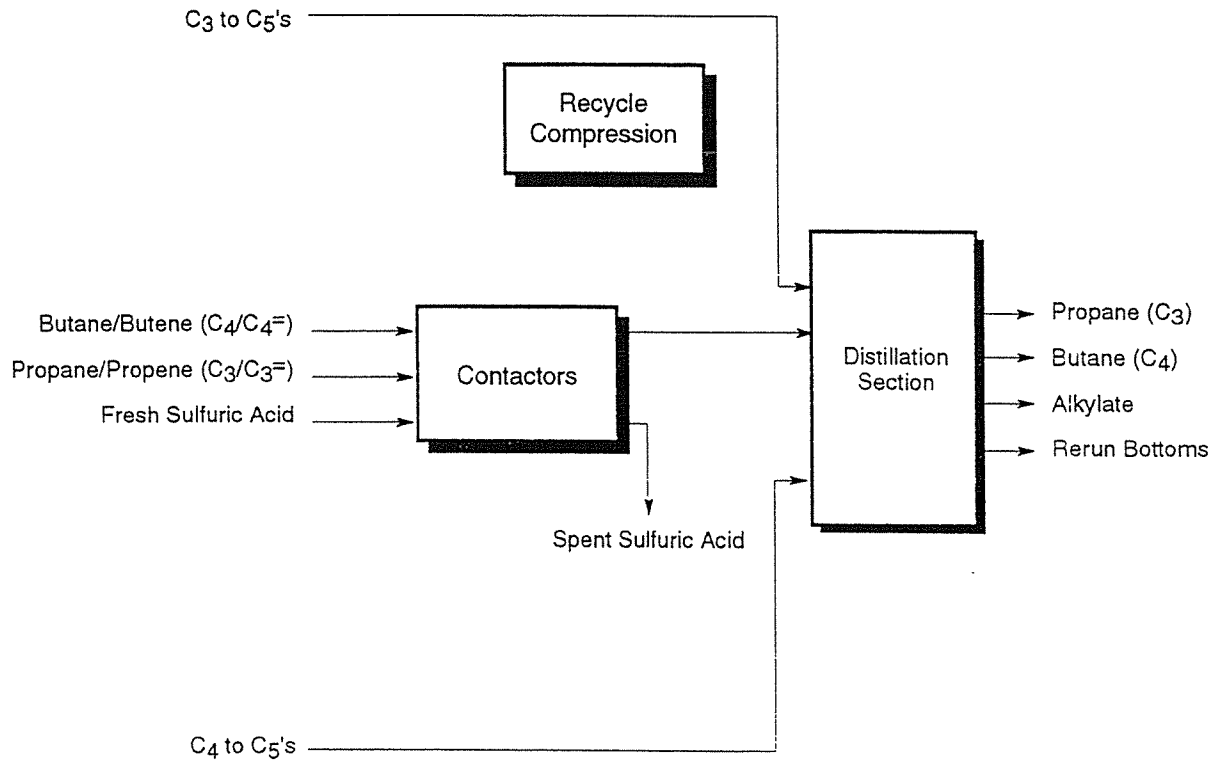
#### **2.3.8.1 Current Process**

The Acid Manufacturing area of the Hawaii Refinery includes sulfuric acid manufacturing, acid storage, and amine processing facilities. The Amine Plant is an amine regeneration system used to recover hydrogen sulfide. The Acid Plant manufactures sulfuric acid from feedstocks available in the refinery.

The principal feeds are spent acid returned from the alkylation plant and H<sub>2</sub>S gas from the amine regeneration system. The Acid Plant produces acid by decomposition of spent acid and combustion of hydrogen sulfide gas to form sulfur dioxide (SO<sub>2</sub>). The SO<sub>2</sub> is then oxidized to form sulfur trioxide (SO<sub>3</sub>). Finally, the SO<sub>3</sub> is absorbed in a strong sulfuric acid solution to form sulfuric acid. Residual unconverted SO<sub>2</sub> is emitted from the absorber stack. Fugitive component emissions result from the acid and amine regeneration facilities. The acid plant combustion chamber and preheater emit combustion products. The combustion chamber exhaust passes through the plant and is emitted from the adsorbing tower stack. A simplified process flow diagram is presented as Figure 2-10.

#### **2.3.8.2 Future Process**

A Flare Sulfur Emission Reduction Project (FSERP) was installed during 2003. The project entailed installation of a caustic system to remove hydrogen sulfide from the acid gas feed stream during periods when the acid plant is shut down and all the acid plant gas is routed to the FCC unit flare. This change was implemented to improve process operations, rather than as an air pollution project.



**ALKYLATION PLANT**  
**SIMPLIFIED PROCESS FLOW DIAGRAM**  
**CHEVRON HAWAII REFINERY**

**URS**

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DATE: MAY 2003

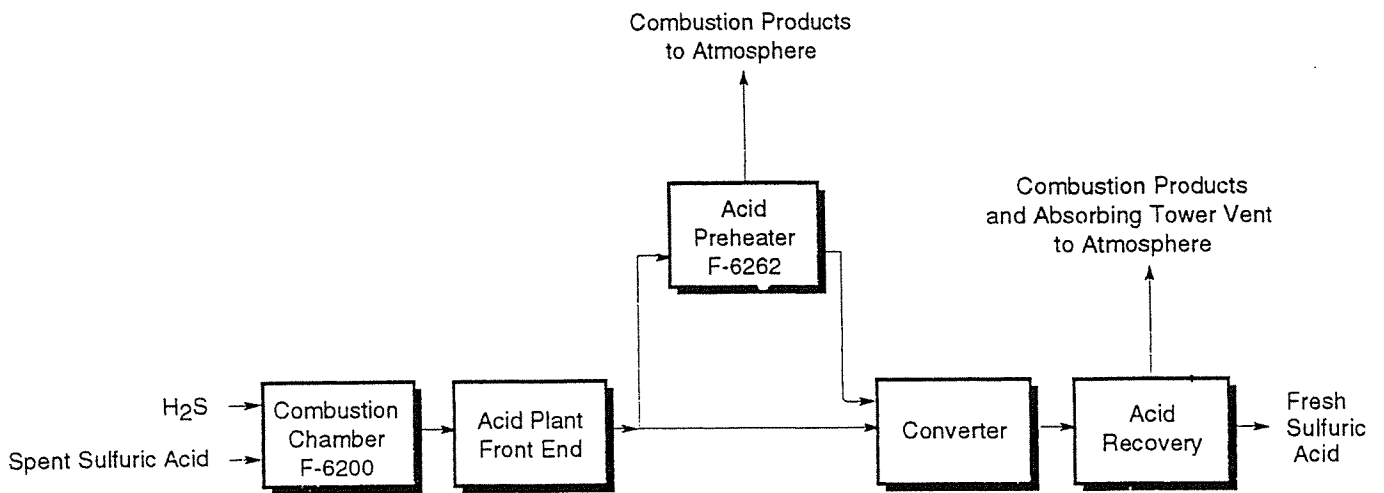
FIG. NO:

PM: JL

PROJ. NO: 27653013.01000

2-9





<b>ACID PLANT</b> <b>SIMPLIFIED PROCESS FLOW DIAGRAM</b> <b>CHEVRON HAWAII REFINERY</b>			
<b>URS</b>	CHECKED BY:	DATE: MAY 2003	FIG. NO:
	PM: JL	PROJ. NO: 27653013.01000	2-10

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### **2.3.9 Boiler Plant**

#### **2.3.9.1 Current Process**

Steam is critical to the refinery processes and 600-pound steam is used throughout the facility. Steam is supplied by three boilers in the Boiler Plant and three Cogeneration Plant turbines, each of which is equipped with a heat recovery steam generator (HRSG). The Boiler Plant consists of the three boilers and ancillary fuel supply systems. Both refinery gas and fuel oil are used as fuels in the boilers.

#### **2.3.9.2 Future Process**

No changes have occurred in the Boiler Plant since the original Title V permit for the refinery was issued. The only change in this area being considered for implementation during the term of the renewed permit is an energy project that would replace the steam generation function of the existing boilers with a new cogeneration plant (see Section 2.3.10).

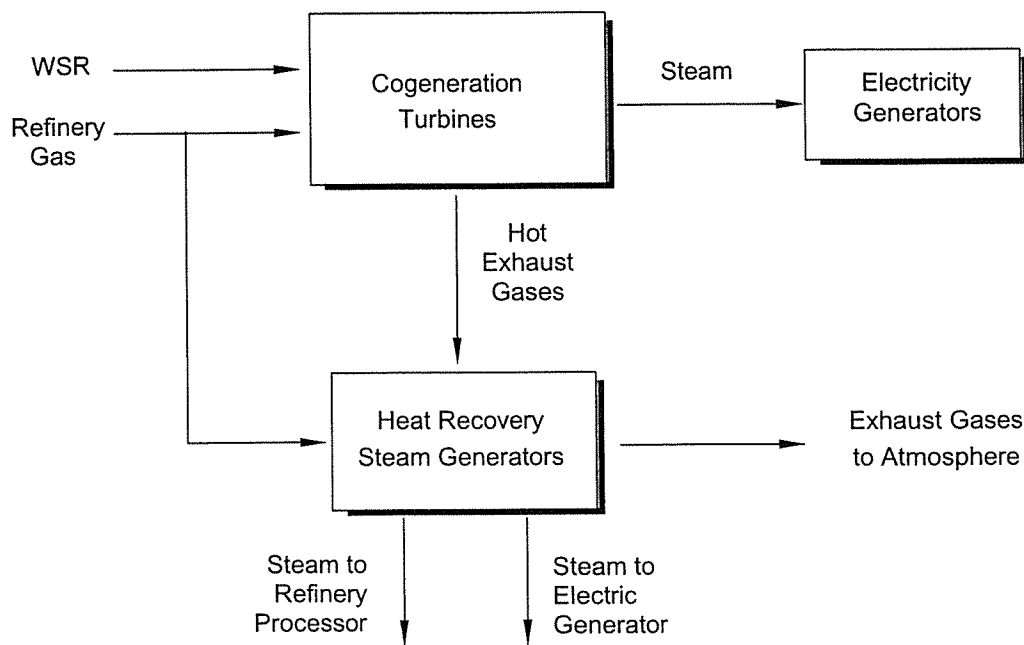
### **2.3.10 Cogeneration Plant**

#### **2.3.10.1 Current Process**

This area includes three 40 MMBtu/hr gas turbines with Heat Recovery Steam Generators (HRSGs). These units are equipped with low-NO<sub>x</sub> burners and water injection for control of NO<sub>x</sub> emissions. Refinery fuel gas (RFG) and whole straight run naphtha (WSR) are used as fuels in the cogeneration turbines. Only RFG is combusted in the HRSGs. Fuel combustion products are emitted from these units. A process flow diagram for the Cogeneration Plant is provided in Figure 2-11.

#### **2.3.10.2 Future Process**

A possible future energy project that would install two new cogeneration turbines with a capacity of 5 to 6 MW electrical generation and HRSGs is under consideration, and may be funded during the term of the renewed Covered Source Permit. This project would likely result in a net decrease in emissions for most pollutants, because it would replace the steam generation function of the three existing uncontrolled boilers (see Section 2.3.9) with cleaner, more efficient modern cogeneration technology. The new units would likely be configured to burn either RFG or WSR.



<b>COGENERATION PLANT SIMPLIFIED PROCESS FLOW DIAGRAM CHEVRON HAWAII REFINERY</b>			
<b>URS</b>	CHECKED BY:	DATE: MAY 2003	FIG. NO:
	PM: JL	PROJ. NO: 27653013.01000	2-11

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### 2.3.11 Blending and Shipping

#### 2.3.11.1 Current Process

The blending and shipping area includes the refinery tank farm, LPG handling system and truck loading racks. Fugitive emissions from tanks and piping components are emitted from this process area, which contains no fuel-burning equipment.

The refinery tank farm consists of storage tanks for the following hydrocarbon liquids: crude oil, refinery products, blending components and recovered oil. The capacities, control equipment and types of service that have been assumed in postulating the maximum emission scenario for the refinery, including tank emissions, are described in Section 3.

Chevron is in the process of installing secondary seals (or equivalent emission reduction technology) on 34 external floating roof petroleum storage tanks, as required by the initial Covered Source Permit. This activity is being conducted for compliance with refinery MACT standards under 40 CFR 63 Subpart CC, and is reducing volatile organic emissions from the facility. Tanks 113, 301 and 302 have been retrofitted separately for compliance with 40 CFR 60 Subpart Kb. As of the date of this application, 17 tanks had been retrofitted with secondary seals or domed roofs, and the remaining tanks are scheduled for completion by August 2005.

The current Covered Source Permit allows the storage capacities of Storage Tanks 105 through 111 to be increased by 12 percent, provided that no new applicable requirement is triggered by such action and the seal requirements pursuant to 40 CFR Part 63, Subpart CC have been met. Since the issuance of the initial permit, Tanks 106, 109, 110 and 111 have received course additions that increased their capacities by about 12 percent. Tanks 107 and 108 may be similarly expanded during the term of the renewed Covered Source Permit.

In 2002, Chevron applied for and received a minor modification to the refinery's Covered Source Permit to install domes on Tanks 249 and 250 for compliance with MACT requirements under 40 CFR 63 Subpart CC. These tank retrofits have been completed.

Typically, products from the refinery are shipped offsite via pipeline, and the truck loading rack is not used. If the pipeline is unavailable, the truck loading rack at the refinery will be used. Estimated loading volumes during such periods, based on the assumption that the refinery would need to meet the outer island fuel demands, are as follows:

- Motor gasoline – 20,000 barrels per day
- Aviation gasoline – 110 barrels per day
- Jet Fuel – 13,000 barrels per day
- Diesel – 10,000 barrels per day

**2.3.11.2 Future Process**

In the future, a tank with a capacity of 80,000 barrels may be moved to the refinery from its current offsite location near the airport. The tank will be in jet fuel service and will have a throughput of about 11,000 barrels per day. This project would not occur until the 2005-2006 time frame.

**2.3.12 Asphalt Plant****2.3.12.1 Current Process**

The asphalt plant consists of tanks, pumps, a fired furnace and loading racks. The Crude Unit produces asphalt, and the Asphalt Plant stores this material in a heated state to prevent hardening and then transfers the asphalt to trucks by means of a loading rack. Because of the low volatility of the products handled in the Asphalt Plant, fugitive organic emissions from this plant are negligibly small. Combustion products are emitted from the asphalt furnace.

**2.3.12.2 Future Process**

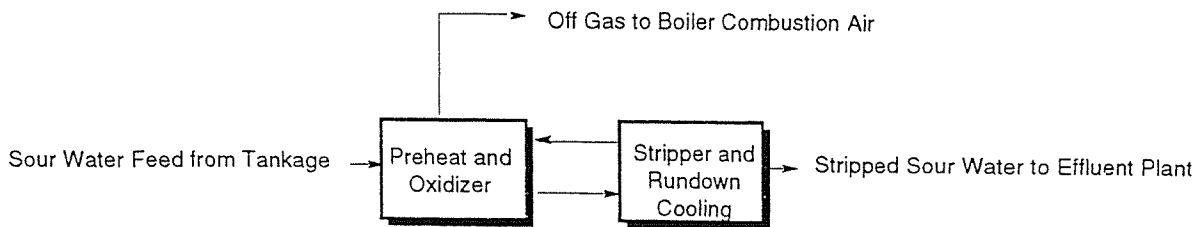
No changes have occurred in the Asphalt Plant since the original Title V permit for the refinery was issued, and none are being considered for implementation during the term of the renewed permit.

**2.3.13 Effluent Treatment****2.3.13.1 Current Process**

Wastewater consists of process area sampling waste, process (oily) wastewater, and stormwater waste. Wastewater containing small amounts of ammonia, sulfides, and hydrocarbons is routed to the sour water tanks, then treated in the Foul Water Oxidizer and pumped to the wastewater treatment plant. Off-gas (primarily ammonia) from the Oxidizer is sent via the combustion air to one of the boilers. A simplified process flow diagram of the Foul Water Oxidizer is presented in Figure 2-12.

Wastewater not sent to the Foul Water Oxidizer (i.e., possibly containing hydrocarbons) is routed to the API separators, where oil is recovered and the resulting wastewater is treated. Treatment for process wastewater uses a nitrogen gas stripper for benzene control. Gaseous hydrocarbons from the nitrogen stripper are removed in a carbon adsorber. Both process wastewater and stormwater waste are then treated by aggressive biological oxidation in ponds. A simplified process flow diagram of the Effluent (Wastewater Treatment) Plant is presented in Figure 2-13. Minimal fugitive emissions result from the foul water and wastewater treatment plants.

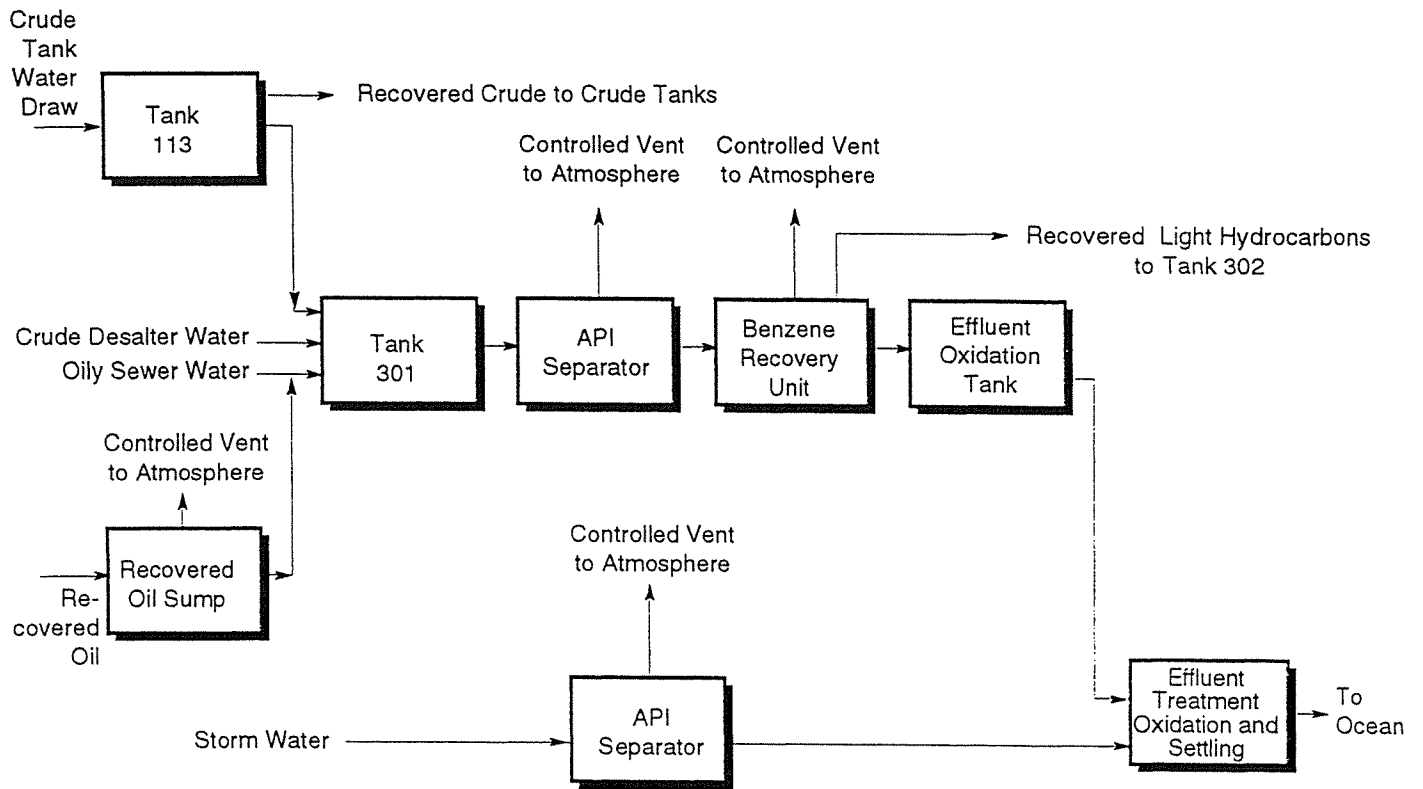
The landfarm previously used to biodegrade hydrocarbon-contaminated soils ceased to receive such materials in July 1995, was capped in November 1997 and received formal closure from EPA in 1998. This facility is no longer in use, but ongoing activities include monthly inspections of the cap integrity and quarterly monitoring of permitted wells for BTEX and semi-volatiles. Groundwater



<b>FOUL WATER OXIDIZER SIMPLIFIED PROCESS FLOW DIAGRAM CHEVRON HAWAII REFINERY</b>			
<b>URS</b>	CHECKED BY:	DATE: MAY 2003	FIG. NO:
	PM: JL	PROJ. NO: 27653013.01000	2-12

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**EFFLUENT PLANT  
SIMPLIFIED PROCESS FLOW DIAGRAM  
CHEVRON HAWAII REFINERY**

**URS**

CHECKED BY:

DATE: MAY 2003

FIG. NO:

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PROJ. NO: 27653013.01000

2-13

monitoring in this area is to be included in the annual “plume-wide Groundwater Monitoring Program” submitted to DOH.

### **2.3.13.2 Future Process**

Except for closure of the landfarm, no changes have occurred in the Effluent Treatment Area since the original Title V permit for the refinery was issued, and no future changes are under consideration at the time of this permit renewal application.

## **2.3.14 Flares**

### **2.3.14.1 Current Process**

Safety is a critical concern in refinery operation. In case of equipment failure or other malfunctions, systems are in place to protect the equipment from damage and the facility’s workers from harm. The refinery has many safety systems, including two flares. During normal operations, the FCC Flare primarily combusts off-gases from the FCC Unit, Isomerization Plant, Alkylation Plant, LPG area, Cogeneration Plant, Acid and Amine Plants, sour water tankage, and fuel gas system. The Crude Unit Flare serves the Crude Unit, Hydrogen Plant, Hydrogenation Plant and Dimersol Plant, as well as the sour water tankage. During shutdown of either the Crude Unit or the FCC Unit, however, all off-gas is routed to the other flare. Either flare is sized to handle the entire potential off-gas production of the refinery during a unit shutdown scenario. Historically, during Acid Plant shutdowns, the H<sub>2</sub>S stream to the plant was routed to the FCC Flare for destruction. However this no longer occurs because of the FSERP project discussed below.

### **2.3.14.2 Future Process**

As described in Section 2.3.8, the FSERP project is currently being implemented and will send acid gas streams through a caustic system for H<sub>2</sub>S removal before routing it to the flare when the Acid Plant is down, thus sharply reducing the SO<sub>2</sub> emissions of the refinery during Acid Plant downtime.

## **2.3.15 Cooling Tower**

### **2.3.15.1 Current Process**

The refinery employs an induced draft evaporative cooling tower to dissipate waste heat from several refinery processes. The cooling tower has ten cells.

### **2.3.15.2 Future Process**

No changes in the cooling system have been undertaken since issuance of the initial Title V permit for the Hawaii Refinery, and none are under consideration at the time of this permit renewal application.



## **2.4 DESIGN AND PRODUCTION RATE AND CAPACITY**

As discussed above, the refinery consists of numerous interrelated process units. Table 2-1 presents design capacity and production capacity/rate information for the major refinery process units and equipment. Actual throughputs of the units will vary over time, depending on numerous variables; however, any one process or piece of equipment may operate at its design capacity periodically or for extended periods.

## **2.5 FUELS AND FUEL USE**

Combustion sources at the refinery are fueled primarily by refinery gas or refinery fuel oil. The cogeneration turbines may be fired on either RFG or whole straight run naphtha. Fuel types and fuel use rates for specific equipment unit are presented in Table 2-2. Fuel usage rates have been estimated based on equipment design heat rates and the estimated lower heating value (LHV) of the applicable fuels. Refinery gas has a lower heating value of approximately 1030 Btu per standard cubic foot.

Actual fuel heating values vary according to refinery operations. Fuel oil has a LHV of approximately 5.78 MMBtu per barrel. Fuel flow rates in the cogeneration turbines and HRSGs are limited by DOH permit conditions.

## **2.6 RAW MATERIALS**

The primary raw material used in the Hawaii Refinery is crude oil. The base operating scenario for the refinery is the processing of a wide variety of crude oils from various sources. Crude oil is processed at a maximum rate of approximately 65,000 barrels per day. A list of the raw materials used at the refinery is presented in Table 2-3.

## **2.7 PLANT LAYOUT AND OPERATING SCHEDULE**

The plant layout is presented on Figure 2-1. The refinery operates 24 hours per day, 7 days per week, 52 weeks per year.

## **2.8 EQUIPMENT SPECIFICATIONS**

The types of processes that are present at the Hawaii Refinery have been described above. There are literally hundreds of pieces of equipment in each process unit. Table 2-1 provided the design capacity for the major pieces of equipment and process units in the refinery. Detailed specifications for each piece of equipment have not been included in this application, because of the large number of equipment and component types.

**Table 2-1  
REFINERY DESIGN CAPACITY AND PRODUCTION RATE INFORMATION**

Plant Area	Unit	Equipment	Capacity
20	Storage	Storage tanks	(see Section 3)
23	Cooling tower	Cooling tower	750 mmbtu/hr
	Crude flare	Flare 2301	253 mlb gas/hr
	FCC flare	Flare 2302	1.85 mmlb gas/hr
36	Wastewater	API separators	1400 gal/min combined
51	Crude	Distillation towers	65,000 bbls per day
		Furnace 5103	151.5 mmbtu/hr
		Furnace 5153	62.5 mmbtu/hr
52/55	Boilers	Boiler 5201	220 mmbtu/hr
		Boiler 5202	160.8 mmbtu/hr
		Boiler 5203	160.8 mmbtu/hr
53	FCC	FCC unit	22,000 bbl per day
		Furnace 5300	61 mmbtu/hr
		Catalyst regenerator	266 mmbtu/hr
56	Hydrogenation Manufacturing Plant	Hydrogenation unit	3200 bbl/day
		Furnace 5600	9 mmbtu/hr
57	Hydrogen Plant	Hydrogen unit	2500 mscf/hr
		Furnace 5700	24.3 mmbtu/hr
58	Alkylation Plant	Alkylation unit	7500 bbl per day
59	Isomerization Plant	Isomerization unit	2500 bbl/day
		Furnace 5930	4 mmbtu/hr
		Furnace 5950	1.6 mmbtu/hr
60	Asphalt Plant	Asphalt plant	Storage for transfer
		Furnace 6003	5.7 mmbtu/hr
61/62	Amine/acid plant	Acid plant	110 ton acid/day
		Combustion chamber 6200	4.2 mscf/hr
		Furnace 6262	5.1 mmbtu/hr
66	Dimersol Plant	Dimersol plant	3000 bbl per day
67	Cogeneration	Turbine 6701	76 mmbtu/hr
		Turbine 6702	76 mmbtu/hr
		Turbine 6703	76 mmbtu/hr

**Table 2-2  
FUELS AND FUEL USE**

Area	Equipment	Fuel	Design Fuel Use
51	Furnace 5103 Furnace 5153	Fuel Oil/Refinery Gas* with Refinery Gas Pilot	630 bbl/Day 260 bbl/Day
52/55	Boiler 5201 Boiler 5202 Boiler 5203	Fuel Oil and Refinery Gas	914 bbl/Day or 214 MSCF/Hr 668 bbl/Day or 156 MSCF/Hr 668 bbl/Day or 156 MSCF/Hr
53	Furnace 5300 FCC Stack	Fuel Oil and Refinery Gas Cat. Coke	254 bbl./Day or 60 MSCF/Hr 22,000 bbl/Day
56	Furnace 5600	Refinery Gas	9 MSCF/Hr
57	Furnace 5700	Refinery Gas	24 MSCF/Hr
59	Furnace 5930 Furnace 5950	Refinery Gas Refinery Gas	4 MSCF/Hr 1.6 MSCF/Hr
60	Furnace 6003	Refinery Gas	5.5 MSCF/Hr
61/62	Comb. Chamber 6200 Furnace 6262	Refinery Gas Refinery Gas	4.2 MSCF/Hr 4.95 MSCF/Hr
67	Turbine 6701, 6702, 6703 Turbine 6701, 6702, 6703 HRSG 6701, 6702, 6703	Refinery Gas Whole Straight Run Naphtha Refinery Gas	38.8 MSCF/Hr (Per Turbine) 192 bbl/Day (Per Turbine) 34 MSCF/Hr (Per HRSG)

\* With future installation of Low-NO<sub>x</sub> dual-fired burners

**Table 2-3  
RAW MATERIALS**

Raw Material	Source
Crude oil	Tankers
Gasoline blending components (example: reformate)	Pipeline, made on site
Sulfuric acid	Made on site (may be imported)
Fuel oil components (example: low sulfur waxy residuum)	Pipeline, made on site
Other feed/blend stocks (example: vacuum gas oil)	Pipeline, made on site

**2.9 BASE OPERATING SCENARIOS**

The base refinery operating scenario consists of the processing of crude oils in the process units and equipment, as indicated in the refinery description in Section 2.3. During normal operations, the refinery may process crude oils from a variety of sources and with various characteristics. Likewise, the refinery normally produces a wide range of intermediate and final products. Although each type of crude oil is processed in a similar manner, each requires specific refining techniques.

Therefore, the base operating scenario for this facility is the receiving and processing of various crude oils, without differentiating the make-up of the different crudes or the mix of refinery products generated. Maximum potential air pollutant emissions for this base scenario can be estimated by assuming operation of all equipment and process units at design capacity and the use of those raw materials and products that would produce the highest emissions. Estimation of these maximum potential emissions, which generally overestimate actual refinery emissions, is presented in Section 3.

**2.10 ALTERNATIVE OPERATING SCENARIOS**

Alternative operating scenarios represent operational characteristics outside the range of normal operations. All operating scenarios for the Hawaii Refinery that are considered likely to occur have been incorporated within the base operating scenario, as described in the previous section. The maximum emissions scenario presented in Section 3 reflects the assumptions of refinery and process unit operations at maximum capacity, as well as the combination of raw materials and products that would correspond to the highest emissions of air pollutants among all the possible variations.

Therefore, there are no alternative operating scenarios, and it will not be necessary to implement inter-facility or process area emissions trading.

This section provides information required in HAR §11-60.1-83(3), (4), (5), and (6). Maximum air pollutant emission estimates are presented for the base operating scenario, as described in Section 2. The following text explains the refinery emission inventory methods and summarizes the results. Detailed calculations of maximum criteria pollutant and HAPs emissions by source type are presented in Appendix B. It should be noted that the calculations of emissions presented in this report represent the maximum potential emissions from the refinery, which are greater than the actual emissions produced by refinery operations.

### **3.1 INVENTORY OF REFINERY POTENTIAL TO EMIT**

The Chevron Hawaii Refinery includes several types of sources that have the potential to emit criteria air pollutants and hazardous air pollutants (HAPs). For purposes of developing the facility's emissions inventory, the refinery sources have been divided into the following eight categories:

- Point combustion sources
- Storage tanks
- Truck loading rack
- Process unit fugitives
- Cooling tower
- Wastewater treatment facilities
- Flaring
- Catalyst transfer operations at the FCC

#### **3.1.1 Point Combustion Sources**

The point combustion sources at the refinery consist of boilers, furnaces, and turbines. Fuels used by these units consist primarily of refinery gas and fuel oil. The turbines may also be fueled by whole straight run naphtha. In order to estimate the Potential to Emit (PTE) for these units, maximum fuel use rates based on equipment design capacities were multiplied by appropriate emission factors, except for sources that have federally enforceable DOH permit limits on either their emission rates or fuel usage rates. Information on the fuel type, maximum fuel use, the origins of emission factors, and comments regarding the emission calculation methods for all point combustion sources are presented in Table 3-1. Emission factors and calculation spreadsheets are contained in Appendix B-1.

