ADMINISTRATIVE RECORD

Par Hawaii Refining, LLC

Application No. 0212-60 for Significant Modification

Par East Refinery

Located At: 91-325 Komohana Street, Kapolei, Oahu

CSP No. 0212-01-C

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Public Notice

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

(Docket No. 24-CA-PA-11)

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. 0212-01-C
Application No. 0212-60 for Significant Modification
Par Hawaii Refining, LLC
Par East Refinery
Located At: 91-325 Komohana Street, Kapolei, Oahu

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

The applicant is proposing to construct and operate a renewable fuel production facility at the existing petroleum refinery. The renewable fuel production facility will process treated renewable feedstocks into renewable biofuels including renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (Renewable LPG). The refinery plans to redesign and repurpose the existing Diesel Hydrotreater (DHT) and convert it into a Renewable Hydrotreater (RHT). The RHT will have a capacity of 4,000 barrels per day (BPD) and be able to flex between maximum SAF and RD mode depending on the market environment for each of those products. This project also includes the construction of a renewable feedstock pretreatment unit (PTU) with a capacity of 5,000 BPD to treat the renewable feedstock prior to processing in the RHT and a new high-pressure (700 psia) steam generating package boiler. This permit, if issued, will supersede CSP No. 0212-01-C issued on May 13, 2021, and amended on June 30, 2021, in its entirety. 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 J:	Standards of Performance for Petroleum Refineries (applies to the Hydrogen Reformer Furnace, ID No. H2001)
Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (applies to the Package Boiler, ID No. F5205)
Subpart Ja:	Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (applies to the Package Boiler, ID No. F5205 and RHT Feed Heater, ID No. H3701)
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 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 §60.481a of 40 CFR Part 60, Subpart VVa, at the RHT and the RHT Compressor (C3701))

Subpart QQQ: Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (applies to 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, at the RHT)

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 all benzene-containing hazardous waste streams at hazardous waste treatment, storage, and disposal facilities at the RHT)

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 all Petroleum Storage Tanks and 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 at the RHT)

Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters (applies to the Hydrogen Reformer Furnace, ID No. H2001, Package Boiler, ID No. SG1102, Package Boiler, ID No. SG1103, Package Boiler, ID No. F5205, RHT Feed Heater, ID No. H3701)

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

The emissions from the renewable fuel production facility are as follows:

RENEWABLE FUEL PRODUCTION FACILITY EMISSIONS[1]

Pollutant	New F5205 Boiler, Fugitives & Increased Utilization of Existing Sources (H3701, H2001, & HGU[2]) (tpy)	PSD Significant Levels (tpy)
CO	55.53	100
H_2S	0.03	10
Pb	0.0008	0.6
NO_X	35.79	40
SO_2	20.01	40
VOC	2.65	40
PM_{Total}	4.16	25
PM_{10}	4.16	15
$PM_{2.5}$	4.16	10
Fluorides	0.01	3
Sulfuric Acid Mist	0.28	7
Total Reduced Sulfur	0.10	10
GHG (CO_2e)[3]	113,757	75,000

[1]Proposed PTE – Baseline Actual
[2]GHG emissions associated with increased feed to and utilization of the HGU are not considered in PSD applicability.
[3]Per 40 CFR §52.21(b)(49)(iv)(b), pollutant GHG's are not subject to PSD regulation if there is not an increase of a regulated NSR pollutant

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 August 31, 2024.

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 (30) 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.

Kenneth S. Fink, MD, MGA, MPH
Director of Health

Draft Permit

DRAFT

JOSH GREEN, M.D.
GOVERNOR OF HAWAIʻI
KE KIAʻĀINA O KA MOKUʻĀINA ʻO HAWAIʻI

KENNETH S. FINK, MD, MGA, MPH
DIRECTOR OF HEALTH
KA LUNA HOʻOKELE

STATE OF HAWAII
DEPARTMENT OF HEALTH
KA ʻOIHANA OLAKINO
P.O. Box 3378
HONOLULU, HAWAII 96801-3378

CERTIFIED MAIL
RETURN RECEIPT REQUESTED
(0000 0000 0000 0000 0000)

In reply, please refer to:
File:

24-xxxE CAB
File No. 0212-01

Issuance Date

Mr. Deaglan McClean
Vice President
Par Hawaii Refining, LLC
91-325 Komohana Street
Kapolei, Hawaii 96707-1713

Dear Mr. McClean:

SUBJECT: Covered Source Permit (CSP) No. 0212-01-C
Significant Modification Application No. 0212-60
Par Hawaii Refining, LLC
Par East Refinery
Located At: 91-325 Komohana Street, Kapolei, Island of Oahu
Date of Expiration: May 12, 2026

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 the plans and specifications that you submitted as part of your significant modification application dated December 8. 2023, revised application dated March 20, 2024, and additional information dated May 2, 2024 and May16, 2024. This permit shall supersede CSP No. 0212-01-C issued on May 13, 2021 and amended on June 30, 2021, in its entirety.

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

Attachment I: Standard Conditions
Attachment II(A): Special Conditions - Crude Distillation Unit
Attachment II(B): Special Conditions - Naphtha Hydrotreater and Catalytic Reformer Unit
Attachment II(C): Special Conditions - Vacuum Distillation Unit
Attachment II(D): Special Conditions - Distillate Hydrocracker Unit
Attachment II(E): Special Conditions - Asphalt Heating and Loading
Attachment II(F): Special Conditions - Visbreaker Unit
Attachment II(G): Special Conditions - Hydrogen Generation Unit
Attachment II(H): Special Conditions - Sulfur Recovery Plant
Attachment II(I): Special Conditions - Cogeneration Gas Turbine and Boilers
Attachment II(J): Special Conditions - Wastewater Treatment Unit
Attachment II(K): Special Conditions - Mercaptan Treatment Units
Attachment II(L): Special Conditions – Flare
Attachment II(M): Special Conditions - Petroleum Storage Tanks
Attachment II(N): Special Conditions - Propane Load Rack and Cylinder Filling Station
Attachment II(O): Special Conditions – Renewable Fuel Production Facility
Attachment II(P): Special Conditions - Air Compressor Engines
Attachment II(Q): Special Conditions - Miscellaneous Process Units and Auxiliary Equipment

Attachment II (INSIG): Special Conditions – Insignificant Activities
Attachment II (GHG): Special Conditions – GHG Reduction Requirements
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: Fuel Consumption - Heaters
Monitoring Report Form: Fuel Consumption - Package Boilers and Process Heaters
Monitoring Report Form: Opacity Exceedances
Monitoring Report Form: Propane Load Rack and Cylinder Filling Station
Monitoring Report Form: Fuel Certification
Monitoring Report Form: GHG Emissions
Annual Emissions Report Form: External/Internal Floating Roof Petroleum Storage Tank
Annual Emissions Report Form: Fixed Roof Petroleum Storage Tank
Annual Emissions Report Form: Refinery Equipment - Fuel Consumption
Annual Emissions Report Form: Refinery Equipment - Process Rate
Excess Emission and Monitoring System Performance Summary Report

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

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, please contact Mr. Darin Lum of the Clean Air Branch at (808) 586-4200.

Sincerely,

JOANNA L. SETO, P.E., CHIEF
Environmental Management Division

DL:tkg

Enclosures

ATTACHMENT I: STANDARD CONDITIONS
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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)[2]

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)[2]

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 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 of 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 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)[2]

17. **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)[2]

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)[2]

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))[1]

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 of Health 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)

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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 II(A): SPECIAL CONDITIONS
CRUDE DISTILLATION UNIT
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date:** **May 12, 2026**

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 of the Crude Distillation Unit (CDU):

   a. Crude Heater No. 1, ID No. H101A

      i. 154 MMBtu/hr heat input; and
      ii. Equipped with combustion air preheater.

   b. Crude Heater No. 2, ID No. H101B

      i. 144 MMBtu/hr heat input; and
      ii. Equipped with combustion air preheater.

   c. Stabilizer Heater No. 1, ID No. H102A

      i. 18 MMBtu/hr heat input.

   d. Stabilizer Heater No. 2, ID No. H102B

      i. 8 MMBtu/hr heat input.

   e. Total Acid Number (TAN) Corrosion Inhibitor System

      i. Consists of one (1) 450-gallon storage tote; and
      ii. Contains Corrosion Inhibitor (with a hazardous air pollutant (HAP) content greater than two (2) percent).

   (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 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)

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<u>Section B</u>. <u>Applicable Federal Regulations</u>

1. The Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), Stabilizer Heater No. 1 (H102A), and Stabilizer Heater No. 2 (H102B) are 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 (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.

   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, §11-60.1-174; 40 CFR §60.1, §60.100, §63.1, §63.7485)[1]

2. The TAN Corrosion Inhibitor System storage tote is 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 §63.1, §63.640)[1]

Section C. Operational and Emission Limitations

1. Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), and Stabilizer Heater No. 1 (H102A), shall be fired only on refinery fuel gas (RFG) with a hydrogen sulfide (H_2S) content not to exceed 230 mg/dscm (0.10 gr/dscf, 162 ppm) and a total sulfur (TS) content not to exceed 258 parts per million (ppm) or liquid fuel with a maximum sulfur content not to exceed 0.5% by weight or a combination of both fuels. Stabilizer heater No. 2 (H102B) shall be fired only on RFG with a H_2S content not to exceed 230 mg/dscm (0.10 gr/dscf, 162 ppm) and a TS content not to exceed 258 ppm. The 0.5% liquid fuel sulfur limit is based on a thirty-day (30-day) rolling average basis.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-38, §11-60.1-90, §11-60.1-161; 40 CFR §60.104)[1]

2. MACT Subpart DDDDD Maximum Emission Limits

   The permittee shall not discharge or cause the discharge into the atmosphere from the Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), and Stabilizer Heater No. 1 (H102A), carbon monoxide (CO), filterable particulate matter (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_2
Filterable PM	0.22 lb/MMBtu
HCl	1.1E-03 lb/MMBtu
Mercury	7.3E-07 lb/MMBtu

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7500)[1]

3. Visible Emissions (VE)

   For any six (6) minute averaging period, the crude heaters and stabilizer heaters shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the crude heaters and stabilizer heaters 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)[2]

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4. Tune-Ups

The permittee shall conduct initial tune-ups of the Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), Stabilizer Heater No. 1 (H102A), and Stabilizer Heater No. 2 (H102B) no later than January 31, 2016, and shall conduct a tune-up of the Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), and Stabilizer Heater No. 1 (H102A) annually, and Stabilizer Heater No. 2 (H102B) 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 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. 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 (NO_x) requirement to which the unit is subject;
e. Measure the concentrations in the effluent stream of CO in ppm by volume and oxygen (O_2) 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 O_2 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)[1])

5. Energy Assessment

The permittee shall have a one-time energy assessment performed for the Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), Stabilizer Heater No. 1 (H102A), and Stabilizer Heater No. 2 (H102B) 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)[1]

Section D. Monitoring and Recordkeeping Requirements

1. Continuous Monitoring System (CMS) for H_2S

a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), Stabilizer Heater No. 1 (H102A), and Stabilizer Heater No. 2 (H102B).

b. The CMS shall meet the following requirements:

i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S.

ii. All fuel gas combustion devices, including Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), Stabilizer Heater No. 1 (H102A), and Stabilizer Heater No. 2 (H102B), having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned.

iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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 shall be used in conducting any relative accuracy test audit (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_2S CMS, RATAs 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.

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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)[1]

2. Sulfur Content in the Fuel

a. The sulfur content of the liquid fuel shall be sampled at least five (5) days per week and tested in accordance with the most current American Society for Testing and Materials (ASTM) Methods D129, D2622, D4294, or D5453, or other test methodologies with prior written approval from the Department. Unless Tank 1103 is taken out of service for repairs or regulatory required inspections, liquid fuel samples shall be taken from the pump/circulation loop of Tank 1103.
b. Compliance, on a continuous basis, with the TS limit specified in Special Condition No. C.1 of this attachment shall be determined by TS analysis in the RFG using ASTM Methods D5504-94, D5453-93, or other methods approved by the Department. A representative sample of the RFG shall be analyzed a minimum of twice a month to ensure continuing compliance. Records of the TS content of the RFG shall be maintained on a monthly basis. Compliance with the TS standard shall be determined by averaging the analytical results obtained throughout the month.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §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.2 of this attachment for Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), and Stabilizer Heater No. 1 (H102A) 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 your process heater. 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 monthly 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 process heaters 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 process heaters 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)[1]

4. Visible Emissions (VE)

The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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 §11-60-15, §11-60-24)[2]

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)[1]

6. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) upon request.

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

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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 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 Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), Stabilizer Heater No. 1 (H102A), and Stabilizer Heater No. 2 (H102B). 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 (CEMS) 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 CEMS operated properly during the period and was not subject to any repairs or adjustments except zero and span checks; and
      v. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices.

   b. All reports shall be postmarked by the **thirtieth** (**30th) 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 any rolling three-hour (3-hour) period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 230 mg/dscm (0.10 gr/dscf).
   d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission and concentration limits for the purposes of the 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)[1]

2. 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** or an equivalent form 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)[2]

3. 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 HAPs. 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; 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. 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 which the excursion or exceedances 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 the 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) days 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 (SPT) 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)[1]

8. MACT Subpart DDDDD Reporting

The permittee shall comply with the reporting requirements per 40 CFR §63.7550 for the Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), Stabilizer Heater No. 1 (H102A), and Stabilizer Heater No. 2 (H102B). The reports shall be submitted to the Department and U.S. EPA, Region 9.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7550)[1]

Section F. Testing Requirements

1. On an annual basis, the permittee shall conduct SPTs to determine emissions of CO and filterable PM from Crude Heater No. 1 (H101A), Crude Heater No. 2 (H101B), and Stabilizer Heater No. 1 (H102A) 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 process heaters, 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 individual process heater 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-year (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)[1]

2. Performance tests for the emissions of CO shall be conducted using EPA Methods 1-4 and 10. Performance tests for the emissions of filterable PM shall be conducted using EPA Methods 1-4 and Method 5 or 17. In lieu of the above mentioned test methods, EPA-approved equivalent methods with prior written approval from the Department may be used.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.7510)[1]

3. The 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)

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. **At least sixty (60) days prior** *to performing a test*, the permittee shall submit a written *performance test plan* to the Department and 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, §11-60.1-174; 40 CFR §63.7)[1]

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

7. **Within sixty (60) days after** *completion of the performance test*, the permittee shall submit to the Department and U.S. EPA, Region 9 the test report which shall include the operating conditions of the process heater, 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)[1]

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8. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual SPT. 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 SPT.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7)[1]

9. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S 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)[1]

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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[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 II(B): SPECIAL CONDITIONS
NAPHTHA HYDROTREATER AND CATALYTIC REFORMER UNIT
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: <u>May 12, 2026</u>**

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 of the Naphtha Hydrotreater (NHT) and Catalytic Reformer Unit (CRU):

   a. Naphtha Hydrotreater Charge Heater, ID No. H401:

      i. 26 MMBtu/hr heat input.

   b. Naphtha Hydrotreater Reboiler, ID No. H402:

      i. 17 MMBtu/hr heat input.

   c. Catalytic Reformer Charge Heater, ID No. H501:

      i. 80.4 MMBtu/hr heat input; and
      ii. Equipped with a combustion air preheater and flue gas recirculation.

   d. Interheater, ID No. H502:

      i. 74 MMBtu/hr heat input; and
      ii Equipped with a combustion air preheater and flue gas recirculation.

   e. Interheater, ID No. H503:

      i. 36.3 MMBtu/hr heat input; and
      ii Equipped with a combustion air preheater and flue gas recirculation.

   f. Interheater, ID No. H504:

      i. 18.4 MMBtu/hr heat input; and
      ii. Equipped with a combustion air preheater and flue gas recirculation.

   g. Methanol Storage Tote:

      i. Vertical Fixed Roof Storage Tote; and
      ii. 350 gallons capacity.

h. Catalytic Regeneration Process Vent D501 – Internal Scrubbing System during regeneration (Low Pressure Separator during normal operation).

(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 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 NHT Charge Heater H401, NHT Reboiler H402, Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504 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.

   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, §11-60.1-174; 40 CFR §60.1, §60.100; §63.1, §63.7485)[1]

2. The Catalytic Regeneration Process Vent D501 from the CRU is 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 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, §11-60.1-174; 40 CFR §63.1, §63.1560)[1]

3. The methanol storage tote is 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 §63.1, §63.640)[1]

<u>Section C</u>. <u>Operational and Emission Limitations</u>

1. The NHT Charge Heater H401 and NHT Reboiler H402 shall be fired only on RFG with a H_2S content not to exceed 230 mg/dscm (0.10 gr/dscf, 162 ppm). Catalytic Reformer Charge Heaters/Interheaters H501, H502, H503, and H504 shall be fired only on RFG with a H_2S content not to exceed 230 mg/dscm (0.10 gr/dscf, 162 ppm) or liquid fuel with a maximum sulfur and nitrogen content not to exceed 0.5% by weight or a combination of both fuels. The 0.5% liquid fuel sulfur limit is based on a thirty-day (30-day) rolling average basis. The total of all sulfur compounds in the RFG shall not exceed the TS equivalent of 258 ppm

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1- 38, §11-60.1-90, §11-60.1-161; 40 CFR §60.104)[1]

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2. Visible Emissions (VE)

   For any six (6) minute averaging period, the NHT Charge Heater H401, the NHT Reboiler H402, and Catalytic Reformer Charge Heaters/Interheaters H501, H502, H503, and H504 shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, these equipment 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)[2]

3. During depressurization and purging operations, emissions from Process Vent D501 are routed to the flare, and are subject to Attachment II(L) of this permit.

   (Auth.: HAR §11-60.1-3; 40 CFR §63.1, §63.1566)[1]

4. During coke burn-off and catalyst regeneration, uncontrolled emissions of HCl shall be reduced to a concentration of 30 ppm by volume (dry basis), corrected to three (3) percent O_2 on a daily average basis.

   (Auth.: HAR §11-60.1-3; 40 CFR §63.1, §63.1567)[1]

5. At all times, the permittee shall follow the procedures set forth in the Operation, Maintenance, and Monitoring Plan (OMMP) for the CRU that was developed pursuant to 40 CFR §63.1574(f) and submitted to the Department.

   (Auth.: HAR §11-60.1-3; 40 CFR §63.1, §63.1566, §63.1567)[1]

6. The combined firing rate of Catalytic Reformer Charge Heaters/Interheaters H501, H502, H503, and H504 on both liquid and gaseous fuel shall not exceed 209.1 MMBtu/hr (HHV) based on a rolling twelve-month (12-month) average.

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

7. Catalytic Reformer Charge Heaters/Interheaters H501, H502, H503, and H504 shall be equipped with a flue gas recirculation system for the control of NO_x emissions.

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

8. Maximum Emission Limits

   Catalytic Reformer Charge Heaters/Interheaters H501, H502, H503, and H504 shall not discharge into the atmosphere emissions of the following:

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Emission Limits for NO_X (as NO_2)

Forced Draft mode, 130 ppm at 0% excess O_2 on a thirty-day (30-day) rolling average (short term) when fired on RFG only.

Force Draft mode, 125 ppm at 0% excess O_2 on a 365-day rolling average (long term) when fired on RFG and liquid fuel.

Natural Draft mode, 150 ppm at 0% excess O_2 on a seven-day (7-day) rolling average when fired on RFG and liquid fuel.

(Auth.: HAR §11-60.1-3, §11-60.1-90, CD 5:16-cv-00722)

9. MACT Subpart DDDDD Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504, 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_2
Filterable PM	0.22 lb/MMBtu
HCl	1.1E-03 lb/MMBtu
Mercury	7.3E-07 lb/MMBtu

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7500)[1]

10. Tune-Ups

The permittee shall conduct initial tune-ups of the NHT Charge Heater H401, NHT Reboiler H402, Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504 no later than January 31, 2016, and shall conduct tune-ups of the NHT Charge Heater H401, NHT Reboiler H402, Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504 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:

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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 NO_x requirement to which the unit is subject;
e. Measure the concentrations in the effluent stream of CO in ppm by volume and O_2 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 O_2 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)[1])

11. Energy Assessment

The permittee shall have a one-time energy assessment performed for the NHT Charge Heater H401, NHT Reboiler H402, Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504 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)[1]

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Section D. Monitoring and Recordkeeping Requirements

1. Continuous Monitoring System for H_2S

   a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in the NHT Charge Heater H401, NHT Reboiler H402, Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504.

   b. The CMS shall meet the following requirements:

      i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S.
      ii. All fuel gas combustion devices, including the NHT Charge Heater H401, NHT Reboiler H402, Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned.
      iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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 shall be used in conducting any RATA.
      iv. 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_2S CMS, RATAs 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. 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)[1]

2. Continuous Emissions Monitoring System for NO_x

   a. The permittee shall operate and maintain a CEMS for continuously monitoring and recording the concentration by volume (dry basis) of NO_x emissions from the Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504.

b. The CEMS shall meet the following requirements:

   i. Performance evaluations for the NO_x CEMS shall be in accordance with 40 CFR §60.13. The NO_x CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 2, Specifications and Test Procedures for SO_2 and NO_X 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.
   ii. 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 NO_x CEMS, RATAs need not be performed on an annual basis, unless requested by the Department; or there is a significant change or performance deficiency of the CEMS.
   iii. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.
   iv. Emissions from the Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504 may be monitored at the common (North and South) stack.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, PS-2)[1]

3. Continuous Monitoring System for O_2

   a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration by volume (dry basis) of O_2 emissions from the Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504.
   b. The CMS shall meet the following requirements:

      i. Performance evaluations for the O_2 CMS shall be in accordance with 40 CFR §60.13. The O_2 CMS shall meet 40 CFR Part 60,Appendix B, Performance Specification 3, Specifications and Test Procedures for O_2 and CO_2 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.
      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.
      iv. Emissions from the Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504 may be monitored at the common (North and South) stack.

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

4. Sulfur and Nitrogen Content and Higher Heating Value (HHV) of the Fuel

   a. The sulfur content of the liquid fuel to be fired shall be tested in accordance with the most current ASTM Methods D129, D2622, D4294, or D5453, or other test methodologies with prior written approval from the Department. The liquid fuel sulfur content shall be verified by having a representative sample of liquid fuel analyzed for sulfur content by weight at least five (5) days per week. Unless Tank 1103 is taken out of service for repairs or regulatory required inspections, liquid fuel samples shall be taken from the pump/circulation loop of Tank 1103. Compliance with the sulfur standard shall be determined by averaging the analytical results obtained throughout the month.
   b. The nitrogen content of the liquid fuel to be fired shall be tested in accordance with the most current version of ASTM Method D5762 or other test methodologies with prior written approval from the Department. The liquid fuel nitrogen content shall be verified by having a representative sample of liquid fuel analyzed for nitrogen content by weight at least twice per **month**. Compliance with the nitrogen standard shall be determined by averaging the analytical results obtained throughout the month.
   c. The higher or gross heating value of the liquid fuel to be fired shall be tested in accordance with the most current version of ASTM Method D4868-00 or D240-02 or other test methodologies with prior written approval from the Department. The liquid fuel HHV content shall be verified by having a representative sample of fuel oil analyzed for HHV at least twice per **month**.
   d. The TS content of the RFG to be fired shall be tested in accordance with the most current version of ASTM Method D5504-94, D5453-93, or other test methodologies with prior written approval from the Department. A representative sample of the RFG shall be taken and analyzed for the TS content by weight at least twice per **month**. Compliance with the TS standard shall be determined by averaging the analytical results obtained throughout the month.
   e. The HHV of the RFG to be fired shall be tested using gas chromatography (ASTM Methods D2504, D2597, and/or D2163), and calculated according to ASTM Method D2598, or other test methodologies with prior written approval from the Department. The HHV of the RFG shall be verified by having a representative sample of the RFG analyzed for HHV at least twice per **month**.

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

5. Liquid Fuel Chlorine and Mercury Monitoring

   The permittee shall demonstrate compliance with the mercury or HCl emission limits in Special Condition No. C.9 of this attachment for the Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504 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

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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 your process heater. 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 monthly 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-day (14-day) restriction does not apply.

a. The chlorine content of the liquid fuel for the process heaters 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 process heaters 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)[1]

6. During coke burn-off and catalyst rejuvenation, a colorimetric tube sampling system shall be used to measure the HCl concentration in the catalyst regenerator exhaust gas. The colorimetric tube sampling system must meet the requirements of 40 CFR §63.1572(c)(1).

   (Auth.: HAR §11-60.1-3; 40 CFR §63.1, §63.1567)[1]

7. Visible Emissions (VE)

   The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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 §11-60-15, §11-60-24)[2]

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8. 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)[1]

9. The permittee shall operate and maintain (either individual or collective) non-resetting fuel meters to record the amount of RFG and liquid fuel fired in the Catalytic Reformer Charge Heaters/Interheaters H501, H502, H503, and H504. The non-resetting meters shall not allow the manual resetting or other manual adjustment 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, §11-60.1-90)[1]

10. The permittee shall keep readily accessible records showing the dimensions of the methanol storage tote and an analysis showing the capacity of the storage tank. This record shall be kept as long as the storage tank retains 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 four (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 2 storage vessel definitions in 40 CFR §63.641.

    (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §63.646, §63.654)[1]

11. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) 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 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 NHT Charge Heater H401, NHT Reboiler H402, Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504. 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 CEMS 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 CEMS operated properly during the period and was not subject to any repairs or adjustments except zero and span checks; and
v. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices.

b. All reports shall be postmarked by the **thirtieth (30th) 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 any:

i. Rolling three-hour (3-hour) period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 230 mg/dscm (0.10 gr/dscf) or 162 ppm.
ii. Thirty-day (30-day) operating period during which the average concentration of NO_x in the flue gas from the Catalytic Reformer Charge Heaters/Interheaters H501, H502, H503, and H504 exceeds 130 ppm at 0% excess O_2.
iii. 365-day operating period during which the average concentration of NO_x in the flue gas from the Catalytic Reformer Charge Heaters/Interheaters H501, H502, H503, and H504 exceeds 125 ppm at 0% excess O_2.
iv. Seven-day (7-day) operating period during which the average concentration of NO_x in the flue gas from the Catalytic Reformer Charge Heaters/Interheaters H501, H502, H503, and H504 exceeds 150 ppm at 0% excess O_2.

d. Excess emissions indicated by the CEMS shall be considered violations of the applicable emission and concentration limits for the purposes of the 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)[1]

2. 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** or an equivalent form shall be used.

   b. Any fuel analysis conducted by the permittee or permittee's laboratory during the reporting period showing the TS content of the RFG and the sulfur and nitrogen content of the liquid fuel, along with the monthly averages.
   c. Any fuel analysis conducted by the permittee or permittee's laboratory during the reporting period showing the HHV of the RFG and gross or HHV of the liquid fuel, along with the monthly averages.
   d. Any other laboratory data such as API gravity which may be necessary to accurately calculate a firing rate based the meters that are used to measure the gaseous and liquid firing rate.
   e. The average aggregated firing rate for all four (4) of the Catalytic Reformer Charge Heaters/Interheaters H501, H502, H503, and H504 in MMBtu/hr (HHV) on a monthly and rolling twelve-month (12-month) basis. The basis for that calculation including fuel rates and heating values shall be clearly defined and reported.
   f. Any periods during which required fuel meters were malfunctioning, being maintained or otherwise unavailable shall be reported.
   g. Any deviations from permit requirements shall be clearly identified.

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

3. 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 HAPs. 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; 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. 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 which the excursion or exceedances 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 the 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) days 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 SPT 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)[1]

8. MACT Subpart DDDDD Reporting

The permittee shall comply with the reporting requirements per 40 CFR §63.7550 for the NHT Charge Heater H401, NHT Reboiler H402, Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504. The reports shall be submitted to the Department and U.S. EPA, Region 9.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7550)[1]

Section F. Testing Requirements

1. On an annual basis, the permittee shall conduct SPTs to determine emissions of CO and filterable PM from the Catalytic Reformer Charge Heater H501, Interheater H502, Interheater H503, and Interheater H504 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 process heaters, 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 individual process heater 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-year (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)[1]

2. Performance tests for the emissions of CO shall be conducted using EPA Methods 1-4 and 10. Performance tests for the emissions of filterable PM shall be conducted using EPA Methods 1-4 and Method 5 or 17. In lieu of the above mentioned test methods, EPA-approved equivalent methods with prior written approval from the Department may be used.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.7510)[1]

3. The 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)

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)

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5. **At least sixty (60) days prior** *to performing a test*, the permittee shall submit a written *performance test plan* to the Department and 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, §11-60.1-174; 40 CFR §63.7)[1]

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

7. **Within sixty (60) days after** *completion of the performance test*, the permittee shall submit to the Department and U.S. EPA, Region 9 the test report which shall include the operating conditions of the process heater, 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)[1]

8. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual SPT. 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 SPT.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7)[1]

9. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S 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)[1]

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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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[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 II(C): SPECIAL CONDITIONS
VACUUM DISTILLATION UNIT
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 of the Vacuum Distillation Unit (VDU):

   a. Vacuum Unit Charge Heater, ID No. H175

      i. 86 MMBtu/hr heat input; and
      ii. Equipped with a combustion air preheater.

   b. Vacuum Distillation Tower, ID No. T175

      i. VDU off-gas vent (D-177).

   c. TAN Corrosion Inhibitor System

      i. Consists of one (1) 450-gallon storage tote; and
      ii. Contains Corrosion Inhibitor (with a HAP content of greater than two (2) percent).

   (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 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 Vacuum Unit Charge Heater H175 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 (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.

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, §11-60.1-174; 40 CFR §60.1, §60.100, §63.1, §63.7485)[1]

2. The VDU off-gas vent and the TAN Corrosion Inhibitor System storage tote 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 §63.1, §63.640)[1]

3. This CSP contains conditional requirements from an existing permit issued pursuant to 40 CFR Part 52.21, Prevention of Significant Deterioration (PSD) of Air Quality.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-132)

Section C. Operational and Emission Limitations

1. The Vacuum Unit Charge Heater H175 shall be fired only on RFG with a H_2S content not to exceed 230 mg/dscm (0.10 gr/dscf, 162 ppm) and with a TS content not to exceed 258 ppm.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-38, §11-60.1-90, §11-60.1-161; 40 CFR §60.104)[1]

2. Firing Rate Limit

   On a monthly average basis, the firing rate on gaseous fuel expressed of the Vacuum Unit Charge Heater H175 shall not exceed the heat input capacity of 86 MMBtu/hr (HHV).

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

3. Ultra-Low NO_x Burners

   The permittee shall operate and maintain ultra-low NO_x burners in the Vacuum Unit Charge Heater H175.

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

4. Maximum Emission Limits

   The permittee shall not discharge or cause the discharge into the atmosphere from the Vacuum Unit Charge Heater H175 emissions of NO_x in excess of 50.0 ppmvd @ 0% excess O_2 (three-hour (3-hour) block average).

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

5. Visible Emissions (VE)

   For any six (6) minute averaging period, the Vacuum Unit Charge Heater H175 shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the vacuum unit charge heater 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)[2]

6. Vapor Collection System for Vacuum Tower

   The permittee shall operate and maintain an operable vapor collection system for the vacuum distillation tower. All gaseous emissions from the tower shall be collected and used as fuel or flared. When the process vent from the vacuum unit is not being recovered and used as a fuel, it shall be routed to a flare that meets the requirements of 40 CFR §63.11.

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

7. Vapor Collection System for Process Vessel Turn-arounds

All volatile organic compounds (VOC) emissions from any pressurized process vessel designated in this attachment which occur during depressurization of such vessel, and which would otherwise be emitted to the atmosphere, shall be collected and used for fuel or flared until the pressure in the vessel is below five (5) pounds per square inch (psi), gauge. Residual liquids, to the extent possible will be pumped out of the vessel to tankage for reprocessing.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

8. Tune-Ups

The permittee shall conduct initial tune-ups of the Vacuum Unit Charge Heater H175 no later than January 31, 2016, and shall conduct tune-ups of the Vacuum Unit Charge Heater H175 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 NO_x requirement to which the unit is subject;
e. Measure the concentrations in the effluent stream of CO in ppm by volume and O_2 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 O_2 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)[1])

9. Energy Assessment

The permittee shall have a one-time energy assessment performed for the Vacuum Unit Charge Heater H175 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)[1]

Section D. Monitoring and Recordkeeping Requirements

1. The permittee shall operate and maintain a fuel meter to record the amount of RFG fired in the Vacuum Unit Charge Heater H175. The permittee shall record the amount of RFG in MSCF/day fired by the Vacuum Unit Charge Heater H175 on a monthly basis.

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

2. Continuous Monitoring System

a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in the Vacuum Unit Charge Heater H175.

b. The CMS shall meet the following requirements:

i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S;
ii. All fuel gas combustion devices, including the Vacuum Unit Charge Heater H175 having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned;

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iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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 shall be used in conducting any RATA;

iv. 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_2S CMS, RATAs 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; and

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, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, PS-7)[1]

3. Sulfur Content and Higher Heating Value of the Fuel

a. Compliance, on a continuous basis, with the TS limit specified in Special Condition No. C.1 of this attachment shall be determined by TS analysis in the RFG using ASTM Methods D5504-94, D5453-93, or other methods approved by the Department. A representative sample of the RFG shall be analyzed a minimum of twice a **month** to ensure continuing compliance. Records of the TS content of the RFG shall be maintained on a **monthly** basis. Compliance with the TS standard shall be determined by averaging the analytical results obtained throughout the month.

b. The HHV of the RFG to be fired shall be tested using gas chromatography (ASTM Methods D2504 and/or D2163), and calculated according to ASTM Method D2598 or by alternative methods as authorized by the Department. The RFG HHV content shall be verified by having a representative sample of the RFG analyzed for HHV at least twice per **month**. Records of the HHV of the RFG shall be maintained on a **monthly** basis.

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

4. Visible Emissions (VE)

The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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 §11-60-15, §11-60-24)[2]

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)[1]

6. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) 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 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 Vacuum Unit Charge Heater H175. 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 CEMS 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 CEMS operated properly during the period and was not subject to any repairs or adjustments except zero and span checks; and
      v. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices.

b. All reports shall be postmarked by the **thirtieth (30th) 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 any rolling three-hour (3-hour) period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 230 mg/dscm (0.10 gr/dscf, 162 ppm) or any during which the TS content of the RFG exceeds 258 ppm.

d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission and concentration limits for the purposes of the 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)[1]

2. 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** or an equivalent form shall be used.

   b. Any fuel analysis conducted by the permittee or permittee's laboratory during the reporting period showing the following:

      i. The average monthly TS content for each month of the RFG; and
      ii. The average monthly HHV for each month of the RFG.

   c. The average fuel consumption rate of RFG (MSCF/day) and the average HHV firing rate (MMBtu/hr) of the Vacuum Unit Charge Heater H175 on a monthly basis. The enclosed **Monitoring Report Form: Fuel Consumption - Heaters** or an equivalent form 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, SIP §11-60-24)[2]

3. 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 HAPs. 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 Condition 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; 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. 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 which the excursion or exceedances 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 the 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) days 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 SPT 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)[1]

8. MACT Subpart DDDDD Reporting

   The permittee shall comply with the reporting requirements per 40 CFR §63.7550 for the Vacuum Unit Charge Heater H175. The reports shall be submitted to the Department and U.S. EPA, Region 9.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7550)[1]

Section F. Testing Requirements

1. The permittee shall conduct or cause to be conducted performance tests on the Vacuum Unit Charge Heater H175. Performance tests shall be conducted for nitrogen oxides (NO_x as NO_2) on the basis of concentration and mass rate. All performance tests shall be conducted at the maximum expected operating capacity of the vacuum unit charge heater 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)

2. Performance tests for the emissions of NO_x shall be conducted using EPA Methods 1 to 4, 7 or 7E, and/or 19, 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)

3. The 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)

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. **At least thirty (30) days prior** *to performing a test*, the permittee shall submit a written *performance test plan* to the Department 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)

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

7. **Within sixty (60) days after** *completion of the performance test*, the permittee shall submit to the Department and U.S. EPA, Region 9 (Attention: AIR-3), the test report which shall include the operating conditions of the vacuum unit charge heater at the time of the test, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

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

8. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S 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)

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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[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 II(D): SPECIAL CONDITIONS
DISTILLATE HYDROCRACKER UNIT
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 of the Distillate Hydrocracker Unit (DHC):

   a. Hydrocracker Second Stage Charge Heater, ID No. H601

      i. 40 MMBtu/hr heat input.

   b. Hydrocracker Fractionator Inlet Heater, ID No. H602

      i. 77 MMBtu/hr heat input.

   c. Hydrocracker First Stage Charge Heater, ID No. H603

      i. 76 MMBtu/hr heat input.

   (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 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 Hydrocracker Second Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, and Hydrocracker First Stage Charge Heater H603 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.

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, §11-60.1-174; 40 CFR §60.1, §60.100, §63.1, §63.7485) [1]

2. The hydrocracker fractionator inlet heater H602 also serves as a control device for the LPG merox vent which is classified as a Group 2 Miscellaneous Process Vent. As a result, the H602 heater is subject to control device 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 §63.1, §63.640, §63.643)[1]

3. This CSP contains conditional requirements from an existing permit issued pursuant to 40 CFR Part 52.21, Prevention of Significant Deterioration of Air Quality.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-132)

<u>Section C.</u> <u>Operational and Emission Limitations</u>

1. The Hydrocracker Second Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, and Hydrocracker First Stage Charge Heater H603 shall be fired only on RFG with a H_2S content not to exceed 230 mg/dscm (0.10 gr/dscf, 162 ppm) and with a TS content not to exceed 258 ppm.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.104)[1]

2. Maximum Fuel Firing Rate

   The maximum fuel firing rate for each of the hydrocracker heaters shall be as follows:

   a. The Hydrocracker Second Stage Charge Heater H601 shall not exceed 40 MMBtu/hr on a monthly basis;
   b. The Hydrocracker Fractionator Inlet Heater H602 shall not exceed 77 MMBtu/hr on a monthly basis; and
   c. The Hydrocracker First Stage Charge Heater H603 shall not exceed 76 MMBtu/hr on a monthly basis.

   The fuel firing rates shall be based on the monthly average HHV of the RFG and the amount of RFG used throughout the month.

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

3. The hydrocracker heaters shall not discharge or cause the discharge into the atmosphere emissions of SO_2 in excess of 20 ppmv (dry basis, 0% excess air) determined hourly on a three-hour (3-hour) rolling average basis and SO_2 in excess of 8 ppmv (dry basis, 0% excess air) determined daily on a 365 successive calendar day rolling average basis.

   (Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §60.102a)[1]

4. Ultra-Low NO_x Burners

   The permittee shall operate and maintain ultra-low NO_x burners on the Hydrocracker Second Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, and the Hydrocracker First Stage Charge Heater H603.

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

5. Maximum Emission Limits

   The permittee shall not discharge or cause the discharge into the atmosphere emissions of NO_x in excess of:

   a. 40.0 ppmvd @ 0% O_2 (three-hour (3-hour) block average) for the Hydrocracker First Stage Charge Heater H603 and the Hydrocracker Second Stage Charge Heater H601; and
   b. 50.0 ppmvd @ 0% O_2 (three-hour (3-hour) block average) for the Hydrocracker Fractionator Inlet Heater H602.

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

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6. Visible Emissions (VE)

For any six (6) minute averaging period, the Hydrocracker Second Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, and Hydrocracker First Stage Charge Heater H603, shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, these equipment 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)[2]

7. Scrubbing System for Catalyst Regeneration

In the event that the catalyst in the catalytic hydrocracker is regenerated in place, the permittee shall install, operate and maintain a quench mixer to remove SO_2, NO_x, and CO from exhaust gases produced as a result of catalyst regeneration. A caustic solution shall be injected into the quench mixer to chemically remove these pollutants. The quench mixer shall be operating at all times while catalyst is being regenerated in place.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

8. Vapor Collection System for Process Vessel Turn-arounds

All VOC emissions from any pressurized process vessel designated in this attachment which occur during depressurization of such vessel, and which would otherwise be emitted to the atmosphere, shall be collected and used for fuel or flared until the pressure in the vessel is below five (5) pounds per square inch, gauge. Residual liquids, to the extent possible will be pumped out of the vessel to tankage for reprocessing.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

9. Sulfur Recovery Unit (SRU) and Oxidation System

The permittee shall operate and maintain an operable Claus SRU, to remove H_2S from the waste gas produced by the catalytic hydrocracker. In addition, the permittee shall operate and maintain an operable oxidation system to convert H_2S not removed by the Claus SRU to SO_2. The Claus SRU and the oxidation system shall be operating at all times during the operation of the catalytic hydrocracker.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

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10. Tune-Ups

The permittee shall conduct initial tune-ups of the Hydrocracker Second Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, and Hydrocracker First Stage Charge Heater H603 no later than January 31, 2016, and shall conduct tune-ups of the Hydrocracker Second Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, and Hydrocracker First Stage Charge Heater H603 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 NO_x requirement to which the unit is subject;
e. Measure the concentrations in the effluent stream of CO in ppm by volume and O_2 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 O_2 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)[1]

11. Energy Assessment

The permittee shall have a one-time energy assessment performed for the Hydrocracker Second Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, and Hydrocracker First Stage Charge Heater H603 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)[1]

Section D. Monitoring and Recordkeeping Requirements

1. The permittee shall operate and maintain fuel meters to record the amount of RFG fired in Hydrocracker Heaters H601, H602, and H603.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

2. Compliance, on a continuous basis, with the TS limit specified in Special Condition No. C.1 of this attachment shall be determined by TS analysis in the RFG using ASTM Methods D5504-94, D5453-93, or other methods approved by the Department. A representative sample of the RFG shall be analyzed a minimum of twice a month to ensure continuing compliance. Records of the TS content of the RFG shall be maintained on a monthly basis. Compliance with the TS standard shall be determined by averaging the analytical results obtained throughout the month.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

3. Continuous Monitoring System

a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in Hydrocracker Heaters H601, H602, and H603.
b. The CMS shall meet the following requirements:

i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S;

ii. All fuel gas combustion devices, including Hydrocracker Heaters H601, H602, and H603, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned;

iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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 shall be used in conducting any RATA.

iv. 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_2S CMS, RATAs 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. 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)[1]

4. The HHV of the RFG to be fired shall be tested using gas chromatography (ASTM Methods D2504 and/or D2163), and calculated according to ASTM Method D2598 or by alternative methods as authorized by the Department. The HHV of the RFG shall be verified by having a representative sample of the RFG analyzed for HHV at least twice per month. Records of the HHV of the RFG shall be maintained on a monthly basis.

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

5. Visible Emissions (VE)

   The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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 §11-60-15, §11-60-24)[2]

6. The permittee shall record the amount of RFG in standard cubic feet fired by Hydrocracker Heaters H601, H602, and H603 on a monthly basis.

   (Auth.: HAR §11-60.1-3, §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)[1]

8. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) 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 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 Hydrocracker Second Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, or Hydrocracker First Stage Charge Heater H603. 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 CEMS 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 CEMS operated properly during the period and was not subject to any repairs or adjustments except zero and span checks; and
      v. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices.

b. All reports shall be postmarked by the **thirtieth (30th) 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 any rolling three-hour (3-hour) period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 230 mg/dscm (0.10 gr/dscf, 162 ppm) or 258 ppm TS content.
d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission and concentration limits for the purposes of the 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)[1]

2. 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** or an equivalent form shall be used.

   b. The average fuel consumption rate of RFG (scf/hr) and the average HHV firing rate (MMBtu/hr) of the Hydrocracker Heaters H601, H602, and H603 on a monthly basis. Also, the average HHV of RFG (Btu/scf) fired in the Hydrocracker Heaters H601, H602, and H603 on a monthly basis. The enclosed **Monitoring Report Form: Fuel Consumption – Heaters** 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)[2]

3. 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 HAPs. 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 determined 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; 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. 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 which the excursion or exceedances 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 the 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) days 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 SPT 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)[1]

8. MACT Subpart DDDDD Reporting

The permittee shall comply with the reporting requirements per 40 CFR §63.7550 for the Hydrocracker Second Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, and Hydrocracker First Stage Charge Heater H603. The reports shall be submitted to the Department and U.S. EPA, Region 9.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7550)[1]

Section F. Testing Requirements

1. The permittee shall conduct or cause to be conducted performance tests on the Hydrocracker Second Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, and Hydrocracker First Stage Charge Heater H603. Performance tests shall be conducted for nitrogen oxides (NO_x as NO_2) on the basis of concentration and mass rate and SO_2 while fired on RFG. All performance tests shall be conducted at the maximum expected operating capacity of the heater 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.

Note: The SO_2 emissions from Hydrocracker Fractionator Inlet Heater H602 cannot be determined by source performance testing at other locations (combustion sources) because it serves as a control device for the LPG merox vent.

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

2. Performance tests for the emissions of NO_x and SO_2 shall be conducted using EPA Methods 1 to 4, 6, 7 or 7E, and/or 19, 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)

3. The 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)

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. **At least thirty (30) days prior** *to performing a test*, the permittee shall submit a written *performance test plan* to the Department 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)

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

7. **Within sixty (60) days after** *completion of the performance test*, the permittee shall submit to the Department and U.S. EPA, Region 9 (Attention: AIR-3), the test report which shall include the operating conditions of the vacuum unit charge heater 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 §11-60.1-11, §11-60.1-90)

8. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S 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)

<u>Section G</u>. <u>Agency Notifications</u>

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)

[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.

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ATTACHMENT II(E): SPECIAL CONDITIONS
ASPHALT HEATING AND LOADING
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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. Asphalt Heater, ID No. H801

      i. 33 MMBtu/hr heat input.

   b. Asphalt Loading Rack

2. The permittee shall permanently attach an identification tag or nameplate on each piece of equipment which identifies the model number, serial 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 Asphalt Heater H801 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 (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.

   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, §11-60.1-174; 40 CFR §60.1, §60.100, §63.1, §63.7485)[1]

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Section C. Operational and Emission Limitations

1. The Asphalt Heater H801 shall be fired only on RFG with a H_2S content not to exceed 230 mg/dscm (0.10 gr/dscf).

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.104)[1]

2. Maximum Emission Limits

   The permittee shall not discharge or cause the discharge into the atmosphere emissions of nitrogen oxides, (NO_x as NO_2) in excess of 2.73 lb/hr (3-hour average) and 0.155 lb/MMBtu (three-hour (3-hour) average) for the Asphalt Heater H801.

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

3. Visible Emissions (VE)

   For any six (6) minute averaging period, the Asphalt Heater H801 shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the Asphalt Heater H801 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, §11-60.1-161; 40 CFR §60.472)[1]

4. Tune-Ups

   The permittee shall conduct initial tune-ups of the Asphalt Heater H801 no later than January 31, 2016, and shall conduct tune-ups of the Asphalt Heater H801 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 NO_x requirement to which the unit is subject;
e. Measure the concentrations in the effluent stream of CO in ppm by volume and O_2 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 O_2 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)[1]

5. Energy Assessment

The permittee shall have a one-time energy assessment performed for the Asphalt Heater H801 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)[1]

<u>Section D</u>. <u>Monitoring and Recordkeeping Requirements</u>

1. The permittee shall operate and maintain a non-resetting fuel meter on the Asphalt Heater H801 to record the amount of RFG fired in the heater. Records shall be maintained on a monthly and annual basis.

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

2. Continuous Monitoring System

   a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in the Asphalt Heater H801.
   b. The CMS shall meet the following requirements:

      i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S;
      ii. All fuel gas combustion devices, including Asphalt Heater H801, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned;
      iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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 shall be used in conducting any RATA;
      iv. 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_2S CMS, RATAs 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; and
      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, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, PS-7)[1]

3. Visible Emissions (VE)

   The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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 §11-60-15, §11-60-24)[2]

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)[1]

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5. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) 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 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 Asphalt Heater H801. 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 CEMS 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 CEMS operated properly during the period and was not subject to any repairs or adjustments except zero and span checks; and
      v. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices.

   b. All reports shall be postmarked by the **thirtieth (30^{th}) 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 any rolling three-hour (3-hour) hour period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 230 mg/dscm (0.10 gr/dscf).

d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission and concentration limits for the purposes of the 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)[1]

2. 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** 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, SIP §11-60-24)[2]

3. 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 HAPs. 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 determined 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; 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. 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 which the excursion or exceedances 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 the 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) days 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 SPT 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)[1]

8. MACT Subpart DDDDD Reporting

   The permittee shall comply with the reporting requirements per 40 CFR §63.7550 for the Asphalt Heater H801. The reports shall be submitted to the Department and U.S. EPA, Region 9.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7550)[1]

Section F. Testing Requirements

1. The permittee shall conduct or cause to be conducted performance tests on the Asphalt Heater H801. Performance tests shall be conducted for nitrogen oxides (NO_x as NO_2). All performance tests shall be conducted at the maximum expected operating capacity of the source 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)

2. Performance tests for the emissions of nitrogen oxides (NO_x as NO_2) shall be conducted using EPA Method 1 to 4, and 7, 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)

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3. For each run, the refinery gas feed rate in dry standard cubic feet per hour (dscf/hr) shall be provided. The permittee shall document the methodology by which each refinery gas feed rate was determined. The refinery gas shall be sampled and analyzed for the heating value per dscf on the day of the test.

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

4. The 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. For Method 7, each run shall consist of four (4) separate samples collected at approximately fifteen (15) minute intervals.

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

5. 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)

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)

7. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

8. **Within sixty (60) days after** *completion of the performance test*, the permittee shall submit to the Department and U.S. EPA, Region 9 (Attention: AIR-3), the test report which shall include the operating conditions of the vacuum unit charge heater 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 §11-60.1-11, §11-60.1-90)

9. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual SPT. 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 §11-60.1-11, §11-60.1-90)

10. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S 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)

<u>Section G</u>. <u>Agency Notification</u>

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)

[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 II(F): SPECIAL CONDITIONS
VISBREAKER UNIT
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 of the Visbreaker Unit (VBK):

    a. Visbreaker Heater, ID No. H901

        i. 75 MMBtu/hr heat input.

    b. Visbreaker Offgas Treater

    c. Sulfix Storage Tank, TK 913

        i. Vertical Fixed Roof; and
        ii. 6000 gallons capacity.

    d. Sulfix Injection Tank, TK 912

        i. Vertical Fixed Roof; and
        ii. 750 gallons capacity.

    e. Fractionation Tower, ID No. T901

    (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 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 Visbreaker Heater H901 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 (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.

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, §11-60.1-174; 40 CFR §60.1, §60.100, §63.1, §63.7485)[1]

2. The Sulfix Storage Tank TK 913 and Sulfix Injection Tank TK 912, 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 §63.1, §63.640, §63.646)[1]

Section C. Operational and Emission Limitations

1. The visbreaker heater shall be fired only on RFG with a H_2S content not to exceed 230 mg/dscm (0.10 gr/dscf, 162 ppm).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.104) [1]

2. The VBK may be operated as either a thermal cracking unit (as originally designed) or as a crude topping unit. Except when the feed temperature to T901 is less than 800 °F, the permittee shall operate and maintain a visbreaker offgas treater to treat mercaptans, carbonyl sulfide and other reduced sulfur compounds generated by the VBK.

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

3. The total of all sulfur compounds in the RFG shall not exceed the TS equivalent of 258 ppm. The 258 ppm TS limit on RFG applies at all times, even when the VBK is not operating because it serves as an overall cap on the refinery's potential-to-emit SO_2 emissions. The 258 ppm limit was derived from the 20 ppm SO_2 limit specified by NSPS Subpart J, which is applicable to all combustion sources.

   SO_2 Limit = 20 ppmvd @ 0% excess air (three-hour (3-hour) rolling average)
   Higher Heating Value (HHV) = 1476 Btu/scf for RFG, from lab analysis
   Dry Fuel Factor (F_d) = 8740 scf/MMBtu for RFG, from lab analysis

   20 ppm SO_2 x 8740 scf/MMBtu x 1476 Btu/scf x 1 MM/1,000,000 = 258 ppm TS

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.105)[1]

4. Ultra-Low NO_x Burners

   The permittee shall operate and maintain ultra-low NO_x burners on the Visbreaker Heater H901.

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

5. Maximum Emission Limits

   a. The visbreaker heater shall not discharge or cause the discharge into the atmosphere emissions of nitrogen oxides (as NO_2) in excess of 40.0 ppmvd @ 0% excess O_2 (three-hour (3-hour) block average).
   b. The visbreaker heater shall not discharge or cause the discharge into the atmosphere emissions of SO_2 in excess of 20 ppmvd @ 0% excess air (three-hour (3-hour) rolling average).

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

6. The visbreaker heater is exempt from a PSD review due to the emissions restrictions listed above. Any relaxation in these limits that results in an emissions increase above the significant PSD threshold will require a full PSD review of the source.

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

7. Visible Emissions (VE)

For any six (6) minute averaging period, the visbreaker heater shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the visbreaker heater 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) [2]

8. Tune-Ups

The permittee shall conduct initial tune-ups of the visbreaker heater no later than January 31, 2016, and shall conduct tune-ups of the visbreaker heater 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 NO_x requirement to which the unit is subject;
e. Measure the concentrations in the effluent stream of CO in ppm by volume and O_2 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 O_2 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)[1]

9. Energy Assessment

The permittee shall have a one-time energy assessment performed for the visbreaker heater 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)[1]

Section D. Monitoring and Recordkeeping Requirements

1. Compliance, on a continuous basis, with the sulfur limits imposed in Special Condition No. C.3 of this attachment shall be determined by TS analysis in the RFG using ASTM Methods D5504-94, D5453-93 or other methods approved by the Department. A representative sample of the RFG shall be analyzed a minimum of once a week to ensure continuing compliance. Records of the TS content of the RFG shall be maintained on a **monthly** basis.

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

2. Continuous Monitoring System

a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in the visbreaker heater.
b. The CMS shall meet the following requirements:

i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S;
ii. All fuel gas combustion devices, including the visbreaker heater, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned;

iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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, shall be used in conducting any RATA;

iv. 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_2S CMS, RATAs 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; and

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, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, PS-7)[1]

3. Visible Emissions (VE)

The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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 §11-60-15, §11-60-24)[2]

4. The permittee shall maintain a file containing records of the concentration of H_2S in RFG, as measured by the CMS.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7)[1]

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)[1]

6. The permittee shall keep readily accessible records showing the dimensions of the Sulfix Storage Tank TK 913, and Sulfix Injection Tank TK 912, and an analysis showing the capacity of each storage tank. This record shall be kept as long as the storage tank retains 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 four (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 2 storage vessel definitions in 40 CFR §63.641.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §63.646, §63.654)[1]

7. The permittee shall continuously monitor and record the feed temperature to Fractionation Tower T901 at the outlet of Visbreaker Heater H901, as demonstrated by a thermocouple, or equivalent device, in order to demonstrate compliance with Special Condition No. C.2 of this attachment.

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

8. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) 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 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 visbreaker heater. 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 CEMS 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 CEMS operated properly during the period and was not subject to any repairs or adjustments except zero and span checks; and

v. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices.

b. All reports shall be postmarked by the **thirtieth (30^{th}) 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 any rolling three-hour (3-hour) period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 230 mg/dscm (0.10 gr/dscf, 162 ppm), or 258 ppm TS content.

d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission and concentration limits for the purposes of the 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) [1]

2. 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. The average one-hour (1-hour) H_2S concentration in RFG on a daily, monthly and annual basis. All TS lab results along with a semi-annual average thereof.

b. 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** 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)[2]

3. 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 HAPs. 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 determined 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; 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. 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 which the excursion or exceedances 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 the 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) days 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 SPT 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)[1]

8. MACT Subpart DDDDD Reporting

The permittee shall comply with the reporting requirements per 40 CFR §63.7550 for the visbreaker heater. The reports shall be submitted to the Department and U.S. EPA, Region 9.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7550)[1]

9. The permittee shall report any period in which the visbreaker offgas treater is not operating while the VBK is in operation and the temperature of the feed to Fractionation Tower T901 is 800 °F or greater, in accordance with Standard Condition No. 17 of Attachment I.

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

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Section F. Testing Requirements

1. The permittee shall conduct or cause to be conducted performance tests on the visbreaker heater. Performance tests shall be conducted for nitrogen oxides (NO_x as NO_2) and SO_2 while fired on RFG. All performance tests shall be conducted at the maximum expected operating capacity of the visbreaker heater, or at other operating loads as may be specified by the Department. Performance test 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)

2. Performance tests for the emissions of NO_x and SO_2 shall be conducted using EPA Method 1 to 4, 6, and 7, or EPA approved equivalent methods with prior written approval from the Department. Performance tests for SO_2 may be conducted at any fuel gas combustion device having a common source of fuel gas.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §60.105(a)(3))

3. For each run, the emissions of nitrogen oxides (as NO_2) and the emission of SO_2 expressed in ppm at 0% excess O_2 shall be determined by the following procedure:

   $$C_{adj} = C_{meas}[20.9/(20.9 - \%O_2)]$$

   Where:

   C_{adj} = pollutant concentration adjusted zero percent O_2, ppm or g/dscm
   C_{meas} = pollutant concentration measured dry basis, ppm or g/dscm
   20.9 = O_2 concentration in air, percent
   $\%O_2$ = O_2 concentration measured dry basis, percent

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR 60.106)[1]

4. For each run, the RFG feed rate in dry standard cubic feet per hour (dscf/hr) shall be provided. The permittee shall document the methodology by which each refinery gas feed rate was determined. The refinery gas shall be sampled and analyzed for the heating value per dscf on the day of the test. The heater fuel gas firing rate on the basis of HHV in the terms of MMBtu/hr shall be determined and included in the source test report.

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

5. The 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. For Method 7, each run shall consist of four (4) separate samples collected at approximately fifteen (15) minute intervals.

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

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, 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)

7. **At least thirty (30) days prior** *to performing a test*, the permittee shall submit a written *performance test plan* to the Department 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)

8. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

9. **Within sixty (60) days after** *completion of the performance test*, the permittee shall submit to the Department and U.S. EPA, Region 9 (Attention: AIR-3), the test report which shall include the operating conditions of the visbreaker heater 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 §11-60.1-11, §11-60.1-90)

10. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S 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 §11-60.1-11, §11-60.1-90)

Section G. Agency Notification

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)

[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.

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ATTACHMENT II(G): SPECIAL CONDITIONS
HYDROGEN GENERATION UNIT
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 of the Hydrogen Generation Unit (HGU):

   a. Hydrogen Reformer Furnace, ID No. H2001

      i. 172.8 MMBtu/hr heat input; and
      ii. Equipped with a combustion air preheater and flue gas recirculation.

   (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 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 Hydrogen Reformer Furnace H2001 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, Standard 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.

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, §11-60.1-174; 40 CFR §60.1, §60.100, §63.1, §63.7485)[1]

2. This CSP contains conditional requirements from an existing permit issued pursuant to 40 CFR Part 52.21, Prevention of Significant Deterioration of Air Quality.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-132)

Section C. Operational and Emission Limitations

1. The Hydrogen Reformer Furnace H2001 shall be fired only on RFG with a H_2S content not to exceed 230 mg/dscm (0.10 gr/dscf, 162 ppm) and with a TS content not to exceed 258 ppm.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.104)[1]

2. Maximum Fuel Consumption

   The heating value of the RFG used to fire the Hydrogen Reformer Furnace H2001 shall not exceed 96,973 MMBtu/month based on a rolling twelve-month (12-month) average which is equivalent to a firing rate of 132.84 MMBtu/hr.

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

3. Maximum Emission Limits

   The Hydrogen Reformer Furnace H2001 shall not discharge or cause the discharge into the atmosphere emissions of the following:

   a. Nitrogen oxides (NO_x as NO_2) in excess of:

      i. 60.0 ppmvd @ 0% O_2 (30-day rolling average); and
      ii. 50.0 ppmvd @ 0% O_2 (365-day rolling average).

   b. Total suspended particulates (TSP) in excess of 1.4 lb/hr.

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

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4. Ultra-Low NO_x Burners and Flue Gas Recirculation

   The permittee shall operate and maintain ultra-low NO_x burners and sufficient flue gas recirculation on the Hydrogen Reformer Furnace H2001 to meet the NO_x limits in Special Condition No. C.3.a of this attachment.

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

5. Visible Emissions (VE)

   For any six (6) minute averaging period, the Hydrogen Reformer Furnace H2001 shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the hydrogen reformer 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, §11-60.1-32, §11-60.1-90, SIP §11-60-24)[2]

6. Tune-Ups

   The permittee shall conduct initial tune-ups of the Hydrogen Reformer Furnace H2001 no later than January 31, 2016, and shall conduct tune-ups of the Hydrogen Reformer Furnace H2001 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 NO_x requirement to which the unit is subject;

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e. Measure the concentrations in the effluent stream of CO in ppm by volume and O_2 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 O_2 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)[1]

7. Energy Assessment

The permittee shall have a one-time energy assessment performed for the Hydrogen Reformer Furnace H2001 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)[1]

<u>Section D</u>. <u>Monitoring and Recordkeeping Requirements</u>

1. Compliance, on a continuous basis, with the TS limit specified in Special Condition No. C.1 of this attachment shall be determined by TS analysis in the RFG using ASTM Methods D5504-94, D5453-93, or other methods approved by the Department. A representative sample of the RFG shall be analyzed a minimum of twice a month to ensure continuing compliance. Records of the TS content of the RFG shall be maintained on a monthly basis. Compliance with the TS standard shall be determined by averaging the analytical results obtained throughout the month.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

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2. Continuous Monitoring System for H_2S

   a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in the Hydrogen Reformer Furnace H2001.

   b. The CMS shall meet the following requirements:

      i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S.

      ii. All fuel gas combustion devices, including the Hydrogen Reformer Furnace H2001, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned.

      iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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 shall be used in conducting any RATA.

      iv. 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_2S CMS, RATAs 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. 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) [1]

3. Continuous Emissions Monitoring System for NO_x

   a. The permittee shall install, operate and maintain a CEMS for continuously monitoring and recording the concentration by volume (dry basis) of NO_x emissions from the Hydrogen Reformer Furnace H2001.

   b. The CEMS shall meet the following requirements:

      i. Performance evaluations for the NO_x CEMS shall be in accordance with 40 CFR §60.13. The NO_x CEMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 2, Specifications and Test Procedures for SO_2 and NO_X 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.

ii. 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 NO_x CEMS, RATAs need not be performed on an annual basis, unless requested by the Department; or there is a significant change or performance deficiency of the CEMS.

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, §11-60.1-11, §11-60.1-90, PS-2)[1]

4. Continuous Monitoring System for O_2

a. The permittee shall install, operate and maintain a CMS for continuously monitoring and recording the concentration by volume (dry basis) of O_2 emissions from the Hydrogen Reformer Furnace H2001.

b. The CMS shall meet the following requirements:

i. Performance evaluations for the O_2 CMS shall be in accordance with 40 CFR §60.13. The O_2 CMS shall meet 40 CFR Part 60, Appendix B, Performance Specification 3, Specifications and Test Procedures for O_2 and CO_2 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.

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, §11-60.1-11, §11-60.1-90)

5. Visible Emissions (VE)

The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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 §11-60-15, §11-60-24)[2]

6. The permittee shall record the total quantity of RFG (MMSCF) fired by the Hydrogen Reformer Furnace H2001 on a monthly and rolling twelve-month (12-month) basis. Also, the total quantity of RFG (MMBtu) fired by the Hydrogen Reformer Furnace H2001 on a monthly, rolling twelve-month (12-month), and rolling twelve-month (12-month) average basis.

   (Auth.: HAR §11-60.1-3, §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)[1]

8. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) 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 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 Hydrogen Reformer Furnace H2001. 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 CEMS was inoperative except for zero and span checks. The nature of each system repair or adjustment shall be described;

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iv. 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 zero and span checks; and

v. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices.

b. All reports shall be postmarked by the **thirtieth (30th) 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:

i. Any rolling three-hour (3-hour) period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 230 mg/dscm (0.10 gr/dscf, 162 ppm) or 258 ppm TS content.

ii. Any thirty-day (30-day) operating period during which the average concentration of NO_x in the flue gas from H2001 exceeds 60 ppm @ 0% excess O_2.

iii. Any 365-day operating period during which the average concentration of NO_x in the flue gas from H2001 exceeds 50 ppm @ 0% excess O_2.

d. Excess emissions indicated by the CEMS shall be considered violations of the applicable emission and concentration limits for the purposes of the 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)[1]

2. 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** or an equivalent form shall be used.

b. The total quantity of RFG (MMBtu) fired by the Hydrogen Reformer Furnace H2001 on a monthly, rolling twelve-month (12-month), and rolling twelve-month (12-month) average basis. The enclosed **Monitoring Report Form: Fuel Consumption – Package Boilers and Process Heaters** 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)[2]

3. 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 HAPs. 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 determined 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; 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. 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 which the excursion or exceedances 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 the 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) calendar days 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 SPT 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)[1]

8. MACT Subpart DDDDD Reporting

The permittee shall comply with the reporting requirements per 40 CFR §63.7550 for the Hydrogen Reformer Furnace H2001. The reports shall be submitted to the Department and U.S. EPA, Region 9.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7550)[1]

Section F. Testing Requirements

1. The permittee shall conduct or cause to be conducted performance tests on the Hydrogen Reformer Furnace H2001. Performance tests shall be conducted for TSP while fired on RFG. All tests shall be conducted at the maximum operating capacity of the hydrogen reformer, or at other operating loads as may be specified by the Department. The test for TSP shall be conducted on at least 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)

2. Performance tests for the emissions of TSP shall be conducted using EPA Method 1 to 5, 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)

3. The 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)

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. **At least thirty (30) days prior** *to performing a test*, the permittee shall submit a written *performance test plan* to the Department 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)

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

7. **Within sixty (60) days after** *completion of the performance test*, the permittee shall submit to the Department and U.S. EPA, Region 9 (Attention: AIR-3), the test report which shall include the operating conditions of the visbreaker heater 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 §11-60.1-11, §11-60.1-90)

8. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual SPT. 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 SPT.

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

9. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S 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)

<u>Section G</u>. <u>Agency Notification</u>

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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[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 II(H): SPECIAL CONDITIONS
SULFUR RECOVERY PLANT
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date:** **<u>May 12, 2026</u>**

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 of the Sulfur Recovery Plant (SRP):

   a. Claus Sulfur Recovery Unit No. 2 (SRU #2), ID No. BR1371

      i. 2.5 MMBtu/hr heat input (normally fired on refinery-generated hydrogen); and
      ii. Twenty (20) long tons per day (LTPD) capacity without O_2 injection (nominal).

   b. Claus Sulfur Recovery Unit No. 3 (SRU #3), ID No. BR1381

      i. 3.9 MMBtu/hr heat input (normally fired on refinery-generated hydrogen); and
      ii. Twenty (20) long tons per day (LTPD) capacity without O_2 injection (nominal).

   c. SCOT Tail Gas Unit, ID No. BR1393

      i. 1.0 MMBtu/hr heat input (normally fired on refinery-generated hydrogen).

   d. Vent Gas Incinerator, ID No. H1353

      i. 3.8 MMBtu/hr heat input.

   e. Tail Gas Incinerator, ID No. H1391

      i. 4.4 MMBtu/hr heat input.

   f. Sulfur Recovery Unit #2 Pit

      i. Subsurface Tank TK-1371;
      ii. Pit Vent; and
      iii. Steam-driven Vent Eductor (J-1372).

   g. Sulfur Recovery Unit #3 Pit

      i. Subsurface Tank (D-1391);
      ii. Pit Vent; and
      iii. Steam-driven Vent Eductor (J-1386).

h. Amine Treating Unit

i. Lean Amine Drum (D1304) Vent.