The primary source of emission factors used to quantify criteria pollutant and HAP emissions from combustion sources is EPA Publication AP-42 (EPA, 1985 et seq). Fuel use rates for the furnaces and boilers were derived from the design fuel heat input rate and the lower heating value of the fuel used in each unit. The refinery's fuel oil has a nominal lower heating value of 5.78 million Btu per barrel, whereas refinery gas has a nominal lower heating value of 1030 Btu per standard cubic foot. The actual heating values vary according to refinery operations.

Table 3-1  
 MAXIMUM EMISSION ESTIMATE BASIS FOR POINT COMBUSTION SOURCES

Area	Equipment	Fuel	Maximum Fuel Use	Emissions Estimate Basis
23(Cooling towers, flares)	Flares	Ref. Gas	N/A	Emission Factors From AP-42 Section 5.1-1
51 (Crude Unit)	Furnace 5103 Furnace 5153	Fuel Oil Fuel Oil (gas pilots)	630 bbl/Day 260 bbl/Day	SO <sub>2</sub> , NO <sub>2</sub> , and CO Limited By Permit VOC, PM and HAP emission factors from AP-42 Section 1.3 (Oil) and Section 1.4 (Gas)
52/55 (Boiler Plant)	Boiler 5201 Boiler 5202 Boiler 5203	Fuel Oil and Refinery Gas	914 bbl/Day or 214 MSCF/Hr 668 bbl/Day or 156 MSCF/Hr 668 bbl/Day or 156 MSCF/Hr	Emission factors from AP-42 Section 1.3 (Oil) and Section 1.4 (Gas)
53 (FCCU)	Furnace 5300 FCC Stack	Refinery Gas Cat. Coke	60 MSCF/Hr 22,000 bbl/day	Emission factors from AP-42 Sections 1.3 and 1.4 HAP emission factors for FCC stack from Chevron source emissions tests
56 (Hydrogenation Plant)	Furnace 5600	Ref. Gas	9 MSCF/Hr	Emission factors from AP-42 Section 1.4
57 (Hydrogen Manufacturing Plant)	Furnace 5700	Ref. Gas	24 MSCF/Hr	Emission factors from AP-42 Section 1.4
59 (Isomerization Plant)	Furnace 5930 Furnace 5950	Ref. Gas Ref. Gas	4 MSCF/Hr 1.6 MSCF/Hr	Emission factors from AP-42 Section 1.4
60 (Asphalt Plant)	Furnace 6003	Ref. Gas	5.5 MSCF/Hr	Emission factors from AP-42 Section 1.4
61/62 (Amine, Acid Plant)	Furnace 6262 Comb. Chamber F-6200 Acid Plant	Ref. Gas Ref. Gas	4.95 MSCF/Hr 8.5 Mmbtu/Hr (Max in 2002) 110 Ton Acid Production/Day	Emission factors from AP-42 Section 1.4
67 (Cogeneration Plant)	Turbine 6701, 6702, 6703 Turbine 6701, 6702, 6703 HRSG 6701, 6702, 6703	Ref. Gas WSR Ref. Gas	38.8 MSCR/Hr (Per Turbine) 192 bbl/Day (Per Turbine) 34 MSCF/Hr (Per HRSG)	Mass balance for SO <sub>2</sub> emissions NO <sub>2</sub> and CO limited by permit VOC and PM factors from AP-42 Section 3.1

The particulate emissions from the FCC precipitator are conservatively assumed to be at the DOH prohibitory limit.

Emissions of SO<sub>2</sub>, NO<sub>x</sub> and CO from the Crude Unit and Cogeneration Plant were based on federally enforceable DOH permit limits. Consumption of refinery gas and whole straight run naphtha (WSR) in the cogeneration turbines is limited by federally enforceable DOH permit conditions. Crude unit furnaces 5103 and 5153 are currently permitted to combust RFG on only 12 of 36 burners. Maximum estimated emissions for these furnaces were obtained assuming that these units operate to the full limit of the permit conditions.

WSR sulfur content in the cogeneration units is no more than 0.03 percent, as allowed by the current Title V permit. Fuel oil burned in the boilers (5201, 5202, 5203) and crude unit furnaces (5103 and 5153) may contain up to 0.5 percent sulfur and fuel gas up to 2% sulfur. Sulfur content in the RFG (0.0037 percent) was taken from 2002 monitoring data. Hazardous Air Pollutant (HAP) emission factors were taken from the EPA AP-42 compilation or from Chevron source tests.

Maximum potential criteria pollutant emissions for refinery point sources are presented in Table 3-2. HAP emissions from point sources are summarized in Table 3-3. Please note that these tables present the maximum emission rates. Thus, if fuel oil combustion results in higher emissions for a given pollutant than refinery gas, the use of fuel oil is assumed in calculating emissions. Additionally, it is unlikely—if not impossible—for all of the refinery processes to operate concurrently at their maximum potential emission rates for all pollutants.

### 3.1.2 Storage Tanks

Crude oil, intermediate products, blending components, and finished products are placed in storage tanks. The refinery stores different classes of material in designated tanks. For example, specific tanks may store motor gasoline or several of its blend components. These same tanks, however, would not store diesel fuel. To estimate emissions, each storage tank is classified according to the class of material it contains, based on similar characteristics. Data from a Year 2002 tank emission inventory were used as the basis for calculating the tanks' PTE. Because the maximum crude oil throughput for the refinery (65,000 bbl/day) is 22 percent higher than the crude oil throughput during 2002, the throughput quantities and turnovers for all tanks were increased by 22 percent over the values in the 2002 inventory data in order to estimate their corresponding maximum potential emissions.

The classes of regulated hydrocarbon materials stored at the refinery are as follows:

- Crude oil
- Motor gasoline and its blend components
- Aviation gas
- Jet fuel
- Heavy liquids
- Liquid propane gas (LPG)
- Recovered oil

Table 3-2  
 MAXIMUM CRITERIA POLLUTANT EMISSIONS FROM POINT SOURCES

Sources	Pollutant Emission Rates (ton/yr)							Total Criteria Pollutant Emissions
	PM <sub>10</sub>	SO <sub>2</sub>	CO	NO <sub>2</sub>	VOC	Lead		
Boilers	372.5	5415.3	86.2	551.9	13.1	0.0	6439	
Cogen Turbines	11.7	16.0	52.5	193.2	2.3	0.0	276	
Crude Furnaces	44.5	482.0	75.0	302.9	5.1	0.0	909	
FCC Furnace	2.0	1.6	22.1	26.3	1.4	0.0	53	
Isomerization Furnaces	0.2	0.2	2.1	2.5	0.1	0.0	5	
Hydrogenation & Hydrogen Plant Furnaces	1.1	0.9	12.1	14.5	0.8	0.0	29	
Acid preheater & combustion chamber	0.4	0.4	4.8	5.7	0.3	0.0	12	
Asphalt Furnace	0.2	0.1	2.0	2.4	0.1	0.0	5	
FCC Stack	175.2	450.0	499.3	285.1	14.7	0.0	1424	
<b>Totals</b>	<b>607.8</b>	<b>6366.4</b>	<b>756.1</b>	<b>1384.3</b>	<b>38.0</b>	<b>0.0</b>	<b>9152.8</b>	



Table 3-3  
 MAXIMUM HAP EMISSIONS FROM POINT SOURCES

Number	Area Description	Benzene CAS# 71432 (Ton/Yr)	Naphthalene CAS# 91203 (Ton/Yr)	o-Xylene CAS# 95476 (Ton/Yr)	Ethylbenzene CAS# 100414 (Ton/Yr)	p-Xylene CAS# 106423 (Ton/Yr)	Ethylene Dibromide CAS# 106934 (Ton/Yr)	Ethylene Dichloride CAS# 107062 (Ton/Yr)
52	Boiler Plant	0.003	0.008	0.001	0.000			
67	Cogen Plant	0.000	0.000					
51	Crude Plant	0.001	0.006	0.001	0.000			
53	FCC Plant	0.001	0.000					
59	Isom Plant	0.000	0.000					
56	Hydrogenation Plant	0.000	0.000					
57	Hydrogen Manufacturing Plant	0.000	0.000					
62	Acid Plant CC and Preheater Plant	0.000	0.000					
60	Asphalt Plant	0.000	0.000					
53	FCC Stack							
	Flare							
	Total	0.005	0.014	0.001	0.001	0.000	0.000	0.000

Table 3-3 (continued)  
 MAXIMUM HAP EMISSIONS FROM POINT SOURCES

Number	Area Description	m-Xylene CAS# 108383 (Ton/Yr)	Toluene CAS# 108883 (Ton/Yr)	1,3-Butadiene CAS# 106990 (Ton/Yr)	n-Hexane CAS# 110543 (Ton/Yr)	Formaldehyde (Ton/Yr)	POM/PAH (Ton/Yr)	Total HAPs Ton/Yr
52	Boiler Plant		0.046		1.230	0.349	0.298	1.935
67	Cogen Plant	0.000	0.000	0.000		0.001	0.000	0.002
51	Crude Unit		0.030		0.002	0.208	0.006	0.253
53	FCC Unit Furnace		0.001		0.473	0.020	0.000	0.494
59	Isomerization Plant		0.000		0.044	0.002	0.000	0.046
56	Hydrogenation Plant		0.000		0.071	0.003	0.000	0.074
57	Hydrogen Manufacturing Plant		0.000		0.189	0.008	0.000	0.198
62	Acid Plant CC and Preheater		0.000		0.103	0.004	0.000	0.107
60	Asphalt Point		0.000		0.043	0.002	0.000	0.045
53	FCC Stack					0.890		0.890
	Flare			0.002				0.002
	Total	0.000	0.078	0.002	2.155	1.487	0.304	4.046

To date, 17 external floating roof petroleum storage tanks have been fitted with secondary seals or domed roofs. Additional secondary seal installations are planned, which will further reduce tank emissions, although these future reductions have not been accounted for in the PTE emissions estimates presented in this permit renewal application.

Storage tank emissions were estimated using the EPA TANKS4 computer software package, with partial speciation (EPA, 1999). A list of each regulated tank in hydrocarbon service, its class of service, and estimated maximum total VOC emissions is provided in Table 3-4. A summary of maximum total HAP emissions by tank is presented in Table 3-5. Detailed emission reports for each tank, as generated by the TANKS4 emissions model, are presented in an accompanying document (Appendix B-2).

Storage tanks in LPG service are pressurized and have negligible emissions. Emissions from heavy liquids, specifically materials with vapor pressures less than 0.3 kPa (EPA, 1993a), are also excluded from this inventory. This exclusion is consistent with the December 15, 1993, "Model Permit for Leaking Sources" published by the EPA, and is discussed further in Section 3.6 of this application. For clarity, liquids having a vapor pressure less than 0.3 kPa will subsequently be referred to as insignificant heavy liquids. Section 3.6.10 contains justification for the exemption of these materials from the refining PTE inventory.

### 3.1.3 Truck Loading Rack

Typically, products are shipped from the refinery via pipeline. If Chevron were unable to use the pipeline (for example, in case of a shutdown for extended repairs), certain products would be loaded into trucks at the refinery truck loading rack. The current Covered Source Permit specifies the following maximum daily material loading rates:

- Motor gasoline - 7,300,000 barrels per any rolling 12-month period
- Aviation gasoline - 47,450 barrels per any rolling 12-month period
- Diesel - 2,920,000 barrels per any rolling 12-month period
- Jet Fuel - 438,000 barrels per any rolling 12-month period

Section 5.2 of AP-42 provides the following equation to estimate VOC emissions from loading activities:

$$L_L = 12.46 \text{ SPM/T}$$

Where:

- L = VOC Emissions, lb/1000 gal. liquid loaded
- S = Saturation factor (Chevron employs splash loading)
- P = True vapor pressure, psia
- M = Molecular weight of vapors, lb/lb mole
- T = Temperature of material, °K

Estimated emissions and the parameter values used in the emission calculations are presented in Table 3-6. The PTE calculations assume that the maximum allowable quantities shown above for all fuels would be loaded during the year. The emissions from the loading rack have been

**Table 3-4  
MAXIMUM POTENTIAL VOC EMISSIONS FROM STORAGE TANKS**

Tank ID	Type of Tank	Service of Tank	Losses (lb/yr)	Losses (ton/yr)
Tk 104	External Floating Roof	Crude: Widuri Group	6,329	3.2
Tk 105	External Floating Roof	Crude: ANS Group	1,294	0.6
Tk 106	External Floating Roof	Crude: ANS Group	1,953	1.0
Tk 107	External Floating Roof	Crude: Minas Group	11,481	5.7
Tk 108	External Floating Roof	Crude: Tapis Group	18,849	9.4
Tk 109	External Floating Roof	Crude: ANS Group	941	0.5
Tk 110	External Floating Roof	Crude: ANS Group	1,204	0.6
Tk 111	External Floating Roof	WSR	18,109	9.1
Tk 113	External Floating Roof	Rec Crude	638	0.3
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt)	101	0.1
Tk 162	External Floating Roof	Rec Oil	7,953	4.0
Tk 163	External Floating Roof	Rec Oil	7,953	4.0
Tk 232	External Floating Roof	HCC	1,236	0.6
Tk 233	External Floating Roof	HCC	1,236	0.6
Tk 236	External Floating Roof	U/L	45,489	22.7
Tk 237	External Floating Roof	U/L	24,499	12.2
Tk 249	Domed External Floating Roof	Avgas	2,069	1.0
Tk 250	Domed External Floating Roof	Avgas	1,695	0.8
Tk 252	External Floating Roof	LCC	49,065	24.5
Tk 253	External Floating Roof	LCC	49,065	24.5
Tk 254	External Floating Roof	U/L Plus	43,701	21.9
Tk 255	External Floating Roof	SUP	45,487	22.7
Tk 256	External Floating Roof	SUP	45,423	22.7
Tk 257	External Floating Roof	Dimate Gasoline	38,508	19.3
Tk 258	External Floating Roof	Alkylate Gasoline	25,577	12.8
Tk 262	External Floating Roof	SUP	23,848	11.9
Tk 263	External Floating Roof	JetA	1,634	0.8
Tk 264	External Floating Roof	JetA	1,641	0.8
Tk 265	External Floating Roof	JetA	1,670	0.8
Tk 266	External Floating Roof	WSR	26,602	13.3
Tk 267	External Floating Roof	JetA	1,670	0.8
Tk 268	External Floating Roof	Diesel	182	0.1
Tk 269	External Floating Roof	WSR	22,729	11.4
Tk 270	External Floating Roof	Diesel	189	0.1
Tk 271	External Floating Roof	WSR	14,038	7.0
Tk 272	Vertical Fixed Roof	ULSD	2,712	1.4
Tk 273	External Floating Roof	U/L	38,045	19.0
Tk 274	Vertical Fixed Roof	ULSD	3,328	1.7
Tk 275	External Floating Roof	HS WSR	17,748	8.9
Tk 301	External Floating Roof	Rec Oil	13,623	6.8
Tk 302	External Floating Roof	Rec Oil	13,623	6.8
<b>Total Emissions for all Tanks:</b>			<b>633,136</b>	<b>316.6</b>

Table 3-5  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank ID	Type of Tank	Service of Tank	Benzene Losses (ton/yr) CAS# 71432	Naphthalene Losses (ton/yr) CAS# 91203	o-Xylene Losses (ton/yr) CAS# 95476	Ethylbenzene Losses (ton/yr) CAS# 100414	p-Xylene Losses (ton/yr) CAS# 106423	Ethylene Dibromide Losses (ton/yr) CAS# 106934
Tk 104	External Floating Roof	Crude: Widuri Group	0.0013	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 105	External Floating Roof	Crude: ANS Group	0.0014	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 106	External Floating Roof	Crude: ANS Group	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 107	External Floating Roof	Crude: Minas Group	0.0080	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 108	External Floating Roof	Crude: Tapis Group	0.0368	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 109	External Floating Roof	Crude: ANS Group	0.0010	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 110	External Floating Roof	Crude: ANS Group	0.0013	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 111	External Floating Roof	WSR	0.1892	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 113	External Floating Roof	Rec Crude	0.0007	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 122	Vertical Fixed Roof	Crude: Bossan (asphalt)	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 162	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 163	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 232	External Floating Roof	HCC	0.0001	0.0205	0.0307	0.0075	0.0143	0.0000
Tk 233	External Floating Roof	HCC	0.0001	0.0205	0.0307	0.0075	0.0143	0.0000
Tk 236	External Floating Roof	U/L	0.1365	0.1137	0.4253	0.2229	0.3230	0.0000
Tk 237	External Floating Roof	U/L	0.0735	0.0612	0.2291	0.1200	0.1739	0.0000
Tk 249	Domed External Floating Roof	Avgas	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003
Tk 250	Domed External Floating Roof	Avgas	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002
Tk 252	External Floating Roof	LCC	0.1840	0.0000	0.3165	0.2453	0.3140	0.0000
Tk 253	External Floating Roof	LCC	0.1840	0.0000	0.3165	0.2453	0.3140	0.0000
Tk 254	External Floating Roof	U/L Plus	0.1093	0.0961	0.3081	0.1617	0.2294	0.0000
Tk 255	External Floating Roof	SUP	0.0227	0.0682	0.1046	0.0273	0.0500	0.0000
Tk 256	External Floating Roof	SUP	0.0227	0.0681	0.1045	0.0273	0.0500	0.0000
Tk 257	External Floating Roof	Dimale Gasoline	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 258	External Floating Roof	Allylate Gasoline	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 262	External Floating Roof	SUP	0.0119	0.0358	0.0549	0.0143	0.0262	0.0000
Tk 263	External Floating Roof	JeA	0.0000	0.0106	0.0195	0.0065	0.0086	0.0000
Tk 264	External Floating Roof	JeA	0.0000	0.0107	0.0196	0.0066	0.0086	0.0000
Tk 265	External Floating Roof	JeA	0.0000	0.0109	0.0200	0.0067	0.0088	0.0000
Tk 266	External Floating Roof	WSR	0.2780	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 267	External Floating Roof	JeA	0.0000	0.0109	0.0200	0.0067	0.0088	0.0000
Tk 268	External Floating Roof	Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 269	External Floating Roof	WSR	0.2375	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 270	External Floating Roof	Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 271	External Floating Roof	WSR	0.1467	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 272	Vertical Fixed Roof	ULSD	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 273	External Floating Roof	U/L	0.1141	0.0951	0.3557	0.1864	0.2701	0.0000
Tk 274	Vertical Fixed Roof	ULSD	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 275	External Floating Roof	WSR	0.1855	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 301	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 302	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
<b>Total Emissions for all Tanks:</b>			<b>1.1663</b>	<b>0.0189</b>	<b>0.2419</b>	<b>0.1232</b>	<b>0.0777</b>	<b>0.0005</b>

\* Data from TANKSA specification information  
 Otherwise, used liq w/ fraction for data with no specification in TANKSA data base.

Table 3-5  
MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS

Tank ID	Type of Tank	Service of Tank	Ethylene Dichloride Losses (ton/yr) CAS# 107062	m-Xylene Losses (ton/yr) CAS# 108383	Toluene Losses (ton/yr) CAS# 108883	1,3-Butadiene Losses (ton/yr) CAS# 106990	n-Hexane Losses (ton/yr) CAS# 110543	Aniline Losses (ton/yr) CAS# 62533
Tk 104	External Floating Roof	Crude: Wildcat Group	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003
Tk 105	External Floating Roof	Crude: ANS Group	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
Tk 106	External Floating Roof	Crude: ANS Group	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
Tk 107	External Floating Roof	Crude: Minns Group	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006
Tk 108	External Floating Roof	Crude: Tapis Group	0.0000	0.0000	0.0000	0.0000	0.0000	0.0009
Tk 109	External Floating Roof	Crude: ANS Group	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 110	External Floating Roof	Crude: ANS Group	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
Tk 111	External Floating Roof	WSR	0.0000	0.0000	0.1068	0.0000	0.4138	0.0000
Tk 113	External Floating Roof	Rec Crude	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 162	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 163	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 232	External Floating Roof	HCC	0.0000	0.0390	0.0047	0.0000	0.0000	0.0006
Tk 233	External Floating Roof	HCC	0.0000	0.0390	0.0047	0.0000	0.0000	0.0006
Tk 236	External Floating Roof	U/L	0.0000	0.8120	1.4375	0.0000	0.3048	0.0023
Tk 237	External Floating Roof	U/L	0.0000	0.4373	0.7742	0.0000	0.1641	0.0012
Tk 249	Domed External Floating Roof	Avgas	0.0000	0.0000	0.0000	0.0000	0.0003	0.0000
Tk 260	Domed External Floating Roof	Avgas	0.0000	0.0000	0.0000	0.0000	0.0003	0.0000
Tk 252	External Floating Roof	LCC	0.0000	0.7728	1.8105	0.0000	0.1987	0.0025
Tk 253	External Floating Roof	LCC	0.0000	0.7728	1.8105	0.0000	0.1987	0.0025
Tk 254	External Floating Roof	U/L Plus	0.0000	0.5834	0.9592	0.0000	0.2928	0.0022
Tk 255	External Floating Roof	SUP	0.0000	0.1387	0.0387	0.0000	0.3048	0.0023
Tk 256	External Floating Roof	SUP	0.0000	0.1385	0.0386	0.0000	0.3043	0.0023
Tk 257	External Floating Roof	Dimate Gasoline	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 258	External Floating Roof	Alkylate Gasoline	0.0000	0.0000	0.0000	0.0000	0.0038	0.0000
Tk 262	External Floating Roof	SUP	0.0000	0.0727	0.0203	0.0000	0.1598	0.0012
Tk 263	External Floating Roof	JetA	0.0000	0.0214	0.0000	0.0000	0.0000	0.0000
Tk 264	External Floating Roof	JetA	0.0000	0.0215	0.0000	0.0000	0.0000	0.0000
Tk 265	External Floating Roof	JetA	0.0000	0.0219	0.0000	0.0000	0.0000	0.0000
Tk 266	External Floating Roof	WSR	0.0000	0.0000	0.1570	0.0000	0.6079	0.0000
Tk 267	External Floating Roof	JetA	0.0000	0.0219	0.0000	0.0000	0.0000	0.0000
Tk 268	External Floating Roof	Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 269	External Floating Roof	WSR	0.0000	0.0000	0.1341	0.0000	0.5194	0.0000
Tk 270	External Floating Roof	Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 271	External Floating Roof	WSR	0.0000	0.0000	0.0828	0.0000	0.3208	0.0000
Tk 272	Vertical Fixed Roof	U/LSD	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 273	External Floating Roof	U/L	0.0000	0.6791	1.2022	0.0000	0.2549	0.0019
Tk 274	Vertical Fixed Roof	U/LSD	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 275	External Floating Roof	WSR	0.0000	0.0000	0.1047	0.0000	0.4055	0.0000
Tk 301	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 302	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
<b>Total Emissions for all Tanks:</b>			0.0003	0.4367	1.5172	0.0000	3.9389	0.0012

\* Data from TANKS4 speciation information  
Otherwise, used liq wt fraction for data with no speciation in TANKS4 data base.

Table 3-5  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank ID	Type of Tank	Service of Tank	Cresol Mixture Losses (ton/yr) CAS# 1319773	Phenol Losses (ton/yr) CAS# 108952	Styrene Losses (ton/yr) CAS# 100425	Methanol Losses (ton/yr) CAS# 67561	Nickel Losses (ton/yr) CAS# 7440020
Tk 104	External Floating Roof	Crude: Widuri Group	0.0044	0.0003	0.0000	0.0000	0.0000
Tk 105	External Floating Roof	Crude: ANS Group	0.0009	0.0001	0.0000	0.0000	0.0000
Tk 106	External Floating Roof	Crude: ANS Group	0.0014	0.0001	0.0000	0.0000	0.0000
Tk 107	External Floating Roof	Crude: Minas Group	0.0080	0.0006	0.0000	0.0000	0.0000
Tk 108	External Floating Roof	Crude: Tapis Group	0.0132	0.0009	0.0000	0.0000	0.0000
Tk 109	External Floating Roof	Crude: ANS Group	0.0007	0.0000	0.0000	0.0000	0.0000
Tk 110	External Floating Roof	Crude: ANS Group	0.0008	0.0001	0.0000	0.0000	0.0000
Tk 111	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 113	External Floating Roof	Rec Crude	0.0004	0.0000	0.0000	0.0000	0.0000
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt)	0.0001	0.0000	0.0000	0.0000	0.0000
Tk 162	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 163	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 232	External Floating Roof	HCC	0.0000	0.0001	0.0000	0.0000	0.0000
Tk 233	External Floating Roof	HCC	0.0000	0.0001	0.0000	0.0000	0.0000
Tk 236	External Floating Roof	U/L	0.0000	0.0023	0.0000	0.0000	0.0000
Tk 237	External Floating Roof	U/L	0.0000	0.0012	0.0000	0.0000	0.0000
Tk 249	Domed External Floating Roof	Avgas	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 250	Domed External Floating Roof	Avgas	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 252	External Floating Roof	LCC	0.0000	0.0025	0.0245	0.0000	0.0000
Tk 253	External Floating Roof	LCC	0.0000	0.0025	0.0245	0.0000	0.0000
Tk 254	External Floating Roof	U/L Plus	0.0000	0.0022	0.0000	0.0000	0.0000
Tk 255	External Floating Roof	SUP	0.0000	0.0023	0.0000	0.0000	0.0000
Tk 256	External Floating Roof	SUP	0.0000	0.0023	0.0000	0.0000	0.0000
Tk 257	External Floating Roof	Dimate Gasoline	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 258	External Floating Roof	Alkylate Gasoline	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 262	External Floating Roof	SUP	0.0000	0.0012	0.0000	0.0000	0.0000
Tk 263	External Floating Roof	JeA	0.0008	0.0008	0.0000	0.0000	0.0000
Tk 264	External Floating Roof	JeA	0.0008	0.0008	0.0000	0.0000	0.0000
Tk 265	External Floating Roof	JeA	0.0008	0.0008	0.0000	0.0000	0.0000
Tk 266	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 267	External Floating Roof	JeA	0.0008	0.0008	0.0000	0.0000	0.0000
Tk 268	External Floating Roof	Diesel	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 269	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 270	External Floating Roof	Diesel	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 271	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 272	Vertical Fixed Roof	ULSD	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 273	External Floating Roof	U/L	0.0000	0.0019	0.0000	0.0000	0.0000
Tk 274	Vertical Fixed Roof	ULSD	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 275	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 301	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 302	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000	0.0000
<b>Total Emissions for all Tanks:</b>			0.0333	0.0018	0.0014	0.0000	0.0000

\* Data from TANKS4 speciation information  
 Otherwise, used liq wt fraction for data with no speciation in TANKS4 data base.

Table 3-5  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank ID	Type of Tank	Service of Tank	HCL Losses (ton/yr) CASH# 7647010	Perchloroethylene Losses (ton/yr) CASH# 127184	Biphenyl Losses (ton/yr) CASH# 92524	2,2,4 Trimethylpentane Losses (ton/yr) CASH# 540841
Tk 104	External Floating Roof	Crude: Widuri Group	0.0000	0.0000	0.0000	0.0003
Tk 105	External Floating Roof	Crude: ANS Group	0.0000	0.0000	0.0000	0.0001
Tk 106	External Floating Roof	Crude: ANS Group	0.0000	0.0000	0.0000	0.0001
Tk 107	External Floating Roof	Crude: Minas Group	0.0000	0.0000	0.0000	0.0006
Tk 108	External Floating Roof	Crude: Tapis Group	0.0000	0.0000	0.0000	0.0009
Tk 109	External Floating Roof	Crude: ANS Group	0.0000	0.0000	0.0000	0.0000
Tk 110	External Floating Roof	Crude: ANS Group	0.0000	0.0000	0.0000	0.0001
Tk 111	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0724
Tk 113	External Floating Roof	Rec Crude	0.0000	0.0000	0.0000	0.0000
Tk 152	Vertical Fixed Roof	Crude: Boscana (asphalt)	0.0000	0.0000	0.0000	0.0000
Tk 162	External Floating Roof	Rec Oil	0.0000	0.0000	0.0016	0.0000
Tk 163	External Floating Roof	Rec Oil	0.0000	0.0000	0.0016	0.0000
Tk 232	External Floating Roof	HCC	0.0000	0.0000	0.0000	0.0000
Tk 233	External Floating Roof	HCC	0.0000	0.0000	0.0000	0.0000
Tk 236	External Floating Roof	U/L	0.0000	0.0000	0.0000	0.1137
Tk 237	External Floating Roof	U/L	0.0000	0.0000	0.0000	0.0612
Tk 249	Domed External Floating Roof	Avgas	0.0000	0.0000	0.0000	0.0228
Tk 250	Domed External Floating Roof	Avgas	0.0000	0.0000	0.0000	0.0186
Tk 252	External Floating Roof	LCC	0.0000	0.0000	0.0000	0.0000
Tk 253	External Floating Roof	LCC	0.0000	0.0000	0.0000	0.0000
Tk 254	External Floating Roof	U/L Plus	0.0000	0.0000	0.0000	0.1093
Tk 255	External Floating Roof	SUP	0.0000	0.0000	0.0000	0.1137
Tk 256	External Floating Roof	SUP	0.0000	0.0000	0.0000	0.1136
Tk 257	External Floating Roof	Dimate Gasoline	0.0000	0.0000	0.0000	0.0000
Tk 258	External Floating Roof	Alkylate Gasoline	0.0000	0.0000	0.0000	0.2813
Tk 262	External Floating Roof	SUP	0.0000	0.0000	0.0000	0.0596
Tk 263	External Floating Roof	JetA	0.0000	0.0000	0.0008	0.0000
Tk 264	External Floating Roof	JetA	0.0000	0.0000	0.0008	0.0000
Tk 265	External Floating Roof	JetA	0.0000	0.0000	0.0008	0.0000
Tk 266	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.1064
Tk 267	External Floating Roof	JetA	0.0000	0.0000	0.0000	0.0000
Tk 268	External Floating Roof	Diesel	0.0000	0.0000	0.0000	0.0000
Tk 269	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0909
Tk 270	External Floating Roof	Diesel	0.0000	0.0000	0.0000	0.0000
Tk 271	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0562
Tk 272	Vertical Fixed Roof	ULSD	0.0000	0.0000	0.0000	0.0000
Tk 273	External Floating Roof	U/L	0.0000	0.0000	0.0005	0.0951
Tk 274	Vertical Fixed Roof	ULSD	0.0000	0.0000	0.0000	0.0000
Tk 275	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0710
Tk 301	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0000
Tk 302	External Floating Roof	Rec Oil	0.0000	0.0000	0.0027	0.0000
<b>Total Emissions for all Tanks:</b>			<b>0.0000</b>	<b>0.0000</b>	<b>0.0132</b>	<b>1.3880</b>

\* Data from TANKS4 speciation information  
 Otherwise, used liq wt fraction for data with no speciation in TANKS4 data base.



Table 3-5  
**MAXIMUM POTENTIAL HAP EMISSIONS FROM STORAGE TANKS**

Tank ID	Type of Tank	Service of Tank	Cumene Losses (ton/yr) CAS# 98828	o-Toluidine Losses (ton/yr) CAS# 95534	Acrylamide Losses (ton/yr) CAS# 79061	Antimony Compounds Losses (ton/yr) CAS#	Arsenic Losses (ton/yr) CAS#	Cyanide Compounds Losses (ton/yr) CAS#
Tk 104	External Floating Roof	Crude: Whium Group	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000
Tk 105	External Floating Roof	Crude: ANS Group	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000
Tk 106	External Floating Roof	Crude: ANS Group	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000
Tk 107	External Floating Roof	Crude: Minas Group	0.0006	0.0006	0.0000	0.0001	0.0001	0.0001
Tk 108	External Floating Roof	Crude: Tapis Group	0.0009	0.0009	0.0000	0.0001	0.0001	0.0001
Tk 109	External Floating Roof	Crude: ANS Group	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 110	External Floating Roof	Crude: ANS Group	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000
Tk 111	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 113	External Floating Roof	Res. Crude	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 152	Vertical Fixed Roof	Crude: Bossan (asphalt)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 162	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0004	0.0004	0.0004
Tk 163	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0004	0.0004	0.0004
Tk 232	External Floating Roof	HCC	0.0001	0.0062	0.0000	0.0000	0.0000	0.0000
Tk 233	External Floating Roof	HCC	0.0001	0.0062	0.0000	0.0000	0.0000	0.0000
Tk 236	External Floating Roof	UIL	0.0023	0.0023	0.0000	0.0000	0.0000	0.0000
Tk 237	External Floating Roof	UIL	0.0012	0.0012	0.0000	0.0000	0.0000	0.0000
Tk 249	Domed External Floating Roof	Avgas	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 250	Domed External Floating Roof	Avgas	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 252	External Floating Roof	LCC	0.0245	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 253	External Floating Roof	LCC	0.0245	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 254	External Floating Roof	UIL Plus	0.0022	0.0022	0.0000	0.0000	0.0000	0.0000
Tk 255	External Floating Roof	SUP	0.0023	0.0023	0.0000	0.0000	0.0000	0.0000
Tk 256	External Floating Roof	SUP	0.0023	0.0023	0.0000	0.0000	0.0000	0.0000
Tk 257	External Floating Roof	Dimate Gasoline	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 258	External Floating Roof	Alkylate Gasoline	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 262	External Floating Roof	SUP	0.0012	0.0012	0.0000	0.0000	0.0000	0.0000
Tk 263	External Floating Roof	JetA	0.0008	0.0082	0.0000	0.0000	0.0000	0.0000
Tk 284	External Floating Roof	JetA	0.0008	0.0082	0.0000	0.0000	0.0000	0.0000
Tk 265	External Floating Roof	JetA	0.0008	0.0084	0.0000	0.0000	0.0000	0.0000
Tk 266	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 267	External Floating Roof	JetA	0.0008	0.0084	0.0000	0.0000	0.0000	0.0000
Tk 268	External Floating Roof	Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 269	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 270	External Floating Roof	Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 271	External Floating Roof	WSR	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 272	Vertical Fixed Roof	ULSD	0.0000	0.0000	0.0000	0.0001	0.0001	0.0001
Tk 273	External Floating Roof	UIL	0.0019	0.0019	0.0000	0.0000	0.0000	0.0000
Tk 274	Vertical Fixed Roof	ULSD	0.0000	0.0000	0.0000	0.0002	0.0002	0.0002
Tk 275	External Floating Roof	WAR	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tk 301	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0007	0.0007	0.0007
Tk 302	External Floating Roof	Rec Oil	0.0000	0.0000	0.0000	0.0007	0.0007	0.0007
<b>Total Emissions for all Tanks:</b>			<b>0.0145</b>	<b>0.0609</b>	<b>0.0001</b>	<b>0.0027</b>	<b>0.0027</b>	<b>0.0027</b>

\* Data from TANKSA specification information  
 Otherwise, used liq wt fraction for data with no specification in TANKSA data base.

**Table 3-6  
POTENTIAL EMISSIONS FROM REFINERY TRUCK LOADING RACK**

(Note: emissions from this source normally do not occur and the indicated emissions represent an extremely conservative scenario in which the normal delivery of refinery products by pipeline is interrupted for a full year)

Product Loaded	S	P	M	T	VOC Factor (lb/103 gal)	Throughput (10 <sup>3</sup> gal/year)	VOC Emission (ton/yr)	Benzene tons/yr	Naphthalene tons/yr	o-Xylene tons/yr	Ethylbenzene tons/yr
Motor Gasoline	0.5	8.27	66	537	6.3323	306,600	970.75	4.8537	4.2713	13.6875	7.1835
Aviation Gas	0.5	5.22	60	537	3.6336	1,686	3.06	0.0000	0.0000	0.0000	0.0000
Diesel	0.5	0.0143	130	537	0.0216	153,300	1.65	0.0000	0.0000	0.0000	0.0000
Jet Fuel	0.5	0.205	130	537	0.3092	199,290	30.81	0.0000	0.4005	0.7363	0.2465

Product Loaded	p-Xylene tons/yr	Ethylene Dibromide tons/yr	Ethylene Dichloride tons/yr	m-Xylene tons/yr	Toluene tons/yr	1,3-Butadiene tons/yr	n-Hexane tons/yr	Aniline tons/yr	Cresol Mixture tons/yr
Motor Gasoline	10.1928	0.0000	0.0000	25.9189	42.6157	0.0000	13.0080	0.0971	0.0000
Aviation Gas	0.0000	0.0008	0.0000	0.0000	0.0000	0.0000	0.0009	0.0000	0.0000
Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017
Jet Fuel	0.3235	0.0000	0.0000	0.8072	0.0000	0.0000	0.0000	0.0003	0.0308

Table 3-6 (continued)  
 POTENTIAL EMISSIONS FROM REFINERY TRUCK LOADING RACK

Product Loaded	Phenol tons/yr	Styrene tons/yr	Methanol tons/yr	Nickel tons/yr	HCL tons/yr	Perchloroethylene tons/yr	Biphenyl tons/yr
Motor Gasoline	0.0971	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Aviation Gas	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Diesel	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017
Jet Fuel	0.0308	0.0000	0.0000	0.0000	0.0000	0.0000	0.0308

Product Loaded	2,2,4 Trimethylpentane tons/yr	Cumene tons/yr	o-Toluidine tons/yr	Acrylamide tons/yr	Antimony Compounds tons/yr	Arsenic tons/yr	Cyanide Compounds tons/yr
Motor Gasoline	4.8537	0.0971	0.0971	0.0010	0.0000	0.0000	0.0000
Aviation Gas	0.0674	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Jet Fuel	0.0000	0.0308	0.3081	0.0000	0.0000	0.0000	0.0000

**3.1.4 Process Unit Fugitives**

As discussed in Section 2, the refinery incorporates numerous processes and storage facilities. These facilities are interconnected by piping, which uses tens of thousands of components such as valves, flanges, connectors, pumps, and compressors necessary for safe and efficient refinery operation. Fugitive emissions are defined as emissions that could not reasonably be expected to pass through a stack or vent. VOC emissions and emissions of the associated HAPs that occur due to leakage from piping components are defined as process fugitive emissions.

The estimation of process fugitive emissions was accomplished using published emission factors for specific components (e.g., valves, flanges, pumps, etc.) in a specific service (light liquid, heavy liquid, gas), and applying these factors to the total number of components in each process area. The refinery process areas are summarized in Table 3-7. The emission factors used for estimating total VOC emissions from components are presented in the EPA document "Protocol for Equipment Leak Estimates" (EPA, 1995). The fugitive emissions estimates were based on the Protocol's refinery average VOC emission factors, which are summarized in Table 3-8. Although a leak detection and repair (LDAR) program has been put in place within a number of refinery areas, non-LDAR emission factors are conservatively used to estimate the worst-case potential fugitive emissions from process units throughout the facility.

Calculation of fugitive emissions requires estimates of the total numbers of refinery components by type. In the original Covered Source Permit application, actual component counts for refinery process units were largely unavailable and the basis of the counts was the refinery Piping and Instrumentation Diagrams (P&IDs). Actual component counts obtained from implementation of the refinery LDAR program were used in this renewal application for those process areas where the LDAR program has been implemented. Component counts for the remaining refinery areas continue to rely on the data provided by the P&IDs.

The numbers of components by process area using non-LDAR emission factors are summarized in Table 3-9. Calculated VOC fugitive emissions by process area are summarized in Table 3-10. Detailed spreadsheets of component counts and emission estimates for individual components are provided on CD in Appendix B-3.

The above estimates reflect only streams in VOC service, which are defined as streams having a VOC content in excess of 10 percent by weight (EPA, 1995).

Pressure relief devices (PRV) that vent to a flare or control device are excluded from the fugitive emissions inventory because these emissions are controlled. As discussed previously, streams in insignificant liquid service (vapor pressure less than 0.3 kPa) have also been excluded from the inventory.

The total VOC emissions estimated by means of the above methods served as the basis for estimating fugitive emissions of HAPs from the refinery process units. Each component, or group of components in the same service, was assigned a stream code that corresponds to a specific distribution of HAPs by weight. The stream compositions were developed by Chevron based on process engineering information, stream analyses or available literature. The total VOC emission

Table 3-7  
REFINERY PROCESS AREAS

Area Number	Area Description
20	LPG area and field piping Blending and shipping storage tanks
23	Relief systems/cooling towers
36	Waste water treatment Land treatment unit Foul water tanks
51	Crude unit
52/55	Boilers/foul water oxidizer
53/54	Fluid catalytic cracker unit
56	Hydrogenation plant
57	Hydrogen plant
58	Alkylation plant
59	Isomerization plant
60	Asphalt plant
61/62	Amine/acid plant
66	Dimersol plant
67	Cogeneration plant

**Table 3-8  
REFINERY AVERAGE PROCESS FUGITIVE VOC EMISSION FACTORS (\*)**

Equipment Type	Service	Emission Factor (kg/hr/source)
Valves	G	0.0268
	LL	0.0109
	HL	0.00023
Pump Seals	G	0.2803**
	LL	0.114
	HL	0.021
Compressor Seals	G	0.636
PRVs	G	0.16
Connectors	ALL	0.00025
Open-ended Lines	ALL	0.0023
Sampling Connections	ALL	0.015

\* Obtained from Table 2-2 of EPA Document "Protocol for Equipment Leak Emission Estimates" 1995

\*\* No emission factor available for pump seals in gas service. Emission factor above reflects LL service for pump seals adjusted by the ratio of the gas to light liquid service emission factors for valves.

**Table 3-9  
COMPONENT COUNTS BY REFINERY AREA**

Area Number	Area Description	Service	Valves	Flanges	Pumps	Compressors	PRVS
20	LPG area and field piping Blending and shipping storage tanks	All	2,421	11,432	58	4	32
23	Relief systems	All	53	220	0	0	0
36	Waste water treatment	All	246	335	12	0	2
51	Crude unit	All	1,403	6,558	29	1	4
52/55	Boilers/foul water oxidizer	All	103	181	0	0	0
53	Fluid catalytic cracker unit	All	1,908	2,452	33	0	12
56	Hydrogenation plant	All	422	812	1	2	4
57	Hydrogen plant	All	166	914	1	0	4
58	Alkylation plant	All	1,180	5,821	21	1	0
59	Isomerization plant	All	570	1,493	9	0	0
60	Asphalt plant	All	53	236	0	0	0
61/62	Amine/acid plant	All	12	49	0	0	0
66	Dimersol plant	All	974	1,272	21	0	12
67	Cogeneration plant	All	253	1,264	2	1	0
	<b>Total</b>	<b>All</b>	<b>9,765</b>	<b>33,039</b>	<b>187</b>	<b>9</b>	<b>71</b>

Note: For summary purposes, both connectors and fittings have been grouped under the category of flanges

**Table 3-10  
MAXIMUM FUGITIVE VOC EMISSIONS FROM  
FIELD PIPING COMPONENT LEAKS BY PROCESS AREA**

Area Number	Area Description	VOC Emissions (Ton/Yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	438.3
23	Relief Systems	14.3
36	Waste Water Treatment Foul Water Tanks	1.6
51	Crude Unit	204.8
52/55	Boilers/Foul Water Oxidizer	27.1
53/54	Fluid Catalytic Cracker Unit	222.0
56	Hydrogenation Plant	71.5
57	Hydrogen Plant	34.4
58	Alkylation Plant	179.9
59	Isomerization Plant	107.9
60	Asphalt Plant	14.3
61/62	Amine/Acid Plant	3.3
66	Dimersol Plant	20.5
67	Cogeneration Plant	62.5
<b>Total</b>		<b>1402.2</b>



estimate was then multiplied by the weight fractions for individual HAPs to estimate the corresponding species emissions.

Maximum estimated fugitive HAP emissions from process units are summarized in Table 3-11.

### **3.1.5 Wastewater and Foul Water Treatment**

Wastewater and foul water treatment facilities process units are physically covered and controlled emission sources, excluding the downstream oxidizers after the Benzene Recovery Unit (BRU). AP-42 provides an emission factor of 0.2 pounds of VOC per thousand gallons of throughput for effluent treatment systems having control measures such as carbon adsorbers. The maximum capacity of the wastewater treatment system is 1,400 gallons per minute, yielding a maximum estimated VOC emission of 73.6 tons/year (147,200 lbs/year). HAP emissions are based on the VOC emissions and the speciation profile for recovered oil.

### **3.1.6 Cooling Tower**

The primary source of VOC emissions from cooling towers is leakage from process equipment that results in organic liquids mixing with the cooling water. Chevron has a monitoring and maintenance program to minimize the occurrence of such leaks. Section 5.1 of AP-42 presents a VOC emission factor for cooling towers at refineries with a program to minimize leaks. This factor is 0.7 pounds of VOC per million gallons of water. The cooling tower at the Chevron Hawaii Refinery has a cooling water rate of 50,000 gallons per minute, resulting in an estimated VOC emission rate of 2.1 pounds per hour (9.2 tons per year).

### **3.1.7 Flaring**

The refinery flares are necessary to control emissions from various equipment vents and to provide for safe operations in case of upset conditions or an emergency. Catastrophic upset condition gas rates are highly variable and difficult to predict; therefore, Chevron has primarily estimated emissions using AP-42 emission factors that are functions of the maximum refinery throughput. The flaring emission factors are based on an estimate of gas flaring rates as a function of refinery process rates. Note that the emissions are only provided as an estimate and that actual emissions may vary. Chevron attempts to minimize flaring events; however, in case of an emergency, flaring rates cannot be limited.

Table 5.1-1 of EPA document AP-42 provides the following refinery flaring emission factors (in pounds per thousand barrels of feed):

- Carbon monoxide - 4.3
- VOC - 0.8
- Nitrogen oxides - 18.9
- Sulfur oxides (as SO<sub>2</sub>) - 26.9

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## Emission Information

Table 3-11  
MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS

Number	Area Description	Benzene CAS# 71432 (ton/yr)	Naphthalene CAS# 91203 (ton/yr)	o-Xylene CAS# 95476 (ton/yr)	Ethylbenzene CAS# 100414 (ton/yr)	p-Xylene CAS# 106423 (ton/yr)	Ethylene Dibromide CAS# 106934 (ton/yr)	Ethylene Dichloride CAS# 107062 (ton/yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	0.823	1.405	3.32	1.25	1.71	0.45	0.27
23	Relief Systems	0.000	0.00	0.00	0.00	0.00	0.00	0.000
36	Waste Water Treatment Unit	0.007	0.006	0.01	0.00	0.00	0.00	0.00
51	Crude Unit	1.153	0.23	0.75	0.18	0.33	0.00	0.00
52/55	Boilers/Foul Water Oxidizer	0.000	0.00	0.00	0.00	0.00	0.00	0.00
53	Fluid Catalytic Cracker Unit	0.872	0.61	1.81	0.91	1.30	0.00	0.00
56	Hydrogenation Plant	0.000	0.00	0.00	0.00	0.00	0.00	0.00
57	Hydrogen Plant	0.000	0.00	0.00	0.00	0.00	0.00	0.00
58	Alkylation Plant	0.000	0.00	0.00	0.00	0.00	0.00	0.00
59	Isomerization Plant	0.000	0.00	0.00	0.00	0.00	0.00	0.00
60	Asphalt Plant	0.000	0.00	0.00	0.00	0.00	0.00	0.00
61/62	Amine/Acid Plant	0.000	0.00	0.00	0.00	0.00	0.00	0.00
66	Dimersol Plant	0.000	0.00	0.00	0.00	0.00	0.00	0.00
67	Cogeneration Plant	0.271	0.00	0.00	0.00	0.00	0.00	0.00
	Process Fugitive Summary	3.125	2.26	5.89	2.34	3.35	0.45	0.27

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## Emission Information

Table 3-11 (continued)  
MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS

Number	Area Description	m-Xylene CAS# 108383 (ton/yr)	Toluene CAS# 108883 (ton/yr)	1,3-Butadiene CAS# 106990 (ton/yr)	n-Hexane CAS# 110543 (ton/yr)	Aniline CAS# 62533 (ton/yr)	Cresol Mixture CAS# 1319773 (ton/yr)	Phenol CAS# 108952 (ton/yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	4.634	4.60	0.295	1.206	0.015	0.16	0.098
23	Relief Systems	0.000	0.000	0.00	0.000	0.000	0.00	0.000
36	Waste Water Treatment Unit	0.017	0.02	0.000	0.028	0.000	0.02	0.001
51	Crude Unit	1.219	2.57	0.024	3.505	0.008	0.05	0.011
52/55	Boilers/Foul Water Oxidizer	0.000	0.00	0.000	0.000	0.000	0.00	0.000
53	Fluid Catalytic Cracker Unit	3.328	5.19	0.250	0.368	0.023	0.00	0.006
56	Hydrogenation Plant	0.000	0.00	0.134	0.000	0.000	0.00	0.000
57	Hydrogen Plant	0.000	0.00	0.000	0.000	0.000	0.00	0.000
58	Alkylation Plant	0.000	0.00	0.050	0.005	0.000	0.00	0.000
59	Isomerization Plant	0.000	0.00	0.047	0.000	0.000	0.00	0.000
60	Asphalt Plant	0.000	0.00	0.000	0.000	0.000	0.00	0.000
61/62	Amine/Acid Plant	0.000	0.00	0.000	0.000	0.000	0.00	0.000
66	Dimersol Plant	0.000	0.00	0.000	0.000	0.000	0.00	0.000
67	Cogeneration Plant	0.000	0.15	0.000	0.592	0.000	0.00	0.000
	Process Fugitive Summary	9.197	12.54	0.800	5.704	0.046	0.23	0.116

# SECTION THREE

## Emission Information

Table 3-11 (continued)  
 MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS

Number	Area Description	Styrene CAS# 100425 (ton/yr)	Methanol CAS# 67561 (ton/yr)	Nickel CAS# 7440020 (ton/yr)	HCL CAS# 7647010 (ton/yr)	Perchloroethylene CAS# 127184 (ton/yr)	Biphenyl CAS# 92524 (ton/yr)	2,2,4 Trimethylpentane CAS# 540841 (ton/yr)
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	0.025	0.029	0.000	0.000	0.000	0.091	0.445
23	Relief Systems	0.000	0.000	0.000	0.000	0.000	0.000	0.000
36	Waste Water Treatment Unit	0.000	0.000	0.000	0.000	0.000	0.000	0.010
51	Crude Unit	0.004	0.000	0.000	0.000	0.000	0.013	0.554
52/55	Boilers/Foul Water Oxidizer	0.000	0.000	0.000	0.000	0.000	0.000	0.000
53	Fluid Catalytic Cracker Unit	0.037	0.000	0.000	0.000	0.000	0.010	0.000
56	Hydrogenation Plant	0.000	0.000	0.000	0.000	0.000	0.000	0.000
57	Hydrogen Plant	0.000	0.000	0.000	0.000	0.000	0.000	0.000
58	Alkylation Plant	0.000	0.000	0.000	0.000	0.000	0.000	0.398
59	Isomerization Plant	0.000	0.000	0.000	0.000	0.046	0.000	0.000
60	Asphalt Plant	0.000	0.000	0.000	0.000	0.000	0.000	0.000
61/62	Amine/Acid Plant	0.000	0.000	0.000	0.000	0.000	0.000	0.000
66	Dimersol Plant	0.000	0.000	0.340	0.000	0.000	0.000	0.000
67	Cogeneration Plant	0.000	0.000	0.000	0.000	0.000	0.000	0.104
	Process Fugitive Summary	0.066	0.029	0.340	0.000	0.046	0.114	1.511

# SECTION THREE

## Emission Information

Table 3-11 (continued)

### MAXIMUM FUGITIVE HAP EMISSIONS FROM PROCESS UNITS

Number	Area Description	Cumene CAS# 98828 (ton/yr)	o-Toluidine CAS# 95534 (ton/yr)	Acrylamide CAS# 79061 (ton/yr)	Antimony Compounds CAS# (ton/yr)	Arsenic CAS# (ton/yr)	Cyanide Compounds CAS# (ton/yr)	Total HAPs ton/yr
20	LPG Area and Field Piping Blending and Shipping Storage Tanks	0.165	0.863	0.000	0.001	0.009	0.009	21.873
23	Relief Systems	0.000	0.000	0.000	0.000	0.001	0.001	0.003
36	Waste Water Treatment Unit	0.002	0.002	0.000	0.000	0.000	0.000	0.130
51	Crude Unit	0.078	0.090	0.000	0.002	0.009	0.009	10.794
52/55	Boilers/Foul Water Oxidizer	0.000	0.000	0.000	0.000	0.003	0.003	0.005
53	Fluid Catalytic Cracker Unit	0.039	0.184	0.000	0.003	0.016	0.016	14.976
56	Hydrogenation Plant	0.000	0.000	0.000	0.000	0.004	0.004	0.143
57	Hydrogen Plant	0.000	0.000	0.000	0.000	0.000	0.000	0.000
58	Alkylation Plant	0.000	0.000	0.000	0.000	0.002	0.002	0.459
59	Isomerization Plant	0.000	0.000	0.000	0.000	0.001	0.001	0.095
60	Asphalt Plant	0.000	0.000	0.000	0.000	0.001	0.001	0.003
61/62	Amine/Acid Plant	0.000	0.000	0.000	0.000	0.000	0.000	0.001
66	Dimersol Plant	0.000	0.000	0.000	0.000	0.003	0.003	0.345
67	Cogeneration Plant	0.000	0.000	0.000	0.000	0.005	0.005	1.129
	Process Fugitive Summary	0.285	1.139	0.000	0.007	0.055	0.055	49.957

During normal operations, sulfur is stripped from the refinery gas in the acid plant (before it is flared). In the past when the acid plant was down, the sulfur was not removed from the acid plant gas stream, and additional SO<sub>2</sub> was produced by flaring. However, with the implementation of the Flare Sulfur Emission Reduction Project (see Section 5.3.2), such high-SO<sub>2</sub> events will no longer occur.

Applying the AP-42 factors for CO, VOC, SO<sub>2</sub> and NO<sub>x</sub> to a rate of 65,000 bbl/day of crude oil feed, results in the following estimated emissions (tons per year) from both flares combined. This conservative approach to estimating flaring emissions was selected because of safety concerns associated with limiting the throughput to the flares. HAP emissions for the flare have not been quantified, because the flares combust a variety of process streams. Therefore, neither the specific HAPs present nor their quantities can be meaningfully determined.

- Carbon monoxide – 51.0 tons per year
- VOC – 9.5 tons per year
- Nitrogen oxides – 224.2 tons per year
- Sulfur dioxide – 319.1 tons per year

### **3.1.8 Catalyst Transfer Operations at the FCC**

Operation of the FCC unit requires the removal and disposal of spent catalyst and the addition of fresh catalyst. Based on historical records, it is estimated that 77 tons per month of catalyst is disposed of and replaced with fresh catalyst. No emission factor was identified to address this specific catalyst handling activity. AP-42 (Section 8.23), however, provides factors for material transfer operations in the metallic minerals processing industry. The transfer of catalyst was assumed to be represented by the factor for material transfer (0.06 pounds of particulate per ton of material transferred [i.e., removal of spent catalyst plus replacement with new catalyst]). Using this factor results in an estimated particulate matter emission of 9.22 pounds per month.

## **3.2 SUMMARY**

The refinery inventory of maximum potential criteria pollutant emissions is summarized in Table 3-12. The corresponding maximum potential HAP emissions are summarized in Table 3-13. These emissions reflect the estimation methods and assumptions for the individual source types described in Sections 3.1.1 through 3.1.8.

## **3.3 IDENTIFICATION OF CONTROL DEVICES**

Emission control devices exist on the cogeneration turbines and compressor, the FCC stack, on many storage tanks, and the wastewater treatment system. The cogeneration turbines have low-NO<sub>x</sub> burners and water injection to reduce emissions of nitrogen oxides. This turbine control system is designed to limit NO<sub>x</sub> emissions to a level of no more than 67 and 69 parts per million on a volume basis at 15 percent O<sub>2</sub> for RFG and WSR fuels, respectively. The cogeneration compressor vents directly to the flare.

**Table 3-12  
SUMMARY OF MAXIMUM POTENTIAL CRITERIA POLLUTANT EMISSIONS  
FROM THE CHEVRON HAWAII REFINERY**

Sources	Pollutant Emission Rates (ton/yr)						Total Criteria Pollutant Emissions
	PM <sub>10</sub>	SO <sub>2</sub>	CO	NO <sub>2</sub>	VOC	Lead	
Boilers	372.5	5415.3	86.2	551.9	13.1	0.0	6439
Cogen Turbines	11.7	16.0	52.5	193.2	2.3	0.0	276
Crude Furnaces	44.5	482.0	75.0	302.9	5.1	0.0	909
FCC Furnace	2.0	1.6	22.1	26.3	1.4	0.0	53
Isom Furnaces	0.2	0.2	2.1	2.5	0.1	0.0	5
H&H Furnaces	1.1	0.9	12.1	14.5	0.8	0.0	29
Acid preheater & combustion chamber	0.4	0.4	4.8	5.7	0.3	0.0	12
Asphalt Furnace	0.2	0.1	2.0	2.4	0.1	0.0	5
FCC Stack	175.2	450.0	499.3	285.1	14.7	0.0	1424
Cooling Tower	3.2	-	-	-	9.2	-	12
Acid plant absorber stack (*)	-	803.0	-	-	-	-	803
Catalyst transfer	0.0	-	-	-	-	-	0
Wastewater treatment	-	-	-	-	73.6	0.0	74
Loading Rack	-	-	-	-	3.6	0.0	4
Process Fugitives	-	-	-	-	1402.2	1.4	1404
Tanks	-	-	-	-	316.6	0.0	317
Marine loading	-	-	-	-	196.6	0.0	197
Refinery Flares	-	319.1	51.0	224.2	9.5	-	3685
<b>Totals</b>	<b>611.1</b>	<b>7,488.5</b>	<b>807.1</b>	<b>1,608.5</b>	<b>2,049.3</b>	<b>1.4</b>	<b>15,647</b>

Notes: (\*) Criteria pollutant emissions from the acid preheater and combustion chamber are vented to the acid plant absorber stack. The listed SO<sub>2</sub> emissions from the acid plant absorber stack are only from acid production.

# SECTION THREE

## Emission Information

Table 3-13  
SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY

	LPG Area and Field Piping Blending and Shipping Storage Tanks	Relief Systems	Waste Water Treatment Unit	Crude Unit	Boilers/Foul Water Oxidizer	Fluid Catalytic Cracker Unit	Hydrogenation Plant	Hydrogen Plant	Alkylation Plant	Isomerization Plant
Benzene	CAS# 71432	0.0000	0.0068	1.1530	0.0000	0.8724	0.0000	0.0000	0.0000	0.0000
Naphthalene	CAS# 91203	0.0000	0.0059	0.2322	0.0000	0.6136	0.0000	0.0000	0.0000	0.0000
o-Xylene	CAS# 95476	0.0000	0.0128	0.7494	0.0000	1.8054	0.0000	0.0000	0.0000	0.0000
Ethylbenzene	CAS# 100414	0.0000	0.0030	0.1803	0.0000	0.9089	0.0000	0.0000	0.0000	0.0000
p-Xylene	CAS# 106423	0.0000	0.0047	0.3312	0.0000	1.3032	0.0000	0.0000	0.0000	0.0000
Ethylene Dibromide	CAS# 106934	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ethylene Dichloride	CAS# 107062	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
mXylene	CAS# 108383	0.0000	0.0171	1.2185	0.0000	3.3278	0.0000	0.0000	0.0000	0.0000
Toluene	CAS# 108863	0.0000	0.0202	2.5684	0.0000	5.1932	0.0000	0.0000	0.0000	0.0000
1,3-Butadiene	CAS# 106990	0.0000	0.0001	0.0236	0.0000	0.2497	0.1344	0.0000	0.0501	0.0471
n-Hexane	CAS# 110543	0.0000	0.0281	3.5047	0.0000	0.3683	0.0000	0.0000	0.0054	0.0000
Aniline	CAS# 62533	0.0000	0.0000	0.0082	0.0000	0.0226	0.0000	0.0000	0.0000	0.0000
Cresol Mixture	CAS# 1319773	0.0000	0.0162	0.0543	0.0000	0.0007	0.0000	0.0000	0.0000	0.0000
Phenol	CAS# 108952	0.0000	0.0010	0.0109	0.0000	0.0061	0.0000	0.0000	0.0000	0.0000
Styrene	CAS# 100425	0.0000	0.0000	0.0040	0.0000	0.0369	0.0000	0.0000	0.0000	0.0000
Methanol	CAS# 67561	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0000
Nickel	CAS#	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
HCL	CAS# 7647010	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Perchloroethylene	CAS# 127184	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
Biphenyl	CAS# 92524	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0463
2,4 Trimethylpentane	CAS# 540841	0.0000	0.0004	0.0129	0.0000	0.0097	0.0001	0.0000	0.0000	0.0000
Cumene	CAS# 98828	0.0000	0.0103	0.5543	0.0000	0.0000	0.0000	0.0000	0.3984	0.0000
o-Toluidine	CAS# 95534	0.0000	0.0025	0.0783	0.0000	0.0388	0.0000	0.0000	0.0000	0.0000
Acrylamide	CAS# 79061	0.0000	0.0015	0.0900	0.0000	0.1842	0.0000	0.0000	0.0000	0.0000
Antimony Compounds	CAS#	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Arsenic	CAS#	0.0001	0.0000	0.0015	0.0003	0.0026	0.0004	0.0000	0.0002	0.0001
Cyanide Compounds	CAS#	0.0014	0.0000	0.0091	0.0026	0.0159	0.0043	0.0000	0.0024	0.0007
Formaldehyde	CAS#	0.0014	0.0000	0.0091	0.0026	0.0159	0.0043	0.0000	0.0024	0.0007
POM/PAH										
Total HAPs	21.8730	0.0030	0.1304	10.7939	0.0054	14.9759	0.1435	0.0000	0.4593	0.0950
	ton/yr									



# SECTION THREE

## Emission Information

Table 3-13 (continued)  
SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY

	Asphalt Plant	Amine/Acid Plant	Dimersol Plant	Cogeneration Plant	Tank Farm	Boiler Point	Cogen Point	Crude Point	FCC Point	Isom Point
Benzene	0.0000	0.0000	0.0000	0.2705	1.1863	0.0029	0.0002	0.0010	0.0006	0.0001
Naphthalene	0.0000	0.0000	0.0000	0.0000	0.0189	0.0083	0.0002	0.0055	0.0002	0.0000
o-Xylene	0.0000	0.0000	0.0000	0.0000	0.2419	0.0008		0.0005		
Ethylbenzene	0.0000	0.0000	0.0000	0.0000	0.1232	0.0004		0.0003		
p-Xylene	0.0000	0.0000	0.0000	0.0000	0.0777					
Ethylene Dibromide	0.0000	0.0000	0.0000	0.0000	0.0005					
Ethylene Dichloride	0.0000	0.0000	0.0000	0.0000	0.0003		0.0000			
m-Xylene	0.0000	0.0000	0.0000	0.0000	0.4367					
Toluene	0.0000	0.0000	0.0000	0.1527	1.5172	0.0458	0.0000	0.0303	0.0009	0.0001
1,3-Butadiene	0.0000	0.0000	0.0000	0.0000	0.0000		0.0001			
n-Hexane	0.0000	0.0000	0.0000	0.5915	3.9389	1.2297		0.0018	0.4730	0.0441
Aniline	0.0000	0.0000	0.0000	0.0000	0.0012					
Cresol Mixture	0.0000	0.0000	0.0000	0.0000	0.0333					
Phenol	0.0000	0.0000	0.0000	0.0000	0.0018					
Styrene	0.0000	0.0000	0.0000	0.0000	0.0014					
Methanol	0.0000	0.0000	0.0000	0.0000	0.0000					
Nickel	0.0000	0.0000	0.3398	0.0000	0.0000					
HCL	0.0000	0.0000	0.0000	0.0000	0.0000					
Perchloroethylene	0.0000	0.0000	0.0000	0.0000	0.0000					
Biphenyl	0.0000	0.0000	0.0000	0.0000	0.0132					
2,2,4, Trimethylpentane	0.0000	0.0000	0.0000	0.1036	1.3880					
Cumene	0.0000	0.0000	0.0000	0.0000	0.0145					
o-Toluidine	0.0000	0.0000	0.0000	0.0000	0.0609					
Acrylamide	0.0000	0.0000	0.0000	0.0000	0.0001					
Antimony Compounds	0.0001	0.0000	0.0003	0.0005	0.0027					
Arsenic	0.0014	0.0003	0.0025	0.0050	0.0027					
Cyanide Compounds	0.0014	0.0003	0.0025	0.0050	0.0027					
Formaldehyde						0.3490	0.0012	0.2077	0.0197	0.0018
POM/PAH						0.2978	0.0002	0.0059	0.0000	0.0000
Total HAPs	0.0030	0.0007	0.3452	1.1288	9.0638	1.9347	0.0019	0.2531	0.4943	0.0461

# SECTION THREE

## Emission Information

Table 3-13 (continued)  
SUMMARY OF MAXIMUM POTENTIAL HAP EMISSIONS FROM THE CHEVRON HAWAII REFINERY

	H&H Point	H&H Point	Acid Plant CC and Preheater Point	Asphalt Point	FCC Stack	Wastewater	Load Rack	Marine Loading	Flare	Haps Summary
Benzene	0.0001	0.0002	0.0001	0.0001		0.1398	0.0000	4.1081		8.5649
Naphthalene	0.0000	0.0001	0.0000	0.0000		0.3458	0.0000	0.0000		2.6354
o-Xylene						0.5887	0.0000	0.0000		6.7173
Ethylbenzene						0.1840	0.0000	0.0000		2.6494
p-Xylene						0.2796	0.0000	0.0000		3.7034
Ethylene Dibromide						0.0002	0.0009	0.0000		0.4517
Ethylene Dichloride						0.0000	0.0000	0.0000		0.2703
m-Xylene						0.7211	0.0000	0.0000		10.3550
Toluene	0.0001	0.0004	0.0002	0.0001		0.4709	0.0000	2.3194	0.0015	16.9219
1,3-Butadiene	0.0709	0.1892	0.1028	0.0434		0.0000	0.0000	8.9828		21.8252
n-Hexane						1.0449	0.0011			
Aniline						0.0007	0.0000	0.0000		0.0479
Cresol Mixture						1.0670	0.0000	0.0000		1.3348
Phenol						0.0589	0.0000	0.0000		0.1770
Styrene						0.0000	0.0000	0.0000		0.0671
Methanol						0.0000	0.0000	0.0000		0.0292
Nickel						0.0000	0.0000	0.0000		0.3398
HCL						0.0001	0.0000	0.0000		0.0001
Perchloroethylene						0.0001	0.0000	0.0000		0.0464
Biphenyl						0.0221	0.0000	0.0000		0.1498
2,2,4 Trimethylpentane						0.5151	0.0797	1.5725		5.0667
Cumene						0.1251	0.0000	0.0000		0.4245
o-Toluidine						0.0589	0.0000	0.0000		1.2590
Acrylamide						0.0000	0.0000	0.0000		0.0002
Antimony Compounds						0.0001	0.0000	0.0000		0.0097
Arsenic						0.0001	0.0000	0.0000		0.0574
Cyanide Compounds						0.0001	0.0000	0.0000		0.0574
Formaldehyde	0.0030	0.0079	0.0043	0.0018	0.8902		0.0000	0.0000		1.4866
POMPAH	0.0000	0.0000	0.0000	0.0000			0.0000	0.0000		0.3039
Total HAPs	0.0741	0.1977	0.1075	0.0453	0.8902	5.6230	0.0817	16.9828	0.0015	85.7546

Both flare stacks are also considered control devices because they are used to combust emissions from the venting of equipment that is regulated under NSPS and MACT requirements.