(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 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 SRU #2, SRU #3, SCOT Tail Gas Unit, Vent Gas Incinerator H1353, and Tail Gas Incinerator H1391 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.

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, §60.100)[1]

2. As a consequence of a consent decree (5:16-cv-00722) with EPA, the SRU #2, SRU #2 Pit, SRU #3, SRU #3 Pit, SCOT Tail Gas Unit, Vent Gas Incinerator H1353, and Tail Gas Incinerator H1391, and the SRP as a whole 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 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)[1]

3. The SRU #2, SRU #2 Pit Vent, SRU #3, SRU #3 Pit Vent, SCOT Tail Gas Unit, Vent Gas Incinerator H1353, and Tail Gas Incinerator H1391, 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 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, §11-60.1-174; 40 CFR §63.1, §63.1562)[1]

4. The lean amine drum (D1304) vent is 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 §63.1, §63.640)[1]

5. This CSP contains conditional requirements from an existing permit issued pursuant to 40 CFR Part 52.21, Prevention of Significant Deterioration of Air Quality.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-132)

Section C. Operational and Emission Limitations

1. Vent Gas Incinerator H1353 and Tail Gas Incinerator H1391 shall be fired only on RFG with a H_2S content not to exceed 230 mg/dscm (0.10 gr/dscf, 162 ppm) and with a TS content not to exceed 258 ppm, or hydrogen.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.104)[1]

2. The permittee shall operate and maintain SRU #2, and/or SRU #3, and the SCOT Tail Gas Unit to remove H_2S contained in the sour offgases from the Sour Water Stripper (SWS) and the DHC, which are treated and concentrated in the Amine Treatment Unit (ATU). In addition, the permittee shall operate and maintain the Tail Gas Incinerator H1391 to oxidize H_2S and other reduced sulfur compounds not removed by the SRUs and the SCOT Tail Gas Unit to SO_2. Tail gas from either SRU #2 or SRU #3 shall be routed through the SCOT Tail Gas Unit and to either the Vent Gas Incinerator H1353 or Tail Gas Incinerator H1391 at all times.

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

3. The permittee shall not discharge or cause the discharge into the atmosphere SO_2 in excess of the following emission limits:

Operating Unit(s)	Rolling 12-hour average**
SRU #2 and/or SRU #3	250 ppm by volume*,**,***
SRU #2 only without O_2 injection	5.34 lb/hr**,***
SRU #3 only without O_2 injection	7.63 lb/hr**,***
SRU #3 without O_2 injection, plus SRU #2 without O_2 injection	12.97 lb/hr**,***
	Rolling 365-day average*,**,***
Tail Gas Incinerator H1391 and Vent Gas Incinerator H1353	180 ppm by volume*

   *At 0% O_2 on a dry basis individually or on a flow-weighted average basis
   **Includes sulfur pit vapors upon incineration in either or both incinerators
   ***Includes periods of start-up, shutdown, and/or malfunction (when the Sulfur Recovery Plant is or should be receiving acid gas).

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.102a)[1]

4. At all times, the permittee shall follow the procedures set forth in the OMMP for the SRP and associated by-pass lines (including by-pass of the SCOT unit or incinerators) that was developed pursuant to 40 CFR Part 63, Subpart UUU and submitted to the Department. Any changes to the OMMP must be submitted to the Department and approved prior to their adoption.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1568, §63.1574)[1]

5. At all times, including periods of startups, shutdowns, and malfunctions (SSM), the permittee shall, to the extent practicable, maintain and operate the SRP including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Department which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.11, §63.6)[1]

6. During periods of startup, shutdown and malfunction, the permittee must operate and maintain the affected source (including associated air pollution control equipment and monitoring equipment) in accordance with the Startup, Shutdown and Malfunction Plan (SSMP) that was developed pursuant to 40 CFR Part 63, Subpart A.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.6)[1]

7. At all times, the vent from SRU #2 pit shall be actively routed to either the Vent Gas Incinerator H1353 or the front-end of SRU #2, except when SRU #2 is not recovering elemental sulfur.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1569, §63.1579)[1]

8. At all times, the vent from SRU #3 pit shall be actively routed to Vent Gas Incinerator 1353 or Tail Gas Incinerator H1391, except when SRU #3 is not recovering elemental sulfur.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1569, §63.1579)[1]

9. When receiving either sulfur pit vent gas or tail gas the average daily temperature of the Vent Gas Incinerator H1353 and the Tail Gas Incinerator H1391 shall not be less than the minimum value set forth in the OMMP, 1100 ºF.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1568)[1]

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10. When exclusively hydrogen is being used to keep either or both of the SRUs hot, and/or while using other gases (most commonly nitrogen) for purging or cooling during startup or shutdown (and while no acid gas is being fed to the SRP), to ensure complete combustion the incinerator receiving the off-gas shall maintain an hourly average temperature of at least 1200 ºF and an hourly average outlet O_2 content of at least two (2) volume percent (dry basis).

    (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1568)[1]

11. At all times, the Group 2 miscellaneous process vent (MPV) from the lean amine drum (D1304) shall be routed to a flare that meets the requirements of 40 CFR §63.11(b).

    (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.643)[1]

12. Visible Emissions (VE)

    For any six (6) minute averaging period, the Vent Gas Incinerator H1353 and Tail Gas Incinerator H1391 shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the Vent Gas Incinerator H1353 and Tail Gas Incinerator H1391 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)

13. The SRU #3 and SCOT Tail Gas Unit are exempt from a PSD review and Best Available Control Technology (BACT) analysis due to the operating and emissions restrictions listed above. Any relaxation in these limits that results in a net emissions increase above the applicable PSD and Significant Level threshold will require a full PSD and BACT review of the source.

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

Section D. Monitoring and Recordkeeping Requirements

1. Continuous Emissions Monitoring System, Continuous Parameter Monitoring System (CPMS), and Continuous Emission Rate Monitoring System (CERMS) for SO_2

    a. The permittee shall operate and maintain CEMS to measure and record the SO_2 emission concentrations, and O_2 content of exhaust stack gases from the Tail Gas Incinerator H1391 and Vent Gas Incinerator H1353. The permittee shall operate and maintain a volumetric flow monitor and other monitoring equipment so that SO_2 mass emission rates may be determined from a CERMS and to measure and record the volumetric gas flow rate of each release point within the group of release points from the SRP.

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b. The CEMS, CERMS, and CPMS shall meet the following requirements:

i. Both the SO_2 and the O_2 shall be measured on a dry basis;
ii. The CEMS span value is 500 ppm for SO_2 (as measured, without O_2 compensation) and either ten (10) percent or twenty-five (25) percent for O_2;
iii. Pursuant to NSPS Subpart J, Ja, and NESHAP Subpart UUU, the SO_2 concentration shall be reported on a dry basis at 0% excess O_2;
iv. All valid data shall be reduced to one-hour (1-hour) averages and expressed in the terms of the relevant emission standard. A minimum of four (4) or more equally spaced data points must be obtained to validate an hourly average, except for the following: during periods of calibration, quality assurance or maintenance, a minimum of at least two (2) data points representing two (2) separate fifteen (15) minute intervals are required to validate an hourly average;
v. Monitoring data recorded during periods of unavoidable CEMS breakdowns, out-of-control periods, repairs, maintenance or during calibration checks, must not be used to determine averages used to assess emission limits;
vi. The CEMS shall meet EPA performance specifications (40 CFR §60.13, 40 CFR Part 60, Appendices B and F, and 40 CFR §63.1568 and §63.1572. The CERMS shall meet the relative accuracy standard specified in Performance Specification 6 of Appendix B to 40 CFR Part 60, based on the emission limits set forth in Special Condition No. C.3 of this attachment (when applicable); and
vii. At least once per quarter, all of the components used to measure the flow of flue gas rate from the incinerators shall be visually inspected and checked for operational integrity and recalibrated at least once every two (2) years or in accordance with the manufacture's recommendations.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.13, §60.106a, §63.8, §63.1568, §63.1572)[1]

2. Continuous Monitoring System for H_2S

a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in Tail Gas Incinerator H1391 and Vent Gas Incinerator H1353.

b. The CMS shall meet the following requirements:

i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S;
ii. All fuel gas combustion devices, including the Tail Gas and Vent Gas Incinerators H1391and H1353, respectively, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned;

iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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 shall be used in conducting any RATA;

iv. 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_2S CMS, RATAs 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; and

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, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, PS-7)[1]

3. Monitoring Provisions for the Vent Gas Incinerator H1353 and Tail Gas Incinerator H1391

a. In addition to the CEMS and CERMS, the permittee shall operate and maintain a temperature indicator on the incinerator.

b. The temperature monitoring device shall meet the following requirements:

i. Be installed in the firebox or in the ductwork immediately downstream of the firebox;

ii. Operate continuously and be equipped with or routed to a system capable of recording or averaging the data at least once an hour; and

iii. The daily average temperature shall be calculated and reported using only valid data.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1572)[1]

4. Monitoring Provisions for the Sulfur Pit Vents

a. A flow meter shall be operated and maintained to measure the amount of steam used in the eductor to draw vapors from the SRU #2 and SRU #3 pits and route them to the Vent Gas and Tail Gas Incinerators, respectively.

b. In the event the flow meter malfunctions or reads zero while the SRU is recovering elemental sulfur, and while both the eductor and the incinerator for each sulfur pit remains operational, then verification of the vent line routing shall be done in accordance with Special Condition No. D.5. of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.644, §63.654)[1]

5. A flow indicator, electronic valve or controller position monitor shall be operated and maintained to determine if there is flow through a by-pass line that would allow control equipment, necessary for meeting applicable standards to be by-passed. This device shall be monitored at least once an hour or continuously monitored and recorded.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1568)[1]

6. Each CPMS, which includes CEMS, temperature indicators, flow meters and valve positioners, must have valid hourly average data from at least seventy-five (75) percent of the hours during which the process operated. The downtime and monitoring performance assessment will be reported semi-annually. For each temperature indicator required for an incinerator by 40 CFR Part 63, Subpart UUU, conduct a calibration check at least once a year and conduct inspections once a quarter and record the results. The permittee shall operate and maintain the CPMS in a manner consistent with the manufacturer's specification or other written procedures.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1572)[1]

7. Visible Emissions (VE)

   The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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 §11-60-15, §11-60-24)[2]

8. The permittee shall develop, implement and maintain (update as appropriate) a Startup, Shutdown, and Malfunction Plan (SSMP), which ensures that affected sources and associated air pollution control and monitoring equipment will be operated and maintained in a manner which will minimize emissions during periods of startup, shutdown and malfunction and institute a corrective measures program when deficiencies are identified. If the SSMP fails to address or inadequately addresses the event, then the SSMP must be revised within **forty-five (45) days** of the event. The permittee shall provide the Department written notice of any material revisions to the SSMP in the semi-annual SSM report.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.6)[1]

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)[1]

10. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) 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) and 40 CFR §63.1575, and a SSM report pursuant to 40 CFR §63.10(d), to the Department 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. The operating status of SRU #3 and SRU #2;
      iii. Specific identification of each period of excess emissions that occur during startups, shutdowns, and malfunctions of SRU #3 and SRU #2; and each period of excess emissions that occur during malfunctions of the SCOT Tail Gas Unit. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted, shall also be reported. The SSM report shall also provide notice whether the SSMP has or should be revised;
      iv. The date and time identifying each period during which the CEMS or any other required monitoring system was inoperative or out-of-control except for zero and span checks. The nature of each system repair or adjustment shall be described. The report will determine and clearly denote a deviation for each monitoring system that does not obtain and record valid data for at least seventy-five (75) percent of the time the affected source was operating. A description of any changes made in the CMS or, processes or controls since the last reporting period;

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v. The report shall so state if no excess emissions have occurred and if no deviations in work practice standards 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 zero and span checks;

vi. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices; and

vii. Any deviations from any applicable work practice standard during the reporting period including those specified by paragraph e below. Separate from the excess emissions report, the deviation report shall include the number, date, time duration, and cause of deviation. Report how the work practice was deviated and any deviations in any monitoring requirements, other than those associated with CEMS or CPMS.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.10, §63.1569, §63.1572, §63.1573, §63.1575, §63.1577)[1]

b. All reports shall be postmarked by the **thirtieth (30th) 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. The semi-annual reports shall quantify excess emissions and downtime on at least a quarterly basis. Alternatively, the reports may be submitted on a quarterly basis.

c. Excess emissions shall be defined as follows:

i. Any rolling twelve-hour (12-hour) period during which the average SO_2 emission concentrations or mass emissions, as measured by the CEMS, exceed the emission limits set forth in Special Condition No. C.3 of this attachment.

ii. Any rolling 365-day period during which the flow weighted average SO_2 concentration exceeds 180 ppmv at 0% excess O_2.

iii. Any rolling three-hour (3-hour) period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 230 mg/dscm (0.10 gr/dscf).

d. Excess emissions indicated by the CEMS or CERMS shall be considered a violation of the applicable emission and concentration limits for the purposes of the permit.

e. A deviation from Work Practice Standards includes, but is not limited to:

i. Failure to operate and maintain bypass line monitoring devices;

ii. Failure of a monitoring device or system (including valve positioners) to detect a bypass event;

iii. Failure to vent a bypass line to an alternative control device (incinerator or flare);

iv. Failure to maintain the minimum temperature of the incinerators;
v. Failure to educt, monitor, and/or control sulfur and vapors.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.7, §60.105, §63.10, §63.654, §63.1569)[1]

2. 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** 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, SIP §11-60-24)[2]

3. 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 HAPs. 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 determined 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; 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. 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 which the excursion or exceedances 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 the 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) days prior** to the following events, the permittee shall notify the Department in writing of:

   a. Conducting a RATA on the CEMS, CERMS, and CPMS. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13(c).
   b. Conducting a SPT 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)[1]

Section F. Testing Requirements

1. At least once every four (4) calendar quarters, the permittee shall conduct or cause to be conducted a RATA of the CERMS installed on Vent Gas Incinerator H1353 and the Tail Gas Incinerator H1391 in accordance with 40 CFR Part 60, Appendix F.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §60.13)[1]

2. The permittee shall provide sampling and testing facilities at its own expense.

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

3. **At least thirty (30) days prior** *to performing a test*, the permittee shall submit a written *performance test plan* to the Department 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)

4. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

5. **Within sixty (60) days after** *completion of the RATA*, the permittee shall submit to the Department and the U.S. EPA, Region 9 (Attention: AIR-3) the test report which shall include the operating conditions of the SRU #2 and/or SRU #3 with the SCOT Tail Gas Unit, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

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

6. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S 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)

Section G. Agency Notification

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)

[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 II(I): SPECIAL CONDITIONS
COGENERATION GAS TURBINE AND BOILERS
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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. Cogeneration Gas Turbine (ID No. TU2301)

      i. General Electric LM2500;
      ii. 230 MMBtu/hr heat input; and
      iii. NO_x Control Device:

         (1) Water Injection System.

   b. Duct Burner (ID No. DB2301)

      i. 37 MMBtu/hr heat input.

   c. Waste Heat Boiler (heat recovery steam generator) (ID No. SG2301)

   d. Package Boiler (steam generator) (ID No. SG1102)

      i. 82 MMBtu/hr heat input.

   e. Package Boiler (steam generator) (ID No. SG1103)

      i. 98 MMBtu/hr heat input.
      ii. Equipped with a low NO_x burner and flue gas recirculation.

   f. Package Boiler (steam generator) (ID No. F5205)

      i. 99 MMBtu/hr heat input.
      ii. Equipped with a low NO_x burner and flue gas recirculation.
      iii. Foster Wheeler, Model No. AG-5060, Serial No. 7414, National Board No. 585.

   (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 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 Cogeneration Gas Turbine TU2301 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;
      ii. Subpart J, Standards of Performance for Petroleum Refineries; and
      iii. Subpart GG, Standards of Performance for Stationary Gas Turbines.

   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, §60.100, §60.330)[1]

2. The Package Boilers SG1102 and SG1103 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 Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

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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, §11-60.1-174; 40 CFR §60.1, §60.100, §63.1, §63.7485)[1]

3. The Package Boiler F5205 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;
      ii. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007; 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, §60.100a, §63.1, §63.7480, §63.7485, §63.7490)[1]

4. This CSP contains conditional requirements from an existing permit issued pursuant to 40 CFR Part 52.21, Prevention of Significant Deterioration of Air Quality.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-132)

Section C. Operational and Emission Limitations, and/or Work Practice Standards

1. Fuel Specifications

   a. The Cogeneration Gas Turbine TU2301 shall be fired on liquid fuel with a sulfur content not to exceed 0.25% by weight.
   b. The Duct Burner DB2301 and the Package Boiler SG1103 shall be fired only on RFG with a H_2S content not to exceed 230 mg/dscm (0.10 gr/dscf, 162 ppm) and a TS content not to exceed 258 ppm.

c. The Package Boiler SG1102 shall be fired only on liquid fuel with a sulfur content not to exceed 0.5% by weight. The 0.5% liquid fuel sulfur limit is based on a thirty-day (30-day) rolling average basis.

d. The Package Boiler F5205 shall be fired only on distillate oil with a sulfur content not to exceed 0.25% by weight, RFG with a H_2S content not to exceed 162 ppmv determined hourly on a three-hour (3-hour) rolling average basis and not to exceed 60 ppmv determined daily on a 365 successive calendar day rolling average basis, or a combination of distillate oil and RFG. The 0.25 wt% distillate oil sulfur limit is based on a thirty-day (30-day) rolling average basis. The distillate oil fuel sulfur limit shall apply at all times, including periods of startup, shutdown, and malfunction.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-38, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.1, §60.42c(d),(g)&(i), §60.46c(d)(2), §60.102a(g)(1)(ii), §60.104(a)(1), §60.333, §63.1, §63.7540)[1]

2. Air Pollution Control Equipment

a. The permittee shall continuously operate and maintain a water injection system for the control of NO_x emissions from the Cogeneration Gas Turbine TU2301. The system shall be fully capable of operating upon startup. The ratio of water to fuel being fired in the Cogeneration Gas Turbine TU2301 shall not average less than 0.50 lb water/lb fuel over any unit operating hour or shall comply with the NO_x emission limits specified in Special Condition Nos. C.3.b.i and C.3.b.ii of this attachment on a basis of each single unit operating hour. A unit operating hour shall be as defined in 40 CFR §60.331.

b. All emissions from the gas turbine/heat recovery boiler shall be discharged from a stack not less than forty (40) feet tall.

c. The Package Boiler SG1103 shall be equipped with a flue gas recirculation system and a low NO_x burner for the control of NO_x emissions.

d. The Package Boiler F5205 shall be equipped with a flue gas recirculation system and a low NO_x burner for the control of NO_x emissions. The flue gas recirculation system shall be in service whenever the package boiler is making steam and firing more than 15 MMBtu/hr or an alternative criteria as specified by the existing design criteria or by a qualified third-party subject matter expert.

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

3. Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the Cogeneration Gas Turbine TU2301 and Package Boilers SG1102, SG1103, and F5205 exhaust stacks emissions in excess of the following:

a. Emission Limits for SO_2

i. From the Cogeneration Gas Turbine TU2301- 59.5 lbs/hr (two-hour (2-hour) average) and 0.26 lbs/MMBtu (two-hour (2-hour) average) without the Duct Burner DB2301 or 64.1 lbs/hr (2-hour average); and 0.24 lbs/MMBtu (two-hour (2-hour) average) with the duct burner DB2301 operating.

ii. From the Package Boiler SG1103 - the more stringent of 2.85 lbs/hr (three-hour (3-hour) average) or 20 ppm at 0% excess O_2 (three-hour (3-hour) average).

b. Emission Limits for NO_X (as NO_2)

i. When the Cogeneration Gas Turbine TU2301 is firing liquid fuel and the Duct Burner DB2301 is not in operation, 66.8 lbs/hr (2-hour average) and 0.30 lbs/MMBtu (2-hour average).

ii. When the Cogeneration Gas Turbine TU2301 is firing liquid fuel and the Duct Burner DB2301 is in operation, 71.0 lbs/hr (two-hour (2-hour) average) and 0.28 lbs/MMBtu (two-hour (2-hour) average).

iii. The NO_x concentrations shall not exceed the standards set forth in 40 CFR §60.332(a)(2). Note: the most stringent application of the NO_x standard applicable to the Cogeneration Unit is 150 ppm NO_2 on a dry basis at fifteen (15) percent excess O_2.

iv. From the Package Boiler SG1103, 35 ppmvd at 0% excess O_2 (three-hour (3-hour) average) when the main fuel valve is open and the unit is firing at or more than 25 MMBtu/hr, and 70 ppmvd at 0% excess O_2 (three-hour (3-hour) average) when the main valve is open and the unit is firing less than 25 MMBu/hr.

v. From the Package Boiler F5205, while firing on distillate oil, the NO_x emissions shall not exceed 130 ppm at 0% excess O_2 (three-hour (3-hour) average) when the flue gas recirculation is in operation. While firing on RFG, the NO_x emissions shall not exceed 50 ppm at 0% excess O_2 (three-hour (3-hour) average) when the flue gas recirculation is in operation.

c. Emission Limits for CO

i. From the Cogeneration Gas Turbine TU2301 - 50.3 lbs/hr (two-hour (2-hour) average).

ii. From the Package Boiler SG1103 - 8.1 lbs/hr (three-hour (3-hour) average).

d. Emission Limits for PM

From the Package Boiler F5205, PM emissions shall not exceed 0.03 lb/MMBtu while firing on distillate oil or RFG. The PM limit shall apply at all times, except during periods of startup, shutdown, and malfunction.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161, 40 CFR §60.1, §60.43c(e)(4))[1]

e. MACT Subpart DDDDD Maximum Emission Limits

The permittee shall not discharge or cause the discharge into the atmosphere from the Package Boilers SG1102 and F5205, 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_2
Filterable PM	0.22 lb/MMBtu
HCl	1.1E-03 lb/MMBtu
Mercury	7.3E-07 lb/MMBtu

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.1, §60.332, §60.333, §63.1, §63.7500, §63.7540, PSD HI 83-01)[1]

4. Operating Limitations

a. The Package Boiler SG1103 when fired on RFG shall not exceed 71,586 MMBtu/month based on a rolling twelve-month (12-month) average.
b. The Package Boiler F5205 when fired on distillate oil shall not exceed 788,000 gallons per any rolling twelve-months (12-months). The Package Boiler F5205 when fired on RFG shall not exceed 36,792 MMBtu/month based on a rolling twelve-month (12-month) average. These limits do not change if the boiler is fired on a combination of distillate oil and RFG. The HHV of the RFG shall be determined using the method in Attachment II(B), Special Condition No. D.4.e.
c. The Cogeneration Gas Turbine TU2301 may be operated utilizing the hot gas bypass stack under the following conditions:

i. During periods of startup and shutdown; and
ii. During periods when the waste heat boiler cannot be operated due to safety, operational or maintenance concerns if the following conditions are met:

(1) A portion of the flue gas continues to exit through the NO_x and SO_2 CEMS measuring NO_x and SO_2 concentration, and the CEMS continues to operate;

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(2) Fuel flow is monitored continuously and the fuel flowmeter calibration is current;
(3) Pounds per hour (PPH) NO_x and SO_2 is calculated using f factors and recorded;
(4) PPH NO_x and SO_2 is calculated using the applicable current water flow, flue gas O_2 content, and fuel composition;
(5) Periods when this alternative method is used are reported in excess emissions reports along with all assumptions used and the reason the waste heat boiler could not be operated; and
(6) The Duct Burner DB2301 is not in use.

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

5. Visible Emissions (VE) for the Cogeneration Gas Turbine TU2301, and Package Boilers SG1102, SG1103, and F5205

For any six (6) minute averaging period, the Cogeneration Gas Turbine TU2301, and Package Boilers SG1102, SG1103, and F5205 shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during start-up, shutdown, or equipment malfunction, the Cogeneration Gas Turbine TU2301, and Package Boilers SG1102, SG1103, and F5205 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, §11-60.1-161,
40 CFR §60.1, §60.43c(c)&(d))[1]

6. Gas Turbine Overhaul

Substitution of the General Electric LM2500 engine with an identical LM2500 engine shall be considered routine maintenance to the extent that routine repair/replacement does not meet the definition of modification or reconstruction. This condition shall not be construed as allowing any other engine to be used except a General Electric LM2500 engine with the same emission characteristics as those submitted with the CSP application. The replacement unit shall comply with all applicable requirements of the originally permitted unit.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

7. Package Boilers SG1102, SG1103, and F5205 Tune-Ups

The permittee shall conduct initial tune-ups of the Package Boilers SG1102, SG1103, and F5205 no later than January 31, 2016, and shall conduct a tune-up of the Package Boilers SG1102, SG1103, and F5205 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

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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 NO_x requirement to which the unit is subject;
e. Measure the concentrations in the effluent stream of CO in ppm by volume and O_2 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 O_2 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)[1])

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8. Package Boilers SG1102, SG1103, and F5205 Energy Assessment

The permittee shall have a one-time energy assessment performed for the Package Boilers SG1102, SG1103, and F5205 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)[1]

Section D. Monitoring and Recordkeeping Requirements

1. Fuel Consumption Monitoring

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

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

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

2. The permittee shall maintain and operate the following CEMS in the Cogeneration Gas Turbine TU2301 exhaust stack:

   A CEMS to measure stack gas NO_x and SO_2 concentrations and stack flow rates. These parameters shall be used to continuously determine the NO_x and SO_2 emission rate in terms of lbs per hour and concentration in terms of lbs/MMBtu. This system shall meet EPA monitoring performance specifications (40 CFR §60.13, 40 CFR Part 60, Appendix B, Performance Specifications and 40 CFR Part 60, Appendix F, Quality Assurance Procedures). The SO_2 CERMS and fuel meters shall be used to continuously calculate the sulfur content of fuel on a weight % basis.

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

3. The permittee shall install, operate, and maintain an O_2 analyzer system on the Package Boiler SG1102 when burning liquid fuel.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.7525)[1]

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4. Continuous Monitoring System for H_2S

   a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in the Duct Burner DB2301, and Package Boilers SG1103, SG1102, and SG1104.
   b. The CMS shall meet the following requirements:

      i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S;
      ii. All fuel gas combustion devices, including the Cogeneration Gas Turbine TU2301, and Package Boilers SG1103, SG1102, and SG1104, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned;
      iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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, shall be used in conducting any RATA;
      iv. 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_2S CMS, RATAs 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; and
      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, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, PS-7)[1]

5. Sulfur Content in the Liquid Fuel

   a. The sulfur content of the liquid fuel for the Cogeneration Gas Turbine TU2301 shall be tested in accordance with the most current ASTM methods whenever the SO_2 CEMS data is not available for more than six (6) hours a day, as the 0.26 lbs/MMBtu SO_2 limit is equivalent to the 0.25% by weight sulfur content limit of the liquid fuel. ASTM Method D4294-90 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 day. When naphtha is used as a fuel to Cogeneration Gas Turbine TU2301, the sulfur analysis of the naphtha fuel used to fire the Cogeneration Gas Turbine TU2301 shall be sampled and analyzed once a day to satisfy this requirement. ASTM D4045 is an acceptable analytical method for determining sulfur content of naphtha.
   b. The sulfur content of the liquid fuel for the Package Boiler SG1102 shall be sampled at least five (5) days per week and tested in accordance with the most current ASTM Methods D129, D2622, D4294, D5453, or D7039, or other test methodologies with

prior written approval from the Department. Unless Tank 1103 is taken out of service for repairs or regulatory required inspections, fuel oil samples shall be taken from the pump/circulation loop of Tank 1103.

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

6. Fuel Consumption for Package Boiler F5205

The permittee shall operate and maintain non-resetting fuel meters for the continuous measurement and recording of the amount of distillate oil and RFG fired in the boiler. The non-resetting meter shall not allow the manual resetting or other manual adjustment 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, §11-60.1-11, §11-60.1-90)

7. Distillate Oil Sampling for Sulfur Content for Package Boiler F5205

Distillate oil samples may be collected from the fuel tank for the boiler immediately after the fuel tank is filled and before any distillate oil is combusted. The permittee shall analyze the distillate oil sample to determine the sulfur content of the distillate 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 supply of distillate oil is received shall be used as the daily value when calculating the thirty (30) day rolling average until the next supply is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.25 weight percent sulfur, the permittee shall ensure that the sulfur content of subsequent distillate oil supplies is low enough to cause the thirty (30) day rolling average sulfur content to be 0.25 weight percent sulfur or less.

The sulfur content of the distillate oil for Package Boiler F5205 shall be tested in accordance with the most current ASTM Methods D129, D2622, D4294, D5453, or D7039 or other test methodologies with prior written approval from the Department and the U.S. EPA.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.46c(d)(2))[1]

8. Liquid Fuel Chlorine and Mercury Monitoring for Package Boilers SG1102 and F5205

The permittee shall demonstrate compliance with the mercury or HCl emission limits in Special Condition No. C.3.e of this attachment for Package Boilers SG1102 and F5205 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 your boiler. 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 monthly 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-day (14-day) restriction does not apply.

a. The chlorine content of the liquid fuel for the boiler 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 boiler 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)[1]

9. Visible Emissions (VE) for all equipment

The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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, §11-60.1-161; 40 CFR §60.1, §60.47c(f)(3); SIP §11-60-15, §11-60-24)[1,2]

10. The permittee shall maintain a file containing records on the following items:

a. Total quantity of liquid fuel (barrels) fired by the Cogeneration Gas Turbine TU2301 on a monthly and annual basis;

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b. Total quantity of RFG (million cubic feet) fired by the Duct Burner DB2301 on a monthly and annual basis;
c. Total quantity of RFG (MMSCF) fired by the Package Boiler SG1103 on a monthly and rolling twelve-month (12-month) basis. Also, the total quantity of RFG (MMBtu) fired by the Package Boiler SG1103 on a monthly, rolling twelve-month (12-month), and rolling twelve-month (12-month) average basis.
d. Continuous ratio of water injection rate to fuel being fired in the Cogeneration Gas Turbine TU2301;
e. The total quantity of distillate oil (gallons) fired by the Package Boiler F5205 on a daily, monthly and rolling twelve-month (12-month) basis;
f. Total quantity of RFG (MMSCF) fired by the Package Boiler F5205 on a monthly and rolling twelve-month (12-month) basis. Also, the total quantity of RFG (MMBtu) fired by the Package Boiler F5205 on a monthly, rolling twelve-month (12-month), and rolling twelve-month (12-month) average basis; and
g. The sulfur content by weight of the liquid fuel and H_2S content of the RFG burned in the Cogeneration Gas Turbine TU2301, Package Boiler SG1102, Package Boiler SG1103, and Package Boiler F5205 (as applicable).

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.48c(d), §60.48c(e)(1)&(2), §60.48c(g)(1), §60.334)[1]

11. 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 systems 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)[1]

12. MACT Subpart DDDDD Recordkeeping

    The permittee shall comply with the recordkeeping requirements of 40 CFR §63.7555 and §63.7560 for Package Boilers SG1102, SG1103, and F5205

    (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.7555, §63.7560)[1]

13. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) upon request.

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

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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 on a **semi-annual calendar period** for the average water-to-fuel ratio, average concentration of H_2S in RFG, and average emissions of NO_x and SO_2. 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 SSM of the Cogeneration Gas Turbine TU2301, Package Boiler SG1102, and Package Boiler SG1103. 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 CEMS 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 CEMS operated properly during the period and was not subject to any repairs or adjustments except zero and span checks; and
      v. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices.

   b. All reports shall be postmarked by the **thirtieth (30^{th}) 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 two-hour (2-hour) period during which the average emissions of NO_x or SO_2, as measured by the CEMS, exceed the emission limits set forth in Special Condition Nos. C.3.b or C.3.a of this attachment;
      ii. Any unit operating 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 NO_x CEMS concurrently shows compliance with the NO_x limits set forth in Special Condition No. C.3.b of this attachment;
      iii. Any unit operating hour period during which the sulfur content of the liquid fuel exceeds 0.25% by weight and the SO_2 CEMS data is not available beginning when the sulfur content of the liquid fuel is first determined to exceed 0.25% by

weight until the sulfur content of the liquid fuel is demonstrated to be less than 0.25% by weight as determined by fuel analysis; or

iv. Any rolling three-hour (3-hour) period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 230 mg/dscm (0.10 gr/dscf).

d. Excess emissions indicated by the CEMS shall be considered violations of the applicable emission and concentration limits for the purposes of the 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, §60.334)[1]

2. 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 exceedance 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,** or an equivalent form, shall be used.

b. The sulfur content by weight of the liquid fuel and H_2S content of the RFG burned in the Cogeneration Gas Turbine TU2301, Package Boiler SG1102, and Package Boiler SG1103 (as applicable). The enclosed **Monitoring Report Form: Fuel Certification** or an equivalent form shall be used.

c. The sulfur content of the distillate oil burned in Package Boiler F5205

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.

d. The total quantity of RFG (MMBtu) fired by the Package Boiler SG1103 and Package Boiler F5205 on a monthly, rolling twelve-month (12-month), and rolling twelve-month (12-month) average basis. Also, the total quantity of distillate oil (gallons) fired by the Package Boiler F5205 on a monthly and rolling twelve (12) month basis. The enclosed **Monitoring Report Form: Fuel Consumption - Package Boilers and Process Heaters** or an equivalent form shall be used.
e. 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 §60.1, §60.48c(d), §60.48c(e)(1)&(2))[1]

3. 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 HAPs. 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 determined 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; and
c. Permanent discontinuance of construction, modification, relocation or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-5, §11-60.1-8, §11-60.1-15, §11-60.1-16)

5. 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 which the excursion or exceedances 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 the 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 SPT 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)[1]

8. Gas Turbine Overhaul

   a. The permittee shall submit overhaul notifications to the Department at least **twenty-four (24) hours** prior to gas turbine overhaul.

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)

9. MACT Subpart DDDDD Reporting

The permittee shall comply with the reporting requirements per 40 CFR §63.7550 for Package Boilers SG1102, SG1103, and F5205. The reports shall be submitted to the Department and U.S. EPA, Region 9.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7550)[1]

<u>Section F</u>. <u>Testing Requirements</u>

1. Testing

a. The permittee shall conduct or cause to be conducted performance tests on the cogeneration gas turbine/duct burner for SO_2, NO_x, and CO. All performance tests shall be conducted at the maximum operating capacity of the equipment being tested, or at other operating loads as may be specified by the Department. The performance test shall be conducted on an annual basis or at such times as may be specified by the Department.

b. The permittee shall conduct or cause to be conducted performance tests on the Package Boiler SG1103 for NO_x and CO. All performance tests shall be conducted at the maximum operating capacity of the equipment being tested, or at other operating loads as may be specified by the Department. The performance test shall be conducted on an annual basis or at such times as may be specified by the Department.

c. Within **one hundred eighty (180) days** after initial start-up of Package Boiler F5205, and **annually** thereafter, the permittee shall conduct performance tests to determine emissions of CO and filterable PM from Package Boiler F5205 when burning distillate oil. On an annual basis, the permittee shall conduct performance tests to determine emissions of CO and filterable PM from Package Boiler SG1102 when burning liquid fuel. Performance tests shall be conducted at the maximum expected operating capacity of the respective boiler (Package Boiler SG1102 or F5205), 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:

i. 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 individual boiler 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.

ii. 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-year (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).

d. Within **sixty (60) days** after achieving the maximum production rate of Package Boiler F5205, but not later than **one hundred eighty (180) days** after initial start-up of Package Boiler F5205, and **annually** thereafter (for NO_x and PM only), the permittee shall conduct, or cause to be conducted, performance tests on Package Boiler F5205 to determine the emission rates of NO_x, PM, and the opacity of stack emissions from Package Boiler F5205 when burning distillate oil or RFG. Performance tests shall be conducted at the maximum expected operating capacity of the boiler, 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, §11-60.1-174; 40 CFR §60.1, §60.8, §60.45c(a), §63.7, §63.7510, §63.7515, §63.7530)[1]

2. Performance tests for the emissions of NO_x shall be conducted using EPA Methods 1-4 and 7. Performance tests for the emissions of SO_2 shall be conducted using EPA Methods 1-4 and 8. Performance tests for the emissions of CO shall be conducted using EPA Methods 1-4 and 10. Performance tests for the emissions of filterable PM/PM shall be conducted using EPA Methods 1-4 and Method 5 or 17. Compliance with the opacity standard of Special Condition No. C.5 of this attachment shall be determined using EPA Method 9. In lieu of the above mentioned test methods, EPA-approved equivalent methods with prior written approval from the Department may be used.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §60.1, §60.8, §60.45c(a)(3)&(8), §63.1, §63.7510(d))[1]

3. The 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)

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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. **At least thirty (30) or sixty (60) days (as applicable) prior** *to performing a test*, the permittee shall submit a written *performance test plan* to the Department and 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, §11-60.1-174; 40 CFR §63.7)[1]

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

7. **Within sixty (60) days after** *completion of the performance test*, the permittee shall submit to the Department and U.S. EPA, Region 9 the test report which shall include the operating conditions of the cogeneration gas turbine/duct burner and packaged boiler, 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)[1]

8. 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. Written waiver requests are not required for the 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.c.i 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 performance test. The annual performance test for NO_x emissions from the Package Boiler SG1103 may not be waived, until the consent decree is terminated.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7)[1]

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9. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S 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)

Section G. Agency Notification

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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[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.

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ATTACHMENT II(J): SPECIAL CONDITIONS
WASTEWATER TREATMENT UNIT
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 of the Wastewater Treatment Unit (WTU):

   a. Oil-Water Separation and Recovery System

      i. Gross oil water separator with fixed roof*;
      ii. API gravity separator with fixed roof*;
      iii. API effluent tank with fixed roof (T3512)*;
      iv. Oil skimming tank with fixed roof (T3510)*;
      v. Recovered oil tank with external floating roof (T3522);
      vi. Induced air floatation (IAF) unit with fixed roof*;
      vii. IAF float thickener with fixed roof*;
      viii. Two (2) emulsion breaking tanks with fixed roof (T3521A and T3521B); and
      ix. Two (2) equalization/surge tanks with external floating roof (T3520 and T3526).

   b. VOC Treatment System

      i. Two (2) air strippers*.

   c. Oily Sludge Dewatering System

      i. Oily sludge tank with fixed roof (T3551)*;
      ii. Oily sludge conditioning tank with fixed roof (T3553)*; and
      iii. Oily sludge filter press.

   d. Air Pollution Control Equipment

      i. Thermal Oxidizer, ID No. Z3560 - 6.5 MMBtu/hr heat input or 3.0 MMBtu/hr heat input;
      ii. Carbon canisters; and
      iii. Closed vent system.

   e. Activated Sludge Units

      i. Splitter box;
      ii. Three (3) aeration tanks;
      iii. Two (2) biosystem clarifier tanks;

iv. Clarifier effluent tank;
v. WTU effluent tank;
vi. Biosludge thickener tank; and
vii. Aerobic digester tank.

f. Biosludge Dewatering System

i. Biosludge storage tank;
ii. Biosludge conditioning tank; and
iii. Biosludge filter press.

g. Demineralizer Wastewater Treatment

i. Demineralizer Waste Clarifier.

h. Wastewater Storage and Collection System

i. Three (3) WTU process/stormwater sumps*;
ii. One (1) - 474,024 gallon (nominal) vertical fixed roof storage tank No. 517;
iii. One (1) - 302,234 gallon (nominal) external floating roof storage tank identified as Wastewater Equalization Tank 3520; and
iv. One (1) - 616,805 gallon (nominal) external floating roof storage tank identified as Wastewater Equalization Tank 3526.

*Indicates equipment whose emissions are transported through the closed vent system to the thermal oxidizer and/or carbon.

(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 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 WTU is subject to the provisions of the following federal regulations:

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

i. Subpart A, General Provisions;

ii. Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels; and
iii. Subpart QQQ, Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems.

b. 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.

c. 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, §11-60.1-161, §11-60.1-174, §11-60.1-180; 40 CFR §60.1, §60.110b, §60.690, §61.01, §61.340, §63.1, §63.640)[1]

2. The Thermal Oxidizer is subject to the provisions of the following federal regulations:

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

i. Subpart A, General Provisions; and
ii. Subpart J, Standards of Performance for 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, §60.100)[1]

<u>Section C</u>. <u>Operational and Emission Limitations</u>

1. The wastewater processed by the WTU shall not exceed 233 million gallons per year in any rolling 365-day period as measured at the collective inlet of the gross oil water separator (Z3511).

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

2. The following conditions pertain to the oil-water separation and recovery system:

   a. All equipment with a fixed roof equipped with access doors or openings shall be gasketed, latched, and kept closed at all times during operation of the WTU, except during inspection and maintenance.
   b. Any pressure relief valve shall be set at the maximum pressure necessary for proper system operation, but such that the valve will not vent continuously.
   c. The standards for oil-water separators specified in 40 CFR Part 61, Subpart FF shall apply.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-3)[1]

3. The following conditions apply to external floating roof tanks (T3520 and T3526) used to treat and store wastewater.

   a. These tanks shall meet the alternative standards for tanks as allowed by 40 CFR Part 61, Subpart FF by 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)[1]

4. The following conditions apply to external floating roof tank (T3522).

   a. This tank shall meet the alternative standards for tanks as allowed by 40 CFR Part 61, Subpart FF by 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)[1]

5. The following applies to the VOC treatment system.

   a. The system shall be designed and operated to keep the benzene content less than 10 ppm by weight on a flow-weighted annual average basis.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.348)[1]

6. The following conditions pertain to the thermal oxidizer:

   a. The thermal oxidizer shall be operated to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.
   b. The thermal oxidizer shall provide a minimum efficiency of ninety-eight (98) percent destruction of all VOC emissions directed to it.
   c. The thermal oxidizer shall be fired only on RFG or commercial grade propane or liquefied petroleum gas (LPG) as a supplementary fuel to the VOC stream. The H_2S content of the RFG shall not exceed 230 mg/dscm (0.10 gr/dscf) or a TS content not to exceed 258 ppm.

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d. Visible Emissions (VE)

For any six (6) minute averaging period, the thermal oxidizer shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the thermal oxidizer 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, §11-60.1-161; 40 CFR §60.104, §60.692-5)[1]

7. Except during maintenance of the thermal oxidizer, or during periods when the thermal oxidizer malfunctions, all VOC emissions from the gross oil water separator, API gravity separator, API effluent tank, IAF unit, air strippers, oil skimming tank, IAF float thickener, emulsion breaking tanks, oil sludge tank, oil sludge conditioning tank, and three (3) WTU process/stormwater sumps shall be exhausted through the thermal oxidizer at all times wastewater is being process through the WTU. During scheduled maintenance of the thermal oxidizer, either all inflows to the WTU shall be suspended or the air strippers shall be shut down and all VOC emissions from the closed vent system shall be redirected to a portable air pollution control device (carbon). During periods of thermal oxidizer malfunctions, the VOC emissions from the closed vent system shall be redirected immediately to a portable air pollution control device. If the system cannot be restarted within thirty (30) minutes, either all inflows to the WTU shall be suspended or the air strippers shall be shut down. The portable air pollution device shall maintain a minimum VOC removal efficiency of ninety-five (95) percent.

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

8. The following conditions apply to the closed vent system:

   a. The closed vent system of the WTU facility shall be operated with VOC emissions measuring less than 500 ppm above background. The closed vent system encompasses the portion of the WTU facility that is not open to the atmosphere. It includes the gross oil water separator, API gravity separator, API effluent tank, oil skimming and emulsion breaking tanks, IAF unit, air strippers, and the associated piping, connections, and flow inducing devices (blowers) that transport gas or vapor from the emission sources to the thermal oxidizer.
   b. A pressure indicator shall be operated and maintained at the outlet vent stream of the gross oil water separator, API gravity separator, oil skimming tank, IAF unit, and each air stripper to ensure that the VOC vapors are being routed to the thermal oxidizer. The pressure indicator shall be in the vent stream at the nearest feasible point to the control device inlet, but before being combined with other vent streams.

c. The normal operating pressure for each pressure indicator associated with the gross oil water separator, API gravity separator, oil skimming tank, IAF unit, and the two (2) air strippers which all exhaust to the thermal oxidizer shall be maintained in order to facilitate detection of abnormal flow of the VOC vapors.

d. All gauging and sampling devices for the closed vent system shall be gas-tight, except when gauging or sampling is taking place.

e. When emissions from the closed vent system are detected, first efforts to initiate repair in eliminating emissions shall be made as soon as practical, but not later than **five (5) calendar days** from the date emissions are detected; repairs shall be completed no later than **(15) calendar days** after detection, unless the permittee can demonstrate in writing to the Department that repair is technically impossible without a complete or partial refinery or WTU shutdown. Repair of the necessary equipment shall be made before the end of the next refinery or WTU shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-5, §61.349(f))[1]

9. The Department reserves the right to require installation of odor controls, or more stringent air controls if during operation, unanticipated odors which present a nuisance are present, or higher levels of VOC's are emitted due to increased concentration of VOC in the waste stream or nonperforming air controls.

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

Section D. Monitoring and Recordkeeping Requirements

1. A continuous flow meter shall be operated and maintained at the inlet of the gross oil water separator to measure and record the gallons per year in any rolling 365-day period the wastewater processed.

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

2. The following conditions pertain to the oil-water separator system:

a. Roof seals, access doors, and other openings shall be checked by visual inspection semi-annually to ensure that no cracks or gaps occur between the roof and tank wall, and that access doors and other openings are closed and gasketed properly.

b. When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as possible, but not later than **fifteen (15) calendar days** after it is identified, except if the permittee can demonstrate in writing to the Department that repair is technically impossible without a complete or partial refinery or WTU shutdown. Repair of the necessary equipment shall be made before the end of the next refinery or WTU shutdown.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.692-3)[1]

3. The following conditions pertains to the VOC treatment system:

   a. The benzene concentration of the air stripper effluent shall be collected and analyzed at least once per month using procedures specified in 40 CFR 61.355(c)(3), or
   b. The air stripper flow rate shall be continuously monitored to ensure benzene levels are treated to design standards.

   (Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §61.354, §61.355)[1]

4. The following conditions pertain to the closed vent system:

   a. At least twice per year, the permittee shall demonstrate, by means of instrument readings, that detectable emissions are controlled to be less than 500 ppmv above background.
   b. A visual inspection of ductwork, piping, and connection to covers and control devices for defects such as holes shall be conducted at least once per calendar quarter.

   (Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §60.692-5, §61.349)[1]

5. The following conditions pertain to the thermal oxidizer:

   a. A temperature monitoring device equipped with a continuous recorder shall be operated and maintained to measure and record the temperature of the gas stream in the combustion zone of the thermal oxidizer. The temperature monitoring device shall have an accuracy of one (1) percent of the temperature being measured in °C or ± 0.5 °C (± 1.0 °F), whichever is greater.
   b. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in the thermal oxidizer. The CMS shall meet the following requirements:

      i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S;
      ii. All fuel gas combustion devices, including the thermal oxidizer, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned;
      iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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 shall be used in conducting any RATA.
      iv. 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_2S CMS, RATAs 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. CD assessments shall be performed on a daily basis pursuant to 40 CFR Part 60, Appendix F, Section 4.1.

c. The permittee shall operate and maintain a fuel meter to monitor the standard cubic feet (SCF) of RFG fired by the thermal oxidizer.

d. Compliance, on a continuous basis, with the TS limit specified in Special Condition No. C.6.c of this attachment shall be determined by TS analysis in the RFG using ASTM Methods D5504-94, D5453-93, or other methods approved by the Department. A representative sample of the RFG shall be analyzed a minimum of twice a month to ensure continuous compliance. Records of the TS content of the RFG shall be maintained on a monthly basis. Compliance with the TS standard shall be determined by averaging the analytical results obtained throughout the month.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.105, §60.695, PS-7)[1]

6. Visible Emissions (VE)

The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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 §11-60-15, §11-60-24)[2]

7. The permittee shall maintain a file containing records of the following:

a. The location, date, and corrective action of the required inspections for the oil-water separator system. Include documentation of any problems identified that could result in VOC emissions.

b. The location, date, and corrective action of the required inspections for the closed vent system. Include dates of each measurement of detectable emissions and the corresponding background levels of VOC measured during each detectable emissions measurement. The maximum instrument reading measured during each detectable emission measurement shall also be recorded. Include documentation of any problems identified that could result in detectable VOC emissions.

c. Reasons for delays for any repair or correction of an emission point by the specified time, with the expected and actual date of repair completion. The documentation shall be signed by a responsible official (or designee) who determined that the repair could not be done without a refinery or WTU shutdown.

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d. Dates of startup and shutdown of the closed vent system and thermal oxidizer, and periods where the system is not operated as designed. Document any problems with the flow of VOC's to the thermal oxidizer as determined by the pressure indicators installed in each vent stream to the thermal oxidizer.
e. Maintain continuous records of the temperature of the gas stream in the combustion zone of the thermal oxidizer, and record all three-hour (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 required combustion zone temperature.
f. Record the concentration of H_2S in the RFG, as measured by the CMS. The data shall be summarized as an average one-hour (1-hour) H_2S concentration on a daily, monthly, and annual basis.
g. The SCF of RFG fired in the thermal oxidizer each month.
h. Test results of benzene concentrations in the wastestreams as required by NESHAP, Subpart FF.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-180; 40 CFR §60.107, §60.697, §61.356)[1]

8. A copy of the design specifications and drawings for all equipment in the WTU used to comply with the conditions of this permit shall be kept for the life of the WTU in a readily accessible location. The design specifications include:

a. Detailed schematics, and piping and instrumentation diagrams;
b. Dates and description of any changes in the design specifications;
c. Operating and maintenance information on the closed vent system, thermal oxidizer, and the portable air pollution control devices; and
d. Documentation that the thermal oxidizer and the closed vent system will achieve the required control efficiency of ninety-eight (98) percent VOC destruction during the maximum loading conditions, and is capable of achieving a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C (1500 °F). The documentation shall include a general description of the gas streams that enter the thermal oxidizer, including flow and VOC content under varying wastewater level conditions (dynamic and static) and the manufacturer's design specifications for the thermal oxidizer. Include parameter(s) to be monitored which ensures that the thermal oxidizer and closed vent system are operated in conformance with the permit requirements and design specifications. Provide an explanation of the criteria used for selecting the parameters.
e. Documentation that the portable air pollution control device used during scheduled maintenance can achieve a minimum VOC removal of ninety-five (95) percent or alternatively demonstrate through monitoring and retain records thereof that there are no detectable (less than 500 ppm above background levels) VOC emissions as measured by a detection instrument.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.697)[1]

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 systems 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)[1]

10. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) 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 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 thermal oxidizer. 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 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 and span checks; and
      v. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices.

b. All reports shall be postmarked by the **thirtieth (30th) 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 any rolling three-hour (3-hour) period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 230 mg/dscm (0.10 gr/dscf).

d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission and concentration limits for the purposes of the 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)[1]

2. The permittee shall submit written reports to the Department for each calendar quarter. The reports shall be submitted within **thirty (30) days** after the end of each calendar quarter and shall include the following:

   a. Certification that all required inspections and monitoring have been carried out.

   b. For the wastewater treatment process and the air stripper effluent, that the benzene levels are less than 10 ppm.

   c. All three-hour (3-hour) periods of operation during which the average temperature of the gas stream in the combustion zone of the thermal oxidizer as measured by the temperature monitoring device, is more than 28 ºC (50 ºF) below the required combustion zone temperature.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.357(d))[1]

3. 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. For the WTU:

      The gallons of wastewater processed for the semi-annual period and all exceedances measured greater than 233 million gallons per year on a rolling 365-day period as measured by the continuous flow meter.

   b. For the thermal oxidizer:

      Amount of RFG or LPG fired in the thermal oxidizer on a monthly and semi-annual basis. Average monthly TS content of the RFG or LPG for each month.

c. For the closed vent system:

All instrument readings 500 ppm above background as measured pursuant to Special Condition No. D.4. of this attachment.

d. A summary of (quarterly visual, semi-annual monitoring, and annual tank) inspections required by 40 CFR §61.342 through §61.354 that could result in benzene emissions.

e. 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** or an equivalent form shall be used.

e. 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 §60.698, §61.342)[1]

4. 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 HAPs. 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 determined 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)

5. 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 unless in-flow to the closed -portion of the WTU has been suspended;

b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit; and

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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)

6. 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)

7. 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 which the excursion or exceedances 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 the 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)

8. The permittee shall notify the Department in writing at least **thirty (30) days** prior to 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 §60.8, §60.13)[1]

9. If compliance with any provisions of this permit is delayed to initiate corrective actions, the notification required under 40 CFR §60.7(a)(4) shall include the estimated date of the next scheduled refinery or WTU shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or WTU shutdown.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.698)[1]

10. The permittee shall submit the total benzene quantity pursuant to 40 CFR Part 61, Subpart FF, on an annual basis.

    (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.357)[1]

Section F. Testing Requirements

1. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S 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)

2. At least **thirty (30) days** prior to performing a test, the permittee shall submit a written performance test plan to the Department 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 or require a retest.

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

3. The permittee shall provide required testing at its own expense. The Department may monitor the tests.

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

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4. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

5. Inspection and measurement of emissions concentrations for the closed vent system shall be made on a **semi-annual basis**, in accordance with 40 CFR §60.696 and 40 CFR, Appendix A, Method 21. The instrument used for emission measurements shall be calibrated before each use. The calibration gases shall be zero air (less than 10 ppm of hydrocarbon in air), and a mixture of either methane or n-hexane and air at a concentration of approximately, but less than 10,000 ppm methane or n-hexane.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.696)[1]

<u>Section G</u>. <u>Agency Notification</u>

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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[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 II(K): SPECIAL CONDITIONS
MERCAPTAN TREATMENT UNITS
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 of the Mercaptan Treatment Units:

   a. Mercaptan Treatment Units

      i. LPG Mercaptan Extraction Unit;
      ii. Deisopentanizer (DIP) Overhead Sweetening Unit;
      iii. Deisopentanizer (DIP) Bottoms Sweetening Unit; and
      iv. Kerosene Sweetening Unit.

   (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 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 Mercaptan Treatment Units 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 §63.1, §63.640)[1]

Section C. Operational and Emission Limitations

1. A flare, incinerator, boiler, or process heater shall be used as a control device for the LPG Mercaptan Extraction Unit process vent stream.

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

2. If the emission rate of total volatile organic compounds (TOC) discharged from the LPG Mercaptan Extraction Unit process vent is greater than or equal to 33.0 kg/day prior to any control device and prior to discharge into the atmosphere, the provisions of a Group 1 miscellaneous process vent per 40 CFR §63.643 shall be complied with, including any additional monitoring and testing requirements as specified in 40 CFR §63.644 and 40 CFR §63.645.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.641)[1]

Section D. Monitoring and Recordkeeping Requirements

1. The permittee shall record in a log kept in a readily accessible location for the use in determining exemptions from the requirements of 40 CFR Part 61, Subpart J and V, information as specified in 40 CFR §61.246(i) including:

   a. An analysis demonstrating the design capacity of the process unit, and
   b. An analysis demonstrating that equipment is not in VHAP service.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-173; 40 CFR §61.246)[1]

2. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) upon request.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.654)[1]

Section E. Notification and Reporting Requirements

1. If the recalculated emission rate of TOC discharged from the LPG Mercaptan Extraction Unit process vent is greater than 33 kg/day, the permittee shall submit a report as specified in 40 CFR §63.654(d), (e), (f), or (h).

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.10, §63.654)[1]

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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 HAPs. 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 process emissions.

   Upon written request of the permittee, the deadline for reporting annual emissions may be extended if the Department determined 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; 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 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)

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 which the excursion or exceedances 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 the 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:

   Any deviations from permit requirements shall be clearly identified.

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

<u>Section F</u>. <u>Testing Requirements</u>

1. The testing method to determine the TOC mass flow rate for Special Condition No. C.2. of this attachment shall be in accordance with 40 CFR §63.645 - Test Methods and procedures for miscellaneous process vents. The TOC mass flow rate shall be calculated on an annual basis, or recalculated, as necessary, whenever process changes are made. Process changes include, but are not limited to, changes in production capacity, production rate, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.645)[1]

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

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

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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[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.

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ATTACHMENT II(L): SPECIAL CONDITIONS
FLARE
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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:

   Flare (steam-assisted)

   (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 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 flare 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;
      ii. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007; and
      iii. 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.

   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, §11-60.1-174; 40 CFR §60.1, §60.100a, §60.590a, §63.1, §63.640)[1]

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Section C. Operational and Emissions Limitations

1. The flare shall be designed for and operated with no visible emissions except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours, when waste gas or 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, §11-60.1-161, §11-60.1-174; 40 CFR §60.18, §63.670, CD 5:16-cv-00722)[1]

2. The flare shall be operated with a pilot flame present at all times when waste gas or regulated material is routed to the flare. Each fifteen-minute (15-minute) block during which there is at least one (1) minute where no pilot flame is present when waste gas or regulated material is routed to the flare is a deviation of the standard. Deviations in different fifteen-minute (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, CD 5:16-cv-00722)[1]

3. Flare Tip Velocity

   For the flare, the permittee shall comply with either 40 CFR §63.670(d)(1) or (2), provided the appropriate monitoring systems are in-place, whenever waste gas or 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)[1]

4. Combustion Zone Operating Limits

   For the flare, the permittee shall operate each flare to maintain the net heating value of flare combustion zone gas (NHV_{cz}) at or above 270 Btu/scf determined on a fifteen-minute (15-minute) block period basis when waste gas or 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, CD 5:16-cv-00722)[1]

5. The permittee shall not burn in the flare any fuel gas that contains H_2S in excess of 230 mg/dscm (0.10 gr/dscf) and 162 ppmv determined hourly on a three-hour (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))[1]

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6. The permittee shall conduct a root cause analysis and a corrective action analysis for the flare for each of the following conditions:

   a. Any time the SO_2 emissions exceed 227 kilograms (kg) (500 lb) in any twenty-four-hour (24-hour) period; or
   b. Any discharge to the flare in excess of 14,160 standard cubic meters (m^3) (500,000 standard cubic feet (scf)) above the baseline, determined in 40 CFR §60.103a(a)(4), in any twenty-four-hour (24-hour) period.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.103a)[1]

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). The FMP shall additionally be written and implemented to minimize flaring during periods of startup, shutdown, or emergency releases, in accord with the provisions of 40 CFR §63.670(o)(1) through (o)(7).

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.103a, §63.670)[1]

8. Waste gas venting from the flare shall not exceed 293,861 scf/day based on a thirty-day (30-day) rolling average beginning January 1, 2018. Waste gas does not include hydrogen, nitrogen, carbon dioxide (CO_2), CO, or O_2 and these compounds are not subject to the flare gas flow limits if properly measured. The hydrocarbon waste gas limit may be revised in accord with the provisions of the consent decree (CD 5:16-cv-00722).

   (Auth.: HAR §11-60.1-3, §11-60.1-90, CD 5:16-cv-00722)

9. Waste gas venting from the flare shall not exceed 195,787 scf/day based on a 365-day rolling average beginning January 1, 2019. Waste gas does not include hydrogen, nitrogen, CO_2, CO, or O_2 and these compounds are not subject to the flare gas flow limits if properly measure. The hydrocarbon waste gas limit may be revised in accord with the provisions of the consent decree (CD 5:16-cv-00722).

   (Auth.: HAR §11-60.1-3, §11-60.1-90, CD 5:16-cv-00722)

10. When potentially recoverable gas is being generated, one (1) compressor shall be available and/or in operation ninety-eight (98) percent of the time, and two compressors shall be available and/or in operation ninety-five (95) percent of the time. Excess Fuel Gas and excess gases generated during Shutdown, in turnaround, and during Startup, caused by a gas imbalance that cannot be consumed by Fuel Gas consumers in the refinery, because there is not sufficient demand for the gas, is not Potentially Recoverable Gas provided that, no natural gas is being supplied to the Fuel Gas mix drum. Nitrogen purges of Flaring Process Units that are being Shutdown, in turnaround and during Startup, or the nitrogen

purging of operating Flaring Process Units during a partial refinery turnaround scenario, that cause the NHV of the Fuel Gas at the exit of the mix drum to fall below 740 BTU/scf, shall not be considered Potentially Recoverable Gas.

(Auth.: HAR §11-60.1-3, §11-60.1-90, CD 5:16-cv-00722)

Section D. Monitoring and Recordkeeping Requirements

1. Visible Emissions Monitoring

   The permittee shall monitor the flare for visible emissions using either of the methods shown below:

   a. At least once per day for each day waste gas or regulated material is routed to the flare, the permittee shall conduct visible emissions 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 visible emissions while waste gas or regulated material is routed to the flare, even if the minimum required daily visible emissions 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 visible emissions are observed for more than one continuous minute during any five-minute (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 visible emissions are observed. Daily five-minute (5-minute) Method 22 observations are not required to be conducted for days the flare does not receive any waste gas or 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, CD 5:16-cv-00722)[1]

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)[1]

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3. Continuous Monitoring System for H_2S

a. The permittee shall operate, calibrate, and maintain a CMS for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in routinely-generated refinery fuel gases before being burned in the flare.
b. The CMS shall meet the following requirements:

i. The span value for the CMS is 425 mg/dscm (300 ppmv) H_2S.
ii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13(c). The H_2S 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-5, Method 11, 15, or 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_2 and NO_x Continuous Monitoring Emission Monitoring Systems in Stationary Sources, Section 16.0, Alternative Procedures (CGA) 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.

c. The permittee may apply for an exemption from the H_2S 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_2S 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_2S 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 5 ppm H_2S; and

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(5) A description of how the two (2) weeks of monitoring results compares to the typical range of H_2S 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))[1]

4. Continuous Monitoring System for Total Sulfur

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 flare.

b. The CMS shall meet the following requirements:

i. The span value for the CMS is 250,000 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 Continuous Emission Monitoring Systems 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_2 and NO_x Continuous Monitoring Emission Monitoring Systems in Stationary Sources, Section 16.0, Alternative Procedures (CGA) 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))[1]

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

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.107a(f))[1]

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 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).

   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. The gas chromatography (GC) used to determine the NHV of the Vent Gas (and to speciate the compounds that may be excluded from the amount of Waste Gas) shall be operated and maintained in accordance with Performance Specification 9 of 40 CFR Part 60 Appendix B, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly) and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C).

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.670)[1]

7. The permittee shall comply with the flare monitoring systems requirements in 40 CFR §63.671 for the flare. The GC used to determine the NHV of the Vent Gas (and to speciate the compounds that may be excluded from the amount of Waste Gas) shall be operated and maintained in accordance with Performance Specification 9 of 40 CFR Part 60, Appendix B, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly) and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C).

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.671)[1]

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), §63.670)[1]

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9. The permittee shall keep records pursuant to 40 CFR §60.108a(c)(6).

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.108a(c)(6))[1]

10. Flare Recordkeeping Requirements

    For the 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-minute (15-minute) block during which there was at least one minute that no pilot flame is present when waste gas or regulated material is routed to a flare for a minimum of five (5) years.
    b. Retain records of daily visible emissions 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 visible emissions observations are performed using Method 22 at 40 CFR Part 60, Appendix A-7, the record must identify whether the visible emissions observation was performed, the results of each observation, total duration of observed visible emissions, and whether it was a five-minute (5-minute) or two-hour (2-hour) observation. If the permittee performs visible emissions observations more than one (1) time during the day, the record must also identify the date and time of day each visible emissions 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-hour (2-hour) period during which visible emissions are observed or captured by video for more than five (5) minutes in two (2) consecutive hours, the record must include the date and time of the two-hour (2-hour) period and an estimate of the cumulative number of minutes in the two-hour (2-hour) period for which emissions were visible.

    c. The fifteen-minute (15-minute) block average cumulative flows for flare vent gas and, if applicable, total steam specified to be monitored under 40 CFR §63.670(i), along with the date and time interval for the fifteen-minute (15-minute) block. If multiple monitoring locations are used to determine cumulative vent gas flow and total steam, retain records of the fifteen-minute (15-minute) block average flows for each monitoring location for a minimum of two (2) years, and retain the fifteen-minute (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-minute (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-minute (15-minute) block average cumulative flows for a minimum of two (2) years, and retain the fifteen-minute (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-minute (15-minute) block average values for a minimum of five (5) years.
e. Each fifteen-minute (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 waste gas or 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, CD 5:16-CV-00722)[1]

11. The permittee shall install and maintain a device for recording the amount of offgas being recovered by the flare gas recovery system.

    (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)[1]

12. The permittee shall keep records of the quantity of offgas recovered by the flare gas recovery system in Mscf/day on a monthly average and a six-month (6-month) average basis.

    (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)[1]

13. 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 systems 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)[1]

14. 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)[1]

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 HAPs. 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 determined 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; 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 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

   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 which the excursion or exceedances 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 the 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. 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 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 and span checks; and
v. The report shall include the information specified in 40 CFR §60.108a(d)(1) through (d)(7).

b. All reports shall be postmarked by the **thirtieth (30th) 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-hour (3-hour) period during which the average concentration of H_2S in routinely-generated refinery fuel gases, as measured by the H_2S 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), §60.108a(d))[1]

6. 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 visible emissions test performed. Include the time and date of test and the corrective actions taken.
b. The monthly average and six-month (6-month) average quantity of offgas recovered by the flare vapor recovery system in Mscf/day.
c. The monthly average and six-month (6-month) average of the flare waste gas venting rates in Mscf/day.
d. A record/report of any exceedances of the thirty-day (30-day) rolling average or 365-day rolling average limits of flare waste gas venting rates as specified by Special Condition Nos. C.8 and C.9 of this attachment.

e. A record/report of any exceedances of the ninety-five (95) percent and ninety-eight (98) percent rolling flare gas compressor availability requirements.
f. Any deviations from permit requirements shall be clearly identified.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-174; 40 CFR §63.655, CD 5:16-cv-00722)[1]

7. Flare Reporting Requirements

The permittee shall submit Periodic Reports no later than sixty (60) days after the end of each six-month (6-month) period when any of the information specified in the paragraph below is collected. The first six-month (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-month (6-month) period unless emissions averaging is utilized. 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.9.a of this attachment for each fifteen-minute (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. Visible emissions records as specified in Special Condition No. D.9.b.iii of this attachment for each period of two (2) consecutive hours during which visible emissions exceeded a total of five (5) minutes.
c. The fifteen-minute (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-minute (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)[1]

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8. Supplemental Continuous Parameter Monitoring System Performance Report

The permittee shall submit a supplemental CPMS Performance Report which quantifies the actual downtime and downtime as a percent of operating for any CPMS that is used to demonstrate or ensure compliance with various Flare limits specified by the consent decree (CD 5:16-cv-00722), including but not limited to the flare vent gas flow meter, purge gas flow meter, steam flow or mass meter, waste gas or vent gas compositional analyzer, video camera and recording device.

a. The calculation of instrument downtime shall be made in accordance with 40 CFR §60.13(h)(2) and Appendix C-1.1 of the consent decree.
b. For each required instrument, the CPMS Performance Report shall include a summary of monitoring system malfunctions or recognized performance deficiencies, repair periods, routine span adjustment calibration checks and other Quality Assurance/Quality Control Activities on a semi-annual basis.
c. The Flare CPMS Performance Report shall quantify instrument downtime and explain any monitoring system malfunctions, deficiencies and repair efforts other than downtime necessitated by routine Quality Assurance/Quantity Control Activities as appropriately denoted.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, CD 5:16-cv-00722)

Section F. Agency Notification

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)

[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.