The FCC stack is routed through a cyclone and electrostatic precipitator (ESP). These devices remove particulate matter from the FCC flue gas. The removal efficiency of these controls ranges from 95 to more than 99 percent.

The wastewater treatment plant uses several devices to control emissions. The foul water tanks are vented to a flare and the foul water oxidizer is vented to the Boiler Plant boilers. The nitrogen strippers of the benzene recovery unit (BRU) remove hydrocarbons from the wastewater. These hydrocarbons are controlled by carbon absorbers and are subsequently sent to the recovered oil tankage. The BRU vents some nitrogen at the end of the adsorber regeneration. This vent is controlled by carbon canisters, as is the purge gas from the API separators. The recovered oil sump is connected to carbon canisters.

Secondary seals or equivalent (i.e., dome roofs) are installed on Tank Nos. 105, 106, 109, 110, 111, 113, 162, 163, 232, 233, 237, 249, 250, 262, 271, 301, and 302. Chevron is currently planning to install secondary seals on several additional tanks.

### **3.4 IDENTIFICATION OF COMPLIANCE MONITORING DEVICES**

Chevron monitors numerous surrogate parameters that are used to estimate emissions from specific processes, and operates several monitors for compliance tracking. Usage of both fuel oil and refinery gas is monitored for each furnace and cogeneration turbine. For each storage tank, records are maintained on the material stored, its chemical properties, and the throughput of the tank.

Specific compliance monitors within the Hawaii Refinery consist of refinery gas H<sub>2</sub>S monitoring at the effluent from the gas treatment unit, NO<sub>x</sub> and O<sub>2</sub> monitors on the cogeneration turbine exhaust stacks, flare pilot light monitors, and API separator control device outlet VOC content. Additionally, at the BRU, control device outlet VOC content, regeneration steam flow, temperature, and duration of regeneration are monitored. Further information on compliance monitoring requirements is provided in Section 5 of this application.

Emissions trading between process areas or group designations is not proposed. Information regarding compliance monitoring and reporting for each source group within the refinery is presented in Section 5.

### **3.5 INSIGNIFICANT ACTIVITIES**

The operating permit regulations (Section 11-60.1-82(d)(e)(f)(g)) exempt specific activities from permitting requirements, but requires that such activities be listed. The following activities are exempted under 11-60.1-82(f)(g):

- A stand-by 335 hp diesel-fired generator is maintained in the cogeneration area. It is used in case of a power and cogeneration failure. The generator provides “black start” or “startup” power to begin turbine operation.

- Numerous tanks storing organic liquids have a capacity of less than 40,000 gallons and are not subject to other requirements in Sections 111 and 112 of the Act. These tanks are summarized as follows:

Tank Number	Service	Capacity (gallons)
20TD1	Anti Icing Additive	11,340
20TD2	HCC	11,340
20TD3	Out of Service	11,340
20TD4	ULMidgrade	11,340
20TD6	Anti Icing Additive	8,148
2010	Aviation Lead	15,288
5198	Nalco 5300	8,068

Additionally, the refinery operates numerous pieces of diesel-fired equipment with a horsepower rating of less than 200. Table 3-14 lists this equipment.

### 3.6 REQUEST FOR ADDITIONAL EXEMPTIONS

Section 11-60.1-82(f)(7) allows the Director to exempt “other activities as determined on a case-by-case basis to be insignificant.” Petroleum refineries are complex facilities with numerous types and sizes of sources. Some of these sources are small and will have no significant impact on ambient air quality, are not covered by any applicable requirement, and were granted exemption status in the original Title V permit. Chevron requests that the Director again exempt the following sources from the requirements of 11-60.1-82:

- Meter stations, sampling points and filters.* These sources are present throughout the various process areas. Leakage from the connections and fittings associated with such equipment has been accounted for in the fugitive emissions estimates for each process unit. When sampling occurs or filters are changed, however, a small amount of VOC may be emitted. It is estimated that emissions are typically less than 10 pounds per occurrence. Inclusion of such equipment emissions and operations in the permit would impose a significant burden for monitoring and recordkeeping without significant air quality benefit. Chevron uses good engineering and operating practices to minimize emissions during these operations.
- Pump and tank degassing operations.* Occasionally, pumps in liquid service malfunction if a gas bubble is encountered in the fuel flow. The only practical method of returning the pump to operation is to vent the gas bubble, and prime the pump with liquid. Most pumps are tied into the flare relief system, so that such venting is controlled. Some pumps are not tied into the flare

**Table 3-14  
DIESEL POWERED EQUIPMENT LESS THAN 200 HORSEPOWER\***

Description	Refinery Area
Amero Aero Waterblaster #1	Maintenance Shop
Amero Aero Waterblaster #2	Maintenance Shop
Lincoln Diesel Welders (7 each)	Maintenance Shop
Amidalight Tower	Maintenance Shop
Gorman Rup Pumps (2 each)	Maintenance Shop
1979 Joy D185QP Air Compressor	Maintenance Shop
1981 Joy D800QP Air Compressor	Maintenance Shop
Ingersoll-Rand Large Compressor	Boiler Plant
Ingersoll-Rand Small Compressor	Maintenance Shop

\* Data taken from original Covered Source Permit Application

system, however, and must be vented to atmosphere in order to prime the pump with liquid. Pumps are vented only when degassing is required.

There are 98 tanks in hydrocarbon service at the refinery. Tank degassing is performed approximately every 10 years to enable tank interiors to be inspected. Degassing may be done more frequently (three or four times in 10 years), however, if maintenance issues arise. Degassing operations consist of draining a tank to the minimum pump-out level. Vapors under the area of the floating roof are vented to the atmosphere. It is impossible to control these emissions using the flare because the tanks are not under pressure during degassing.

3. *Training fires.* The regulations exempt smoke generating equipment used in certified fire training facilities. Chevron requests DOH concurrence that this exemption also applies to open pit fires used by Chevron for fire training.
4. *Process upset vents.* Pressurized equipment such as the crude towers and FCC unit are equipped with relief vents that open only during malfunctions or severe process upset conditions. The frequency of such occurrences cannot be predicted, and the vents are critical for safe operation. Historically, venting episodes are rare. Chevron requests that emissions from upset vents be exempted. However, applicable NSPS, Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and National Emission Standards for Hazardous Air Pollutants (NESHAP) standards will be satisfied.
5. *Refinery gasoline pump.* A single service station style gasoline pump is located at the refinery, and is used to fill all gasoline-powered vehicles. Its typical monthly throughput is less than 2,000 gallons. Gasoline service station operations are exempted from permitting requirements and Chevron requests this exemption be extended to the single refinery gasoline pump.
6. *Mercury.* The instrumentation repair shop and the laboratory periodically repair instruments and gauges that contain liquid mercury. Only small amounts of mercury are removed from such equipment and the mercury is in an unheated liquid state. The total inventory of mercury at the refinery is estimated to be less than 1 gallon. Insignificant emissions are expected from this activity.
7. *Oily sewer and stormwater vents.* Oily water and stormwater sewers exist beneath the refinery. The oily water sewer routes to an oil/water separator and contains minor amounts of oil mixed with water. Additionally, some trace amounts of oil may be present in the stormwater system. To prevent over-pressure, vent pipes 3 inches in diameter and less are placed along the sewer route. There are 76 of these vent pipes, plus six manholes with vent openings. These vent pipes are expected to have insignificant emissions.
8. *Maintenance and cleaning activities.* Routine maintenance and cleaning activities at the refinery use small amounts of commercial chemicals. These chemicals are delivered to the refinery in small containers or drums. Their use is expected to result in insignificant emissions.

Black Oil Tanks must be cleaned to remove accumulated sludge before inspection. It is estimated that approximately two tanks per year are cleaned. Insignificant emissions are expected from this activity.

Process unit shutdown and turnaround activities are performed infrequently as needed for maintenance. Typically, turnaround is performed every 2 to 4 years depending on the process unit. Process fluids are removed and displaced by water. The unit is drained and steamed. Steam is vented to the flares.

- 9. *Additives, promoters, passivators, and antifoam agents.* Various chemicals are used in the refinery operation to facilitate the refining process. Addition of these chemicals is not anticipated to materially change facility VOC or HAP emissions, and results in insignificant incremental emissions.
- 10. *Insignificant Heavy Liquids.* Chevron has reviewed applicable requirements for numerous source categories to determine the implication of developing an insignificant heavy liquids source category. Insignificant heavy liquids are hydrocarbon liquids that have a vapor pressure less than 0.3 kPa. In general, this includes diesel and the heavier hydrocarbon liquids.

Emission calculation equations and emission factors were reviewed to assess the impact of excluding insignificant heavy liquids from the refinery inventory. Fugitive and storage tank emissions factors for heavy liquids are one to two orders of magnitude less than those for light liquids.

- 11. *FCCU Baghouse.* A small baghouse (Flex-Kleen bin vent filter) is located on the electrostatic precipitator of the FCCU to capture potential fugitive dust emissions when the ESP hopper is emptied. DOE has already agreed that emissions from this pollution control device meet the definition of an insignificant activity.
- 12. *Storage of Regulated Pollutants not in VOC service.* Numerous onsite tanks store substances containing regulated pollutants. These tanks are not in VOC service, consistent with Subpart VV 40 CFR 60.481. In addition, these tanks are not in petroleum liquid service, consistent with Subpart K 40 CFR 60.111. Insignificant fugitive emissions result from these tanks, which are listed below:

Tank Number	Service	Capacity (gallons)
350	Refinery Fuel Oil	120,918
351	Refinery Fuel Oil	120,918
175	Out of Service	50,904
5211	25% Aqueous Ammonia	11,760
5481	Out of service	10,164
6673	Nickel Catalyst	5,418
5197	25% Aqueous Ammonia	120

- 13. *Storage of Spent Sulfuric Acid.* Spent sulfuric acid is stored in up to two tanks at the refinery. Sulfuric acid is not a regulated pollutant; however, spent acid may contain residual amounts of VOC. Insignificant emissions are anticipated from these tanks, which are numbered 62AP1 and 62AP3.

14. *Storage of Non-Regulated Pollutants.* The tanks shown in Table 3-15 contain non-regulated pollutants. These tanks are not subject to federal or state requirements. The list is provided to clarify the contents of all tanks at the refinery.



**Table 3-15  
NON-REGULATED POLLUTANT STORAGE TANKS\***

Tank Number	Service	Roof Type	Capacity (bbls)
305	Neutralized Water	Cone	24
306	Neutralized Water	Cone	72
62AP2	Sulfuric Acid	Cone	2,422
120	Gutwater	Cone	240
352	Raw Water	None	24,000
353	Condensate	Cone	253
354	Hot Line Reactor Bottoms Accumulator	Cone	810
381	Dirty Backwash Water Tank	Cone	758
382	De-ionized Water	Cone	274
AP-4	Regenerated MEA	Cone	504
AP-5	Regenerated MEA	Cone	504
AP-6	Caustic (25° Be)	Cone	280
2301	Sulfuric Acid	Cone	14
V-5182A&B	Caustic (25° Be & 5° Be)	Cone	242
5206	20° Be Caustic	Cone	179
5210	50° Be Caustic	Cone	1360
5390	Condensate	Cone	107
5480	Caustic	Cone	70
V-5486	Water	Cone	2
V-5897	Water	Cone	11
6646	Caustic	Cone	155
6658	Condensate	Cone	40
5311	Spent Catalyst (FCC)	Cone	4,000
5312	Catalyst Fines (FCC)	Cone	317
5313	Catalyst Fines (FCC)	Cone	317
5314	Fresh Catalyst (FCC)	Cone	60
5316	Fresh Catalyst (FCC)	Cone	1,128

\* Does not include Reverse Osmosis boiler water tank or caustic tank for FSERP project.

The initial Title V permit application for the Chevron Refinery included a dispersion modeling analysis that demonstrated that the facility's emissions would not cause or contribute to pollutant concentrations in excess of federal or Hawaii ambient standards. In recognition that the refinery's normal operations entail processing of a variety of crude oil feedstocks to produce numerous different products, the representation of emissions from the various sources was undertaken in a manner to ensure that the resulting pollutant concentration estimates would not be underestimated for any foreseeable operational condition of the refinery.

Accordingly, the dispersion modeling analysis to estimate maximum short-term impacts (24 hours or less) assumed that any source capable of using multiple fuels was operating with the fuel that would result in the highest potential emissions. Additionally, despite the actual intermittent operation of some sources, the emissions used for modeling were based on the worst-case assumption of continuous operation at maximum capacity for all hours of the year. This is an extremely conservative representation of emissions, especially for the annual averaging period.

Since the initial Covered Source Permit Application was submitted, Chevron has applied for several minor and major permit modifications to implement various refinery projects. In each such instance, DOH has made a decision as to whether additional dispersion modeling was required as part of the application to ensure that the proposed modification would not result in pollutant concentrations in excess of applicable ambient standards. These analyses have been conducted and submitted to DOH when required, and, in each case, have shown that compliance with the standards continues to be maintained.

Of the three proposed changes to existing conditions of the Covered Source Permit being requested in this application (Section 5.3.2), none would result in increased emissions or changes in the conditions of pollutant releases to the atmosphere that would justify remodeling for this renewal application.

- The request to remove the current permit restrictions on RFG and WSR usage by the turbines of the cogeneration plant would allow more flexibility in the operation of this plant area. The emissions corresponding to any split of these fuels between the cogeneration turbines would be lower than those assumed in the modeling for the previous Covered Source Permit application, because that analysis was based on a presumed future scenario with four turbines operating at maximum capacity. The actual number of turbines installed has never increased above three, so a scenario with emissions higher than those that would result from this proposed change in permit condition has already been modeled and shown to comply with ambient air quality standards.
- The request to replace the conditions limiting the amounts and sulfur contents of feedstocks to the FCCU by a single limit on the average feed sulfur content will not increase emissions of any pollutant.
- The request to remove the current permit restrictions on the number of burners of the crude unit atmospheric and vacuum furnaces that can burn refinery gas could lead to more RFG usage than at present. This change, however, would represent a decrease in emissions for

NO<sub>x</sub>, SO<sub>2</sub> and PM<sub>10</sub>, and, would not result in higher modeled concentrations of these pollutants than the scenarios that were modeled for the initial application. Maximum emissions of CO would potentially be increased for the case with all burners using RFG fuel, but the wide margin of compliance with CO ambient standards that has been demonstrated by previous modeling will ensure that this increase will not result in exceedances of these standards.

Thus, it is Chevron's position that there is no reason to conduct additional dispersion modeling as part of this permit renewal package.

## 5.1 INTRODUCTION

As required by HAR §11.60.1-83(a) and §11-60.1-86, this chapter presents information describing air quality requirements applicable to operations at the Chevron Hawaii Refinery and methods for monitoring compliance. The Chevron Hawaii Refinery was built and commenced operation in 1960. No changes triggering air quality requirements were implemented from 1960 through 1976. Several source modifications were implemented from 1976 through September 1994, and these changes were addressed when Chevron filed the application for the initial Title V Covered Source Permit in September 1994. On February 22, 1999 the State of Hawaii, Department of Health (DOH) Environmental Management Division issued the initial Title V Covered Sources Permit No. 0088-01-C to Chevron USA Products Company for the Hawaii Refinery. The Covered Source Permit issued by DOH addressed all applicable requirements and compliance monitoring for the facility, including modifications through 1994 and compliance with NESHAP Subpart CC, which was adopted between the times the application was submitted and the Covered Source Permit was issued.

The initial Covered Source Permit is incorporated by reference into this renewal application and a detailed analysis of requirements and compliance monitoring has not been reiterated. However, Section 5.2 contains a summary of the applicable requirements taken directly from the initial Title V Covered Source Permit Review Summary (File #0088-01) prepared by DOH to support issuance of the initial Covered Source Permit. Section 5.3.1 addresses applicable requirements and compliance for modifications or regulations that have been implemented since the time of initial Covered Source Permit issuance in 1999 through the current operations. Section 5.3.2 describes proposed facility changes and regulations that may take effect during the term of the permit renewal through 2009, and anticipated changes to applicable requirements during this period, including proposed changes to the DOH insignificant source classifications. Section 5.4 addresses MACT applicability and Compliance Assurance Monitoring. Requirements that are not contained in the initial Covered Source Permit or in this application are deemed not to be applicable to the facility. Section 5.5 addresses potential future changes to DOH rules, and Section 5.6 presents the required compliance forms pursuant to §11-60.1-86.

## 5.2 INITIAL COVERED SOURCE PERMIT APPLICATION REQUIREMENTS

The initial permit application and resulting Title V Covered Source Permit identified the facility applicable requirements, and the permit incorporated conditions to confirm compliance with these requirements. This section is a summary of the applicable rules and methods for monitoring compliance at the Chevron Hawaii Refinery, as required by §11-60.1-86. The following discussion was excerpted from the Covered Source Permit Review Summary prepared by DOH in support of the initial Covered Source Permit. This section is intended to be a comprehensive summary of applicable requirements and these requirements will also apply to the Renewed Covered Source Permit.

### 5.2.1 Applicable Federal Regulations

40 CFR 60: New Source Performance Standards (NSPS)

Subpart A: General Provisions (apply to all units that are subject to one or more of the following NSPS Subparts)

Subpart J: Standards of Performance for Petroleum Refineries (applies to the Crude Unit Furnaces, Asphalt Furnace, Acid Plant Preheater, and the Gas Turbines with Heat Recovery Steam Generators (HRSGs) in the Cogeneration Plant)

Subpart GG: Standards of Performance for Stationary Gas Turbines (applies to the Gas Turbines with HRSGs in the Cogeneration Plant)

Subpart GGG: Standards of Performance for Equipment Leaks in Petroleum Refineries (applies to equipment -- valves, pumps, flanges, etc. -- in VOC/VOL service associated with the FCC Unit, Crude Unit, LPG Refrigeration System, Dimersol Plant, Cogeneration Plant Compressor, and Flares)

Subpart QQQ: Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems (applies to process drains and sewer lines associated with the Crude Unit Furnaces and Desalter, Cogeneration Plant, and API Separators)

40 CFR Part 61: National Emission Standards for Hazardous Air Pollutants (NESHAP)

Subpart A: General Provisions (applicable to units that are subject to the following NESHAP Subpart):

Subpart FF: National Emission Standards for Hazardous Air Pollutants From Benzene Waste Operations (applies to the API Separators, Benzene Recovery Unit, Recovered Oil Sump, Skim Oil Tank, Wastewater Surge Tank, Recovered Oil Tank, and Crude Water Draw Tank)

40 CFR Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)

Subpart A: General Provisions (apply to units that are subject to the following Category-Specific NESHAP Subpart)

Subpart CC: National Emission Standards from Petroleum Refineries applies to streams in the FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor and Liquid Fuel System, Alkylation Plant and Effluent Treatment Plant, all Group 1 and Group 2 petroleum storage tanks and the petroleum truck loading rack. Specifically, the equipment leaks provisions of Subpart CC apply to streams in organic HAP service (at least 5% by weight total HAPs). These existing streams must comply with the equipment leak provisions in 40 CFR Part 60, Subpart VV. The processes at the Chevron Hawaii Refinery mentioned above must comply with Subpart VV for those streams in organic HAP service.

Compliance Dates: All noted units, except for the petroleum storage tanks and petroleum truck loading rack, have a compliance date on or before August 18, 1998. The Group 1 petroleum storage tanks (all storage tanks except for storage tanks 152, 263, 267 and 274) have a compliance date of August 18, 2005, or the next time the storage vessel is emptied or degassed after August 18, 1998. The petroleum truck loading rack is currently classified as a Group 2 gasoline loading rack, and must comply with Subpart CC upon classification as a Group 1 gasoline loading rack.

CFR Part 68: Chemical Accident Prevention Provisions (applies to the storage and use of flammable substances in the facility.)

### **Notes on Applicability**

Although the crude flare and FCC flare were constructed in 1959, prior to promulgation of NSPS requirements, these flares are now subject to NSPS Subpart GGG and 40 CFR 60.18, *General Pollution Control Requirements for Flares*, because both flares are used as control devices to comply with NSPS Subpart GGG.

Chevron requested in the initial Covered Source Permit application to increase the storage capacity of petroleum storage tanks Nos. 105, 106, 107, 108, 109, 110, and 111 by 12 percent over a five-year period. This increase in tank capacity was determined by DOH to result in a net decrease in tank emissions, due to fewer tank turnovers (tank filling and emptying operations). The secondary seals required by Subpart CC are being installed at the same times when the tank capacities are increased. Reconstruction and modification requirements under NSPS were deemed by DOH not to be triggered by these changes in tank capacity and seal configuration.

### **5.2.2 State Regulations**

The requirements governing sources of air contaminants in Hawaii are contained in Hawaii's Administrative Rules (HAR) Title 11, Department of Health Chapter 59 *Ambient Air Quality Standards*, and Chapter 60.1 - *Air Pollution Control*. Chapter 59 establishes the ambient air quality standards for the State of Hawaii and prohibits any person from contributing to a violation of these standards. Chapter 59 is applicable to the Chevron refinery; consequently, compliance with the National Ambient Air Quality Standards is a state enforceable requirement. Chapter 60.1 establishes the air pollution permit program for the State of Hawaii, and contains many general and equipment-specific regulations. The following applicable requirements are addressed in the facility initial Covered Source Permit and will continue to apply to the renewed permit.

HAR Title 11, Chapter 59 - Ambient Air Quality Standards

HAR Title 11, Chapter 60.1 - Air Pollution Control

Subchapter 1: General Requirements

Subchapter 2: General Prohibitions

HAR 11-60.1-31: Applicability

HAR 11-60.1-32: Visible Emissions (applies to Crude Furnaces, Boilers, FCCU, Process Unit Furnaces, Asphalt Plant, Acid plant, and Cogeneration Plant)

HAR 11-60.1-33: Fugitive Dust (applies to FCCU catalyst transfer operations)

HAR 11-60.1-38: Sulfur Oxides from Fuel Combustion (Crude Furnaces, Boilers, FCCU, Process Unit Furnaces, Asphalt Plant, Acid Plant Preheater, and Cogeneration Plant)

HAR 11-60.1-39: Storage of Volatile Organic Compounds (applies to Petroleum Storage Tanks)

HAR 11-60.1-40: Volatile Organic Compound Water Separation (applies to API Separators)

HAR 11-60.1-41: Pump and Compressor Requirements (seal requirements apply to pumps and compressors handling VOC with a Reid vapour pressure greater than or equal to 1.5 psia in FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor)

HAR 11-60.1-42: Waste Gas Disposal (flare/abatement requirement for VOC vapor blowdown applies to equipment in FCC Unit, Crude Unit, Blending and Shipping Area, Dimersol Plant, Cogeneration Plant Compressor)

Subchapter 5: Covered Sources

Subchapter 6: Fees for Covered Sources, Noncovered Sources, and Agricultural Burning

Subchapter 8: Standards of Performance for Stationary Sources

HAR 11-60.1-161: New Source Performance Standards (apply to all units that are subject to one or more of the NSPS Subparts in 40 CFR 60, as noted above under Federal Requirements)

Subchapter 9: Hazardous Air Pollutant Sources

HAR 11-60.1-174: Maximum Achievable Control Technology Standards (apply to units that are subject to the Category-Specific NESHAP in Subpart in 40 CFR 63 as noted above under Federal Requirements)

HAR 11-60.1-180: National Emission Standards for Hazardous Air Pollutants (apply to units that are subject to the NESHAP Subpart in 40 CFR 61 noted above under Federal Requirements)

Subchapter 7, Prevention of Significant Deterioration (PSD) was not applicable for the initial Covered Source Permit, because this facility was not a new major stationary source, nor did Chevron propose any major modifications to a major stationary source as defined in HAR 11-60.1-131. Applicability of PSD will need to be addressed on a project-by-project basis for future proposed facility modifications.

**BACT Requirements** – A Best Available Control Technology (BACT) analysis is required for new or modified sources that have the potential to cause a net increase of air emissions above specified significance levels as defined in HAR 11-60.1. The initial Covered Source Permit did not consider the facility to be a new source, nor were any modifications proposed that had the potential to cause a significant net increase in air emissions. Therefore, a BACT analysis was not required. Applicability of BACT requirements will need to be assessed on a project-by-project basis for all future proposed modifications to refinery facilities.

**Compliance Data System (CDS)** – CDS annual emissions reporting is applicable, because the Hawaii Refinery emits more than 100 tpy of PM, PM<sub>10</sub>, SO<sub>2</sub>, VOC, or NO<sub>x</sub>.

**National Emissions Data System (NEDS)** – NEDS annual emissions reporting is applicable to a number of sources within the refinery [except for the process unit furnaces (5600, 5700, 5930, and 5950), asphalt furnace, and cooling tower], since these are point sources within the facility that emit more than 25 tpy for PM, PM<sub>10</sub>, SO<sub>2</sub>, VOC, or NO<sub>x</sub> or more than 250 tpy of CO. The DOH also requires reporting of annual emissions for facilities that: (1) have total combined emissions of a single criteria pollutant equal to or exceeding 25 tpy; or (2) for which the sum of all hazardous air pollutants (HAPs) equals or exceeds 5 tpy.

**Compliance Assurance Monitoring (CAM)** – CAM was not applicable to the initial Covered Source Permit, because a complete Title V application was submitted before April 20, 1998. However, certain CAM requirements are applicable to this permit renewal, as discussed in Section 5.4.3.

***Alternate Operating Scenarios:***

There were no alternate operating scenarios proposed in the initial covered source application for this facility, and none are requested in this application for permit renewal.

### **5.3 APPLICABLE REQUIREMENTS FOR MODIFICATIONS**

This section addresses facility operations, applicable requirements, and compliance issues for modifications to the Hawaii Refinery that have been implemented since the time of the initial Covered Source Permit issuance in 1999, or that may be implemented during the term of the renewed permit, which will extend into 2009. Section 5.3.1 identifies facility changes and requirements for the past permit term of 1999 through 2003. Future facility changes through the end of the renewed permit term in 2009 and the requirements potentially triggered by such changes are discussed in Section 5.3.2.

#### **5.3.1 Facility Changes and Requirements: 1999 through 2003**

The facility modifications that have already been implemented for the timeframe from 1999 through the submittal of this renewal application include the following:

1. The initial Covered Source Permit allowed tanks 105 through 111 to be modified to increase storage capacity by 12 percent. Tanks 105, 106, 109, 110, and 111 have been modified and secondary seals have been installed, as required by 40 CFR Part 63, Subpart CC. Tank numbers 107 and 108 have yet to be modified. DOH has determined that this increase in tank capacity will result in a net decrease in tank emissions due to fewer tank turnovers (tank filling and emptying). Due to the reduction in emissions and based on the cost to alter the tanks, DOH has previously determined that the change does not constitute a modification or reconstruction, and that the requirements of NSPS Subpart K are not triggered. Since the tanks have been modified, they have complied with the standards of 40 CFR Part 63, Subpart A, General Provisions and Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. The Subpart CC requirements applicable to these



tanks are specified in the facility Covered Source Permit Attachment II(B), Section G, 40 CFR Part 63, Subpart CC Requirements. Additionally, these tanks must comply with the conditions specified in the facility Covered Source Permit, Attachment II(b), Section C through F. No additional amendments to the Covered Source Permit are necessary to accommodate this alteration.

2. Group 1 storage tanks at the first tank degassing and cleaning activity after August 18, 1998 or before August 18, 2005, whichever comes first, must comply with 40 CFR Part 63, Subpart CC. To date, 17 Group 1 storage tanks have been modified to date; the affected tank numbers are 105, 106, 109, 110, 111, 113, 162, 163, 232, 233, 237, 249, 250, 262, 271, 301 and 302. Secondary seals (or equivalent devices) will be installed on the remaining Group 1 storage tanks no later than August 18, 2005 and monitoring, notification, testing and recordkeeping as required by Subpart CC will be implemented. The Subpart CC requirements applicable to these tanks are specified in the facility Covered Source Permit Attachment II(B), Section G, 40 CFR Part 63, Subpart CC Requirements. Additionally, the tanks need to comply with the conditions specified in the facility Covered Source Permit Attachment II(B), Section C through F. No additional amendments or changes to the Covered Source Permit are required to allow for ongoing tank upgrades to achieve compliance with Part 63, Subpart CC.
3. The Chevron Hawaii Refinery applied for and obtained DOH approval for the installation of dome roofs on Tanks 249 and 250. This request was processed as a minor modification, and the DOH issued an amendment to the Covered Source Permit on April 16, 2002 consisting of a replacement of Attachment II(B). The revised Attachment IIB, which also reflects the changes described in Items 1 and 2 above is provided as Appendix C.
4. The Chevron Hawaii Refinery has applied for and received approval for a modification to the FCC unit. The FCC Revamp project consisted of installing a slide control valve to improve the ability to balance the operation of the catalyst reaction vessel and the catalyst regenerator vessel. The application presented to DOH for this change in equipment showed that the project would not cause an emission increase, and therefore would not trigger any new federal New Source Performance Standards (NSPS) or the Prevention of Significant Deterioration (PSD) permitting process. The DOH processed the application as a significant modification, because DOH added federally enforceable permit conditions to maintain emissions below PSD levels. Dispersion modeling showed that the project would have a negligible effect on local air quality. This modification resulted in an amendment to Covered Source Permit No. 0088-01-C Attachment II(I) on March 3, 2003. Construction of the modification was completed in May 2003.

The amendment requirements resulting from the FCC Revamp project will need to be incorporated into the Covered Source Permit renewal. However, as discussed in further detail in Section 5.3.2, Chevron seeks to alter one of the conditions in the permit that pertain to this refinery area.

5. The Chevron Hawaii Refinery installed an equivalent replacement electrostatic precipitator on the FCC regenerator exhaust in 2002. Chevron coordinated with DOH on the proposed replacement and obtained prior approval for the installation of the equipment. The equivalent replacement does

not alter the description of permitted equipment or the applicable requirements currently contained in the Covered Source Permit.

### **5.3.2 Facility Changes for 2004 through 2009**

This section describes the proposed facility changes to be implemented during the renewal permit term from 2004 through 2009. It is requested that DOH process the proposed changes to current permit conditions relating to the FCCU feedstock as part of this renewal application. Additionally, it is requested that DOH process proposed changes in the permit conditions pertaining to cogeneration plant and crude unit furnace fuel usage. These proposed changes to the Covered Source Permit conditions are summarized below. Descriptions of several other proposed facility alterations that are currently less well developed are also provided for notification purposes only.

#### ***Proposed Condition Change 1***

Chevron seeks to alter two conditions in the amendment to Covered Source Permit No. 0088-01-C Attachment II(I) dated March 3, 2003. These following conditions restrict the sulfur content of feedstock to the FCCU:

- a) Section B, Condition 5, and
- b) Section C, Condition 3

Currently, Section B, Condition 5 contains a condition limiting the feedstock processed by the FCCU to a total feed rate of 22,000 bbl/day (365-day rolling average), which may include a maximum of 5,500 bbl/day high-sulfur feedstock (defined as a sulfur content no higher than 1.26 percent by weight). The other 16,500 bbl/day are required to have a sulfur content no higher than 0.12 percent by weight. This permit condition results in an emission limit of 450 tons of SO<sub>2</sub> per year. Chevron requests that this condition be altered to remove the volume limits for high-sulfur and low-sulfur feedstocks and to specify only an annual average sulfur content of 0.405 percent by weight for feedstocks sent to the FCCU. This change results in an equivalent quantity of emissions (450 tons of SO<sub>2</sub> per year) as that currently allowed by Section B, Condition 5. The requested date for implementing this change is before January 1, 2006, when the Hawaii Refinery becomes subject to federal Clean Fuels requirements that will limit the sulfur in produced gasoline to very low levels and lower the average sulfur content of crude oils received at the facility. Therefore, a simpler permit condition specifying a single allowable average FCCU feedstock sulfur content is justified.

The maximum daily feed rate of 22,000 barrels in Section B, Condition 5 is acceptable, and Chevron does not seek to modify this portion of the condition.

Compliance with this average limit will be confirmed by testing each batch of feedstock sent to the FCCU. Section C, Condition 3 of Attachment II(I) will need to be revised from its present form to require this increased monitoring frequency and to establish a single average sulfur content value.

Chevron understands that the request to alter these conditions will result in a significant modification to the facility permit, since Section B, Condition 5 was developed to ensure that the refinery would avoid

triggering PSD requirements for the FCCU amendment. The proposed change to the condition will still maintain emissions at levels below the PSD thresholds, but will need to be noticed and processed as a significant modification. Proposed revised permit condition language is provided in Appendix A.

***Proposed Condition Change 2***

Chevron seeks to alter conditions restricting the usage of specific fuels by Cogeneration Plant turbines in Attachment II(M) Section C, Condition 1.c of the current Covered Source Permit. The permit contains the following conditions restricting the usage of specific fuels in the cogeneration plant:

The fuel consumption of the three (3) 40 MMBtu/hr gas turbines while fired on LSR or HSR naphthas shall not exceed 171,409 barrels per any rolling 12-month period. The fuel consumption of the three (3) 40 MMBtu/hr gas turbines while fired on RFG shall not exceed 955.5 million cubic feet per any rolling 12-month period. The fuel consumption of the three (3) heat recovery steam generators fired on RFG shall not exceed 836.1 million cubic feet per any rolling 12-month period.

Chevron requests that the portion of the condition limiting the consumption of RFG and naphtha fuels be eliminated. Note that the refinery no longer produces or uses LSR or HSR, but rather whole straight run naphtha (WSR). For this reason, only WSR is referenced in the remainder of this discussion. The other element of the condition requiring RFG as the exclusive fuel for the HRSGs is acceptable in its current form.

Source tests that have been conducted since 1998 on the cogeneration turbines show that when fired on WSR, actual emissions of all pollutants from the cogeneration turbines are lower than the limits cited in the original Title V application. Operation on RFG results in even lower emissions that are well below the current hourly and annual PTE emissions.

The site-specific source test data are presented in Appendix B-1 in the spreadsheet labeled "cogen\_up&test.xls." This spreadsheet also shows that annual NO<sub>x</sub> and CO emissions calculated from the source test data will be less than current PTE levels, no matter how much RFG or WSR fuel is used by the turbines.

As required by Section D, Condition 3 the combined turbine/heat recovery generator NO<sub>x</sub> and CO emissions are monitored using a continuous emissions monitor. Additionally, the refinery has a non-resettable fuel use meter for WSR and RFG, a CEMS for RFG H<sub>2</sub>S and periodically monitors sulfur of the WSR, resulting in enforceable permitted emission limits.

It is understood that the request to alter these conditions will result in a significant modification to the facility permit, since Section C, Condition 1.c was developed to ensure that the Hawaii Refinery would avoid triggering PSD requirements for the cogeneration installation. The proposed change to the language of this condition will still maintain emissions at the levels below the PSD thresholds, but will need to be noticed and processed as a significant modification. Proposed revised permit condition language is provided in Appendix A.

***Proposed Condition Change 3***

The current Covered Source Permit (Attachment II[G], Condition C4) includes limits on the maximum hourly emissions of SO<sub>2</sub>, NO<sub>x</sub>, and CO and a prohibition against burning refinery gas on more than one-third (12 of 36) of the burners on these furnaces. There is no restriction on the number of burners that may be fired with low-sulfur fuel oil.

Chevron seeks to change the current permit to allow the combustion of refinery gas in all the burners of the atmospheric and vacuum crude furnaces. Chevron may elect to replace 24 burners with new, low-NO<sub>x</sub> burners. This change would result in a reduction of emissions during refinery gas operations and will improve startup operations. The periodic use of refinery gas would have the added benefit of less fouling of the unit. Although the timing of this potential project is currently uncertain, Chevron requests that Condition C.4 be deleted in order to enable the change-out of the 24-burners to dual-fuel for implementation of this project. However, as presented in the recommended permit language in Appendix A, wording requiring low-NO<sub>x</sub> burner technology for all burners on RFG fuel is acceptable.

As shown in the following table, greater use of RFG has the potential to significantly reduce the combined emissions of SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub> from these furnaces, whereas there will be a modest increase in the annual PTE for CO if all burners are equipped to burn RFG. However, this increase would be far below the DOH significant increase level for CO of 100 tpy and thus would not trigger PSD or BACT requirements. The current limit on hourly CO emissions for the larger furnace (F-5103) would need to be increased from 9.0 to 12.12 lb/hr to accommodate RFG fuel use on all 36 burners of these furnaces. The additional CO emissions that could occur under a scenario with all burners on RFG fuel will be far below the levels that would lead to offsite concentrations of this pollutant approaching or exceeding the ambient standards.

**MAXIMUM COMBINED EMISSIONS (TPY) FOR  
CRUDE UNIT FURNACES**

Scenario	PM <sub>10</sub>	SO <sub>2</sub>	CO	NO <sub>x</sub>	VOC
All Burners Using Oil Fuel	44.5	481.98	34.18	302.88	4.23
All Burners Using Gas Fuel	6.7	5.51	74.99	101.52	4.91
PTE for Existing Permit	44.5	551.88	39.42	306.60	5.10

The following proposed facility modifications are described below for information purposes only. As further information on the specific projects is developed, the quantitative effects on emissions, if any, will be evaluated and applicable rules will be addressed on a case-by-case basis.

- Fixed speed motors may be changed to variable speed motors for the forced draft fan and induced draft fan at the crude unit. This is an energy savings project that will optimize performance of the combustion process. The change would not increase the unit's operation beyond its original capacity, although it could result in a slight increase in fuel combustion relative to recent years. Emissions will remain below the limits specified in the current Operating Permit, Section IIG, Section C, Items 1 through 5. Installation could occur as early as 2005. It is anticipated that this proposed modification may trigger New Source Review (NSR), but will not be subject to NSPS.
- Tubes in the convection section of the crude unit furnace may be changed out. This project would correct a configuration design problem with the current tubes, which become coated and cannot be adequately cleaned by soot blowing. The project would not change the design throughput limit of this furnace, and would not cause emissions to exceed the existing permit limits. Installation is planned for 2008. Since this is primarily a maintenance activity, it is not anticipated to trigger NSR or NSPS requirements.
- A diesel draw may be added to the vacuum column in the crude unit. This is a change in piping off the column and would only add a few piping components. Installation could occur by 2005, and Chevron's position is that it would constitute an insignificant activity per DOH Rule Subchapter 5, 11-60.1-82(f)(7).
- The whole straight run naphtha overhead of the crude unit may be optimized. This would essentially be a change in pipe size to optimize the crude unit's production for certain crudes that are used to make naphtha. No change to the unit's fuel use rate would result from such a change. Chevron's position is that it would constitute an insignificant activity per DOH Rule Subchapter 5, 11-60.1-82(f)(7). This modification is considered to have a low probability of occurrence in the next several years.
- A Flare Sulfur Emission Reduction Project (FSERP) was completed during the third quarter of 2003. The project is an upstream process modification that included installation of a caustic system to remove hydrogen sulfide from the acid gas feed stream at times when the acid plant is shut down and the acid plant gas is routed to the FCC Unit flare. This change was implemented to

improve process operations, rather than an air pollution project, and did not require a modification to the existing permit (i.e. it is an insignificant activity). However, DOH may elect to add this equipment to the description for the acid plant.

- The possible installation of two new 5-6 MW cogeneration turbines is being considered. This project would likely result in a net decrease in emissions for most pollutants, because it would replace the steam generation function of the three existing boilers (see Section 2.3.9) with more efficient modern cogeneration technology. The new units would likely be configured to burn either refinery gas or WSR. It is anticipated that a modification application would need to be submitted under separate cover when the project is more fully designed.

## **5.4 MACT AND CAM REQUIREMENTS**

The Chevron Hawaii Refinery is a major source of hazardous air pollutants as described in Section 3 of this Covered Source Permit renewal application. As a major air toxic source, the refinery is potentially subject to MACT regulations that are codified under NESHAP. USEPA has adopted and proposed several MACT requirements over the past several years that pertain to refinery operations. Section 5.4.1 addresses potential applicable MACT standards that have already been adopted, and identifies the associated applicable requirements for the Chevron Hawaii Refinery. Section 5.4.2 addresses potentially applicable MACT standards that have been proposed, but not yet promulgated, and identifies the associated applicable requirements. Section 5.4.3 discusses the applicability of Compliance Assurance Monitoring requirements.

### **5.4.1 Applicability of Adopted MACT Standards**

The following MACT requirements have been adopted and finalized in the Code of Federal Regulations. Therefore, the determination of applicability of these requirements for the Covered Source Permit renewal can be considered final.

40 CFR 63, Subpart A, National Emission Standards for Hazardous Air Pollutants General Provisions. Subpart A contains general NESHAP definitions and notifications that are applicable to the Chevron Hawaii Refinery. These requirements are applicable to emission units that must comply with MACT standards. Compliance requirements for Subpart A were incorporated into the initial Covered Source Permit and are briefly addressed above in Section 5.2.

40 CFR 63, Subpart R, National Emission Standards for Hazardous Air Pollutants from Gasoline Distribution. The final Subpart R rule appeared in the Federal Register on 12/14/1994. Subpart R is not an applicable requirement pursuant to 40 CFR 63.420(i), which exempts loading racks at refineries that are subject to Subpart CC. As specified in the current Covered Source Permit Attachment II(C), Section B, Condition 1, the Chevron Hawaii Refinery loading rack is subject to Subpart CC requirements and complies with the requirements contained in Attachment II(C). Therefore, Subpart R is not an applicable requirement.

40 CFR 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. The final Subpart CC rule appeared in the Federal Register August 18, 1995 and the date

for compliance was 8/18/98. Subpart CC requires refineries to monitor and control emissions from tanks, process vents, piping components and wastewater operations. Compliance requirements for Subpart CC are applicable to the refinery. These requirements were incorporated into the initial Covered Source Permit, and are briefly addressed above in Section 5.2.

40 CFR 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries that occur at Catalytic Cracking Units, Catalytic Reforming Units and Sulphur Plants. The final Subpart UUU rule appeared in the Federal Register on April 11, 2002 and the date for compliance is April 11, 2005. Subpart UUU will apply to the FCC Unit at the Chevron Hawaii Refinery. The refinery does not have Catalytic Reforming Units or Sulphur Plants that are regulated under Subpart UUU. Subpart UUU limits emissions of metals and organic HAPs from FCC units. To demonstrate compliance with this MACT standard, particulate matter and nickel are used as surrogates for metals. Carbon monoxide (CO) is used as a surrogate for organic HAPs. Chevron proposes to comply with the requirements of Option 2 in Subpart UUU. Under Option 2, the FCCU will need to meet emissions limits of 1 pound of PM<sub>10</sub> per 1,000 pounds of coke burned and 500 ppm CO. To demonstrate initial compliance, Chevron will prepare a site-specific test plan and implement a performance test to demonstrate that the facility complies with a PM<sub>10</sub> limit of 1 pound PM<sub>10</sub> per 1000 pounds of coke burned. During the performance test a site-specific opacity limit will be established. To demonstrate ongoing continuous compliance with the PM<sub>10</sub> limit a Continuous Opacity Monitor (COM) will be installed to confirm that the site-specific opacity limit is achieved. Compliance with the CO limit will be demonstrated initially and continuously using a CO CEMS. Before April 11, 2005, the facility will install an opacity monitor and a CO CEMS to satisfy monitoring requirements. Before installation of the monitors, Chevron will obtain all necessary approvals from DOH. The Covered Source Permit Attachment II(I) will need to be modified in the renewed permit to identify Subpart UUU as an applicable requirement and to incorporate applicable operational and emission limitations, monitoring, record-keeping and reporting requirements.

40 CFR 63, Subpart LLLLL, National Emission Standards for Hazardous Air Pollutants for Asphalt Processing and Asphalt Roof Manufacturing. The final Subpart LLLLL rule appeared in the Federal Register on April 29, 2003 and the date for compliance is May 1, 2006. Subpart LLLLL is not an applicable requirement pursuant to 40 CFR 63.8682, which specifies that the rule only applies to asphalt processing facilities and asphalt roofing manufacturing lines. The Chevron Hawaii Refinery does produce asphalt, but does not perform operations regulated under Subpart LLLLL. Asphalt producing facilities as defined in Subpart LLLLL utilize air to change the softening point of asphalt flux. Asphalt roof manufacturing is defined as the collection of equipment used to manufacture asphalt roofing products (e.g. roll roofing, laminated shingles). The Chevron Hawaii Refinery does not perform these types of operations, and therefore Subpart LLLLL is not an applicable requirement.

#### **5.4.2 Applicability of Proposed MACT Standards**

The following MACT requirements have been proposed in the Code of Federal Regulations, but have thus far not been finalized. Therefore, the determination of their applicability for the Covered

Source Permit renewal is preliminary and may need to be reassessed at the time the requirements are codified.

40 CFR 63, Subpart GGGGG, National Emission Standards for Hazardous Air Pollutants for Site Remediation. The proposed Subpart GGGGG standard appeared in the Federal Register on July 30, 2002 and the tentative date for the final rule is August 31, 2003. The Chevron Hawaii Refinery no longer performs remediation onsite and, therefore, Subpart GGGGG is not anticipated to be applicable.

40 CFR 63, Subpart ZZZZZ, National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines. The proposed Subpart ZZZZZ appeared in the Federal Register on December 19, 2002 and the tentative final date for issuance of the regulation is February 28, 2004. The compliance date for existing sources is proposed to be three years after the rule is finalized. Subpart ZZZZZ does not apply to internal combustion engines that are rated at 500 brake horsepower (bhp) or less. All of the internal combustion engines at the Hawaii Refinery are below this bhp rating, and therefore this Subpart is not anticipated to be applicable.

40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters. The proposed Subpart DDDDD appeared in the Federal Register on January 13, 2003 and the tentative final date for issuance of the regulation is February 28, 2004. The compliance date for existing sources is proposed to be three years after the rule is finalized. The Hawaii Refinery boilers 5201, 5202, and 5203 are likely to be affected units pursuant to Subpart DDDDD. Additionally, Furnaces 5103, 5153, 5300, 5600, 5700, 5930, 5950, 6003 and 6262 satisfy the broad definition of process heaters, and are therefore also likely affected units. All of these combustion sources utilize either liquid or gaseous fuels. Pursuant to Subpart DDDDD, existing units that only combust gaseous or liquid fuels have no applicable emission limits, performance testing or monitoring requirements. While Subpart DDDDD may be an applicable rule, there appear to be no associated requirements for the Hawaii Refinery, except for possible notification that the facility is an affected source.

40 CFR 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The proposed Subpart YYYY appeared in the Federal Register on January 14, 2003, and the tentative final date for issuance of the regulation is August 31, 2003. Compliance with the regulation for existing sources is proposed to be three years after the rule is finalized. The Hawaii Refinery cogeneration units 6701, 6702, and 6703 are existing diffusion flame stationary combustion sources. Based on the Federal Register, Vol. 68, No 9 subsection 63.6090 (b) Exceptions (3), existing diffusion flame turbines do not have to meet the requirements of this Subpart or Subpart A. Therefore Subpart YYYY, as currently proposed, will not be an applicable requirement.

All other proposed 40 CFR 63 MACT requirements have been determined not to be applicable to the Chevron Hawaii Refinery.



**5.4.3 Compliance Assurance Monitoring**

Compliance Assurance Monitoring (CAM) requirements are codified in 40 CFR 64. These requirements are applicable to specific units of a facility on a pollutant-specific emissions basis. For these requirements to be applicable, all of the following three criteria must be met:

- The unit must use a control device to achieve compliance with emission standards,
- The unit must be subject to an emission standard for the applicable regulated pollutant, and
- The unit pre-control device potential to emit must be greater than 100 tons per year.

Pursuant to 64.2(b) the CAM applicability requirements do not apply to emissions limitations or standards that are proposed by EPA after November 1990 under Section 111 or 112 of the Clean Air Act. Simply stated, CAM is not applicable to units that are subject to NSPS, NESHAP, or MACT standards that were developed after 1990.

As stated in the preamble to the CAM rule, the rule does not apply to process fugitive emissions or tanks.

Most emission units at the Hawaii Refinery do not use control devices to comply with emissions standards, and therefore CAM is not applicable to these units. Specifically, furnaces, process heaters, flares, and the acid plant absorbing tower do not utilize control devices in order to satisfy emission standards. Based on the first of the three criteria presented above, CAM is not an applicable requirement for these units.

The FCC unit uses an electrostatic precipitator and a cyclone to meet applicable Hawaii rules 11-60.1-32 (opacity limits) and 11-60.1-38 (sulfur oxide emissions). The pre-control device PM<sub>10</sub> and SO<sub>2</sub> potential to emit are greater than 100 tons per year. However, the unit is subject to the MACT 40 CFR 63 Subpart UUU, which was promulgated after 1990, and therefore CAM is not applicable to PM<sub>10</sub> emissions from the FCC unit. The SO<sub>2</sub> emission limits in 11-60.1-38 are not incorporated into the Hawaii State Implementation Plan and, accordingly, do not constitute an "emission limit." Therefore, CAM requirements are not applicable to the FCC unit.

The cogeneration units use low-NO<sub>x</sub> burners and water injection to reduce NO<sub>x</sub> emissions. Based on discussions in the preamble to 40 CFR 64, the low NO<sub>x</sub> burners are not considered a "control device" and do not trigger CAM applicability. Water injection is considered a control device and can trigger CAM requirements. The cogeneration units are subject to NSPS Subpart GG, which was promulgated prior to 1990 and contains an emissions standard for both NO<sub>x</sub> and SO<sub>x</sub>. However, the water injection is only used to control NO<sub>x</sub> emissions and there is no control device for SO<sub>x</sub> emissions. The NO<sub>x</sub> emissions with water injection are less than 100 tons per year per unit, although emissions without water injection would be anticipated to exceed the 100 ton per year threshold. Therefore, CAM is applicable to NO<sub>x</sub> emissions from the cogeneration units. The cogeneration units already utilize a CEMS to monitor NO<sub>x</sub> emissions, as required by the existing (initial) Covered Source Permit. Further, Attachment II(M), Section D, Condition 3 of this permit requires that the CEMS system meet EPA performance specification 40 CFR 60.13 and 40 CFR 60, Appendix B. Pursuant to CAM requirements contained in 40 CFR 64.4(b)(2) and 64.3(d)(2)(ii), a CEMS system is

presumptively acceptable if it meets the requirements of Section 60.13 and Appendix B of part 60. Therefore, while CAM is applicable to the cogeneration units, no additional or new monitoring is required. Chevron does need to meet the submittal requirements of 40 CFR 64.4 and these are addressed in Appendix D.

CAM is not an applicable requirement for any other units within the Hawaii Refinery.

### **5.5 ANTICIPATED HAWAII RULE CHANGES**

It is understood that the DOH has proposed to modify its covered source rules pertaining to insignificant sources in response to EPA concerns regarding the current rules. Chevron does not expect that these rule changes will alter the status or operations of refinery emission units that have previously been determined to be insignificant sources. However, after these rule changes are adopted, it may be necessary to modify the Covered Source Permit.

### **5.6 COMPLIANCE FORMS**

The facility complies with the applicable regulations, as identified in the attached Form C-1, pages 1-3, Compliance Plan. Chevron personnel have evaluated the applicable requirements, performed site inspections, reviewed monitoring data, and confirmed work practices to determine that the facility is in compliance. Continued adherence to these requirements will result in on-going compliance. The attached Form C-2, page 1, Compliance Certification verifies compliance with the applicable regulations. Monitoring, as required by applicable regulations, will be used to confirm continuing compliance. The information presented in this section is consistent with the information requested in the Form C-2, pages 2 and 3.

Chevron has previously demonstrated compliance with the NAAQS, based on maximum facility emissions of criteria pollutants and ambient dispersion modeling, which is discussed in Section 4 of this application. Note that verifying compliance with the NAAQS is a state requirement. The facility does not propose to adopt an emissions cap to avoid having to comply with any federal regulations. There are no applicable federal regulations that stipulate that an emissions cap must be placed on the facility.

*COMPLIANCE PLAN*

The Responsible Official shall submit a Compliance Plan with the following permit applications, and at such other times as requested by the director.

- Initial Noncovered Source Permit Application
- Initial Covered Source Permit Application
- Temporary Noncovered Source Permit Application
- Temporary Covered Source Permit Application
- General Noncovered Source Permit Application
- General Covered Source Permit Application
- Application for a Noncovered Source
- Application for a Covered Source Permit Renewal
- Application for a Modification to a Covered Source
- Application for a Significant Modification to a Covered Source

1. Compliance status with respect to all Applicable Requirements:

Will your facility be in compliance, or Is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

- YES      {If YES, complete items a and c below}
- NO      {If NO, complete items a-c below}

a. Identify all applicable requirement(s) for which compliance is achieved:

*Please refer to current Covered Source Permit and Section 5 of Covered Source Permit renewal application*

\_\_\_\_\_

Provide a statement that the source is in compliance and will continue to comply with all such requirements.

*The source is in compliance and will continue to comply with all such requirements*

\_\_\_\_\_

\_\_\_\_\_

b. Identify all applicable requirement(s) for which compliance is NOT achieved:

*None*

\_\_\_\_\_

\_\_\_\_\_

Provide a detailed Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements. Use separate sheets of paper, if necessary.

<u>Description of Remedial Action</u>	<u>Expected Date of Completion</u>
<i>Not applicable</i>	<i>Not applicable</i>

c. Identify any other applicable requirement(s) with a future compliance date that your source is subject to. These applicable requirements may be in effect AFTER permit issuance:

<u>Effective Applicable Requirement</u>	<u>Date</u>	<u>Currently in Compliance?</u>
40 CFR 63 Subpart UUU	4/11/05	no, but will be by <u>4/11/05</u>
40 CFR 63 Subpart DDDDD (potentially)	2/28/07	yes

If the source is not currently in compliance, submit a Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements:

<u>Description of Proposed Action/Steps to Achieve Compliance</u>	<u>Expected Date of Achieving Compliance</u>
<i>Will install monitoring equipment and perform testing to demonstrate compliance with 40 CFR 63 Subpart UUU.</i>	<i>4/11/05, as required</i>

Provide a statement that the source on a timely basis will meet all these applicable requirements.

*The source on a timely basis will meet all applicable requirements.*

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of all remedial actions and the expected dates of completion.

<u>Description of Remedial Action</u>	<u>Expected Date of Completion</u>
<i>Not applicable</i>	_____
	_____
	_____

2. Compliance Progress Reports:

- a. If a compliance plan is being submitted to remedy a violation, complete the following information:

*Not applicable*

Frequency of Submittal: \_\_\_\_\_ Beginning Date: \_\_\_\_\_  
(less than or equal to 6 months)

- b. Date(s) that the Action described in (1)(b) was achieved:  
Remedial Action

Date Achieved

*Not applicable*

- c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

*Not applicable*

*Certification of Compliance with all Applicable Requirements:*

This certification must be signed by a Responsible Official. Applications without a signed certification will be deemed incomplete.

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Martha A. Gilles, Refinery Manager

(Signature): *M. A. Gilles* Date: 8/1/03

FOR AGENCY USE ONLY:

File/Application No.:

Island:

**COMPLIANCE CERTIFICATION**

The Responsible Official shall submit a Compliance Certification with the following covered source permit applications, and at such other times as requested by the director.

- Initial Covered Source Permit Application;
- Temporary Covered Source Permit Application;
- General Covered Source Permit Application;
- Application for a Covered Source Permit Renewal; and
- Application for a Significant Modification to a Covered Source.

COMPLETE & SUBMIT THIS COVER PAGE AND SECTION A OF THIS FORM.

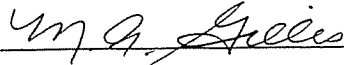
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***Certification of Compliance with all Applicable Requirements:***

This certification must be signed by a Responsible Official. Applications without a signed certification will be deemed incomplete.

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution control, and any permit issued thereof.

Name (Print/Type): Martha A. Gilles, Refinery Manager

(Signature):  Date: 8/1/03

Complete the following information for **each** applicable requirement and/or term or condition of the permit that applies to **each** emissions unit at the source. Also include any additional information as required by the director. The compliance certification may reference information contained in a previous compliance certification submittal to the director, provided such referenced information is certified as being current and

still applicable.

**A. For compliance certifications submitted with any covered source permit application.**

1. Schedule for submission of Compliance Certifications during the term of the permit:

Frequency of Submittal: **Annual** Beginning Date: **March 30, 2004**

2. Emissions Unit No./Description: *Refer to Section 2 of CSP renewal application*

3. Identify the applicable requirement(s) that is/are the basis of this certification:

***Please refer to Section 5 of Covered Source Permit renewal application***

4. Compliance status:

a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

**YES**       **NO**

b. If YES, will compliance be continuous or intermittent?

**Continuous**       **Intermittent**

c. If NO, explain.

5. The methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

***Please refer to the current Covered Source Permit and Section 5 of the Covered Source Permit Renewal Application***

Provide a detailed description of the methods used to determine compliance: (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.)

***Please refer to the current Covered Source Permit and Section 5 of the Covered Source Permit Renewal Application***

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

YES                       NO

b. If YES, identify the requirements and the provisions being taken to achieve compliance:

***A continuous emissions monitoring system (CEMS) for NO<sub>x</sub> has been installed on cogeneration combustion turbines pursuant to 40 CFR 60 Subpart GG (water injection control measure). The CEMS is required to meet EPA performance specifications in 40 CFR 60.13 and 40 CFR 60, Appendix B, as well as the submittal requirements of 40 CFR 64.4.***

c. If NO, describe below which requirements will not be met:

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FOR AGENCY USE ONLY:	
File/Application _____	No.:
Island:	





I. Chevron seeks to alter two conditions in the amendment to Covered Source Permit No. 0088-01-C Attachment II(I) dated March 3, 2003. These following conditions restrict the sulfur content of feedstock to the FCCU;

- 1) Section B, Condition 5, and
- 2) Section C, Condition 3

It is requested that the conditions be revised as follows:

Section B, 5. The feed processed by the FCCU shall not exceed the following feed rates and sulfur content limits:

- a. A maximum total feed rate of 22,000 bbls/day\*; and,
- b. A maximum sulfur content of 0.405 percent by weight\*.

\*Based on a rolling 365-day average

Section C, 3 FCCU Feed

- a. The permittee shall monitor the total feed rate (in barrels per day) to the FCCU. Records shall be kept on a daily and rolling 365-day average.
- b. The sulfur content of the feed to the FCCU shall be tested in accordance with the most current American Society for Testing and Materials (ASTM) methods. ASTM Method D4294-02 is a suitable alternative to Method D129-00 for determining the sulfur content. The sulfur content shall be verified by having a representative sample analyzed for sulfur content whenever a crude switch occurs and the Crude Unit is operating in a normal state. The feed sample shall be taken from sample points on the hot feed line and the cold feed line. Records of the sulfur content shall be maintained on a weekly, monthly, and rolling 365-day average.

II. Chevron seeks to alter language in Attachment II(M) Section C, Condition 1 of the current Covered Source Permit. This condition limits annual emissions by restricting specific fuel use. The facility utilizes CEMs to monitor emissions and would prefer to restrict actual emissions in lieu of fuel use. It is requested that the condition be revised as follows:

1. Fuel Specifications and Annual Emission Limits

- a. The three (3) 40 MMBtu/hr gas turbines shall be fired only on refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscm (160 ppmv), or whole straight run naphtha with a sulfur content not to exceed 0.03 percent by weight.

b. The three (3) heat recovery steam generators shall be fired only on refinery fuel gas (RFG) with a hydrogen sulfide (H<sub>2</sub>S) content not to exceed 230 mg/dscf (160 ppmv).