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ATTACHMENT II(M): SPECIAL CONDITIONS
PETROLEUM STORAGE TANKS
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date:** **May 12, 2026**

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. Seven (7) Crude Oil Storage Tanks

      i. One (1) - 9,868,877 gallon (nominal) external floating roof storage tank identified as Tank 101;
      ii. Five (5) - 13,989,087 gallon (nominal) external floating roof storage tanks identified as Tanks 102, 103, 104, 105, and 106; and
      iii. One (1) - 18,298,590 gallon (nominal) external floating roof storage tank identified as Tank 107.

   b. Seven (7) Recovered Oil/Wastewater Storage Tanks

      i. One (1) - 1,107,535 gallon (nominal) internal floating roof storage tank identified as Tank 109;
      ii. One (1) - 2,650,792 gallon (nominal) internal floating roof storage tank identified as Tank 111;
      iii. One (1) - 2,283,940 gallon (nominal) external floating roof storage tank identified as Tank 902;
      iv. One (1) - 302,234 gallon (nominal) external floating roof storage tank identified as Wastewater Equalization Tank 3520;
      v. One (1) - 509,305 gallon (nominal) external floating roof storage tank identified as Recovered Oil Tank 3522;
      vi. One (1) - 616,805 gallon (nominal) external floating roof storage tank identified as Wastewater Equalization Tank 3526; and
      vii. One (1) - 1,107,535 gallon (nominal) external floating roof storage tank identified as Tank 110.

   c. Fifteen (15) Naphtha/Gasoline Storage Tanks

      i. Three (3) - 1,015,085 gallon (nominal) external floating roof storage tanks identified as Tanks 202, 203, and 204;
      ii. Two (2) - 3,289,626 gallon (nominal) external floating roof storage tanks identified as Tanks 405 and 509;

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iii. One (1) - 2,134,215 gallon (nominal) external floating roof storage tank identified as Tank 406;
iv. Two (2) - 2,283,940 gallon (nominal) internal floating roof storage tanks identified as Tanks 407 and 408;
v. Three (3) - 1,998,448 gallon (nominal) external floating roof storage tanks identified as Tanks 501, 502, and 503;
vi. One (1) -5,296,298 gallon (nominal) internal floating roof storage tank identified as Tank 510;
vii. One (1) - 4,605,476 gallon (nominal) internal floating roof storage tank identified as Tank 604; and
viii. Two (2) - 3,095,209 gallon (nominal) internal floating roof storage tanks identified as Tanks 610 and 611.

d. Thirty-Four (34) Heavy Oil Storage Tanks

i. One (1) - 2,650,792 gallon (nominal) vertical fixed roof storage tank identified as Tank 112;
ii. One (1) - 68,159 gallon (nominal) vertical fixed roof storage tank identified as Tank 200;
iii. Four (4) - 1,015,085 gallon (nominal) vertical fixed roof storage tanks identified as Tanks 205, 206, 301, and 302;
iv. Two (2) - 1,804,595 gallon (nominal) vertical fixed roof storage tanks identified as Tanks 207 and 303;
v. Two (2) - 2,141,194 gallon (nominal) vertical fixed roof storage tanks identified as Tanks 304 and 305;
vi. Four (4) - 4,605,476 gallon (nominal) vertical fixed roof storage tanks identified as Tanks 306, 307, 606, and 607;
vii. One (1) - 455,942 gallon (nominal) vertical fixed roof storage tank identified as Tank 311;
viii. One (1) - 1,998,448 gallon (nominal) external floating roof storage tank identified as Tank 504;
ix. Four (4) - 1,998,448 gallon (nominal) vertical fixed roof storage tanks identified as Tanks 505, 506, 507, and 508;
x. One (1) - 5,526,571 gallon (nominal) internal floating roof storage tank identified as Tank 511;
xi. One (1) - 5,168,496 gallon (nominal) vertical fixed roof storage tank identified as Tank 512;
xii. One (1) – 1,265,848 gallon (nominal) vertical fixed roof storage tank identified as Tank 513;
xiii. Two (2) - 2,968,887 gallon (nominal) vertical fixed roof storage tank identified as Tanks 514 and 515;

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xiv. One (1) - 8,518 gallon (nominal) vertical fixed roof storage tank identified as Tank 516;
xv. Two (2) - 4,856,228 gallon (nominal) internal floating roof storage tanks identified as Tanks 608 and 609;
xvi. Two (2) - 22,557 gallon (nominal) vertical fixed roof storage tanks identified as Tanks 903 and 905;
xvii. One (1) - 117,487 gallon (nominal) vertical fixed roof storage tank identified as Tank 1103;
xviii. One (1) - 230,274 gallon (nominal) internal floating roof storage tank identified as Tank 2301;
xix. One (1) – 4,605,476 gallon (nominal) vertical fixed roof storage tank identified as Tank 605; and
xx One (1) – 474,024 gallon (nominal) vertical fixed roof storage tank identified as Tank 517.

e. Seven (7) Renewable Feedstock/Renewable Biofuel/Heavy Oil Storage Tanks

i. One (1) - 2,141,194 gallon (nominal) internal floating roof storage tank identified as Tank 601;
ii. One (1) - 2,141,194 gallon (nominal) vertical fixed roof storage tanks identified as Tank 602;
iii. One (1) - 4,605,476 gallon (nominal) vertical fixed roof storage tank identified as Tank 603;
iv. Two (2) - 1,804,595 gallon (nominal) external floating roof storage tanks identified as Tanks 401 and 402; and
v. Two (2) - 1,804,595 gallon (nominal) external floating roof storage tanks identified as Tanks 403 and 404.

f. One (1) Renewable Biofuel/Naphtha/Gasoline Storage Tank

One (1) - 1,015,085 gallon (nominal) external floating roof storage tank identified as Tank 201.

(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., and manufacturer of each tank.

(Auth.: HAR §11-60.1-5, §11-60.1-90)

Section B. Applicable Federal Regulations

1. Petroleum Storage Tanks 106, 406, 407, 408, and 510 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 K, 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.

   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, §60.110)[1]

2. Petroleum Storage Tank 902 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 Ka, 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.

   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, §60.110a)[1]

3. Petroleum Storage Tanks 107, 109, 110, 111, 604, 610, 611, 3520, 3522, and 3526 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 Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984; and

iii. 40 CFR §60.110b(e)(5) – Option to comply with Part 63, Subpart WW, is included in these requirements as an alternative means of compliance.

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, §60.110b)[1]

4. 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.

      <u>Compliance Date</u>

      For Group 1 storage tanks (Petroleum Storage Tanks 101, 102, 103, 104, 105, 106, 107, 109, 110, 111, 201, 202, 203, 204, 405, 406, 407, 408, 501, 502, 503, 509, 510, 604, 610, 611, 902, 3520, 3522, and 3526), 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; except for Tank 109, which shall already be in compliance with these standards.

      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 (Petroleum Storage Tanks 112, 200, 205, 206, 207, 301, 302, 303, 304, 305, 306, 307, 311, 401, 402, 403, 404, 504, 505, 506, 507, 508, 511, 512, 513, 514, 515, 516, 517, 601, 602, 603, 605, 606, 607, 608, 609, 903, 905, 1103, and 2301) shall comply with Sections C through F below.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.640, §63.646)[1]

Section C. Operational and Emission Limitations

1. The petroleum storage tanks identified in Special Condition No. A.1.a of this attachment shall only store petroleum liquids with a true vapor pressure of 11.1 psia or less.

   (Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

2. The petroleum storage tanks identified in Special Condition No. A.1.b of this attachment shall only store petroleum liquids with a true vapor pressure of 11.1 psia or less.

   (Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

3. The petroleum storage tanks identified in Special Condition No. A.1.c of this attachment shall only store petroleum liquids with a true vapor pressure of 11.1 psia or less.

   (Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

4. The petroleum storage tanks identified in Special Condition No. A.1.d of this attachment (except for Petroleum Storage Tanks 903 and 905) shall only store petroleum liquids with a true vapor pressure of 1.5 psia or less. Tank 605 shall only store petroleum liquids with a liquid HAP content of 0.5% by weight or less. Jet or kerosene shall not be stored in Tank 605.

   (Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

5. The petroleum storage tanks identified in Special Condition No. A.1.e of this attachment shall only store renewable feedstock or heavy oil with a true vapor pressure of 1.5 psia or less. The petroleum storage tank identified in Special Condition No. A.1.f of this attachment shall only store renewable feedstock or naphtha/gasoline with a true vapor pressure of 11.1 psia or less.

   (Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

6. Petroleum Storage Tanks 106, 406, 407, 408, and 510

   a. The true vapor pressure of the petroleum liquid stored shall be maintained below 11.1 psia (76.6 kPa) at all times. Determination of the true vapor pressure shall be done according to an applicable method specified in NSPS, Subpart K.
   b. The petroleum storage tanks 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 closure seals to close the space between the roof edge and the tank wall.

   (Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90, §11-60.1-161; 40 CFR §60.112)[1]

7. Petroleum Storage Tank 902

   a. The true vapor pressure of the petroleum liquid stored shall be maintained below 11.1 psia (76.6 kPa) at all times. Determination of the true vapor pressure shall be done according to an applicable method specified in NSPS, Subpart Ka.

   b. The petroleum storage tank shall be equipped with an external floating roof which will rest on the surface of the liquid contents and be equipped with a primary seal and secondary seal to close the space between the roof edge and the tank wall. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports), except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. The tank shall meet the following specifications:

      i. The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:

         (1) The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm^2 per meter of tank diameter (10.0 in^2 per ft. of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1.5 in);
         (2) The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm^2 per meter of tank diameter (1.0 in^2 per ft. of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (0.5 in);
         (3) One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of sixty-one (61) cm (24 in) above the stored liquid surface; and
         (4) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

      ii. The secondary seal is to meet the following requirements:

         (1) The secondary seal is to 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. C.7.b.ii(2) of this attachment;
         (2) The accumulated area of gaps between the tank wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed 21.2 cm^2 per meter of tank diameter (1.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (0.5 in). There shall be no gaps between the tank wall and the secondary seal used in combination with a vapor-mounted primary seal;
         (3) There are to be no holes, tears or other openings in the seal or seal fabric; and

(4) The permittee is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.

iii. Each opening in the roof except for automatic bleeder vents and rim space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap), except when the device is in actual use or as described in Special Condition No. C.7.b.iv of this attachment. 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. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended settings.

iv. Each emergency roof drain is to be provided with a slotted membrane fabric cover than covers at least ninety (90) percent of the area of the opening.

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90, §11-60.1-161; 40 CFR §60.112a)[1]

8. Petroleum Storage Tanks 107, 109, 110, 111, 604, 610, 611, 3520, 3522, and 3526

a. The true vapor pressure of the volatile organic liquid (VOL) stored shall be maintained below 11.1 psia (76.6 kPa) at all times. Determination of the true vapor pressure shall be done according to an applicable method specified in NSPS, Subpart Kb.

b. Petroleum Storage Tanks 109, 111, 604, 610, and 611 shall each have a fixed roof with an internal floating roof and shall meet the specifications pursuant to 40 CFR Part 60, Section 60.112b(a)(1) consisting of the following:

i. The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel 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 vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

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 (2) 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

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(3) A mechanical shoe seal.

iii. Each opening in a noncontact internal floating roof, except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

iv. Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap), except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

v. Automatic bleeder vents shall be equipped with a gasket and 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 support legs.

vi. Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

vii. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least ninety (90) percent of the opening.

viii. Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

ix. Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

c. Petroleum Storage Tanks 107, 110, 3520, 3522, and 3526 shall each have an external floating roof and shall meet the specifications pursuant to 40 CFR Part 60, Section 60.112b(a)(2) consisting of 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 as allowed in 40 CFR Part 60, Section 60.113b(b)(4).

ii. Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap), except when the device is in actual use. 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. Rim vents are to be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least ninety (90) percent of the area of the opening.

iii. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports), except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90, §11-60.1-161; 40 CFR §60.112b)[1]

9. Each petroleum storage tank identified in Section A of this attachment shall be equipped with a permanent submerged fill pipe. A submerged fill pipe means a fill pipe the discharged opening of which is entirely submerged when the liquid level is six (6) inches above the bottom of the tank; or when applied to a tank which is loaded from the side, shall mean a fill pipe where the bottom of the discharge opening is no more than eighteen (18) inches above the bottom of the tank.

(Auth.: HAR §11-60.1-3, §11-60.1-39, §11-60.1-90)

Section D. Monitoring and Recordkeeping Requirements

1. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, § 11-60.1-161, §11-60.1-174; 40 CFR §60.113, §60.115a, §60.115b, §63.646, §63.654)[1]

2. Petroleum Storage Tanks 106, 406, 407, 408, and 510

   a. Records shall be maintained on the petroleum liquid stored, the period of storage, and the maximum true vapor pressure (kPa or psia) of that liquid during the respective storage period. Determination of the maximum true vapor pressure shall be in accordance with 40 CFR Part 60, Section 113(b). Records shall be maintained on a monthly basis.

b. The internal roof seals for Petroleum Storage Tanks 510, 407, and 408, shall be inspected **periodically** and repaired or replaced as **needed**. *In no case shall the period between inspections exceed two (2) years*. This requirement is only applicable until the tanks have their seals upgraded to MACT standards. Thereafter, the requirements of Section G shall be followed.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.113)[1]

3. Petroleum Storage Tank 902

a. Records shall be maintained on the petroleum liquid stored, the period of storage, and the maximum true vapor pressure (kPa or psia) of that liquid during the respective storage period. Determination of the maximum true vapor pressure shall be in accordance with 40 CFR Part 60, Section 115a. Records shall be maintained on a monthly basis.

b. The permittee shall determine compliance with the specifications in Special Condition No. C.7.b of this attachment by determining the gap areas and maximum gap widths between the primary seal and the tank wall and between the secondary seal and the tank wall according to the following frequencies specified below:

i. For primary seals, gap measurements shall be performed within **sixty (60) days** of the initial fill with petroleum liquid and at least once every **five (5) years** thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.

ii. For secondary seals, gap measurements shall be performed within **sixty (60) days** of the initial fill with petroleum liquid and at least once every year thereafter.

iii. If any storage tank is out of service for a period of one (1) year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of Special Conditions Nos. D.3.b.i and D.3.b.ii above.

c. The permittee shall determine gap widths and gap areas in the primary and secondary seals individually by the procedures in 40 CFR Part 60, Section 60.113a(a)(1)(ii) and (iii), respectively.

d. Records of each gap measurement shall be maintained. Each record shall identify the tank on which the measurement was performed and shall contain the date of the seal gap measurement, and the raw data obtained in the measurement process and the calculation required in Special Condition No. D.3.c of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.115a)[1]

4. Petroleum Storage Tanks 107, 109, 110, 111, 604, 610, 611, 3520, 3522, and 3526

   a. Records showing the dimensions (meters or feet) of the petroleum storage tank and the analysis showing the capacity (cubic meters or cubic feet) of the storage tank shall be maintained for the life of the tank.
   b. Records shall be maintained on the type of VOL stored, the period of storage, and the maximum true vapor pressure (kPa or psia) of that VOL during the respective storage period. Determination of the maximum true vapor pressure shall be in accordance with 40 CFR Part 60, Section 116b(e). Records shall be maintained on a monthly basis.
   c. Petroleum Storage Tanks 109, 111, 604, 610, and 611

      i. Inspections and repairs of the petroleum storage tanks shall be conducted in accordance with 40 CFR Part 60, Section 60.113b(a) as follows:

         (1) For storage tanks equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every **twelve (12) months** after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage tank, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the permittee shall repair the items or empty and remove the storage tank from service within **forty-five (45) days**. If a failure that is detected during inspections required in this paragraph cannot be repaired within **forty-five (45) days**, a thirty-day (30-day) extension may be requested from the Department in the inspection report required in 40 CFR §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the permittee will take that will assure that the control equipment will be repaired or the tank will be emptied as soon as possible.
         (2) For storage tanks equipped with a double-seal system, visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), 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**. If the internal floating roof has defects, 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 surfaces from the atmosphere, or the slotted membrane has more than ten (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 VOL; **or** visually inspect the storage tank as specified in Special Condition No. D.4.c.i(1) of this attachment at least once every **twelve (12) months** and as specified in Special Condition No. D.4.c.i(2) of this attachment at least once every **ten (10) years.**

ii. The permittee shall keep records of each inspection performed as required by 40 CFR Part 60, Section 60.113b(a)(1), (a)(2), (a)(3), and (a)(4). Records shall include the storage tank identification, the date the tank was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

d. Petroleum Storage Tanks 107, 110, 3520, 3522, and 3526

i. The permittee shall determine the gap areas and maximum gap widths between the primary seal and the tank wall and between the secondary seal and the tank wall according to the following frequencies:

(1) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the tank or within **sixty (60) days** of the initial fill with VOL and at least **once every five (5) years** thereafter.
(2) Measurements of gaps between the tank wall and the secondary seal shall be performed within **sixty (60) days** of the initial fill with VOL and at least **once per year** thereafter.
(3) If any of the storage tanks ceases to store VOL for a period of one (1) year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of Special Conditions (1) and (2) above.

ii. The permittee shall determine gap widths and areas in the primary and secondary individually by the procedures in 40 CFR Part 60, Section 60.113b(b)(2)(i) through (iii), and 60.113b(3).
iii. The permittee shall make necessary repairs or empty the storage tank within **forty-five (45) days** of identification in any inspection for seals not meeting the requirements listed below:

(1) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm:

(a) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of sixty-one (61) cm above the stored liquid surface; and
(b) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(2) The secondary seal is to meet the following requirements:

(a) The secondary seal is to 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 40 CFR Part 60, Section 60.113b(b)(2)(iii);

(b) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm; and
(c) There are to be no holes, tears, or other openings in the seal or seal fabric.

iv. The permittee shall keep a record of each gap measurement performed as required by 40 CFR Part 60, Section 60.113b(b). Each record shall identify the storage tank in which the measurement was performed and shall contain the following:

(1) The date of measurement.
(2) The raw data obtained in the measurement.
(3) The calculations described in 40 CFR Part 60, Section 60.113b(b)(2) and (b)(3).

v. The permittee shall visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the storage tank is emptied and degassed. If the external floating roof has defects, 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, the permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage tank with VOL.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.115b)[1]

5. Petroleum Storage Tanks 101, 102, 103, 104, 105, 112, 200, 201, 202, 203, 204, 205, 206, 207, 301, 302, 303, 304, 305, 306, 307, 311, 401, 402, 403, 404, 405, 501, 502, 503, 504, 505, 506, 507, 508, 509, 511, 512, 513, 514, 515, 516, 517, 601, 602, 603, 605, 606, 607, 608, 609, 903, 905, 1103, and 2301.

   The permittee shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure (kPa or psia) of that liquid during the respective storage period. Determination of the maximum true vapor pressure shall be in accordance with an applicable method in 40 CFR Part 60, Subpart K, Ka, or Kb. Records shall be maintained on a monthly basis.

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

6. 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

four (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, §11-60.1-11, §11-60.1-90; 40 CFR §63.646, §63.654)[1]

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 HAPs. 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 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; 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 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, §11-60.1-5, §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 which the excursion or exceedances 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 the 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. Petroleum Storage Tanks 107, 109, 110, 111, 604, 610, 611, 3520, 3522, and 3526

   a. Petroleum Storage Tanks 109, 111, 604, 610, and 611

      i. The permittee shall notify the Department in writing at least **thirty (30) days** prior to each time the petroleum storage tank is to be filled or refilled for which an inspection is required pursuant to 40 CFR Part 60, Section 60.113b(a)(1) and (a)(4). If the inspection required by 40 CFR Part 60, Section 60.113b(a)(4), is unplanned and the required **thirty (30) day** advance notice cannot be given, the permittee shall notify the Department at least **seven (7) days** prior to refilling the tank. Notification shall be made by telephone followed immediately by written

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documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail, so that the Department receives the notice at least **seven (7) days** prior to the refilling.

ii. The permittee shall furnish the Department a report within **thirty (30) days** of the following inspections:

(1) During the annual visual inspection required by Special Condition No. D.4.c.i(1) of this attachment, if any of the conditions described in Special Condition No. D.4.c.i(1) of this attachment are detected. Each report shall identify the storage tank, the nature of the defects, and the date the storage tank was emptied or the nature and date the repair was made.

(2) After each inspection required by Special Condition No. D.4.c.i(2) of this attachment that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in Special Condition No. D.4.c.i(1) of this attachment. The report shall identify the storage tank and the reasons it did not meet the specifications of Special Conditions Nos. C.8.b or D.4.c.i(2) of this attachment and list each repair made.

b. Petroleum Storage Tanks 107, 110, 3520, 3522, and 3526

i. The permittee shall notify the Department in writing at least **thirty (30) days** prior to the filling or refilling of each storage tank to afford the Department the opportunity to inspect the storage tank prior to refilling. If the inspection required by this paragraph is not planned and the permittee could not have known about the inspection **thirty (30) days** in advance of refilling the tank, the permittee shall notify the Department at least **seven (7) days** prior to the refilling of the storage tank. Notification shall be made by telephone 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 by express mail so that it is received by the Department at least **seven (7) days** prior to the refilling.

ii. The permittee shall furnish the Department a report within **sixty (60) days** of performing the seal gap measurements required by 40 CFR Part 60, Section 60.113b(b)(1). The report shall contain:

(1) The date of measurement;
(2) The raw data obtained in the measurement; and
(3) The calculations described in 40 CFR Part 60, Section 60.113b(b)(2) and (b)(3).

iii. The permittee shall furnish the Department a report within **thirty (30) days** of the inspection, if the seal gap measurement exceeded the limitations specified by 40 CFR Part 60, Section 60.113b(b)(4). The report shall identify the storage tank and contain the information specified in Special Condition No. E.6.b.ii of this attachment and the date the tank was emptied or the repairs made and the date of repair. The report shall also contain a **thirty (30) day** extension request if the storage tank cannot be repaired within **forty-five (45) days** and if the storage tank cannot be emptied within **forty-five (45) days**. Such an extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the storage tank will be emptied as soon as possible.

iv. The permittee shall notify the Department **thirty (30) days** in advance of any gap measurements required by 40 CFR Part 60, Section 60.113b(b)(1) to afford the Department the opportunity to have an observer present.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.113b)[1]

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. Type of VOL stored in each storage tank, dates of storage, and maximum true vapor pressure (kPa) of the VOL stored during the respective storage period by month; and
   b. Any deviations from permit requirements shall be clearly identified.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

Section F. Agency Notification

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)

Section G. 40 CFR Part 63, Subpart CC Requirements

1. Operational and Emission Limitations

   a. Group 1 storage tanks with internal floating roofs (Petroleum Storage Tanks 109, 111, 407, 408, 510, 604, 610, and 611) shall meet the requirements described in Special Condition Nos. C.8.b.i and C.8.b.ii of this attachment.

b. Group 1 storage tanks with external floating roofs (Petroleum Storage Tanks 101, 102, 103, 104, 105, 106, 107, 110, 201, 202, 203, 204, 405, 406, 501, 502, 503, 509, 902, 3520, 3522, and 3526) shall meet the requirements described in Special Condition Nos. C.8.c.i and C.8.c.iii of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.646)[1]

2. Monitoring and Recordkeeping Requirements

a. For the Group 1 storage tanks with internal floating roofs (Petroleum Storage Tanks 109, 111, 407, 408, 510, 604, 610, and 611), 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.4 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.4 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.4 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.4 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.4 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 two (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 in writing at least **thirty (30) calendar days** prior to the refilling of each storage tank to afford the Department 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 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 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 ten (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 101, 102, 103, 104, 105, 106, 107, 110, 201, 202, 203, 204, 405, 406, 501, 502, 503, 509, 902, 3520, 3522, and 3526), 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 a 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; and
(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.

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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 sixty-one (61) centimeters (24 inches) above the stored liquid surface; and
(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; and
(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 (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 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 in writing **thirty (30) calendar days** in advance of any gap measurements to afford the Department 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 in writing as least **thirty (30) calendar days** prior to filling or refilling each storage tank with organic HAP to afford the Department 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 at least **seven (7) calendar days** prior to refilling of the storage tank. 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 at least **seven (7) calendar days** prior to the refilling.

c. For Group 1 storage tanks with internal floating roofs (Petroleum Storage Tanks 109, 111, 407, 408, 510, 604, 610, and 611).

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 101, 102, 103, 104, 105, 106, 107, 110, 201, 202, 203, 204, 405, 406, 501, 502, 503, 509, 902, 3520, 3522, and 3526).

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)[1]

3. Notification and Reporting Requirements

   a. The permittee shall submit **semi-annually** written 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)* and shall include the following:

      i. For Group 1 storage tanks with internal floating roofs (Petroleum Storage Tanks 109, 111, 407, 408, 510, 604, 610, and 611).

         (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; and
            (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 ten (10) percent open area; and

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(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 101, 102, 103, 104, 105, 106, 107, 110, 201, 202, 203, 204, 405, 406, 501, 502, 503, 509, 902, 3520, 3522, and 3526)

(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)[1]

[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 II(N): SPECIAL CONDITIONS
PROPANE LOAD RACK AND CYLINDER FILLING STATION
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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) Propane Load Rack with Six (6) Truck Loading Stations consisting of liquid fill lines, vapor equalization lines, emergency shut-off valves, isolation valves, and thermal relief valves.

   b. One (1) Cylinder Filling Station with Two (2) Cylinder Filling Positions consisting of:

      i. One (1) 2,000-gallon Odorized Propane Storage Tank;
      ii. One (1) Transfer Pump; and
      iii. Associated Piping and shut-off valves.

   (Auth.: HAR §11-60.1-3)

2. The permittee shall install an identification tag or name plate on the propane load rack and cylinder filling station which identifies, if applicable, the model no., serial no., capacity, 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. Operational Limitations

1. The maximum throughput of the propane load rack shall not exceed 438,000 barrels per rolling twelve-month (12-month) period.

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

2. The maximum throughput of the cylinder filling station shall not exceed 10,000 barrels per rolling twelve-month (12-month) period.

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

3. During filling operations of the trucks or cylinders, the permittee shall act to assure that when the bleed stream goes from vapor to liquid (visible as a white liquid vapor cloud), filling is stopped and the bleed valve is shut.

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

4. The permittee shall maintain the propane load rack and cylinder filling station in good operating condition.

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

Section C. Monitoring and Recordkeeping Requirements

1. The permittee shall operate and maintain flow meters to monitor the total throughput (gallons) of the propane load rack and the cylinder filling station.

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

2. The permittee shall keep records of the throughput records of the propane load rack and cylinder filling station on a monthly and rolling twelve-month (12-month) basis.

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

3. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) upon request.

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

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 HAPs. The reporting of annual emissions is due within **sixty (60) days** *following the end of each calendar year*. Completion and submittal of the **Annual Emissions Report Form: Refinery Equipment - Process Rate** or an equivalent form may be used to satisfy this requirement for annual emissions reporting.

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. 17 and 24, respectively.

    a. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit; and
    b. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

    (Auth.: HAR §11-60.1-8, §11-60.1-16, §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 preventive 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, §11-60.1-16, §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 which the excursion or exceedances as defined in 40 CFR Part 64 occurred; and

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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 the 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- June 30 and July 1 - December 31)* and shall include the following:

   a. The throughput (barrels) summary of the propane load rack and cylinder filling station on a monthly and rolling twelve-month (12-month) basis. The enclosed **Monitoring Report Form - Propane Load Rack and Cylinder Filling Station** or an equivalent form shall be used for reporting.

   b. Deviations from permit requirements shall be clearly identified and addressed in these reports.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §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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[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 II(O): SPECIAL CONDITIONS
RENEWABLE FUEL PRODUCTION FACILITY
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 of the Renewable Fuel Production Facility:

   a. Renewable Feedstock Pretreatment Unit (PTU)
   b. Renewable Hydrotreater (RHT)

      i. RHT Feed Heater, ID No. H3701
      ii. 30 MMBtu/hr heat input.

   (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 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 RHT Feed Heater H3701 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 Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

   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, §60.100a; §63.1, §63.7485)[1]

2. 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)

<u>Section C</u>. <u>Operational and Emission Limitations</u>

1. The RHT Feed Heater H3701 shall be fired only on RFG with a H_2S content not to exceed 162 ppmv determined hourly on a three-hour (3-hour) rolling average basis and not to exceed 60 ppmv determined daily on a 365 successive calendar day rolling average basis. The heating value of the RFG used to fire the RHT Feed Heater H3701 shall not exceed 21,945 MMBtu/month based on a rolling twelve-month (12-month) average which is equivalent to a firing rate of 30 MMBtu/hr.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.102a(g)(1)(ii))[1]

2. Air Pollution Control Equipment

   The RHT Feed Heater H3701 shall be equipped with a low NO_x burner for the control of NO_x emissions.

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

3. Maximum Emission Limits

   The RHT Feed Heater H3701 shall not discharge or cause the discharge into the atmosphere emissions of the following:

   a. For nitrogen oxides (NO_x as NO_2), 1.24 lbs/hr (three-hour (3-hour) average).
   b. For SO_2, the more stringent of 0.73 lbs/hr (three-hour (3-hour) average) or 20 ppmv (dry basis, corrected to 0% excess air) determined hourly on a three-hour (3-hour) rolling average basis and 8 ppmv (dry basis, corrected to 0% excess air) determined daily on a 365 successive calendar day rolling average basis.

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

4. Visible Emissions (VE)

   For any six (6) minute averaging period, the RHT Feed Heater H3701 shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the RHT Feed Heater H3701 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)[2]

5. Tune-ups

The permittee shall conduct an annual tune-up of the RHT Feed Heater H3701 to demonstrate continuous compliance. Each annual tune-up must be no more than thirteen (13) months after the previous tune-up. The first annual tune-up must be no later than thirteen (13) months after the initial startup of the RHT Feed Heater H3701. The tune-up shall be conducted as follows:

a. As applicable, inspect the burner, and clean and replace any components of the burner as necessary (the burner inspection may be performed any time prior to the tune-up or delay the burner inspection until the next scheduled heater 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 into 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 inspection may be delayed until the next scheduled heater shutdown);
d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_x requirement to which the heater is subject;
e. Measure the concentrations in the effluent stream of CO in ppm, by volume, and O_2 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 an annual report on-site containing the following information:

   i. The concentrations of CO in the effluent stream in ppm, by volume, and O_2 in volume percent, measured at high fire or typical operating load, before and after the tune-up of the heater; and
   ii. A description of any corrective actions taken as part of the tune-up of the heater.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.7500(a)(1), §63.7515(d), §63.7540(a)(10))[1]

6. At all times, the permittee must operate and maintain the RHT Feed Heater H3701, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Department and the U.S. EPA, Region 9, that may

include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.7500(a)(3))[1]

Section D. Monitoring and Recordkeeping Requirements

1. Fuel Consumption Monitoring

   The permittee shall operate and maintain a non-resetting fuel meter to record the amount of RFG fired in the RHT Feed Heater H3701. The non-resetting meter shall not allow the manual resetting or other manual adjustment 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, §11-60.1-90)

2. Continuous Monitoring System for H_2S

   a. The permittee shall operate and maintain a CMS for continuously monitoring and recording the concentration (dry basis) of H_2S in the RFG before being burned in the RHT Feed Heater H3701.

   b. The H_2S CMS shall meet the following requirements:

      i. The span value for the H_2S CMS is 425 mg/dscm (300 ppmv) H_2S;
      ii. All fuel gas combustion devices, including the RHT Feed Heater H3701, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the RFG being burned;
      iii. Performance evaluations for the H_2S CMS shall be in accordance with 40 CFR §60.13. The H_2S 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-5, Method 11, 15, or 15A or Appendix A-6, Method 16, shall be used in conducting any RATA;
      iv. 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_2S CMS, RATAs need not be performed on an annual basis, unless requested by the Department; or there is a significant change or performance deficiency of the H_2S CMS;

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, §11-60.1-90, §11-60.1-161; 40 CFR §60.107a(a)(2), PS-7)[1]

3. Visible Emissions (VE)

The permittee shall conduct **monthly** *(calendar month)* VE observations for each equipment subject to opacity limitations 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 and the U.S. EPA. 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 §11-60-15, §11-60-24)[2]

4. The permittee shall record the total quantity of RFG (MMSCF) fired by the RHT Feed Heater H3701 on a monthly and rolling twelve-month (12-month) basis. Also, the total quantity of RFG (MMBtu) fired by the RHT Feed Heater H3701 on a monthly, rolling twelve-month (12-month), and rolling twelve-month (12-month) average basis.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

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) [1]

6. All records, including supporting information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and 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 its representative(s) upon request.

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

<u>Section E</u>. <u>Notification and Reporting Requirements</u>

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 U.S. EPA, Region 9, for every **semi-annual calendar period** for the average concentration of H_2S in RFG. 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 SSM of the RHT Feed Heater H3701. 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 CEMS 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 CEMS operated properly during the period and was not subject to any repairs or adjustments except zero and span checks; and
   v. A single report may be submitted for all combustion sources receiving a common source of fuel when there is one common CMS used to monitor H_2S of the RFG being supplied to multiple combustion devices.

b. All reports shall be postmarked by the **thirtieth (30th) 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 any rolling three-hour (3-hour) period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 162 ppmv, and any rolling 365-day period during which the average concentration of H_2S in RFG, as measured by the CMS, exceeds 60 ppmv.
d. Excess emissions indicated by the CMS shall be considered violations of the applicable emission and concentration limits for the purposes of the permit.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.7, §60.107a(i)(1)(ii), §60.108a(d))[1]

2. 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** or an equivalent form shall be used.

b. The total quantity of RFG (MMBtu) fired by the RHT Feed Heater H3701 on a monthly, rolling twelve-month (12-month), and rolling twelve-month (12-month) average basis. The enclosed **Monitoring Report Form: Fuel Consumption – Package Boilers and Process Heaters** 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)[2]

3. 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 HAPs. 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; 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. 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 which the excursion or exceedances 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 the 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) days** 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 SPT 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)[1]

8. MACT Subpart DDDDD Reporting

   The permittee shall comply with the reporting requirements per 40 CFR §63.7550 for the RHT Feed Heater H3701. The reports shall be submitted to the Department and U.S. EPA, Region 9.

   Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.7550)[1]

Section F. Testing Requirements

1. Within **sixty (60) days** after achieving the maximum production rate of the RHT Feed Heater H3701, but not later than **180 days** after initial start-up of the RHT Feed Heater H3701, the permittee shall conduct, or cause to be conducted, performance tests on the RHT Feed Heater H3701 to determine the emission rates of NO_x (as NO_2) and SO_2, for the purpose of determining compliance with the emission limits specified in Special Condition No. C.3 of this attachment.

   All performance tests shall be conducted with the RHT Feed Heater H3701 fired on RFG. All tests shall be conducted at representative operating conditions, i.e., normal operating conditions of the RHT Feed Heater H3701, or at other operating conditions as may be specified by the Department. The performance test for NO_x shall be conducted on an annual basis or at such times as may be specified by the Department. The permittee shall not conduct performance tests during periods of startup, shutdown, or malfunction.

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

2. Performance tests for the emissions of NO_x and SO_2 shall be conducted using EPA Method 1 to 4, 6, and 7, 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)

3. The 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)[1]

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. **At least thirty (30) days** prior to performing a test, the permittee shall submit a written performance test plan to the Department and 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 or require a retest.

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

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations receive written approval by the Department before the tests.

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

7. **Within sixty (60) days after** *completion of the performance test*, the permittee shall submit to the Department and U.S. EPA, Region 9, the test report which shall include the operating conditions of the RHT Feed Heater H3701, 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 §11-60.1-11, §11-60.1-90)

8. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual SPT. 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 SPT.

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

9. Upon the Department's request, or if a significant change or performance deficiency occurs with the CMS, performance tests for the H_2S levels in the RFG shall be conducted and results reported in accordance with the instructions and test methods set forth in 40 CFR §60.104a, and Appendix A, Method 11, 15, 15A, or 16.

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

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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[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 II(P): SPECIAL CONDITIONS
AIR COMPRESSOR ENGINES
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 permit encompasses the following equipment and related appurtenances:

   a. One (1) rental Diesel Engine Air Compressor, designated AC34, which shall meet the following specifications:

      i. A rating of 305 HP (235 kW), or smaller; and
      ii. EPA Tier 4 or higher, or CARB equivalent or higher.

   b. One (1) 225 kW (300 HP) Diesel Engine Air Compressor, designated AC35, EPA Tier 3 or higher

   (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 two (2) diesel engine air compressors 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.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.1, §60.4200, §63.1, §63.6585)[1]

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)

Section C. Emission and Operational Limitations, and/or Standards

1. Fuel Limits

The diesel engine air compressors 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)[1]

2. Visible Emissions (VE)

For any six (6) minute averaging period, the diesel engine air compressors shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during start-up, shut-down, or equipment malfunction, the diesel engine air compressors may exhibit VE 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)

3. The diesel engine air compressors shall be properly maintained and kept in good operating condition at all times with scheduled inspections and maintenance as recommended by the manufacturer; and/or as needed.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

Section D. Monitoring and Recordkeeping Requirements

1. The permittee shall maintain records on the following items:

a. 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 diesel engine air compressors 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. 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.
b. Records on inspections, maintenance, and any repair work conducted on the diesel engine air compressors. 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.
c. Records of the serial numbers, dates of operation, and appropriate EPA certification specifying the Tier rating for each diesel engine air compressor identified in Special Condition No. A.1 of this attachment.

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

2. Visible Emissions (VE)

The permittee shall conduct **monthly** (calendar month) VE observations for the diesel engine air compressors 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 and the U.S. EPA. 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 requirement to conduct monthly VE observations shall be waived when performing readiness testing and maintenance checks with a duration not exceeding fifteen (15) minutes.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90)

3. 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)

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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. 17 and 24, respectively:

   a. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit; 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)

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 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
   b. 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.

   c. 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 HAPs. 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

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 Part 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)

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)

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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 II(Q): SPECIAL CONDITIONS
MISCELLANEOUS PROCESS UNITS AND AUXILIARY EQUIPMENT
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 requirements for miscellaneous emission sources from petroleum refining process units not detailed in the Special Conditions of Attachments II(A) through II(P). Miscellaneous facility-wide requirements are also listed here.

   (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, at the CDU, VDU, DHC, Asphalt Manufacturing Unit (AMU), VBK, Mercaptan Treatment Units, ATU, Light Ends Recovery Unit (LERU), except for T2501 (Deethanizer) and T2502 (C3/C4 Splitter), Fuel Gas System in the Utilities Area, the Flare Gas Vapor Recovery System, Compressors C103, C602C, C901, C1180, and C2503, NHT, CRU, and HGU, 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;
      ii. Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries; and
      iii. 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, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.590, CD 5:16-CV-00722)[1]

2. 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 §60.481a of 40 CFR Part 60, Subpart VVa, at the propane load rack and the cylinder filling station, the RHT and the RHT Compressor (C3701), 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 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, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.590a)[1]

3. 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, at the CDU, AMU, VBK, CRU, LERU, Hydrogen Compressor and Compressor C604, and RHT, 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)[1]

4. All pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, flanges and other connectors, product accumulator vessels, control devices, or systems intended to operate *in benzene service* as defined in §61.111 of 40 CFR Part 61, Subpart J, are subject to the provisions of the following federal regulations:

   a. 40 CFR Part 61, National Emission Standard for Hazardous Air Pollutants (NESHAP)

      i. Subpart A, General Provisions; and
      ii. Subpart J, National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene.

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. If a source is also subject to the provisions of 40 CFR Part 60, Subpart GGG, the source shall only be required to comply with the above standards.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11.60.1-180; 40 CFR §61.01, §61.110)[1]

5. All benzene-containing hazardous waste streams at hazardous waste treatment, storage, and disposal facilities at the petroleum refinery are subject to the provisions of the following federal regulations:

    a. 40 CFR Part 61, National Emission Standard 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, §11.60.1-180; 40 CFR §61.340)[1]

6. All pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, or instrumentation systems *in organic HAP service*, as defined in §63.641 of 40 CFR Part 63, Subpart CC, 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 §63.1, §63.640)[1]

7. 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)[1]

<u>Section C</u>. <u>Operational and Emission Limitations</u>

1. All pumps and compressors handling VOC having a Reid Vapor Pressure (RVP) of 1.5 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. Equipment subject to 40 CFR Part 60, Subpart GGGa and/or 40 CFR Part 63, Subpart CC:

   a. Compressors

      i. Compressors 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).
      ii. Each compressor seal system as required in Special Condition No. C.3.a.i of this attachment shall be as follows:

         (1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) 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.

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

iii. The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

iv. A compressor is exempt from the requirements of Special Condition Nos. C.3.a.i and C.3.a.ii 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.a.v of this attachment.

v. 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.i through C.3.a.iv, D.2.b.i, and D.2.b.ii of this attachment.

b. Pressure Relief Devices in Gas/Vapor Service

i. 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 §60.485a(c).

ii. *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.3.f of this attachment.

iii. Any pressure relief device is exempt from the requirements of Special Condition Nos. C.3.b.i and C.3.b.ii of this attachment if it is equipped with a closed vent system capable of capturing and transporting leakage from the pressure relief device to a control device that complies with the requirements of 40 CFR §60.482-10a.

c. Open-Ended Valves/Lines

i. 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 §60.482-1a(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.

ii. 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.

iii. 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.3.c.i of this attachment at all other times.

d. Sampling Connection Systems

i. Each sampling connection system shall be equipped with a closed-purged, closed-loop, or closed-vent system, except as provided in 40 CFR §60.482-1a(c).
ii. Each closed-purged, closed-loop, or closed-vent system shall comply with the following requirements:

(1) Return the purged process fluid directly to the process line; or
(2) Collect and recycle the purged process fluid to a process; or
(3) 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.
(4) In situ sampling systems and sampling systems without purges are exempt from the requirements of Special Condition Nos. C.3.d.i and C.3.d.ii of this attachment.

e. Pressure Relief Devices in Organic HAP Gas/Vapor Service

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.

f. Delay of Repair

i. 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.
ii. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.
iii. Delay of repair for valves will be allowed if:

(1) 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
(2) 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 §60.482-10a.

iv. Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and
(2) Repair is completed as soon as practicable, but not later than six (6) months after the leak was detected.

v. 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)[1]

4. Equipment subject to 40 CFR Part 61, Subpart J

   a. Compressors

      i. Compressors shall be equipped and operated with a seal system that includes a barrier fluid system and that prevents leakage of process fluid to the atmosphere, except as provided in 40 CFR §61.242-1(c), 40 CFR §61.242-3(h), and 40 CFR §61.242-3(i).
      ii. Each compressor seal system as required in Special Condition No. C.4.a.i of this attachment shall be as follows:

         (1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or
         (2) 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 §61.242-11; or
         (3) Equipped with a system that purges the barrier fluid into a process stream with zero volatile hazardous air pollutant (VHAP) emissions to the atmosphere.

      iii. The barrier fluid system shall not be in VHAP service and, if the compressor is covered by standards under 40 CFR Part 60, shall not be in VOC service.
      iv. A compressor is exempt from the requirements of Special Condition Nos. C.4.a.i and C.4.a.ii 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 §61.242-11, except as provided in Special Condition No. C.4.a.v of this attachment.
      v. 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 §61.245(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.4.a.i through C.4.a.iv, D.3.b.i, and D.3.b.ii of this attachment.

   b. Pressure Relief Devices in Gas/Vapor Service

      i. 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 §61.245(c).
      ii. *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.4.f of this attachment.

iii. Any pressure relief device is exempt from the requirements of Special Condition Nos. C.4.b.i and C.4.b.ii of this attachment if it is equipped with a closed vent system capable of capturing and transporting leakage from the pressure relief device to a control device that complies with the requirements of 40 CFR §61.242-11.

c. Open-Ended Valves/Lines

i. 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 §61.242-1(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.
ii. 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.
iii. 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.4.c.i of this attachment at all other times.

d. Sampling Connection Systems

i. Each sampling connection system shall be equipped with a closed-purged system or closed-vent system, except as provided in 40 CFR §61.242-1(c).
ii. Each closed-purged system or closed-vent system shall comply with the following requirements:

(1) Return the purged process fluid directly to the process line with zero VHAP emissions to atmosphere; or
(2) Collect and recycle the purged process fluid with zero VHAP emissions to atmosphere; or
(3) 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 §61.242-11.
(4) In-situ sampling systems are exempt from the requirements of Special Condition Nos. C.4.d.i and C.4.d.ii of this attachment.

e. Product Accumulator Vessels

i. Each product accumulator vessel shall be equipped with a closed-vent system capable of capturing and transporting any leakage from the vessel to a control device as described in 40 CFR §61.242-11.

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f. Delay of Repair

i. 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.
ii. Delay of repair of equipment for which leaks have been detected will be allowed for equipment that is isolated from the process and which does not remain in VHAP service.
iii. Delay of repair for valves will be allowed if:

(1) 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
(2) 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 §61.242-11.

iv. Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and
(2) Repair is completed as soon as practicable, but not later than six (6) months after the leak was detected.

v. 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, §11-60.1-180; 40 CFR §61.112)[1]

5. Equipment subject to 40 CFR Part 60, Subpart QQQ

a. Individual Drain Systems

i. Sewer drains shall be equipped with water seal controls.
ii. Junction boxes 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.
iii. 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.

iv. 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.

v. 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)[1]

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 sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and repair 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 its representative(s) upon request.

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

2. Equipment subject to 40 CFR Part 60, Subpart GGGa and/or 40 CFR Part 63, Subpart CC

   a. Pumps in Light Liquid Service

      i. Each pump in light liquid service 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).

      ii. Each pump in light liquid service shall be checked by visual inspection **each calendar week** for indications of liquids dripping from the pump seal.

      iii. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

      iv. If there are indications of liquids dripping from the pump seal, a leak is detected.

      v. 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.3.e of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days** *after each leak is detected*.

      vi. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of Special Condition Nos. D.2.a.i and D.2.a.ii of this attachment provided the requirements of 40 CFR §60.482-2a(d)(1) through (6) are met.

      vii. 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.i, D.2.a.ii, D.2.a.v, and D.2.a.vi of this attachment if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;
(2) 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
(3) Is tested for compliance with Special Condition No. D.2.a.vii.(2) of this attachment initially upon designation, annually, and at other times requested by the Department.

viii. 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.i through D.2.a.vii of this attachment.

b. Compressors

i. 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.
ii. 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.3.e of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days** *after each leak is detected*.

c. Pressure Relief Devices in Gas/Vapor Service

i. **No later than five (5) calendar days** *after a pressure release*, the pressure relief device shall be monitored to confirm the condition 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).

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

i. Each valve in light liquid service shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §60.485a(b).
ii. If an instrument reading of 500 ppm or greater is measured, a leak is detected.
iii. 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*.
iv. *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.3.e of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days** *after each leak is detected*.

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v. First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;
(2) Replacement of bonnet bolts;
(3) Tightening of packing gland nuts; and
(4) Injection of lubricant into lubricated packing.

vi. 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.2.d.i of this attachment if the valve:

(1) Has no external actuating mechanism in contact with the process fluid;
(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR §60.485a(c); and
(3) Is tested for compliance with the Special Condition No. D.2.d.vi.(2) of this attachment initially upon designation, annually, and at other times requested by the Department.

vii. 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.2.d.i of this attachment.
viii. 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.2.d.i of this attachment.

e. 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

i. 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, 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*.
ii. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
iii. *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.3.e of this attachment. The first attempt at repair shall be made **no later than five (5) calendar days** *after each leak is detected*.
iv. First attempts at repair include, but are not limited to, the best practices described in Special Condition No. D.2.d.v of this attachment.

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

i. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
ii. 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.2.d.iii of this attachment and no leak has been detected during those two (2) months.
iii. The identification on equipment, except a valve or connector, may be removed after it has been repaired.

g. *When each leak is detected*, including as specified in 40 CFR §60.483-2a, the following information shall be recorded in a log and shall be kept for five (5) years in a readily accessible location:

i. The instrument and operator identification numbers and the equipment identification number;
ii. The date the leak was detected and the dates of each attempt to repair the leak;
iii. Repair methods applied in each attempt to repair the leak;
iv. "Above 10,000" if the maximum instrument reading measured by the methods specified in 40 CFR §60.485a after each repair attempt is equal to or greater than 10,000 ppm;
v. "Repair delayed" and the reason for the delay if a leak is not repaired within fifteen (15) calendar days after discovery of the leak;
vi. The signature of the permittee whose decision it was that repair could not be effected without a process shutdown;
vii. The expected date of successful repair of the leak if a leak is not repaired within fifteen (15) days;
viii. Dates of process unit shutdown that occur while the equipment is unrepaired; and
ix. The date of successful repair of the leak.

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

i. A list of identification numbers for all equipment;
ii. A list of identification numbers for equipment that are designated for no detectable emissions which is signed by the permittee;
iii. A list of equipment identification numbers for pressure relief devices required to comply with the requirements of Special Condition No. C.3.b of this attachment;
iv. For each compliance test used to determine no detectable emissions:

(1) The dates of each compliance test;
(2) The background level measured during each compliance test; and
(3) The maximum instrument reading measured at the equipment during each compliance test.

v. A list of identification numbers for equipment in vacuum service.

i. The following information pertaining to all valves shall be recorded in a log that is kept in a readily accessible location:

i. 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
ii. 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.

j. The following information shall be recorded for valves complying with 40 CFR §60.483-2a:

i. A schedule of monitoring; and
ii. The percent of valves found leaking during each monitoring period.

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

i. 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; and
ii. 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, §11-60.1-174; 40 CFR §60.592a, §63.648)[1]

3. Equipment subject to 40 CFR Part 61, Subpart J

a. Pumps

i. Each pump shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §61.245(b), except as provided in 40 CFR §61.242-1(c) and 40 CFR §61.242-2(d), (e) and (f).
ii. Each pump shall be checked by visual inspection **each calendar week** for indications of liquids dripping from the pump seal.
iii. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
iv. If there are indications of liquids dripping from the pump seal, a leak is detected.
v. 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.4.f of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days** *after each leak is detected*.

vi. 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.3.a.i through D.3.a.iv of this attachment provided the requirements of 40 CFR §61.242-2(d)(1) through (6) are met.

vii. 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.3.a.i, D.3.a.ii., D.3.a.v, and D.3.a.vi of this attachment if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;
(2) 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 §61.245(c); and
(3) Is tested for compliance with Special Condition No. D.3.a.vii.(2) of this attachment initially upon designation, annually, and at other times requested by the Department.

viii. 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 §61.242-11, it is exempt from the requirements of Special Condition Nos. D.3.a.i through D.3.a.vii of this attachment.

b. Compressors

i. 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 fluid system, or both, a leak is detected.

ii. 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.4.f of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days** *after each leak is detected*.

c. Pressure Relief Devices in Gas/Vapor Service

i. **No later than five (5) calendar days** *after a pressure release*, the pressure relief device shall be monitored to confirm the condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR §61.245(c).

d. Valves

i. Each valve shall be monitored **monthly** to detect leaks in accordance with the requirements set forth in 40 CFR §61.245(b), except as provided in 40 CFR §61.243-2.

ii. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

iii. 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*.

iv. *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.4.f of this attachment. A first attempt at repair shall be made **no later than five (5) calendar days** *after each leak is detected*.

v. First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;
(2) Replacement of bonnet bolts;
(3) Tightening of packing gland nuts; and
(4) Injection of lubricant into lubricated packing.

vi. Any valve that is designated, as described in 40 CFR §61.246(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.3.d.i of this attachment if the valve:

(1) Has no external actuating mechanism in contact with the process fluid;
(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR §61.245(c); and
(3) Is tested for compliance with the Special Condition No. D.3.d.vi.(2) of this attachment initially upon designation, annually, and at other times requested by the Department.

vii. Any valve that is designated, as described in 40 CFR §61.246(f)(1), as unsafe-to-monitor valve and satisfies the criteria outlined in 40 CFR §61.242-7(g) is exempt from the requirements of Special Condition No. D.3.d.i of this attachment.

viii. Any valve that is designated, as described in 40 CFR §61.246(f)(2), as difficult-to-monitor valve and satisfies the criteria outlined in 40 CFR §61.242-7(h) is exempt from the requirements of Special Condition No. D.3.d.i of this attachment.

e. Pressure Relief Devices in Liquid Service and Flanges and other Connectors

i. Pressure relief devices in liquid service and flanges and other connectors shall be monitored **within five (5) days** by the method specified in 40 CFR §61.245(b) *if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method*.

ii. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

iii. *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.4.f of this attachment. The first attempt at repair shall be made **no later than five (5) calendar days** *after each leak is detected*.
iv. First attempts at repair include, but are not limited to, the best practices described in Special Condition No. D.3.d.v of this attachment.

f. *When each leak is detected*, a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
g. 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.3.d.iii 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.
h. *When each leak is detected*, the following information shall be recorded in a log and shall be kept for five (5) years in a readily accessible location:

i. The instrument and operator identification numbers and the equipment identification number;
ii. The date the leak was detected and the dates of each attempt to repair the leak;
iii. Repair methods applied in each attempt to repair the leak;
iv. "Above 10,000" if the maximum instrument reading measured by the methods specified in 40 CFR §61.245(a) after each repair attempt is equal to or greater than 10,000 ppm;
v. "Repair delayed" and the reason for the delay if a leak is not repaired within fifteen (15) calendar days after discovery of the leak;
vi. The signature of the permittee whose decision it was that repair could not be effected without a process shutdown;
vii. The expected date of successful repair of the leak if a leak is not repaired within fifteen (15) days;
viii. Dates of process unit shutdown that occur while the equipment is unrepaired; and
ix. The date of successful repair of the leak.

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

i. A list of identification numbers for all equipment (except welded fittings);
ii. A list of identification numbers for equipment that are designated for no detectable emissions which is signed by the permittee;
iii. A list of equipment identification numbers for pressure relief devices required to comply with the requirements of Special Condition No. C.4.b of this attachment;
iv. For each compliance test used to determine no detectable emissions:

(1) The dates of each compliance test;
(2) The background level measured during each compliance test; and

(3) The maximum instrument reading measured at the equipment during each compliance test.

v. A list of identification numbers for equipment in vacuum service.

j. The following information pertaining to all valves shall be recorded in a log that is kept in a readily accessible location:

i. 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
ii. 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 planned schedule for monitoring each valve.

k. The following information shall be recorded for valves complying with 40 CFR §61.243-2:

i. A schedule of monitoring; and
ii. The percent of valves found leaking during each monitoring period.

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

i. 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.
ii. 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)[1]

4. Equipment subject to 40 CFR Part 60, Subpart QQQ

a. 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.
b. 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.

c. *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.

d. Junction boxes 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.

e. *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.

f. The portion of each unburied sewer line shall be visually inspected **initially and semi-annually** for indication of cracks, gaps, or other problems that could result in VOC emissions.

g. *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.

h. 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.

i. For each individual drain system 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.

j. 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.

k. 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, §11-60.1-180; 40 CFR §61.112)[1]

5. 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 Δc 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.5.g of this attachment, the Δc value for the next fourteen-day (14-day) sampling period for which the sampling start time begins after the completion of the corrective actions is greater than 9 $\mu g/m^3$ 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 fenceline 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 Δc value for the fourteen-day (14-day) sampling period following completion of the initial corrective action is greater than 9 $\mu g/m^3$ 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.5.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))[1]

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 HAPs. 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 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 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; 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 which the excursion or exceedances 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 the 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. Equipment subject to 40 CFR Part 60, Subpart GGGa and/or 40 CFR Part 63, Subpart CC

   a. The permittee shall submit for valves, pumps and compressors, **semi-annual** reports to the Department beginning six months after the initial start-up date. 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:

      i. Process unit identification;
      ii. Number of valves subject to the requirements of Special Condition No. D.2.d of this attachment, excluding those valves designated for no detectable emission under the provisions of Special Condition No. D.2.d.vi of this attachment;
      iii. Number of pumps subject to the requirements of Special Condition No. D.2.a of this attachment, excluding those pumps designated for no detectable emissions under the provisions of Special Condition No. D.2.a.vii of this attachment and those pumps complying with Special Condition No. D.2.a.viii of this attachment; and
      iv. Number of compressors subject to the requirements of Special Condition No. C.3.a of this attachment, excluding those compressors designated for no detectable emissions under the provisions of Special Condition No. C.3.a.v of this attachment and those compressors complying with Special Condition No. C.3.a.iv of this attachment.

   b. All semi-annual reports, required in Special Condition No. E.5.a of this attachment, shall include the following information:

      i. Process unit identification;
      ii. For each month during the semi-annual reporting period:

         (1) Number of valves for which leaks were detected, including as described in 40 CFR §60.483-2;
         (2) Number of valves for which leaks were not repaired;
         (3) Number of pumps for which leaks were detected;
         (4) Number of pumps for which leaks were not repaired;
         (5) Number of compressors for which leaks were detected;
         (6) Number of compressors for which leaks were not repaired; and
         (7) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

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

c. If the permittee elects to comply with the provisions of 40 CFR §60.483-2, the Department shall be notified of the alternate standard selected **ninety (90) days** before implementing the provision.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §60.592a, §63.648)[1]

6. The permittee shall comply with the reporting provisions of 40 CFR §63.654, including §63.654(d), (e), (f) and (h) for equipment subject to the equipment leak standards in 40 CFR Part 63, Subpart CC.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.654)[1]

7. Equipment subject to 40 CFR Part 61, Subpart J

   a. The permittee shall submit an **initial report** notifying the Department that the requirements of 40 CFR §61.242, §61.245, §61.246, and §61.247 are being implemented. The initial report shall include the following information:

      i. Equipment identification number and process unit identification;
      ii. Type of equipment;
      iii. Percent by weight VHAP in the fluid at the equipment;
      iv. Process fluid state at the equipment (gas/vapor or liquid); and
      v. Method of compliance with the standard.

   b. The permittee shall submit for valves, pumps and compressors, **semi-annual** reports to the Department beginning six (6) months after the initial report required in Special Condition No. E.7.a of this attachment. 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).* All semi-annual reports shall include the following information:

      i. Process unit identification;
      ii. For each month during the semi-annual reporting period:

         (1) Number of valves for which leaks were detected, including as described in 40 CFR §61.243-2;
         (2) Number of valves for which leaks were not repaired;
         (3) Number of pumps for which leaks were detected;
         (4) Number of pumps for which leaks were not repaired;
         (5) Number of compressors for which leaks were detected;
         (6) Number of compressors for which leaks were not repaired; and
         (7) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

iii. Dates of process unit shutdowns which occurred within the semi-annual reporting period;
iv. Revisions to items reported in the initial semiannual report if changes have occurred since the initial report or subsequent revisions to the initial report; and
v. The results of all performance tests and monitoring to determine compliance with no detectable limits and with 40 CFR §61.243-1 and 40 CFR §61.243-2 conducted within the semi-annual reporting period.

c. If the permittee elects to comply with the provisions of 40 CFR §61.243-2, the Department shall be notified of the alternate standard selected **ninety (90) days** before implementing the provision.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-180; 40 CFR §61.112)[1]

8. Equipment subject to 40 CFR Part 60, Subpart QQQ

a. The permittee shall submit to the Department within **sixty (60) days** after initial start-up 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.
b. 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.
c. 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)[1]

9. 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 $\mu g/m^3$ 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 (Δc) for benzene for each sampling period and the annual average Δc 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))[1]

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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[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 II (INSIG): SPECIAL CONDITIONS
INSIGNIFICANT ACTIVITIES
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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. Specifically, the following equipment are insignificant activities:

1. Two (2) Renewable Feedstock StorageTanks

   Two (2) - 2,478,000 gallon (nominal) vertical fixed roof storage tanks identified as Tanks 701 and 702.

   (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 for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Supporting information includes all maintenance, inspection, and repair records, and copies of all reports required by this permit. These records shall be true, accurate, and maintained

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in a permanent form suitable for inspection and made available to the Department or its representative(s) 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)

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ATTACHMENT II (GHG): SPECIAL CONDITIONS
GHG REDUCTION REQUIREMENTS
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

In addition to the standard conditions of the CSP, the following state enforceable special conditions shall apply to the permitted facility:

Section A. Equipment Description

1. Attachment II - GHG of this permit encompasses the following plants, equipment, and associated appurtenances:

Stationary Combustion Sources	
Unit No.	**Description**
H101A	154 MMBtu/hr Process Heater
H101B	144 MMBtu/hr Process Heater
H102A	18 MMBtu/hr Process Heater
H102B	8 MMBtu/hr Process Heater
H175	86 MMBtu/hr Process Heater
H401	26 MMBtu/hr Process Heater
H402	17 MMBtu/hr Process Heater
H501	124 MMBtu/hr Process Heater
H502	96.4 MMBtu/hr Process Heater
H503	44.5 MMBtu/hr Process Heater
H504	21.7 MMBtu/hr Process Heater
H601	40 MMBtu/hr Process Heater
H602	77 MMBtu/hr Process Heater
H603	76 MMBtu/hr Process Heater
H801	33 MMBtu/hr Process Heater
H901	75 MMBtu/hr Process Heater
CC2301	230 MMBtu/hr Combined Cycle (Boiler/Gas Turbine)
DB2301	37 MMBtu/hr Cogeneration Unit Duct Burner
SG1102	82 MMBtu/hr Package Boiler (Steam Generator)
SG1103	98 MMBtu/hr Package Boiler (Steam Generator)
F5205	99 MMBtu/hr Package Boiler (Steam Generator)
H3701	30 MMBtu/hr Process Heater
H1353	3.8 MMBtu/hr Vent Gas Incinerator
H1391	4.4 MMBtu/hr Tail Gas Incinerator
FZ3560	6.5 or 3.0 MMBtu/hr Thermal Oxidizer
AC34	305 hp (235 kW) or Smaller Diesel Air Compressor Engine
AC35	225 kW (300 hp) Diesel Air Compressor Engine
Note: Horsepower (hp), Hour (hr), Kilowatt (kW), and Million British Thermal Units (MMBtu).	

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Hydrogen Production	
Unit No.	**Description**
H2001	172.8 MMBtu/hr Hydrogen Reformer Furnace
HGU	Feedstock for Hydrogen Generation Unit
Note: Hour (hr), Hydrogen Generation Unit (HGU), and Million British Thermal Units (MMBtu).	

Petroleum Refineries Source Category	
Unit No.	**Description**
Flare	Refinery Flare
--------------	CRU Coke Burn-off
--------------	Equipment Leaks
--------------	SRU (amine acid off-gas and sour water stripper gas)
Note: Catalytic Reforming Unit (CRU) and Sulfur Recovery Unit (SRU).	

(Auth.: HAR §11-60.1-3)

2. The plants and equipment are subject to GHG emission reduction requirements of HAR, Chapter 11-60.1, Subchapter 11, and associated permit conditions based on information from the GHG emission reduction plan, permit application for significant modification, and additional information provided in emails from Par Hawaii Refining, LLC, personnel on February 21, 2021, May 19, 2021, and June 16, 2021. The GHG emission reduction plan shall become a part of the CSP application process for renewals and any required modifications pursuant to HAR, Chapter 11-60.1, Subchapter 5. With each subsequent GHG reduction plan submittal, the permittee shall report:

   a. The GHG emission reduction status;
   b. Factors contributing to the emission changes;
   c. Any control measure updates; and
   d. Any new developments or changes that would affect the basis of the facility-wide GHG emissions cap.

   (Auth.: HAR §11-60.1-5, §11-60.1-204(g))

<u>Section B</u>. <u>GHG Permit Conditions</u>

1. Permit conditions specified in Attachment II – GHG, including provisions to limit maximum potential GHG emissions, are state-only enforceable requirements which are not federally enforceable under the federal Clean Air Act.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, 11-60.1-161; 40 CFR §70.6)[1]

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

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

Section C. GHG Emission Limitations

1. GHG Emission Caps

   a. Each partnering facility shall not emit or cause to be emitted carbon dioxide equivalent (CO_2e) emissions in excess of the following individual caps, except as specified in Attachment II – GHG, Special Condition No. C.1.c.iv:

Partnering Facility	**Permit No.**	**CO_2e Emission Cap[a]**	
		Metric Tons per Calendar Year	**Short Tons per Calendar Year**
Par East Refinery	CSP No. 0212-01-C	616,288	679,341
Par West Refinery	CSP No. 0088-01-C	288,657	318,190

[a]Metric Tons = (0.90718474) x (Short Tons)

   b. All partnering facilities shall not emit or cause to be emitted total combined CO_2e emissions in excess of 997,531 short tons (904,945 metric tons) per calendar year.
   c. For purposes of the CO_2e emission limits in Attachment II - GHG, Special Condition Nos. C.1.a and C.1.b:

      i. The CO_2e emissions shall have the same meaning as that specified in HAR §11-60.1-1;
      ii. In accordance with HAR §11-60.1-204(d)(6)(B), biogenic CO_2 emissions shall not be included when determining compliance with the emissions limit;
      iii. The permittee shall be in compliance with the emissions limits by the end of 2019 and each calendar year thereafter;
      iv. The permittee may exceed the emissions cap specified in Attachment II – GHG, Special Condition No. C.1.a, if the GHG emissions limit specified in Attachment II – GHG, Special Condition No. C.1.b, is met; and

v. At no time shall the permittee exceed Attachment II - GHG, Special Condition Nos. C.1.a and C.1.b, simultaneously over a calendar year. For incidences when Attachment II - GHG, Special Condition Nos. C.1.a and C.1.b, are exceeded simultaneously, emissions in excess of the total combined cap shall be allocated according to the following equation for compliance purposes:

$$X = XG \frac{(A - C)}{\sum_{A_i > C_i}(A_i - C_i)}$$

Where:

X = Adjusted portion in metric tons or short tons of GHG emissions that are in excess of total combined cap specified in Attachment II -GHG, Special Condition No. C.1.b. The equation applies to all affected facilities that do not meet the individual and total combined GHG emission caps specified in Attachment II – GHG, Special Condition Nos. C.1.a and C.1.b, respectively.

XG = Total combined actual GHG emissions from affected facilities minus total combined GHG emissions cap. Total combined emissions cap shall be sixteen percent (16%) below the total combined baseline emission level less biogenic CO_2 emissions.

A = Actual GHG emissions from the affected facility.

C = GHG emissions cap for the affected facility.

$\sum_{Ai>ci}(Ai - Ci)$ = The sum of the difference between the actual emissions and cap emissions for all facilities that did not achieve the individual facility-wide GHG emissions cap.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-204)

2. GHG Emission Cap Revisions

a. The facility-wide GHG emissions cap may be re-evaluated and revised by the Department in accordance with HAR §11-60.1-204(h).
b. Any revision to the facility-wide GHG emissions caps shall be considered a significant modification subject to the application and review requirements of HAR §11-60.1-104. For each GHG emission cap revision, the Department may impose additional emission limits or requirements, or limit the time-frame allowed for the revised GHG emissions cap.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-204)

<u>Section D</u>. <u>Monitoring and Record Keeping Requirements</u>

1. GHG Emissions (Stationary Combustion Sources)

For calculating GHG emissions from stationary combustion and quality assurance (QA)/quality control (QC) requirements, the permittee shall:

a. Monitor mass emissions data with the appropriate methods specified in 40 Code of Federal Regulations (CFR) §98.34;

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b. Estimate missing data in accordance with the applicable procedures in 40 CFR §98.35; and
c. Determine the metric tons of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) in accordance with the appropriate calculation methodology in 40 CFR §98.33.

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §98.33, §98.34, §98.35)

2. GHG Emissions (Hydrogen Production)

For calculating GHG emissions from hydrogen production and QA/QC requirements, the permittee shall:

a. Monitor the GHG emissions data in accordance with 40 CFR §98.164;
b. Estimate missing data in accordance with the applicable procedures in 40 CFR §98.165; and
c. Calculate CO_2 emissions for hydrogen manufacturing with the appropriate methods specified in 40 CFR §98.163.

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §98.164, §98.165)

3. GHG Emissions (Petroleum Refineries Source Category)

For calculating GHG emissions from sources in the petroleum refineries source category and QA/QC requirements, the permittee shall:

a. Monitor the GHG emissions data in accordance with the applicable procedures of 40 CFR §98.254;
b. Estimate missing data in accordance with the applicable procedures in 40 CFR §98.255; and
c. Calculate the CO_2, CH_4, and N_2O emissions with the appropriate methods specified in 40 CFR §98.253.

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §98.253, §98.254, §98.255)

4. Total CO_2e Emissions

For determining CO_2e emissions for purposes of determining compliance with the GHG emission caps and assessing fees, the permittee shall:

a. Sum the emission estimates from Attachment II – GHG, Special Condition Nos. D.1, D.2, and D.3 using Equation A-1 of 40 CFR §98.2;

b. Convert the metric tons of CO_2e emissions to short tons for monitoring and annual emissions reporting as applicable. For the conversion, one (1) short ton is equal to 0.90718474 metric tons; and
c. Report CO_2e emissions to the Department in accordance with Attachment II – GHG, Special Condition No. E.4.

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR §98.2)

5. Records

All records, including support information, shall be maintained for **at least five (5) years** from the date of the monitoring sample, measurement, test, report, or applications. Support information includes all maintenance, inspection, and 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 be made available to the Department or authorized representative(s) upon request.

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

Section E. Notification and Reporting Requirements

1. Standard Condition Reporting

Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Condition Nos. 17 and 24, respectively:

a. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit; 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; SIP §11-60-10, SIP §11-60-16)[2]

2. Deviations

The permittee shall report in writing **within five (5) working days** any deviations from permit requirements, including those attributed to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. Corrective actions may include a requirement for testing, or 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)

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3. Compliance Certification

a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. Environmental Protection Agency, Region 9, the attached **Compliance Certification Form** pursuant to HAR, Subsection 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 which the excursion or exceedances 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 the 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)

4. Monitoring Reports

a. The permittee shall complete and submit **semi-annual** monitoring reports to the Department that provide the metric tons and short tons of CO_2e emitted by all partnering facilities, except that biogenic CO_2 shall be excluded from the total CO_2e emissions. All reports shall be submitted **within sixty (60) days after** the end of each semi-annual calendar period (January 1 – June 30 and July 1 – December 31). The following enclosed form, or equivalent form, shall be used for reporting and shall be signed and dated by a responsible official:

Monitoring Report Form: GHG Emissions

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b. For calendar years 2019 and 2020, the permittee shall report the CO_2e emissions **within sixty (60) days** after the issuance of this permit. The Monitoring Report Form: GHG Emissions, or equivalent form, for the 2019 and 2020 calendar years shall be used for reporting and shall be signed and dated by a responsible official.

c. For calendar year 2021, the permittee shall report the CO_2e emissions **within sixty (60) days** after the issuance of this permit or **within sixty (60) days** after the end of the semi-annual calendar period, whichever is later. The Monitoring Report Form: GHG Emissions, or equivalent form, for the 2021 calendar year shall be used for reporting and shall be signed and dated by a responsible official.

d. Upon written request by the permittee, the deadline for submitting the monitoring report 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)

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)

[1]The citations to the 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. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 on which the annual fees are based shall accompany the submittal of any annual fees and submitted on forms furnished by the Department.

4. The annual fees and the emissions 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. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 emission.

1. Complete the attached **Annual Emissions Report Form for Refinery Equipment - Fuel Consumption, Refinery Equipment - Process Rate, External/Internal Floating Roof Petroleum Storage Tank, and Fixed Roof Petroleum Storage Tank**.

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 by submitting a written request to the Director and clearly identifying the specific information that is to be accorded confidential treatment.

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COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0212-01-C
(PAGE 1 OF ___)

Issuance Date: **Expiration Date: May 12, 2026**

In accordance with the Hawaii Administrative Rules (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.

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COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0212-01-C
(CONTINUED, PAGE 2 OF ___)

Issuance Date: **Expiration Date: May 12, 2026**

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

Permit term/condition	Equipment	Compliance
All standard conditions	All Equipment listed in the permit	☐ Continuous ☐ Intermittent

B. Special Conditions - Monitoring, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment	Compliance
All monitoring conditions	All Equipment listed in the permit	☐ Continuous ☐ Intermittent
Permit term/condition All recordkeeping conditions	Equipment All Equipment listed in the permit	Compliance ☐ Continuous ☐ Intermittent
Permit term/condition All reporting conditions	Equipment All Equipment listed in the permit	Compliance ☐ Continuous ☐ Intermittent
Permit term/condition All testing conditions	Equipment All Equipment listed in the permit	Compliance ☐ Continuous ☐ Intermittent
Permit term/condition All INSIG conditions	Equipment All Equipment listed in the permit	Compliance ☐ Continuous ☐ Intermittent

COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0212-01-C
(CONTINUED, PAGE ____ OF ___)

Issuance Date: **Expiration Date: May 12, 2026**

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
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent

(Make Additional Copies if Needed)

COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0212-01-C
(CONTINUED, PAGE ___ OF ___)

Issuance Date: **Expiration Date: May 12, 2026**

D. Deviations

Permit Term/ Condition	Equipment / Brief Summary of Deviation*	Deviation Period time (am/pm) & date (mo/day/yr)	Date of Written Deviation Report to DOH (mo/day/yr)
		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)

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MONITORING REPORT FORM
FUEL CONSUMPTION - HEATERS
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 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: ________________ Maximum 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	AVERAGE FUEL CONSUMPTION RATE OF RFG (MSCF/day or scf/hr)	AVERAGE FUEL CONSUMPTION RATE OF RFG - ROLLING 12-MONTH (MSCF/day or scf/hr) [1]	AVERAGE HHV FIRING RATE (MMBtu/hr) [1]	AVERAGE HHV OF RFG (Btu/scf) [1]
January				
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				

[1] If applicable

MONITORING REPORT FORM
FUEL CONSUMPTION – PACKAGE BOILERS AND PROCESS HEATERS
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 on a semi-annual basis:

(Make Copies for Future Use)

For Period: ____ Date: __________________

Facility Name: ____

Equipment Location: ____

Equipment Description: Package Boilers SG1103, F5205, Hydrogen Reformer Furnace H2001, RHT Feed Heater H3701____

Equipment Capacity/Rating (specify units): ___________________________________
(Units such as Horsepower, kilowatt, tons/hour, 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):____

1. Package Boiler SG1103

MONTH	MONTHLY FUEL CONSUMPTION OF RFG (MMBTU)	ROLLING 12-MONTHS FUEL CONSUMPTION OF RFG (MMBTU)	AVERAGE FUEL CONSUMPTION OF RFG (MMBTU/MONTH)
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

MONITORING REPORT FORM
FUEL CONSUMPTION – PACKAGE BOILERS AND PROCESS HEATERS
COVERED SOURCE PERMIT NO. 0212-01-C
(Page 2 of 3)

Issuance Date: **Expiration Date: May 12, 2026**

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 on a semi-annual basis:

2. Package Boiler F5205

MONTH	MONTHLY FUEL CONSUMPTION OF RFG (MMBTU)	ROLLING 12-MONTHS FUEL CONSUMPTION OF RFG (MMBTU)	AVERAGE FUEL CONSUMPTION OF RFG (MMBTU/MONTH)
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

3. Package Boiler F5205

MONTH	MONTHLY FUEL CONSUMPTION OF DISTILLATE OIL (GALLONS)	ROLLING 12-MONTHS FUEL CONSUMPTION OF DISTILLATE OIL (GALLONS)
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		

MONITORING REPORT FORM
FUEL CONSUMPTION – PACKAGE BOILERS AND PROCESS HEATERS
COVERED SOURCE PERMIT NO. 0212-01-C
(Page 3 of 3)

Issuance Date: **Expiration Date: May 12, 2026**

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 on a semi-annual basis:

4. Hydrogen Reformer Furnace H2001

MONTH	MONTHLY FUEL CONSUMPTION OF RFG (MMBTU)	ROLLING 12-MONTHS FUEL CONSUMPTION OF RFG (MMBTU)	AVERAGE FUEL CONSUMPTION OF RFG (MMBTU/MONTH)
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

5. RHT Feed Heater H3701

MONTH	MONTHLY FUEL CONSUMPTION OF RFG (MMBTU)	ROLLING 12-MONTHS FUEL CONSUMPTION OF RFG (MMBTU)	AVERAGE FUEL CONSUMPTION OF RFG (MMBTU/MONTH)
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

MONITORING REPORT FORM
OPACITY EXCEEDANCES
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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:______________________________

Facility Name:______________________________

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):______________________________

Visible Emissions:

Report the following on the lines provided below: all date(s) and six (6) minute average opacity reading(s) which the opacity limit was exceeded during the monthly observations; or if there were no exceedances during the monthly observations, then write “no exceedances” in the comment column.

EQUIPMENT or EMISSION POINT DESCRIPTION	SERIAL/ID NO.	DATE	6 MIN. AVER. (%)	COMMENTS

MONITORING REPORT FORM
PROPANE LOAD RACK AND CYLINDER FILLING STATION
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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: ______________________________

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): ______________________________

THROUGHPUTS

	PROPANE LOAD RACK		CYLINDER FILLING STATION	
MONTH	MONTHLY THROUGHPUT (BARRELS)	ROLLING 12-MONTHS THROUGHPUT (BARRELS)	MONTHLY THROUGHPUT (BARRELS)	ROLLING 12-MONTHS THROUGHPUT (BARRELS)
January				
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				

No. of stations: ____________________
No. of arms per station: ______________

MONITORING REPORT FORM
FUEL CERTIFICATION
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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, 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): ______________________________

Equipment	Fuel	Maximum Sulfur Content (% By Weight)	Minimum Centane Index	Maximum Aromatic Content (Volume %)
Diesel Engine Air Compressors	Diesel No. 2			

Equipment	Fuel	Sulfur Content (% by weight)[1]	Reason(s) for Noncompliance	Description of Corrective Actions Taken
F5205 Boiler	Distillate Oil	(30-day average)		

[1]Report the highest sulfur content during the reporting period.

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MONITORING REPORT FORM
GHG EMISSIONS
COVERED SOURCE PERMIT NO. 0212-01-C
(PAGE 14 OF 2)

Issuance Date: **Expiration Date: May 12, 2026**

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: ____

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): ____

1. Report the carbon dioxide equivalent (CO_2e) emitted by the Par East Refinery during each reporting period for purposes of the facility's individual GHG emissions cap:

Emission Year Reporting For __________________					
Reporting Period	Par East Refinery Emissions (Metric Tons of CO_2e)			Par East Refinery Emissions (Total CO_2e)	
	CO_2 (Non-Biogenic)	CHy_4	N_2O	Metric Tons	Short Tons
January 1 – June 30 (1st Semi-Annual Period)					
July 1 – December 31 (2nd Semi-Annual Period)					
Total Emissions →					

2. Report the total combined CO_2e emitted by all partnering facilities during each reporting period for purposes of the total combined GHG emissions cap for these facilities:

Emission Year Reporting For___________________					
Reporting Period	Total Combined Emissions from all Partnering Facilities (Metric Tons of CO_2e)			Total CO_2e	
	CO_2 (Non-Biogenic)	CH_4	N_2O	Metric Tons	Short Tons
January 1 – June 30 (1st Semi-Annual Period)					
July 1 – December 31 (2nd Semi-Annual Period)					
Total Emissions →					

3. For incidences when the individual cap for Par East Refinery and total combined cap for all partnering facilities is exceeded, report the emissions in excess of the total combined cap using the following equation:

$$X = XG\ \frac{(A-C)}{\sum_{A_i > C_i}(A_i - C_i)} = \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_$$

Where:
X = Adjusted portion in metric tons or short tons of GHG emissions that are in excess of total combined cap specified in Attachment II - GHG, Special Condition No. C.1.b. The equation applies to all affected facilities that do not meet the individual and total combined GHG emission caps specified in Attachment II - GHG, Special Condition Nos. C.1.a and C.1.b, respectively.
XG = Total combined actual GHG emissions from affected facilities minus total combined GHG emissions cap. Total combined emissions cap shall be sixteen percent (16%) below the total combined baseline emission level less biogenic CO_2 emissions.
A = Actual GHG emissions from the affected facility.
C = GHG emissions cap for the affected facility.
$\sum_{Ai>ci}(Ai - Ci)$ = The sum of the difference between the actual emissions and cap emissions for all facilities that did not achieve the individual facility-wide GHG emissions cap.

ANNUAL EMISSIONS REPORT FORM
EXTERNAL/INTERNAL FLOATING ROOF PETROLEUM STORAGE TANK
COVERED SOURCE PERMIT NO. 0212-01-C
(PAGE 1 OF 2)

Issuance Date: **Expiration Date: May 12, 2026**

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:____

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): ____

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ANNUAL EMISSIONS REPORT FORM
EXTERNAL/INTERNAL FLOATING ROOF PETROLEUM STORAGE TANK
COVERED SOURCE PERMIT NO. 0212-01-C
(CONTINUED, PAGE 2 OF 2)

Issuance Date: **Expiration Date: May 12, 2026**

(Make Copies for Future Use)

TANK	IDENTIFICATION NO.					
	CAPACITY (bbl)					
	DIAMETER (ft) - **D**					
	COLOR					
	TYPE OF DECK[1]					
	NUMBER OF COLUMNS (DIMENSIONLESS) - **Nc**					
	TYPE OF RIM SEAL[2]					
	TOTAL NUMBER OF DIFFERENT TYPE DECK FITTINGS[3] (DIMENSIONLESS) - $\mathbf{n}_f$					
PRODUCT	NAME					
	REID VAPOR PRESSURE (psi)					
	TRUE VAPOR PRESSURE (psia) - $\mathbf{P}_{VA}$					
	STORAGE TEMP. (^{o}F)					
ANNUAL THROUGHPUT (bbl/yr) - **Q**						

[1]Type A: Column-supported fixed roof with bolted deck
Type B: Column-supported fixed roof with welded deck
Type C: Self-supporting fixed roof with bolted deck
Type D: Self-supporting fixed roof with welded deck

[2]Type VMP: Vapor-mounted resilient foam-filled primary seal only
Type LMP: Liquid-mounted resilient foam-filled primary seal only
Type LFP: Liquid-filled primary seal only
Type MSP: Mechanical shoe primary seal only
Type VMPS: Vapor-mounted resilient foam-filled primary seal plus secondary seal
Type LMPS: Liquid-mounted resilient foam-filled primary seal plus secondary seal
Type LFPS: Liquid-filled primary seal plus secondary seal
Type MSPSS: Mechanical shoe primary seal plus secondary seal (shoe mounted)
Type MSPSR: Mechanical shoe primary seal plus secondary seal (rim mounted)

[3]For each tank, provide a listing of each type of deck fitting and the corresponding quantity of each fitting. [See Table 7.1-12, AP-42, Section 7.1(2/96)]

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ANNUAL EMISSIONS REPORT FORM
FIXED ROOF PETROLEUM STORAGE TANK
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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: ____________________

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): ____________________

TANK	IDENTIFICATION NO.					
	CAPACITY (bbl)					
	DIAMETER (ft)					
	HEIGHT (ft)					
	PAINT CONDITION[a]					
	COLOR[b]					
	POSITION[c]					
	TYPE OF ROOF[d]					
PRODUCT	PRODUCT NAME					
	REID VAPOR PRESSURE (psi)					
	TRUE VAPOR PRESSURE (psia)					
	STORAGE TEMP. (^{o}F)					
ANNUAL THROUGHPUT (bbl/yr)						
AIR POLLUTION CONTROL DEVICE/METHOD[e]						

[a]Indicate paint condition as "G" (good) or "P" (poor).
[b]If the tank is totally underground, indicate a "und" in lieu of specifying a color.
[c]Indicate whether the tank's position is "V" (vertical) or "H" (Horizontal).
[d]Indicate whether the roof construction is "F" (flat), "C" (cone) or "D" (dome).
[e]Indicate applicable control device/method (i.e., vapor recovery system, vapor balance, etc.).

ANNUAL EMISSIONS REPORT FORM
REFINERY EQUIPMENT- FUEL CONSUMPTION
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date:** **May 12, 2026**

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): ______________________________

Type of Fuel Fired	Fuel Usage Gallons/yr or Ft^3/yr	Maximum Sulfur Content (% by weight)	Identify % Nitrogen, % Ash, & % Lead, if applicable

Types of Fuel:
- •Residual Oil: Specify Grade, No. 6, 5, or 4;
- •Distillate Oil (No. 2);
- •Liquefied Petroleum Gas, Butane or Propane;
- •Fuel Oil Reclaimed or Spec Used Oil;
- •If Other, specify.

Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Eff.(%)
____________	Yes or No	____________	____________
____________	Yes or No	____________	____________
____________	Yes or No	____________	____________

DRAFT

ANNUAL EMISSIONS REPORT FORM
REFINERY EQUIPMENT - PROCESS RATE
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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[1]	ANNUAL PROCESS RATE[2]	NOTES

[1]Specify emission source. For example, list wastewater treatment unit, flare, valves, flanges, compressor seals, etc.
[2]Specify annual process rate. For example, list gallons wastewater/yr, etc.

EXCESS EMISSION AND MONITORING SYSTEM
PERFORMANCE SUMMARY REPORT
COVERED SOURCE PERMIT NO. 0212-01-C
(PAGE 1 OF 2)

Issuance Date: **Expiration Date:** **May 12, 2026**

(Make Copies for Future Use)

Facility Name: ______________________________

Equipment Location: ______________________________

Process Unit(s) Description: ______________________________

Pollutant Monitored: ______________________________

Reporting Period Dates:

From: Date ______________ - Time ____________

To: Date ________________ - Time ____________

Emission Limitation: ______________________________

Monitor Manufacturer and Model No.: ______________________________

Date of Latest CMS Certification or Audit: ______________________________

Total Source Operating Time in Reporting Period: ______________________________

EMISSION DATA SUMMARY

1. Duration of excess emissions in reporting period due to:
   a. Startup/shutdown ________
   b. Control equipment problems ________
   c. Process problems ________
   d. Other known causes ________
   e. Unknown causes ________
2. Total duration of excess emission ________
3. Total duration of excess emissions [% of total source operating time] ________%

CMS PERFORMANCE SUMMARY

1. CMS downtime 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 ________
2. Total CMS downtime ________
3. Total CMS downtime [% of total source operating time] ________%

EXCESS EMISSION AND MONITORING SYSTEM
PERFORMANCE SUMMARY REPORT
COVERED SOURCE PERMIT NO. 0212-01-C
(CONTINUED, PAGE 2 OF 2)

Issuance Date: **Expiration Date:** **May 12, 2026**

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): ____

Date: ____

VISIBLE EMISSIONS FORM REQUIREMENTS
STATE OF HAWAII
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: May 12, 2026**

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 and the U.S. EPA. 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 (fifteen (15) feet) from the VE 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 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.

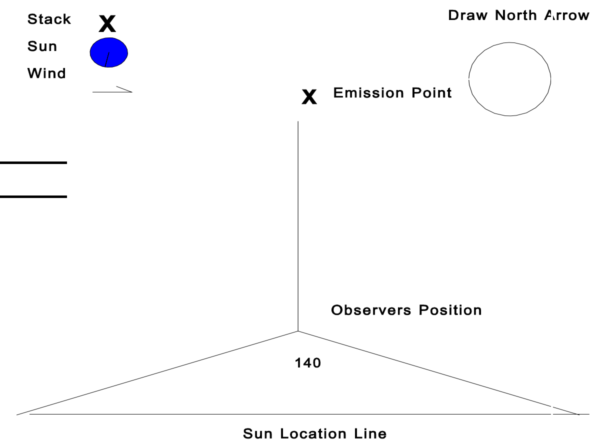
DRAFT

VISIBLE EMISSIONS FORM
COVERED SOURCE PERMIT NO. 0212-01-C

Issuance Date: **Expiration Date: <u>May 12, 2026</u>**

(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)



<u>Site Conditions</u>:
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:______________________

	Seconds				
MINUTES	0	15	30	45	COMMENTS
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

Observation Date and Start Time:______________________________________

	Seconds				
MINUTES	0	15	30	45	COMMENTS
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

Draft Review Summary

Permit Application Review Summary

Application No.:	Significant Modification Application No. 0212-60
Permit No.:	Covered Source Permit (CSP) No. 0212-01-C
Applicant:	Par Hawaii Refining, LLC
Facility Title:	Par East Refinery Located At: 91-325 Komohana Street, Kapolei, Oahu UTM: 2,356,175.9 m N, 594,327 m E, Zone 4, NAD-83
Mailing Address:	Par Hawaii Refining, LLC 91-325 Komohana Street Kapolei, Hawaii 96707
Responsible Official:	Mr. Deaglan McClean Vice President Par Hawaii Refining, LLC (808) 547-3841
Point of Contact:	Ms. Benton Widlansky Environmental Manager (808) 547-3993
Application Dates:	Significant modification application dated December 8, 2023 Revised application dated March 20, 2024 Additional information dated May 2, 2024 and May 16, 2024

Proposed Project:

SICC 2911 (Petroleum Refining)

Par Hawaii Refining owns and operates a petroleum refinery in Campbell Industrial Park, located in the city of Kapolei, Hawaii. The refinery produces jet, diesel and gasoline for the island of Oahu and neighboring islands. Combustion equipment at the refinery includes heaters, boilers, furnaces, a cogeneration unit, incinerator, thermal oxidizer, and a flare.

As part of Par Pacific's renewable fuels strategy, Par Hawaii Refining plans to develop and commission the state's largest renewable fuel production facility in Kapolei to supplement existing conventional petroleum fuel production by 2025. This strategy aligns with the national Renewable Fuel Standard (RFS) program that was created to "reduce greenhouse gas emissions and expand the nation's renewable fuels sector while reducing reliance on imported oil. The RFS program "requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel. The Renewable Fuel Production Facility will enable Par Hawaii Refining to meet its federally-mandated renewable volume obligation (which is more than 12% in 2024) and to meet the growing demand for low-carbon and renewable fuel in the State of Hawaii.

The renewable fuel production facility will process treated renewable feedstocks into renewable biofuels including renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (Renewable LPG). The refinery plans to redesign and repurpose the existing Diesel Hydrotreater (DHT) and convert it into a Renewable Hydrotreater (RHT). The RHT will have a capacity of 4,000 barrels per day (BPD) and be able to flex between maximum SAF and RD mode depending on the market environment for each of those products. This project also includes the construction of a renewable feedstock pretreatment unit (PTU) with a capacity of 5,000 BPD to treat the renewable feedstock prior to processing in the RHT and a new high-pressure (700 psia) steam generating boiler.

The proposed renewable fuel production facility consists of two parts, the renewable feedstock pretreatment unit (PTU) and the renewable hydrotreater (RHT) unit. A new high-pressure (700 psia) package boiler is needed to support operation of the PTU and will be added to the refinery's steam/utility system. Pretreatment of the renewable feedstock in the PTU primarily removes gummy and phosphorous contaminants before being processed in the RHT. As implied by its name, the RHT utilizes hydrogen to remove oxygen from bioseed oils and other renewable feedstocks. The refinery's existing and currently permitted hydrogen generating unit (HGU) will not be modified but will be more fully utilized to provide hydrogen for the RHT.

The most likely feedstock for the renewable fuel production facility (PTU and RHT) is imported soybean oil. Other sources include locally produced biofuel crops (such as camelina), vegetable oils (canola oil and distiller's corn oil). Used cooking oil, tallow, and other animal fats will also be considered, and may become equally viable renewable feedstocks for the RHT. The primary biofuels that will be produced by the RHT are renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (Renewable LPG). Nine (9) existing petroleum storage tanks will be used, and two (2) new tanks will be constructed to store renewable feedstocks and renewable fuels produced by Par Hawaii Refining.

<u>Renewable Feedstock Pretreatment Unit (PTU)</u>

The renewable feedstock PTU is designed to process 5,000 BPD of untreated renewable feedstock. The PTU utilizes high pressure (700 psia) steam and is comprised of feedstock tanks, a feed vacuum deaerator, reaction and mixing towers, and various feed filters, heat recovery exchangers and oil/water separators. Untreated renewable feedstock will be imported to the refinery via barge or isotainer and stored in four (4) tanks; two (2) existing vertical fixed-roof tanks, TK-602, TK-603, and two (2) new vertical fixed-roof tanks, TK-701 and TK-702. Untreated renewable feedstock, such as soybean oil, is vacuum dried and preheated to about 200 °F by waste heat and fed to the bottom of a high-pressure reactor.

A high-pressure package boiler (F2505) will be relocated from the Par West Refinery (CSP No. 0088-01-C, the former Chevron Hawaii Refinery) to the Par East Refinery. It will be used to supply 700 psia steam and is described separately below. The steam is injected into the high-pressure extraction reactor (R-4101), where it mixes with the untreated renewable feedstock. The hot oil is transferred to the water wash tower (T-4101), where it rises up the column and cold water, added at the top of the column, flows downward creating a counter-current flow of oil and water. The temperature, pressure, and time of contact between water and oil is controlled to allow water to remove (extract) gums and phosphorous, and other contaminants from the untreated renewable feedstock. The renewable feedstock exits the top of the column and goes through a coalescer to remove entrained water and the treated renewable feedstock is sent to the RHT via intermediate tankage. Water exiting the extraction column bottom is passed through a coalescer to remove oil carry over and other entrained impurities. Further treatment to reduce the organic loading may be required if the water is to be discharged to an underground injection well. The refinery's existing Wastewater Treatment Unit (WTU) would be expanded, with an additional aeration tank, new wet surface air cooler (WSAC) and two new blowers to be installed in the non-oily wastewater of the WTU. Because the untreated and treated renewable feedstocks have no measurable amount of volatile organic compounds (VOCs) and hazardous air pollutants (HAPS), no significant air emissions are expected from the PTU and related renewable feedstock tanks and effluent water.

Renewable Hydrotreater Unit (RHT) (Repurposed Distillate Hydrotreater (DHT))

The RHT will be designed to process 4,000 BPD of treated renewable feedstock into renewable biofuels. Primary biofuels produced will be renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (Renewable LPG). The existing DHT consists primarily of a catalytic hydrotreating reactor, a charge heater, and a fractionation tower. The conversion of the DHT to the RHT includes modifying the existing reactor into an isomerization reactor, constructing a new larger catalytic hydrotreating reactor, and adding several new exchangers, pumps, towers, compressors, and a mixer. The existing vertical fixed-roof tank, TK-601, will be converted into a treated renewable feedstock storage tank and retrofitted with an internal floating-roof to limit the amount of oxygen its contents will be exposed to. Limiting the oxygen presence will mitigate the corrosion of the carbon steel tank walls and extend the service life of the tank. Five (5) existing vertical external floating roof tanks, TK-401, TK-402, TK-403, TK-404, and TK-201, will also be converted to renewable biofuel storage tanks.

The amount of hydrogen needed to support the RHT will be nominally 3,000 standard cubic feet (scf) per barrel of renewable feed, or about 10-13 MMSCF/day. Relative to the refinery's current baseline operation, the additional hydrogen required for the RHT will be produced by the Hydrogen Generating Unit (HGU). Hydrogen for the RHT may also be provided by the Catalytic Reforming Unit (CRU) when the HGU is not operating. The HGU will not be modified or expanded to support the operation of the RHT, however the existing design capacity of the HGU will be more fully utilized. Emissions from the HGU are addressed in the Project Emissions section of this review. Hydrogen from the HGU will be supplied to the RHT from a new compressor (C-3702) and hydrogen from the RHT will be recovered and routed back to the Distillate Hydrocracker (DHC) via existing compressors. Renewable LPG generated from the RHT would be used as the feedstock to the HGU. Alternatively, to further the State of Hawaii's goal that public utilities reduce GHG emissions, the renewable LPG may be sold as feedstock to the neighboring Synthetic Natural Gas (SNG) plant owned by Hawaii Gas.

The RHT will generate significantly less sulfur than the current DHT operation because, by comparison, there is relatively little sulfur in the renewable feedstock. Any sulfur removed by the RHT in form of sour off-gas will be routed to the existing Amine Treating Unit (ATU) and Sulfur Recovery Plant (SRP) along with sour off-gas from other refinery process units. The capacity of the ATU and SRP are adequate to handle the sulfur generated by and ultimately removed from the RHT.

<u>High-Pressure (700 psia) Package Boiler (Steam Generator) (F5205)</u>
A package boiler (F5205) manufactured by Foster Wheeler will be relocated and installed principally to supply 700 psia steam to the high-pressure extraction reactor (R-4101) in the PTU. Excess steam may also be supplied to existing refinery operations. The Foster Wheeler package boiler (Model AG-5060, Serial No. 7414, National Board No 585) was built in 2007. It will be operated to produce about 75,000 lb/hr of 700 psi steam while operating at the design/permitted firing rate of 99 MMBtu/hr (HHV).

The boiler will normally be fired either on refinery fuel gas (RFG) or low sulfur distillate oil. The boiler has the capacity to be fired on both fuels simultaneously, but based on its historic use by Chevron, dual fuel mode of operation is expected to be uncommon. The boiler's annual fuel use and heat input has been limited in this permitting action to 551,880 MMBtu/year, which is the equivalent of an annual average firing rate of 63 MMBtu/hr. Although the boiler is projected to normally operate at about 35% of its Maximum Continuous Rating (MCR) to support operation of the PTU, at times, the full fired duty (i.e. 99 MMBtu/hr) and steam generating capacity of Package Boiler F5205 will be utilized. The boiler has a low NO_x burner and was designed with a fully integrated and automated flue gas recirculation (FGR) system to control NO_x emissions.

The boiler is required for the renewable fuels production facility and is the primary source of new air emissions associated with the renewable fuels production facility. Liquid fuel firing of the high-pressure (700 psia) boiler is essential because the refinery's other two package boilers (steam generators) (SG1102 and SG1103) are low pressure (235 - 250 psia) and because there are intermittent shortages of RFG based on the type and composition of crude oil being refined. Additionally, SG1103 only burns RFG. To control SO_2 emissions while firing Package Boiler F5205 on distillate oil, the boiler would be restricted to burn only distillate oil with sulfur content limited to no more than 0.25% by weight. The limit on the sulfur content of the distillate fuel is not mandated by State or federal regulations but, is being proposed as an enforceable permit condition to limit SO_2 emissions.

While NO_x emissions from the boiler are well controlled because it is equipped with FGR and a low NO_x burner, principally to stay under the 40 TPY PSD threshold for the entire renewable fuels project, the use of distillate oil will be limited to 110,376 MMBtu/yr (equivalent to 788,000 gallons per year) which is approximately 20% of the total heat input of the fuel (in terms of Btu's) that may be used to fire the boiler throughout the year, with the balance of heat input coming from RFG.

The limitation on the type of liquid fuel, i.e., distillate oil as defined by 40 CFR §60.41(c) (with a sulfur content of less than 0.25% by weight), and the amount of distillate oil (or more precisely the amount of heat from distillate oil) will have the combined effect of also limiting the emissions of most criteria and non-criteria pollutants. Since the boiler was built in 2007, it is subject to 40 CFR Part 60, Subpart Dc, which limits particulate matter (PM) emissions, but because the fuel use is being limited to RFG and low sulfur (< 0.25 wt%) distillate fuel, the PM emission limit in 40 CFR §60.43c(e)(1) of 0.03 lb/MMBtu does not apply pursuant to 40 CFR §60.43c(e)(4). However, Par Hawaii Refining is proposing the 0.03 lb/MMBtu PM emission limit as an enforceable permit limit, to ensure that the 10 TPY PSD threshold for $PM_{2.5}$ is not exceeded. Without a stringent PM limit in place, the maximum potential-to-emit (PTE) for PM emissions under the PSD analysis would have been only limited by the 0.22 lb/MMBTU filterable PM limit of 40 CFR Part 63, Subpart DDDDD, for existing non-continental boilers and process heaters. Likewise, because the liquid fuel used to fire Package Boiler F5205 will be limited to low sulfur distillate oil, the boiler will readily meet the CO and filterable PM emissions limits specified in 40 CFR Part 63, Subpart DDDDD for existing non-continental boilers and process heaters which burn liquid fuel.

A permit modification application fee of $3,000.00 for a significant modification was submitted by the applicant and processed.

Equipment Description:

1. Hydrogen Reformer Furnace, ID No. H2001

    a. 172.8 MMBtu/hr heat input; and
    b. Equipped with a combustion air preheater and flue gas recirculation.

2. Package Boiler (steam generator) (ID No. F5205)

    a. 99 MMBtu/hr heat input.
    b. Equipped with a low NO_x burner and flue gas recirculation.
    c. Foster Wheeler, Model No. AG-5060, Serial No. 7414, National Board No. 585.

3. Seven (7) Renewable Feedstock/Renewable Biofuel/Heavy Oil Storage Tanks

    a. One (1) - 2,141,194 gallon (nominal) internal floating roof storage tank identified as Tank 601;
    b. One (1) - 2,141,194 gallon (nominal) vertical fixed roof storage tanks identified as Tank 602;
    c. One (1) - 4,605,476 gallon (nominal) vertical fixed roof storage tank identified as Tank 603;
    d. Two (2) - 1,804,595 gallon (nominal) external floating roof storage tanks identified as Tanks 401 and 402; and
    e. Two (2) - 1,804,595 gallon (nominal) external floating roof storage tanks identified as Tanks 403 and 404.

4. One (1) Renewable Biofuel/Naphtha/Gasoline Storage Tank

   One (1) - 1,015,085 gallon (nominal) external floating roof storage tank identified as Tank 201.

5. Two (2) Renewable Feedstock Storage Tanks (also listed in the Insignificant Activities Section)

   Two (2) - 2,478,000 gallon (nominal) vertical fixed roof storage tanks identified as Tanks 701 and 702.

6. Renewable Fuel Production Facility:

   a. Renewable Feedstock Pretreatment Unit (PTU).
   b. Renewable Hydrotreater (RHT).

      i. RHT Feed Heater, ID No. H3701.
      ii. 30 MMBtu/hr heat input.

7. One (1) additional aeration tank in the Activated Sludge Unit of the WTU

Air Pollution Controls:

1. Package Boiler (steam generator) (ID No. F5205) is equipped with a low NO_x burner and flue gas recirculation.

Proposed Fuels and Fuel Limits:

1. Hydrogen Reformer Furnace H2001

   New Permit Condition:

   Maximum Fuel Consumption

   The heating value of the RFG used to fire the Hydrogen Reformer Furnace H2001 shall not exceed 96,973 MMBtu/month based on a rolling twelve-month (12-month) average which is equivalent to a firing rate of 132.84 MMBtu/hr.

   Existing Permit Condition:

   Maximum Fuel Consumption

   The maximum fuel consumption for the Hydrogen Reformer Furnace H2001 shall not exceed 90,000 standard cubic feet per hour (scf/hr) of RFG based on a rolling twelve-month (12-month) average. The maximum fuel consumption limit is based on a RFG HHV of 1,476 Btu/scf. In the event of significant variations in the HHV of the RFG, the maximum fuel consumption limit shall be as follows:

   Maximum fuel consumption (scf/hr) = 172.8 MMBtu/hr ÷ HHV of RFG (Btu/scf)

2. Package Boiler SG1103 (although this boiler is not involved in proposed project, the applicant is requesting to change the operating limit to be consistent with the other proposed changes in the permit).

   New Permit Condition:

   Operating Limitations

   The Package Boiler SG1103 when fired on RFG shall not exceed 71,586 MMBtu/month based on a rolling twelve-month (12-month) average.

   Existing Permit Condition:

   Operating Limitations

   The Package Boiler SG1103 shall not consume more than 582 million standard cubic feet of RFG per year based on a rolling twelve-month (12-month) period. The maximum fuel consumption limit for RFG is based on a HHV of 1476 Btu/scf. In the event of significant variation in the HHV, the maximum fuel consumption limit shall be as follows:

   Maximum fuel consumption (scf/hr) = 98 MMBtu/hr / HHV of RFG (Btu/scf)

3. Package Boiler F5205

   Operating Limitations

   The Package Boiler F5205 when fired on distillate oil shall not exceed 788,000 gallons per any rolling twelve-months (12-months). The Package Boiler F5205 when fired on RFG shall not exceed 36,792 MMBtu/month based on a rolling twelve-month (12-month) average.

4. RHT Feed Heater H3701

   The heating value of the RFG used to fire the RHT Feed Heater H3701 shall not exceed 21,945 MMBtu/month based on a rolling twelve-month (12-month) average which is equivalent to a firing rate of 30 MMBtu/hr.

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 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 J: Standards of Performance for Petroleum Refineries (applies to the Hydrogen Reformer Furnace, ID No. H2001)
Subpart Dc Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (applies to the Package Boiler, ID No. F5205)
Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (applies to the Package Boiler, ID No. F5205 and RHT Feed Heater, ID No. H3701)
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 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 §60.481a of 40 CFR Part 60, Subpart VVa, at the Renewable Hydrotreater (RHT) and the RHT Compressor (C3701))
Subpart QQQ: Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (applies to 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, at the RHT)
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 all benzene-containing hazardous waste streams at hazardous waste treatment, storage, and disposal facilities at the RHT)
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 all Petroleum Storage Tanks and 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 at the RHT)

Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters (applies to the Hydrogen Reformer Furnace, ID No. H2001, Package Boiler, ID No. F5205, RHT Feed Heater, ID No. H3701)

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

NSPS Subpart Dc emission limits for the Package Boiler F5205 when burning oil.

Pollutant	NSPS Subpart Dc Maximum Emission Limits	Regulation
SO_2	0.50 lb/MMBtu or oil with sulfur content < 0.5 wt%	40 CFR §60.42c(d), §60.42c(g), §60.42c(i)
PM	0.03 lb/MMBtu (not applicable, if sulfur content < 0.5 wt%)	40 CFR §60.43c(d), §60.43c(e)(1), §60.43c(e)(4)
Opacity	< 20% (6-minute average) except for one 6-minute period per hour < 27%	40 CFR §60.43c(c), §60.43c(d)

Notes:

1. For Package Boiler F5205, the applicant is proposing to utilize only RFG or distillate oil with a 0.25 wt% sulfur limit to minimize opacity and to qualify for the monitoring requirements in 40 CFR §60.47c(f)(3) and not require a Continuous Opacity Monitoring System (COMS). Note that when this boiler was operating at the Par West Refinery, a COMS was also used to monitor opacity. This was proposed by the applicant (Chevron) when the boiler was initially permitted, and not because of NSPS Subpart Dc, as the boiler was also burning only RFG and low sulfur (< 0.5 wt%) liquid fuel.

2. In accordance with the exclusion set forth by 40 CFR §60.43c(e)(4), because only RFG and low sulfur (< 0.25 wt%) distillate oil will be used, Package Boiler F5205 is not subject to the PM limits specified in NSPS Subpart Dc. However, the applicant is proposing the 0.03 lb/MMBtu limit on PM, specified in 40 CFR §60.43c(e)(1), as an enforceable permit condition to ensure the significant PSD thresholds will not be exceeded.

3. Hawaii Administrative Rules (HAR) §11-60.1-32(b) requires the following:

   For any six (6) minute averaging period, stationary sources shall not exhibit visible emissions of twenty (20) percent opacity or greater, except as follows: during start-up, shutdown, or equipment malfunction, stationary sources 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.

   Since the opacity limits in HAR §11-60.1-32(b) are more stringent than the opacity limits in NSPS Subpart Dc, the permit will only contain the opacity limits in HAR §11-60.1-32(b).

4. Note that although Package Boiler F5205 is subject to the opacity standard in 40 CFR §60.43c(c), the applicant is not required to operate a COMS pursuant to 40 CFR §60.47c(f)(3) by operating Package Boiler F5205 according to a written site-specific monitoring plan approved by the DOH. Also, since Package Boiler F5205 must comply with the opacity requirement in HAR §11-60.1-32(b) (see item no. 3 above), which also requires monthly Method 9 monitoring for opacity, the use of monthly Method 9 monitoring over an observation time consisting of two six (6) minute periods, can also be used to meet the requirements of a site-specific monitoring plan. A monitoring plan was submitted by the applicant on May 2, 2024.

NSPS Subpart J and Ja emission limits for affected combustion devices burning RFG in petroleum refineries.

Pollutant	NSPS Subpart J and Ja Maximum Emission Limits	Regulation
H_2S in RFG	< 230 mg/dscm (0.10 gr/dscf)	40 CFR §60.104(a)(1)
H_2S in RFG	< 162 ppmv (3-hr rolling average) and < 60 ppmv (365-day rolling average)	40 CFR §60.102a(g)(1)(ii)
SO_2	< 20 ppmv at 0% excess O_2 (3-hr rolling average) and 8 ppmv at 0% excess O_2 (365-day rolling average)	40 CFR §60.102a(g)(1)(i)

Notes:

1. The provisions of NSPS Subpart Ja applies to affected facilities in petroleum refineries, i.e., boilers and process heaters which either commence construction, modification or reconstruction after May 14, 2007, or elect to comply with the provisions of Subpart Ja in lieu of complying with the provisions of NSPS Subpart J. The Package Boiler F5205 was constructed prior to the applicability date for NSPS Subpart Ja and will be relocated from the Par West Refinery to the Par East Refinery. The Package Boiler F5205 was subject to NSPS Subpart J when it was permitted at the Par West Refinery. The relocation of the boiler is not considered modification or reconstruction under NSPS. However, there is some uncertainty as to whether relocation is considered construction under NSPS. Construction means fabrication, erection, or installation of an affected facility per the definition in 40 CFR §60.2. It is not as clearly defined as in 40 CFR §63.2, which explicitly excludes relocation of equipment. However, since the Package Boiler F5205 will receive RFG from a common fuel gas system which includes amine treatment designed and operated to ensure that the NSPS Subpart Ja standards will be met (the DHT Feed Heater H3701 was permitted in 2018 and NSPS Subpart Ja was an applicable requirement), the applicant has elected to subject the boiler to NSPS Subpart Ja instead of NSPS Subpart J.

2. NSPS Subpart Ja provides the option of either complying with the H_2S in RFG limit or SO_2 limit. The applicant has requested that the H_2S in RFG limit be used.

MACT Subpart DDDDD emission limits for existing non-continental combustion sources burning liquid fuel.

Pollutant	MACT Subpart DDDDD Maximum Emission Limits (as of July1, 2023)	Regulation
CO	130 ppmvd @ 3% excess O_2	40 CFR §63.7500, Table 2, Item No. 17
Filterable PM	0.22 lb/MMBtu	40 CFR §63.7500, Table 2, Item No. 17
Hydrogen Chloride	1.1E-03 lb/MMBtu	40 CFR §63.7500, Table 2, Item No. 14
Mercury	7.3E-07 lb/MMBtu	40 CFR §63.7500, Table 2, Item No. 14

Notes:

1. The applicant is proposing to utilize only RFG or low sulfur (<0.25 wt%) distillate oil to comply with the MACT Subpart DDDDD limits and minimize PM and HAP emissions. Since the applicant has elected to use low sulfur distillate fuel and has proposed a 0.03 lb/MMBtu limit for PM emissions (based on NSPS Subpart Dc), the less stringent 0.22 lb/MMBtu limit specified under MACT Subpart DDDDD for existing non-continental sources has been rendered somewhat irrelevant.

2. The Package Boiler F5205 was built in 2007 and was originally designed and permitted for to be fired on low sulfur fuel oil (LSFO) or RFG. Per 40 CFR §63.7490, the relocation of Package Boiler F5205 from the Par West Refinery (where the boiler was first permitted by Chevron) to the Par East Refinery is not classified as commencing construction of a boiler after June 4, 2010 or commencing reconstruction of a boiler after June 4, 2010, therefore the Package Boiler F5205 is not a new boiler or reconstructed boiler and is classified as an existing boiler and is subject to the MACT Subpart DDDDD limits for existing boilers and process heaters.

   Per the definitions in 40 CFR §63.2, construction is defined as follows:

   Construction means the on-site fabrication, erection, or installation of an affected source. Construction does not include the removal of all equipment comprising an affected source from an existing location and reinstallation of such equipment at a new location. The owner or operator of an existing affected source that is relocated may elect not to reinstall minor ancillary equipment including, but not limited to piping, ductwork, and valves. However, removal and reinstallation of an affected source will be construed as reconstruction if it satisfies the criteria for reconstruction as defined in this section. The costs of replacing minor ancillary equipment must be considered in determining whether the existing affected source is reconstructed.

3. Note that when the Package Boiler F5205 was permitted at the Par West Refinery, it was subject to a ≤ 10% opacity limit (Table 4 of MACT Subpart DDDDD) and a COMS was also installed. This was probably the result of the initial permit application by Chevron voluntarily subjecting the boiler to the MACT Subpart DDDDD opacity limit. Upon further review of the MACT Subpart DDDDD regulations, the Package Boiler F5205 should not be

subject to the MACT Subpart DDDDD opacity limit since there are no air pollution control equipment for PM on Package Boiler F5205 and therefore a COMS is not required.

Non-Applicable Requirements:

Hawaii Administrative Rules
Title 11, Chapter 60.1 - Air Pollution Control
Subchapter 7 - Prevention of Significant Deterioration Review

Federal Requirements
40 CFR Part 52, §52.21 – Prevention of Significant Deterioration of Air Quality (see page 13 for details)

PTU Applicable Federal Regulations
The renewable feedstock pretreatment unit (PTU) is not subject to any federal regulations since the renewable PTU is not a refinery process unit nor is it directly connected to a refinery process unit. Feedstocks are limited to low volatility vegetable oil, waste cooking oils and animal fats (tallow). The applicant proposes to utilize filters, gravity phase separation and water/steam, (but no fossil fuels such as naphtha or hexane) to extract and remove contaminants from renewable feedstocks.

SOCMI Regulations
The regulations listed below for Synthetic Organic Chemical Manufacturing Industry (SOCMI) sources were reviewed. Although general provisions apply (by reference), no substantive requirements apply and no additional controls are required. The PTU and RHT are either categorically exempt from the following 40 CFR Part 60 (NSPS) federal regulations or – more commonly - the emission limits, standard and work practices do not directly apply to any of the new or modified equipment which is being installed for the renewable fuels project.

Subpart VVa — 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.

Subpart VVa standards are inapplicable to the PTU and RHT principally because they do not produce, as intermediate or final products, one or more of the chemicals listed in 40 CFR §60.489a. As a result, the PTU and RHT and do not meet the definition of a SOCMI process unit which is subject to regulation under Subpart VVa.

Only indirectly is the RHT subject to some of the same standards for equipment leaks as those specified under Subpart VVa as a consequence being cross referenced by Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

Subpart III — Standards of Performance for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes.

Subpart NNN — Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations.

Subpart RRR — Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes.

Subpart RRR standards are inapplicable to the PTU and RHT principally because there are no atmospheric vents to which the SOCMI standards would apply. In addition to renewable fuels which are normally liquids under standard conditions, the RHT is going to make renewable propane and butane, which may be either used as a feedstock to the HGU or sold to the neighboring SNG plant. Propane and butane are chemical products which are listed in 40 CFR §60.707 and they are produced with the potential to be sold as a final product. However, there are no atmospheric vents from the PTU or RHT.

The PTU and RHT are either categorically exempt from the following 40 CFR Part 63 (NESHAP) regulations or more commonly the emission limits, standards and work practices do not apply to any of the new or modified equipment which is being installed for the renewable fuels project.

Subpart G — National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater.

Subpart H — National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks.

Subpart FFFF — National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing.

Subpart GGGG — National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production.

Only steam is used as a solvent and as a stripping agent to remove gums and other contaminates in the PTU (not a regulated solvent such as naphtha). The renewable facility is not producing vegetable oil, but rather the PTU is removing contaminates from raw vegetable and seed oils.

<u>Wastewater Treatment Unit (WTU)</u>

The WSAC is not a cooling tower or a heat exchanger per the definitions in 40 CFR Part 63 Subpart Q, National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers, and 40 CFR Part 63 Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, Heat Exchange Systems, and therefore is not subject to those regulations.

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 there are no emission increases above significant levels for this application.

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 Part 52, §52.21.

The potential increase in emissions from the project were compared to the PSD significant levels as shown in the table below. PSD is not applicable because all calculations show that the PTE is less than the PSD significant levels for all pollutants, i.e., there are no significant emissions increases.

RENEWABLE FUEL PRODUCTION FACILITY EMISSIONS[1]

Pollutant	New F5205 Boiler, Fugitives & Increased Utilization of Existing Sources (H3701, H2001, & HGU[2]) (tpy)	PSD Significant Levels (tpy)
CO	55.53	100
H_2S	0.03	10
Pb	0.0008	0.6
NO_X	35.79	40
SO_2	20.01	40
VOC	2.65	40
PM_{Total}	4.16	25
PM_{10}	4.16	15
$PM_{2.5}$	4.16	10
Fluorides	0.01	3
Sulfuric Acid Mist	0.28	7
Total Reduced Sulfur	0.10	10
GHG (CO_2e)[3]	113,757	75,000

[1] Proposed PTE – Baseline Actual
[2] GHG emissions associated with increased feed to and utilization of the HGU are not considered in PSD applicability.
[3] Per 40 CFR §52.21(b)(49)(iv)(b), pollutant GHG's are not subject to PSD regulation if there is not an increase of a regulated NSR pollutant.

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[1,2] (TPY)	Type B Triggering Levels[1] (TPY)	Pollutant	In-house Total Facility Triggering Levels[1] (TPY)	Potential Emissions (TPY)
NO_x	≥2500	≥100	NO_x	≥25	2,202
SO_2	≥2500	≥100	SO_2	≥25	2,635
CO	≥2500	≥1000	CO	≥250	653
$PM_{10}/PM_{2.5}$	≥250/250	≥100/100	PM/PM_{10}	≥25/25	PM = 263 PM_{10} = 190 $PM_{2.5}$ = 131
VOC	≥250	≥100	VOC	≥25	705
Pb		≥0.5 (actual)	Pb	≥5	0.0472
			HAPS	≥5	120.5

[1] Based on potential emissions.
[2] 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.

The Package Boiler F5205 is not subject to CAM because both the 40 CFR Part 60, Subpart Dc and 40 CFR Part 63, Subpart DDDDD regulations which contain emission standards that the boiler is subject to are post November 15, 1990 regulations that are exempt from CAM.

Insignificant Activities:

Per HAR 11-60.1-82(f)(7) - Activities deemed to be insignificant on a case by case basis by the Director: Two (2) Renewable Feedstock Storage Tanks - Two (2) - 2,478,000 gallon (nominal) vertical fixed roof storage tanks identified as TK-701 and TK-702.

Alternate Operating Scenarios:

There are no alternate operating scenarios proposed for this facility.

Project Emissions:

Relocated Package Boiler F5205

Hourly emissions rates (lb/hr) for the Package Boiler F5205 were determined for each pollutant based on the fuel (either RFG or distillate oil) with the highest emission rate for that pollutant (at the max design operation rate of 99 MMBtu/hr). The maximum total annual emission rate (tpy) for each pollutant was determined by multiplying the pollutant's emission factor for each fuel by the annual fuel use limit for that fuel, and then summing the two.

Distillate Oil Combustion

Hourly emissions for the Package Boiler F5205 while firing distillate oil were calculated by multiplying the emission factors by the maximum design heat input capacity of 99 MMBtu/hr. Annual emission rates were calculated by multiplying the same emission factors by the fuel limit of 9,198 MMBtu/month based on a rolling 12-month average which is approximately equal to 12.6 MMBtu/hr of distillate fuel.

The physical properties of the distillate fuel used in emissions calculations are as follows:

HHV	= 140,000 Btu/gal, as provided in AP-42, Section 1.3 - Fuel Oil Combustion
Sulfur Content	= 0.25 wt% limit, proposed limit
Fd	= Dry Fuel Factor (SCF/ MMBtu) = 9190 SCF/ MMBtu, based on Part 60 Meth.19 & Part 75 Table 1

The emission factors for low-sulfur distillate oil are as follows:

CO	= 0.101 lb/MMBtu based on the MACT limit of 130 ppm at 3% O_2
NH_3	= 0.8 lb/1000 gal, based on EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emission. Factor, Table 5-2, 8/94 (3.2 lb/MMscf).
Pb	= 0.000009 lb/MMBtu, based on AP-42, Table 1.3-10
NO_x	= 0.143 lb/MMBtu, based AP-42 Table 1.3-1 (20 lb/1000 gal) and an equivalent NO_x limit of 130 ppm at 0% excess O_2 proposed by the applicant along with fuel use limits to prevent exceeding the PSD threshold.
SO_2	= 35.5 lb/1000 gal, based on AP-42, Table 1.3-10 and a proposed sulfur limit of 0.25 wt% in distillate oil.
VOC	= 0.2 lb/1000 gal, based on AP-42 Table 1.3-3
PM_{Tot}	= 0.03 lb/MMBtu, proposed limit based on the NSPS Subpart Dc (and parallels NESHAPs Subpart JJJJJJ Table 1)
PM_{10}	= 0.03 lb/MMBtu, proposed limit based on the NSPS Subpart Dc (and parallels NESHAPs JJJJJJ Table 1)
$PM_{2.5}$	= 0.03 lb/MMBtu, proposed limit based on the NSPS Subpart Dc (and parallels NESHAPs Subpart JJJJJJ Table 1)
HCl	= 0.0011 lb/MMBtu based on MACT Subpart DDDDD Table 2.
Mercury	= 0.00000073 lb/MMBtu based on MACT Subpart DDDDD Table 2.
Total Greenhouse Gases (GHGs) CO_2e	163 lb/MMBtu (based 40 CFR 98 calculation methodologies, using standard emission factors for CO_2, CH_4 and N_2O.
Other Individual HAPs	lb/MMBtu or lb/1000gal rates from rates from AP-42 Section 1.3 - Fuel Oil Combustion. Tables 1.3-1,2,3,6,8,10,14. May 2010. Uses factors for Distillate oil when available.

<u>Fuel Gas Combustion</u>

Hourly emission rates for Package Boiler F5205 while firing on refinery fuel gas are calculated by multiplying emission factors by the max design operation rate of 99 MMBtu/hr. Annual emission rates are calculated by multiplying the same emission factors by the fuel limit of 36,792 MMBtu/month based on a rolling 12-month average or approximately equal to 50.4 MMBtu/hr of fuel gas.

The physical properties of the RFG used in emissions calculations are as follows:

HHV	= Higher Heating Value (Btu/SCF) = 1595 Btu/SCF
Fd	= Dry Fuel Factor (SCF/ MMBtu) = 8622 SCF/ MMBtu

Note: Even though CSP No. 0212-01-C includes several references to a more typical heating value for RFG (1476 Btu/SCF) and a dry fuel factor of 8740 SCF/Btu, the physical properties of the RFG presented above were based on the two most recent years (2021-2022) of refinery lab analysis. Notably only the dry fuel factor (a near constant) is used to convert common concentration-based limits to equivalent lb/MMBtu emission factors through application of the generalized equation below.

$$\text{lb/MMBtu} = \frac{(\text{Pollutant PPM at 0\% excess } O_2) * (\text{Pollutant MW}) * (\text{Fd SCF/MMBtu})}{(1{,}000{,}000) * (385.3 \text{ SCF/Mole})}$$

Because there is little variability in Fd factors for each category of gaseous or liquid fuel, the calculated or published lb/MMBtu emission factors do not vary much based on the composition of the RFG or the low sulfur oil (over time). Even though HHV of natural gas, propane and butane range from 1050 to 3225 Btu/SCF, in Method 19 of Appendix A-7 to Part 60 the EPA assigned a singular Fd factor of 8710 SCF/Btu for all three because the ratio of carbon to hydrogen in all of these gases is nearly the same. So, too, is the amount of flue gas from their combustion.

The emission factors for RFG used for estimating emissions for this project are as follows:

CO	= 0.095 lb/MMBtu based on the MACT limit of 130 ppm at 3% excess O_2 and an average Fd factor of 8622 dscf/MMBtu.
H_2S (3-hr)	= 0.00018 lb/MMBtu, NSPS Ja limit of 162 ppmv in RFG with 98% destruction efficiency upon combustion and 2% slip-by.
NH_3	= 0.0020 lb/MMBtu, based on EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emission Factor, Table 5-2, 8/94 (3.2 lb/MMscf).
Pb	= 0.00000049 lb/MMBtu, based on EPA's Emission Estimation Protocol for Petroleum Refineries, version 3, April 2015, Table 4-3.
NO_x	= 0.051 lb/MMBtu, based on a NO_x concentration limit of 50 ppm at 0% excess O_2 proposed by the applicant along with fuel use limits to prevent from exceeding the PSD threshold.
SO_2 (3-hr) (365-day)	= 0.029 lb/MMBtu, NSPS Ja limit of 20 ppmv in flue gas = 0.011 lb/MMBtu, NSPS Ja limit of 8 ppmv in flue gas (ppm limits are for dry flue gas, at 0% excess air).

VOC	= 0.0035 lb/MMBtu, based on AP-42, Table 1.4-1 boilers fired on natural gas (5.5 lb/MMSCF).
PM_{Tot}	= 0.00476 lb/MMBtu, based on AP-42, Table 1.4-1 for natural gas (7.6 lb/MMscf), includes filterable and condensable. (All PM assumed $PM_{2.5}$).
Total Greenhouse Gases (GHGs) CO_2e	127 lb/MMBtu, based on 40 CFR 98 calculation methodologies, using 2021-2022 sample data for CO_2 and standard emission factors for CH_4 and N_2O.
Individual HAPs	lb/MMBtu rates from EPA's International's Emission Estimation Protocol for Petroleum Refineries- Table 4-3.

Untreated Renewable Feedstock Tanks, TK-701 and TK-702

Two (2) new vertical fixed cone-roof tanks (TK-701 and TK-702) will be constructed to store untreated renewable feedstock for the pretreatment unit. The new heated tanks will be built in the same location that had been previously planned for permitted ethanol tanks (TK-518 and TK-519), which were never constructed.

Although the most likely option for feedstock is soybean oil, other options include seed oil, used cooking oil, and animal fats. Emissions from these tanks are considered insignificant because soybean oil, other seed oils and animal fats are all low volatility and essentially void of VOCs and HAPs. The Clean Air Branch affirmed this determination by issuing an insignificant activity approval letter (dated August 9, 2023) authorizing construction and operation of Tanks 701 and 702.
There are no significant emissions or controls required for the tanks because vegetable/seed oil/animal fat has low volatility and have no or negligible hazardous air pollutants (HAPs) present. Likewise, there are no applicable state or federal regulations for TK-701 and TK-702. Associated piping, pumps and filters to the tanks are also exempt from fugitive monitoring and requirements because they are free of VOCs and HAPs.

RHT Fugitive Emissions

In addition to repurposing much of the existing DHT, a number of new vessels and towers, reactors and exchangers will be installed for the RHT. As with the DHT, miscellaneous sources of potential equipment leaks of VOC, including valves, pumps, pressure relief devices sampling connection systems, open-ended valves or lines, and flanges or other connectors in VOC service, will be subject to NSPS Subpart GGGa. Unless not commercially available, all new valves in light hydrocarbon service will be Certified Low Leaking Technology (CLLT) valves or packed with Certified Low Leaking Packing to reduce VOC emissions. The leak threshold for fugitive emissions from pumps will be 2,000 ppm and the leak threshold from valves will be 100 ppm. The calculations of the potential emissions from the new fugitive sources were based on the EPA Emission Estimation Protocol for Petroleum Refineries and an approximate count of components based on design plans.

The following correlation equations from Table 2-2 of the Emission Estimation Protocol for Petroleum Refineries (Version 3, April 2015) were used to determine VOC emissions from each component:

kg/hr/valve	= 0.00000229*(SV^0.746), where the screening value (SV) is 100 ppm based on the Certified Low Leak Technology (CLLT) limit.
kg/hr/pump	=0.0000503*(SV^0.61), where the SV is the monitoring leak threshold of 2,000 ppm.
kg/hr/connector	=0.00000153*(SV^0.735), where the SV is the monitoring leak threshold of 500 ppm for connectors that will be monitored with valves.
kg/hr/sample connection	=0.0000136*(SV^0.589), where the SV is the Standard leak threshold of 10,000 ppm for remaining sources (Except compressors).

The new compressors are excluded from the fugitive emissions calculations because they will be routed to the flare. Annual VOC and speciated emissions were obtained by multiplying the hourly emission rate by 8760 hours per year. The total VOCs from the fugitive sources above were then speciated as individual HAP and non-HAP constituents following Table 2-7 concentration ratios for Hydrotreating/Hydrodesulfurization and the methodology in the Emission Estimation Protocol for Petroleum Refineries.

Biogenic CO_2e Byproduct from RHT

In addition to producing a variety of renewable fuels, the RHT will also produce a relatively small (1,325 TPY) amount of biogenic CO_2 byproduct which will pass to the refinery fuel gas system and released through various refinery fuel gas combustion sources.

Tanks

Eleven (11) tanks will be used to support the renewable fuel production facility, two (2) new, TK-701 and TK-702, and nine (9) existing, TK-201, TK-401, TK-402, TK-403, TK-404, TK-517, TK-601, TK-602, and TK-603. The properties of the renewable feedstock and biofuel are compatible with the existing petroleum-based storage tanks they will be stored in. However, TK-601 will be retrofitted with an internal floating roof for corrosion mitigation of the tank and not for regulatory reasons. Existing tank utilization will not increase and there are no emissions increases expected. The table below lists all the tanks that will support the Renewable Fuel Production Facility with their current and future contents.

Insignificant Addition of Transmix to Refinery Fuel Oil

As a result of the pipeline flush during the receipt of renewable feedstock from the barge harbor, a negligible amount of transmix (~20 BPD) composed of roughly 50% low sulfur diesel and 50% renewable feedstock may be blended into the current refinery fuel oil system for on-site combustion in fuel oil sources. There will be no increase in fuel oil consumption and no change to the fuel oil specification itself. TK-517 will be utilized for storage of this material.

RHT Tank Storage

Tank No.	Liquid Stored	
	Before	After

TK-701	*new*	Untreated Renewable Feedstock
TK-702	*new*	Untreated Renewable Feedstock
TK-601	Fuel Oil	Treated Renewable Feedstock
TK-602	Fuel Oil	Untreated Renewable Feedstock
TK-603	High Sulfur Vacuum Residual	Untreated Renewable Feedstock
TK-517	Heavy Oil/Water	Heavy Oil/Water/Transmix (Pipeline Interface – Diesel & Renewable Feedstock)
TK-401	Jet A	SAF/RD
TK-402	Jet A	SAF/RD
TK-403	Jet A	RD
TK-404	Jet A	RD
TK-201	Naphtha	RN

Feed Heater H3701

The RHT will directly utilize the existing Feed Heater H3701 (for which the PTE will now use the maximum safe design capacity of 30 MMBtu/hr heat input versus the currently permitted heat input of 26 MMBtu/hr).

The emissions factors for Feed Heater H3701 are the same as those for the combustion of RFG in Package Boiler F5205, with the exception of NO_x emissions, for which there is a different basis and limit.

NO_x = 0.040 lb/MMBtu based on design basis of 40 ppm at 0% excess O_2 and an average Fd factor of 8622 dscf/MMBtu (as previously permitted). However, due to the increase to the maximum safe design capacity (30 MMBtu/hr), the equivalent NO_x emission limit requested is 1.24 lb/hr (vs 1.05 lb/hr currently specified on the permit). The limit was set as a mass rate because NO_x concentrations are not as well controlled when firing the heater at low rates.

Note: Although the PTEs have been calculated at the requested maximum design rate as required for the PSD assessment, the applicant is expecting Feed Heater H3701 will be fired less as the RHT Feed Heater than it had historically been fired as the DHT Feed Heater.

Hydrogen Reformer Furnace H2001

The new RHT will require more hydrogen to remove oxygen from the renewable feedstocks. Because the Catalytic Reforming Unit (CRU), which produces hydrogen as by-product of the reforming process, is already operated at near maximum rates, additional hydrogen for the RHT will be supplied by the Hydrogen Generation Unit (HGU).

In order to accommodate the product demand growth for hydrogen, the HGU will be more routinely operated at a rate of about 18 MMSCF/day and Hydrogen Reformer Furnace H2001 will be fired at an estimated average rate of 132.8 MMBtu/hr. Because of the RHT, Hydrogen Reformer Furnace H2001 will fire harder than normal which will lead to an increase in actual emissions from Hydrogen Reformer Furnace H2001. Although Hydrogen Reformer Furnace H2001 was designed and permitted for 172.8 MMBtu/hr to accommodate peak (and future demand), Hydrogen Reformer Furnace H2001 is already effectively limited to a 12-month rolling average limit of 132.8 MMBtu/hr by an existing permit condition which limits the 12-month rolling average of RFG to 90,000 SCF/hr at a RFG HHV of 1,476 Btu/scf. The applicant is proposing to retain the existing PSD limits for NO_x emissions and requests to list it as a heat input limit which equates to 132.8 MMBtu/hr instead of 90,000 SCF/hr.

For most pollutants, the emissions factors for Hydrogen Reformer Furnace H2001 are the same as those presented above for the combustion of RFG in Package Boiler F5205, because both combustion sources are equipped with a low NO_x burner and FGR. Whereas there is no NO_x CEMS on Package Boiler F5205, however, Hydrogen Reformer Furnace H2001 is equipped with a CEMS and subject to the consent decree. Therefore, emissions estimates for baseline TPY, baseline maximum lb/hr, and future maximum lb/hr (not expected to change) are based on actual CEMS data. Emissions for future/potential TPY are based on the on 365-day rolling limit of 50 ppm at 0% as specified by CSP No. 0212-01-C and the consent decree (equivalent to 0.051 lb/MMBtu). Feedstocks to the HGU will also increase, which generate an additional amount CO_2 byproduct (36,769 TPY, 67% of which will be biogenic).

Greenhouse Gas Emission Reduction Plan

With increased utilization of existing combustion equipment there will be an increase in total direct GHG emissions. However, no change is needed to the CO_2e Emission Cap because all three (3) combustion sources described in this modification application were in existence in 2021 when the DOH issued the CO_2e Emission Cap for the Par East and Par West Partnering Facilities (referenced below). GHG emission will increase modestly but, will remain below the cap. To reflect its relocation, the steam generator/boiler from the Par West Refinery (F5205) will need to be removed from the Par West Refinery Permit (CSP No. 0088-01-C) and listed on the Par East Refinery Permit (CSP No. 0212-01-C), as Package Boiler F5205.