III. Chevron seeks to replace Attachment II(G) Section C, Condition 4 to allow low-NO<sub>x</sub> burners to be used for all burners of the Crude Unit atmospheric and vacuum furnaces. The suggested language to effect this change is provided below:

Section C.4	Any burners of the atmospheric and vacuum furnaces that burn RFG shall be low-NO <sub>x</sub> burners.
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## Summary

SOURCES	Pollutant emission rates (ton/yr)						Total Criteria Pollutant Emissions
	PM10	SO2	CO	NO2	VOC	Lead	
Boilers	372.5	5415.3	86.2	551.9	13.1	0.0	6439
Cogen Turbines	11.7	16.0	52.5	193.2	2.3	0.0	276
Crude Furnaces	44.5	482.0	75.0	302.9	5.1	0.0	909
FCC Furnace	2.0	1.6	22.1	26.3	1.4	0.0	53
Isom Furnaces	0.2	0.2	2.1	2.5	0.1	0.0	5
H&H Furnaces	1.1	0.9	12.1	14.5	0.8	0.0	29
Acid preheater & combustion chamber	0.4	0.4	4.8	5.7	0.3	0.0	12
Asphalt Furnace	0.2	0.1	2.0	2.4	0.1	0.0	5
FCC Stack	175.2	450.0	499.3	285.1	14.7	0.0	1424
Cooling Tower	3.2	-	-	-	9.2	-	12
Acid plant absorber stack (*)	-	803.0	-	-	-	-	803
Catalyst transfer	0.0	-	-	-	-	-	0
Wastewater treatment	-	-	-	-	73.6	0.0	74
Loading Rack	-	-	-	-	1006.3	0.0	1006
Process Fugitives	-	-	-	-	1402.2	1.4	1404
Tanks	-	-	-	-	316.6	0.0	317
Marine loading	-	-	-	-	196.6	0.0	197
Refinery Flares	-	319.1	51.0	224.2	9.5	-	604
<b>Totals</b>	<b>611.1</b>	<b>7488.5</b>	<b>807.1</b>	<b>1608.5</b>	<b>2045.7</b>	<b>1.4</b>	<b>13569</b>
<b>Total Point Sources</b>	<b>607.83</b>	<b>6366.43</b>	<b>756.13</b>	<b>1384.29</b>	<b>38.05</b>	<b>0.04</b>	<b>9152.78</b>

Notes: (\*) Criteria pollutant emissions from the acid preheater and combustion chamber are vented to the acid plant absorber stack. The listed SO2 emissions from the acid plant absorber stack are only from acid production.

Note: Loading rack normal year operations don't include entire refinery production sent out via load rack.

Point sources

Summary of Potential Emissions From Point Combustion Sources

SOURCES	Pollutant emission rates (ton/yr)							Total Criteria Pollutant Emissions
	PM10	SO2	CO	NOx	VOC	Lead		
Boilers	372.52	5415.32	86.23	551.88	13.11	0.026	6439	
Cogen Turbines	11.72	15.95	52.49	193.16	2.34	0.006	276	
Crude Furnaces	44.49	481.97	74.99	302.88	5.11	0.010	909	
FCC Furnace	2.00	1.62	22.08	26.28	1.45	0.000	53	
Isom Furnaces	0.19	0.15	2.06	2.45	0.13	0.000	5	
H&H Furnaces	1.10	0.89	12.14	14.45	0.79	0.000	29	
Acid preheater & combustion chamber	0.43	0.35	4.80	5.71	0.31	0.000	12	
Asphalt Furnace	0.18	0.15	2.02	2.41	0.13	0.000	5	
FCC Stack	175.20	450.02	499.32	285.07	14.67	0.000	1424	
<b>Totals</b>	<b>607.8</b>	<b>6366.4</b>	<b>756.1</b>	<b>1384.3</b>	<b>38.0</b>	<b>0.0</b>	<b>9153</b>	

## Tank data

### CHEVRON-HAWAII REFINERY POTENTIAL VOC EMISSIONS

#### FROM STORAGE TANKS

2003

Tank Id	Type of tank	Service of Tank	Losses (lb/yr)	Losses (ton/yr)
Tk 104	External Floating Roof	Crude: Widuri Group	6,329	3.2
Tk 105	External Floating Roof	Crude: ANS Group	1,294	0.6
Tk 106	External Floating Roof	Crude: ANS Group	1,953	1.0
Tk 107	External Floating Roof	Crude: Minas Group	11,481	5.7
Tk 108	External Floating Roof	Crude: Tapis Group	18,849	9.4
Tk 109	External Floating Roof	Crude: ANS Group	941	0.5
Tk 110	External Floating Roof	Crude: ANS Group	1,204	0.6
Tk 111	External Floating Roof	WSR	18,109	9.1
Tk 113	External Floating Roof	Rec Crude	638	0.3
Tk 152	Vertical Fixed Roof	Crude: Boscan (asphalt fd)	101	0.1
Tk 162	External Floating Roof	Rec Oil	7,953	4.0
Tk 163	External Floating Roof	Rec Oil	7,953	4.0
Tk 232	External Floating Roof	HCC	1,236	0.6
Tk 233	External Floating Roof	HCC	1,236	0.6
Tk 236	External Floating Roof	U/L	45,489	22.7
Tk 237	External Floating Roof	U/L	24,499	12.2
Tk 249	Domed External Floating Roof	Avgas	2,069	1.0
Tk 250	Domed External Floating Roof	Avgas	1,695	0.8
Tk 252	External Floating Roof	LCC	49,065	24.5
Tk 253	External Floating Roof	LCC	49,065	24.5
Tk 254	External Floating Roof	U/L Plus	43,701	21.9
Tk 255	External Floating Roof	SUP	45,487	22.7
Tk 256	External Floating Roof	SUP	45,423	22.7
Tk 257	External Floating Roof	Dimate Gasoline	38,508	19.3
Tk 258	External Floating Roof	Alkylate Gasoline	25,577	12.8
Tk 262	External Floating Roof	SUP	23,848	11.9
Tk 263	External Floating Roof	JetA	1,634	0.8
Tk 264	External Floating Roof	JetA	1,641	0.8
Tk 265	External Floating Roof	JetA	1,670	0.8
Tk 266	External Floating Roof	WSR	26,602	13.3
Tk 267	External Floating Roof	JetA	1,670	0.8
Tk 268	External Floating Roof	Diesel	182	0.1
Tk 269	External Floating Roof	WSR	22,729	11.4
Tk 270	External Floating Roof	Diesel	189	0.1
Tk 271	External Floating Roof	WSR	14,038	7.0
Tk 272	Vertical Fixed Roof	ULSD	2,712	1.4
Tk 273	External Floating Roof	U/L	38,045	19.0
Tk 274	Vertical Fixed Roof	ULSD	3,328	1.7
Tk 275	External Floating Roof	WSR	17,748	8.9
Tk 301	External Floating Roof	Rec Oil	13,623	6.8
Tk 302	External Floating Roof	Rec Oil	13,623	6.8

**Total Emissions for all Tanks:**

**633,136**

**316.6**

VOC EF

REFINERY POTENTIAL VOC EMISSION FACTORS

Equipment Type	Non-LDAR	
	Service	Emission factor * (kg/hr/source) All non-LDAR
Valves	G	0.0268
	LL	0.0109
	HL	0.00023
Pump Seals	G	0.280
	LL	0.114
	HL	0.021
Compressor Seals PRVs	G	0.636
	G	0.16
Connectors (Flanges)	ALL	0.00025
Connectors (Fittings)	ALL	0.00025
Open-ended Lines	ALL	0.0023
Sampling Connections	ALL	0.015

\* Obtained from Table 2-2 of EPA Document "Protocol for Equipment Leak Emission Estimates" (1995)

\*\* No emission factor available for pump seals in gas service. Emission factor above reflects LL service for pump seals adjusted by the ratio of the gas to light liquid service emission factors for valves.



**Speciation Data**

HAPS COMPOSITIONS IN REFINERY STREAMS (LOOKUP TABLE)  
 TITLE V AIR PERMIT  
 CHEVRON HAWAII REFINERY

DATE OF LAST REVISION:

30-May-03

PLANT	BLEND COMPONENTS	STREAM	API <sup>o</sup>	DENSITY	BENZENE	NAPHTHALENE	O-XYLENE
		LOOKUP		(lb/bbl)	CAS# 71432	CAS# 91203	CAS# 95476
		NUMBER			liq wt ( %)	liq wt ( %)	liq wt ( %)
					1	2	3
CU	ATMOS OVHD LIQ	1	67	250	1.17%	0.01%	0.71%
	STAB OVHD	2		224	0.00%	0.00%	0.00%
	LSR	3	77	243	2.09%	0.00%	0.00%
	HSR	4	62	256	1.24%	0.00%	1.03%
	LGO	5	47	277	0.00%	1.00%	2.01%
	HGO (Diesel)	6	37	294	0.00%	0.00%	0.00%
	VGO (AVERAGE) (USE FCC feed)	7	28	311	0.00%	0.00%	0.00%
	RESID (& ASPHALT)	8	15	338	0.00%	0.00%	0.00%
	SPLITTER FEED	9	64	253	1.33%	0.00%	0.81%
	ACCUMULATOR GAS	10			0.00%	0.00%	0.00%
			11				
		12					
FCC	FRAC VAPOR	13			0.74%	0.00%	0.75%
	SEC. LEAN OIL	14	73	242	1.27%	0.00%	1.29%
	EQUIL. MIX	15			0.50%	0.43%	1.15%
	RICH SPONGE OIL	16	18	331	0.00%	0.00%	0.00%
	ABSORBER GAS	17			0.00%	0.00%	0.00%
	FUEL GAS (MIXDRUM)	18			0.00%	0.00%	0.00%
	C4 OLEFINS	19	135	186	0.00%	0.00%	0.00%
	C3-C4 MIX OLEFINS	20			0.00%	0.00%	0.00%
	LCC	21	73	242	0.75%	0.00%	1.29%
	HCC	22	32	303	0.01%	3.31%	4.97%
	LCO	23	18	331	0.00%	0.00%	0.00%
	FRAC BTMS	24	2.5	370	0.00%	0.00%	0.00%
	DEBUT FEED	25			0.71%	0.00%	0.73%
			26				
		27					
		28					
ALKY	LER BOTTOMS	29	135	186	0.00%	0.00%	0.00%
	LA	30	72	243	0.00%	0.00%	0.00%
	HA	31	40	289	0.00%	0.00%	0.00%
	ISOM RX EFFLUENT	32	135	186	0.00%	0.00%	0.00%
H=	CHLORIDE CHEMICAL	33		571	0.00%	0.00%	0.00%
	H= PLT C4'S	34	135	186	0.00%	0.00%	0.00%
		35					
		36					
DIM	DIM FD	37	140	182	0.00%	0.00%	0.00%
	DIM STAB OVHD	38	140	182	0.00%	0.00%	0.00%
	DIMATE	39	70	246	0.00%	0.00%	0.00%
B&S	REACTOR EFFLUENT	40	84	233	0.00%	0.00%	0.00%
	NICKEL CATALYST	41		406	0.00%	0.00%	0.00%
	MINAS	42	32	303	0.14%	0.00%	0.00%
	ANS	43	33	301	0.21%	0.00%	0.00%
	WIDURI	44	28	311	0.04%	0.00%	0.00%
	BELIDA	45	43	281	0.39%	0.00%	0.00%
	PUL	46	71	236	0.10%	0.30%	0.46%
	MUL (Use for Mogas)	47	65	239	0.50%	0.44%	1.41%
	RUL	48	65	248	0.60%	0.50%	1.87%
	JP-8	49	46	278	0.00%	1.02%	2.00%
	AVGAS	50	72	244	0.00%	0.00%	0.00%
	JET-A	51	45	279	0.00%	1.30%	2.39%
	LSFO (Same as LFO)	52			0.00%	0.00%	0.00%
	MOTOR LPG	53	146	178	0.00%	0.00%	0.00%
COMMERCIAL LPG	54	141	182	0.00%	0.00%	0.00%	
		55					
		56					
	REFORMATE	57	57	263	7.06%	0.09%	7.51%
	AVIATION TEL	58	N/A	611	0.00%	0.00%	0.00%
	TOLUENE	59	31	306	0.00%	0.00%	0.00%
		60					
		61					
	WHITE OIL	62	54	267	0.46%	0.47%	1.19%
	RO	63	38	291	0.19%	0.47%	0.80%
	BRU BTEX OFFGAS	64			0.00%	0.00%	0.30%
		65					
MISC	MEA	66	2	371	0.00%	0.00%	0.00%
	SPENT CAUSTIC	67			0.01%	0.01%	0.01%
	DESALTER CHEMICAL	68	14	340	0.00%	10.00%	3.30%
		69					
		70					
	NO HAPS	71			0.00%	0.00%	0.00%
		72					
		73					

**Speciation Data**

HAPS COMPOSITIONS IN REFINERY  
TITLE V AIR PERMIT  
CHEVRON HAWAII REFINERY

PLANT	BLEND COMPONENTS	ETHYLBENZENE	P-XYLENE	ETHYLENE DIBROMIDE	ETHYLENE DICHLORIDE	M-XYLENE
		CAS# 100414 liq wt (%)	CAS# 106423 liq wt (%)	CAS# 106934 liq wt (%)	CAS# 107062 liq wt (%)	CAS# 108383 liq wt (%)
		4	5	6	7	8
CU	ATMOS OVHD LIQ	0.00%	0.54%	0.00%	0.00%	1.31%
	STAB OVHD	0.00%	0.00%	0.00%	0.00%	0.00%
	LSR	0.00%	0.00%	0.00%	0.00%	0.00%
	HSR	0.00%	0.00%	0.00%	0.00%	1.89%
	LGO	0.00%	0.00%	0.00%	0.00%	2.07%
	HGO (Diesel)	0.00%	0.00%	0.00%	0.00%	0.00%
	VGO (AVERAGE) (USE FCC feed)	0.00%	0.00%	0.00%	0.00%	0.00%
	RESID (& ASPHALT)	0.00%	0.00%	0.00%	0.00%	0.00%
	SPLITTER FEED	0.00%	0.62%	0.00%	0.00%	1.50%
	ACCUMULATOR GAS	0.00%	0.00%	0.00%	0.00%	0.00%
FCC	FRAC VAPOR	0.58%	0.74%	0.00%	0.00%	1.83%
	SEC. LEAN OIL	1.00%	1.28%	0.00%	0.00%	3.15%
	EQUIL. MIX	0.55%	0.80%	0.00%	0.00%	2.05%
	RICH SPONGE OIL	0.00%	0.00%	0.00%	0.00%	0.00%
	ABSORBER GAS	0.00%	0.00%	0.00%	0.00%	0.00%
	FUEL GAS (MIXDRUM)	0.00%	0.00%	0.00%	0.00%	0.00%
	C4 OLEFINS	0.00%	0.00%	0.00%	0.00%	0.00%
	C3-C4 MIX OLEFINS	0.00%	0.00%	0.00%	0.00%	0.00%
	LCC	1.00%	1.28%	0.00%	0.00%	3.15%
	HCC	1.21%	2.31%	0.00%	0.00%	6.31%
	LCO	0.00%	0.00%	0.00%	0.00%	0.00%
	FRAC BTMS	0.00%	0.00%	0.00%	0.00%	0.00%
	DEBUT FEED	0.56%	0.72%	0.00%	0.00%	1.77%
ALKY	LER BOTTOMS	0.00%	0.00%	0.00%	0.00%	0.00%
	LA	0.00%	0.00%	0.00%	0.00%	0.00%
	HA	0.00%	0.00%	0.00%	0.00%	0.00%
	ISOM RX EFFLUENT	0.00%	0.00%	0.00%	0.00%	0.00%
	CHLORIDE CHEMICAL	0.00%	0.00%	0.00%	0.00%	0.00%
H=	H= PLT C4'S	0.00%	0.00%	0.00%	0.00%	0.00%
DIM	DIM FD	0.00%	0.00%	0.00%	0.00%	0.00%
	DIM STAB OVHD	0.00%	0.00%	0.00%	0.00%	0.00%
B&S	DIMATE	0.00%	0.00%	0.00%	0.00%	0.00%
	REACTOR EFFLUENT	0.00%	0.00%	0.00%	0.00%	0.00%
	NICKEL CATALYST	0.00%	0.00%	0.00%	0.00%	0.00%
	MINAS	0.00%	0.00%	0.00%	0.00%	0.00%
	ANS	0.00%	0.00%	0.00%	0.00%	0.00%
	WIDURI	0.00%	0.00%	0.00%	0.00%	0.00%
	BELIDA	0.00%	0.00%	0.00%	0.00%	0.00%
	PUL	0.12%	0.22%	0.00%	0.00%	0.61%
	MUL (Use for Mogas)	0.74%	1.05%	0.00%	0.00%	2.67%
	RUL	0.98%	1.42%	0.00%	0.00%	3.57%
	JP-8	0.72%	0.86%	0.00%	0.00%	2.09%
	AVGAS	0.00%	0.00%	0.03%	0.00%	0.00%
	JET-A	0.80%	1.05%	0.00%	0.00%	2.62%
	LSFO (Same as LFO)	0.00%	0.00%	0.00%	0.00%	0.00%
MOTOR LPG	0.00%	0.00%	0.00%	0.00%	0.00%	
COMMERCIAL LPG	0.00%	0.00%	0.00%	0.00%	0.00%	
	REFORMATE	4.62%	6.61%	0.00%	0.00%	14.87%
	AVIATION TEL	0.00%	0.00%	20.00%	12.00%	0.00%
	TOLUENE	0.00%	0.00%	0.00%	0.00%	0.00%
	WHITE OIL	0.45%	0.70%	0.00%	0.00%	1.74%
	RO	0.25%	0.38%	0.00%	0.00%	0.98%
	BRU BTEX OFFGAS	0.00%	0.30%	0.00%	0.00%	0.30%
MISC	MEA	0.00%	0.00%	0.00%	0.00%	0.00%
	SPENT CAUSTIC	0.01%	0.01%	0.00%	0.00%	0.01%
	DESALTER CHEMICAL	10.00%	3.30%	0.00%	0.00%	3.30%
	NO HAPS	0.00%	0.00%	0.00%	0.00%	0.00%

**Speciation Data**

HAPS COMPOSITIONS IN REFINERY  
TITLE V AIR PERMIT  
CHEVRON HAWAII REFINERY

PLANT	BLEND COMPONENTS	TOLUENE	1,3-BUTADIENE	n-HEXANE	ANILINE	CRESOL MIXTURE
		CAS# 108883	CAS# 106990	CAS# 110543	CAS# 62533	CAS# 1319773
		liq wt (%)	liq wt (%)	liq wt (%)	liq wt (%)	liq wt (%)
		9	10	11	12	13
CU	ATMOS OVHD LIQ	3.54%	0.00%	7.00%	0.01%	0.00%
	STAB OVHD	0.00%	0.00%	0.00%	0.00%	0.00%
	LSR	1.18%	0.00%	4.57%	0.00%	0.00%
	HSR	4.82%	0.00%	3.09%	0.01%	0.00%
	LGO	0.00%	0.00%	0.00%	0.00%	0.10%
	HGO (Diesel)	0.00%	0.00%	0.00%	0.00%	0.10%
	VGO (AVERAGE) (USE FCC feed)	0.00%	0.00%	0.00%	0.00%	0.00%
	RESID (& ASPHALT)	0.00%	0.00%	0.00%	0.00%	0.00%
	SPLITTER FEED	4.06%	0.00%	7.50%	0.01%	0.00%
	ACCUMULATOR GAS	0.00%	0.00%	0.00%	0.00%	0.00%
FCC	FRAC VAPOR	4.28%	0.15%	0.01%	0.00%	0.00%
	SEC. LEAN OIL	7.38%	0.00%	1.00%	0.01%	0.00%
	EQUIL. MIX	2.98%	0.10%	0.02%	0.00%	0.00%
	RICH SPONGE OIL	0.00%	0.00%	0.00%	0.00%	0.00%
	ABSORBER GAS	0.00%	0.00%	0.00%	0.00%	0.00%
	FUEL GAS (MIXDRUM)	0.00%	0.00%	0.00%	0.00%	0.00%
	C4 OLEFINS	0.00%	0.50%	0.00%	0.00%	0.00%
	C3-C4 MIX OLEFINS	0.00%	0.35%	0.00%	0.00%	0.00%
	LCC	7.38%	0.00%	0.81%	0.01%	0.00%
	HCC	0.76%	0.00%	0.00%	0.10%	0.00%
	LCO	0.00%	0.00%	0.00%	0.00%	0.00%
	FRAC BTMS	0.00%	0.00%	0.00%	0.00%	0.00%
	DEBUT FEED	4.15%	0.15%	0.00%	0.00%	0.00%
	ALKY	LER BOTTOMS	0.00%	0.00%	0.00%	0.00%
LA		0.00%	0.00%	0.03%	0.00%	0.00%
HA		0.00%	0.00%	0.03%	0.00%	0.00%
ISOM RX EFFLUENT		0.00%	0.50%	0.00%	0.00%	0.00%
CHLORIDE CHEMICAL		0.00%	0.00%	0.00%	0.00%	0.00%
H= PLT C4'S		0.00%	0.50%	0.00%	0.00%	0.00%
DIM	DIM FD	0.00%	0.00%	0.00%	0.00%	0.00%
	DIM STAB OVHD	0.00%	0.00%	0.00%	0.00%	0.00%
	DIMATE	0.00%	0.00%	0.00%	0.00%	0.00%
	REACTOR EFFLUENT	0.00%	0.00%	0.00%	0.00%	0.00%
	NICKEL CATALYST	0.00%	0.00%	0.00%	0.00%	0.00%
	MINAS	0.00%	0.00%	0.00%	0.01%	0.14%
	ANS	0.00%	0.00%	0.00%	0.01%	0.14%
	WIDURI	0.00%	0.00%	0.00%	0.01%	0.14%
	BELIDA	0.00%	0.00%	0.00%	0.01%	0.14%
	PUL	0.17%	0.00%	1.34%	0.01%	0.00%
	MUL (Use for Mogas)	4.39%	0.00%	1.34%	0.01%	0.00%
	RUL	6.32%	0.00%	1.34%	0.01%	0.00%
	JP-8	0.57%	0.00%	5.87%	0.01%	0.00%
	AVGAS	0.00%	0.00%	0.03%	0.00%	0.00%
	JET-A	0.00%	0.00%	0.00%	0.00%	0.10%
	LSFO (Same as LFO)	0.00%	0.00%	0.00%	0.00%	0.00%
	MOTOR LPG	0.00%	0.00%	0.00%	0.00%	0.00%
	COMMERCIAL LPG	0.00%	0.00%	0.00%	0.00%	0.00%
	REFORMATE	37.44%	0.00%	0.00%	0.00%	0.00%
	AVIATION TEL	3.00%	0.00%	0.00%	0.00%	0.00%
	TOLUENE	100.00%	0.00%	0.00%	0.00%	0.00%
	WHITE OIL	2.24%	0.00%	0.05%	0.00%	0.03%
	RO	0.64%	0.00%	1.42%	0.00%	1.45%
	BRU BTEX OFFGAS	5.00%	3.00%	1.00%	0.00%	0.00%
MISC	MEA	0.00%	0.00%	0.00%	0.00%	0.00%
	SPENT CAUSTIC	0.01%	0.01%	0.01%	0.00%	0.01%
	DESALTER CHEMICAL	0.00%	0.00%	0.00%	0.00%	0.00%
	NO HAPS	0.00%	0.00%	0.00%	0.00%	0.00%

**Speciation Data**

HAPS COMPOSITIONS IN REFINERY  
TITLE V AIR PERMIT  
CHEVRON HAWAII REFINERY

PLANT	BLEND COMPONENTS	PHENOL	STYRENE	METHANOL	NICKEL	HCL	PERCHLOROETHYLENE	BIPHENYL
		CAS# 108952 liq wt ( %)	CAS# 100425 liq wt ( %)	CAS# 67561 liq wt ( %)	CAS# AS# 7647010 liq wt ( %)	CAS# 127184 liq wt ( %)	CAS# 92524 liq wt ( %)	
		14	15	16	17	19	20	22
CU	ATMOS OVHD LIQ	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	STAB OVHD	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	LSR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	HSR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	LGO	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%
	HGO (Diesel)	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%
	VGO (AVERAGE) (USE FCC feed)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	RESID (& ASPHALT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%
	SPLITTER FEED	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	ACCUMULATOR GAS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FCC	FRAC VAPOR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	SEC LEAN OIL	0.01%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%
	EQUIL MIX	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	RICH SPONGE OIL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	ABSORBER GAS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	FUEL GAS (MIXDRUM)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	C4 OLEFINS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	C3-C4 MIX OLEFINS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	LCC	0.01%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%
	HCC	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	LCO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	FRAC BTMS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%
	DEBUT FEED	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ALKY	LER BOTTOMS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	LA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	HA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	ISOM RX EFFLUENT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	CHLORIDE CHEMICAL	0.00%	0.00%	0.00%	0.00%	0.00%	1.00%	0.00%
H=	PLT C4S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DIM	DIM FD	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DIM STAB OVHD	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DIMATE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	REACTOR EFFLUENT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	NICKEL CATALYST	0.00%	0.00%	0.00%	10.10%	0.00%	0.00%	0.00%
	MINAS	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	ANS	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	WIDURI	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	BELIDA	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	PUL	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	MUL (Use for Mogas)	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	RUL	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	JP-S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	AVGAS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	JET-A	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%
	LSFO (Same as LFO)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%
	MOTOR LPG	0.00%	0.00%	0.05%	0.00%	0.00%	0.00%	0.00%
COMMERCIAL LPG	0.00%	0.00%	0.05%	0.00%	0.00%	0.00%	0.00%	
	REFORMATE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	AVIATION TEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	TOLUENE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RO	WHITE OIL	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.03%
	RO	0.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.03%
	BRU BTEX OFFGAS	1.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MISC	MEA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	SPENT CAUSTIC	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
	DESALTER CHEMICAL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	NO HAPS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

**Speciation Data**

HAPS COMPOSITIONS IN REFINERY  
TITLE V AIR PERMIT  
CHEVRON HAWAII REFINERY

PLANT	BLEND COMPONENTS	2,2,4 TRIMETHYLPENTANE		CUMENE		O-TOLUIDINE	ACRYLAMIDE	ANTIMONY COMPOUNDS		ARSENIC	CYANIDE COMPOUNDS
		CAS# 540841	CAS# 98828	CAS# 95534	CAS# 79061	CAS#		CAS#	CAS#		
		liq wt (%)	liq wt (%)	liq wt (%)	liq wt (%)	liq wt (%)	liq wt (%)	liq wt (%)	liq wt (%)		
		23	24	25	26	27	28	29	30		
CU	ATMOS OVHD LIQ	0.80%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	STAB OVHD	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	LSR	0.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	HSR	0.80%	0.23%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	LGO	0.00%	0.10%	1.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	HGO (Diesel)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	VGO (AVERAGE) (USE FCC feed)	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	
	RESID (& ASPHALT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	
	SPLITTER FEED	0.80%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	ACCUMULATOR GAS	0.00%	0.00%	0	0	0	0	0	0	0	
FCC	FRAC VAPOR	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%		
	SEC. LEAN OIL	0.00%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	EQUIL. MIX	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%		
	RICH SPONGE OIL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	ABSORBER GAS	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%		
	FUEL GAS (MIXDRUM)	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%		
	C4 OLEFINS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	C3-C4 MIX OLEFINS	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%		
	LCC	0.00%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	HCC	0.00%	0.01%	1.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	LCO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	FRAC BTMS	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%		
	DEBUT FEED	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%		
ALKY	LER BOTTOMS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	LA	2.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	HA	2.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	ISOM RX EFFLUENT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	CHLORIDE CHEMICAL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
H=	H= PLT C4'S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
DIM	DIM FD	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%		
	DIM STAB OVHD	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%		
	DIMATE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	REACTOR EFFLUENT	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%		
	NICKEL CATALYST	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	MINAS	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%		
	ANS	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%		
	WIDURI	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%		
	BELIDA	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%		
	PUL	0.50%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%		
	MUL (Use for Mogas)	0.50%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%		
	RUL	0.50%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%		
	JP-8	0.80%	0.23%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	AVGAS	2.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	JET-A	0.00%	0.10%	1.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	LSFO (Same as LFO)	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%		
	MOTOR LPG	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%		
COMMERCIAL LPG	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%			
	REFORMATE	1.36%	0.87%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	AVIATION TEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	TOLUENE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	WHITE OIL	0.50%	0.02%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%		
	RO	0.70%	0.17%	0.08%	0.00%	0.00%	0.00%	0.00%	0.00%		
	BRU BTEX OFFGAS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
MISC	MEA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	SPENT CAUSTIC	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	DESALTER CHEMICAL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
	NO HAPS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		

53 - FCC point

53- FCC POINT SOURCE POTENTIAL TO EMIT CALCULATIONS

FCC SO2 emissions									
FCC Feed	S%	lb/bbl	Bbls/day to FCC	Total lbs S	% conv to coke	lb/day S	lbs/day SO2	day/yr	ton/yr
VGO	0.405	308	22,000	27398	4.5	1,233	2,465.84	365	450

FCC emissions from source testing - 1996 and 1999 - six values					
Pollutant	lbs/hr	Annual downtime	Op hr/yr		TPY
			lbs/yr	lbs/year	
CO	114	0	8760	998640	499.32
VOC	3.35	0	8760	29346	14.67

	Allowed by Permit
High Sulfur VGO	5500 bbl/day
Low Sulfur VGO	16500 bbl/day

FCC NOx emissions (from AP-42)					
Pollutant	lb/10 <sup>3</sup> bbl	Bbls/day to FCC	Op hr/yr		ton/yr
			lbs/hour	lbs/yr	
NOx	71	22,000	65.08	8760	285.07

FCC PM10 emissions (from mass balance)			
Pollutant	lbs/hour	up hours	ton/yr
PM	40	8760	175.2

	wt lb/bbl	% total VGO	wt lb/bbl	% sulfur
HS Crude	324	25%	81	1.26
LS Crude	302	75%	227	0.12
			308	0.405

## Flare

### FLARE POINT SOURCE POTENTIAL TO EMIT CALCULATIONS

**Flare Pilots - F/G acid plant down**

Unit	F/G SCFH	downtime hr/year	S ppm	lbs SO2/MMSCF	SO2 lb/hr	Lbs/Year	Tons/Yr
FCC	15000	8760	36.5809	6.1772	0.09266	811.690	0.40585

lb SO2/MMSCF = 1/379\*ppm S \*64

**Flare Pilots - F/G normal**

Unit	F/G SCFH	op hrshr/year	S ppm	lbs SO2/MMSCF	SO2 lb/hr	Lbs/Year	Tons/Yr	lb/day
Crude	100	8760	36.581	6.177	0.00062	5.41	0.00271	0.015
FCC	150	0	36.581	6.177	0.00093	0.00	0.00000	0.022

lb SO2/MMSCF = 1/379\*ppm S \*64

**Flare emissions (from AP-42)**

Pollutant	lb/10 <sup>3</sup> bbl	crude unit throughput (bbl/day)	lb/day	day/yr	TPY
NOx	18.9	65000	1229	365	224.2
VOC	0.8	65000	52	365	9.5
CO	4.3	65000	280	365	51.0
PM	neg				
SO2	26.9	65000	1748.5	365	319.1
<b>Total</b>					<b>603.8</b>