Partnering Facility	Permit No.	CO_2e Emission Cap	
		metric tons per calendar year	short tons per calendar year
Par East Refinery	CSP No. 0212-01-C	616,288	679,341
Par West Refinery	CSP No. 0088-01-C	292,549	322,480

The partnering facilities are compliant with the combined CO_2e emissions cap and are expected to continue to be compliant with the emissions cap after the renewable fuel production facility commences operation. The Package Boiler F5205 will be relocated from Par West facility because operations there have been scaled back and steam is no longer needed to operate the tanks and equipment in the Effluent Treatment Plant. There are no updates to GHG control measures for direct emissions although, as previously described, some of the HGU emissions will be biogenic and will be exempt from the cap. Furthermore, it should be noted that the purpose of the project is to produce renewable fuels, thus emissions from supplies products reported under 40 CFR 98 Subpart MM (which represents well over 90% of emissions reported by the refinery under 40 CFR 98) will have a notable reduction in non-biogenic GHG emissions.

The emissions from the renewable fuel production facility are as follows:

RENEWABLE FUEL PRODUCTION FACILITY EMISSIONS[1]

Pollutant	Relocated F5205 Boiler (tpy)	New CO_2 Byproduct Stream (tpy)	New Fugitive Components (tpy)	Existing DHT Heater H3701 (tpy)	HGU LPG Feed (Biogenic Portion) (tpy)	HGU LPG Feed (Non-Biogenic Portion) (tpy)	Existing HGU Heater H2001 (tpy)	Total (tpy)
CO	26.60			5.96			22.97	55.53
H_2S	0.01			0.00			0.02	0.03
Pb	6.05E-04			3.07E-05			1.18E-04	0.0008
NO_X	19.25			2.58			13.97	35.79
SO_2	16.52			0.72			2.77	20.01
VOC	0.84		0.76	0.22			0.83	2.65
PM_{Total}	2.71			0.30			1.15	4.16
PM_{10}	2.71			0.30			1.15	4.16
$PM_{2.5}$	2.71			0.30			1.15	4.16
Fluorides	1.48E-02							0.01
Sulfuric Acid Mist	1.16E-01			3.29E-02			1.27E-01	0.28
Total Reduced Sulfur	4.20E-02			1.19E-02			4.60E-02	0.10
GHG (CO_2e)	37,048	1,325		7,950	24,513	12,256	30,665	113,757
HAPs	0.522		0.05	0.123			0.474	1.17

[1] Proposed PTE – Baseline Actual

The total potential emissions from the Par East Refinery with the addition of the renewable fuel production facility are as follows:

PAR EAST REFINERY TOTAL POTENTIAL EMISSIONS

Sources	SO_2 (tpy)	NO_2 (tpy)	CO (tpy)	VOC (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	Pb (tpy)	Total HAPs (tpy)	GHG (CO_2e) (tpy)
Heaters and Boilers	1,953	2,166	571	25.2	259	187	128	0.0471	17.5	925,069
SRU/TGU/H1391	56.8	5.29	1.10	0.0718	0.099	0.099	0.099	9.44E-06	1	318,268.7
Incinerators H1353 & TOU	12.96	12.4	3.29	0.375	0.305	0.305	0.305	2.21E-05	0.0886	5,980.38
Flare	611	9.3	66.1	26.4	1.41	1.41	1.41	9.25E-05	4.11	18,182.39
Fugitives				304.8					48	0.165
Drains				107					23	
Tanks				236					20.2	
Loading Racks				4.35	1.23				9.81E-04	
Other - CRU									6.50	14.13
Other - HGU										214,086
Air Compressor Engines	1.4	8.97	11.6	0.8	0.9	0.9	0.9	0	0.08	3,073
Total	2,635	2,202	653	705	263	190	131	0.0472	120.5	1,484,674

Ambient Air Quality Assessment (AAQA):

A modeling analysis was performed by the applicant using EPA's AERMOD model using the following parameters:

Analysis type and Pollutants evaluated:

- NAAQS/SAAQS analysis for NO_x (1-hr and Annual), SO_2 (1-hr, 3-hr, 24-hr, and Annual), CO (1-hr and 8-hr), PM_{10} (24-hr and Annual), $PM_{2.5}$ (24-hr and Annual), H_2S (1-hr).

Model:

- AERMOD version 23132
- Dispersion Option: rural
- Surface roughness determination: AERSURFACE version 20060
- Ambient Ratio Method Ver 2 (ARM2) used for NO_2 conversion

Meteorological Data:

- Surface station: Honolulu International Airport Station ID PHNL
- Upper air station: Lihue Airport Station 22536; incomplete 2022 data; incomplete in NOAA/ESRL Radiosonde Database. Missing data after Oct 11, 2022
- Most recent five years of available data: 2017-2021
- Processed using AERMET version 22112

Terrain:

- Elevated
- 1/3 arc-second US DEMs (Digital Elevation Models) published by USGS on The National Map (TNM)
- Processed using AERMAP version 18081

Building Downwash

- Considered downwash in this analysis
- Processed using BPIP-PRIME version 04274

Receptor Grid:

- 25-meter spacing extending from the property line out to 300 meters;
- 100-meter spacing within 300 meters to 1 km of property line;
- 500-meter spacing within 1 km to 5 km of property line; and
- 1,000-meter spacing within 5 km to 10 km of property line.

Modeled Sources:

- Project sources will be modeled as vertical point sources with the following stack parameters shown in the table below:

Source Input Parameters

Source Description	UTM East (m)	UTM North (m)	Base Elevation (m)	Stack Temperature (K)	Stack Diameter (m)	Stack Height (m)	Stack Exit Velocity (m/s)
H2001	594,245	2,356,269	5.00	480.37	1.96	19.15	7.80
H3701	594,325	2,356,179	5.00	569.32	1.07	27.93	4.02
F5205	594,356	2,356,187	5.00	418.87	0.90	25.20	11.91

The listed sources were modeled with maximum hourly emission rates (converted to g/s) for short-term averaging periods and average annual emission rates (converted to g/s) for annual periods. For each of these sources, the emission rates were based on the potential to emit rather than the project increase to provide a more conservative modeling analysis. The table below shows the emission rates used in the modeling analysis.

Modeled Emission Rates (g/s)

Source Description	CO 1-hr, 8-hr	H_2S 1-hr	NO_x 1-hr	NO_x Annual	SO_2 1-hr, 3-hr, 24-hr	SO_2 Annual	$PM_{10}/PM_{2.5}$ 24-hr	$PM_{10}/PM_{2.5}$ Annual
H2001	1.59	3.01E-03	4.55	8.62E-01	4.79E-01	1.92E-01	7.98E-02	7.98E-02
H3701	3.60E-01	6.81E-04	1.56E-01	1.56E-01	1.08E-01	4.34E-02	1.80E-02	1.80E-02
F5205	1.26	2.24E-03	1.78	5.54E-01	3.16	4.75E-01	3.74E-01	7.79E-02

The results were combined with DOH monitoring data as background data to produce final estimates for comparison with the ambient air quality standards. There were no exceedances of the State or National Ambient Air Quality Standards as shown in the table below.

Modeled Impacts Summary

Pollutant	Averaging Periods	Predicted Concentrations Design Values	Modeled Concentration ($\mu g/m^3$)	Background Calculations Basis	Background Concentration [1] ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	AAQS [2] ($\mu g/m^3$)	Percent of AAQS (%)
CO	1-HR	H2H	69.99	H2H	1374.72	1444.72	10,000	14.4
	8-HR	H2H	31.37	H2H	458.24	489.61	5,000	9.8
NO_2	1-HR	maximum 98th percentile/H8H	55.70	3-year average of the 98th percentile	47.36	103.05	188	54.8
	ANNUAL	Maximum	4.13	3-year average of Annual Mean	6.27	10.41	75	12.2
H_2S	1-HR	H1H	0.13	H1H	7.73	7.86	35	22.5
SO_2	1-HR	maximum 99th percentile/ H4H	34.75	3-year average of the 99th percentile	9.35	44.09	196	22.5
	3-HR	H2H	40.98	H2H	7.86	48.84	1,300	3.8
	24-HR	H2H	24.46	H2H	5.24	29.70	365	8.1
	ANNUAL	Maximum	2.09	3-year average of Annual Mean	1.66	3.75	80	4.7
PM_{10}	24-HR	H2H	2.96	H2H	46.00	48.96	150	32.6
	ANNUAL	Highest five-year average	0.41	3-year average of Annual Mean	12.67	13.07	50	26.1
$PM_{2.5}$	24-HR	maximum 98th percentile/H8H	2.11	3-year average of the 98th percentile	7.60	9.71	35	27.7
	ANNUAL	Highest five-year average	0.41	3-year average of Annual Mean	3.70	4.11	9	45.7

[1] Background data from DOH Kapolei Air Monitoring Station for NO_x, SO_2, CO, PM_{10} and $PM_{2.5}$ from 2020-2022 and the DOH Leilani Air Monitoring Station for H_2S from 2021-2022.
[2] The AAQS shown represents the NAAQS or the most restrictive standard between the SAAQS and NAAQS.

Significant Permit Conditions/Changes:

1. Added Special Condition No. A.1.f to Attachment II(I) as follows:

   f. Package Boiler (steam generator) (ID No. F5205)

      i. 99 MMBtu/hr heat input.
      ii. Equipped with a low NO_x burner and flue gas recirculation.
      iii. Foster Wheeler, Model No. AG-5060, Serial No. 7414, National Board No. 585.

   Reason: The applicant is proposing this boiler as part of the Renewable Fuel Production Facility.

2. Added Special Condition No. B.3 to Attachment II(I) as follows:

   3. The Package Boiler F5205 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;
         ii. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007; 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.

   Reason: This boiler is subject to following federal requirements: NSPS Subpart Ja and Dc, and MACT Subpart DDDDD.

3. Added Special Condition No. C.1.d to Attachment II(I) as follows:

   d. The Package Boiler F5205 shall be fired only on distillate oil with a sulfur content not to exceed 0.25% by weight, RFG with a H_2S content not to exceed 162 ppmv determined hourly on a three-hour (3-hour) rolling average basis and not to exceed 60 ppmv determined daily on a 365 successive calendar day rolling average basis, or a combination of distillate oil and RFG. The 0.25 wt% distillate oil sulfur limit is based on a thirty-day (30-day) rolling average basis. The distillate oil fuel sulfur limit shall apply at all times, including periods of startup, shutdown, and malfunction.

   Reason: The applicant is proposing to operate the boiler on distillate oil, RFG, or a combination of distillate oil and RFG.

4. Added Special Condition No. C.2.d to Attachment II(I) as follows:

   d. The Package Boiler F5205 shall be equipped with a flue gas recirculation system and a low NO_x burner for the control of NO_x emissions. The flue gas recirculation system shall be in service whenever the package boiler is making steam and firing more than 15 MMBtu/hr or an alternative criteria as specified by the existing design criteria or by a qualified third-party subject matter expert.

   Reason: The applicant is proposing a flue gas recirculation system and a low NO_x burner for NO_x control for the boiler.

5 Added Special Condition No. C.3.b.v to Attachment II(I) as follows:

   v. From the Package Boiler F5205, while firing on distillate oil, the NO_x emissions shall not exceed 130 ppm at 0% excess O_2 (three-hour (3-hour) average) when the flue gas recirculation is in operation. While firing on RFG, the NO_x emissions shall not exceed 50 ppm at 0% excess O_2 (three-hour (3-hour) average) when the flue gas recirculation is in operation.

   Reason: The applicant is proposing NO_x limits for the boiler to avoid triggering PSD.

6. Added Special Condition No. C.3.d to Attachment II(I) as follows:

   d. Emission Limits for PM

   From the Package Boiler F5205, PM emissions shall not exceed 0.03 lb/MMBtu while firing on distillate oil or RFG. The PM limit shall apply at all times, except during periods of startup, shutdown, and malfunction.

   Reason: The applicant is proposing a PM limit for the boiler to avoid triggering PSD.

7. Revised Special Condition No. C.3.e to Attachment II(I) as follows:

   e. MACT Subpart DDDDD Maximum Emission Limits

   The permittee shall not discharge or cause the discharge into the atmosphere from the Package Boilers SG1102 and F5205, 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_2
Filterable PM	0.22 lb/MMBtu
HCl	1.1E-03 lb/MMBtu
Mercury	7.3E-07 lb/MMBtu

   Reason: Updated the MACT Subpart DDDDD emission limits (Filterable PM and Mercury) for Package Boilers SG1102 and F5205.

8. Revised Special Condition No. C.4.a and added Special Condition No. C.4.b to Attachment II(I) as follows:

   4. Operating Limitations

      a. The Package Boiler SG1103 when fired on RFG shall not exceed 71,586 MMBtu/month based on a rolling twelve-month (12-month) average.
      b. The Package Boiler F5205 when fired on distillate oil shall not exceed 788,000 gallons per any rolling twelve-months (12-months). The Package Boiler F5205 when fired on RFG shall not exceed 36,792 MMBtu/month based on a rolling twelve-month (12-month) average. These limits do not change if the boiler is fired on a combination of distillate oil and RFG.

   Reason: The applicant is proposing fuel consumption limits to limit the PTE of the boilers. The use of a monthly heat input limit when firing RFG allows for variability in the operation of the units and RFG composition.

9. Revised Special Condition No. C.5 of Attachment II(I) as follows:

   5. Visible Emissions (VE) for the Cogeneration Gas Turbine TU2301, and Package Boilers SG1102, SG1103, and F5205

      For any six (6) minute averaging period, the Cogeneration Gas Turbine TU2301, and Package Boilers SG1102, SG1103, and F5205 shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during start-up, shutdown, or equipment malfunction, the Cogeneration Gas Turbine TU2301, and Package Boilers SG1102, SG1103, and F5205 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.

   Reason: Revised the visible emissions requirements for stationary sources in Attachment II(I) of CSP No. 0212-01-C subject to HAR §11-60.1-32(b) per the amendment to HAR Chapter 11-60.1 issued on 2/8/2024. Note that since the opacity limits in HAR §11-60.1-32(b) are more stringent than the opacity limits in NSPS Subpart Dc, the permit will only contain the opacity limits in HAR §11-60.1-32(b).

10. Revised Special Condition No. C.7 by adding Package Boiler F5205.

    7. Package Boilers SG1102, SG1103, and F5205 Tune-Ups

    Reason: Tune-Ups are a MACT Subpart DDDDD requirement.

11. Revised Special Condition No. C.8 by adding Package Boiler F5205

    8. Package Boilers SG1102, SG1103, and F5205 Energy Assessment

    Reason: Energy Assessments are a MACT Subpart DDDDD requirement.

12. Added Special Condition No. D.6 to Attachment II(I) as follows:

    6. Fuel Consumption for Package Boiler F5205

       The permittee shall operate and maintain non-resetting fuel meters for the continuous measurement and recording of the amount of distillate oil and RFG fired in the boiler. The non-resetting meter shall not allow the manual resetting or other manual adjustment 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.

    Reason: This is to monitor the fuel consumption of distillate oil and RFG in the boiler.

13. Added Special Condition No. D.7 to Attachment II(I) as follows:

    7. Distillate Oil Sampling for Sulfur Content for Package Boiler F5205

       Distillate oil samples may be collected from the fuel tank for the boiler immediately after the fuel tank is filled and before any distillate oil is combusted. The permittee shall analyze the distillate oil sample to determine the sulfur content of the distillate 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 supply of distillate oil is received shall be used as the daily value when calculating the thirty (30) day rolling average until the next supply is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.25 weight percent sulfur, the permittee shall ensure that the sulfur content of subsequent distillate oil supplies is low enough to cause the thirty (30) day rolling average sulfur content to be 0.25 weight percent sulfur or less.

       The sulfur content of the distillate oil for Package Boiler F5205 shall be tested in accordance with the most current ASTM Methods D129, D2622, D4294, D5453, or D7039 or other test methodologies with prior written approval from the Department and the U.S. EPA.

    Reason: This is a NSPS Subpart Dc requirement for oil sampling for sulfur content for the boiler.

14. Added Special Condition No. D.8 to Attachment II(I) as follows:

    8. Liquid Fuel Chlorine and Mercury Monitoring for Package Boilers SG1102 and F5205

       The permittee shall demonstrate compliance with the mercury or HCl emission limits in Special Condition No. C.3.e of this attachment for Package Boilers SG1102 and F5205 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 your boiler. 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 monthly 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-day (14-day) restriction does not apply.

a. The chlorine content of the liquid fuel for the boiler 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 boiler 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).

Reason: This is a MACT Subpart DDDDD requirement to demonstrate compliance with the mercury or HCl emission limits based on fuel analysis for Package Boilers SG1102 and F5205.

15. Revised Special Condition No. F.1.c as follows:

c. Within **one hundred eighty (180) days** after initial start-up of Package Boiler F5205, and **annually** thereafter, the permittee shall conduct performance tests to determine emissions of CO and filterable PM from Package Boiler F5205 when burning distillate oil. On an annual basis, the permittee shall conduct performance tests to determine emissions of CO and filterable PM from Package Boiler SG1102 when burning liquid fuel. Performance tests shall be conducted at the maximum expected operating capacity of the respective boiler (Package Boiler SG1102 or F5205), 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:

Reason: This is a MACT Subpart DDDDD requirement to demonstrate compliance with the CO and filterable PM emission limits based on conducting performance tests for Package Boilers SG1102 and F5205.

16. Added Special Condition No. F.1.d to Attachment II(I) as follows:

d. Within **sixty (60) days** after achieving the maximum production rate of Package Boiler F5205, but not later than **one hundred eighty (180) days** after initial start-up of Package Boiler F5205, and **annually** thereafter (for NO_x and PM only), the permittee shall conduct, or cause to be conducted, performance tests on Package Boiler F5205 to determine the emission rates of NO_x, PM, and the opacity of stack emissions from

Package Boiler F5205 when burning distillate oil or RFG. Performance tests shall be conducted at the maximum expected operating capacity of the boiler, or at other operating loads as may be specified by the Department.

Reason: A performance test is required to demonstrate compliance with the emission rates of NO_x and PM for the boiler, and also the opacity of stack emissions.

17. Revised Special Condition No. F.2 of Attachment II(I) as follows:

    2. Performance tests for the emissions of NO_x shall be conducted using EPA Methods 1-4 and 7. Performance tests for the emissions of SO_2 shall be conducted using EPA Methods 1-4 and 8. Performance tests for the emissions of CO shall be conducted using EPA Methods 1-4 and 10. Performance tests for the emissions of filterable PM/PM shall be conducted using EPA Methods 1-4 and Method 5 or 17. Compliance with the opacity standard of Special Condition No. C.5 of this attachment shall be determined using EPA Method 9. In lieu of the above mentioned test methods, EPA-approved equivalent methods with prior written approval from the Department may be used.

Reason: These are the test methods for the various performance tests.

18. Revised Special Condition No. C.2 of Attachment II(G) as follows:

    2. Maximum Fuel Consumption

    The heating value of the RFG used to fire the Hydrogen Reformer Furnace H2001 shall not exceed 96,973 MMBtu/month based on a rolling twelve-month (12-month) average which is equivalent to a firing rate of 132.84 MMBtu/hr.

Reason: The applicant is proposing a fuel consumption limit to limit the PTE of the heater. The use of a monthly heat input limit when firing RFG allows for variability in the operation of the unit and RFG composition.

19. Revised Special Condition No. A.1 of Attachment II(O) as follows:

    1. This portion of the CSP encompasses the following equipment and associated appurtenances of the Renewable Fuel Production Facility:

        a. Renewable Feedstock Pretreatment Unit (PTU)

        b. Renewable Hydrotreater (RHT)

            i. RHT Feed Heater, ID No. H3701
            ii. 30 MMBtu/hr heat input.

Reason: The applicant is proposing the PTU and RHT as part of the Renewable Fuel Production Facility.

20. Revised Special Condition No. C.1 of Attachment II(O) as follows:

    1. The RHT Feed Heater H3701 shall be fired only on RFG with a H_2S content not to exceed 162 ppmv determined hourly on a three-hour (3-hour) rolling average basis and not to exceed 60 ppmv determined daily on a 365 successive calendar day rolling average basis. The heating value of the RFG used to fire the RHT Feed Heater H3701 shall not exceed 21,945 MMBtu/month based on a rolling twelve-month (12-month) average which is equivalent to a firing rate of 30 MMBtu/hr.

    Reason: The applicant is proposing a fuel consumption limit to limit the PTE of the heater. The use of a monthly heat input limit when firing RFG allows for variability in the operation of the unit and RFG composition.

21. Revised Special Condition No. C.3.a of Attachment II(O) as follows:

    3. Maximum Emission Limits

       The RHT Feed Heater H3701 shall not discharge or cause the discharge into the atmosphere emissions of the following:

       a. For nitrogen oxides (NO_x as NO_2), 1.24 lbs/hr (three-hour (3-hour) average).

    Reason: The applicant is proposing to increase the NO_x emission rate from 1.05 lbs/hr to 1.24 lbs/hr because of the increase in the design capacity from 26 MMBtu/hr to 30 MMBtu/hr.

22. Revised Special Condition No. A.1.e of Attachment II(M) as follows:

    e. Seven (7) Renewable Feedstock/Renewable Biofuel/Heavy Oil Storage Tanks

       i. One (1) - 2,141,194 gallon (nominal) internal floating roof storage tank identified as Tank 601;
       ii. One (1) - 2,141,194 gallon (nominal) vertical fixed roof storage tanks identified as Tank 602;
       iii. One (1) - 4,605,476 gallon (nominal) vertical fixed roof storage tank identified as Tank 603;
       iv. Two (2) - 1,804,595 gallon (nominal) external floating roof storage tanks identified as Tanks 401 and 402; and
       v. Two (2) - 1,804,595 gallon (nominal) external floating roof storage tanks identified as Tanks 403 and 404.

    Reason: The applicant is proposing to use these seven (7) existing tanks as Renewable Feedstock/Renewable Biofuel Storage Tanks or as Heavy Oil Storage Tanks for future flexibility.

23. Added Special Condition No. A.1.f to Attachment II(M) as follows:

    f. One (1) Renewable Biofuel/Naphtha/Gasoline Storage Tank

       One (1) - 1,015,085 gallon (nominal) external floating roof storage tank identified as Tank 201.

    Reason: The applicant is proposing to use this existing tank as a Renewable Biofuel Storage Tank or as a Naphtha/Gasoline Storage Tank for future flexibility.

24. Revised Special Condition No. A.1 of Attachment II(INSIG) as follows:

    1. Two (2) Renewable Feedstock Storage Tanks

       Two (2) - 2,478,000 gallon (nominal) vertical fixed roof storage tanks identified as Tanks 701 and 702.

    Reason: These two (2) new tanks will be used as Renewable Feedstock Tanks, but qualify as insignificant activities.

25. Updated the MACT Subpart DDDDD emission limits (Filterable PM and Mercury) per the amendment dated 10/6/2022 for the heaters in Attachment II(A): H101A, H101B, and H102A, and the heaters in Attachment II(B): H501, H502, H503, and H504.

Pollutant	MACT Subpart DDDDD Maximum Emission Limits
CO	130 ppmvd @ 3% O_2
Filterable PM	0.22 lb/MMBtu
HCl	1.1E-03 lb/MMBtu
Mercury	7.3E-07 lb/MMBtu

26. Removed the Title V Emergency Affirmative Defense Provisions from CSP No. 0212-01-C per the U.S. EPA (7/12/2023).

27. Revised the visible emissions requirements for stationary sources in CSP No. 0212-01-C subject to HAR §11-60.1-32(b) per the amendment to HAR Chapter 11-60.1 issued on 2/8/2024.

Conclusion and Recommendations:

Recommend issuance of the significant modification of CSP No. 0212-01-C, subject to the significant permit conditions/changes shown above. This permit would supersede CSP No. 0212-01-C issued on May 13, 2021, and amended on June 30, 2021, in its entirety. A thirty-day (30-day) public comment period and forty-five (45-day) EPA review period are also required.

Reviewer: Darin Lum
Date: 5/2024

Application
and
Supporting Information

Par Hawaii

DEC 1 4 2023

POSTMARK DEC 1 1 2023

Certified Mail: 9489 0090 0027 6516 6924 45

December 8, 2023

Ms. Marianne Rossio, Manager
Hawaii Department of Health
Clean Air Branch
2827 Waimano Home Road
Hale Ola Building, Room 130
Pearl City, Hawaii 96782

Dear Ms. Rossio:

Subject:

Par Hawaii Refining, LLC: Petroleum Refinery, CSP No. 0212-01-C
Significant Permit Modification
Renewable Fuel Production Facility

Dear Ms. Rossio:

Enclosed is a $1,000 check and an application to modify Par Hawaii Refining's (PHR's) Covered Source Permit, CSP No. 0212-010C, to construct a renewable fuel production facility by converting the Diesel Hydrotreater (DHT) to a Renewable Hydrotreater (RHT) and adding a renewable feedstock pretreatment unit (PTU) and high-pressure (700 psia) steam generating boiler to the refinery.

As part of Par Pacific's renewable fuels strategy, PHR plans to develop and commission the state's largest renewable fuel production facility in Kapolei to supplement existing conventional fuel production by 2025. This strategy aligns with the national Renewable Fuel Standard (RFS) program that was created to "reduce greenhouse gas emissions and expand the nation's renewable fuels sector while reducing reliance on imported oil.[1]" The RFS program "requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel.[2]" The Renewable Fuel Production Facility will enable PHR to meet its federally- mandated renewable volume obligation (which is more than 12% in 2024) and to meet the growing demand for low-carbon and renewable fuel in the State.

The renewable fuel production facility consists of two parts, the renewable feedstock pretreatment unit (PTU) and the renewable hydrotreater (RHT) unit. The PTU will have a capacity of 5,000 barrels per day (BPD) to treat the renewable feedstock prior to processing in the RHT. A new high-pressure (700 psia) steam generating boiler will support operation of the PTU and be added to the refinery's steam/utility system. The RHT will have a capacity of 4,000 BPD and process treated renewable feedstocks into renewable biofuels including renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (renewable LPG). The RHT unit will be able to flex between maximum SAF and RD mode depending on the market environment for each of those products.

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[1] https://www.epa.gov/renewable-fuel-standard-program

[2] https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard

MD 20232

Aside from a potential increase in demand and emissions from the existing DHT Feed Heater, H-3701, and the Hydrogen Reformer Furnace, H-2001, the project will include a new 99 MMBTU/hr steam generating boiler, SG1104, relocated from Par West, which will be fired on refinery fuel gas (RFG) and distillate oil. The boiler will be equipped with ultra-low NOx burners (ULNB's) and a flue gas recovery system. Built in 2007, the boiler is subject to New Source Performance Standard (NSPS) Subpart J which regulates SO2 emissions. However, because the refinery operates on a singular fuel gas system which, has been subject to NSPS Subpart Ja since 2019, the hydrogen sulfide (H2S) content of the RFG fuel will be limited to no more than 60 ppm on an annual basis as required by NSPS Subpart Ja standards. Similarly, the potential-to-emit (PTE) SO2 emissions will also be limited based on the NSPS Subpart Ja standards. More specifically, the SO2 concentration of the flue gas will be limited to no more than 20 ppm (corrected to 0% excess air) on a 3-hour basis and average no more than 8 ppm on an annual basis (corrected to 0% excess air).

Potential air emissions for the renewable fuel production facility will remain below the regulatory thresholds specified under the federal Prevention of Significant Deterioration (PSD) program. However, since Criteria Air Pollutant (CAP) and Hazardous Air Pollutant (HAP) emissions will increase and exceed the state's minor permit modification thresholds, a significant permit modification is required for the refinery's air permit. A more comprehensive description of the emissions changes is part of this application package.

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.

If there are any specific questions concerning our request or the emission calculations, please call Anna Chung at (808) 726-3271.

Sincerely,

Deaglan McClean
Vice President, Par Hawaii Refining

Attachments

cc: Darin Lum Darin.Lum@doh.hawaii.gov

Chief
Permits Office, (Attention: Air-3)
Air Division, USEPA Region 9
75 Hawthorne Street
San Francisco, CA 94105

Par Hawaii Refining

Permit Application Packet

Renewable Fuel Production Facility

December 2023

Contents

Background

Par Hawaii Refining (PHR) owns and operates a petroleum refinery in Campbell Industrial Park, located in the city of Kapolei, Hawaii. The refinery produces jet, diesel and gasoline for the island of Oahu and neighboring islands. Combustion equipment at the refinery includes heaters, boilers, furnaces, a cogeneration unit, incinerator, thermal oxidizer, and flare.

As part of Par Pacific's renewable fuels strategy, PHR plans to develop and commission the state's largest renewable fuel production facility in Kapolei to supplement existing conventional petroleum fuel production by 2025. This strategy aligns with the national Renewable Fuel Standard (RFS) program that was created to "reduce greenhouse gas emissions and expand the nation's renewable fuels sector while reducing reliance on imported oil.[1]" The RFS program "requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel.[2]" The Renewable Fuel Production Facility will enable PHR to meet its federally-mandated renewable volume obligation (which is more than 12% in 2024) and to meet the growing demand for low-carbon and renewable fuel in the State.

The renewable fuel production facility will process treated renewable feedstocks into renewable biofuels including renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (renewable LPG). The refinery plans to redesign and repurpose the existing Diesel Hydrotreater (DHT) and convert it into a Renewable Hydrotreater (RHT). The RHT will have a capacity of 4,000 barrels per day (BPD) and be able to flex between maximum SAF and RD mode depending on the market environment for each of those products. This project also includes the construction of a renewable pretreatment unit (PTU) with a capacity of 5,000 BPD to treat the renewable feedstock prior to processing in the RHT and a new high-pressure (700 psia) steam generating boiler.

[1] https://www.epa.gov/renewable-fuel-standard-program
[2] https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard

Project Description

The proposed renewable fuel production facility consists of two parts, the renewable feedstock pretreatment unit (PTU) and the renewable hydrotreater (RHT) unit. A new high-pressure (700 psia) package boiler is needed to support operation of the PTU and will be added to the refinery's steam/utility system. Pretreatment of the renewable feedstock removes gummy and phosphorous contaminants before being processed in the RHT. As implied by its name, the RHT utilizes hydrogen to remove oxygen from bioseed oils and other renewable feedstocks. The refinery's existing and fully permitted hydrogen generating unit (HGU) will not be modified but will be more fully utilized to provide hydrogen for the RHT.

The most likely feedstock for the renewable fuel production facility (PTU and RHT) is imported soybean oil. Other sources include locally produced biofuel crops (such as camelina), vegetable oils (canola oil and distiller's corn oil). Used cooking oil, tallow, and other animal fats will also be considered, and may become equally viable renewable feedstocks for the RHT. The primary biofuels that will be produced by the RHT are renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (renewable LPG). Eight (8) existing petroleum storage tanks will be converted, and two (2) new tanks will be constructed to store renewable feedstocks and renewable fuels produced by PHR.

Pretreatment Unit (PTU)

The renewable PTU is designed to process 5,000 BPD of untreated renewable feedstock. The PTU utilizes high pressure (700 psia) steam and is comprised of feedstock tanks, a feed vacuum deaerator, a mixing tower, and various feed filters, heat recovery exchangers and oil/water separators. Untreated renewable feedstock will be imported to the refinery via barge or isotainer and stored in four (4) tanks; two (2) existing vertical fixed-roof tanks, TK-602, TK-603, and two (2) new vertical fixed-roof tanks, TK-701 and TK-702. Untreated renewable feedstock, such as soybean oil, is vacuum dried and preheated to about 200 °F by waste heat and fed to the bottom of a high-pressure column.

A high-pressure package boiler (F2505) will be relocated from Par West (the former Chevron Hawaii Refinery) and recommissioned as SG1104 at Par East. It will be used to supply 700 psia steam and is described separately below. The steam is injected into the high-pressure extraction column (T-4101), where it mixes with the bioseed oil (untreated renewable feedstock). The hot oil rises up the column and cold water, added at the top of the column, flows downward creating a counter-current flow of oil and water. The temperature, pressure, and time of contact between water and oil is controlled to allow water to remove (extract) gums and phosphorous contaminants from the untreated renewable feedstock. The renewable feedstock exits the top of the column and goes through a coalescer to remove entrained water and the treated renewable feedstock is sent to the RHT via intermediate tankage. Water exiting the extraction column bottom is passed through a coalescer to remove impurities entrained in the renewable feedstock, before being discharged to an underground injection well. An additional pretreatment step may be required before injection of the non-toxic aqueous effluent from the PTU. Because the untreated and treated renewable feedstocks have no measurable amount of volatile organic compounds (VOCs) and hazardous air pollutants (HAPS), no significant air emissions are expected from the PTU and related renewable feedstock tanks.

Renewable Hydrotreater Unit (RHT) (Re-purposed Distillate Hydrotreater (DHT))

The RHT will be designed to process 4,000 BPD of treated renewable feedstock into renewable biofuels. Primary biofuels produced will be renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (Renewable LPG). The existing DHT consists primarily of a catalytic hydrotreating reactor, a charge heater, and a fractionation tower. The conversion of the DHT to the RHT includes modifying the existing reactor into an isomerization reactor, constructing a new larger catalytic hydrotreating reactor, and adding several new exchangers, pumps, towers, compressors, and a mixer. Existing vertical fixed-roof tank, TK-601, will be converted into treated feedstock storage and retrofitted with an internal floating-roof to protect its contents from exposure to air. Five (5) existing vertical floating tanks, TK-401, TK-402, TK-403, TK-404, and TK-201, will also be converted to renewable biofuel storage tanks.

The amount of hydrogen needed to support the RHT will be nominally 3000 standard cubic feet (scf) per barrel of renewable feed, or about 10-13 MMSCF/day. Relative to the refinery's current baseline operation, the additional hydrogen required for the RHT will be produced by the Hydrogen Generating Unit (HGU). Hydrogen for the RHT may also be provided by the Catalytic Reforming Unit (CRU) when the HGU is not operating. The HGU will not be modified or expanded to support the operation of the RHT, however the existing design capacity of the HGU will be more fully utilized. Hydrogen from the HGU will be supplied to the RHT from a new compressor (C-3702) and hydrogen from the RHT will be recovered and routed back to the Distillate Hydrocracker (DHC) via existing compressors. Renewable LPG generated from the RHT would be used as the feedstock to the HGU. Alternatively, to further State's goal that public utilities reduce GHG emissions, the renewable LPG may be sold as feedstock to the neighboring Synthetic Natural Gas (SNG) plant owned by Hawaii Gas.

The RHT will generate significantly less sulfur than the current DHT operation because, by comparison, there is relatively little sulfur in the renewable feedstock. Any sulfur removed by the RHT in form of sour off-gas will be routed to the existing Amine Treating Unit (ATU) and Sulfur Recovery Plant (SRP) along with sour off-gas from other refinery process units. The capacity of the ATU and SRP are adequate to handle the sulfur generated by and ultimately removed from the RHT.

High-Pressure (700 psia) Steam Generator (SG1104)

A new steam generator (SG1104) manufactured by Foster Wheeler will be relocated and installed principally to supply 700 psia steam to the high-pressure extraction column (T-4101) in the PTU. The Foster Wheeler package boiler (Model AG-5060, Serial No. 7414, National Board No 585) was built in 2007 and designed with 765 psi MAWP. It will be operated to produce about 75,000 lb/hr of 700 psi steam while operating at the design/permitted firing rate of 99 MMBtu/hr (HHV).

The relocated package boiler will normally be fired either on refinery fuel gas (RFG) or low sulfur distillate oil. The boiler has the capacity to be fired on both fuels simultaneously, but based on its historic use by Chevron, dual fuel mode of operation is expected to be uncommon. The boiler's annual fuel use and heat input has been limited in this permitting action to 551,880 MMBTU/year, which is the equivalent of an annual average firing rate of 63 MMBtu/hr. Although the boiler is projected to normally operate at about 35% of its Maximum Continuous Rating (MCR) to support operation of the PTU, at times, the full fired duty (i.e. 99 MMBTU/hr) and steam generating capacity of SG1104 will be utilized. The relatively new boiler has a Low NOx Burner (LNB) and was designed with a fully integrated and automated flue gas recirculation (FGR) system to control NOx emissions.

The relocated package boiler is the primary source of new air emissions associated with and required for the renewable fuels production facility. The package boiler, which in addition to having a FGR, is equipped with an economizer and super heater, was built in 2007 and is subject to New Source Performance Standard (NSPS) Subpart J which regulates SO2 emissions. However, because the refinery operates on a singular fuel gas system, which has been subject to NSPS Subpart Ja since 2019, the hydrogen sulfide content of the RFG used to fire SG1104 will be limited to no more than 230 mg/dscm (0.10 gr/dscf). This is equivalent to 162 ppm Subpart J limit and the more stringent Subpart Ja standard which limits the H2S content to no more than 60 ppm on an annual average basis. Because of the common fuel gas system, and as reflected by Title V permit condition, the SO2 concentration of the flue gas from SG1104 will be limited to no more than 20 ppm and average no more than 8 ppm on an annual basis while firing exclusively on RFG. Both the short term and long term SO2 concentration limits are expressed on dry basis (corrected to 0% excess air) and typically assured by monitoring the H2S content of the RFG because the boiler may be cofired.

Liquid fuel firing of the new high-pressure (700 psia) boiler is essential because the refinery's other two steam generators (SG1102 and SG1103) are low pressure (235 - 250 psia) and because there are intermittent shortages of RFG based on the type and composition of crude oil being refined. Additionally, SG1103 only burns RFG. To control SO2 emissions while firing SG1104 on distillate oil, the boiler would be restricted to burn only distillate oil with sulfur content limited to no more than 0.25% by weight. The limit on the sulfur content of the distillate fuel is not mandated by State or federal regulations but, is being proposed as an enforceable permit condition to cap or limit SO2 emissions. The sulfur content of the distillate oil will be sampled and analyzed by the refinery's lab at least once a week.

While NOx emissions from the 99 MMBTU/hr boiler are well controlled because it is equipped with FGR and a low NOx burner, principally to stay under the 40 TPY PSD threshold for the entire renewable fuels project, the use of distillate oil will be limited to 110,376 MMBtu/yr (equivalent to 788 thousand gallons per year) which is approximately 20% of the total heating value of the fuel (in terms of BTU's) that may be used to fire the boiler throughout the year, with the balance of heat input coming from RFG.

The limitation on the type of liquid fuel, distillate oil as defined by 40 CFR 60.41(c) (with a sulfur content of less 0.25%), and the amount of distillate oil (or more precisely the amount of heat from distillate oil) will have the combined effect of also limiting emissions of most criteria and non-criteria pollutants. Because the package boiler was built in 2007, it is also subject to NSPS Subpart Dc which also limits particulate matter (PM) emissions, but because the fuel use is being limited to RFG and clean burning low (<0.25%) sulfur distillate fuel, the PM emissions limit and many of the related requirements do not strictly apply. As explicitly provided by 40 CFR 60.43c(e)(4) because SG1104 will be fired on RFG or low sulfur distillate oil (< 0.5 wt%), it is not bound to the PM limits and testing requirements in NSPS Dc. Although this is true, PHR is proposing to voluntarily accept the 0.03 lb/MMBTU particulate emission limit set forth by 60.43c(e)(4) as an enforceable permit limit, to ensure that the 10 TPY PSD threshold for particulate matter is not exceeded. Without a stringent PM limit in place, the maximum potential-to-emit (PTE) particulate under the PSD analysis would have been projected and only limited by the 0.22 lb/MMBTU limit of NESHAPS Subpart DDDDD, for non-continental combustion sources, most of which burn a heavier mix of residual and distillate fuel.

Likewise, because the liquid fuel used to fire SG1104 will be limited to low sulfur distillate oil, which produces relatively little hazardous air pollutants (HAPS), the relocated package boiler will readily meet the CO and filterable PM emissions limits and national emission standards specified in NESHAPS Subpart DDDDD for non-continental steam generators (and process heaters) which burn liquid fuel. While the selection and restriction on fuel type severely limits the potential for metallic HAPS, the voluntary addition of a 0.03 lb/MMBTU PM limit, which is much more stringent than the 0.22 filterable PM limit specified for non-continental combustion, ensures that HAPS will be well controlled and that the PSD threshold for PM will not be encroached upon. With the 0.03 lb/MMBTU PM limit on SG1104 (which, as stated before, can fire low sulfur distillate oil), the potential to emit for PM emissions is less than 3 TPY. Additional details on the PSD determination are discussed and quantified in subsequent sections.

The location of the new renewable PTU and RHT is shown in Appendix A. Process Flow Diagrams for the renewable fuel production facility and the design specifications for the new steam generator are included in Appendix B.

Emission Estimates for Relocated and New Emission Sources

Distillate Oil and Fuel Gas Combustion in Relocated SG1104

Emissions from the relocated steam generator (SG1104) will occur at the stack described below.

Emission Point ID	24
UTM East (m)	594356
UTM North (m)	2356187
Elevation (m)	4.88
Height of Stack (m)	25.0
Temp (K)	300
Exit Velocity (m/s)	7.14
Diameter (m)	0.90

Peak, short-term hourly emissions rates (lb/hr) for the boiler are determined for each pollutant based on the fuel (either RFG or distillate oil) with the highest emission rate for that pollutant (at the max design operation rate of 99 MMBtu/Hr). The maximum total annual emission rate (TPY) for the boiler, for each pollutant was determined by multiplying the emission factor for each fuel (subject to the annual fuel use limit for that fuel) and then summing the two.

Distillate Oil Combustion

Hourly emissions for SG1104 while firing distillate oil are calculated by multiplying emission factors by the maximum design heat input capacity of 99 MMBtu/hr. Annual emission rates are calculated by multiplying the same emission factors by the fuel cap limit of 9,198 MMBtu/month based on a rolling 12-month average which is approximately equal to 12.6 MMBtu/hr of distillate fuel.

The physical properties of the distillate fuel used in emissions calculations are as follows:

HHV	= 140,000 Btu/gal, as provided in AP-42 Section 1.3 - Fuel Oil Combustion
Sulfur Content	= 0.25 wt% limit, proposed limit
Fd	= Dry Fuel Factor (SCF/ MMBtu) = 9190 SCF/ MMBtu, based on Part 60 Meth.19 & Part 75 Table 1

The emission factors for low-sulfur distillate oil are as follows:

CO	= 0.101 lb/MMBtu based on the MACT limit of 130 ppm at 3% O2
NH_3	= 0.8 lb/1000 gal, based on EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emission. Factor, Table 5-2, 8/94 (3.2 lb/MMscf).
Pb	= 0.000009 lb/MMBtu, based on AP-42, Table 1.3-10
NO_x	= 0.143 lb/MMBTU based AP42 Table 1.3-1 (20 lb/1000 gal) and an equivalent NOx limit of 130 ppm at 0% excess O2 proposed by the applicant along with fuel use limits to prevent from exceeding a PSD threshold.
SO_2	= 35.5 lb/1000 gal, based on AP-42, Table 1.3-10 and a proposed sulfur limit of 0.25 wt% in distillate oil.
VOC	= 0.2 lb/1000 gal, based on AP42 Table 1.3-3
PM_{Tot}	= 0.03 lb/MMBtu, proposed limit based on the NSPS Subpart Dc (and parallels NESHAPs Subpart JJJJJJ Table 1)
PM_{10}	= 0.03 lb/MMBtu, proposed limit based on the NSPS Subpart Dc (and parallels JJJJJJ Table 1)
$PM_{2.5}$	= 0.03 lb/MMBtu, proposed limit based on the NSPS Subpart Dc (and parallels NESHAPs Subpart JJJJJJ Table 1)
HCl	= 0.0011 lb/MMBtu based on MACT DDDDD Table 2.
Mercury	= 0.00000073 lb/MMBtu based on MACT DDDDD Table 2.
Total Greenhouse Gases (GHGs) CO2e	0.0163 lb/MMBtu (based 40 CFR 98 calculation methodologies, using standard emission factors for CO2, CH4 and NO2.
Other Individual HAPs	lb/MMBtu or lb/1000gal rates from rates from AP-42 Section 1.3 - Fuel Oil Combustion. Tables 1.3-1,2,3,6,8,10,14. May 2010. Uses factors for Distillate oil when available.

Based on the fuel use limitations and emission factors above, the potential emissions from operation of SG1104 on distillate oil are shown on permit application Form S-1 and calculations in Appendix C, Table C-2.

Fuel Gas Combustion

Hourly emission rates for SG1104 while firing on fuel gas are calculated by multiplying emission factors by the max design operation rate of 99 MMBtu/Hr. Annual emission rates are calculated by multiplying the same emission factors by the fuel cap limit of 36,792 MMBtu/month based on a rolling 12-month average or approximately equal to 50.4 MMBtu/hr of fuel gas.

While firing on RFG, the boiler will be subject to the NSPS J standard which limits the H2S in the fuel gas to no more than 162 ppm on volume basis for any 3-hour period, and because of the common fuel gas system the H2S will be limited to less than 60 ppm over a 365-day average. These limits along with a 98% combustion efficiency factor are used to determine the H2S slip and resulting emissions in Appendix C. Likewise, the new and closely aligned NSPS Ja standard for SO2 in flue gas (20 ppm on volume basis for any 3-hour period, and 8 ppm over a 365-day average) will be explicit permit limits and are used as the basis for emission estimates.

The physical properties of the RFG used in emissions calculations are as follows:

HHV	= Higher Heating Value (Btu/SCF) = 1595 Btu/SCF
Fd	= Dry Fuel Factor (SCF/ MMBtu) = 8622 SCF/ MMBtu

Note: Even though the Title V permit includes several references to a more typical heating value for RFG (1476 BTU/SCF) and a dry fuel factor of 8740 SCF/BTU, to be consistent with the air emissions modeling the physical properties of the RFG presented above were based on the two most recent years (2021-2022) of refinery lab analysis. Notably only the dry fuel factor (a near constant) is used to convert common concentration-based limits to equivalent lb/MMBTU emission factors through application of the generalized equation below.

$$\text{lb/MMBTU} = \frac{(\text{Pollutant PPM at 0\% excess O2}) * (\text{Pollutant MW}) * (\text{Fd SCF/MMBTU})}{(1{,}000{,}000) * (385.3 \text{ SCF/Mole})}$$

Because there is little variability in Fd factors for each category of gaseous or liquid fuel, the calculated or published lb/MMBTU emission factors do not vary much based on the composition of the RFG or the low sulfur oil (over time). Even though HHV of natural gas, propane and butane range from 1050 to 3225 BTU/SCF, in Method 19 of Appendix A-7 to Part 60 the EPA assigned a singular Fd factor of 8710 SCF/BTU for all three because the ratio of carbon to hydrogen in all of these gases is nearly the same. So, too, is the amount of flue gas from their combustion.

The emission factors for RFG used for estimating emissions for this project are as follows:

CO	= 0.095 lb/MMBtu based on the MACT limit of 130 ppm at 3% excess O2 and an average Fd factor of 8622 dscf/MMBtu
H_2S (3-hr)	= 0.00018 lb/MMBtu, NSPS Ja limit of 162 ppmv in RFG with 98% destruction efficiency upon combustion and 2% slip-by

NH_3	= 0.0020 lb/MMBtu, based on EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emission Factor, Table 5-2, 8/94 (3.2 lb/MMscf).
Pb	= 0.00000049 lb/MMBtu, based on EPA's Emission Estimation Protocol for Petroleum Refineries, version 3, April 2015, Table 4-3.
NO_x	= 0.051 lb/MMBtu, based on a NOx concentration limit of 50 ppm at 0% excess O2 proposed by the applicant along with fuel use limits to prevent from exceeding PSD threshold.
SO_2 (3-hr) (365-day)	= 0.029 lb/MMBtu, NSPS Ja limit of 20 ppmv in flue gas = 0.011 lb/MMBtu, NSPS Ja limit of 8 ppmv in flue gas (ppm limits are for dry flue gas, at 0% excess air)
VOC	= 0.0035 lb/MMBtu, based on AP-42, Table 1.4-1 boilers fired on natural gas (5.5 lb/MMSCF)
PM_{Tot}	= 0.00476 lb/MMBtu, based on AP-42, Table 1.4-1 for natural gas (7.6 lb/MMscf), includes filterable and condensable. (All PM assumed PM 2.5)
Total Greenhouse Gases (GHGs) CO2e	0.013 lb/MMBtu, based on 40 CFR 98 calculation methodologies, using 2021-2022 sample data for CO2 and standard emission factors for CH4 and NO2.
Individual HAPs	lb/MMBtu rates from EPA's International's Emission Estimation Protocol for Petroleum Refineries- Table 4-3.

Based on the fuel use limitations and emission factors above, the potential emissions from operation of SG1104 on RFG are shown on permit application form S-1 and calculations in Appendix C, Table C-2.

New Untreated Renewable Feedstock Tanks, TK-701 and TK-702

Two (2) new vertical fixed cone-roof tanks 701 and 702 will be constructed to store untreated renewable feedstock for the pretreatment unit. The 2 new heated tanks (TK-701 and TK-702) will be built in the same location that had been previously planned for permitted ethanol tanks (Tk-518 and Tk-519), which were never constructed.

Although the most likely option for feedstock is soybean oil, other options include seed oil and animal fats. Emissions from these tanks are considered insignificant because soybean oil, other seed oils and animal fats are all low volatility and essentially void of VOCs and HAPs. The Clean Air Branch affirmed this determination by issuing an insignificant activity approval letter (dated August 9, 2023) authorizing construction and operation of Tanks 701 and 702.

There are no significant emissions or controls required for the tanks because vegetable/seed oil/animal fat has low volatility and have no or negligible hazardous air pollutants (HAPs) present.

Likewise, there are no applicable state or federal regulations for TK-701 and TK-702. Associated piping, pumps and filters to the tanks are also exempt from fugitive monitoring and requirements because they are free of VOCs and HAPs.

New RHT Fugitive Emissions

In addition to repurposing much of the existing DHT, a number of new vessels and towers, reactors and exchangers will be installed for the RHT. As with the DHT, miscellaneous sources of potential equipment leaks of VOC, including valves, pumps, pressure relief devices sampling connection systems, open-ended valves or lines, and flanges or other connectors in VOC service, will be subject to New Source Performance Standards (NSPS) Subpart GGGa. Unless not commercially available, all new valves in light hydrocarbon service will be Certified Low Leaking Technology (CLLT) valves or packed with Certified Low Leaking Packing to reduce VOC emissions. The leak threshold for fugitive emissions from pumps will be 2,000 ppm and the leak threshold from valves will be 100 ppm.

Detailed emissions calculations are provided in Appendix C. Calculations were based on the EPA Emission Estimation Protocol for Petroleum Refineries and an approximate count of components based on design plans. Potential emissions from the new fugitive sources are also shown on permit application form S-1.

The following correlation equations from Table 2-2 of the Emission Estimation Protocol for Petroleum Refineries (Version 3, April 2015) were used to determine VOC emissions from each component:

kg/hr/valve	= 0.00000229*(SV^0.746), where the screening value (SV) is 100 ppm based on the Certified Low Leak Technology (CLLT) limit.
kg/hr/pump	=0.0000503*(SV^0.61), where the SV is the monitoring leak threshold of 2,000 ppm
kg/hr/connector	=0.00000153*(SV^0.735), where the SV is the monitoring leak threshold of 500 ppm for connectors that will be monitored with valves
kg/hr/sample connection	=0.0000136*(SV^0.589), where the SV is the Standard leak threshold of 10,000 ppm for remaining sources (Except compressors)

The new compressors are excluded from the fugitive emissions calculations because they will be routed to the flare.

Annual VOC and speciated emissions were obtained by multiplying the hourly emission rate by 8760 hours per year. The total VOCs from the fugitive sources above were then speciated as individual HAP and non-HAP constituents following Table 2-7 concentration ratios for Hydrotreating/Hydrodesulfurization and the methodology in the Emission Estimation Protocol for Petroleum Refineries.

The potential emissions from fugitive emissions in the RHT are shown on permit application form S-1 and Appendix C, Table C-3. While not specified in the Emission Protocol, estimates for some additional pollutants are included in Table C-3 based on typical emission profiles from storage tanks at the refinery as well as Polycyclic Organic Matter expected to be proportional to naphthalene emissions.

New Biogenic CO2e Byproduct from RHT

In addition to producing a variety of renewable fuels, the RHT will also produce a relatively small (1,325 TPY) amount of biogenic CO2 byproduct which will pass to the refinery fuel gas system and released through various refinery fuel gas combustion sources. The additional emissions associated with the CO2 byproduct from the RHT are also captured in Form S-1 and Appendix C, Table C-1.

Additional Emissions from Increased or Alternative Utilization of Existing Sources

Effected Sources - Tanks

Ten (10) tanks will be used to support the renewable fuel production facility, two (2) new, TK-701 and TK-701, and eight (8) existing, TK-201, TK-401, TK-402, TK-403, TK-404, TK-601, TK-602, TK-603. The properties of the renewable feedstock and biofuel are compatible with the existing petroleum-based storage tanks they will be stored in. However, TK-601 will be retrofitted with an internal floating roof to protect the treated renewable feedstock from exposure to air and not for regulatory reasons. Existing tank utilization will not increase and there are no emissions increases expected. New tanks 701 and 702 have no significant emissions, as described earlier under "New Emission Sources". Table 1 below lists all the tanks that will support the Renewable Fuel Production Facility with their current and future contents.

Table 1. RHT Tank Storage

Tank No.	Liquid Stored	
	Before	After
TK-701	*new*	Untreated Renewable Feedstock
TK-702	*new*	Untreated Renewable Feedstock
TK-601	Fuel Oil	Treated Renewable Feedstock
TK-602	Fuel Oil	Untreated Renewable Feedstock
TK-603	HS Vaccum Resid	Untreated Renewable Feedstock
TK-401	Jet A	SAF/RD
TK-402	Jet A	SAF/RD
TK-403	Jet A	RD
TK-404	Jet A	RD
TK-201	Naphtha	RN

Effected Sources – Combustion Sources

H-3701 Potential Emission Increase from Actual to Design (PTE)

The RHT will directly utilize the existing feed heater H-3701 (for which PTE will now use the maximum safe design capacity).

The emissions factors for H-3701 are the same as those presented above for the combustion of RFG in SG1104, with the exception of NOx emissions, for which there is a different basis and limit.

NOx	= 0.040 lb/MMBtu based on design basis of 40 ppm at 0% excess O2 and an average Fd factor of 8622 dscf/MMBtu (as previously permitted). However, due to the increase to maximum safe design capacity (30 MMBtu/hr) the equivalent NOx emission limit requested is 1.24 lb/hr (vs 1.05 lb/hr currently specified on the permit). The limit was set as a mass rate because NOx concentrations are not as well controlled when firing the heater at low rates.

Based on the maximum safe design duty of 30 MMBTU/hr and the emission factors above, the potential emissions from operation of H-3701, are also shown on permit application form S-1 and in Appendix C, Table C-4.

Note: Although the PTE's have been calculated at the requested maximum design rate as required for the PSD assessment, the applicant is expecting H-3701 will be fired less as the RHT feed heater than it had historically been fired as the DHT feed heater.

H-2001 Projected Emission Increase from Actual to Max Permitted (PTE)

The new RHT will require more hydrogen to remove oxygen from the renewable feedstocks. Because the Catalytic Reforming Unit (CRU), which produces hydrogen as by-product of the reforming process, is already operated at near maximum rates, additional hydrogen for the RHT will be supplied by the Hydrogen Generation Unit (HGU).

In order to accommodate the product demand growth for hydrogen, the HGU will be more routinely operated at a rate of about 18 MMSCF/D and H-2001 will be fired at an estimated average rate of 132.8 MMBtu/hr. Because of the RHT, H-2001 will fire harder than normal which will lead to an increase in actual emissions from H-2001. Although H-2001 was designed and permitted for 172.8 MMBtu/Hr to accommodate peak (and future demand), the hydrogen reformer furnace is already effectively limited to a 12-month rolling average limit of 132.8 MMBTU/hr by an existing permit condition which limits the 12-month rolling average of RFG to 90,000 SCF/Hr. PHR is proposing to retain the existing PSD limits for NOx emissions and requests to list it as a heat input limit which equates to 132.8 MMBTU/hr instead of 90,000 SCF/hr.

For most pollutants, the emissions factors for H-2001 are the same as those presented above for the combustion of RFG in SG1104, because both combustion sources are equipped with low NOx burner and FGR. Whereas there is no NOx CEMS on SG1104 however, the hydrogen reformer furnace is equipped with a CEMS and subject to the consent decree. Therefore, emissions estimates for baseline TPY, baseline maximum lb/hr, and future maximum lb/hr (not expected to change) are based on actual CEMS data. Emissions for future/potential TPY are based on the on 365-day rolling limit of 50 ppm at 0% as specified by the Title V permit and the consent decree (equivalent to 0.051 lb/MMBtu).

Based on the full proposed heat input limits and the emission factors above, the potential and projected actual emissions increase from operation of H-2001, are also shown on permit application form S-1 and in Appendix C, Table C-5. Note that calculations of PTE minus baseline are conservatively higher than would be allowed by rule (40 CFR 52.21(b)41)(ii)(c)) which could further exclude the additional hydrogen product demand that the existing unit could have accommodate.

Feedstocks to the HGU will also increase, which generate an additional amount CO2 byproduct (36,769 TPY, 67% of which will be biogenic). Other refinery units will continue to operate and will not be affected. Potential emissions above baseline actuals for the affected units are shown on permit application form S-1 and in Appendix C, Table C-6.

Greenhouse Gas Emissions Reduction Plan

With increased utilization of existing combustion equipment there will be an increase in total direct GHG emissions. However, no change is needed to the CO_2e Emission Cap because all three (3) combustion sources described in this modification application were in existence in 2021 when the DOH issued the CO2e Emission Cap for the Par East and Par West Partnering Facilities (referenced below). GHG emission will increase modestly but, will remain below the cap. To reflect its relocation, the steam generator/boiler from Par West (F5205) will need to be removed from the Par West Permit (CSP 0088-01-C) and listed on the Par East Permit (CSP 0212-01-C), now as SG1104.

Partnering Facility	**Permit No.**	**CO_2e Emission Cap**	
		metric tons per calendar year	**short tons per calendar year**
Par East Refinery	CSP No. 0212-01-C	616,288	679,341
Par West Refinery	CSP No. 0088-01-C	292,549	322,480

The partnering facilities are compliant with the combined CO2e emissions cap and are expected to continue to be compliant with the emissions cap after the renewable fuel production facility commences operation. The steam generator/boiler may be relocated from Par West facility because operations there have been scaled back and steam is no longer needed to operate the tanks and equipment in the Effluent Treatment Plant. There are no updates to GHG control measures for direct emissions although, as previously described, some of the HGU emissions will be biogenic and will be exempt from the cap. Furthermore, it should be noted that the purpose of the project is to produce renewable fuels, thus emissions from supplies products reported under 40 CFR 98 Subpart MM (which represents well over 90% of emissions reported by the refinery under 40 CFR 98) will have a notable reduction in non-biogenic GHG emissions.

Rule Applicability

The rule applicability for existing equipment which will be utilized as part of the renewable fuel production facility is unchanged. The applicability of federal regulations on equipment that will be purchased, relocated, installed, and operated upon approval of this permit application are presented below. The applicability of State and Federal regulations which apply more broadly to all of the units and the refinery at large are summarized in permit application form C-1 Compliance Plan.

SG1104 Applicable Federal Regulations

The package boiler SG1104 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 Dc Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units; and
   iii. Subpart J, Standards of Performance for Petroleum Refineries

Subpart Dc emission limits for affected combustion sources burning liquid fuel.

Pollutant	NSPS Subpart Dc Maximum Emission Limits
SO2	0.50 lb/MMBtu or sulfur < 0.5 Wt%
PM	0.03 lb/ MMBTU (See note) Not applicable, if sulfur < 0.5 Wt%
Opacity	< 20 % (6 min ave.) except (*)

(*) The opacity limit is 27% for up to but not more than 6 minutes per hour.

(Auth.: 40 CFR §60.42c, §60.43c)

Notes:

1. Applicant is proposing a 0.25 wt% sulfur limit for liquid fuel.
   Applicant is proposing to utilize only RFG or low-sulfur distillate fuel to minimize opacity and to qualify for reduced monitoring requirements (§60.47c(c)).
2. In accordance with the exclusion set forth by §60.43c(e)(4), because only RFG and low sulfur distillate fuel will be used, SG1104 is not subject to the PM limits specified NSPS Subpart Dc. However, the applicant is nonetheless accepting the 0.03 lb/MMBTU limit on PM, specified in §60.43c(e)(1), as an enforceable permit condition to ensure significant PSD thresholds will not be exceeded.
3. Even though the EPA and the federal regulations recognize that the combustion of low sulfur distillate fuel does not normally generate appreciable particulate emissions, SG1104 will remain subject to the Subpart Dc opacity standard (40 CFR 60.43c(c)). While there is no categorical exemption from the Subpart Dc opacity limit for steam generators that use distillate fuel, the opacity monitoring requirements are somewhat relaxed. Pursuant to 40 CFR 60.47c(c), a Continuous Opacity Monitoring System

(COMS) is not required provided the refinery develops and follows an approved plan for controlling opacity as required by 40 CFR 60.47c(f)(3). As allowed by regulation and appropriate for low sulfur distillate fuel, PHR intends to submit a monitoring plan that will ensure that the opacity from exhaust stack of SG1104 normally remains less than 20% and continuously meets the standard set by NSPS Subpart Dc.

Subpart J emission limits for affected combustion devices burning RFG.

Pollutant	NSPS Subpart J Maximum Emission Limits
SO2 or H2S in RFG	< 20 ppm at 0% excess O2 (3-hr ave.) <162 ppm (3-hr ave.)

(Auth.: 40 CFR §60.104, §60.105)

Note: While Subpart J is applicable, applicant also will limit the 365-day average of SO2 < 8 ppm by limiting the 365-day average of H2S < 60 ppm because the RFG is sourced from a common system that complies with Subpart Ja.

SG1104 is not directly subject to the requirements of NSPS Ja because the boiler was constructed prior to the applicability date for Subpart Ja (May 14, 2007) and relocation of the boiler from Par West to Par East will not constitute reconstruction as a new source. Nonetheless, SG1104 will be held to the H2S and SOx limits of NSPS Subpart Ja because it will receive RFG from a common fuel gas system which includes amine treatment designed and operated to ensure that Ja standards will be met for other combustion devices (most notably H-3701). Elements from the Ja standards for combustion sources will be proposed as permit conditions by the applicant.

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.

SG1104 was built in 2007 and was originally designed and permitted for to be fired on low sulfur fuel oil (LSFO) or refinery fuel gas. Relocation of the steam generator from Par West (where the boiler was first permitted by Chevron) to Par East is not considered reconstruction, consequently the boiler remains subject to the Subpart DDDDD limits for boilers and process heaters which were existing prior to June 4, 2010.

Subpart DDDDD Emission limits for existing non-continental combustion sources burning liquid fuel.

Pollutant	MACT Subpart DDDDD Maximum Emission Limits
CO	130 ppmvd @ 3% excess O_2
Filterable PM (or TSM)	0.22 lb/MMBtu (or 0.00086 lb/MMBtu)
Hydrogen Chloride	1.1E-03 lb/MMBtu (based on liquid fuel testing)
Mercury	7.3E-07 lb/MMBtu (based on liquid fuel testing)

(Auth.: 40 CFR§63.7500 §63.7510, §63.7521)

Note: Subpart DDDDD emission limits (above) for non-continental combustion sources were established and intended to limit HAP emissions from the combustion of residual fuels or mixtures residual fuel and distillate fuel.

Note: Applicant is proposing to utilize only RFG or low (<0.25 wt%) sulfur distillate oil to comply with MACT Subpart DDDDD limits and minimize PM and HAP emissions. Because the applicant has elected to use low sulfur distillate fuel and has proposed a stringent 0.03 lb/MMBTU limit on PM emissions, the less stringent 0.22 lb/MMBTU limit specified under NESHAPS subpart DDDDD for existing non-continental sources has been rendered somewhat irrelevant.

PTU Applicable Federal Regulations

The renewable feedstock pretreatment unit (PTU) is subject to the provisions of the following federal regulations:

a. None

Note: The renewable PTU is not a refinery process unit nor is it directly connected to a refinery process unit. Feedstocks are limited to low volatility vegetable oil, waste cooking oils and animal fats (tallow). Applicant proposes to utilize filters, gravity phase separation and water/steam, (but no fossil fuels such as naphtha or hexane) to extract and remove contaminants from renewable feedstocks.

RHT Applicable Federal Regulations

The renewable hydrotreater (RHT) 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 Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007; and
   iii. Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006; and
   iv. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

b. 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAPS)
   i. Subpart A, General Provisions; and
   ii. Subpart FF, National Emission Standard for Benzene Waste Operations.

c. 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.

Note: All of the regulatory requirements above shown as applicable for RHT are already listed on the existing Title V permit as applicable to the DHT, which is to re-purposed.

Note: The regulatory requirements for repurposed 30 MMBtu/hr Feed Heater (H-3701), which will also become a key part of the RHT are already set forth in the Attachment II(O) of the existing Title V permit and will not be altered by this application.

Facility-wide Applicable Federal Regulations

The newly installed equipment for the Renewable Fuel Production Facility is subject to the provisions of the following facility-wide federal regulations:

a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):
   i. Subpart A, General Provisions; and
   ii. Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006; and
   iii. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

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.

c. 40 CFR Part 68, Chemical Accident Prevention Provisions

d. 40 CFR 98 Mandatory Greenhouse Gas Reporting:
   i. Subpart A, General Provision; and
   ii. Subpart C, General Stationary Fuel Combustion Sources; and
   iii. Subpart P, Hydrogen Production; and
   iv. Subpart Y, Petroleum Refineries; and
   v. Subpart MM, Suppliers of Petroleum Products.

Review of SOCMI Regulations

In addition to the regulations described above as applicable to the PTU and RHT, the regulations listed below for Synthetic Organic Chemical Manufacturing Industry (SOCMI) sources were reviewed. Although general provisions apply (by reference), no substantive requirements apply and no additional controls are required. The PTU and RHT are either categorically exempt from the following Part 60 NSPS federal regulations or – more commonly - the emission limits, standard and work practices do not directly apply to any of the new or modified equipment which is being installed for the renewable fuels project.

Subpart VVa 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

Subpart VVa standards are inapplicable to the PTU and RHT principally because they do not produce, as intermediate or final products, one or more of the chemicals listed in § 60.489. As result the PTU and RHT and do not meet the definition of a SOCMI process unit which is subject to regulation under Subpart VVa.

Only indirectly as consequence being cross referenced by Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, is RHT subject to some of the same standards for equipment leaks as those specified under Subpart VVa.

Subpart III Standards of Performance for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes

Subpart NNN Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations

Subpart RRR Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes

Subpart RRR standards are inapplicable to the PTU and RHT principally because there are no atmospheric vents to which the SOCMI standards would apply. In addition to renewable fuels which are normally liquids under standard conditions the RHT is going to make renewable propane and butane, which maybe either used as a feedstock to the HGU or sold to the neighboring SNG plant. Propane and butane are chemical products which are listed in § 60.707 and they are produced with the potential to sold as a final product. However, there are no atmospheric vents from the PTU or RHT.

The PTU and RHT are either categorically exempt from the following Part 63 NESHAP regulations or more commonly the emission limits, standards and work practices do not apply to any of the new or modified equipment which is being installed for the renewable fuels project.

Subpart G National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater

Subpart H National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

Subpart FFFF National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing

Subpart GGGG National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production

Only steam is used as a solvent and as stripping gent to remove gums and other contaminates in the PTU (not a regulated solvent such as naphtha). The renewable facility is not producing vegetable oil, but rather the PTU is removing contaminates from raw vegetable and seed oils.

Proposed Changes to Title V Permit - General

The following sections of the CSP 0212-01-C should be revised to describe and represent the changes that are being proposed to accommodate the Renewable Fuel Production Facility more accurately:

1. Attachment II(I) Cogeneration Unit:
    a. Add SG1104 and associated limits and monitoring requirements
    b. Change section title to "Cogen and Steam Generators"
2. Attachment II(N) Petroleum Storage Tanks:
    a. Create a category for renewable feedstock tanks and add TK-701 and TK-702. While the CAB has already confirmed that storage of untreated renewable feedstocks in Tanks 701 and 702 are insignificant activities, to ensure their construction and operation is fully authorized, applicant would like to list them on the Title V permit.
    b. Change the equipment description for TK-601 to internal floating roof
    c. Remove Ethanol Tanks TK-518 and TK-519 from the permit.
3. Attachment II(O) Diesel Hydrotreater:
    a. Rename to Renewable Fuel Production Facility
    b. Add the following units: Renewable Pretreatment Unit (PTU), Renewable Hydrotreater (RHT), and Renewable Fuel Effluent Treatment (RET).
    c. Rename the DHT Feed Heater (H-3701) to RHT Feed Heater.
    d. Update equipment description DHT Feed Heater (H-3701) to 30 MMBtu/hr
    e. Increase the NOx limit to 1.24 lb/hr, accordingly
4. Attachment II(Q) Miscellaneous Process Units and Auxiliary Equipment:
    a. Change DHT to RHT
    b. Include SG1104 because it receives refinery fuel gas.
5. Attachment II(INSIG) Insignificant Activities:
    a. Include Tanks 701 and 702
6. Attachment II – GHG:
    a. Revise to include "SG1104 99 MMBTU/Hr Steam Generator (Boiler)." This naming convention is preferred for SG1102 and SG1103, as well.

Proposed Title V Operating Limits and Permit Conditions

In addition to the previously discussed applicable State and Federal requirements and general changes to the permit, below is an additional list of proposed operating and emission limits which are intended to limit emissions and, in some cases, are necessary to prevent potential emissions related to the entire the renewal fuels project from exceeding PSD thresholds, thereby creating a synthetic minor permit modification. The CSP 0212-01-C should be revised to reflect the following conditions:

A. Attachment II(I) Cogeneration Unit for SG1104:
    1. Fuel Usage and Specifications:
        - Fuel cap limit of 36,792 MMBtu/month based on a rolling 12-month average for RFG. Aside from RFG, any liquid fuel used to fire SG1104 will be limited to distillate oil with a maximum sulfur content of 0.25 wt% based on a rolling 30-day average and fuel cap limit of 9,198 MMBtu/month based on a rolling 12-month average.
    2. Sulfur Content of the Distillate Fuel:
        - Distillate fuel used to fire SG1104 shall be sampled and tested for sulfur content and verification of distillate properties at least once per week. Results shall be summarized and reported semi-annual. The use of distillate fuel shall be limited to 788 thousand gallons per rolling 12- month period.
    3. Air Pollution Control Equipment:
        - The flue gas recirculation system on SG1104 shall be in service whenever the package boiler is making steam and firing more than 15 MMBtu/hr or alternative criteria as specified by existing design criteria or by qualified third-party subject matter expert.
    4. Emission Limits for NOx:
        - While firing on distillate fuel, the NOx emissions from SG1104 shall be limited to 130 ppm at zero percent excess O2, based on a 3-hour average, when the FGR is in operation.
        - While firing on RFG, the NOx emissions from SG1104 shall be limited to 50 ppm at zero percent excess O2, based on a 3-hour average, when the FGR is in operation.
    5. Testing:
        - In addition to performance testing required by federal regulation, SG1104 shall be source tested for NOx emissions while firing on both fuels at least once per calendar year unless use of one of the two fuels in the prior calendar year represents less than 10% of the total heat input or 10% of the annual capacity factor.

B. Attachment II(G) Hydrogen Generating Unit:
    1. Maximum Fuel Consumption:
        - The heating value of the RFG used to fire H-2001 shall be limited to 96,973 MMBtu per /month over a rolling 12-month averaging period which is equivalent to a firing rate of 132.84 MMBTU/hr.

          This proposed limit would replace the existing fuel gas limit of 90,000 SCF/hr and the HHV of the RFG which is also listed on the permit (1476 BTU/SCF) to account for variability in the RFG. Like its predecessor, the monthly heat input limit is being retained to cap the annual PTE for the overall renewable fuel project which will require more hydrogen.

C. Attachment II(O) Diesel Hydrotreater:

1. Maximum Fuel Consumption:

    - The heating value of the RFG used to fire H-3701 shall be limited to 21,945 MMBtu per /month over a rolling 12-month averaging period which is equivalent to a firing rate of 30 MMBTU/hr.

      This proposed limit would represent an increased fuel gas limit from the previously permitted firing rate of the heater (25.6 MMBTU/hr). This monthly heat input limit allows for variability in the operation of the unit and RFG composition and will serve as a constraint on H-3701 for the overall renewable fuel project.

Emission Summary and PSD Applicability

The potential increase in emissions from the RHT project are compared to PSD significance levels in the table below. Emissions from new source SG1104, H3-3701, and additional fugitive emissions associated with new equipment installed for the pretreatment unit and RHT are calculated as the difference between the Baseline Actual Emissions (BAE) and Potential to Emit (PTE) with fuel limit caps of 277 MMscf/yr of fuel gas and 788 Mgal/yr of distillate fuel on SG1104. Emission increases from existing sources H-2001 and HGU LPG feed are calculated as the difference between their Baseline Actual Emissions (BAE) and Projected Actual Emissions (PAE). The applicability of more stringent Subpart Ja sulfur limits to the entire RFG system are reflected in the estimates provided below.

PSD is not applicable because all calculations show that the PTE is less than the PSD significant thresholds for all pollutants.

Pollutant	**New SG-1104, Fugitives & Increased Utilization of Existing Sources (H-3701, H-2001 & HGU*) (TPY)**	**PSD Significance Level (TPY)**
CO	55.53	**100**
H_2S	0.03	**10**
Pb	0.0008	**0.6**
NO_X	35.79	**40**
SO_2	20.01	**40**
VOC	2.65	**40**
PM_{Total}	4.16	**25**
PM_{10}	4.16	**15**
$PM_{2.5}$	4.16	**10**
Fluorides	0.01	**3**
Sulfuric Acid Mist	0.28	**7**
Total Reduced Sulfur	0.10	**10**
GHG (CO_{2e})**	113,757	**75,000**

(*) GHG emissions associated with increased feed to and utilization of the HGU are not considered in PSD applicability.
(**) Per 40 CFR 52.21(b)(49)(iv)(b), pollutant GHG's are not subject to PSD regulation if there is not an increase of a regulated NSR pollutant.

Ambient Air Quality Analysis

Air quality dispersion modeling analysis of the new sources demonstrate compliance of the existing facility with all applicable state and federal ambient air quality standards. The modeling methodology is described in the modeling analysis. Results of the analysis are provided in Appendix D.

Modeled Impacts Summary

Pollutants	Averaging Periods	Predicted Concentrations Design Values	GLCmax (µg/m³)	Background Calculations Basis	Background Values (µg/m³)	Background + GLC max (µg/m³)	Hawaii Standard (ppb)	Hawaii Standard (µg/m³)	Federal Standard (ppb)	Federal Standard (µg/m³)
CO	1-HR	H2H	33.28	H2H	1374.72	1408.00	9000	10310	35000	40096
	8-HR	H2H	18.86	H2H	458.24	477.11	4400	5041	9000	10310
NO_2	1-HR	maximum 98th percentile/H8H	15.48	3-year average of the 98th percentile	47.36	62.84			100	188
	ANNUAL	Maximum	2.89	3-year average of Annual Mean	6.27	9.16	40	76	53	100
H_2S	1-HR	H1H	0.06	H1H	7.73	7.79	25	35		
SO_2	1-HR	maximum 99th percentile/ H4H	33.69	3-year average of the 99th percentile	9.35	43.03			75	197
	3-HR	H2H	40.04	H2H	7.86	47.90	500	1310		
	24-HR	H2H	23.68	H2H	5.24	28.93	140	367		
	ANNUAL	Maximum	1.78	3-year average of Annual Mean	1.66	3.44	30	79		
PM_{10}	24-HR	H6H	2.18	H2H	46.00	48.18		150		150
	ANNUAL	Highest five-year average	0.30	3-year average of Annual Mean	12.67	12.96		50		
$PM_{2.5}$	24-HR	maximum 98th percentile/H8H	1.94	3-year average of the 98th percentile	7.60	9.54				35
	ANNUAL	Highest five-year average	0.30	3-year average of Annual Mean	3.70	4.00				12

Permit Application Forms

File/Application No.: 0212-01-C

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: Par Hawaii Refining, LLC

2. Facility Name (if different from the Company): Kapolei Refinery

3. Mailing Address: 91-325 Komohana St.

   City: Kapolei State: HI Zip Code: 96707-1713

   Phone Number: (808)

4. Name of Owner/Owner's Agent: Deaglan McClean

   Title: Vice President Phone: (808) 547-3841

   Mailing Address: 91-325 Komohana St.

   City: Kapolei State: HI Zip Code: 96707-1713

5. Plant Site Manager/Other Contact: Benton Widlansky

   Title: Environmental Manager Phone: (808) 547-3993

   Mailing Address: 91-325 Komohana St.

   City: Kapolei State: HI Zip Code: 96707-1713

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. 0212-01-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): Kapolei Refinery

City: Kapolei State: HI Zip Code: 96707-1713

UTM Coordinates (meters): East: 594327 North: 2356175.9

UTM Zone: ☐ 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: 2024

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): McClean (First): Deaglan (MI): ________

Title: Vice President Phone: (808) 547-3841

Mailing Address: 91-325 Komohana St.

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): Deaglan McClean

(Signature): [signature] Date: 12/11/2023

FOR AGENCY USE ONLY:

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.

See Form S1

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_x), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM_{10}). 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.

See Form S1

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.

See Form S1

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.

See Form S1

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.

See enclosed process flow diagram

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.

See enclosed plot plan and 100m radius map

D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

See enclosed description

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 ᵃ: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)ᵇ	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
New Boiler (SG1104)																	
					Criteria Pollutants (CAPS):												
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	CO	630080	9.42E+00	2.10E+01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	H2S	7783064	1.78E-02	1.47E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	NH3	7664417	1.99E-01	4.43E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Lead	7439921	4.85E-05	1.08E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	NOx	NOX	5.10E+00	1.14E+01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	SO2	7446095	2.84E+00	2.53E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	VOC	VOC	3.41E-01	7.61E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Particulate Matter:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Total (Filterable + Condensable)	PM-PRI	4.72E-01	1.05E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Filterable	PM-FIL	1.18E-01	2.63E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Condensable	PM-CON	3.54E-01	7.89E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	PM10 (Filterable + Condensable)	PM10-PRI	4.72E-01	1.05E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	PM10 (Filterable)	PM10-FIL	1.18E-01	2.63E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	PM2.5 (Filterable + Condensable)	PM25-PRI	4.72E-01	1.05E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	PM2.5 (Filterable)	PM25-FIL	1.18E-01	2.63E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					PSD-Specific categories:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Fluorides	16984488	NA	NA	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Sulfuric Acid Mist	7664939	1.30E-01	1.16E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Total Reduced Sulfur	TRS	1.89E-02	4.20E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Greenhouse Gases (GHGs):									11.911			

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Total GHG (CO2e):	CO2e	1.26E+04	2.80E+04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					Individual Components:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Carbon Dioxide	124389	1.25E+04	2.79E+04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methane	74828	6.53E-01	1.46E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Nitrous Oxide	10024972	1.31E-01	2.91E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Hazardous Air Pollutants (HAPS):									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	1,3-Butadiene	106990			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	1,4-Dichlorobenzene(p)	106467	1.19E-04	2.65E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Acetaldehyde	75070	1.19E-03	2.65E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Acrolein	107028	1.68E-03	3.75E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Antimony	7440360	5.15E-05	1.15E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Arsenic	7440382	1.98E-05	4.42E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzene	71432	2.08E-04	4.64E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Beryllium	7440417	1.29E-05	2.87E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Biphenyl, 1,1-	92524			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Cadmium	7440439	1.09E-04	2.43E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Carbon disulfide	75150			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Carbonyl sulfide	463581			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Chlorine	7782505			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Chloroform	67663			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					Chromium:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Total Chromium	7440473	1.39E-04	3.09E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Hexavalent Chromium	18540299	NA	NA	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Cobalt	7440484	8.12E-06	1.81E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Cumene	98828			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Dichloroethane, 1,2-	107062			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Diethanolamine	111422			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Ethyl benzene	100414	1.58E-03	3.53E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Ethylene glycol	107211			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Formaldehyde	50000	7.33E-03	1.63E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Hexane	110543	1.78E-01	3.97E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	m-Cresol	108394			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Hydrochloric acid	7647010			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Manganese	7439965	3.66E-05	8.17E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Mercury	7439976	2.48E-05	5.52E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methanol	67561			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)		Methyl chloroform (1,1,1-Trichloroetl	71556			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methyl isobutyl ketone	108101			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methyl tert butyl ether	1634044			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Naphthalene	91203	5.94E-05	1.32E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Nickel	7440020	2.08E-04	4.64E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Phenol	108952	3.96E-04	8.83E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Phosphorus	7723140	6.34E-05	1.41E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)		Polychlorinated biphenyls (Aroclors)	PCBs			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Selenium	7782492	8.71E-05	1.94E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Styrene	100425			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Toluene	108883	3.27E-04	7.28E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Trimethylpentane, 2,2,4-	540841			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Xylenes	1330207	2.48E-03	5.52E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					HAPs - Polycylic Organic Matter (POM)									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Total Polycylic Organic Matter	POM	2.76E-05	6.15E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					Individual Components:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	2-Methylnapthalene	91576	2.38E-06	5.30E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	3-methylchloranthrene	56495	1.78E-07	3.97E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	7,12-dimethylbenz(a)anthracene	57976	1.58E-06	3.53E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Acenaphthylene	208968	6.44E-07	1.43E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Anthracene	120127	4.65E-07	1.04E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(a)anthracene	56553	2.18E-06	4.86E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(a)pyrene	50328	5.64E-06	1.26E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(b)fluoranthene	205992	2.67E-06	5.96E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(g,h,i)perylene	191242	1.29E-07	2.87E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(k)fluoroanthene	207089	1.68E-06	3.75E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Chrysene	218019	1.58E-07	3.53E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Dibenz(a,h)anthracene	53703	1.19E-07	2.65E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Fluoranthene	206440	2.87E-07	6.40E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Fluorene	86737	2.67E-07	5.96E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Indeno(1,2,3-cd)pyrene	193395	7.03E-06	1.57E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					PAH:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Phenanthrene	85018	1.68E-06	3.75E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Pyrene	129000	4.85E-07	1.08E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Non-HAPs:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	1,2,4- Trimethylbenzene	95636			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	2-Chloronaphthalene	91587			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Acenaphthene	83329	2.38E-07	5.30E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Barium	7440393	4.26E-04	9.49E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(e)pyrene	192972			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Copper	7440508	8.42E-05	1.88E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Cyclohexane	110827			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Ethane	74840	3.27E-01	7.28E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Fluorides	16984488	NA	NA	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methyl ethyl ketone (2-Butanone)	78933			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Molybdenum	7439987	1.09E-04	2.43E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	n-Butane	106978	2.08E-01	4.64E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	n-pentane	109660	2.48E-01	5.52E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Perylene	198550			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Propane	74986	1.58E-01	3.53E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Propylene	115071	1.49E-02	3.31E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Vanadium	7440622	2.28E-04	5.08E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Zinc	7440666	2.87E-03	6.40E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	**Criteria Pollutants (CAPS):**				594356	594356				11.911		418.8722	
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	CO	630080	1.00E+01	5.60E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	H2S	7783064			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	NH3	7664417	5.66E-01	3.15E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Lead	7439921	8.91E-04	4.97E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	NOx	NOX	1.41E+01	7.88E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	SO2	7446095	2.51E+01	1.40E+01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	VOC	VOC	1.41E-01	7.88E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Particulate Matter:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Total (Filterable + Condensable)	PM-PRI	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Filterable	PM-FIL	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Condensable	PM-CON	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	PM10 (Filterable + Condensable)	PM10-PRI	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	PM10 (Filterable)	PM10-FIL	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	PM2.5 (Filterable + Condensable)	PM25-PRI	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	PM2.5 (Filterable)	PM25-FIL	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					PSD-Specific categories:									1.19E+01			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Fluorides	16984488	2.65E-02	1.48E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Sulfuric Acid Mist	7664939			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Total Reduced Sulfur	TRS			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Greenhouse Gases (GHGs):									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Total GHG (CO2e):	CO2e	1.62E+04	9.01E+03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					Individual Components:									11.911			

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum ᵃ: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)ᵇ	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Carbon Dioxide	124389	1.61E+04	8.98E+03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methane	74828	6.53E-01	3.64E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Nitrous Oxide	10024972	1.31E-01	7.28E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Hazardous Air Pollutants (HAPS):									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		1,3-Butadiene	106990			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		1,4-Dichlorobenzene(p)	106467			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Acetaldehyde	75070	7.43E-04	4.14E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Acrolein	107028			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Antimony	7440360	3.71E-03	2.07E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Arsenic	7440382	3.96E-04	2.21E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Benzene	71432	1.51E-04	8.44E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Beryllium	7440417	2.97E-04	1.66E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Biphenyl, 1,1	92524			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Cadmium	7440439	2.97E-04	1.66E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Carbon disulfide	75150			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Carbonyl sulfide	463581			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Chlorine	7782505			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Chloroform	67663	3.61E-03	2.01E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					Chromium:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Total Chromium	7440473	2.97E-04	1.66E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Hexavalent Chromium	18540299	2.97E-04	1.66E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Cobalt	7440484	4.26E-03	2.37E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Cumene	98828			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Dichloroethane, 1,2-	107062			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Diethanolamine	111422			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Ethyl benzene	100414	4.50E-05	2.51E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Ethylene glycol	107211			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Formaldehyde	50000	2.33E-02	1.30E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Hexane	110543			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		m-Cresol	108394			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)		Hydrochloric acid	7647010	1.09E-01	6.07E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
(Make as many copies of this page as necessary)

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Manganese	7439965	5.94E-04	3.31E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Mercury	7439976	7.23E-05	4.03E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methanol	67561			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methyl chloroform (1,1,1-Trichloroetl	71556	1.67E-04	9.30E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methyl isobutyl ketone	108101			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methyl tert butyl ether	1634044			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Naphthalene	91203	7.99E-04	4.45E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Nickel	7440020	2.97E-04	1.66E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Phenol	108952			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Phosphorus	7723140	6.68E-03	3.73E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Polychlorinated biphenyls (Aroclors)	PCBs			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Selenium	7782492	1.49E-03	8.28E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Styrene	100425			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Toluene	108883	7.71E-05	4.30E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Trimethylpentane, 2,2,4-	540841			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Xylenes	1330207	7.74E-04	4.32E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					HAPs - Polycyclic Organic Matter (POM)									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Total Polycylic Organic Matter	POM	2.33E-03	1.30E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Individual Components:				594356	594356				11.911		418.8722	
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	2-Methylnapthalene	91576	7.85E-06	4.38E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	3-methylchloranthrene	56495			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	7,12-dimethylbenz(a)anthracene	57976			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Acenaphthylene	208968	1.79E-07	9.97E-08	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Anthracene	120127	8.63E-07	4.81E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(a)anthracene	56553	2.84E-06	1.58E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(a)pyrene	50328	1.49E-07	8.28E-08	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(b)fluoranthene	205992	1.05E-06	5.83E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(g,h,i)perylene	191242	1.60E-06	8.91E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(k)fluoroanthene	207089	1.05E-06	5.83E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Chrysene	218019	1.70E-06	9.46E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Dibenz(a,h)anthracene	53703	1.17E-06	6.50E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Fluoranthene	206440	3.39E-06	1.89E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Fluorene	86737	3.18E-06	1.77E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Indeno(1,2,3-cd)pyrene	193395	1.49E-06	8.28E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					PAH:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Phenanthrene	85018	7.43E-06	4.14E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Pyrene	129000	2.97E-06	1.66E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Non-HAPs:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	1,2,4- Trimethylbenzene	95636			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	2-Chloronaphthalene	91587	1.59E-08	8.87E-09	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Acenaphthene	83329	1.49E-05	8.32E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Barium	7440393	1.20E-05	6.70E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(e)pyrene	192972	6.15E-07	3.43E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Copper	7440508	5.94E-04	3.31E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Cyclohexane	110827			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Ethane	74840			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Fluoride	16984488	2.65E-02	1.48E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methyl ethyl ketone (2-Butanone)	78933			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Molybdenum	7439987			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	n-Butane	106978			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	n-pentane	109660			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Perylene	198550	7.85E-08	4.38E-08	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Propane	74986			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Propylene	115071			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Vanadium	7440622	2.23E-02	1.24E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Zinc	7440666	3.96E-04	2.21E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
so in previous Insignificant Modification																	
103	TS-701	TK701 Vegetable Oil Processing Holding Tank, Standing Loss	30201941	2024 (Plan)	VOC	VOC	No or negligibile emissions (see separate Insigniifcant Activity Letter dated August 3, 2023)										
103	TW-701	TK701 Vegetable Oil Processing Holding Tank, Working Loss	30201941	2024 (Plan)	VOC	VOC	No or negligibile emissions (see separate Insigniifcant Activity Letter dated August 3, 2023)										
104	TS-702	TK702 Vegetable Oil Processing Holding Tank, Standing Loss	30201941	2024 (Plan)	VOC	VOC	No or negligibile emissions (see separate Insigniifcant Activity Letter dated August 3, 2023)										

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
104	TW-702	TK702 Vegetable Oil Processing Holding Tank, Working Loss	30201941	2024 (Plan)	VOC	VOC	No or negligibile emissions (see separate Insigniifcant Activity Letter dated August 3, 2023)										
New Fugitive Sources																	
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	**Criteria Pollutants (CAPS):**												
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	VOC	VOC	1.53E+03	7.63E-01									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)													
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	**Hazardous Air Pollutants (HAPS):**												
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	1,3-Butadiene	106990											
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Benzene	71432	5.64E+00	2.82E-03									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Biphenyl, 1,1-	92524	3.36E+00	1.68E-03									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Cumene	98828	1.07E+00	5.34E-04									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Ethyl benzene	100414	5.64E+00	2.82E-03									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Hexane	110543	2.90E+01	1.45E-02									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	m-Cresol	108394	1.53E-02	7.63E-06									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Methyl isobutyl ketone	108101	6.87E-01	3.43E-04									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Naphthalene	91203	3.81E+00	1.91E-03									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Phenol	108952	1.53E-02	7.63E-06									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Toluene	108883	2.59E+01	1.30E-02									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Trimethylpentane, 2,2,4-	540841	0.00E+00	0.00E+00									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Xylenes	1330207	2.90E+01	1.45E-02									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)													
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	**HAPs - Polycylic Organic Matter (POM)**												
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Total Polycylic Organic Matter	POM	7.78E-01	3.89E-04									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Individual Components:												
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Benzo(g,h,i)perylene	191242	5.68E-02	2.84E-05									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	PAH		7.21E-01	3.60E-04									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	**Non-HAPs:**												
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	1,2,4- Trimethylbenzene	95636	6.10E+00	3.05E-03									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Cyclohexane	110827	2.82E+01	1.41E-02									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Methyl ethyl ketone (2-Butanone)	78933	8.39E+00	4.20E-03									
CO2 Increases Passed Through Existing Fuel Gas System																	
					Greenhouse Gases (GHGs):												
		Biogenic RHT CO2 Byproduct Carryover (New) Releases through various Refinery Fuel Gas Combustion Sources	Gas-fired Process Heaters (SCC 30600104) Refinery Fuel Gas Boilers (SCC 10200701)		Carbon Dioxide	124389	3.03E+02	1.32E+03									
CO2 Increases Passed Through Existing HGU																	
					Greenhouse Gases (GHGs):												
14	HGU	Hydrogen Generation Unit *Biogenic* LPG Feed (New)	Hydrogen Generation Unit General (SCC 30601801)	1982	Carbon Dioxide	124389	5.60E+03	2.45E+04	594001.32	2356192.968	36.94176	u	2.19456	11.21664	42.42751336	432.95	N
14	HGU	Hydrogen Generation Unit *Non-Biogenic* LPG Feed (Increase)	Hydrogen Generation Unit General (SCC 30601801)	1982	Carbon Dioxide	124389	2.80E+03	1.23E+04	594001.32	2356192.968	36.94176	u	2.19456	11.21664	42.42751336	432.95	N
Existing FH2001 (PTE)																	
					Criteria Pollutants (CAPS):												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	CO	630080	1.26E+01	5.54E+01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	H2S	7783064	2.39E-02	3.87E-02	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	NH3	7664417	2.67E-01	1.17E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Lead	7439921	6.51E-05	2.85E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	NOx	NOX	3.61E+01	3.00E+01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	SO2	7446095	3.81E+00	6.67E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	VOC	VOC	4.58E-01	2.01E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
					Particulate Matter:												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Total (Filterable + Condensable)	PM-PRI	6.33E-01	2.77E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Filterable	PM-FIL	1.58E-01	6.93E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Condensable	PM-CON	4.75E-01	2.08E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	PM10 (Filterable + Condensable)	PM10-PRI	6.33E-01	2.77E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	PM10 (Filterable)	PM10-FIL	1.58E-01	6.93E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	PM2.5 (Filterable + Condensable)	PM25-PRI	6.33E-01	2.77E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	PM2.5 (Filterable)	PM25-FIL	1.58E-01	6.93E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
					PSD-Specific categories:												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Fluorides	16984488	NA	NA	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Sulfuric Acid Mist	7664939	1.75E-01	3.06E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Total Reduced Sulfur	TRS	2.53E-02	1.11E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	**Greenhouse Gases (GHGs):**				594245.944	2356263.654	19.15058		1.955804	7.802499	23.44	480.3722	
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Total GHG (CO2e):	CO2e	1.69E+04	7.39E+04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Individual Components:				594245.944	2356263.654	19.15058		1.955804	7.802499	23.44	480.3722	

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
(Make as many copies of this page as necessary)

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Carbon Dioxide	124389	1.68E+04	7.36E+04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methane	74828	8.77E-01	3.84E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Nitrous Oxide	10024972	1.75E-01	7.68E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
					Hazardous Air Pollutants (HAPS):												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	1,3-Butadiene	106990			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	1,4-Dichlorobenzene(p)	106467	1.59E-04	6.98E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Acetaldehyde	75070	1.59E-03	6.98E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Acrolein	107028	2.26E-03	9.89E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Antimony	7440360	6.91E-05	3.03E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Arsenic	7440382	2.66E-05	1.16E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzene	71432	2.79E-04	1.22E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Beryllium	7440417	1.73E-05	7.56E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Biphenyl, 1,1-	92524			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Cadmium	7440439	1.46E-04	6.40E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Carbon disulfide	75150			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Carbonyl sulfide	463581			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Chlorine	7782505			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Chloroform	67663			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
					Chromium:												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Total Chromium	7440473	1.86E-04	8.15E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Hexavalent Chromium	18540299			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Cobalt	7440484	1.09E-05	4.77E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Cumene	98828			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Dichloroethane, 1,2-	107062			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Diethanolamine	111422			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Ethyl benzene	100414	2.13E-03	9.31E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Ethylene glycol	107211			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Formaldehyde	50000	9.83E-03	4.31E-02	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Hexane	110543	2.39E-01	1.05E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	m-Cresol	108394			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Hydrochloric acid	7647010			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Manganese	7439965	4.92E-05	2.15E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Mercury	7439976	3.32E-05	1.45E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methanol	67561			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methyl chloroform (1,1,1-Trichloroetl	71556			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methyl isobutyl ketone	108101			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methyl tert butyl ether	1634044			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Naphthalene	91203	7.97E-05	3.49E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Nickel	7440020	2.79E-04	1.22E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Phenol	108952	5.31E-04	2.33E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Phosphorus	7723140	8.50E-05	3.72E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Polychlorinated biphenyls (Aroclors)	PCBs			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Selenium	7782492	1.17E-04	5.12E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Styrene	100425			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Toluene	108883	4.38E-04	1.92E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Trimethylpentane, 2,2,4-	540841			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Xylenes	1330207	3.32E-03	1.45E-02	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	**HAPs - Polycylic Organic Matter (POM)**				594245.944	2356263.654	19.15058		1.955804	7.802499	23.44	480.3722	
					Total Polycylic Organic Matter	POM	3.70E-05	1.62E-04									
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Individual Components:				594245.944	2356263.654	19.15058		1.955804	7.802499	23.44	480.3722	
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	2-Methylnapthalene	91576	3.19E-06	1.40E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	3-methylchloranthrene	56495	2.39E-07	1.05E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	7,12-dimethylbenz(a)anthracene	57976	2.13E-06	9.31E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Acenaphthylene	208968	8.63E-07	3.78E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Anthracene	120127	6.24E-07	2.73E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(a)anthracene	56553	2.92E-06	1.28E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(a)pyrene	50328	7.57E-06	3.32E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(b)fluoranthene	205992	3.59E-06	1.57E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(g,h,i)perylene	191242	1.73E-07	7.56E-07	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(k)fluoroanthene	207089	2.26E-06	9.89E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Chrysene	218019	2.13E-07	9.31E-07	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)*	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Dibenz(a,h)anthracene	53703	1.59E-07	6.98E-07	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Fluoranthene	206440	3.85E-07	1.69E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Fluorene	86737	3.59E-07	1.57E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Indeno(1,2,3-cd)pyrene	193395	9.43E-06	4.13E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	**PAH:**				594245.944	2356263.654	19.15058		1.955804	7.802499	23.44	480.3722	
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Phenanthrene	85018	2.26E-06	9.89E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Pyrene	129000	6.51E-07	2.85E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
					Non-HAPs:												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	1,2,4- Trimethylbenzene	95636			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	2-Chloronaphthalene	91587			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Acenaphthene	83329	3.19E-07	1.40E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Barium	7440393	5.71E-04	2.50E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(e)pyrene	192972			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Copper	7440508	1.13E-04	4.95E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Cyclohexane	110827			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Ethane	74840	4.38E-01	1.92E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Fluorides	16984488	NA	NA	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methyl ethyl ketone (2-Butanone)	78933			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Molybdenum	7439987	1.46E-04	6.40E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	n-Butane	106978	2.79E-01	1.22E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	n-pentane	109660	3.32E-01	1.45E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Perylene	198550			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Propane	74986	2.13E-01	9.31E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Propylene	115071	1.99E-02	8.73E-02	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Vanadium	7440622	3.06E-04	1.34E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Zinc	7440666	3.85E-03	1.69E-02	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
Existing FH3701 (PTE)																	
					Criteria Pollutants (CAPS):												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	CO	630080	2.86E+00	1.25E+01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	H2S	7783064	5.40E-03	8.76E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	NH3	7664417	6.03E-02	2.64E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Lead	7439921	1.47E-05	6.45E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	NOx	NOX	1.24E+00	5.42E+00	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	SO2	7446095	8.61E-01	1.51E+00	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	VOC	VOC	1.04E-01	4.54E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Particulate Matter:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Total (Filterable + Condensable)	PM-PRI	1.43E-01	6.27E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Filterable	PM-FIL	3.58E-02	1.57E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Condensable	PM-CON	1.07E-01	4.71E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	PM10 (Filterable + Condensable)	PM10-PRI	1.43E-01	6.27E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	PM10 (Filterable)	PM10-FIL	3.58E-02	1.57E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
(Make as many copies of this page as necessary)

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum ª: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)ᵇ	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	PM2.5 (Filterable + Condensable)	PM25-PRI	1.43E-01	6.27E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	PM2.5 (Filterable)	PM25-FIL	3.58E-02	1.57E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					PSD-Specific categories:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Fluorides	16984488	NA	NA	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Sulfuric Acid Mist	7664939	3.96E-02	6.93E-02	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Total Reduced Sulfur	TRS	5.73E-03	2.51E-02	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Greenhouse Gases (GHGs):												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Carbon Dioxide	124389	3.80E+03	1.66E+04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Methane	74828	1.98E-01	8.69E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Nitrous Oxide	10024972	3.97E-02	1.74E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Hazardous Air Pollutants (HAPS):												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	1,4-Dichlorobenzene(p)	106467	3.61E-05	1.58E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Acetaldehyde	75070	3.61E-04	1.58E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Acrolein	107028	5.11E-04	2.24E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Antimony	7440360	1.56E-05	6.85E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Arsenic	7440382	6.01E-06	2.63E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzene	71432	6.31E-05	2.77E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Beryllium	7440417	3.91E-06	1.71E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Cadmium	7440439	3.31E-05	1.45E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Chromium:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Total Chromium	7440473	4.21E-05	1.84E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Hexavalent Chromium	18540299	NA	NA	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Cobalt	7440484	2.47E-06	1.08E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Ethyl benzene	100414	4.81E-04	2.11E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Formaldehyde	50000	2.22E-03	9.74E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Hexane	110543	5.41E-02	2.37E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Hydrochloric acid	7647010			594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Manganese	7439965	1.11E-05	4.87E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Mercury	7439976	7.52E-06	3.29E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Naphthalene	91203	1.80E-05	7.90E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Nickel	7440020	6.31E-05	2.77E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Phenol	108952	1.20E-04	5.27E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Phosphorus	7723140	1.92E-05	8.43E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Selenium	7782492	2.65E-05	1.16E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Toluene	108883	9.92E-05	4.35E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Xylenes	1330207	7.52E-04	3.29E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					HAPs - Polycylic Organic Matter (POM)												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Total Polycylic Organic Matter	POM	8.38E-06	3.67E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Individual Components:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	2-Methylnapthalene	91576	7.21E-07	3.16E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	3-methylchloranthrene	56495	5.41E-08	2.37E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	7,12-dimethylbenz(a)anthracene	57976	4.81E-07	2.11E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)°	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Anthracene	120127	1.41E-07	6.19E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzo(a)anthracene	56553	6.61E-07	2.90E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzo(a)pyrene	50328	1.71E-06	7.51E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzo(b)fluoranthene	205992	8.12E-07	3.56E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzo(g,h,i)perylene	191242	3.91E-08	1.71E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzo(k)fluoroanthene	207089	5.11E-07	2.24E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Chrysene	218019	4.81E-08	2.11E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Dibenz(a,h)anthracene	53703	3.61E-08	1.58E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Fluoranthene	206440	8.72E-08	3.82E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Fluorene	86737	8.12E-08	3.56E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Indeno(1,2,3-cd)pyrene	193395	2.13E-06	9.35E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					PAH:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Phenanthrene	85018	5.11E-07	2.24E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Pyrene	129000	1.47E-07	6.45E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Non-HAPs:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Acenaphthene	83329	7.21E-08	3.16E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Acenaphthylene	208968	1.95E-07	8.56E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Barium	7440393	1.29E-04	5.66E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Copper	7440508	2.56E-05	1.12E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Ethane	74840	9.92E-02	4.35E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Molybdenum	7439987	3.31E-05	1.45E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
(Make as many copies of this page as necessary)

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	n-Butane	106978	6.31E-02	2.77E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	n-pentane	109660	7.52E-02	3.29E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Propane	74986	4.81E-02	2.11E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Propylene	115071	4.51E-03	1.98E-02	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Vanadium	7440622	6.91E-05	3.03E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Zinc	7440666	8.72E-04	3.82E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N

a Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27
b Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal

File No.: 0212-01-C

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.

For purposes of this Compliance Plan, Par has reviewed the Par Hawaii Refinery's most-recent annual Title V compliance certification and semi-annual Title V deviation reports to identify the applicable requirements to complete Parts 1.a and 1.b. (identification of applicable requirements for which compliance is achieved and identification of applicable requirements for which compliance is not achieved).

In order to identify the applicable requirements for which compliance is achieved, Par reviewed the most-recent semi-annual Title V deviation reports to identify applicable requirements for which either no deviations were reported or for which reported deviations have been resolved. Par identified the following applicable requirements for which either no deviations were reported or for which reported deviations have been resolved:

- *HAR Title 11, Chapters 60.1, 60.1-32, 60.1-38, 60.1-39, 60.1-40, 60.1-41, 60.1-42, 60.1-161, 60.1-174, 60.1-203, 60.1-204*
- *40 CFR 60 Subparts A, J, Ja, K, Ka, GG, IIII*
- *40 CFR 63 Subparts A, UUU, YYYY, ZZZZ, and DDDDD*
- *40 CFR 68*
- *40 CFR 98 Subparts A, C, P, Y, and MM*

In the event that Par identifies additional deviations during the preparation if its Title V Annual Compliance Certification and Deviation Report, then Par will update this Form C-1: Compliance Plan , provided that deviation report is submitted while this application is pending. With regard to 40 CFR 68, Par conducts triennial audits as required by EPA's RMP rule; those audits often identify observations; Par is currently working to resolve observations identified by the auditors.

Provide a statement that the source is in compliance and will continue to comply with all such requirements.

In order to determine whether the source is in compliance with the requirements listed above, Par reviewed the most-recent semi-annual Title V deviation reports to identify applicable requirements for which either no deviations were reported or for which reported deviations have been resolved. Par identified the applicable requirements listed above for which either no deviations were reported or for which reported deviations have been resolved

Par implements a compliance management program designed to maintain compliance with all applicable requirements. As stated above, Par will supplement this version of Form C-1 to identify any noncompliance not listed in Part 1.b. below upon submittal of its next semi-annual Title V deviation report.

b. Identify all applicable requirement(s) for which compliance is NOT achieved.

In order to identify applicable requirements for which compliance is not achieves, Par reviewed the most-recent semi-annual Title V deviation reports to determine the applicable requirements for which deviations have been reported and for which reported deviations have not been resolved. Par identified the following applicable requirements for which deviations were reported and for which reported deviations have not been resolved, i.e applicable requirements for which noncompliance is ongoing:

- *40 CFR 60 Subparts Kb, VVa, GGGa and QQQ*
- *40 CFR 61 Subparts A and FF*
- *40 CFR 63 Subparts CC*
- *CSP 0212-01-C, Consent Decree NOx Emission Limits*
- *CSP 0212-01-C, Consent Decree Requirement 99 for Certified Low-Leaking Valves*

As stated above, Par will supplement this version of Form C-1 to identify any noncompliance not listed in Part 1.b. below upon submittal of its next semi-annual Title V deviation report.

Provide a detailed Schedule of Compliance Schedule and a description of how the source will achieve compliance with all such applicable requirements.

Description of Remedial Action

Below is a Detailed Schedule of Compliance for all of the applicable requirements identified above for which compliance is not achieved:

Emission Unit	*Applicable Requirement*	*Corrective Action Plan*	*Expected Date Of Completion*
Miscellaneous Emissions Sources - Oily Water Sewer	*40 CFR § 60.692-3*	*Par is redesigning the Stainless Steel Sump (SSS) to include additional emissions control.*	*6/30/2024*
Wastewater Treatment Unit -	*40 CFR § 61.349*	*Par submitted an alternative monitoring request for*	*Request submitted*

Closed Vent System	*(a)(1)(ii)(a)*	*assurance that the water seal on the Thermal Oxidizer Seal Drum D-3560 vent legs remains in place.*	*10/31/2023*
Package Boiler (SG1103)	*Consent Decree and CSP 0212-01-C II(I)C.3.c.ii II(I)C.3.c.iii*	*Operational limits were placed on production until repair to remain within required limits. Repairs will be followed by a repeat source test.*	*12/31/2023*
DHC Heaters H601, H602, H603	*Consent Decree and CSP 0212-01-C II(D)C.5*	*Par is in discussions with EPA to determine corrective actions. Oxygen concentrations are minimized, and additional operational testing will be conducted.*	*Updated plan expected by 1/31/2024*
VDU Heater H175	*Consent Decree and CSP 0212-01-C II(C)C.4*		
VBK Heater H901	*Consent Decree and CSP 0212-01-C II(F)C.5.a*		
Miscellaneous Emissions Sources – Valves in VOC Service	*Consent Decree Paragraph 99*	*Valve will be upgraded with Certified Low Leak Technology Packing (MOV7)*	*12/31/2023*

This Compliance Schedule does NOT include applicable requirements for which Par has reported deviations, but for which Par has already completed corrective actions as of the date of this application. Par is in discussions with EPA Region 9 regarding additional items identified during a February 2023 inspection to determine compliance status and any remaining corrective actions. Par may decide to report additional deviations based on the outcome of those discussion that are not included in this application.

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:

Applicable Requirement	Effective Date	Currently in Compliance?
40 CFR 60 Subpart Dc, Applicable to the new boiler (SG1104)	*Upon SG1104 Startup*	*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:

Description of Proposed Action/Steps to Achieve Compliance	Expected Date of Achieving Compliance
Source will be compliant upon startup	*Upon SG1104 Startup*

Provide a statement that the source on a timely basis will meet all these applicable requirements:

The source will meet all applicable requirements on a timely basis.

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>	Expected Date <u>of Completion</u>
NA	*NA*

2. Compliance Progress Reports:

   a. If a compliance plan is being submitted to remedy a violation, complete the following information:

   Frequency of Submittal: *6 months* (less than or equal to 6 months) Beginning Date: Following Permit Issuance

   b. Date(s) that the Action described in (1)(b) was achieved:

<u>Remedial Action</u>	<u>Date Achieved</u>
NA	*NA*

   c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

   NA

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): *McClean* (First): *Deaglan* (MI):

Title: *Vice President* Phone: *(808) 547-3841*

Mailing Address: *91-325 Komohana St.*

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): *Deaglan McClean*

(Signature): McClean Date: 12/11/2023

Facility Name: *Par Hawaii Refining, LLC, Par East Refinery*

Location: *91-325 Komohana St., Kapolei, HI 96707*

Permit Number: *CSP No. 0212-01-C*

FOR AGENCY USE ONLY

File/Application No.: ____________

Island: ____________

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: **3/30/2026**

2. Emissions Unit No./Description: **Renewable Hydrotreater (RHT) with Package Boiler Steam Generator (SG1104)**

3. Identify the applicable requirement(s) that is/are the basis of this certification:

   - **40 CFR 60 Subpart A General Provisions**
   - **40 CFR 60 Subpart Dc Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units**
   - **40 CFR 60 Subpart J Standards of Performance for Petroleum Refineries**
   - **40 CFR 60 Subpart Ja Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011**
   - **40 CFR 60 Subpart GGGa Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries**
   - **40 CFR 60 Subpart QQQ Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems**

   - **40 CFR 61 Subpart A General Provisions**
   - **40 CFR 61 Subpart FF Standards of Benzene Waste Operations**

   - **40 CFR 63 Subpart A General Provisions**
   - **40 CFR 63 Subpart CC NESHAPS for HAPs from Petroleum Refineries**
   - **40 CFR 63 Subpart DDDDD NESHAPS for Industrial/Commercial/Institutional Boilers and Process Heaters**

   - **40 CFR 98 Subpart A General Provisions**
   - **40 CFR 98 Subpart C General Stationary Fuel Combustion Sources**
   - **40 CFR 98 Subpart P Hydrogen Production**
   - **40 CFR 98 Subpart Y Petroleum Refineries**
   - **40 CFR 98 Subpart MM Suppliers of Petroleum Products**

4. Compliance status:

a. Will the emissions units be in compliance with the identified applicable requirement(s)?

X YES ☐ NO

b. If YES, will compliance be continuous or intermittent?

X Continuous ☐ Intermittent

c. If NO, explain.

5. Detailed below are 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. This will include detailed descriptions of the methods used to determine compliance if appropriate (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.).

Proposed methods for determining compliance forthe new RHT and SG1104 are detailed in the enclosed proposed permit additions to the current permit (CSP 0212-01-C) special conditions. In addition:

- **A site-specific Opacity Monitoring Plan will be created for SG1104 per 40 CFR 60.47c(f) for approval by the agency. The plan will include procedures and criteria to establish and monitor the sulfur content of the distillate fuel to ensure it does not exceed 0.25 wt% based on a rolling 30-day average, Method 9 monitoring, and demonstrate that the distillate fuel complies with the specification under the definition of distillate oil in in § 60.41c.**
- **The Par Fuel Monitoring and Analysis Plan for Hg and HCl emissions compliance required by 40 CFR 63.7521 will updated to includethe distillate fuel used in SG1104.**
- **Par's GHG Monitoring Plan will be updated to include fuel metering of SG1104 and other meters, as required.**

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

The RHT and SG-1104 will not be subject to the CAM rule.

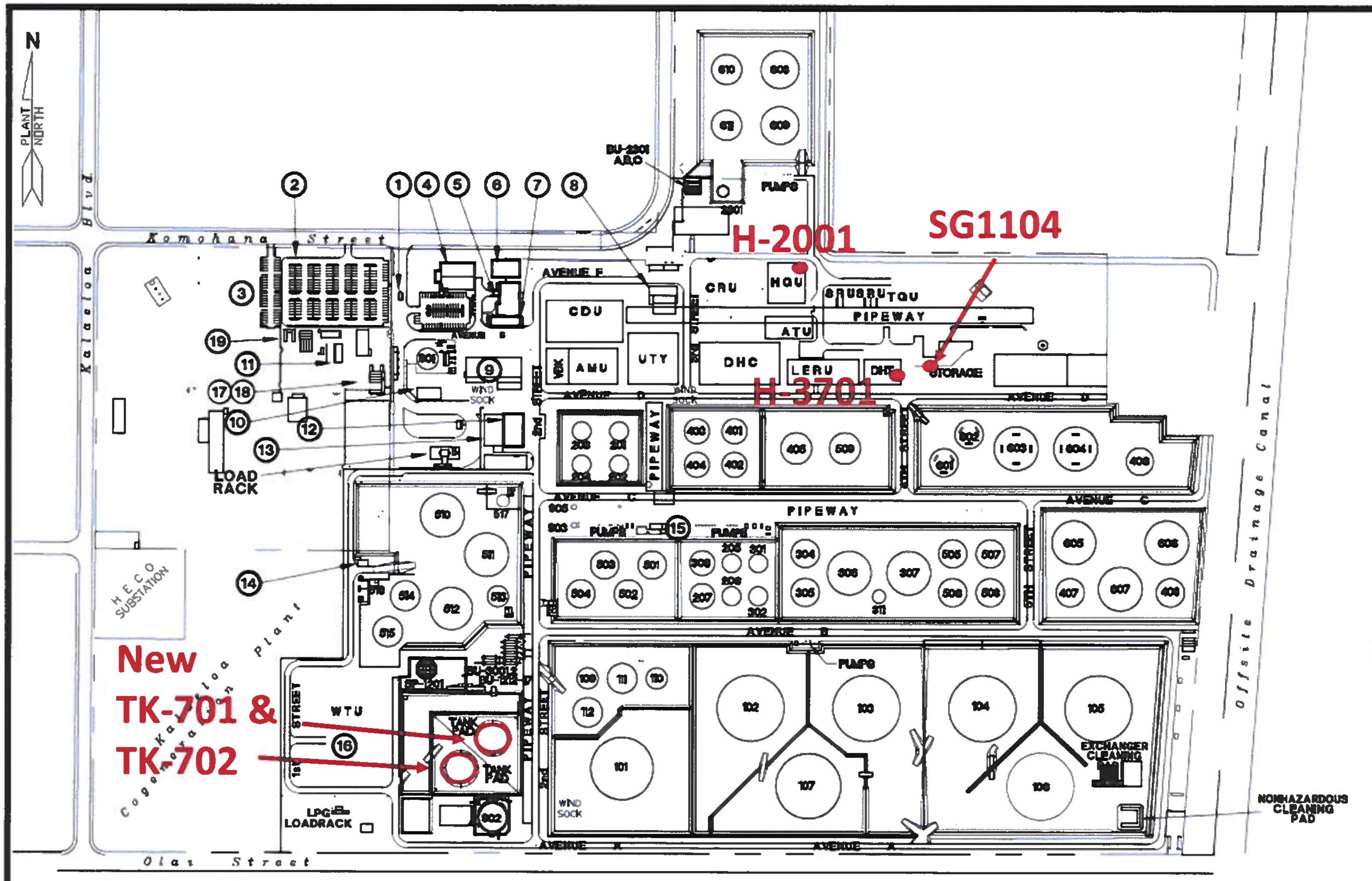
b. If YES, identify the requirements and the provisions being taken to achieve compliance:

c. If NO, describe below which requirements will not be met:

FOR	**AGENCY**	**USE**	**ONLY:**
File/Application No.:			
Island:			
Date Received:			

Appendix A – Location Plots

Renewable Fuel Facility Plot Plan



LEGEND

1. MAIN GATE AND SECURITY GUARD HOUSE
2. MAIN PARKING
3. CONTRACTOR PARKING
4. ADMIN. BLDG.
5. FIRE HOUSE, FIRST AID
6. PROCESS CTRL. HOUSE
7. LAB
8. DCS BUILDING
9. MAINT. BLDG.
10. FAB SHOP
11. MAINT. SHUTDOWN/ PLANNING TRAILER
12. PURCHASING
13. WAREHOUSE
14. FTP CTRL. HOUSE
15. TKF PUMP HOUSE
16. WTU CTRL. HOUSE
17. MAINT. SHUTDOWN TRAILERS
18. I&E SHUTDOWN TRAILERS
19. INSPECTION TRAILERS

3	2/9/10	JMM	GENERAL UPDATE	MJT	
4	2/3/20	HOT	GENERAL UPDATE	MH	
2	11/1/05	JMM	GENERAL UPDATE	JXM	

Par Hawaii Refining
91-325 KOMOHANA STREET
KAPOLEI, HAWAII 96707
TELEPHONE (808) 547-3111

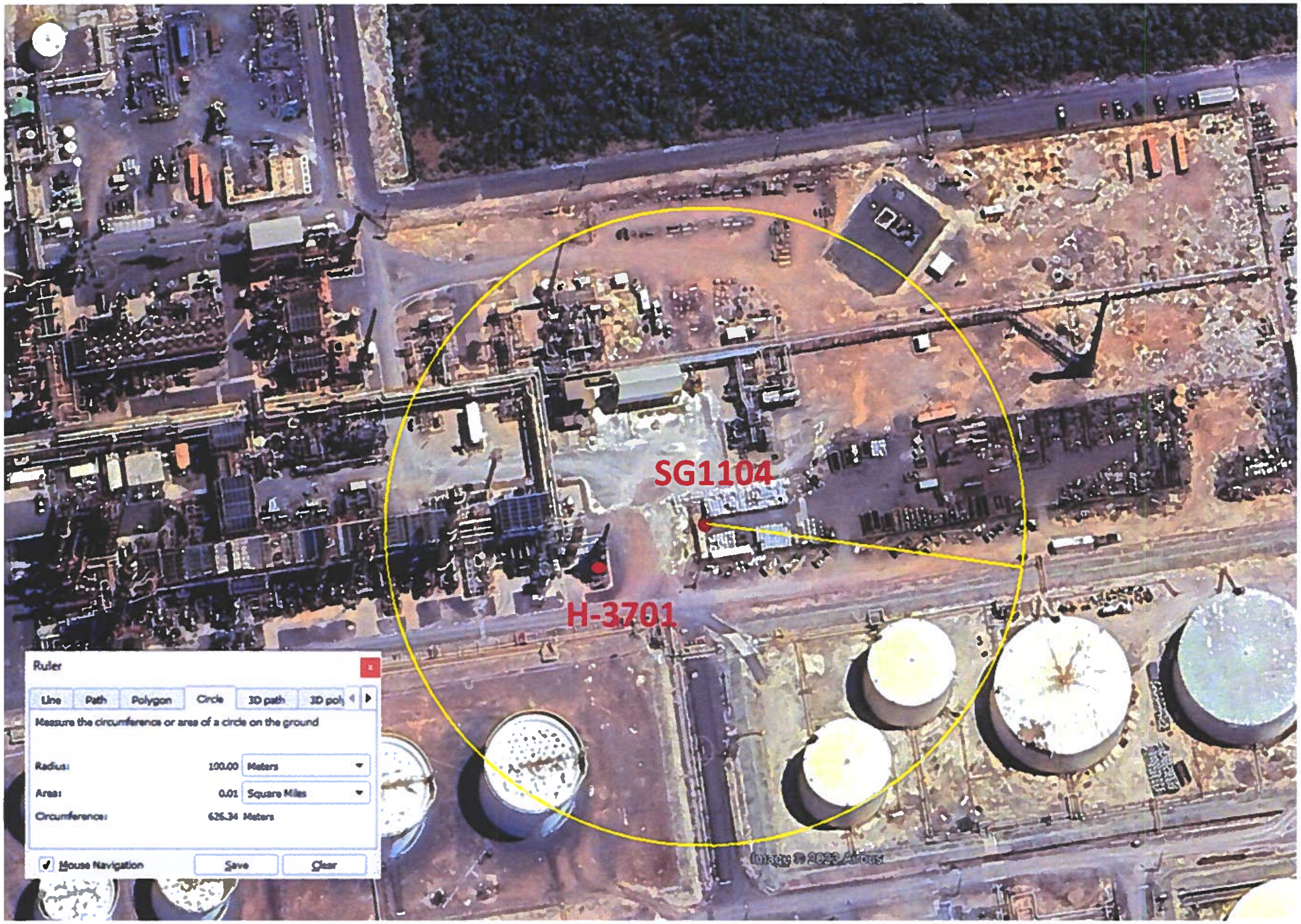
010 – GENERAL
GENERAL ENGINEERING

REFINERY GENERAL MAP

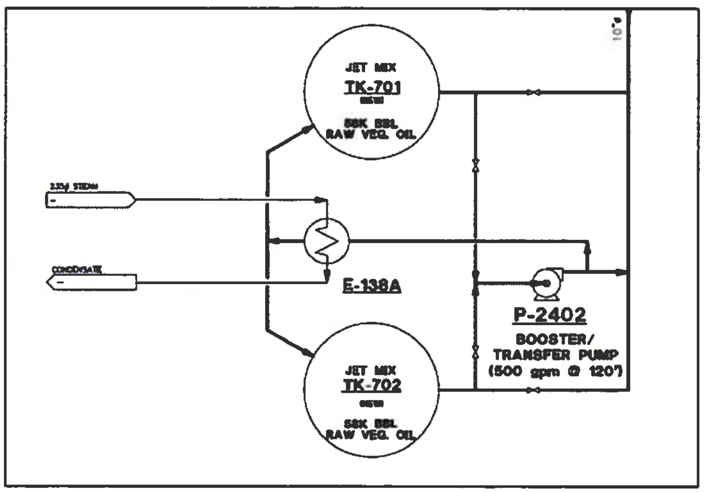
DESIGN JMM
DATE 5/29/98
CHECKED
OPERATIONS
APPROVED

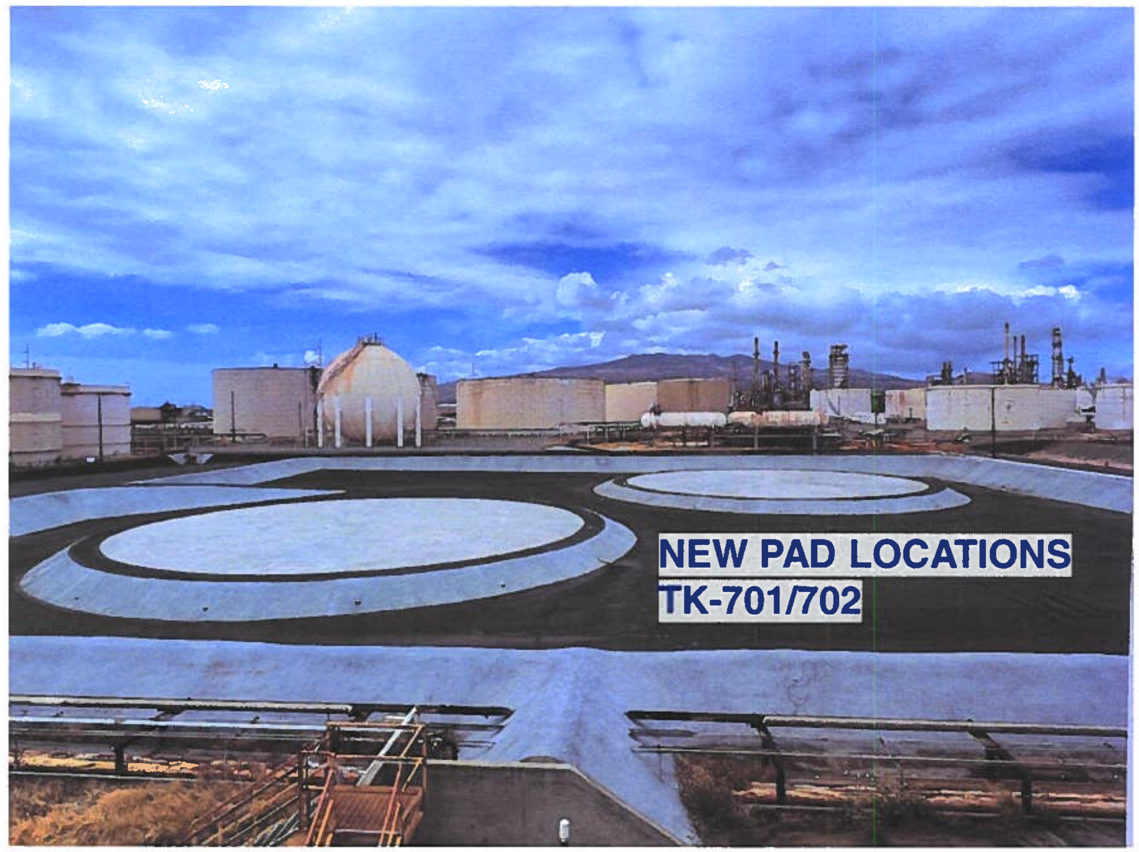
SCALE NONE
PROJECT NO. –
DRAWING NO. A-010-C-57
REV. 4

100 meter radius – Contained within facility fenceline



TK701/702 Pad Locations

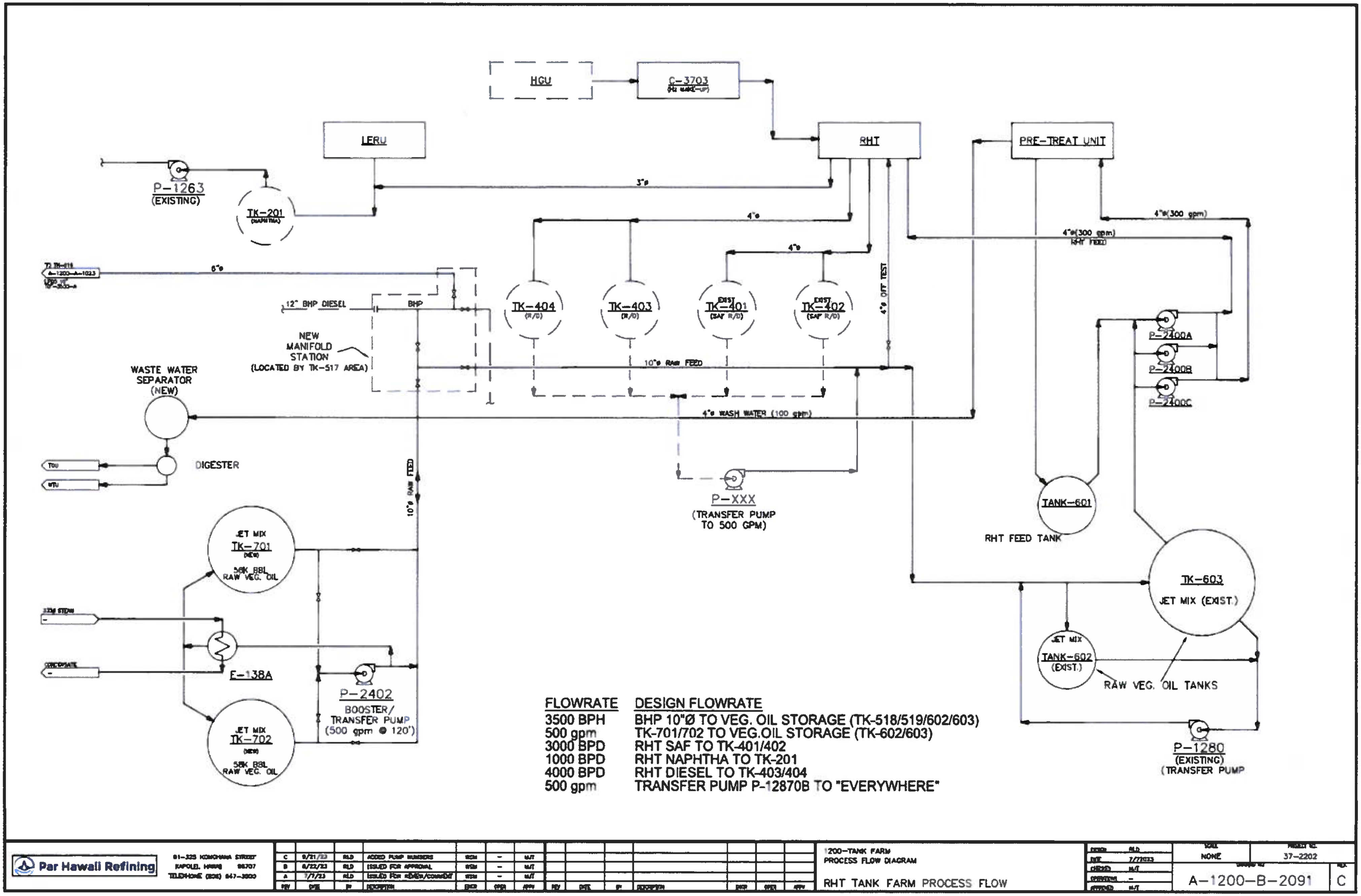


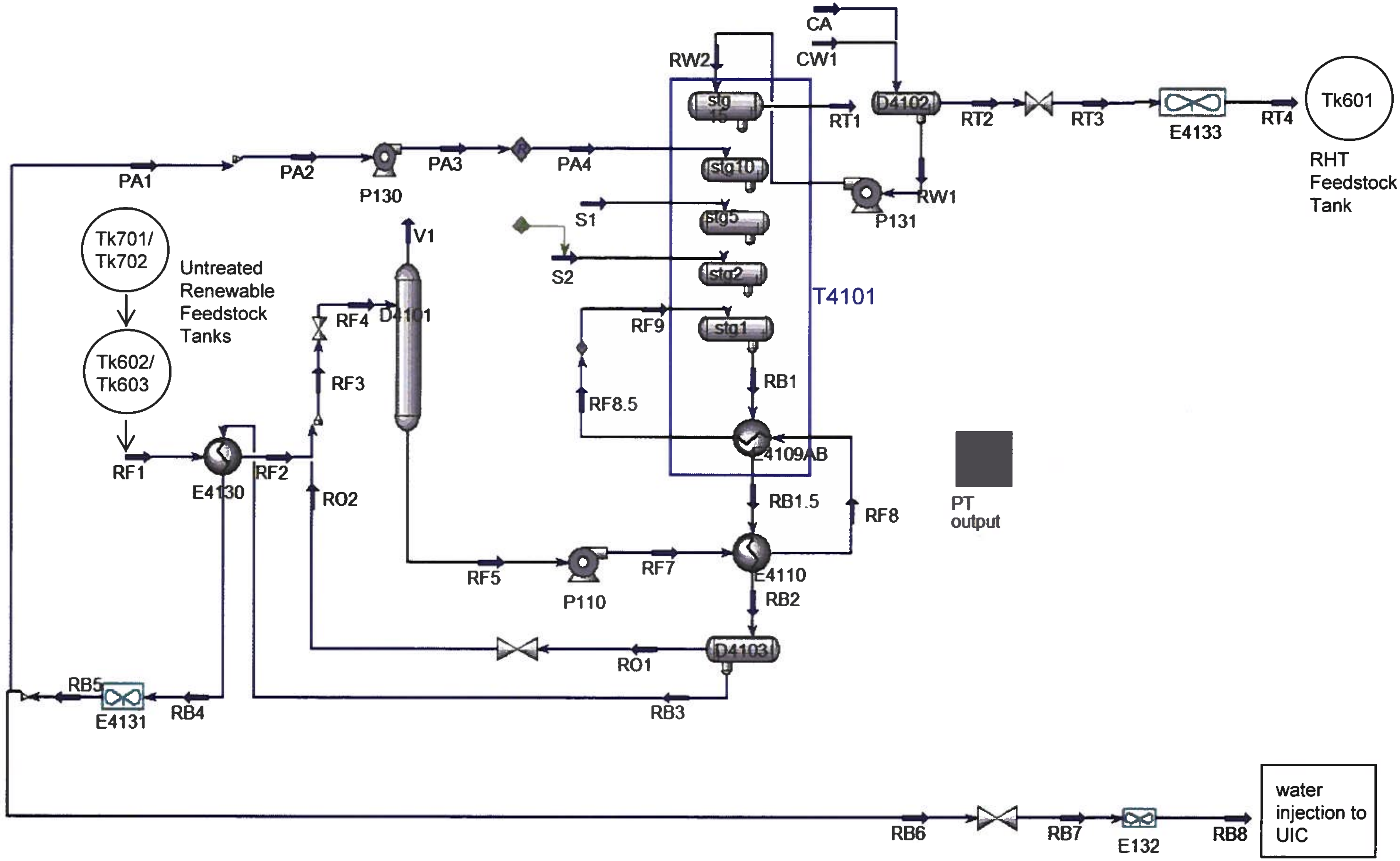


SG1104
Relocated from
Par West

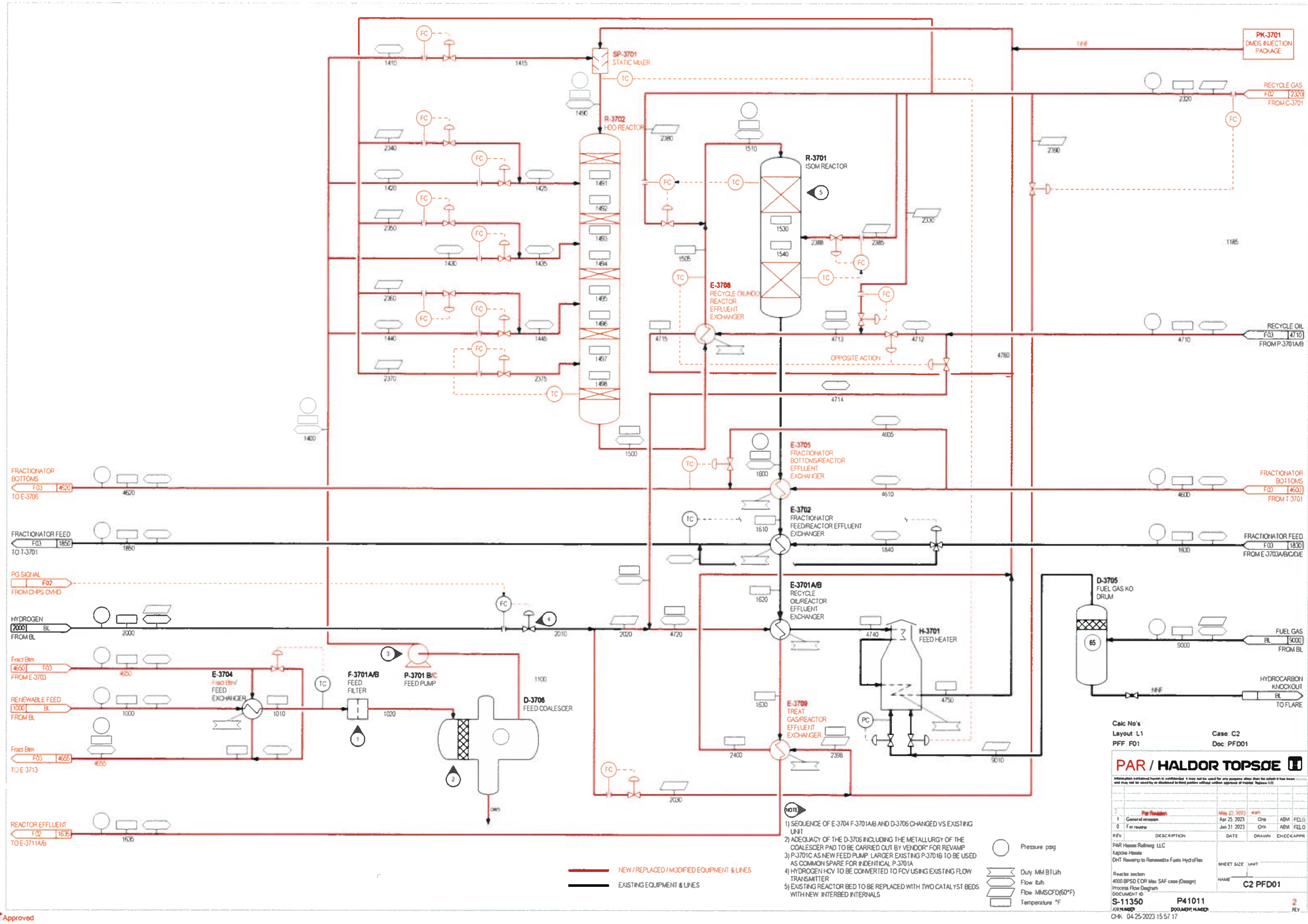
Appendix B – Process Flow Diagrams and Boiler Design