HAP Summary

		Total Speciated VOC emissions (kg/hr)																						
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	BENZENE CAS# 71432 (ton/yr)	1	NAPHTHALENE CAS# 91203 (ton/yr)	2	O-XYLENE CAS# 95476 (ton/yr)	3	ETHYLBENZENE CAS# 100414 (ton/yr)	4	P-XYLENE CAS# 106423 (ton/yr)	5	ETHYLENE DIBROMIDE CAS# 106934 (ton/yr)	6	ETHYLENE DICHLORIDE CAS# 107062 (ton/yr)	7	M-XYLENE CAS# 108383 (ton/yr)	8	TOLUENE CAS# 108883 (ton/yr)	9	1,3-BUTADIENE CAS# 106990 (ton/yr)	10	n-HEXANE CAS# 110543 (ton/yr)	11	
	LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE																							
20	TANKS	0.82	1.40	3.32	1.25	1.71	0.45	0.27	0.00	0.00	4.63	0.00	0.00	0.00	4.60	0.30	0.00	0.00	0.00	0.00	1.21	0.00		
23	WASTE WATER RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
36	TREATMENT LAND TREATMENT UNIT	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03		
51	CRUDE UNIT	1.15	0.23	0.75	0.18	0.33	0.00	0.00	0.00	0.00	1.22	0.00	0.00	0.00	2.57	0.02	0.00	0.00	0.00	0.00	0.02	3.50		
52/55	BOILERS/FOUL WATER OXIDIZER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
53	FLUID CATALYTIC CRACKER UNIT	0.87	0.61	1.81	0.91	1.30	0.00	0.00	0.00	0.00	3.33	0.00	0.00	0.00	5.19	0.25	0.00	0.00	0.00	0.00	0.25	0.37		
56	HYDROGENATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00		
57	HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
58	ALKYLATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.05	0.01		
59	ISOMERIZATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.05	0.00		
60	ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
61/62	AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
66	DIMERSOL PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
67	COGENERATION PLANT	0.271	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.153	0.000	0.000	0.000	0.000	0.000	0.000	0.592		
	Process Fugitive Summary	3.13	2.26	5.89	2.34	3.35	0.45	0.27	0.00	0.00	9.20	0.00	0.00	0.00	12.54	0.80	0.00	0.00	0.00	0.00	0.80	5.70		
20	TANK FARM	1.19	0.02	0.24	0.12	0.08	0.00	0.00	0.00	0.00	0.44	0.00	0.00	0.00	1.52	0.00	0.00	0.00	0.00	0.00	0.00	3.94		
52	BOILER POINT	0.003	0.008	0.001	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.046	0.000	0.000	0.000	0.000	0.000	0.000	1.230		
67	COGEN POINT	0.000	0.000	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.030	0.000	0.000	0.000	0.000	0.000	0.000	0.002		
51	CRUDE POINT	0.001	0.006	0.001	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.473		
53	FCC POINT	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.044		
59	ISOM POINT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.071		
56	H&H POINT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.189		
57	H&H POINT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.260		
	H&H summary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.260		
62	ACID PLANT CC AND PREHEATER POINT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.103		
60	ASPHALT POINT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.043		
53	FCC STACK	0.1398	0.3458	0.5887	0.1840	0.2796	0.0002	0.0000	0.0000	0.0000	0.7211	0.0000	0.0000	0.0000	0.4709	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0449		
	WASTEWATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
	LOAD RACK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
	MARINE LOADING	4.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.98		
	FLARE	8.56	2.64	6.72	2.65	3.70	0.45	0.27	0.00	0.00	10.35	0.00	0.00	0.00	16.92	0.80	0.00	0.00	0.00	0.00	0.80	21.83		
	HAPs Summary	8.56	2.64	6.72	2.65	3.70	0.45	0.27	0.00	0.00	10.35	0.00	0.00	0.00	16.92	0.80	0.00	0.00	0.00	0.00	0.80	21.83		



HAP Summary

Total speciated VOC emis (kg/yr)												
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	ANILINE CAS# 62533 (ton/yr) 12	CRESOL MIXTURE CAS# 1319773 (ton/yr) 13	PHENOL CAS# 108952 (ton/yr) 14	STYRENE CAS# 100425 (ton/yr) 15	METHANOL CAS# 67561 (ton/yr) 16	NICKEL CAS# (ton/yr) 17	HCL CAS# 7647010 (ton/yr) 19	PERCHLOROETHYLENE CAS# 127184 (ton/yr) 20	BIPHENYL CAS# 92524 (ton/yr) 22	2,2,4 TRIMETHYLPENTANE CAS# 540841 (ton/yr) 23	
20	LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE	0.02	0.16	0.10	0.02	0.03	0.00	0.00	0.00	0.09	0.44	
23	TANKS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	RELIEF SYSTEMS											
	WASTE WATER											
36	TREATMENT LAND	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	
51	TREATMENT UNIT	0.01	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.55	
	CRUDE UNIT											
52/55	BOILERS/FOUL WATER OXIDIZER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	FLUID CATALYTIC CRACKER UNIT	0.02	0.00	0.01	0.04	0.00	0.00	0.00	0.00	0.01	0.00	
53	HYDROGENATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
56	HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
57	ALKYLATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
58	ISOMERIZATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	
59	ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
60	AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
61/62	DIMERSOL PLANT	0.00	0.00	0.00	0.00	0.00	0.34	0.00	0.00	0.00	0.00	
66	COGENERATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.104	
67	Process Fugitive Summary	0.05	0.23	0.12	0.07	0.03	0.34	0.00	0.05	0.11	1.51	
20	TANK FARM	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.01	1.39	
52	BOILER POINT											
67	COGEN POINT											
51	CRUDE POINT											
53	FCC POINT											
59	ISOM POINT											
56	H&H POINT											
57	H&H POINT											
	H&H summary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
62	ACID PLANT CC AND PREHEATER POINT											
60	ASPHALT POINT											
53	FCC STACK	0.0007	1.0670	0.0589	0.0000	0.0000	0.0000	0.0000	0.0001	0.0221	0.5151	
	WASTEWATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	
	LOAD RACK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.57	
	MARINE LOADING											
	FLARE											
	HAP's Summary	0.05	1.33	0.18	0.07	0.03	0.34	0.00	0.05	0.15	5.05	

HAP Summary

Total speciated VOC emis (kg/hr)										
Fugitive Emission by Area NUMBER	AREA DESCRIPTION	CUMENE CAS# 98828 (ton/yr) 24	O-TOLUIDINE CAS# 95534 (ton/yr) 25	ACRYLAMIDE CAS# 79061 (ton/yr) 26	ANTIMONY COMPOUNDS CAS# (ton/yr) 27	ARSENIC CAS# (ton/yr) 28	CYANIDE COMPOUNDS CAS# (ton/yr) 30	Formaldehyde (ton/yr)	POM/PAH (ton/yr)	Total Haps ton/yr
20	LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	0.17	0.86	0.00	0.00	0.01	0.01			21.873
23	RELIEF SYSTEMS	0.00	0.00	0.00	0.00	0.00	0.00			0.003
36	WASTE WATER TREATMENT LAND TREATMENT UNIT	0.00	0.00	0.00	0.00	0.00	0.00			0.130
51	CRUDE UNIT	0.08	0.09	0.00	0.00	0.01	0.01			10.794
52/55	BOILERS/FOUL WATER OXIDIZER	0.00	0.00	0.00	0.00	0.00	0.00			0.005
53	FLUID CATALYTIC CRACKER UNIT	0.04	0.18	0.00	0.00	0.02	0.02			14.976
56	HYDROGENATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00			0.143
57	HYDROGEN PLANT	0.00	0.00	0.00	0.00	0.00	0.00			0.000
58	ALKYLATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00			0.459
59	ISOMERIZATION PLANT	0.00	0.00	0.00	0.00	0.00	0.00			0.095
60	ASPHALT PLANT	0.00	0.00	0.00	0.00	0.00	0.00			0.003
61/62	AMINE/ACID PLANT	0.00	0.00	0.00	0.00	0.00	0.00			0.001
66	DIMERSOL PLANT	0.00	0.00	0.00	0.00	0.00	0.00			0.345
67	COGENERATION PLANT	0.000	0.000	0.000	0.000	0.005	0.005			1.129
	Process Fugitive Summary	0.28	1.14	0.00	0.01	0.05	0.05	0.00	0.00	49.957
20	TANK FARM	0.01	0.06	0.00	0.00	0.00	0.00			9.064
52	BOILER POINT							0.349	0.298	1.935
57	COGEN POINT							0.001	0.000	0.002
61	CRUDE POINT							0.208	0.006	0.253
53	FCC POINT							0.020	0.000	0.494
59	ISOM POINT							0.002	0.000	0.046
56	H&H POINT							0.003	0.000	0.074
57	H&H POINT							0.008	0.000	0.198
	H&H summary	0.000	0.000	0.000	0.000	0.000	0.000	0.011	0.000	0.272
62	ACID PLANT CC AND PREHEATER POINT							0.004	0.000	0.107
60	ASPHALT POINT							0.002	0.000	0.045
53	FCC STACK							0.890		0.890
	WASTEWATER	0.1251	0.0589	0.0000	0.0001	0.0001	0.0001	0.001	0.000	5.623
	LOAD RACK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.069
	MARINE LOADING	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.983
	FLARE									0.002
	HAPs Summary	0.42	1.26	0.00	0.01	0.06	0.06	1.49	0.30	85.74

**HAPs Point**

AP-42 HAPs listing for F/O and F/G Combustion

EF AP-42 Table 1.3-11 for F/O combustion

Metal	EF (lb/1000 Gal)	Crude GPY	Boilers GPY	Crude lb/yr	Boiler lb/yr	Crude ton/yr	Boiler ton/yr
Antimony	0.00525	9,771,736	14,011,620	51.30	73.56	0.0	0.0
Arsenic	0.00132	9,771,736	14,011,620	12.90	18.50	0.0	0.0
Barium	0.00257	9,771,736	14,011,620	-	-	-	-
Beryllium	0.00003	9,771,736	14,011,620	0.27	0.39	0.0	0.0
Cadmium	0.00040	9,771,736	14,011,620	3.89	5.58	0.0	0.0
Chloride	0.34700	9,771,736	14,011,620	-	-	-	-
Chromium	0.00085	9,771,736	14,011,620	8.26	11.84	0.0	0.0
Chromium (VI)	0.00025	9,771,736	14,011,620	2.42	3.47	0.0	0.0
Cobalt	0.00602	9,771,736	14,011,620	58.83	84.35	0.0	0.0
Copper	0.00176	9,771,736	14,011,620	-	-	-	-
Fluoride	0.03730	9,771,736	14,011,620	-	-	-	-
Lead	0.00151	9,771,736	14,011,620	-	-	-	-
Manganese	0.00300	9,771,736	14,011,620	29.32	42.03	0.0	0.0
Mercury	0.00011	9,771,736	14,011,620	1.10	1.58	0.0	0.0
Molybdenum	0.00079	9,771,736	14,011,620	-	-	-	-
Nickel	0.08450	9,771,736	14,011,620	825.71	1,183.98	0.4	0.6
Phosphorous	0.00946	9,771,736	14,011,620	92.44	132.55	0.0	0.1
Selenium	0.00068	9,771,736	14,011,620	6.67	9.57	0.0	0.0
Vanadium	0.03180	9,771,736	14,011,620	-	-	-	-
Zinc	0.02910	9,771,736	14,011,620	-	-	-	-

EF AP-42 Table 1.3-9 for F/O combustion

Organic/Other HAPs	EF (lb/1000 Gal)	Crude GPY	Boilers GPY	Crude lb/hr	Boiler lb/hr	Crude ton/yr	Boiler ton/yr
Benzene	0.0002140	9,771,736	14,011,620	2.09	3.00	0.00	0.00
Ethylbenzene	0.0000636	9,771,736	14,011,620	0.62	0.89	0.00	0.00
Formaldehyde	see below	9,771,736	14,011,620	-	-	-	-
Naphthalene	0.0011300	9,771,736	14,011,620	11.04	15.83	0.01	0.01
1,1,1-Trichloroethane	0.0002360	9,771,736	14,011,620	-	-	-	-
Toluene	0.0062000	9,771,736	14,011,620	60.58	86.87	0.03	0.04
o-xylene	0.0001090	9,771,736	14,011,620	1.07	1.53	0.00	0.00
several individual POMs	see below	-	-	-	-	-	-

EF AP42- Table 1.3-8 for F/O combustion

Organic/Other HAPs	EF (lb/1000 Gal)	Crude GPY	Boilers GPY	Crude lb/hr	Boiler lb/hr	Crude ton/yr	Boiler ton/yr
Formaldehyde	0.04250	9,771,736	14,011,620	415.30	595.49	0.2	0.3
POM	0.00120	9,771,736	14,011,620	11.73	16.81	0.0	0.0

EF Gas Turbine AP-42 Table 3.1-5 for Distillate combustion

Metal	EF (lb/1000 Gal)	Cogen LSR/HSR GPY	Cogen lb/hr	Cogen ton/yr
Antimony	0.00001	8,830,080	0.10	0.0
Beryllium	0.00000	8,830,080	0.00	0.0
Cadmium	0.00000	8,830,080	0.04	0.0
Chromium	0.00001	8,830,080	0.10	0.0
Lead	0.00001	8,830,080	-	-
Manganese	0.00079	8,830,080	6.98	0.0
Mercury	0.00000	8,830,080	0.01	0.0
Nickel	0.00000	8,830,080	0.04	0.0
Selenium	0.00003	8,830,080	0.22	0.0

HAPs Point

AP-42 HAPs listing for F/O and F/G Combustion

EF Gas Turbine AP-42 Table 3.1-4 for Distillate combustion

Organic	EF (lb/1000 Gal)	Cogen LSR/HSR GPY	Cogen lb/hr	Cogen ton/yr
1,3-Butadiene	0.00002	8,830,080	0.14	0.0
Benzene	0.00006	8,830,080	0.49	0.0
Formaldehyde	0.00028	8,830,080	2.47	0.0
Naphthalene	0.0000350	8,830,080	0.31	0.0
PAH	0.00004	8,830,080	0.35	0.0

EF Gas Turbine AP-42 Table 3.1-3 F/G COMBUSTION

Organic	EF (lb/MMSCF)	Cogen RFG MMSCF/Y	Cogen lb/hr	Cogen ton/yr
1,3-Butadiene	0.00000	893.52	0.00000	0.0
Acetaldehyde	0.00004	893.52	0.00004	0.0
Acrolein	0.00001	893.52	0.00001	0.0
Benzene	0.00001	893.52	0.00001	0.0
Ethylbenzene	0.00003	893.52	0.00003	0.0
Formaldehyde	0.00071	893.52	0.00063	0.0
Naphthalene	0.00000	893.52	0.00000	0.0
PAH	0.00000	893.52	0.00000	0.0
Propylene oxide	0.00003	893.52	0.00003	0.0
Toluene	0.00013	893.52	0.00012	0.0
Xylene	0.00006	893.52	0.00006	0.0

EF AP-42 Table 1.4-4 F/G COMBUSTION

double counted fix for 2002

Metal	EF (lb/MMSCF)	Cogeneration Units		Crude	Hydrogen				Acid Plant preheater F-6200	Asphalt Furnace F-6003	Total MMSCF/yr
		Boilers K-6703	FCC Furnace F-5301		Isom Furnace F-5930	Manufacturing furnace F-5700	Hydrogenation furnace F-5600				
Arsenic	0.0002000	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.2
Barium	0.0044000	-	-	-	-	-	-	-	-	-	-
Beryllium	0.0000120	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.2
Cadmium	0.0011000	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.2
Chromium	0.0014000	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.2
Cobalt	0.0000840	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.2
Copper	0.0008500	-	-	-	-	-	-	-	-	-	-
Manganese	0.0003800	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.2
Mercury	0.0002600	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.2
Molybdenum	0.0011000	-	-	-	-	-	-	-	-	-	-
Nickel	0.0021000	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.2
Selenium	0.0000240	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.2
Vanadium	0.0023000	-	-	-	-	-	-	-	-	-	-
Zinc	0.0290000	-	-	-	-	-	-	-	-	-	-

EF AP-42 Table 1.4-3 F/G COMBUSTION

Organics	EF (lb/MMSCF)	Cogeneration Units		Crude	Hydrogen				Acid Plant preheater F-6200	Asphalt Furnace F-6003	Total MMSCF/yr
		Boilers K-6703	FCC Furnace F-5301		Isom Furnace F-5930	Manufacturing furnace F-5700	Hydrogenation furnace F-5600				
Benzene	2.10E-03	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.2
Dichlorobenzene	1.20E-03	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.24
Formaldehyde	7.50E-02	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.24
Hexane	1.80E+00	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.24
Naphthalene	6.10E-04	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.24
Toluene	3.40E-03	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.24
POM	8.87E-05	1,366.56	893.52	1.96	525.60	49.06	210.24	78.84	43.36	48.18	3,288.24

HAPs Point

AP-42 HAPs listing for F/O and F/G Com

EF AP-42 Table 1.3-11 for F/O combusti

Metal	EF (lb/1000 Gal)
Antimony	0.00525
Arsenic	0.00132
Barium	0.00257
Beryllium	0.00003
Cadmium	0.00040
Chloride	0.34700
Chromium	0.00085
Chromium (VI)	0.00025
Cobalt	0.00602
Copper	0.00176
Fluoride	0.03730
Lead	0.00151
Manganese	0.00300
Mercury	0.00011
Molybdenum	0.00079
Nickel	0.08450
Phosphorous	0.00946
Selenium	0.00068
Vanadium	0.03180
Zinc	0.02910

EF AP-42 Table 1.3-9 for F/O combusti

Organic/Other HAPs	EF (lb/1000 Gal)
Benzene	0.0002140
Ethylbenzene	0.0000636
Formaldehyde	see below
Naphthalene	0.0011300
1,1,1-Trichloroethane	0.0002360
Toluene	0.0062000
o-xylene	0.0001090
several individual POMs	see below

EF AP42- Table 1.3-8 for F/O combusti

Organic/Other HAPs	EF (lb/1000 Gal)
Formaldehyde	0.04250
POM	0.00120

EF Gas Turbine AP-42 Table 3.1-5 for Di

Metal	EF (lb/1000 Gal)
Antimony	0.00001
Beryllium	0.00000
Cadmium	0.00000
Chromium	0.00001
Lead	0.00001
Manganese	0.00079
Mercury	0.00000
Nickel	0.00000
Selenium	0.00003

**HAPs Point**

AP-42 HAPs listing for F/O and F/G Cor

EF Gas Turbine AP-42 Table 3.1-4 for Di

Organic	EF (lb/1000 Gal)
1,3-Butadiene	0.00002
Benzene	0.00006
Formaldehyde	0.00028
Naphthalene	0.0000350
PAH	0.00004

EF Gas Turbine AP-42 Table 3.1-3 F/G

Organic	EF (lb/MMSCF)
1,3-Butadiene	0.00000
Acetaldehyde	0.00004
Acrolein	0.00001
Benzene	0.00001
Ethylbenzene	0.00003
Formaldehyde	0.00071
Naphthalene	0.00000
PAH	0.00000
Propylene oxide	0.00003
Toluene	0.00013
Xylene	0.00006

EF AP-42 Table 1.4-4 F/G COMBUSTION

Metal	EF (lb/MMSCF)
Arsenic	0.0002000
Barium	0.0044000
Beryllium	0.0000120
Cadmium	0.0011000
Chromium	0.0014000
Cobalt	0.0000840
Copper	0.0008500
Manganese	0.0003800
Mercury	0.0002600
Molybdenum	0.0011000
Nickel	0.0021000
Selenium	0.0000240
Vanadium	0.0023000
Zinc	0.0290000

Boilers	Cogeneration Units K-6703	Crude	Hydrogen			Hydrogenation furnace F-5600	Acid Plant CC F-6262	Acid Plant preheater F-6200	Asphalt Furnace F-6003	Total F/G Combustion
			FCC Furnace F-5301	Isom Furnace F-5930	Manufacturing furnace F-5700					
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
-	-	-	-	-	-	-	-	-	-	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	

EF AP-42 Table 1.4-3 F/G COMBUSTION

Organics	EF (lb/MMSCF)
Benzene	2.10E-03
Dichlorobenzene	1.20E-03
Formaldehyde	7.50E-02
Hexane	1.80E+00
Naphthalene	6.10E-04
Toluene	3.40E-03
POM	8.87E-05

Boilers	Cogeneration Units K-6703	Crude	Hydrogen			Hydrogenation furnace F-5600	Acid Plant CC F-6262	Acid Plant preheater F-6200	Asphalt Furnace F-6003	Total F/G Combustion
			FCC Furnace F-5301	Isom Furnace F-5930	Manufacturing furnace F-5700					
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.05	0.03	0.00	0.02	0.00	0.01	0.00	0.00	0.00	0.12	
1.23	0.80	0.00	0.47	0.04	0.19	0.07	0.06	0.04	2.96	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	

# Loadrack

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BENZENE CAS# 71432 liq wt ( %)	NAPHTHALENE CAS# 91203 liq wt ( %)
1	2
4.8537	4.2713
0.0000	0.0000
0.0000	0.0000
0.0000	0.4005

Product Loaded	S	P	M	T (lb/10 <sup>3</sup> gal)	L <sub>L</sub> (10 <sup>3</sup> gal)	Throughput (10 <sup>3</sup> gal)	Throughput (10 <sup>3</sup> bbl)	VOC Emission (ton/yr)	Stream ID
Motor Gasoline	0.5	8.27	66	537	6.3323	306600		970.75	47
Aviation Gas	0.5	5.22	60	537	3.6336	1686		3.06	50
Diesel	0.5	0.0143	130	537	0.0216	153300		1.65	6
Jet Fuel	0.5	0.205	130	537	0.3092	199290		30.81	51
								1006.27	

536550

load rack

$L_L = 12.46 \cdot SPM/T$

S = 0.5 saturation factor from AP-42 Table 5.2-1 for submerged truck loading

P = true vapor pressure of liquid loaded psia from TANKS4.0 run

M = molecular weight of vapors lb/lb mole from TANKS4.0 run

T = temperature °R (°F+460), mean temperature data taken from TANKS4.0 for Barbers Point (77.°F)

bbl/yr	bbl/day
7300000	20000
40150	110
3650000	10000
4745000	13000
<b>15,735,150</b>	
<b>6.61E+08</b>	gal/yr

Motor Gasoline: 7,300,000 barrels per any rolling twelve (12) month period;  
 Aviation Gasoline: 47,450 barrels per any rolling twelve (12) month period;  
 Diesel: 2,920,000 barrels per any rolling twelve (12) month period; and  
 Jet fuel: 4,380,000 barrels per any rolling twelve (12) month period.

Total:

Loadtrack

	O-XYLENE CAS# 95476 liq wt ( %)	ETHYLBENZENE CAS# 100414 liq wt ( %)	P-XYLENE CAS# 106423 liq wt ( %)	ETHYLENE DIBROMIDE CAS# 106934 liq wt ( %)	ETHYLENE DICHLORIDE CAS# 107062 liq wt ( %)	M-XYLENE CAS# 108383 liq wt ( %)	TOLUENE CAS# 108883 liq wt ( %)	1,3-BUTADIENE CAS# 106990 liq wt ( %)	n-HEXANE CAS# 110543 liq wt ( %)	ANILINE CAS# 62533 liq wt ( %)
Product Loaded	3	4	5	6	7	8	9	10	11	12
Motor Gasoline	13.6875	7.1835	10.1928	0.0000	0.0000	25.9189	42.6157	0.0000	13.0080	0.0971
Aviation Gas	0.0000	0.0000	0.0000	0.0008	0.0000	0.0000	0.0000	0.0000	0.0009	0.0000
Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Jet Fuel	0.7363	0.2465	0.3235	0.0000	0.0000	0.8072	0.0000	0.0000	0.0000	0.0003



**Loadrack**

**Total speciated VOC emissions  
(tons/yr)**

Product Loaded	CRESOL MIXTURE CAS# 1319773 liq wt ( %)	13	PHENOL CAS# 108952 liq wt ( %)	14	STYRENE CAS# 100425 liq wt ( %)	15	METHANOL CAS# 67561 liq wt ( %)	16	NICKEL CAS# liq wt ( %)	17	HCL CAS# 7647010 liq wt ( %)	19	PERCHLOROETHYLENE CAS# 127184 liq wt ( %)	20	BIPHENYL CAS# 92524 liq wt ( %)	22	2,2,4 TRIMETHYLPENTANE CAS# 540841 liq wt ( %)	23
Motor Gasoline	0.0000																	
Aviation Gas	0.0000	0.0971	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	4.8537	0.0674
Diesel	0.0017	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0000	0.0000	0.0000
Jet Fuel	0.0308	0.0308	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0308	0.0000	0.0000	0.0000

**Loadrack**

Product Loaded	CUMENE CAS# 98828 liq wt ( %)	O-TOLUIDINE CAS# 95534 liq wt ( %)	ACRYLAMIDE CAS# 79061 liq wt ( %)	ANTIMONY COMPOUNDS CAS# liq wt ( %)	ARSENIC CAS# liq wt ( %)	PROPYLENE CAS# 115071 (wt %)	CYANIDE COMPOUNDS CAS# liq wt ( %)
	24	25	26	27	28	29	30
Motor Gasoline	0.0971	0.0971	0.0010	0.0000	0.0000	0.0000	0.0000
Aviation Gas	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Diesel	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Jet Fuel	0.0308	0.3081	0.0000	0.0000	0.0000	0.0000	0.0000

## Area Descrip

### REFINERY PROCESS AREAS

AREA NUMBER	AREA DESCRIPTION
20	LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS
23	RELIEF SYSTEMS
36	WASTE WATER TREATMENT LAND TREATMENT UNIT
51	CRUDE UNIT
52/55	BOILERS/FOUL WATER OXIDIZER
53	FLUID CATALYTIC CRACKER UNIT
56	HYDROGENATION PLANT
57	HYDROGEN PLANT
58	ALKYLATION PLANT
59	ISOMERIZATION PLANT
60	ASPHALT PLANT
61/62	AMINE/ACID PLANT
66	DIMERSOL PLANT
67	COGENERATION PLANT

## Component Counts

### COMPONENT COUNTS

AREA NUMBER	AREA DESCRIPTION	SERVICE	COMPONENT TYPE				
			VALVES	FLANGES	PUMPS	COMPRESSORS	
20	LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	ALL	2421	11432	58	4	32
23	RELIEF SYSTEMS	ALL	53	220	0	0	0
36	WASTE WATER TREATMENT LAND TREATMENT UNIT	ALL	246	335	12	0	2
51	CRUDE UNIT	ALL	1403	6558	29	1	4
52/55	BOILERS/FOUL WATER OXIDIZER	ALL	103	181	0	0	0
53	FLUID CATALYTIC CRACKER UNIT	ALL	1908	2452	33	0	12
56	HYDROGENATION PLANT	ALL	422	812	1	2	4
57	HYDROGEN PLANT	ALL	166	914	1	0	4
58	ALKYLATION PLANT	ALL	1180	5821	21	1	0
59	ISOMERIZATION PLANT	ALL	570	1493	9	0	0
60	ASPHALT PLANT	ALL	53	236	0	0	0
61/62	AMINE/ACID PLANT	ALL	12	49	0	0	0
66	DIMERSOL PLANT	ALL	974	1272	21	0	12
67	COGENERATION PLANT	ALL	253	1264	2	1	0
TOTAL			9765	33039	187	9	71

Note: For summary purposes, Both connectors and fittings have been grouped under the category of flanges

## Fugitive VOC Summary

### REFINERY PROCESS AREAS FUGITIVE EMISSIONS

AREA NUMBER	AREA DESCRIPTION	FUGITIVE VOCs TON/YR
20	LPG AREA AND FIELD PIPING BLENDING AND SHIPPING STORAGE TANKS	438.3
23	RELIEF SYSTEMS	14.3
36	WASTE WATER TREATMENT LAND TREATMENT UNIT	1.6
51	CRUDE UNIT	204.8
52/55	BOILERS/FOUL WATER OXIDIZER	27.1
53	FLUID CATALYTIC CRACKER UNIT	222.0
56	HYDROGENATION PLANT	71.5
57	HYDROGEN PLANT	34.4
58	ALKYLATION PLANT	179.9
59	ISOMERIZATION PLANT	107.9
60	ASPHALT PLANT	14.3
61/62	AMINE/ACID PLANT	3.3
66	DIMERSOL PLANT	20.5
67	COGENERATION PLANT	<u>62.5</u>
	<b>TOTAL PROCESS AREAS FUGITIVE EMISSIONS</b>	<b>1402.2</b>

Cooling

**COOLING TOWER POTENTIAL TO EMIT EMISSIONS ESTIMATE**

Cooling Water Circulation rate 50000 gpm (Maximum)

Circulation Rate (gpm) 50000	Emission Factor (lb VOC/MM gal) 0.7	VOC Emissions	
		(lb/hr) 2.100	(tpy) 9.20

Circulation Rate (gpm) 50000	Drift Factor (gal drift/gal circulated) 0.00002	Density (lb/gal) 8.34	Time Conversion (min/hr) 60	Drift (lbs/hr) 500.40	Supply Water Concentration (ppmw) 400.00	Cycles of Concentration 3.7	PM/PM <sub>10</sub> Emissions (lbs/hr) 0.74	PM/PM <sub>10</sub> Emissions (tpy) 3.24
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TDS ppm = conductivity\*2/3  
Per Matt from Nalco use 600\*2/3

Detailed Summary

Summary of potential emissions from the Chevron-Hawaii refinery

Equipment Description/Emission Source	Annual Process Rate	Process Rate Units	Type of Fuel Fired	Fuel Usage Bbl/yr or MSCF/yr	% sulfur content by weight	Heating value	Units	Tons/Year Emissions					
								PM10	SO2	CO	NO2	VOC	Pb
Boilers F-5201	220	MMBTU/Hour	Total Fuel Gas Total Fuel Oil	1,874,640 333,610	0.0037 2			7.12 151.33	5.79 2199.82	22.50 35.03	159.34 224.19	5.16 5.32	0.00 0.01
Boilers F-5202, F-5203	160.8	MMBTU/Hour	Total Fuel Gas Total Fuel Oil	1,366,560 243,820	0.0037 2			5.19 110.60	4.22 1607.75	16.40 25.60	116.16 163.85	3.76 3.89	0.00 0.01
Boilers F-5202, F-5203	160.8	MMBTU/Hour	Total Fuel Gas Total Fuel Oil	1,366,560 243,820	0.0037 2		Total Boiler	5.19 110.60	4.22 1607.75	16.40 25.60	116.16 163.85	3.76 3.89	0.00 0.01
All Intentionally fired								372.52	5415.32	86.23	551.88	13.11	0.03
Cogeneration Units - K-6703 K-6701, K-6702, K-6703 permit limit NOx - 14.4 lb/hr, 67 ppm permit limit CO - 4.3 lb/hr, 25 ppm	192 76	Bbl/day MMBTU/Hour	LSR/HSR	210,240 26280 upline hr	0.03	4757.819	MBTU/bbl						
Cogeneration Units - K-6703 K-6701, K-6702, K-6703	38.8 34 76	MSCF/Hr MSCF/Hr MMBTU/Hour	Fuel Gas	893,520 232,660 1,961 1785371.43	0.0037	1154.90	BTU/SCF	11.72 384.24	15.95 5431.28	52.49 138.72	193.16 745.04	2.34 15.45	0.01 0.03
Crude Furnace - F-5103	161.5 151.5 159075	MMBTU/Hour MMBTU/Hour	Fuel Oil Fuel Gas Pilot Fuel Gas	229,950 1,388 1,263,943	0.45 0.0037 0.0037		Total Cogen	35.52 0.01 4.80	341.17 0.004 3,904	24.14 0.06 53.09	193.16 0.10 88.48	3.67 0.00 3.48	0.01 0.0000003 0.00003160
Crude Furnace - F-5153	62.5 62.5	MMBTU/Hour MMBTU/Hour	Fuel Oil Fuel Gas Pilot Fuel Gas	94,900 573 521,429	0.45 0.0037 0.0037		SubTotal	8.97 0.00 1.98	140.80 0.002 1,610	9.96 0.02 21.90	109.61 0.01 13.04	0.56 0.00 1.43	0.00 0.00000001 0.00001304
FCC Furnace - F-5300	61	MMBTU/Hour	Fuel Gas	525,600	0.0037		SubTotal	2.00	1.62	22.08	26.28	1.45	0.000013
Isom Furnace - F-5930 Isom Furnace - F-5950	4 1.6	MMBTU/Hour MMBTU/Hour	Total Fuel Gas	49,056	0.0037			0.19	0.15	2.06	2.45	0.13	0.000001
Hydrogen Manufacturing furnace - F-5701 Hydrogenation furnace - F-5800	24.3 9	MMBTU/Hour MMBTU/Hour	Fuel Gas Fuel Gas	210,240 78,840	0.0037 0.0037			0.80 0.30	0.65 0.24	8.83 3.31	10.51 3.94	0.58 0.22	0.000005 0.000002
Acid Plant combustion chamber - F-6200	8.5	MMBTU/Hour	Fuel Gas	70,914	0.0037			0.27	0.22	2.98	3.55	0.20	0.000002
Acid Plant preheater - F-6262	5.1	MMBTU/Hour	Fuel Gas	43,362	0.0037			0.16	0.13	1.82	2.17	0.12	0.000001
Asphalt Furnace - F-6003	5.7	MMBTU/Hour	Fuel Gas	48,180	0.0037			0.18	0.15	2.02	2.41	0.13	0.000001
FCC Stack	23,000	Bbls/Day Feed	Fuel Gas	48,180	0.0037		replace with stack limit	175.2	450.02	499.32	285.07	14.67	
Cooling Tower	2,275,940	Gallons/Hour						3.24				9.20	
Acid plant absorber stack	110.0	Tons/Day							803.00				
Catalyst transfer	924	Tons/Year						0.03					
Wastewater treatment	84000 84000	Gallons/Hour										73.56	0.00
Process Fugitives	660876300	Gallons/Year										1402.24	1.37
Load Rack												1006.27	0.00
Tanks												316.57	0.00
Marine Loading	3600	Bbls/year										196.56	0.00
Refinery Flares							Total Criteria Pollutants	611.1	7488.5	807.1	1608.5	3052.0	1.4