Process Flow Diagram



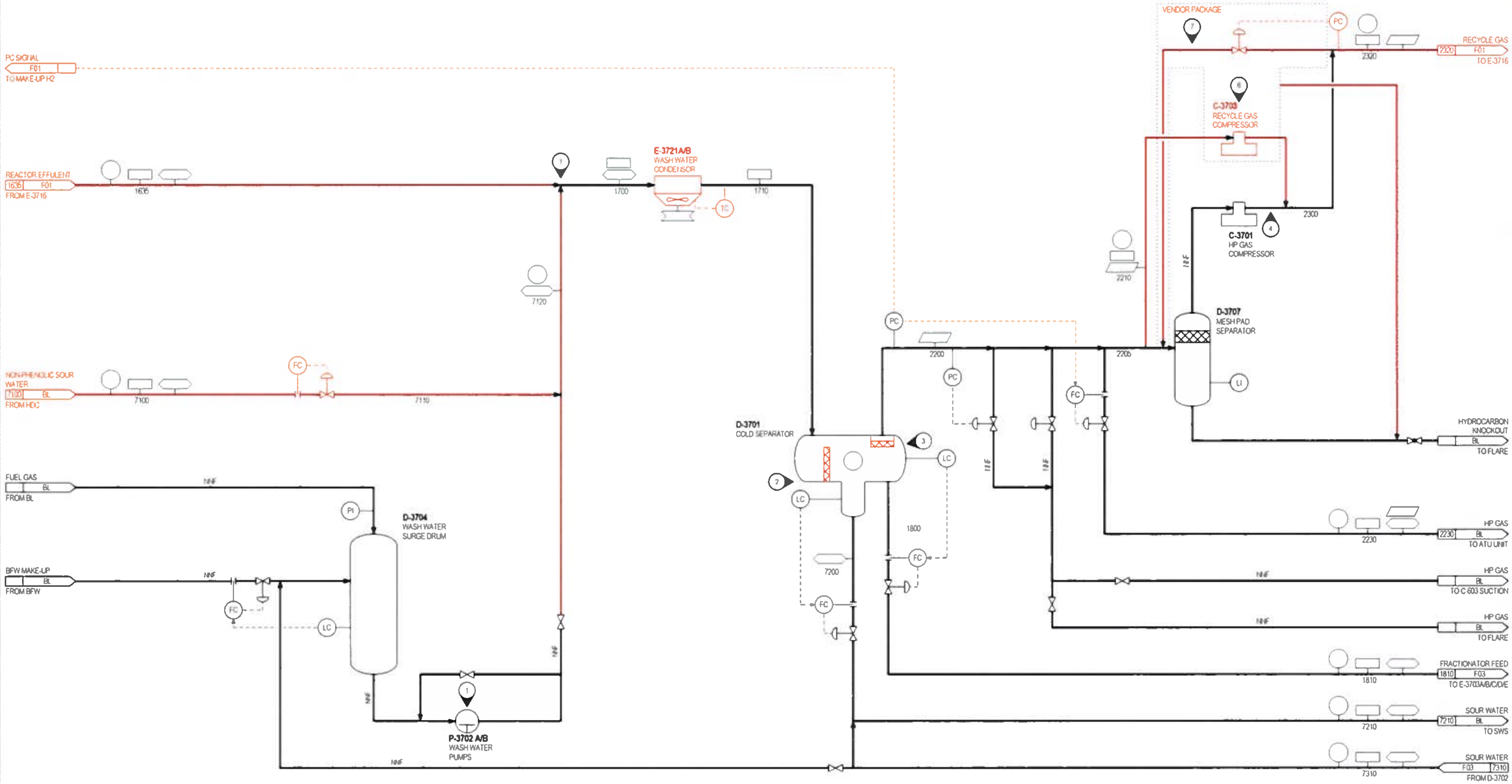


Pretreatment Unit (PTU) Process Flow Diagram



PK-3701
DMDS INJECTION PACKAGE
SP-3701
STATIC MIXER
R-3702
HDO REACTOR
R-3701
ISOM REACTOR
E-3708
RECYCLE OIL/HDO REACTOR EFFLUENT EXCHANGER
RECYCLE GAS
FROM C-3701
RECYCLE OIL
FROM P-3701A/B
OPPOSITE ACTION
E-3705
FRACTIONATOR BOTTOMS/REACTOR EFFLUENT EXCHANGER
FRACTIONATOR BOTTOMS
TO E-3706
FRACTIONATOR BOTTOMS
FROM T-3701
E-3702
FRACTIONATOR FEED/REACTOR EFFLUENT EXCHANGER
FRACTIONATOR FEED
TO T-3701
FRACTIONATOR FEED
FROM E-3703A/B/C/D/E
PG SIGNAL
FROM CHPS OVHD
HYDROGEN
FROM BL
E-3701A/B
RECYCLE OIL/REACTOR EFFLUENT EXCHANGER
D-3705
FUEL GAS KO DRUM
FUEL GAS
FROM BL
HYDROCARBON KNOCKOUT
TO FLARE
H-3701
FEED HEATER
Fract Btm
FROM E-3703
E-3704
Fract Btm/ FEED EXCHANGER
F-3701A/B
FEED FILTER
P-3701 B/C
FEED PUMP
D-3706
FEED COALESCER
RENEWABLE FEED
FROM BL
Fract Btm
TO E-3713
E-3709
TREAT GAS/REACTOR EFFLUENT EXCHANGER
REACTOR EFFLUENT
TO E-3711A/B
Calc No's
Layout L1
PFF F01
Case C2
Doc PFD01
NOTE
1) SEQUENCE OF E-3704 F-3701A/B AND D-3706 CHANGED VS EXISTING UNIT
2) ADEQUACY OF THE D-3706 INCLUDING THE METALLURGY OF THE COALESCER PAD TO BE CARRIED OUT BY VENDOR* FOR REVAMP
3) P-3701C AS NEW FEED PUMP. LARGER EXISTING P-3701B TO BE USED AS COMMON SPARE FOR INDENTICAL P-3701A
4) HYDROGEN HCV TO BE CONVERTED TO FCV USING EXISTING FLOW TRANSMITTER
5) EXISTING REACTOR BED TO BE REPLACED WITH TWO CATALYST BEDS WITH NEW INTERBED INTERNALS
NEW / REPLACED / MODIFIED EQUIPMENT & LINES
EXISTING EQUIPMENT & LINES
Pressure psig
Duty MM BTU/h
Flow lb/h
Flow MMSCFD(60°F)
Temperature °F
PAR / HALDOR TOPSØE
1 General revision Apr 25, 2023 CHK ABM FELO
0 For review Jan 31, 2023 CHK ABM FELO
REV DESCRIPTION DATE DRAWN CHECK APPR
PAR Hawaii Refining LLC
Kapolei Hawaii
DHT Revamp to Renewable Fuels HydroFlex
Reactor section
4000 BPSD EOR Max SAF case (Design)
Process Flow Diagram
C2 PFD01
S-11350
P41011
2
CHK 04-25-2023 15 57 17

Approved



Calc No's
Layout L1
PFF F02

Case C2
Doc PFD02

NEW / REPLACED / MODIFIED EQUIPMENT & LINES

EXISTING EQUIPMENT & LINES

NOTE

1) EXISTING WASH WATER SPRAY NOZZLE TO BE REPLACED WITH NEW SPRAY NOZZLE
2) D-3701 COALESCER TO BE REPLACED POST REVAMP
3) REQUIREMENT OF DEMISTER TO BE FINALIZED POST HAZOP STUDY
4) EXISTING C-3701 HP GAS COMPRESSOR TO REMAIN IN PLACE AS 50% SPARE FOR NEW C-3702 RECYCLE GAS COMPRESSOR
5) NEW WASH WATER PUMP "P-3702 C" WITH SIMILAR CAPACITY TO BE ADDED AS STAND-BY PUMP. TWO PUMPS SHALL BE OPERATING AND ONE STAND-BY
6) THE SUCTION KOD FOR C-3702 SHALL BE DESIGNED AND SUPPLIED BY COMPRESSOR VENDOR
7) THE SPILLBACK LINE, CONTROL AND INSTRUMENTATION FOR BOTH THE C-3701 AND C-3702 COMPRESSORS TO BE DESINGED BY THE COMPRESSOR VENDOR

Pressure psig
Duty MM BTU/h
Flow lb/h
Flow MMSCFD(60°F)
Temperature °F

PAR HALDOR TOPSØE

REV	DESCRIPTION	DATE	DRAWN	CHECK	APPR
2	Par Revision	5/24/23			
1	General revision	Apr 25, 2023	CHK	ABM	FELO
0	For review	Jan 31, 2023	CHK	ABM	FELO

PAR Hawaii Refining LLC
Kapolei Hawaii
DHT Revamp to Renewable Fuels HydroFlex

Separator section
4000 BPSD EOR Max SAF case (Design)
Process Flow Diagram

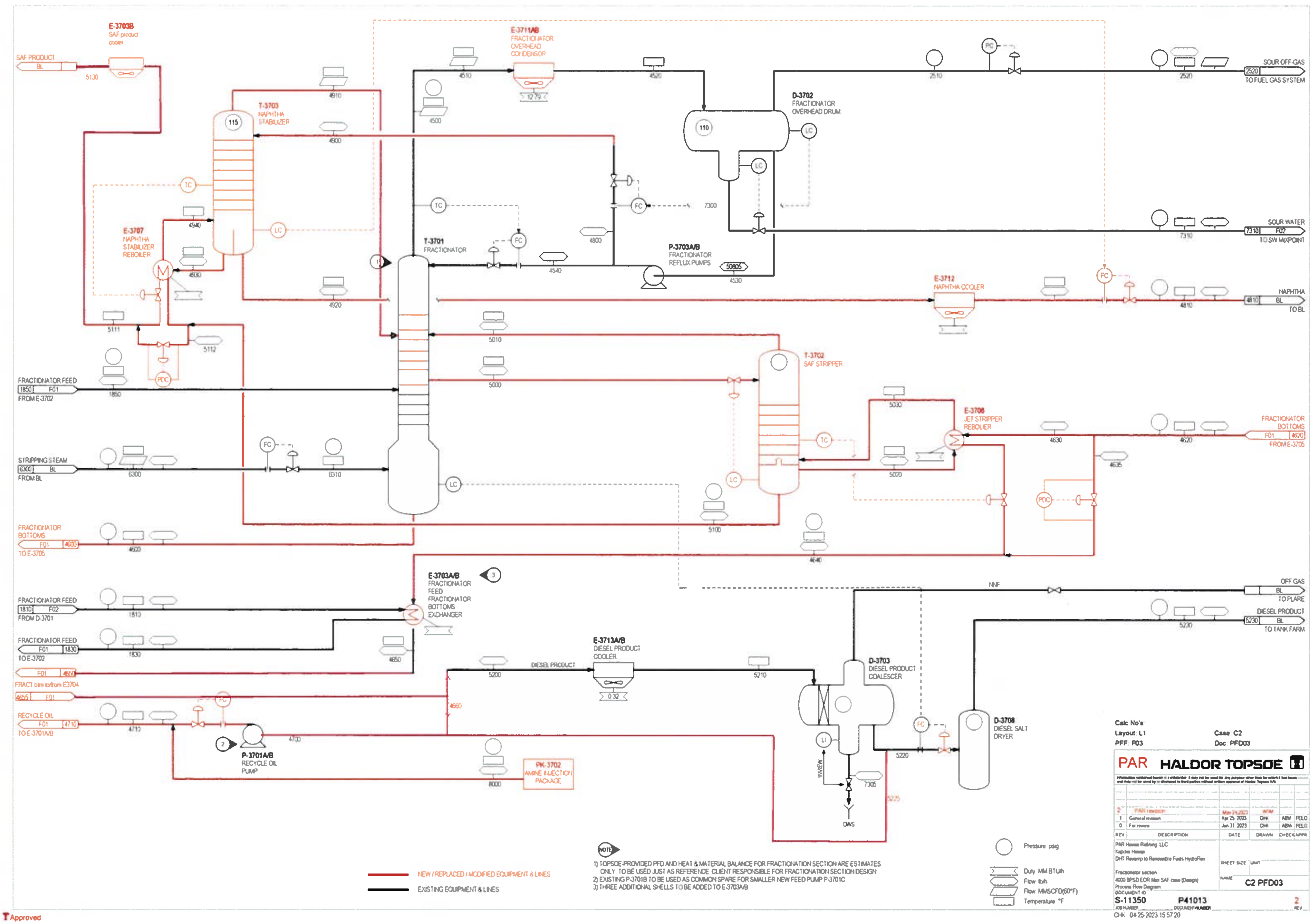
SHEET SIZE UNIT

NAME C2 PFD02

DOCUMENT ID
S-11350 JOB NUMBER
P41012 DOCUMENT NUMBER
2 REV

CHK 04-25-2023 15:57:17

Approved


E-3703B
SAF product cooler
SAF PRODUCT
BL
5130
E-3711A/B
FRACTIONATOR OVERHEAD CONDENSOR
12.79
4510
4520
4500
4910
4900
T-3703
NAPHTHA STABILIZER
115
TC
LC
E-3707
NAPHTHA STABILIZER REBOILER
4940
4930
4920
5111
5112
PDC
D-3702
FRACTIONATOR OVERHEAD DRUM
110
LC
PC
2510
2520
SOUR OFF-GAS
TO FUEL GAS SYSTEM
SOUR WATER
7310
F02
TO SW MIXPOINT
7300
FC
4800
T-3701
FRACTIONATOR
4540
P-3703A/B
FRACTIONATOR REFLUX PUMPS
50805
4530
E-3712
NAPHTHA COOLER
4810
NAPHTHA
TO BL
5010
5000
T-3702
SAF STRIPPER
5030
E-3706
JET STRIPPER REBOILER
4630
4620
4635
FRACTIONATOR BOTTOMS
FROM E-3705
FRACTIONATOR FEED
1850
F01
FROM E-3702
STRIPPING STEAM
6300
FROM BL
6310
5020
5100
4640
FRACTIONATOR BOTTOMS
4600
TO E-3705
E-3703A/B
FRACTIONATOR FEED FRACTIONATOR BOTTOMS EXCHANGER
FRACTIONATOR FEED
1810
FROM D-3701
FRACTIONATOR FEED
1830
TO E-3702
4650
FRACT btm to/from E3704
4655
4660
RECYCLE OIL
4710
TO E-3701A/B
4700
P-3701A/B
RECYCLE OIL PUMP
8000
PK-3702
AMINE INJECTION PACKAGE
5200
DIESEL PRODUCT
E-3713A/B
DIESEL PRODUCT COOLER
0.32
5210
D-3703
DIESEL PRODUCT COALESCER
LI
5220
5225
7305
OWS
D-3708
DIESEL SALT DRYER
NNF
OFF GAS
TO FLARE
DIESEL PRODUCT
5230
TO TANK FARM
NOTE
1) TOPSOE-PROVIDED PFD AND HEAT & MATERIAL BALANCE FOR FRACTIONATION SECTION ARE ESTIMATES ONLY. TO BE USED JUST AS REFERENCE. CLIENT RESPONSIBLE FOR FRACTIONATION SECTION DESIGN
2) EXISTING P-3701B TO BE USED AS COMMON SPARE FOR SMALLER NEW FEED PUMP P-3701C
3) THREE ADDITIONAL SHELLS TO BE ADDED TO E-3703A/B
NEW / REPLACED / MODIFIED EQUIPMENT & LINES
EXISTING EQUIPMENT & LINES
Pressure psig
Duty MM BTU/h
Flow lb/h
Flow MMSCFD(60°F)
Temperature °F
Calc No's
Layout L1
PFF F03
Case C2
Doc PFD03
PAR
HALDOR TOPSOE
1 General revision Apr 25 2023 CHA ABN FELO
0 For review Jan 31 2023 CHA ABN FELO
REV DESCRIPTION DATE DRAWN CHECK APPR
PAR Hawaii Refining LLC
Kapolei Hawaii
DHT Revamp to Renewable Fuels HydroFlex
Fractionator section
4000 BPSD EOR Max SAF case (Design)
Process Flow Diagram
C2 PFD03
S-11350
P41013
2
CHK 04-25-2023 15:57:20
Approved

	DESIGN AND FABRICATION OF STEAM GENERATORS	U-2M9S1
	DATA SHEET	PAGE 1 OF 9

Facility Name/Location: Chevron Hawaii
Item Name: Boiler #5 and Boiler #6 — Purchaser Project Number: ____
Item Tag Number: F-5205 and F-5206 — Purchase Order Number: ____
Supplier: FOSTER WHEELER — Supplier Project Number: 410-118786-01

GENERAL

Number of Units Required TWO (2)
Service: ☒ Power Boiler ☐ CO Boiler ☐ Other: ____ Type Operation: ☒ Continuous ☐ Intermittent
Type: ☒ Shop Assembled Package Boiler ☐ Field Erected Style: ☒ 'D' ☐ Cross Drum
MCR Steam Capacity: pph/Boiler 75,000 Steam Press, psig 600 Steam Temp, °F 625
☐ Peak Rating Required, pph ____ Hr/day ____ Hr/yr ____ Min Design Metal Temp, °F 10
Supply: ☒ Material and Shop Fabrication ☒ Delivery to Site ☐ Site Installation/Erection

SYSTEM REQUIREMENTS

Superheater:
☒ Drainable SH ☒ Attemperator/Desuperheater, Type: ☒ Spray ☐ SH Bypass Mixing ☐ Steam Drum Surface
Superheater Vent Design Flow Rate: >20 %MCR Flow at ~~50~~ 100% Normal Oper Press ☒ Vent Silencer
Superheater Tube/Header Material: ☐ CS/CS ☒ T11/P11 ☐ T12/P12 ☒ Other Seamless
Evaporator:
☒ Natural Circulation ☐ Forced/Assisted Circulation
Boiler Blowdown (BD), % BFW 2-5 ☐ Manual BD Control By ____ ☒ Auto BD Control By Cond.
Economizer:
☐ Bare Tube Economizer ☒ Fintube Economizer ☒ Sootblower Required
Fans:
Qty of fans: Forced Draft ONE/UNIT Induced Draft ____ FGR Induced Other ____
☒ General Purpose Fans ☐ Special Purpose Fans (API 673) ☒ Fans Shop Performance Tested
Fan Drives: ☒ Motor for FD FAN Note 1-2 ☐ Steam Turbines for ____
Air Preheater:
☐ APH Required Type: ☐ Regenerative ☐ Recuperative ☐ Cold Air Bypass ☐ Steam Preheater
Boiler Instruments/Controls:
Drum Level Control: ☒ 3-Element ☐ 2-Element
Supply: ☒ All Insts and Controls ☐ Wetted Insts Only ☒ Non-Return/Stop Valve ☒ BFW Control/NR Valves
Burner System:
No. of Burners ONE Minimum Turndown Ratio: Note 1-3 :1 ☒ NFPA BMS by others
Burner Type: ☐ Mfr Std ☒ LoNO_x ☐ Ultra-LoNO_x ☒ Flue Gas Recirculation ☐ Internal ☒ External
Emission Monitoring/Control:
☒ EPA Stack Sampling Connections ☒ Extractive Flue Gas Sampling Connection
☐ Continuous Emission Monitors (CEM), Model ____ Mfr ____
Mfr to Supply Analyzer For: ☐ NO_x ☐ CO ☒ O_2 ☒ Combustibles ☐ Particulates
☐ Selective Catalytic Recovery (SCR) System
Stack Height, ft 82 Minimum Stack Exit Velocity, fps 7.29 (FRG at min fire)

FOSTER WHEELER LIMITED
CERTIFIED FOR CONSTRUCTION
DATE April 12/10 BY [signature]

No.	Date	Revision	By	Apvd
2	3.28.07	Client comments added	LL	
1	3.7.07	FWL first issue	LL	
0	6.28.06	Issue For Purchase	RHW	MCW

BOILER FEEDWATER

☐ Boiler Feedwater Corrosive To Copper Alloys

Boiler Feedwater Characteristics			Ion Constituents			Drum Water Chemical Treatment
'M' Alkalinity		SEE	Chloride,	ppm_w		☐ Chelants
'P' Alkalinity		PROCESS	Silica,	ppm_w		☐ Phosphate
pH		DESIGN	Phosphate,	ppm_w		☐ Coordinated Phosphate
Turbidity	NTU	BASIS	Sulfate,	ppm_w		☐ Congruent Phosphate
Tds	ppm_w		Sulfite,	ppm_w		☐ Sodium Sulfite
Hardness	ppm_w		Iron,	ppm_w		☐ Hydrazine or Equivalent

CO BOILER PROCESS GAS DATA

Flow Rate (Wet), pph ______ Entrained Catalyst/Coke, Tons/Day ______

		Normal	Maximum	Minimum	Composition:
Temperature: °F:					(See Fuel Data, Page 3)
Pressure, psig:					

UTILITY DATA FOR AUXILIARY EQUIPMENT AND INSTRUMENTS

Economic Evaluation Factor: $/$10^6$ Btu/hr (HHV) ______

Steam Data For Turbine Drivers:

Inlet Pressure, psig ______ Inlet Temperature, °F ______ Exhaust Pressure, psig ______

Steam Data For Soot blowers:

Inlet Pressure, psig 600 Inlet Temperature, °F 625

Air Data:

Instrument Pressure, psig: 60

Pneumatic Drives (If Used For Emergency Drive, Such As Air Preheater Drive) Pressure, psig: ______

Electrical Data:

	Motors	Lights
Volts:	460	120
Cycles:	60	60
Phase:	3	1

Type Enclosure: TEFC, CL1, Div 2, Grps B, C and D (both motors and lights)

Cooling Water Data:

Supply Temperature, °F 80 Max Return Temperature, °F 110

Max. Allowable Δ p, psi 20 Supply Press., psig ~~150~~ 80

SUPPLEMENTARY INFORMATION

NOTE 1-2. FANS TO BE PER API 560

NOTE 1-3. TURNDOWN SHOULD BE 10:1 FOR REFINERY FUEL GAS, 8:1 FOR FUEL OIL

FUEL

Combustion Type: ☐ Gas ☐ Oil ☒ Combination ☒ Other DUAL FUEL–RFG & LSFO

Fuel Type	Gas	Fuel Type	Oil
Description	REF. FUEL	Description	FUEL OIL
Molecular Weight	SEE	H/C Ratio (wt)	SEE
Pressure (Available), psig	PROCESS	Pressure (Available), psig	PROCESS
Temperature, °F	DESIGN	Temperature, °F	DESIGN
Specific Gravity (Ref 60 °F Dry Air)	BASIS	API Gravity (60°/60°)	BASIS
Density (at Press/Temp), lb/ft^3		Density (at Press/Temp), lb/ft^3	
Chemical Heat Content (HHV), Btu/scf		Chemical Heat Content (HHV), Btu/lb	
Chemical Heat Content (LHV), Btu/scf		Chemical Heat Content (LHV), Btu/lb	
		Viscosity at °F ______	
Composition		at °F ________	
Hydrogen (H_2), %		Conradson Carbon No.	
Methane (C1), %		Atomizing Media	
Ethane (C2), %			
Ethylene (C2e), %		**Constituent Analysis**	
Propane (C3), %		Fixed Nitrogen (N), ppm	
Propylene (C3e), %		Vanadium (V), ppm	
Butane (C4), %		Nickel (Ni), ppm	
Pentane (C5), %		Sodium (Na), ppm	
Hexane (C6), %		Potassium (K), ppm	
Nitrogen (N_2), %		Sulfur (S), % wt	
Water (H_2O), %		Water (H_2O), % wt	
Carbon Monoxide (CO), %		Solid Carbon (C), % wt	
Carbonyl Sulfide (COS), %		Total Ash (), % wt	
Carbon Dioxide (CO_2), %			
Hydrogen Sulfide (H_2S), %		**Ultimate Analysis (Dry)**	
Sulfur (S), %		Hydrogen (H), % wt	
Sulfur Dioxide (SO_2), %		Carbon (C), % wt	
Ammonia (NH_3), %		Sulfur (S), % wt	
______________		Nitrogen (N), % wt	
______________		Oxygen (O), % wt	
		______________	

1	**MANUFACTURER PREDICTED PERFORMANCE DATA**					
2	**Section Data:** Note: Complete For Each Performance Analysis	Boiler Output % MCR 100 (RFG)				
3	**Steam Generator Section Water Side**	NRV	SH	Evap	Econ	BFW CV
4	Flow Rate (at Section Outlet), pph	75,000	71,703	75,000	76,531	76,531
5	Pressure (Outlet), psig	600	635	688	693	800
6	Pressure (Inlet), psig	620	688	688	713	720
7	Temperature (Outlet), °F	625	675	504	383	250
8	Temperature (Inlet), °F	625	504	504	250	250
9	Enthalpy (Outlet), Btu/hr (x10^6)	97.77	97.77	90.17	27.36	16.83
10	Enthalpy (Inlet), Btu/hr (x10^6)	97.77	90.17	27.36	16.83	16.83
11	Design Pressure, psig	745	745	745	745	745
12	Design Temperature, °F	650	843	604	408	250
13	Specific Heat (Avg), Btu/lb-°F	0.641	0.793	0.981	1.032	1.011
14	Fouling Factor, hr-ft^2-°F/Btu		0.054	0.079		
15	**Mechanical**					
16	Heating Service, ft^2		431	3,053	6771	
17	Tube Type (ERW/Seamless)		Seamless	Seamless	Seamless	
18	Tube (Diameter X Min Thickness), in. x in.		1.5x0.150	2x.135	2 x 0.150	
19	Tube Length, ft		15.23	9	12	
20	Tube Material (ATSM No.)		SA213-T11	SA-192	SA-192	
21	Tube Spacing (CL to CL) in.		~ 4.0	3.5	4.5	
22	Tube Pitch, (CL to CL) in.		2.5	3.5	4.5	
23	Type Arrangement (Square, Triangular)		square	square	square	
24	Number of Tubes Transverse to Flow No.		6	11	12	
25	Number of Tubes In Direction of Flow No.		12	47	17	
26	Fins (No./Height/Thickness) (No./in./in.)		N/A	N/A	2/.75/.105	
27	Fin Material (ASTM No.)		N/A	N/A	CS	
28	Weight (Hydro), lb		See Evap	228,000	35,000	
29	Weight (Shipping), lb		See Evap	180,000	32,000	
30	Weight (Operating), lb		See Evap	212,000	35,000	
31	Fill Volume (Hydro), gal		79	5762	380	
32	Fill Volume (Operating), gal		N/A	4910	380	
33						
34	**Steam Generator Section Gas Side**	Furnace	SH	BO Bank	Econ	Stack
35	Flow Rate, pph	95,229	95,229	95,229	95,229	85,025
36	Pressure (Outlet), in. H_2O	3.63	3.06	1.68	0.67	0
37	Pressure (Inlet), in. H_2O	10.05	3.63	3.06	1.68	0.67
38	Temperature (Outlet), °F	2070	1666	757	350	350
39	Temperature (Inlet), °F	N/A	1995	1666	757	350
40	Enthalpy (Outlet), Btu/hr	590	457	182	70	70
41	Enthalpy (Inlet), Btu/hr	943	566	457	182	70
42	Design Pressure, in. H_2O	30	25	25	25	0.76
43	Design Temperature, °F	N/A	N/A	N/A	750	750
44	Specific Heat (Avg.), Btu/hr-°F	0.33	0.323	0.297	0.277	0.267
45	Fouling Factor, hr-ft^2-°F /Btu				0.001	N/A
46	Gas Velocity (Outlet), fps	115	69.53	50.7	26.94	70.4

	DESIGN AND FABRICATION OF STEAM GENERATORS DATA SHEET	U-2M9S1 PAGE 5 OF 9

MANUFACTURER PREDICTED PERFORMANCE DATA (CONT)

General Physical Data		Supplemental Data
Total Furnace Volume, ft^3	1602	
Total Projected Radiant Surface, ft^2	1100	
Effective Projected Radiant Surface, ft^2	829	
Cross-sectional Furnace Area, ft^2	79.6	
Steam Drum/Mud Drum Separation (CL-CL), ft	12.5	
Steam Drum ID, in.	48	
Steam Drum Length (head weld to head weld), ft	22.66	
Steam Drum Vol. Between Norm & Min Oper Level ft^3	20	
Steam Drum Thickness, In.	2.625	
Steam Drum Corrosion Allowance, in.	0.125	
Steam Drum Material, ASTM No.	SA-516 GR 70	
Mud Drum ID, In.	24	
Mud Drum Length (head weld to head weld), ft	22.66	
Mud Drum Thickness, in.	1.375	
Mud Drum Corrosion Allowance, in.	0.125	
Mud Drum Material, ASTM No.	SA-516 GR 70	
Stack Exit Height Above Grade, ft	82	
Stack Exit Velocity, fps	70.4	
Stack Diameter Bottom/Top, in./in.	36/36	
Stack Material/Thickness, ASTM No./in.	A36/0.3125	
Stack Internal Coating Insul/Thick, Type/in.	N/A	
Stack External Coating-Insul/Thick, Type/in.	Inorganic Zinc	
Design Pressure, In. H_2O	0.76	
Design Temperature, °F	750	
Specific Heat (Avg.), Btu/hr-°F		
Fouling Factor, hr-ft^2°F/Btu		
Gas Velocity (Outlet), fps		

MANUFACTURER PREDICTED PERFORMANCE DATA (CONT)

	Performance Data (RFG)				
Boiler Output	Peak N/A	MCR	75% MCR	50% MCR	10% MCR
Boiler Efficiency (HHV), %		84.22	85.02	85.55	86.52
Radiation (Setting Losses), %		0.594	0.750	1.157	5.70
Mfr Margin, %		1.00	1.00	1.00	1.00
Steam Purity (TDS), ppm_w		1.00	1.00	1.00	1.00
Sulfur Dew Point, °F					
Circulation Ratio, Maximum	:1	:1	:1	:1	:1
Circulation Ratio, Average	:1	:1	:1	:1	:1
Circulation Ratio, Minimum	:1	:1	:1	:1	:1
Boiler Blowdown, %		2.00	2.00	2.00	2.00
Fuel Gas Consumption, pph		5001	3715	2462	486
Fuel Gas Chemical Heat, Btu/lb		19393	19393	19393	19393
Fuel Gas Sensible Heat, Btu/hr					
Fuel Oil Consumption, pph					
Fuel Oil Chemical Heat, Btu/hr					
Fuel Oil Sensible Heat, Btu/hr					
Alternate Fuel Consumption, pph					
Alternate Fuel Chemical Heat, Btu/hr					
Alternate Fuel Sensible Heat, Btu/hr					
Total Combustion Air, pph		80024	59440	39396	9467
Excess Air, %		15	15	15	40
O_2 In Flue Gas (Wet), % Vol		2.46	2.46	2.46	5.47
O_2 In Flue Gas (Dry), % Vol		2.92	2.92	2.92	6.31
Combustion Air Sensible Heat, Btu/hr					
Heat Available To Furnace (Total), MBtu/hr		96.98	72.04	47.74	9.42
Heat Available To Furnace, Volume, Btu/ft^3		60,536	44,968	29,800	5,883
Heat Available To Proj. Rad. Surf., Btu/ft^2		88,164	65,494	43,402	8,568
Heat Available To EPRS, Btu/ft^2		116,984	86,904	57,591	11,369
Heat Available To X-Sectional Area $MBtu/ft^2$		1.218	0.905	0.599	0.118
Flue Gas [FGR] Recirculation Flow, pph		10,203	7,579	5,022	1,194
FGR Pressure at Fan Inlet, in. H_2O		0.67	0.37	0.16	0.1
FGR Temperature at Burner, °F		350	318	297	258
FGR Sensible Heat, Btu/hr		70	58	56	44

	DESIGN AND FABRICATION OF STEAM GENERATORS **DATA SHEET**

UTILITIES REQUIRED BY AUXILIARY EQUIPMENT

	Electrical				Steam			Air		Cooling
	Qty Units	Bhp Each	Volts/ Phase	kW Total	Qty Units	Bhp Each	Total Consump (Mlb/hr)	Instr (scfm)	Other (scfm)	Water (gpm)
FD Fan Dr	2	125	460/3	93						
ID Fan Dr										
APH Dr										
FGR Fan Dr										
Other (List)										
______										
______										
______										
______										
Lighting		-			-	-	-	-	-	-
Totals										

Notes:

	DESIGN AND FABRICATION OF STEAM GENERATORS DATA SHEET	U-2M9S1 PAGE 8 OF 9

MANUFACTURER PREDICTED PERFORMANCE DATA (CONT)

	Performance Data (LSFO)				
Boiler Output	Peak N/A	MCR	75% MCR	50% MCR	12.5% MCR
Boiler Efficiency (HHV), %		86.18	86.9	86.98	88.43
Radiation (Setting Losses), %		0.594	0.750	1.157	4.5
Mfr Margin, %		1.00	1.00	1.00	1.00
Steam Purity (TDS), ppm_w		1.00	1.00	1.00	1.00
Sulfur Dew Point, °F (5% conversion)		280	280	280	267
Circulation Ratio, Maximum	:1	:1	:1	:1	:1
Circulation Ratio, Average	:1	:1	:1	:1	:1
Circulation Ratio, Minimum	:1	:1	:1	:1	:1
Boiler Blowdown, %		2.00	2.00	2.00	2.00
Fuel Gas Consumption, pph					
Fuel Gas Chemical Heat, Btu/hr					
Fuel Gas Sensible Heat, Btu/hr					
Fuel Oil Consumption, pph		5063	3765	2508	617
Fuel Oil Chemical Heat, Btu/lb		18,720	18,720	18,720	18,720
Fuel Oil Sensible Heat, Btu/hr					
Alternate Fuel Consumption, pph					
Alternate Fuel Chemical Heat, Btu/hr					
Alternate Fuel Sensible Heat, Btu/hr					
Total Combustion Air, pph		83,082	61,783	41,162	13,628
Excess Air, %		15	15	15	55
O_2 In Flue Gas (Wet), % Vol		2.54	2.54	2.54	6.95
O_2 In Flue Gas (Dry), % Vol		2.87	2.87	2.87	7.71
Combustion Air Sensible Heat, Btu/hr					
Heat Available To Furnace (Total), MBtu/hr		94.74	70.48	46.95	11.55
Heat Available To Furnace, Volume, Btu/ft^3		59,160	43,995	29,310	7,209
Heat Available To Proj. Rad. Surf., Btu/ft^2		88,886	64,073	42,686	10,500
Heat Available To EPRS, Btu/ft^2		114,324	85,019	56,640	13,932
Heat Available To X-Sectional Area $MBtu/ft^2$		1.19	0.885	0.589	0.145
Flue Gas [FGR] Recirculation Flow, pph		10,577	7865	5240	2,743
FGR Pressure at Fan Inlet, in. H_2O		0.72	0.39	0.18	0.02
FGR Temperature at Burner, °F		349	320	298	259
FGR Sensible Heat, Btu/hr		68	57	55	33

	DESIGN AND FABRICATION OF STEAM GENERATORS DATA SHEET	U-2M9S1 PAGE 9 OF 9

MANUFACTURER PREDICTED PERFORMANCE DATA (CONT)

	Performance Data (LCO)				
Boiler Output	Peak N/A	MCR	75% MCR	50% MCR	12.5% MCR
Boiler Efficiency (HHV), %		85.46	86.11	86.68	87.71
Radiation (Setting Losses), %		0.594	0.750	1.157	4.5
Mfr Margin, %		1.00	1.00	1.00	1.00
Steam Purity (TDS), ppm_w		1.00	1.00	1.00	1.00
Sulfur Dew Point, °F (5% conversion)		260	260	260	245
Circulation Ratio, Maximum	:1	:1	:1	:1	:1
Circulation Ratio, Average	:1	:1	:1	:1	:1
Circulation Ratio, Minimum	:1	:1	:1	:1	:1
Boiler Blowdown, %		2.00	2.00	2.00	2.00
Fuel Gas Consumption, pph					
Fuel Gas Chemical Heat, Btu/hr					
Fuel Gas Sensible Heat, Btu/hr					
Fuel Oil Consumption, pph		5,054	3761	2491	615
Fuel Oil Chemical Heat, Btu/lb		18,909	18,909	18,909	18,909
Fuel Oil Sensible Heat, Btu/hr					
Alternate Fuel Consumption, pph					
Alternate Fuel Chemical Heat, Btu/hr					
Alternate Fuel Sensible Heat, Btu/hr					
Total Combustion Air, pph		85,210	63,373	41,980	13,911
Excess Air, %		15	15	15	55
O_2 In Flue Gas (Wet), % Vol		2.53	2.53	2.53	6.91
O_2 In Flue Gas (Dry), % Vol		2.88	2.88	2.88	7.73
Combustion Air Sensible Heat, Btu/hr					
Heat Available To Furnace (Total), MBtu/hr		95.58	71.12	47.10	11.63
Heat Available To Furnace, Volume, Btu/ft^3		59,664	44,392	29,402	7,259
Heat Available To Proj. Rad. Surf., Btu/ft^2		86,893	64,651	42,820	10,571
Heat Available To EPRS, Btu/ft^2		115,298	85,786	56,818	14,028
Heat Available To X-Sectional Area MBtu/ft^2		1.201	0.893	0.592	0.146
Flue Gas [FGR] Recirculation Flow, pph		12	12	12	12
FGR Pressure at Fan Inlet, in. H_2O		0.75	0.42	0.18	0.02
FGR Temperature at Burner, °F		348	322	299	259
FGR Sensible Heat, Btu/hr		68	57	55	33

Appendix C – Potential-To-Emit Estimate

Table C-1: Applicability Demonstration	**New Sources (PTE)**				**Existing Sources (PTE - Baseline)**					**PSD Major Mod Det.**			**Sig Permit Modification Det.**			
	Relocated Boiler (SG1104) TPY	New Tanks (TK701 & TK702) TPY (Zero Increase; See Letter))	New CO2 byproduct stream TPY (Biogenic)	New Fugitive Components TPY	Exising DHT Heater H-3701 TPY	Current Tanks TPY (Zero Increase; See Text))	HGU LPG Feed TPY (Biogenic Portion)	Increase in HGU LPG Feed TPY (Non-Biogenic Portion)	Existing HGU Heater H-2001 TPY	Proposed PTE - Baseline Actual TPY	PSD Triggered?	Significance Level TPY	Increase in H-3701 PTE TPY	Proposed Project PTE - Current PTE TPY	Sig Mod?	Threshold TPY
Criteria Air Pollutants (CAPS)																
CO	26.60				5.96				22.97	55.53	N	100	1.88	28.47	Y	25
Hydrogen sulfide	0.01				0.00				0.02	0.03	N	10	0.00	0.02	N	2.5
NH3	0.76				0.13				0.48	1.37			0.04	0.80	N	2
Lead	6.05E-04				3.07E-05				1.18E-04	0.0008	N	0.6	0.0000	0.0006	N	0.15
NOx	19.25				2.58				13.97	35.79	N	40	0.81	20.06	Y	10
SO2	16.52				0.72				2.77	20.01	N	40	0.23	16.75	Y	10
VOC	0.84			0.76	0.22				0.83	2.65	N	40	0.07	1.67	N	10
Particulate Matter:																
Total (Filterable + Condensable)	2.71				0.30				1.15	4.16	N	25	0.09	2.80	N	6.25
Filterable	1.92				0.07				0.29	2.28			0.02	1.94		
Condensable	2.44				0.22				0.86	3.53			0.07	2.51		
PM10 (Filterable + Condensable)	2.71				0.30				1.15	4.16	N	15	0.09	2.80	N	3.75
PM10 (Filterable)	1.92				0.07				0.29	2.28			0.02	1.94		
PM2.5 (Filterable + Condensable)	2.71				0.30				1.15	4.16	N	10	0.09	2.80	Y	2.5
PM2.5 (Filterable)	1.92				0.07				0.29	2.28			0.02	1.94		
PSD-Specific Categories																
Fluorides	1.48E-02									0.01	N	3		0.01	N	0.75
Sulfuric Acid Mist	1.16E-01				3.29E-02				1.27E-01	0.28	N	7	0.01	0.13	N	1.75
Total Reduced Sulfur	4.20E-02				1.19E-02				4.60E-02	0.10	N	10	0.00	0.05	N	2.5
Greenhouse Gases (GHGs)																
Total GHG (CO2e):	37,048		1,325		7,950		24,513	12,256	30,665	113,757	Y	75,000	2,504	40,877	Y	10,000
Individual Components:																
Carbon Dioxide	36,894		1,325		7,915		24,513	12,256	30,530	113,433			2,493	40,712		
Methane	1.82E+00				4.13E-01				1.59E+00	3.83			0.13	1.95		
Nitrous Oxide	3.64E-01				8.26E-02				3.19E-01	0.77			0.03	0.39		
Hazardous Air Pollutants (HAPS)	5.22E-01			0.05	1.23E-01				4.74E-01	1.17			3.87E-02	0.61	Y	0.25

	99.0 MMBtu/hr		441,504 MMBtu/yr		277 MMscf/yr		99.0 MMBtu/hr		110,376 MMBtu/yr		788 1000 gal/yr		551,880 MMBtu/yr	
Table C-2: Future Boiler Potential To Emit	**Fuel Gas**						**Diesel**						**Max**	
	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr (Highest of 2 Fuels)	Max TPY (Sum of 2 Fuels)
Criteria Air Pollutants (CAPS)														
CO	130	ppm	Assume (10)	9.51E-02	9.42	21.00	130	ppm	(10)	1.01E-01	1.00E+01	5.60	10.04	26.60
Hydrogen sulfide	162	ppm in fuel	(2) 3hr	1.80E-04	1.78E-02	1.47E-02							0.02	0.01
	60	ppm in fuel	(2) ann	6.65E-05									0.00	0.00
NH3	2.01E-03	lb/MMBtu	(3)	2.01E-03	0.20	0.44	8.00E-01	lb/1000 gal	(13)	5.71E-03	5.66E-01	0.32	0.57	0.76
Lead	4.90E-07	lb/MMBtu	(1)	4.90E-07	4.85E-05	1.08E-04	9.00E+00	lb/10^12Btu	(12)	9.00E-06	8.91E-04	0.00	0.00	0.00
NOx	50	ppm	(11)	0.051	5.10	11.36	2.00E+01	lb/1000 gal	(12)	1.43E-01	1.41E+01	7.88	14.14	19.25
SO2	20	ppm	(4) 3hr	0.029	2.84	2.53	35.500	lb/1000 gal	(12)	2.54E-01	2.51E+01	13.99	25.10	16.52
	8	ppm	(4) ann	0.011										
VOC	3.45E-03	lb/MMBtu	(8)	0.00345	0.34	0.76	2.00E-01	lb/1000 gal	(12)	1.43E-03	1.41E-01	0.08	0.34	0.84
Particulate Matter:														
Total (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.47	1.05	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	2.71
Filterable	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.12	0.26	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	1.92
Condensable	3.57E-03	lb/MMBtu	(8)	3.57E-03	0.35	0.79	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	2.44
PM10 (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.47	1.05	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	2.71
PM10 (Filterable)	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.12	0.26	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	1.92
PM2.5 (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.47	1.05	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	2.71
PM2.5 (Filterable)	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.12	0.26	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	1.92

Table C-2: Future Boiler Potential To Emit	Fuel Gas						Diesel						Max	
	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr (Highest of 2 Fuels)	Max TPY (Sum of 2 Fuels)
PSD-Specific categories														
Fluorides							3.75E-02	lb/1000 gal	(12)	2.68E-04	2.65E-02	1.48E-02	2.65E-02	0.01
Sulfuric Acid Mist	1.32E-03	lb/MMBtu	(5) 3 hr	1.32E-03	1.30E-01	1.16E-01							0.13	0.12
	5.26E-04	lb/MMBtu	(5) ann	5.26E-04										
Total Reduced Sulfur	1.90E-04	lb/MMBtu	(9)	1.90E-04	1.89E-02	0.04							0.02	0.04
Greenhouse Gases (GHGs)														
Total GHG (CO2e):	5.77E+01	kg/MMBtu	(7)	1.27E+02	12,574	28,037	7.42E+01	kg/MMBtu	(7)	1.63E+02	16,164	9,011	16,163.77	37,047.73
Individual Components:														
Carbon Dioxide	5.75E+01	kg/MMBtu	(6)	1.26E+02	12,518	27,914	7.40E+01	kg/MMBtu	(7)	1.63E+02	16,108	8,980	16,108.49	36,893.66
Methane	3.00E-03	kg/MMBtu	(7)	6.60E-03	6.53E-01	1.46	3.00E-03	kg/MMBtu	(7)	6.60E-03	6.53E-01	0.36	0.65	1.82
Nitrous Oxide	6.00E-04	kg/MMBtu	(7)	1.32E-03	1.31E-01	0.29	6.00E-04	kg/MMBtu	(7)	1.32E-03	1.31E-01	0.07	0.13	0.36
Hazardous Air Pollutants (HAPS)														
1,3-Butadiene														
1,4-Dichlorobenzene(p)	1.20E-06	lb/MMBtu	(1)	1.20E-06	1.19E-04	2.65E-04							1.19E-04	2.65E-04
Acetaldehyde	1.20E-05	lb/MMBtu	(1)	1.20E-05	1.19E-03	2.65E-03	1.05E-03	lb/1000 gal	(12)	7.50E-06	7.43E-04	4.14E-04	1.19E-03	3.06E-03
Acrolein	1.70E-05	lb/MMBtu	(1)	1.70E-05	1.68E-03	3.75E-03							1.68E-03	3.75E-03
Antimony	5.20E-07	lb/MMBtu	(1)	5.20E-07	5.15E-05	1.15E-04	5.25E-03	lb/1000 gal	(12)	3.75E-05	3.71E-03	2.07E-03	3.71E-03	2.18E-03
Arsenic	2.00E-07	lb/MMBtu	(1)	2.00E-07	1.98E-05	4.42E-05	4.00E+00	lb/10^12Btu	(12)	4.00E-06	3.96E-04	2.21E-04	3.96E-04	2.65E-04
Benzene	2.10E-06	lb/MMBtu	(1)	2.10E-06	2.08E-04	4.64E-04	2.14E-04	lb/1000 gal	(12)	1.53E-06	1.51E-04	8.44E-05	2.08E-04	5.48E-04
Beryllium	1.30E-07	lb/MMBtu	(1)	1.30E-07	1.29E-05	2.87E-05	3.00E+00	lb/10^12Btu	(12)	3.00E-06	2.97E-04	1.66E-04	2.97E-04	1.94E-04
Biphenyl, 1,1-														
Cadmium	1.10E-06	lb/MMBtu	(1)	1.10E-06	1.09E-04	2.43E-04	3.00E+00	lb/10^12Btu	(12)	3.00E-06	2.97E-04	1.66E-04	2.97E-04	4.08E-04
Carbon disulfide														
Carbonyl sulfide														
Chlorine														
Chloroform							5.10E-03	lb/1000 gal	(12)	3.64E-05	3.61E-03	2.01E-03	3.61E-03	2.01E-03
Chromium:														
Total Chromium	1.40E-06	lb/MMBtu	(1)	1.40E-06	1.39E-04	3.09E-04	3.00E+00	lb/10^12Btu	(12)	3.00E-06	2.97E-04	1.66E-04	2.97E-04	4.75E-04

Table C-2: Future Boiler Potential To Emit	Fuel Gas						Diesel						Max	
	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr (Highest of 2 Fuels)	Max TPY (Sum of 2 Fuels)
Hexavalent Chromium							3.00E+00	lb/10^12Btu	(12)	3.00E-06	2.97E-04	1.66E-04	2.97E-04	1.66E-04
Cobalt	8.20E-08	lb/MMBtu	(1)	8.20E-08	8.12E-06	1.81E-05	6.02E-03	lb/1000 gal	(12)	4.30E-05	4.26E-03	2.37E-03	4.26E-03	2.39E-03
Cumene														
Dichloroethane, 1,2-														
Diethanolamine														
Ethyl benzene	1.60E-05	lb/MMBtu	(1)	1.60E-05	1.58E-03	3.53E-03	6.36E-05	lb/1000 gal	(12)	4.54E-07	4.50E-05	2.51E-05	1.58E-03	3.56E-03
Ethylene glycol														
Formaldehyde	7.40E-05	lb/MMBtu	(1)	7.40E-05	7.33E-03	1.63E-02	3.30E-02	lb/1000 gal	(12)	2.36E-04	2.33E-02	1.30E-02	2.33E-02	2.93E-02
Hexane	1.80E-03	lb/MMBtu	(1)	1.80E-03	1.78E-01	3.97E-01							1.78E-01	3.97E-01
m-Cresol														
Hydrochloric acid							1.10E-03	lb/MMBtu	(10)	1.10E-03	1.09E-01	6.07E-02	1.09E-01	6.07E-02
Manganese	3.70E-07	lb/MMBtu	(1)	3.70E-07	3.66E-05	8.17E-05	6.00E+00	lb/10^12Btu	(12)	6.00E-06	5.94E-04	3.31E-04	5.94E-04	4.13E-04
Mercury	2.50E-07	lb/MMBtu	(1)	2.50E-07	2.48E-05	5.52E-05	7.30E-07	lb/MMBtu	(10)	7.30E-07	7.23E-05	4.03E-05	7.23E-05	9.55E-05
Methanol														
Methyl chloroform (1,1,1-Trichloroethane)							2.36E-04	lb/1000 gal	(12)	1.69E-06	1.67E-04	9.30E-05	1.67E-04	9.30E-05
Methyl isobutyl ketone														
Methyl tert butyl ether														
Naphthalene	6.00E-07	lb/MMBtu	(1)	6.00E-07	5.94E-05	1.32E-04	1.13E-03	lb/1000 gal	(12)	8.07E-06	7.99E-04	4.45E-04	7.99E-04	5.78E-04
Nickel	2.10E-06	lb/MMBtu	(1)	2.10E-06	2.08E-04	4.64E-04	3.00E+00	lb/10^12Btu	(12)	3.00E-06	2.97E-04	1.66E-04	2.97E-04	6.29E-04
Phenol	4.00E-06	lb/MMBtu	(1)	4.00E-06	3.96E-04	8.83E-04							3.96E-04	8.83E-04
Phosphorus	6.40E-07	lb/MMBtu	(1)	6.40E-07	6.34E-05	1.41E-04	9.45E-03	lb/1000 gal	(12)	6.75E-05	6.68E-03	3.73E-03	6.68E-03	3.87E-03
Polychlorinated biphenyls (Aroclors)														
Selenium	8.80E-07	lb/MMBtu	(1)	8.80E-07	8.71E-05	1.94E-04	1.50E+01	lb/10^12Btu	(12)	1.50E-05	1.49E-03	8.28E-04	1.49E-03	1.02E-03
Styrene														
Toluene	3.30E-06	lb/MMBtu	(1)	3.30E-06	3.27E-04	7.28E-04	1.09E-04	lb/1000 gal	(12)	7.79E-07	7.71E-05	4.30E-05	3.27E-04	7.71E-04
Trimethylpentane, 2,2,4-														
Xylenes	2.50E-05	lb/MMBtu	(1)	2.50E-05	2.48E-03	5.52E-03	1.10E-03	lb/1000 gal	(12)	7.82E-06	7.74E-04	4.32E-04	2.48E-03	5.95E-03

Table C-2: Future Boiler Potential To Emit	Fuel Gas						Diesel						Max	
	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr (Highest of 2 Fuels)	Max TPY (Sum of 2 Fuels)
HAPs - Polycylic Organic Matter (POM)														
Total Polycylic Organic Matter:	2.79E-07	lb/MMBtu	(1), Sum	2.79E-07	2.76E-05	6.15E-05	3.30E-03	lb/1000 gal	(12)	2.36E-05	2.33E-03	1.30E-03	2.33E-03	1.36E-03
Individual Components:														
2-Methylnapthalene	2.40E-08	lb/MMBtu	(1)	2.40E-08	2.38E-06	5.30E-06	1.11E-05	lb/1000 gal	(12)	7.93E-08	7.85E-06	4.38E-06	7.85E-06	9.67E-06
3-methylchloranthrene	1.80E-09	lb/MMBtu	(1)	1.80E-09	1.78E-07	3.97E-07							1.78E-07	3.97E-07
7,12-dimethylbenz(a)anthracene	1.60E-08	lb/MMBtu	(1)	1.60E-08	1.58E-06	3.53E-06							1.58E-06	3.53E-06
Acenaphthylene	6.50E-09	lb/MMBtu	(1)	6.50E-09	6.44E-07	1.43E-06	2.53E-07	lb/1000 gal	(12)	1.81E-09	1.79E-07	9.97E-08	6.44E-07	1.53E-06
Anthracene	4.70E-09	lb/MMBtu	(1)	4.70E-09	4.65E-07	1.04E-06	1.22E-06	lb/1000 gal	(12)	8.71E-09	8.63E-07	4.81E-07	8.63E-07	1.52E-06
Benzo(a)anthracene	2.20E-08	lb/MMBtu	(1)	2.20E-08	2.18E-06	4.86E-06	4.01E-06	lb/1000 gal	(12)	2.86E-08	2.84E-06	1.58E-06	2.84E-06	6.44E-06
Benzo(a)pyrene	5.70E-08	lb/MMBtu	(1)	5.70E-08	5.64E-06	1.26E-05	2.10E-07	lb/1000 gal	(12)	1.50E-09	1.49E-07	8.28E-08	5.64E-06	1.27E-05
Benzo(b)fluoranthene	2.70E-08	lb/MMBtu	(1)	2.70E-08	2.67E-06	5.96E-06	1.48E-06	lb/1000 gal	(12)	1.06E-08	1.05E-06	5.83E-07	2.67E-06	6.54E-06
Benzo(g,h,i)perylene	1.30E-09	lb/MMBtu	(1)	1.30E-09	1.29E-07	2.87E-07	2.26E-06	lb/1000 gal	(12)	1.61E-08	1.60E-06	8.91E-07	1.60E-06	1.18E-06
Benzo(k)fluoroanthene	1.70E-08	lb/MMBtu	(1)	1.70E-08	1.68E-06	3.75E-06	1.48E-06	lb/1000 gal	(12)	1.06E-08	1.05E-06	5.83E-07	1.68E-06	4.34E-06
Chrysene	1.60E-09	lb/MMBtu	(1)	1.60E-09	1.58E-07	3.53E-07	2.40E-06	lb/1000 gal	(12)	1.71E-08	1.70E-06	9.46E-07	1.70E-06	1.30E-06
Dibenz(a,h)anthracene	1.20E-09	lb/MMBtu	(1)	1.20E-09	1.19E-07	2.65E-07	1.65E-06	lb/1000 gal	(12)	1.18E-08	1.17E-06	6.50E-07	1.17E-06	9.15E-07
Fluoranthene	2.90E-09	lb/MMBtu	(1)	2.90E-09	2.87E-07	6.40E-07	4.80E-06	lb/1000 gal	(12)	3.43E-08	3.39E-06	1.89E-06	3.39E-06	2.53E-06
Fluorene	2.70E-09	lb/MMBtu	(1)	2.70E-09	2.67E-07	5.96E-07	4.50E-06	lb/1000 gal	(12)	3.21E-08	3.18E-06	1.77E-06	3.18E-06	2.37E-06
Indeno(1,2,3-cd)pyrene	7.10E-08	lb/MMBtu	(1)	7.10E-08	7.03E-06	1.57E-05	2.10E-06	lb/1000 gal	(12)	1.50E-08	1.49E-06	8.28E-07	7.03E-06	1.65E-05
PAH														
Phenanthrene	1.70E-08	lb/MMBtu	(1)	1.70E-08	1.68E-06	3.75E-06	1.05E-05	lb/1000 gal	(12)	7.50E-08	7.43E-06	4.14E-06	7.43E-06	7.89E-06
Pyrene	4.90E-09	lb/MMBtu	(1)	4.90E-09	4.85E-07	1.08E-06	4.20E-06	lb/1000 gal	(12)	3.00E-08	2.97E-06	1.66E-06	2.97E-06	2.74E-06

Table C-2: Future Boiler Potential To Emit	Fuel Gas						Diesel						Max	
	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr (Highest of 2 Fuels)	Max TPY (Sum of 2 Fuels)
Non-HAPs														
1,2,4- Trimethylbenzene														
2-Chloronaphthalene							2.25E-08	lb/1000 gal	(12)	1.61E-10	1.59E-08	8.87E-09	1.59E-08	8.87E-09
Acenaphthene	2.40E-09	lb/MMBtu	(1)	2.40E-09	2.38E-07	5.30E-07	2.11E-05	lb/1000 gal	(12)	1.51E-07	1.49E-05	8.32E-06	1.49E-05	8.85E-06
Barium	4.30E-06	lb/MMBtu	(1)	4.30E-06	4.26E-04	9.49E-04	1.70E-05	lb/1000 gal	(12)	1.21E-07	1.20E-05	6.70E-06	4.26E-04	9.56E-04
Benzo(e)pyrene							8.70E-07	lb/1000 gal	(12)	6.21E-09	6.15E-07	3.43E-07	6.15E-07	3.43E-07
Copper	8.50E-07	lb/MMBtu	(1)	8.50E-07	8.42E-05	1.88E-04	6.00E+00	lb/10^12Btu	(12)	6.00E-06	5.94E-04	3.31E-04	5.94E-04	5.19E-04
Cyclohexane														
Ethane	3.30E-03	lb/MMBtu	(1)	3.30E-03	3.27E-01	7.28E-01							3.27E-01	7.28E-01
Fluoride							3.75E-02	lb/1000 gal	(12)	2.68E-04	2.65E-02	1.48E-02	2.65E-02	1.48E-02
Methyl ethyl ketone (2-Butanone)													0.00E+00	0.00E+00
Molybdenum	1.10E-06	lb/MMBtu	(1)	1.10E-06	1.09E-04	2.43E-04							1.09E-04	2.43E-04
n-Butane	2.10E-03	lb/MMBtu	(1)	2.10E-03	2.08E-01	4.64E-01							2.08E-01	4.64E-01
n-pentane	2.50E-03	lb/MMBtu	(1)	2.50E-03	2.48E-01	5.52E-01							2.48E-01	5.52E-01
Perylene							1.11E-07	lb/1000 gal	(12)	7.93E-10	7.85E-08	4.38E-08	7.85E-08	4.38E-08
Propane	1.60E-03	lb/MMBtu	(1)	1.60E-03	1.58E-01	3.53E-01							1.58E-01	3.53E-01
Propylene	1.50E-04	lb/MMBtu	(1)	1.50E-04	1.49E-02	3.31E-02							1.49E-02	3.31E-02
Vanadium	2.30E-06	lb/MMBtu	(1)	2.30E-06	2.28E-04	5.08E-04	3.15E-02	lb/1000 gal	(12)	2.25E-04	2.23E-02	1.24E-02	2.23E-02	1.29E-02
Zinc	2.90E-05	lb/MMBtu	(1)	2.90E-05	2.87E-03	6.40E-03	4.00E+00	lb/10^12Btu	(12)	4.00E-06	3.96E-04	2.21E-04	2.87E-03	6.62E-03

Diesel Properties

0.25 % Sulfur
140,000 Btu/Gal (12)
9190 Diesel Fd Factor (dSCF/MMBtu), Part 75 Table 1

Refinery Fuel Gas Properties

1,595 RFG Heat Content (Btu/scf)
8622.193886 RFG Fd Factor (dSCF/MMBtu)

Emission Factor References

1. RTI International's Emission Estimation Protocol for Petroleum Refineries- Table 4-3. Criteria pollutants considered same as natural gas external combustion. Filterable PM determined by subtraction of Condensable PM from from Primary PM. Total POM is sum of individual components.
2. 40 CFR 60 NSPS Subpart Ja H2S in fuel limits: 162 ppmv 3hr and 60 ppmv 365day, assumes 2% H2S Slip, Remainder SO2
3. EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emiss. Factor, Table 5-2, 8/94
4. 40 CFR 60 NSPS Subpart Ja SO2 in flue gas limits: 20 ppmv (dry, 0% O2) 3hr and 8 ppmv (dry, 0% O2) 365day
5. Sulfuric Acid Mist based on conversion from SO2
6. Carbon content in RFG averaged from event-based lab sample data used for GHG reporting
7. GHG Emission factors from Tables C-1 and C-2 of 40 CFR 98. Global warming potentials from Table A-1 of 40 CFR 98.
8. AP-42 Section 1.4 - Natural Gas Combustion.
9. Total Sulfur/H2S Ratio Factor = 1.060 max spec; 0.01 Total Sulfur (as H2S)
10. Boiler MACT DDDDD Standard for liq. Fuel
11. Equivalent of Ja Standard for forced draft process heater (50 ppm)
12. EPA AP-42 Section 1.3 - Fuel Oil Combustion. May 2010.
13. EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emiss. Factor, Table 5-2, 8/94
14. PM from NSPS Dc (Same as Table 1 to Subpart JJJJJJ of Part 63), presuming any PM constituent could be up to the limit.