## Cogen up&test

### 2003 Cogen Uptime

#### COGEN

	K-6701	K-6702	K-6703	AVERAGE
1st Qtr 2002	1518	2029	2114	1887
2nd Qtr 2002	2081	2183	2157	2140
3rd Qtr 2002	2017	2000	1897	1971
4th Qtr 2002	2194	2197	2190	2194
TOTAL	5729	6226	6201	
	total Cogen uptime		<b>18156</b>	

### 2001 Source Test Data

Compliance Source Test Report  
 Combustion Turbine Generators  
 Unit #1, Unit #2, and Unit #3  
 35977

CO data in lb/hr						<u>MAX CO Emission Rate</u>
	LSR -on	LSR -off	FG - on	FG- off		3.15
2001 unit1	1.39	3.15	0.56	1.45		
unit2	1.24	2.64	0.41	1.43		
unit3	1.19	1.50	0.68	1.05		
avg LSR		1.85	avg FG	0.93		
				1.39		

NOx data in lb/hr						<u>MAX NOx Emission Rate</u>
	LSR -on	LSR -off	FG - on	FG- off		8.65
2001 unit1	8.65	7.82	5.77	6.23		
unit2	7.92	7.17	7.60	6.52		
unit3	8.28	7.08	8.25	6.68		
avg LSR		7.82	avg FG	6.84		
				7.33		

### 1998 Source Test Data

Compliance Source Test Report  
 Combustion Turbine Generators  
 Unit #1, Unit #2, and Unit #3  
 35977

CO data in lb/hr						<u>MAX CO Emission Rate</u>
	LSR -on	LSR -off	FG - on	FG- off		2.67
1998 unit1	1.95	2.06	1.29	1.28		
unit2	1.71	1.98	1.18	1.1233333		
unit3	2.67	1.91	1.25	1.16		
avg LSR		2.05	avg FG	1.21		
				1.63		

NOx data in lb/hr						<u>MAX CO Emission Rate</u>
	LSR -on	LSR -off	FG - on	FG- off		10.63
1998 unit1	9.39	8.68	9.68	9.28		
unit2	9.73	9.10	10.63	9.64		
unit3	10.06	9.34	10.55	10.04		
avg LSR		9.38	avg FG	9.97		
				9.68		





**APPENDIX C**

**Current Version of Attachment II(B) of Covered Source Permit**

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April 16, 2002

**APPENDIX C****Current Version of Attachment II(B) of Covered Source Permit**

**CERTIFIED MAIL**  
**RETURN RECEIPT REQUESTED**  
(7000 1670 0003 8531 4937)

02-A163  
File No. 0088-01

Ms. Martha A. Gilles  
Refinery Manager  
Chevron Products Company  
91-480 Malakole Street  
Kapolei, Hawaii 96707-1883

Dear Ms. Gilles:

**Subject: Amendment of Covered Source Permit (CSP) No. 0088-01-C  
Minor Modification Applications Nos. 0088-04 and 0088-05  
Domed Roof Installation for Petroleum Storage Tanks Nos. 249 and 250  
Chevron Products Company  
Petroleum Refinery  
Located at 91-480 Malakole Street, Kapolei, Oahu  
Date of Expiration: February 1, 2004**

In accordance with Hawaii Administrative Rules, Chapter 11-60.1 and pursuant to your applications for Minor Modifications dated November 26, 2001 and December 10, 2001, and additional information dated January 16, 2002, the Department of Health hereby amends Covered Source Permit (CSP) No. 0088-01-C issued to Chevron Products Company on February 22, 1999. The amendment allows the installation of domed roofs on the existing external floating roof petroleum storage tanks nos. 249 and 250.

The enclosed Attachment II(B) supersedes the corresponding Attachment II(B) of CSP No. 0088-01-C issued on February 22, 1999.

All other permit conditions of CSP No. 0088-01-C issued on February 22, 1999, shall not be affected and shall remain valid.

If there are any questions regarding these matters, please contact Mr. Darin Lum of the Clean Air Branch at (808) 586-4200.

Sincerely,

THOMAS E. ARIZUMI, P.E., CHIEF  
Environmental Management Division

DL:lk  
Enclosures  
c: CAB Enforcement Section

## APPENDIX C

## Current Version of Attachment II(B) of Covered Source Permit

### ATTACHMENT II(B): SPECIAL CONDITIONS COVERED SOURCE PERMIT NO. 0088-01-C

#### PETROLEUM STORAGE TANKS

Amended Date: April 16, 2002  
2004

Expiration Date: February 1,

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility.

#### Section A. Equipment Description

1. This portion of the Covered Source Permit encompasses the following equipment and associated appurtenances:
  - a. Twenty-seven (27) Gasoline Intermediates and Finished Products Storage Tanks
    - i. One (1) - 272,000 bbl external floating roof storage tank identified as Tank 111;
    - ii. Two (2) - 19,200 bbl external floating roof storage tanks identified as Tanks 232 and 235;
    - iii. Two (2) - 19,000 bbl external floating roof storage tanks identified as Tanks 233 and 273;
    - iv. Four (4) - 38,000 bbl external floating roof storage tanks identified as Tanks 236, 237, 255, and 256;
    - v. One (1) - 9,500 bbl external floating roof storage tanks identified as Tank 251;
    - vi. One (1) - 37,000 bbl external floating roof storage tank identified as Tank 252;
    - vii. One (1) - 37,400 bbl external floating roof storage tank identified as Tank 253;
    - viii. One (1) - 33,000 bbl external floating roof storage tank identified as Tank 254;
    - ix. Three (3) - 29,000 bbl external floating roof storage tanks identified as Tanks 257, 258, and 262;
    - x. Three (3) - 41,000 bbl external floating roof storage tanks identified as Tanks 264, 265, and 266;
    - xi. One (1) - 23,000 bbl external floating roof storage tank identified as Tank 269;
    - xii. One (1) - 36,000 bbl external floating roof storage tank identified as Tank 271;
    - xiii. One (1) - 5,000 bbl external floating roof storage tanks identified as Tank 275;
    - xiv. Two (2) - 4,700 bbl external floating roof storage tanks identified as Tanks 162 and 163;
    - xv. One (1) - 235,000 bbl external floating roof storage tank identified as Tank 109;
    - xvi. One (1) - 9,500 bbl external floating roof storage tank converted to an internal floating roof storage tank identified as Tank 249; and
    - xvii. One (1) - 5,000 bbl external floating roof storage tank converted to an internal floating roof storage tank identified as Tank 250.
  - b. Eight (8) Crude Oil Storage Tanks

## **APPENDIX C**      **Current Version of Attachment II(B) of Covered Source Permit**

- i. One (1) - 149,000 bbl external floating roof storage tank identified as Tank 104;
  - ii. Two (2) - 237,000 bbl external floating roof storage tanks identified as Tanks 105 and 107;
  - iii. Two (2) - 235,000 bbl external floating roof storage tanks identified as Tanks 106 and 108;
  - iv. One (1) - 272,000 bbl external floating roof storage tank identified as Tank 110;
  - v. One (1) - 23,000 bbl external floating roof storage tank identified as Tank 113; and
  - vi. One (1) - 81,250 bbl vertical fixed roof storage tank identified as Tank 152.
- c. Three (3) Jet Fuel Storage Tanks
- i. One (1) - 50,827 bbl vertical fixed roof storage tank identified as Tank 274;
  - ii. One (1) - 38,000 bbl external floating roof storage tank identified as Tank 263; and
  - iii. One (1) - 41,000 bbl external floating roof storage tank identified as Tank 267.

(Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each tank. The identification tag or nameplate shall be attached to the tank in a conspicuous location. Information shall also be made available upon request that identifies the capacity, date of construction, serial number or I.D. number and manufacturer of each tank.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

### **Section B. Applicable Federal Regulations**

1. Each of the storage tanks identified in Section A of this Attachment are subject to the provisions of the following federal regulations:
  - a. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT),
    - i. Subpart A, General Provisions; and
    - ii. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

For Group 1 storage tanks (all storage tanks except for Storage tanks 152, 263, 267, and 274), the permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, reporting, monitoring, testing and recordkeeping requirements, at the first tank degassing and cleaning activity after August 18, 1998, or before August 18, 2005, whichever comes first. The major requirements of these standards are detailed in **Section G - 40 CFR Part 63, Subpart CC Requirements** of this Attachment. Group 1 storage tanks shall comply with Sections C through G below. Group 2 storage tanks (Storage tanks 152, 263, 267 and 274) shall comply with Sections C through F below.

**Expiration Date: Feb. 1, 2004**

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174, 40 CFR §63.640, §63.646)<sup>1</sup>

**Section C. Operational and Emissions Limitations**

1. The true vapor pressure of the volatile organic liquid stored in each of the storage tanks identified in Special Condition A.1.a. of this Attachment shall not be greater than or equal to 11.0 pounds per square inch absolute (psia).

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

2. The true vapor pressure of the volatile organic liquid stored in Storage Tanks 152 and 274 shall not be greater than or equal to 1.5 pounds per square inch absolute (psia).

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

3. Storage tanks identified in Special Condition No. A.1.b. of this Attachment shall only store crude oil.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

4. Storage tanks identified in Special Condition No. A.1.c. of this Attachment shall only store jet fuel.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

5. Each storage tank identified in Section A of this Attachment, except for Storage Tanks 152 and 274, shall be equipped with a floating roof which will rest on the surface of the liquid contents and be equipped with a closure seal or seals to close the space between the roof edge and tank wall.

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

6. All tank gauging and sampling devices for each of the storage tanks identified in Section A of this Attachment, except for Storage Tanks 152 and 274, shall be gas-tight except when tank gauging or sampling is taking place.

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

7. Each storage tank identified in Section A of this Attachment shall be equipped with a permanent submerged fill pipe.

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

**Expiration Date: Feb. 1, 2004**

8. The permittee may increase the storage capacities of Storage Tanks 105 through 111 by 12% to the capacities listed below, provided that no new applicable requirement is triggered by such action and the permittee has installed the seal requirements pursuant to 40 CFR Part 63, Subpart CC. The permittee must obtain prior written approval of the Department of Health and must demonstrate that a modification or reconstruction under NSPS or a PSD review would not be triggered.

Storage Tanks 105 and 107 - 265,440 bbl  
Storage Tanks 106, 108 and 109 - 263,200 bbl  
Storage Tanks 110 and 111- 304,640 bbl

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

#### **Section D. Monitoring and Recordkeeping Requirements**

1. The permittee shall maintain a record of the volatile organic liquid stored, the period of storage, and the maximum true vapor pressure (psia) of that liquid for each storage tank identified in Section A of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

2. The permittee shall keep readily accessible records showing the dimensions of each storage tank identified in Section A of this Attachment and an analysis showing the capacity of the storage tank. This record shall be kept as long as the storage tank retains Group 1 or Group 2 status and is in operation. If a storage tank is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources, a record of any data, assumptions, and procedures used to make this determination shall be retained. The permittee shall use the Group 1 and Group 2 storage vessel definitions in 40 CFR §63.641.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; 40 CFR §63.646, §63.654)<sup>1</sup>

3. Records shall be retained for five (5) years in a permanent form suitable for inspection and made available to the Department of Health or their representatives upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; 40 CFR §63.646, §63.654)<sup>1</sup>

#### **Section E. Notification and Reporting Requirements**

1. Annual Emissions

**Expiration Date: Feb. 1, 2004**

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **on an annual basis** the total tons per year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due **within sixty (60) days following the end of each calendar year**. The enclosed **Annual Emissions Report Forms: External/Internal Floating Roof Petroleum Storage Tank, and Fixed Roof Petroleum Storage Tank** or equivalent forms, shall be used in reporting emissions.

Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department of Health determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-114)

2. Additional notification and reporting requirements shall be conducted in accordance with the standard conditions found in Attachment I, Standard Conditions 16, 17 and 25, respectively. These notifications shall include, but not be limited to:
  - a. Intent to shutdown air pollution control equipment for necessary scheduled maintenance;
  - b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
  - c. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. The permittee shall report **within five (5) working days any deviations from permit requirements**, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventative measures taken. Corrective actions may include a requirement for more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

4. Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department of Health and EPA Region 9, a compliance certification pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall be submitted **within ninety (90) days after** the end of each calendar year, and shall be signed and dated by an authorized representative.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department of Health determines that reasonable justification exists for the extension.



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(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. The permittee shall notify the Department of Health at least **thirty (30) days** prior to:
  - a. Changing the volatile organic liquid stored in any of the storage tanks identified in Section A.1.a. of this Attachment; and
  - b. Increasing the storage capacity of Storage Tanks 105 thru 111 in accordance with Special Condition No. C.8. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

#### **Section F. Agency Notifications**

1. Any document (including reports) required to be submitted by this Covered Source permit shall be in accordance with Attachment I, Standard Conditions, Condition 29.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

#### **Section G. 40 CFR Part 63, Subpart CC Requirements**

##### **1. Operational and Emission Limitations**

- a. Group 1 storage tanks consisting of an external floating roof converted to an internal floating roof (petroleum storage tanks 249 and 250) shall comply with the provisions of 40 CFR §63.646 including the following:
  - i. The internal floating roof shall rest or float on the liquid surface inside a storage tank that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage tank is completely emptied and degassed or subsequently emptied and refilled. When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as soon as practical.
  - ii. The petroleum storage tanks shall be equipped with one of the following closure devices between the wall of the storage tank and the edge of the internal floating roof:
    - (1) A foam or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal);
    - (2) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage tank and the edge of the internal floating roof. The lower seal may be vapor mounted, but both must be continuous; or
    - (3) A mechanical shoe seal.

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- iii. If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.
  - iv. Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seals exceeds the manufacturer's recommended setting.
  - v. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.
- b. Group 1 storage tanks with an external floating roof (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271, 273 and 275) shall comply with the provisions of 40 CFR §63.646 including the following:
- i. Each external floating roof shall be equipped with a primary seal and secondary seal to close the space between the wall of the storage tank and roof edge. The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. The primary and secondary seals shall completely cover the annular space between the edge of the floating roof and tank wall in a continuous fashion, except during the inspections required by Special Condition No. G.2.b. of this Attachment.
  - ii. The floating roof is to be floating on the liquid at all times (i.e., off the roof leg supports), except during initial fill until the floating roof is lifted off leg supports and during those intervals when the storage tank is completely emptied and degassed or when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the floating roof is resting on the leg supports shall be continuous and shall be accomplished as soon as practical.
  - iii. If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.
  - iv. Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seals exceeds the manufacturer's recommended setting.

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- v. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.646)<sup>1</sup>

## 2. Monitoring and Recordkeeping Requirements

- a. For the Group 1 storage tanks consisting of an external floating roof converted to an internal floating roof (petroleum storage tanks 249 and 250), the permittee shall demonstrate compliance by complying with the requirements of 40 CFR §63.120(a)(1) through (a)(7) including the following:
  - i. The permittee shall visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), according to the schedule specified below:
    - (1) For storage tanks equipped with a single-seal system, the permittee shall perform the inspections specified below:
      - (a) Visually inspect the internal floating roof and the seal through manholes and roof hatches on the fixed roof at least once every **twelve (12) months** after initial fill, or at least once every **twelve (12) months** after the compliance date specified in Special Condition No. B.1. of this Attachment; and
      - (b) Visually inspect the internal floating roof, the seal, gaskets, slotted membranes, and sleeve seals (if any) each time the storage tank is emptied and degassed, and at least once every **ten (10) years** after the compliance date specified in Special Condition No. B.1. of this Attachment.
    - (2) For storage tanks equipped with a double-seal system, the permittee shall perform either one of the inspections indicated below:
      - (a) Visually inspect the internal floating roof, the primary seal, the secondary seal, gaskets, slotted membranes, and sleeve seals (if any) each time the storage tank is emptied and degassed and at least once every **five (5) years** after the compliance date specified in Special Condition No. B.1. of this Attachment; **or**
      - (b) Visually inspect the internal floating roof and the secondary seal through manholes and roof hatches on the fixed roof at least once every **twelve (12) months** after initial fill, or at least once every **twelve (12) months**

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after the compliance date specified in Special Condition No. B.1. of this Attachment, **and**

- (c) Visually inspect the internal floating roof, the primary seal, the secondary seal, gaskets, slotted membranes, and sleeve seals (if any) each time the vessel is emptied and degassed and at least once every **ten (10 ) years** after the compliance date specified in Special Condition No. B.1. of this Attachment.
  
- ii. If during the inspections required by Special Condition Nos. G.2.a.i.(1)(a) or G.2.a.i.(2)(b) of this Attachment, the internal floating roof is not resting on the surface of the liquid inside the storage tank and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached; or there are holes or tears in the seal fabric; or there are visible gaps between the seal and the wall of the storage tank, the permittee shall repair the items or empty and remove the storage tank from service within **forty-five (45) calendar days**. If a failure that is detected during inspections required by Special Condition Nos. G.2.a.i.(1)(a) or G.2.a.i.(2)(b) of this Attachment cannot be repaired within **forty-five (45) calendar days** and if the tank cannot be emptied within **forty-five (45) calendar days**, the permittee may utilize up to 2 extensions of up to **thirty (30)** additional calendar days each. Documentation of a decision to utilize an extension shall include a description of the failure, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the tank will be emptied as soon as practical.
  
- iii. Except as provided in Special Condition No. G.2.a.iv. of this Attachment, for all the inspections required by Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a), and G.2.a.i.(2)(c) of this Attachment, the permittee shall notify the Department of Health in writing at least **thirty (30) calendar days** prior to the refilling of each storage tank to afford the Department of Health the opportunity to have an observer present.
  
- iv. If the inspections required by Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a), and G.2.a.i.(2)(c) of this Attachment is not planned and the permittee could not have known about the inspection **thirty (30) calendar days** in advance of refilling the tank, the permittee shall notify the Department of Health at least **seven (7) calendar days** prior to the refilling of the storage tank. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, the notification including the written documentation may be made in writing and sent so that it is received by the Department of Health at least **seven (7) calendar days** prior to refilling.
  
- v. If during the inspections required by Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a), and G.2.a.i.(2)(c) of this Attachment, the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or

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the seal fabric; or the gaskets no longer close off the liquid surface from the atmosphere; or the slotted membrane has more than 10 percent open area, the permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage tank with organic HAP.

- b. For Group 1 storage tanks with external floating roofs (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271, 273 and 275), the permittee shall demonstrate compliance by complying with the requirements of 40 CFR §63.120(b)(1) through (b)(10) including the following:
- i. Except as provided in Special Condition No. G.2.b.vii. of this Attachment, the permittee shall determine the gap areas and maximum gap widths between the primary seal and the wall of the storage tank, and the secondary seal and the wall of the storage tank as follows:
- (1) Within **ninety (90) calendar days** of installation of the secondary seal, inspection of both the primary and secondary seals; and
  - (2) At least **once every five (5) years** for the primary seal and at least **once per year** for the secondary seal thereafter.
- ii. Except as provided in Special Condition No. G.2.b.vii. of this Attachment, the permittee shall determine gap widths and gap areas in the primary and secondary seals (seal gaps) individually by the procedures described below:
- (1) Seal gaps, if any, shall be measured at one or more floating roof levels when the roof is not resting on the roof leg supports.
  - (2) Seal gaps, if any shall be measured around the entire circumference of the tank in each place where an 0.32 centimeter (1/8 inch) diameter uniform probe passes freely (without forcing or binding against the seal) between the seal and the wall of the storage tank. The circumferential distance of each such location shall also be measured.
  - (3) The total surface area of each gap described in Special Condition No. G.2.b.ii.(2) of this Attachment shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.
- iii. The permittee shall add the gap surface area of each gap location for the primary seal and divide the sum by the nominal diameter of the tank. The accumulated area of gaps between the tank wall and the primary seal shall not exceed

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212 square centimeters per meter of tank diameter and the width of any portion of any gap shall not exceed 3.81 centimeters (1-1/2 inches).

- iv. The permittee shall add the gap surface area of each gap location for the secondary seal and divide the sum by the nominal diameter of the tank. The accumulated area of the gaps between the tank wall and the secondary seal shall not exceed 21.2 square centimeters per meter of tank diameter and the width of any portion of any gap shall not exceed 1.27 centimeters (1/2 inch). These seal gap requirements may be exceeded during the measurement of primary seal gaps as required by Special Condition No. G.2.b.i. of this Attachment.
- v. The primary seal shall meet the following requirements:
  - (1) Where a metallic shoe seal is in use, one end of the metallic shoe shall extend into the stored liquid and the other end shall extend a minimum vertical distance of 61 centimeters (24 inches) above the stored liquid surface.
  - (2) There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.
- vi. The secondary seal shall meet the following requirements:
  - (1) The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall, except as provided in Special Condition No. G.2.b.iv. of this Attachment.
  - (2) There shall be no holes, tears, or other openings in the seal or seal fabric.
- vii. If the permittee determines that it is unsafe to perform the seal gap measurements required in Special Condition No. G.2.b.i. of this Attachment or to inspect the tank to determine compliance with Special Condition No. G.2.b.v. and G.2.b.vi. of this Attachment because the floating roof appears to be structurally unsound and poses an imminent or potential danger to inspecting personnel, the permittee shall comply with one of the following:
  - (1) The permittee shall measure the seal gaps or inspect the storage tank no later than **thirty (30) calendar days** after the determination that the roof is unsafe, or
  - (2) The permittee shall empty and remove the storage tank from service no later than **forty-five (45) calendar days** after determining that the roof is unsafe. If the tank cannot be emptied within **forty-five (45) calendar days**, the permittee may utilize up to two extensions of up to **thirty (30) additional calendar days** each. Documentation of a decision to utilize an extension

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shall include an explanation of why it was unsafe to perform the inspection or seal gap measurement, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the tank will be emptied as soon as practical.

- viii. The permittee shall repair conditions that do not meet the requirements listed in Special Condition Nos. G.2.b.iii., G.2.b.iv., G.2.b.v. and G.2.b.vi. of this Attachment (i.e., failures), no later than **forty-five (45) calendar days** after identification, or shall empty and remove the storage tank from service no later than **forty-five (45) calendar days** after identification. If during seal gap measurements required in Special Condition No. G.2.b.i. of this Attachment or during inspections necessary to determine compliance with Special Condition Nos. G.2.b.v. and G.2.b.vi. of this Attachment a failure is detected that cannot be repaired within **forty-five (45) calendar days** and if the tank cannot be emptied within **forty-five (45) calendar days**, the permittee may utilize up to two extensions of up to **thirty (30) additional calendar days** each. Documentation of a decision to utilize an extension shall include a description of the failure, shall document that alternative storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the tank will be emptied as soon as practical.
- ix. The permittee shall notify the Department of Health in writing **thirty (30) calendar days** in advance of any gap measurements to afford the Department of Health the opportunity to have an observer present.
- x. The permittee shall visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the tank is emptied and degassed.
  - (1) If the external floating roof has defects; the primary seal has holes, tears or other openings in the seal or seal fabric; or the secondary seal has holes, tears or other openings in the seal or seal fabric; the permittee shall repair the items as necessary so that none of the conditions specified above exist before filling or refilling the storage tank with organic HAP.
  - (2) Except as provided below, for all the inspections required above, the permittee shall notify the Department of Health in writing as least **thirty (30) calendar days** prior to filling or refilling each storage tank with organic HAP to afford the Department of Health the opportunity to inspect the storage tank prior to refilling.
  - (3) If the inspections required above is not planned and the permittee could not have known about the inspection **thirty (30) calendar days** in advance of refilling the tank with organic HAP, the permittee shall notify the Department of Health at least **seven (7) calendar days** prior to refilling of the storage tank. Notification may be made by telephone and immediately followed by

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written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent so that it is received by the Department of Health at least **seven (7) calendar days** prior to the refilling.

- c. For Group 1 storage tanks consisting of an external floating roof converted to an internal floating roofs (petroleum storage tanks 249 and 250)
  - i. The permittee shall keep a record that each inspection required by Special Condition No. G.2.a. of this Attachment was performed.
- d. For Group 1 storage tanks with external floating roofs (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271, 273 and 275)
  - i. The permittee shall keep records describing the results of the seal gap measurements made in accordance with Special Condition No. G.2.b. of this Attachment. The records shall include the date of the measurement, the raw data obtained in the measurement, and the calculations described in Special Condition Nos. G.2.b.iii. and G.2.b.iv. of this Attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.646)<sup>1</sup>

### 3. Notification and Reporting Requirements

- a. The permittee shall submit **semi-annually** written reports to the Department of Health. 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:
  - i. For Group 1 storage tanks consisting of an external floating roof converted to an internal floating roof (petroleum storage tanks 249 and 250)
    - (1) Results of each inspection conducted in accordance with Special Condition No. G.2.a. of this Attachment in which a failure is detected in the control equipment. For storage tanks for which annual inspections are required under Special Condition Nos. G.2.a.i.(1)(a) and G.2.a.i.(2)(b) of this Attachment, the following specifications and requirements apply:
      - (a) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage tank and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage tank.



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- (b) Reports shall include the date of the inspection, identification of each storage tank in which a failure was detected, and a description of the failure. The report shall also describe the nature of and date the repair was made or the date the storage tank was emptied.

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- (c) If an extension is utilized in accordance with Special Condition No. G.2.a.ii. of this Attachment, the permittee shall, in the next semi-annual report, identify the tank; include the documentation specified in Special Condition No. G.2.a.ii. of this Attachment; and describe the date the storage tank was emptied and the nature of and date the repair was made.
- (2) For storage tanks for which inspections are required under Special Condition Nos. G.2.a.i.(1)(b), G.2.a.i.(2)(a) or G.2.a.i.(2)(c) of this Attachment (i.e., internal inspections), the following specifications and requirements apply:
  - (a) A failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or seal fabric; or the secondary seal (if one has been installed) has holes, tears or other openings in the seal or the seal fabric; or, for a storage tank that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage tank that is part of a new source, the slotted membrane has more than a 10 percent open area.
  - (b) The report shall include the date of the inspection, identification of each storage tank in which a failure was detected, and a description of the failure. The report shall also describe the nature of and date the repair was made.
- ii. Group 1 storage tanks with external floating roofs (petroleum storage tanks 104, 105, 106, 107, 108, 109, 110, 111, 113, 162, 163, 232, 233, 235, 236, 237, 251, 252, 253, 254, 255, 256, 257, 258, 262, 264, 265, 266, 269, 271, 273 and 275)
  - (1) Documentation of the results of each seal gap measurement made in accordance with Special Condition No. G.2.b. of this Attachment in which the seal and seal gap requirements of Special Condition Nos. G.2.b.iii., G.2.b.iv., G.2.b.v. or G.2.b.vi. of this Attachment are not met. The documentation shall include the following information:
    - (a) The date of the seal gap measurement;
    - (b) The raw data obtained in the seal gap measurement and the calculations described in Special Condition Nos. G.2.b.iii. and G.2.b.iv. of this Attachment;
    - (c) A description of any seal condition specified in Special Condition Nos. G.2.b.v. or G.2.b.vi. of this Attachment that is not met; and
    - (d) A description of the nature of and date the repair was made, or the date the storage tank was emptied.
  - (2) If an extension is utilized in accordance with Special Condition Nos. G.2.b.vii. or G.2.b.viii. of this Attachment, the permittee shall, in the next semi-annual report, identify the tank; include the documentation specified in Special Condition Nos. G.2.b.vii. or G.2.b.viii. of this Attachment, as applicable; and

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describe the date the tank was emptied and the nature of and date the repair was made.

- (3) Documentation of any failures that are identified during the visual inspections required by Special Condition No. G.2.b.x. of this Attachment.
  - (a) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears or other openings in the seal or the seal fabric.
  - (b) Documentation shall include the date of the inspection, identification of each storage tank in which a failure was detected, and a description of the failure. The nature of and the date the repair was made shall also be documented.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.654)<sup>1</sup>

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<sup>1</sup> The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup> The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.



## APPENDIX D

### 40CFR 64.4 Submittal Requirements

The Compliance Assurance Monitoring (CAM) requirements are applicable to the Chevron cogeneration units, identified as K-6701, K-6702 and K-6703. The units already have existing monitoring devices including, fuel oil and fuel gas non-resetting fuel meters, a continuous monitoring system to record the water-to-fuel ratio and a NO<sub>x</sub> Continuous Emission Monitoring system (CEMS) that serves all three cogeneration units sequentially. Requirements for the operation and maintenance of these systems are already addressed in the existing Covered Source Permit for the refinery. Based on review of 40 CFR 64.4(b)(1), it is anticipated that the NO<sub>x</sub> CEMS is presumptively acceptable to comply with CAM. However, the facility is still required under Section 64.4 Submittal Requirements to provide information to the Hawaii Department of Health and EPA on the monitoring equipment configuration and operation. Since this monitoring equipment has previously been reviewed by the DOH, a brief response to each of the submittal requirements specified in 40 CFR 64.4 is presented below.

64.4(a)(1) – The indicator to be monitored to demonstrate that the water injection control device is working properly is a NO<sub>x</sub> CEMS. This is an appropriate indicator as the concentration of NO<sub>x</sub> would increase and be detected by the CEMS in the event that the control device is not working properly.

64.4(a)(2) – The range of the NO<sub>x</sub> monitor is zero to 100 ppmv. The covered source maximum emissions limits are 67 and 69 ppmvd, depending on the fuel used by the cogeneration turbines. Chevron has previously submitted data to the Department of Health that indicates the typical value NO<sub>x</sub> emissions from the units are compliant with these limits. The range of the monitor is appropriate to demonstrate compliance under all process operating conditions.

64.4(a)(3) The performance criteria for the monitor are specified in 40 CFR 60.13 and 40 CFR 60 Appendix B. The Covered Source Permit already requires that the monitor be operated consistent with these criteria and specifies the frequency for monitoring.

64.4(a)(4) The performance criteria for the monitor is 40 CFR 60.13 and 40 CFR 60 Appendix B. The covered source permit already requires that the monitor be operated consistent with this criteria and specifies the frequency for monitoring.

64.4(b) No further justification for the proposed elements of the monitoring is required, since as specified in 64.4(b)(2) the monitoring is anticipated to be presumptively acceptable.

64.4 (c) The facility has previously provided to the Department of Health operating parameter data obtained during performance tests.

64.4(d) This requirement is not applicable, since operating data have previously been submitted.

64.4(e) The NO<sub>x</sub> CEMS has already been installed and therefore an implementation plan and schedule are not required.

64.4(f) This requirement is not applicable. The control devices are unique to each emission unit and are not a shared device.

64.49(g) This requirement is not applicable, since the emissions units are only controlled by one "control device" which consists of water injection. As noted in the preamble to the CAM rule low-NO<sub>x</sub> burners are not a control device.