Table C-3: Future Fugitive Sources Potential To Emit

New Fugitive Components				VOC Emissions			
Class	**Chemical State**	**Count**	**Reference**	**kg/hr/source**	**EF**	**lb/yr**	**TPY**
VALVE		160	Conservative 20% addition to DHT (large than default 100 per	7.11E-05	(1)	219	0.11
PUMP	LT. LIQUID	0	(Exclude) Replacing existing pump P3703A/B with larger pump P3703C/D. No plan to reuse existing at this time.	0.00E+00	NA	0	0.00
PUMP	HEAVY LIQUID	1	1 new multi-renewable product transfer pump for renewable diesel and/or SAF	5.19E-03	(1)	100	0.05
PUMP	HEAVY LIQUID	0	(Exclude) P3701A- changed from fresh diesel to swing between	0.00E+00	NA	0	0.00
PUMP	HEAVY LIQUID	0	(Exclude) P3701B- changed from fresh diesel to recycle diesel	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	P3701C – new treated veg oil	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	2 new raw veg oil feed pump to pretreat unit	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	2 new boiler feed water pump	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	3 new veg oil pumps, swing between untreated and pretreated	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	2 pretreat veg oily water pump around pump	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	1 raw veg oil transfer pump in tank farm	0.00E+00	NA	0	0.00
Compressors		0	(Exclude; Routing to Flare) C2503 Product Compressor (Previously OOS)	1.61E+00	(2)	0	0.00
Compressors		0	(Exclude; Routing to Flare) New C-3702 Makeup H2 Compressor; Emission factor reduced by 90% because 90+% H2 purity	1.61E-01	(2)	0	0.00
Compressors		0	(Exclude; Routing to Flare) New C-3703 Recycle H2 Compressor; Emission factor reduced by 85% because 85% H2 purity	2.41E-01	(2)	0	0.00
CONNECTORS		320	Assumes 2 per valve	1.47E-04	(1)	909	0.45
OPEN-ENDED LINE		0	No OELS	1.44E-03	(1)	0	0.00
SAMPLING CONNECTIONS		5	Estimate	3.09E-03	(1)	297	0.15
Total		486				1,526	0.76

	Emission Factor	Emission Factor Units	Emission Factor Reference	Max lb/hr	Max TPY
Criteria Air Pollutants (CAPS)					
VOC			(1) Calculation Above	1,526	0.76
Hazardous Air Pollutants (HAPS)					
1,3-Butadiene	0	lb/lb VOC	(3)	0	0
Benzene	0.0037	lb/lb VOC	(3)	6	0.002822
Biphenyl, 1,1-	0.0022	lb/lb VOC	(3)	3	0.001678
Cumene	0.0007	lb/lb VOC	(3)	1	0.000534
Ethyl benzene	0.0037	lb/lb VOC	(3)	6	0.002822
Hexane	0.019	lb/lb VOC	(3)	29	0.014493
m-Cresol	0.001%	of Tank VOCs	(4)	0	7.63E-06
Methyl isobutyl ketone	0.05%	of Tank VOCs	(4)	1	0.000343
Naphthalene	0.0025	lb/lb VOC	(3)	4	0.001907
Phenol	0.001%	of Tank VOCs	(4)	0	7.63E-06
Toluene	0.017	lb/lb VOC	(3)	26	0.012968
Trimethylpentane, 2,2,4-	0	lb/lb VOC	(3)	0	0
Xylenes	0.019	lb/lb VOC	(3)	29	0.014493
HAPs - Polycylic Organic Matter (POM)					
Total Polycylic Organic Matter:			(4) Sum of below	1	0.000389
Individual Components:					
Benzo(g,h,i)perylene	1.49E-02	Ratio	(5)	0	2.84E-05
PAH	1.89E-01	Ratio	(5)	1	3.60E-04
Non-HAPs					
1,2,4- Trimethylbenzene	4.00E-03	lb/lb VOC	(3)	6	0.003051
Cyclohexane	1.85%	of Tank VOCs	(4)	28	0.014112
Methyl ethyl ketone (2-Butanone	0.55%	of Tank VOCs	(4)	8	0.004195

Emission Factor References

1. NMOC value for fugitives (except compressor) from Table 2-2 Correlation Equation of Emission Estimation Protocol for Petroleum Refineries (Version 3, April 2015) and the following screening values:
   - Certified Low Leak Technology (CLLT) limit of 100 ppm for valves
   - Monitoring leak threshold of 500 ppm for connectors that will be monitored with valves
   - Monitoring leak threshold of 2,000 ppm for pumps
   - Standard leak threshold of 10,000 ppm for remaining sources (Except compressors)
2. NMOC value for compressor from Table 2-3 of Emission Estimation Protocol for Petroleum Refineries (Version 3, April 2015).
3. Calculated ratio of WFi/WFVOC from Table 2-7. Concentration of HAP in Refinery Process Unit Streams (Emission Estimation Protocol for Petroleum Refineries (Version 3))
4. Though not identified in the Emission Protocol, conservatively added based on typical profile of Tank VOC emissions at the refinery.
5. Also not identified in the Emission Protocol. Conservatively added based on typical ratio of PAH and Benzo(g,h,i)perylene in Sara 312 reporting

Table C-4: H-3701 Actual Increase	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Baseline 15.8 MMBtu/hr Max lb/hr	Baseline 15.8 MMBtu/hr Max TPY	Current PTE 26 MMBtu/hr Max lb/hr	Current PTE 26 MMBtu/hr Max TPY*	Future PTE 30 MMBtu/hr Max lb/hr	Future PTE 30 MMBtu/hr Max TPY*	Future PTE - Baseline 14.3 MMBtu/hr Max lb/hr	Future PTE - Baseline 14.3 MMBtu/hr Max TPY	Future PTE - Current PTE Max lb/hr	Future PTE - Current PTE Max TPY
Criteria Air Pollutants (CAPS)														
CO	130	ppm	Assume (10)	9.51E-02	1.50	6.57	2.43	10.65	2.86	12.53	1.36	5.96	0.43	1.88
Hydrogen sulfide	162 60	ppm in fuel ppm in fuel	(2) 3hr (2) ann	1.80E-04 6.65E-05	2.83E-03	4.60E-03	4.59E-03	7.45E-03	5.40E-03	8.76E-03	2.57E-03	4.17E-03	8.09E-04	1.31E-03
NH3	2.01E-03	lb/MMBtu	(3)	2.01E-03	0.03	0.14	0.05	0.22	0.06	0.26	0.03	0.13	0.01	0.04
Lead	4.90E-07	lb/MMBtu	(1)	4.90E-07	7.73E-06	3.38E-05	1.25E-05	5.49E-05	1.47E-05	6.45E-05	7.00E-06	3.07E-05	2.21E-06	9.66E-06
NOx	40	ppm	(11)	4.12E-02	0.65	2.84	1.05	4.61	1.24	5.42	0.59	2.58	0.19	0.81
SO2	20 8	ppm ppm	(4) 3hr (4) ann	0.029 0.011	0.45	0.79	0.73	1.28	0.86	1.51	0.41	0.72	0.13	0.23
VOC	3.45E-03	lb/MMBtu	(8)	3.45E-03	0.05	0.24	0.09	0.39	0.10	0.45	0.05	0.22	0.02	0.07
Particulate Matter:														
Total (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.08	0.33	0.12	0.53	0.14	0.63	0.07	0.30	0.02	0.09
Filterable	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.02	0.08	0.03	0.13	0.04	0.16	0.02	0.07	0.01	0.02
Condensable	3.57E-03	lb/MMBtu	(8)	3.57E-03	0.06	0.25	0.09	0.40	0.11	0.47	0.05	0.22	0.02	0.07
PM10 (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.08	0.33	0.12	0.53	0.14	0.63	0.07	0.30	0.02	0.09
PM10 (Filterable)	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.02	0.08	0.03	0.13	0.04	0.16	0.02	0.07	0.01	0.02
PM2.5 (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.08	0.33	0.12	0.53	0.14	0.63	0.07	0.30	0.02	0.09
PM2.5 (Filterable)	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.02	0.08	0.03	0.13	0.04	0.16	0.02	0.07	0.01	0.02
PSD-Specificcategories														
Fluorides														
Sulfuric Acid Mist	1.32E-03 5.26E-04	lb/MMBtu lb/MMBtu	(5) 3 hr (5) ann	1.32E-03 5.26E-04	2.08E-02	0.04	3.36E-02	0.06	3.96E-02	0.07	1.88E-02	0.03	5.92E-03	0.01
Total Reduced Sulfur	1.90E-04	lb/MMBtu	(9)	1.90E-04	3.00E-03	0.01	4.87E-03	0.02	5.73E-03	0.03	2.72E-03	0.01	8.57E-04	0.00
Greenhouse Gases (GHGs)														
Total GHG (CO2e):	5.77E+01	kg/MMBtu	(7)	1.27E+02	2,003	8,773	3,246	14,219	3,818	16,723	1,815	7,950	572	2,504
Individual Components:														
Carbon Dioxide	5.75E+01	kg/MMBtu	(6)	1.26E+02	1,994	8,735	3,232	14,157	3,801	16,650	1,807	7,915	569	2,493
Methane	3.00E-03	kg/MMBtu	(7)	6.60E-03	1.04E-01	0.46	1.69E-01	0.74	1.98E-01	0.87	9.43E-02	0.41	2.97E-02	0.13
Nitrous Oxide	6.00E-04	kg/MMBtu	(7)	1.32E-03	2.08E-02	0.09	3.37E-02	0.15	3.97E-02	0.17	1.89E-02	0.08	5.94E-03	0.03
Hazardous Air Pollutants (HAPS)														
1,3-Butadiene														
1,4-Dichlorobenzene(p)	1.20E-06	lb/MMBtu	(1)	1.20E-06	1.89E-05	8.29E-05	3.07E-05	1.34E-04	3.61E-05	1.58E-04	1.71E-05	7.51E-05	5.40E-06	2.37E-05
Acetaldehyde	1.20E-05	lb/MMBtu	(1)	1.20E-05	1.89E-04	8.29E-04	3.07E-04	1.34E-03	3.61E-04	1.58E-03	1.71E-04	7.51E-04	5.40E-05	2.37E-04
Acrolein	1.70E-05	lb/MMBtu	(1)	1.70E-05	2.68E-04	1.17E-03	4.35E-04	1.90E-03	5.11E-04	2.24E-03	2.43E-04	1.06E-03	7.65E-05	3.35E-04
Antimony	5.20E-07	lb/MMBtu	(1)	5.20E-07	8.20E-06	3.59E-05	1.33E-05	5.82E-05	1.56E-05	6.85E-05	7.43E-06	3.26E-05	2.34E-06	1.03E-05
Arsenic	2.00E-07	lb/MMBtu	(1)	2.00E-07	3.15E-06	1.38E-05	5.11E-06	2.24E-05	6.01E-06	2.63E-05	2.86E-06	1.25E-05	9.00E-07	3.94E-06
Benzene	2.10E-06	lb/MMBtu	(1)	2.10E-06	3.31E-05	1.45E-04	5.37E-05	2.35E-04	6.31E-05	2.77E-04	3.00E-05	1.31E-04	9.45E-06	4.14E-05
Beryllium	1.30E-07	lb/MMBtu	(1)	1.30E-07	2.05E-06	8.98E-06	3.32E-06	1.46E-05	3.91E-06	1.71E-05	1.86E-06	8.14E-06	5.85E-07	2.56E-06
Biphenyl, 1,1-														
Cadmium	1.10E-06	lb/MMBtu	(1)	1.10E-06	1.73E-05	7.60E-05	2.81E-05	1.23E-04	3.31E-05	1.45E-04	1.57E-05	6.89E-05	4.95E-06	2.17E-05
Carbon disulfide														
Carbonyl sulfide														
Chlorine														
Chloroform														
Chromium:														
Total Chromium	1.40E-06	lb/MMBtu	(1)	1.40E-06	2.21E-05	9.67E-05	3.58E-05	1.57E-04	4.21E-05	1.84E-04	2.00E-05	8.76E-05	6.30E-06	2.76E-05
Hexavalent Chromium														

Table C-4: H-3701 Actual Increase	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Baseline		Current PTE		Future PTE		Future PTE - Baseline		Future PTE - Current PTE	
					15.8 MMBtu/hr		26 MMBtu/hr		30 MMBtu/hr		14.3 MMBtu/hr			
					Max lb/hr	Max TPY	Max lb/hr	Max TPY*	Max lb/hr	Max TPY*	Max lb/hr	Max TPY	Max lb/hr	Max TPY
Cobalt	8.20E-08	lb/MMBtu	(1)	8.20E-08	1.29E-06	5.66E-06	2.10E-06	9.18E-06	2.47E-06	1.08E-05	1.17E-06	5.13E-06	3.69E-07	1.62E-06
Cumene														
Dichloroethane, 1,2-														
Diethanolamine														
Ethyl benzene	1.60E-05	lb/MMBtu	(1)	1.60E-05	2.52E-04	1.11E-03	4.09E-04	1.79E-03	4.81E-04	2.11E-03	2.29E-04	1.00E-03	7.20E-05	3.15E-04
Ethylene glycol														
Formaldehyde	7.40E-05	lb/MMBtu	(1)	7.40E-05	1.17E-03	5.11E-03	1.89E-03	8.28E-03	2.22E-03	9.74E-03	1.06E-03	4.63E-03	3.33E-04	1.46E-03
Hexane	1.80E-03	lb/MMBtu	(1)	1.80E-03	2.84E-02	1.24E-01	4.60E-02	2.02E-01	5.41E-02	2.37E-01	2.57E-02	1.13E-01	8.10E-03	3.55E-02
m-Cresol														
Hydrochloric acid														
Manganese	3.70E-07	lb/MMBtu	(1)	3.70E-07	5.84E-06	2.56E-05	9.46E-06	4.14E-05	1.11E-05	4.87E-05	5.29E-06	2.32E-05	1.67E-06	7.30E-06
Mercury	2.50E-07	lb/MMBtu	(1)	2.50E-07	3.94E-06	1.73E-05	6.39E-06	2.80E-05	7.52E-06	3.29E-05	3.57E-06	1.56E-05	1.13E-06	4.93E-06
Methanol														
Methyl chloroform (1,1,1-Trichloroethane)														
Methyl isobutyl ketone														
Methyl tert butyl ether														
Naphthalene	6.00E-07	lb/MMBtu	(1)	6.00E-07	9.46E-06	4.14E-05	1.53E-05	6.72E-05	1.80E-05	7.90E-05	8.57E-06	3.76E-05	2.70E-06	1.18E-05
Nickel	2.10E-06	lb/MMBtu	(1)	2.10E-06	3.31E-05	1.45E-04	5.37E-05	2.35E-04	6.31E-05	2.77E-04	3.00E-05	1.31E-04	9.45E-06	4.14E-05
Phenol	4.00E-06	lb/MMBtu	(1)	4.00E-06	6.31E-05	2.76E-04	1.02E-04	4.48E-04	1.20E-04	5.27E-04	5.72E-05	2.50E-04	1.80E-05	7.89E-05
Phosphorus	6.40E-07	lb/MMBtu	(1)	6.40E-07	1.01E-05	4.42E-05	1.64E-05	7.17E-05	1.92E-05	8.43E-05	9.15E-06	4.01E-05	2.88E-06	1.26E-05
Polychlorinated biphenyls (Aroclors)														
Selenium	8.80E-07	lb/MMBtu	(1)	8.80E-07	1.39E-05	6.08E-05	2.25E-05	9.85E-05	2.65E-05	1.16E-04	1.26E-05	5.51E-05	3.96E-06	1.74E-05
Styrene														
Toluene	3.30E-06	lb/MMBtu	(1)	3.30E-06	5.20E-05	2.28E-04	8.43E-05	3.69E-04	9.92E-05	4.35E-04	4.72E-05	2.07E-04	1.49E-05	6.51E-05
Trimethylpentane, 2,2,4-														
Xylenes	2.50E-05	lb/MMBtu	(1)	2.50E-05	3.94E-04	1.73E-03	6.39E-04	2.80E-03	7.52E-04	3.29E-03	3.57E-04	1.56E-03	1.13E-04	4.93E-04

HAPs - Polycylic Organic Matter (POM)

Total Polycylic Organic Matter:	2.79E-07	lb/MMBtu	(1), Sum	2.79E-07	4.39E-06	1.92E-05	7.12E-06	3.12E-05	8.38E-06	3.67E-05	3.98E-06	1.74E-05	1.25E-06	5.49E-06
Individual Components:														
2-Methylnapthalene	2.40E-08	lb/MMBtu	(1)	2.40E-08	3.78E-07	1.66E-06	6.13E-07	2.69E-06	7.21E-07	3.16E-06	3.43E-07	1.50E-06	1.08E-07	4.73E-07
3-methylchloranthrene	1.80E-09	lb/MMBtu	(1)	1.80E-09	2.84E-08	1.24E-07	4.60E-08	2.02E-07	5.41E-08	2.37E-07	2.57E-08	1.13E-07	8.10E-09	3.55E-08
7,12-dimethylbenz(a)anthracene	1.60E-08	lb/MMBtu	(1)	1.60E-08	2.52E-07	1.11E-06	4.09E-07	1.79E-06	4.81E-07	2.11E-06	2.29E-07	1.00E-06	7.20E-08	3.15E-07
Acenaphthylene	6.50E-09	lb/MMBtu	(1)	6.50E-09	1.03E-07	4.49E-07	1.66E-07	7.28E-07	1.95E-07	8.56E-07	9.29E-08	4.07E-07	2.93E-08	1.28E-07
Anthracene	4.70E-09	lb/MMBtu	(1)	4.70E-09	7.41E-08	3.25E-07	1.20E-07	5.26E-07	1.41E-07	6.19E-07	6.72E-08	2.94E-07	2.12E-08	9.27E-08
Benzo(a)anthracene	2.20E-08	lb/MMBtu	(1)	2.20E-08	3.47E-07	1.52E-06	5.62E-07	2.46E-06	6.61E-07	2.90E-06	3.14E-07	1.38E-06	9.90E-08	4.34E-07
Benzo(a)pyrene	5.70E-08	lb/MMBtu	(1)	5.70E-08	8.99E-07	3.94E-06	1.46E-06	6.38E-06	1.71E-06	7.51E-06	8.15E-07	3.57E-06	2.57E-07	1.12E-06
Benzo(b)fluoranthene	2.70E-08	lb/MMBtu	(1)	2.70E-08	4.26E-07	1.87E-06	6.90E-07	3.02E-06	8.12E-07	3.56E-06	3.86E-07	1.69E-06	1.22E-07	5.32E-07
Benzo(g,h,i)perylene	1.30E-09	lb/MMBtu	(1)	1.30E-09	2.05E-08	8.98E-08	3.32E-08	1.46E-07	3.91E-08	1.71E-07	1.86E-08	8.14E-08	5.85E-09	2.56E-08
Benzo(k)fluoroanthene	1.70E-08	lb/MMBtu	(1)	1.70E-08	2.68E-07	1.17E-06	4.35E-07	1.90E-06	5.11E-07	2.24E-06	2.43E-07	1.06E-06	7.65E-08	3.35E-07
Chrysene	1.60E-09	lb/MMBtu	(1)	1.60E-09	2.52E-08	1.11E-07	4.09E-08	1.79E-07	4.81E-08	2.11E-07	2.29E-08	1.00E-07	7.20E-09	3.15E-08
Dibenz(a,h)anthracene	1.20E-09	lb/MMBtu	(1)	1.20E-09	1.89E-08	8.29E-08	3.07E-08	1.34E-07	3.61E-08	1.58E-07	1.71E-08	7.51E-08	5.40E-09	2.37E-08
Fluoranthene	2.90E-09	lb/MMBtu	(1)	2.90E-09	4.57E-08	2.00E-07	7.41E-08	3.25E-07	8.72E-08	3.82E-07	4.14E-08	1.82E-07	1.31E-08	5.72E-08
Fluorene	2.70E-09	lb/MMBtu	(1)	2.70E-09	4.26E-08	1.87E-07	6.90E-08	3.02E-07	8.12E-08	3.56E-07	3.86E-08	1.69E-07	1.22E-08	5.32E-08
Indeno(1,2,3-cd)pyrene	7.10E-08	lb/MMBtu	(1)	7.10E-08	1.12E-06	4.90E-06	1.81E-06	7.95E-06	2.13E-06	9.35E-06	1.01E-06	4.44E-06	3.20E-07	1.40E-06
PAH														
Phenanthrene	1.70E-08	lb/MMBtu	(1)	1.70E-08	2.68E-07	1.17E-06	4.35E-07	1.90E-06	5.11E-07	2.24E-06	2.43E-07	1.06E-06	7.65E-08	3.35E-07
Pyrene	4.90E-09	lb/MMBtu	(1)	4.90E-09	7.73E-08	3.38E-07	1.25E-07	5.49E-07	1.47E-07	6.45E-07	7.00E-08	3.07E-07	2.21E-08	9.66E-08

Table C-4: H-3701 Actual Increase	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Baseline 15.8 MMBtu/hr Max lb/hr	Baseline 15.8 MMBtu/hr Max TPY	Current PTE 26 MMBtu/hr Max lb/hr	Current PTE 26 MMBtu/hr Max TPY*	Future PTE 30 MMBtu/hr Max lb/hr	Future PTE 30 MMBtu/hr Max TPY*	Future PTE - Baseline 14.3 MMBtu/hr Max lb/hr	Future PTE - Baseline 14.3 MMBtu/hr Max TPY	Future PTE - Current PTE Max lb/hr	Future PTE - Current PTE Max TPY
Non-HAPs														
1,2,4- Trimethylbenzene														
2-Chloronaphthalene														
Acenaphthene	2.40E-09	lb/MMBtu	(1)	2.40E-09	3.78E-08	1.66E-07	6.13E-08	2.69E-07	7.21E-08	3.16E-07	3.43E-08	1.50E-07	1.08E-08	4.73E-08
Barium	4.30E-06	lb/MMBtu	(1)	4.30E-06	6.78E-05	2.97E-04	1.10E-04	4.81E-04	1.29E-04	5.66E-04	6.15E-05	2.69E-04	1.94E-05	8.48E-05
Benzo(e)pyrene														
Copper	8.50E-07	lb/MMBtu	(1)	8.50E-07	1.34E-05	5.87E-05	2.17E-05	9.52E-05	2.56E-05	1.12E-04	1.21E-05	5.32E-05	3.83E-06	1.68E-05
Cyclohexane														
Ethane	3.30E-03	lb/MMBtu	(1)	3.30E-03	5.20E-02	2.28E-01	8.43E-02	3.69E-01	9.92E-02	4.35E-01	4.72E-02	2.07E-01	1.49E-02	6.51E-02
Fluoride														
Methyl ethyl ketone (2-Butanone)														
Molybdenum	1.10E-06	lb/MMBtu	(1)	1.10E-06	1.73E-05	7.60E-05	2.81E-05	1.23E-04	3.31E-05	1.45E-04	1.57E-05	6.89E-05	4.95E-06	2.17E-05
n-Butane	2.10E-03	lb/MMBtu	(1)	2.10E-03	3.31E-02	1.45E-01	5.37E-02	2.35E-01	6.31E-02	2.77E-01	3.00E-02	1.31E-01	9.45E-03	4.14E-02
n-pentane	2.50E-03	lb/MMBtu	(1)	2.50E-03	3.94E-02	1.73E-01	6.39E-02	2.80E-01	7.52E-02	3.29E-01	3.57E-02	1.56E-01	1.13E-02	4.93E-02
Perylene														
Propane	1.60E-03	lb/MMBtu	(1)	1.60E-03	2.52E-02	1.11E-01	4.09E-02	1.79E-01	4.81E-02	2.11E-01	2.29E-02	1.00E-01	7.20E-03	3.15E-02
Propylene	1.50E-04	lb/MMBtu	(1)	1.50E-04	2.37E-03	1.04E-02	3.83E-03	1.68E-02	4.51E-03	1.98E-02	2.14E-03	9.39E-03	6.75E-04	2.96E-03
Vanadium	2.30E-06	lb/MMBtu	(1)	2.30E-06	3.63E-05	1.59E-04	5.88E-05	2.57E-04	6.91E-05	3.03E-04	3.29E-05	1.44E-04	1.04E-05	4.54E-05
Zinc	2.90E-05	lb/MMBtu	(1)	2.90E-05	4.57E-04	2.00E-03	7.41E-04	3.25E-03	8.72E-04	3.82E-03	4.14E-04	1.82E-03	1.31E-04	5.72E-04

Refinery Fuel Gas Properties

1,595	RFG Heat Content (Btu/scf)
8,622	RFG Fd Factor (dSCF/MMBtu)

Emission Factor References

1. RTI International's Emission Estimation Protocol for Petroleum Refineries- Table 4-3. Criteria pollutants considered same as natural gas external combustion. Filterable PM determined by subtraction of Condensable PM from from Primary PM. Total POM is sum of individual components.
2. 40 CFR 60 NSPS Subpart Ja H2S in fuel limits: 162 ppmv 3hr and 60 ppmv 365day, assumes 2% H2S Slip, Remainder SO2
3. EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emiss. Factor, Table 5-2, 8/94
4. 40 CFR 60 NSPS Subpart Ja SO2 in flue gas limits: 20 ppmv (dry, 0% O2) 3hr and 8 ppmv (dry, 0% O2) 365day
5. Sulfuric Acid Mist based on conversion from SO2
6. Carbon content in RFG averaged from event-based lab sample data used for GHG reporting
7. GHG Emission factors from Tables C-1 and C-2 of 40 CFR 98. Global warming potentials from Table A-1 of 40 CFR 98.
8. AP-42 Section 1.4 - Natural Gas Combustion.
9. Total Sulfur/H2S Ratio Factor = 1.060 max spec; 0.01 Total Sulfur (as H2S)
10. Boiler MACT DDDDD Standard for liq. Fuel
11. Design basis with Ultra Low Nox Burner (ULNB)

Table C-5: H-2001 Actual Increase (Fuel Burning)	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Baseline Max lb/hr	Baseline Max TPY	Potential Max lb/hr	Potential Max TPY*	Increase Max lb/hr	Increase Max TPY
			MMBTU/rolling 12-mo	96973.2	77.72 MMBtu/hr		132.84 MMBtu/hr		55.12 MMBtu/hr	
Criteria Air Pollutants (CAPS)										
CO	130	ppm	Assume (10)	9.51E-02	7.39	32.39	12.64	55.36	5.24	22.97
Hydrogen sulfide	162	ppm in fuel	Assume (2) 3hr	1.80E-04	0.01	0.02	0.02	0.04	0.01	0.02
	60	ppm in fuel	Assume (2) ann	6.65E-05						
NH3	2.01E-03	lb/MMBtu	(3)	2.01E-03	0.16	0.68	0.27	1.17	0.11	0.48
Lead	4.90E-07	lb/MMBtu	(1)	4.90E-07	3.81E-05	1.67E-04	6.51E-05	2.85E-04	2.70E-05	1.18E-04
NOx	**Baseline (Using CEMS)**				36.1	16.0	36.1	30.0	0.00	14.0
	36.1	lb/hr	CEMS highest hour 2021-2022							
	16.0	TPY	CEMS Avg 2021-2022 (Annual Emiss Inv)							
	Potential									
	36.1	lb/hr	CEMS highest hour 2021-2022							
	60	ppm	(11) 30 day	6.18E-02						
	50	ppm	(11) ann	5.15E-02						
SO2	20	ppm	(4) 3hr	2.86E-02	2.23	3.90	3.81	6.67	1.58	2.77
	8	ppm	(4) ann	1.15E-02						
VOC	3.45E-03	lb/MMBtu	(8)	3.45E-03	0.27	1.17	0.46	2.01	0.19	0.83
Particulate Matter:										
Total (Filterable + Condensable)	0.005	lb/MMBtu	(8)	4.76E-03	0.37	1.62	0.63	2.77	0.26	1.15
Filterable	0.001	lb/MMBtu	(8)	1.19E-03	0.09	0.41	0.16	0.69	0.07	0.29
Condensable	0.004	lb/MMBtu	(8)	3.57E-03	0.28	1.22	0.47	2.08	0.20	0.86
PM10 (Filterable + Condensable)	0.005	lb/MMBtu	(8)	4.76E-03	0.37	1.62	0.63	2.77	0.26	1.15
PM10 (Filterable)	0.00119	lb/MMBtu	(8)	1.19E-03	0.09	0.41	0.16	0.69	0.07	0.29
PM2.5 (Filterable + Condensable)	0.005	lb/MMBtu	(8)	4.76E-03	0.37	1.62	0.63	2.77	0.26	1.15
PM2.5 (Filterable)	0.001	lb/MMBtu	(8)	1.19E-03	0.09	0.41	0.16	0.69	0.07	0.29
PSD-Specificcategories										
Fluorides										
Sulfuric Acid Mist	1.32E-03	lb/MMBtu	(5) 3 hr	1.32E-03	1.02E-01	0.18	1.75E-01	0.31	7.25E-02	0.13
	5.26E-04	lb/MMBtu	(5) ann	5.26E-04						
Total Reduced Sulfur	1.90E-04	lb/MMBtu	(9)	1.90E-04	1.48E-02	0.06	2.53E-02	0.11	1.05E-02	0.05
Greenhouse Gases (GHGs)										
Total GHG (CO2e):	5.77E+01	kg/MMBtu	(7)	1.27E+02	9,871	43,233	16,872	73,898	7,001	30,665
Individual Components:										
Carbon Dioxide	5.75E+01	kg/MMBtu	(6)	1.26E+02	9,827	43,043	16,798	73,573	6,970	30,530
Methane	3.00E-03	kg/MMBtu	(7)	6.60E-03	5.13E-01	2.25	8.77E-01	3.84	3.64E-01	1.59
Nitrous Oxide	6.00E-04	kg/MMBtu	(7)	1.32E-03	1.03E-01	0.45	1.75E-01	0.77	7.28E-02	0.32
Hazardous Air Pollutants (HAPS)					15.987	70.02				
1,3-Butadiene										
1,4-Dichlorobenzene(p)	1.20E-06	lb/MMBtu	(1)	1.20E-06	9.33E-05	4.08E-04	1.59E-04	6.98E-04	6.61E-05	2.90E-04
Acetaldehyde	1.20E-05	lb/MMBtu	(1)	1.20E-05	9.33E-04	4.08E-03	1.59E-03	6.98E-03	6.61E-04	2.90E-03
Acrolein	1.70E-05	lb/MMBtu	(1)	1.70E-05	1.32E-03	5.79E-03	2.26E-03	9.89E-03	9.37E-04	4.10E-03
Antimony	5.20E-07	lb/MMBtu	(1)	5.20E-07	4.04E-05	1.77E-04	6.91E-05	3.03E-04	2.87E-05	1.26E-04
Arsenic	2.00E-07	lb/MMBtu	(1)	2.00E-07	1.55E-05	6.81E-05	2.66E-05	1.16E-04	1.10E-05	4.83E-05
Benzene	2.10E-06	lb/MMBtu	(1)	2.10E-06	1.63E-04	7.15E-04	2.79E-04	1.22E-03	1.16E-04	5.07E-04
Beryllium	1.30E-07	lb/MMBtu	(1)	1.30E-07	1.01E-05	4.43E-05	1.73E-05	7.56E-05	7.17E-06	3.14E-05
Biphenyl, 1,1-										
Cadmium	1.10E-06	lb/MMBtu	(1)	1.10E-06	8.55E-05	3.74E-04	1.46E-04	6.40E-04	6.06E-05	2.66E-04
Carbon disulfide										
Carbonyl sulfide										

Table C-5: H-2001 Actual Increase (Fuel Burning)	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr	Max TPY*	Max lb/hr	Max TPY
Chlorine										
Chloroform										
Chromium:										
Total Chromium	1.40E-06	lb/MMBtu	(1)	1.40E-06	1.09E-04	4.77E-04	1.86E-04	8.15E-04	7.72E-05	3.38E-04
Hexavalent Chromium										
Cobalt	8.20E-08	lb/MMBtu	(1)	8.20E-08	6.37E-06	2.79E-05	1.09E-05	4.77E-05	4.52E-06	1.98E-05
Cumene										
Dichloroethane, 1,2-										
Diethanolamine										
Ethyl benzene	1.60E-05	lb/MMBtu	(1)	1.60E-05	1.24E-03	5.45E-03	2.13E-03	9.31E-03	8.82E-04	3.86E-03
Ethylene glycol										
Formaldehyde	7.40E-05	lb/MMBtu	(1)	7.40E-05	5.75E-03	2.52E-02	9.83E-03	4.31E-02	4.08E-03	1.79E-02
Hexane	1.80E-03	lb/MMBtu	(1)	1.80E-03	1.40E-01	6.13E-01	2.39E-01	1.05E+00	9.92E-02	4.35E-01
m-Cresol										
Hydrochloric acid										
Manganese	3.70E-07	lb/MMBtu	(1)	3.70E-07	2.88E-05	1.26E-04	4.92E-05	2.15E-04	2.04E-05	8.93E-05
Mercury	2.50E-07	lb/MMBtu	(1)	2.50E-07	1.94E-05	8.51E-05	3.32E-05	1.45E-04	1.38E-05	6.04E-05
Methanol										
Methyl chloroform (1,1,1-Trichloroethane)										
Methyl isobutyl ketone										
Methyl tert butyl ether										
Naphthalene	6.00E-07	lb/MMBtu	(1)	6.00E-07	4.66E-05	2.04E-04	7.97E-05	3.49E-04	3.31E-05	1.45E-04
Nickel	2.10E-06	lb/MMBtu	(1)	2.10E-06	1.63E-04	7.15E-04	2.79E-04	1.22E-03	1.16E-04	5.07E-04
Phenol	4.00E-06	lb/MMBtu	(1)	4.00E-06	3.11E-04	1.36E-03	5.31E-04	2.33E-03	2.20E-04	9.66E-04
Phosphorus	6.40E-07	lb/MMBtu	(1)	6.40E-07	4.97E-05	2.18E-04	8.50E-05	3.72E-04	3.53E-05	1.55E-04
Polychlorinated biphenyls (Aroclors)										
Selenium	8.80E-07	lb/MMBtu	(1)	8.80E-07	6.84E-05	3.00E-04	1.17E-04	5.12E-04	4.85E-05	2.12E-04
Styrene										
Toluene	3.30E-06	lb/MMBtu	(1)	3.30E-06	2.56E-04	1.12E-03	4.38E-04	1.92E-03	1.82E-04	7.97E-04
Trimethylpentane, 2,2,4-										
Xylenes	2.50E-05	lb/MMBtu	(1)	2.50E-05	1.94E-03	8.51E-03	3.32E-03	1.45E-02	1.38E-03	6.04E-03

Table C-5: H-2001 Actual Increase (Fuel Burning)	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr	Max TPY*	Max lb/hr	Max TPY
HAPs - Polycylic Organic Matter (POM)										
Total Polycyclic Organic Matter:	2.79E-07	lb/MMBtu	(1), Sum	2.79E-07	2.17E-05	9.48E-05	3.70E-05	1.62E-04	1.54E-05	6.73E-05
Individual Components:										
2-Methylnapthalene	2.40E-08	lb/MMBtu	(1)	2.40E-08	1.87E-06	8.17E-06	3.19E-06	1.40E-05	1.32E-06	5.79E-06
3-methylchloranthrene	1.80E-09	lb/MMBtu	(1)	1.80E-09	1.40E-07	6.13E-07	2.39E-07	1.05E-06	9.92E-08	4.35E-07
7,12-dimethylbenz(a)anthracene	1.60E-08	lb/MMBtu	(1)	1.60E-08	1.24E-06	5.45E-06	2.13E-06	9.31E-06	8.82E-07	3.86E-06
Acenaphthylene	6.50E-09	lb/MMBtu	(1)	6.50E-09	5.05E-07	2.21E-06	8.63E-07	3.78E-06	3.58E-07	1.57E-06
Anthracene	4.70E-09	lb/MMBtu	(1)	4.70E-09	3.65E-07	1.60E-06	6.24E-07	2.73E-06	2.59E-07	1.13E-06
Benzo(a)anthracene	2.20E-08	lb/MMBtu	(1)	2.20E-08	1.71E-06	7.49E-06	2.92E-06	1.28E-05	1.21E-06	5.31E-06
Benzo(a)pyrene	5.70E-08	lb/MMBtu	(1)	5.70E-08	4.43E-06	1.94E-05	7.57E-06	3.32E-05	3.14E-06	1.38E-05
Benzo(b)fluoranthene	2.70E-08	lb/MMBtu	(1)	2.70E-08	2.10E-06	9.19E-06	3.59E-06	1.57E-05	1.49E-06	6.52E-06
Benzo(g,h,i)perylene	1.30E-09	lb/MMBtu	(1)	1.30E-09	1.01E-07	4.43E-07	1.73E-07	7.56E-07	7.17E-08	3.14E-07
Benzo(k)fluoroanthene	1.70E-08	lb/MMBtu	(1)	1.70E-08	1.32E-06	5.79E-06	2.26E-06	9.89E-06	9.37E-07	4.10E-06
Chrysene	1.60E-09	lb/MMBtu	(1)	1.60E-09	1.24E-07	5.45E-07	2.13E-07	9.31E-07	8.82E-08	3.86E-07
Dibenz(a,h)anthracene	1.20E-09	lb/MMBtu	(1)	1.20E-09	9.33E-08	4.08E-07	1.59E-07	6.98E-07	6.61E-08	2.90E-07
Fluoranthene	2.90E-09	lb/MMBtu	(1)	2.90E-09	2.25E-07	9.87E-07	3.85E-07	1.69E-06	1.60E-07	7.00E-07
Fluorene	2.70E-09	lb/MMBtu	(1)	2.70E-09	2.10E-07	9.19E-07	3.59E-07	1.57E-06	1.49E-07	6.52E-07
Indeno(1,2,3-cd)pyrene	7.10E-08	lb/MMBtu	(1)	7.10E-08	5.52E-06	2.42E-05	9.43E-06	4.13E-05	3.91E-06	1.71E-05
PAH										
Phenanthrene	1.70E-08	lb/MMBtu	(1)	1.70E-08	1.32E-06	5.79E-06	2.26E-06	9.89E-06	9.37E-07	4.10E-06
Pyrene	4.90E-09	lb/MMBtu	(1)	4.90E-09	3.81E-07	1.67E-06	6.51E-07	2.85E-06	2.70E-07	1.18E-06
Non-HAPs										
1,2,4- Trimethylbenzene										
2-Chloronaphthalene										
Acenaphthene	2.40E-09	lb/MMBtu	(1)	2.40E-09	1.87E-07	8.17E-07	3.19E-07	1.40E-06	1.32E-07	5.79E-07
Barium	4.30E-06	lb/MMBtu	(1)	4.30E-06	3.34E-04	1.46E-03	5.71E-04	2.50E-03	2.37E-04	1.04E-03
Benzo(e)pyrene										
Copper	8.50E-07	lb/MMBtu	(1)	8.50E-07	6.61E-05	2.89E-04	1.13E-04	4.95E-04	4.69E-05	2.05E-04
Cyclohexane										
Ethane	3.30E-03	lb/MMBtu	(1)	3.30E-03	2.56E-01	1.12E+00	4.38E-01	1.92E+00	1.82E-01	7.97E-01
Fluoride										
Methyl ethyl ketone (2-Butanone)										
Molybdenum	1.10E-06	lb/MMBtu	(1)	1.10E-06	8.55E-05	3.74E-04	1.46E-04	6.40E-04	6.06E-05	2.66E-04
n-Butane	2.10E-03	lb/MMBtu	(1)	2.10E-03	1.63E-01	7.15E-01	2.79E-01	1.22E+00	1.16E-01	5.07E-01
n-pentane	2.50E-03	lb/MMBtu	(1)	2.50E-03	1.94E-01	8.51E-01	3.32E-01	1.45E+00	1.38E-01	6.04E-01
Perylene										
Propane	1.60E-03	lb/MMBtu	(1)	1.60E-03	1.24E-01	5.45E-01	2.13E-01	9.31E-01	8.82E-02	3.86E-01
Propylene	1.50E-04	lb/MMBtu	(1)	1.50E-04	1.17E-02	5.11E-02	1.99E-02	8.73E-02	8.27E-03	3.62E-02
Vanadium	2.30E-06	lb/MMBtu	(1)	2.30E-06	1.79E-04	7.83E-04	3.06E-04	1.34E-03	1.27E-04	5.55E-04
Zinc	2.90E-05	lb/MMBtu	(1)	2.90E-05	2.25E-03	9.87E-03	3.85E-03	1.69E-02	1.60E-03	7.00E-03

Refinery Fuel Gas Properties

1,595	RFG Heat Content (Btu/scf)
8622.193886	RFG Fd Factor (dSCF/MMBtu)

Emission Factor References

1. RTI International's Emission Estimation Protocol for Petroleum Refineries- Table 4-3. Criteria pollutants considered same as natural gas external combustion. Filterable PM determined by subtraction of Condensable PM from from Primary PM. Total POM is sum of individual components.
2. 40 CFR 60 NSPS Subpart Ja H2S in fuel limits: 162 ppmv 3hr and 60 ppmv 365day, assumes 2% H2S Slip, Remainder SO2
3. EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emiss. Factor, Table 5-2, 8/94
4. 40 CFR 60 NSPS Subpart Ja SO2 in flue gas limits: 20 ppmv (dry, 0% O2) 3hr and 8 ppmv (dry, 0% O2) 365day
5. Sulfuric Acid Mist based on conversion from SO2
6. Carbon content in RFG averaged from event-based lab sample data used for GHG reporting
7. GHG Emission factors from Tables C-1 and C-2 of 40 CFR 98. Global warming potentials from Table A-1 of 40 CFR 98.
8. AP-42 Section 1.4 - Natural Gas Combustion.
9. Total Sulfur/H2S Ratio Factor = 1.060 max spec; 0.01 Total Sulfur (as H2S)
10. Boiler MACT DDDDD Standard for liq. Fuel
11. Consent Decree/Permit Limit after installation of ULNB

Table C-6: HGU Increased Feedstock

RATIO 0.069223475 MT CO2 from LPG Fed /MMBtu RFG Burned

	Baseline		Increased Bio		Increased Fossil		Increased Total	
H2001 Firing	680799	MMBtu/yr	37	MMBtu/hr	18	MMBtu/hr	55	MMBtu/hr
Associated LPG Feed CO2	47127.29066	MT CO2/Year	2.5	MTCO2/hr	1.3	MTCO2/hr	3.8	MTCO2/hr
	Max lb/hr	Max TPY	Max lb/hr	Max TPY	Max lb/hr	Max TPY	Max lb/hr	Max TPY
CO2	11,836	51,840	5,597	24,513	2,798	12,256	8,395	36,769

Appendix D – Ambient Air Quality Model Analysis

AECOM

Air Quality Analysis
Par Hawaii Refining Kapolei Refinery
Renewal Hydrotreater Project Modeling

Prepared for:

Par Hawaii Refining
91-325 Komohana Street
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Prepared by:

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December 2023

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1.0 INTRODUCTION

Par Hawaii Refining (Par) owns and operates a petroleum refinery in the Campbell Industrial Park, in the city of Kapolei, Hawaii. The refinery produces diesel and gasoline for the island of Oahu and neighboring islands.

The refinery plans to convert the existing distillate hydrotreater unit into a renewable hydrotreater unit (RHT). The RHT will process up to 61 million gallons per years of renewable feedstocks into renewable fuels such as renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN), and renewable liquefied petroleum gases (RLPGs). A pre-treatment facility will be constructed to treat raw feedstocks prior to processing in the RHT unit. The feedstock for the facility will be imported soybean oil, but other sources including biofuel crops, vegetable oils, used cooking oil, and other animal fats will also be used for production. The goal for the RHT project is to reduce the carbon intensity of liquid fuels in Hawaii and meet the increasing demand for low-carbon energy in the state of Hawaii.

This memo summarizes the methodology used to perform the air dispersion modeling analysis for this proposed project and documents the modeling results.

2.0 MODELING METHODOLOGY

AECOM conducted air dispersion modeling of emissions from the proposed RHT project at the facility. The analysis used the American Meteorological Society/ U.S. Environmental Protection Agency Regulatory (AERMOD) model (Version 22112).

AECOM used the Hawaii Department of Health (HDOH) recommended methodologies for the following pollutants and averaging periods: CO (1-hr and 8-hr), NO_2 (1-hr and Annual), H_2S (1-hr), SO_2 (1-hr, 3-hr, 24-hr, and Annual), PM_{10} (24-hr and Annual), and $PM_{2.5}$ (24-hr and Annual). The modeled impacts were compared with National Ambient Air Quality Standards (NAAQS) and Hawaii Ambient Air Quality Standards. In addition, ambient background concentrations from State of Hawaii Annual Summary Air Quality Data from 2019, 2020, 2021, and 2022 were added to the maximum ground level concentrations predicted by the model; the total concentration was compared to the applicable state and federal standards.

Table 2-1 and Table 2-2 each lists the source release parameters and emission rates used in this modeling exercise. The listed sources were modeled with maximum hourly emission rates (converted to g/s) for short-term averaging periods and average annual emission rates (converted to g/s) for annual periods.

Table 2-1. Source Input Parameters

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Temperature (K)	Stack Diameter (m)	Stack Height (m)	Exit Velocity (m/s)
14	FH2001 (Hydrogen Reformer Heater)	594,245	2,356,269	5.00	480.37	1.96	19.15	7.80
101	FH3701 Hydrotreater Feed Heater	594,325	2,356,179	5.00	569.32	1.07	27.93	4.02
102	SG1104 Steam Generator #4	594,356	2,356,187	5.00	418.87	0.90	25.20	11.91

Table 2-2. Modeled Emission Rates (g/s)

Source ID	CO 1-hr, 8-hr	H_2S 1-hr	NO_x 1-hr	NO_x Ann	SO_2 1-hr, 3-hr, 24-hr	SO_2 Ann	$PM_{10}/PM_{2.5}$ 24-hr	$PM_{10}/PM_{2.5}$ Ann
14	6.61E-01	1.25E-03	0.00E+00	4.02E-01	1.99E-01	7.96E-02	3.31E-02	3.31E-02
101	1.71E-01	3.24E-04	7.42E-02	7.42E-02	5.16E-02	2.06E-02	8.58E-03	8.58E-03
102	1.26E+00	2.24E-03	1.78E+00	5.54E-01	3.16E+00	4.75E-01	3.74E-01	7.79E-02

Five years (2017-2021) of meteorological data were processed using surface station data from Honolulu Airport (Station ID PHNL). Upper air data were collected from the National Weather Service (NWS) station located in LIHUE Airport (Station 22536). All meteorological raw data was processed using AERMET (Version 22112). 1-minute and 5-minute Automated Surface Observing System (ASOS) data from NWS surface station was processed by the subroutine, AERMINUTE, and used for processing. AERSURFACE (Version 20060) was used to process land cover, impervious, and tree canopy data obtained from the National Land Cover Database (NLCD) website to determine the surface characteristics for use in AERMET.

The rural dispersion option was selected based on an examination of the area surrounding the site. The dominant land use types are mostly rural that include common residential, undeveloped land, and water. Therefore, the site is best characterized as "rural" and the rural dispersion option is appropriate.

Terrain data (elevations and hill heights) were processed using AERMOD's terrain preprocessor, AERMAP (Version 18081). National Elevation Data (NED) files are uploaded to the processor, which then generates elevations and hill heights for all sources, buildings, and receptors.

The modeling analysis included consideration of building downwash effects, wherein the potential for emission discharges from a stack to become caught in the turbulent wakes of structures, was evaluated. The analysis used Building Profile Input Program (BPIP-Prime) (Version 04274) to generate wind direction-specific downwash dimensions from downwash structures. AERMOD considers direction-specific downwash using the PRIME algorithm as evaluated in the BPIP-Prime program.

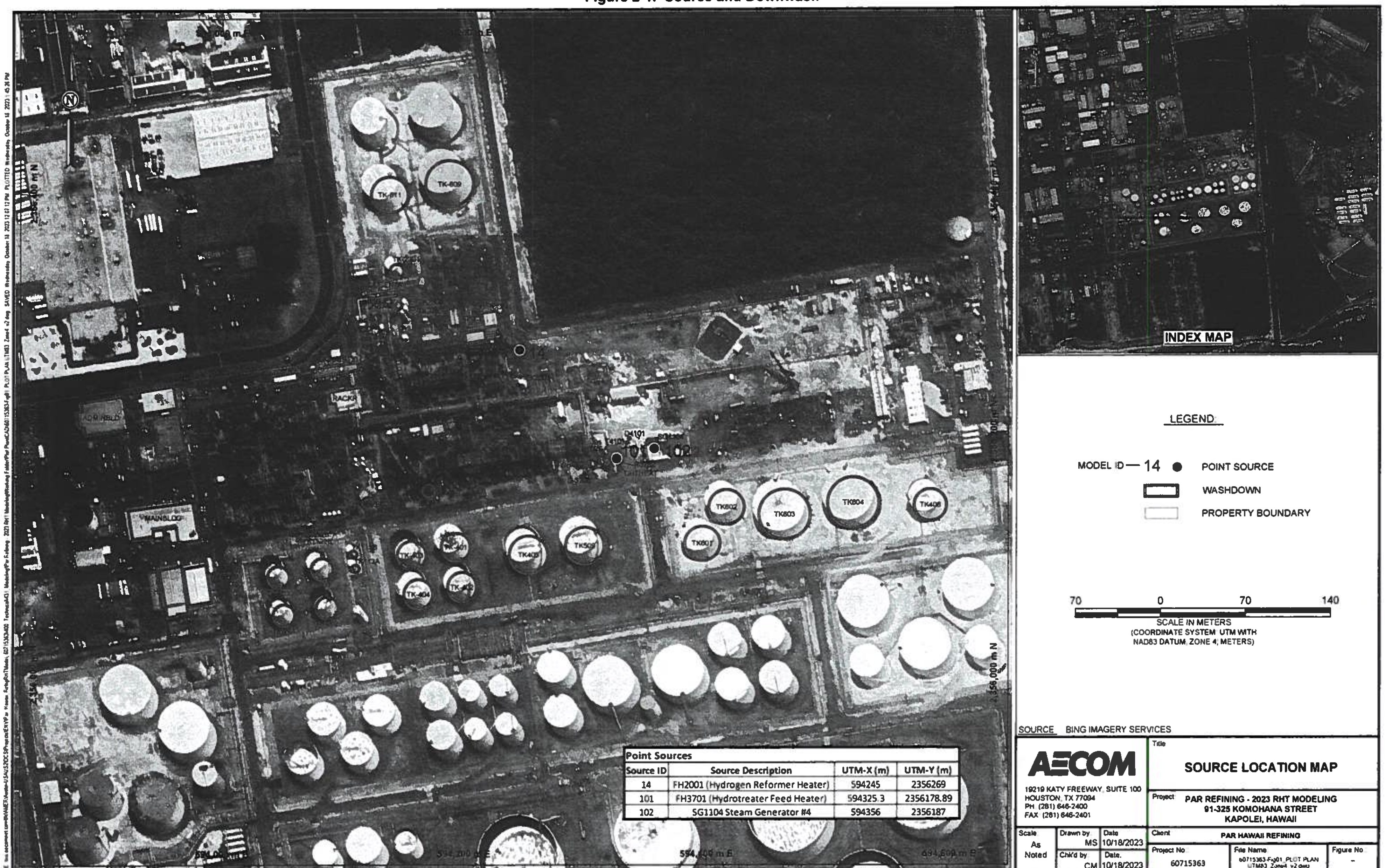
Figure 2-1 shows the plot plan of the modeled stacks, and the proposed structures overlaid the google aerial image.

The basic receptor grid as shown in Figure 2-2 used for the modeling analysis was as follows:

- 25-meter spacing extending from the property line out to 300 meters;
- 100-meter spacing within 300 meters to 1 km of property line for any locations not covered by the 25-meter grid;
- 500-meter spacing within 1 km to 5 km of property line; and
- 1,000-meter spacing within 5 km to 10 km of property line.

Figure 2-1. Source and Downwash

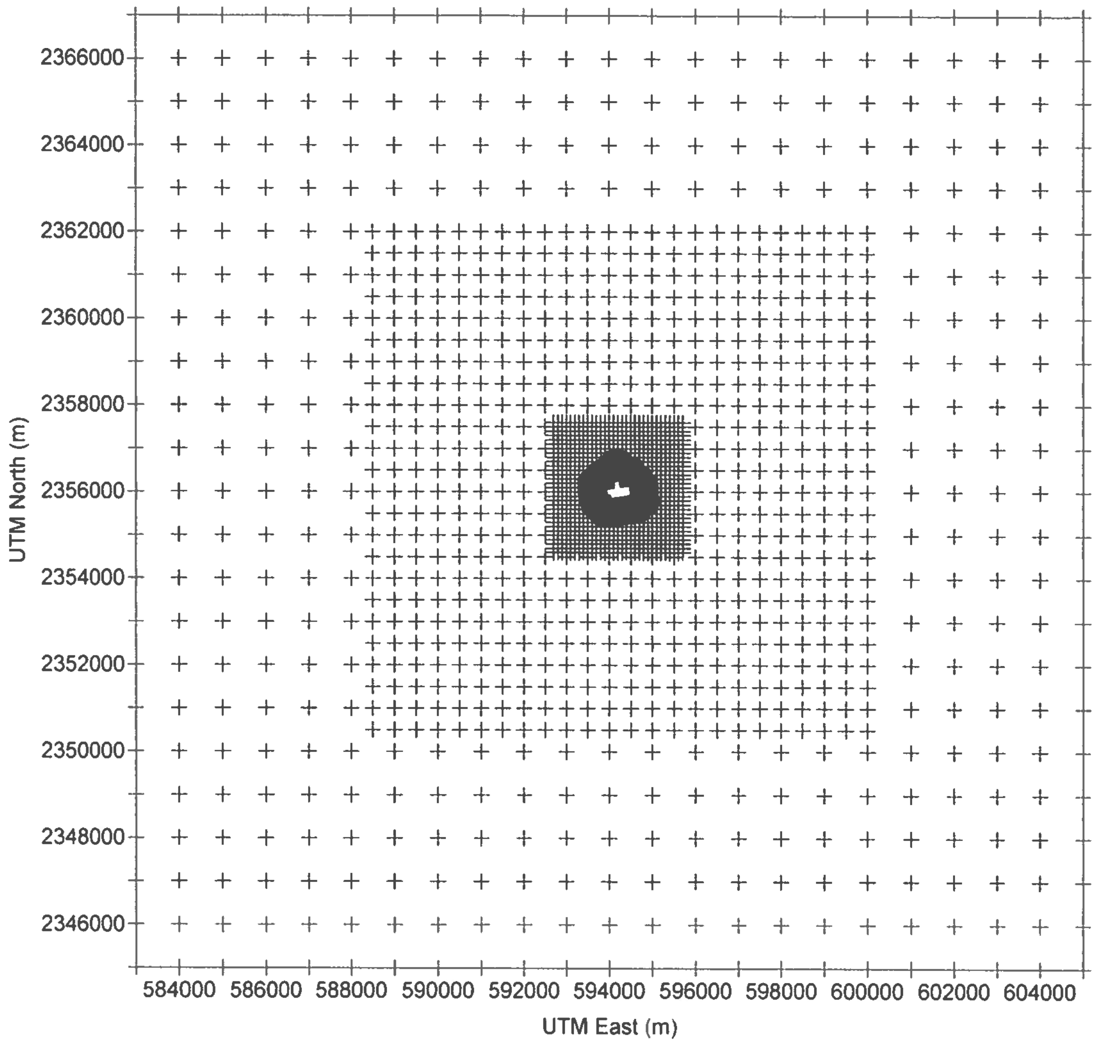
Figure 2-1. Source and Downwash



Point Sources

Source ID	Source Description	UTM-X (m)	UTM-Y (m)
14	FH2001 (Hydrogen Reformer Heater)	594245	2356269
101	FH3701 (Hydrotreater Feed Heater)	594325.3	2356178.89
102	SG1104 Steam Generator #4	594356	2356187

Figure 2-2. Receptors Grid



3.0 Air Quality Data Summary

Representative monitoring data for CO, NO_2, H_2S, SO_2, PM_{10}, and $PM_{2.5}$ was required for use in this modeling analysis.

The published air monitoring data found in the Hawaii Air Quality Data books from 2020 to 2022 were used to determine the ambient background concentrations for the CO, SO_2, PM_{10}, and $PM_{2.5}$ in this modeling analysis. Due to less than 50% of the NO_2 data recovered in the 1st and 2nd quarters in 2022, the published air monitoring data found in the Hawaii Air Quality Data books from 2019 to 2021 were used to determine the ambient background concentrations for NO_2 in this modeling analysis. The selected monitoring stations are located at Kapolei/NCore (Oahu) and Leilani (Pahoa). The Kapolei / NCore monitoring station was selected to represent CO and SO_2 ambient background, the Kapolei monitoring station was selected to represent NO_2, PM_{10}, and $PM_{2.5}$ ambient background, and the Leilani monitoring station was selected to represent H_2S ambient background. The following tables summarize the air quality data used to determine ambient background concentrations in this modeling analysis. Please note, that the 2022 background concentration for 1-hr CO at the Kapolei/NCore monitor exceeds the 1-hr CO Hawai'i state standard of 9ppm. The 2022 air quality data report has explained that in the month of August there was a brush fire right next to the station that caused the elevated levels of CO.

Table 3-1: Kapolei / NCore Air Monitoring Station Location

Kapolei / NCore			
2052 Lauwiliwili St., Kapolei, Oahu			
UTM NAD 83 Zone 4N	Northing: 2,358,251.47 m	Easting: 594,516.6 m	Altitude: 17.9 m MSL

Table 3-2: Kapolei / NCore Air Monitoring Station 2020 – 2022 Data for CO and SO_2

Gas Pollutant	Averaging Time	2020 Maximum ($\mu g/m^3$)	2021 Maximum ($\mu g/m^3$)	2022 Maximum ($\mu g/m^3$)
SO_2	1-hour	24	10	7
	99th percentile	16	7	5
	3-hour	13	8	5
	24-hour	8	5	3
	Annual	3	2	1
CO	1-hour	1375	916	10883
	8-hour	458	458	1489

Table 3-3: Kapolei Air Monitoring Station 2019 – 2021 Data for NO_2

Gas Pollutant	Averaging Time	2019 Maximum ($\mu g/m^3$)	2020 Maximum ($\mu g/m^3$)	2021 Maximum ($\mu g/m^3$)
NO_2	1-hour	64	60	56
	98th percentile	53	49	40
	Annual	8	6	6

Table 3-4: Kapolei/ NCore Air Monitoring Station 2020 - 2022 Averaging SO_2 Background Concentrations

2020 - 2022 Averaging SO_2 Background Concentrations ($\mu g/m^3$)		
SO_2	1-hour 99th percentile	9
	Annual	2

Table 3-5: Kapolei Air Monitoring Station 2019 - 2021 Averaging NO_2 Background Concentrations

2019 - 2021 Averaging NO_2 Background Concentrations ($\mu g/m^3$)		
NO_2	1-hour 98th percentile	47
	Annual	6

Table 3-6: Kapolei Air Monitoring Station 2020 – 2022 Data for PM_{10}

PM_{10} (Highest four 24-hour averages in each year)								
2020			2021			2022		
$\mu g/m^3$	Quarter	Valid/Possible (% complete)	$\mu g/m^3$	Quarter	Valid/Possible (% complete)	$\mu g/m^3$	Quarter	Valid/Possible (% complete)
43	4	Monthly Values Not Available	46	1	Monthly Values Not Available	48	4	Monthly Values Not Available
37	1	Monthly Values Not Available	34	2	Monthly Values Not Available	45	2	Monthly Values Not Available
26	4	Monthly Values Not Available	26	4	Monthly Values Not Available	38	2	Monthly Values Not Available
25	4	Monthly Values Not Available	22	2	Monthly Values Not Available	36	1	Monthly Values Not Available
Annual Average	$\mu g/m^3$	Valid/Possible (% complete)	Annual Average	$\mu g/m^3$	Valid/Possible (% complete)	Annual Average	$\mu g/m^3$	Valid/Possible (% complete)
	12.3	343/366 (93.7%)		9.2	273/365 (74.8%)		16.5	351/365 (96.2%)

Table 3-7: Kapolei Air Monitoring Station 2020 – 2022 Data for $PM_{2.5}$

$PM_{2.5}$	2020		2021		2022	
24-hr	98th percentile	3-year average (2018-2020)	98th percentile	3-year average (2019-2021)	98th percentile	3-year average (2020-2022)
	6.9	6.9	6.0	6.3	9.3	7.6
Annual	Average	3-year average (2018-2020)	Average	3-year average (2019-2021)	Average	3-year average (2020-2022)
	3.4	2.9	3.0	2.7	4.7	3.7

Table 3-8: Leilani Air Monitoring Station Location

Leilani			
13-3441 Moku St., Pahoa			
UTM NAD 83 Zone 5Q	Northing: 2,153,462.21 m	Easting: 298,896.84 m	Altitude: 229 m MSL

Table 3-9: Leilani Air Monitoring Station 2020 – 2022 Data for H_2S

Gas Pollutant	Averaging Time	2020 Maximum ($\mu g/m^3$)	2021 Maximum ($\mu g/m^3$)	2022 Maximum ($\mu g/m^3$)
H_2S	1-hour	1-hour Values Not Available	8	5

4.0 Modeling Results and Conclusions

Proposed emissions of CO, NO_x, H_2S, SO_2, PM_{10}, and $PM_{2.5}$ from the project sources were modeled. The predicted maximum ground level concentrations (GLC_{max}) with the addition of background concentration are compared with NAAQS and Hawaii Ambient Air Quality Standards. Table 4-1 presents the results of the modeling for CO (1-hr and 8-hr), NO_2 (1-hr and Annual), H_2S (1-hr), SO_2 (1-hr, 3-hr, 24-hr, and Annual), PM_{10} (24-hr and Annual), and $PM_{2.5}$ (24-hr and Annual). Impacts for all pollutants and applicable averaging periods are below the applicable standards.

Table 4-1. Modeled Impacts Summary

Pollutants	Averaging Periods	Predicted Concentrations Design Values	GLCmax	Background Calculations Basis	Background Values	Background + GLC max	Hawaii Standard		Federal Standard	
			($\mu g/m^3$)		($\mu g/m^3$)	($\mu g/m^3$)	(ppb)	($\mu g/m^3$)	(ppb)	($\mu g/m^3$)
CO	1-HR	H2H	33.28	H2H	1374.72	1408.00	9000	10310	35000	40096
	8-HR	H2H	18.86	H2H	458.24	477.11	4400	5041	9000	10310
NO_2	1-HR	maximum 98th percentile/H8H	15.48	3-year average of the 98th percentile	47.36	62.84			100	188
	ANNUAL	Maximum	2.89	3-year average of Annual Mean	6.27	9.16	40	76	53	100
H_2S	1-HR	H1H	0.06	H1H	7.73	7.79	25	35		
SO_2	1-HR	maximum 99th percentile/ H4H	33.69	3-year average of the 99th percentile	9.35	43.03			75	197
	3-HR	H2H	40.04	H2H	7.86	47.90	500	1310		
	24-HR	H2H	23.68	H2H	5.24	28.93	140	367		
	ANNUAL	Maximum	1.78	3-year average of Annual Mean	1.66	3.44	30	79		
PM_{10}	24-HR	H6H	2.18	H2H	46.00	48.18		150		150
	ANNUAL	Highest five-year average	0.30	3-year average of Annual Mean	12.67	12.96		50		
$PM_{2.5}$	24-HR	maximum 98th percentile/H8H	1.94	3-year average of the 98th percentile	7.60	9.54				35
	ANNUAL	Highest five-year average	0.30	3-year average of Annual Mean	3.70	4.00				12

5.0 REFERENCES

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Par Hawaii Refining
825 Town & Country Lane Suite 1500, Houston, TX 77024 **Check Date** 10/06/2023 **Check Number** 0000023759 **Page:** 1 of 1
(281) 899-4800 **Vendor NR** 203391 Clean Air Special Fund-Cov

Co Cd./Doc. No	Invoice Date	Invoice No	Purch.Order	Invoice Amount	Discount	Backup WH	Net Amount
0310/1900006891	10/05/2023	CSP 0212-01-C		1,000.00	0.00	0.00	1,000.00
Payment Description:	CSP 0212-01-C Permit Modification						
Total				1,000.00	0.00	0.00	1,000.00

Par Hawaii Refining
825 Town & Country Lane Suite 1500, Houston, TX 77024 (281) 899-4800

AMERICAN SAVINGS BANK, FSB
96750 KEALAKEKUA,

DATE 10/06/2023
CHECK NUMBER 0000023759

59-7076
3213

VOID AFTER 180 DAYS

$ *****1,000.00*

PAY

ONE THOUSAND & 00/100 Dollars

Par Hawaii Refining

TO THE ORDER OF

Clean Air Special Fund-Cov
Po Box 3378
Honolulu HI 96801-3378

By: [signature]

⑈0000023759⑈ ⑆321370765⑆ 81015⑈53784⑈

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MAR 21 2024

MAR 25 2024

Par Hawaii

Certified Mail: 9489 0090 0027 6525 5230 99

March 20, 2024

Ms. Marianne Rossio, Manager
Hawaii Department of Health
Clean Air Branch
2827 Waimano Home Road
Hale Ola Building, Room 130
Pearl City, Hawaii 96782

Dear Ms. Rossio:

Subject:

Par Hawaii Refining, LLC: Petroleum Refinery, CSP No. 0212-01-C
Significant Permit Modification
Renewable Fuel Production Facility
Revised Application Packet

Dear Ms. Rossio:

Par Hawaii Refining is hereby submitting a revised application packet for a significant modification to Covered Source Permit (CSP) No. 0212-010C, to construct a renewable fuel production facility by converting the Diesel Hydrotreater (DHT) to a Renewable Hydrotreater (RHT) and adding a renewable feedstock pretreatment unit (PTU) and high-pressure (700 psia) steam generating boiler to the refinery. We respectfully request that the previous application that was submitted on December 8, 2023 be replaced by this one in its entirety. An updated ambient air quality analysis and Form C-1 is included in this packet. All emissions calculations remain unchanged.

As part of Par Pacific's renewable fuels strategy, PHR plans to develop and commission the state's largest renewable fuel production facility in Kapolei to supplement existing conventional fuel production by 2025. This strategy aligns with the national Renewable Fuel Standard (RFS) program that was created to "reduce greenhouse gas emissions and expand the nation's renewable fuels sector while reducing reliance on imported oil.[1]" The RFS program "requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel.[2]" The Renewable Fuel Production Facility will enable PHR to meet its federally- mandated renewable volume obligation (which is more than 12% in 2024) and to meet the growing demand for low-carbon and renewable fuel in the State.

The renewable fuel production facility consists of two parts, the renewable feedstock pretreatment unit (PTU) and the renewable hydrotreater (RHT) unit. The PTU will have a capacity of 5,000 barrels per day (BPD) to treat the renewable feedstock prior to processing in the RHT. A new high-pressure (700 psia) steam generating boiler will support operation of the PTU and be added to the refinery's steam/utility system. The RHT will have a capacity of 4,000 BPD and process treated renewable feedstocks into renewable biofuels including renewable diesel (RD),

[1] https://www.epa.gov/renewable-fuel-standard-program

[2] https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard

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sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (renewable LPG). The RHT unit will be able to flex between maximum SAF and RD mode depending on the market environment for each of those products.

Aside from a potential increase in demand and emissions from the existing DHT Feed Heater, H-3701, and the Hydrogen Reformer Furnace, H-2001, the project will include a new 99 MMBTU/hr steam generating boiler, SG1104, relocated from Par West, which will be fired on refinery fuel gas (RFG) and distillate oil. The boiler will be equipped with low NOx burners (LNB's) and a flue gas recovery system. Built in 2007, the boiler is subject to New Source Performance Standard (NSPS) Subpart J which regulates SO2 emissions. However, because the refinery operates on a singular fuel gas system which, has been subject to NSPS Subpart Ja since 2019, the hydrogen sulfide (H2S) content of the RFG fuel will be limited to no more than 60 ppm on an annual basis as required by NSPS Subpart Ja standards. Similarly, the potential-to-emit (PTE) SO2 emissions will also be limited based on the NSPS Subpart Ja standards. More specifically, the SO2 concentration of the flue gas will be limited to no more than 20 ppm (corrected to 0% excess air) on a 3-hour basis and average no more than 8 ppm on an annual basis (corrected to 0% excess air).

Potential air emissions for the renewable fuel production facility will remain below the regulatory thresholds specified under the federal Prevention of Significant Deterioration (PSD) program. However, since Criteria Air Pollutant (CAP) and Hazardous Air Pollutant (HAP) emissions will increase and exceed the state's minor permit modification thresholds, a significant permit modification is required for the refinery's air permit. A more comprehensive description of the emissions changes is provided in this application package.

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.

If there are any specific questions concerning our request or the emission calculations, please call Anna Chung at (808) 440-5576.

Sincerely,

Deaglan McClean
Vice President, Par Hawaii Refining

Attachments

cc: Darin Lum Darin.Lum@doh.hawaii.gov

Chief
Permits Office, (Attention: Air-3)
Air Division, USEPA Region 9
75 Hawthorne Street
San Francisco, CA 94105

Par Hawaii Refining

Permit Application Packet

Renewable Fuel Production Facility

March 2024
Revised

Contents

Background

Par Hawaii Refining (PHR) owns and operates a petroleum refinery in Campbell Industrial Park, located in the city of Kapolei, Hawaii. The refinery produces jet, diesel and gasoline for the island of Oahu and neighboring islands. Combustion equipment at the refinery includes heaters, boilers, furnaces, a cogeneration unit, incinerator, thermal oxidizer, and flare.

As part of Par Pacific's renewable fuels strategy, PHR plans to develop and commission the state's largest renewable fuel production facility in Kapolei to supplement existing conventional petroleum fuel production by 2025. This strategy aligns with the national Renewable Fuel Standard (RFS) program that was created to "reduce greenhouse gas emissions and expand the nation's renewable fuels sector while reducing reliance on imported oil.[1]" The RFS program "requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel.[2]" The Renewable Fuel Production Facility will enable PHR to meet its federally-mandated renewable volume obligation (which is more than 12% in 2024) and to meet the growing demand for low-carbon and renewable fuel in the State.

The renewable fuel production facility will process treated renewable feedstocks into renewable biofuels including renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (renewable LPG). The refinery plans to redesign and repurpose the existing Diesel Hydrotreater (DHT) and convert it into a Renewable Hydrotreater (RHT). The RHT will have a capacity of 4,000 barrels per day (BPD) and be able to flex between maximum SAF and RD mode depending on the market environment for each of those products. This project also includes the construction of a renewable pretreatment unit (PTU) with a capacity of 5,000 BPD to treat the renewable feedstock prior to processing in the RHT and a new high-pressure (700 psia) steam generating boiler.

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[1] https://www.epa.gov/renewable-fuel-standard-program
[2] https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard

Project Description

The proposed renewable fuel production facility consists of two parts, the renewable feedstock pretreatment unit (PTU) and the renewable hydrotreater (RHT) unit. A new high-pressure (700 psia) package boiler is needed to support operation of the PTU and will be added to the refinery's steam/utility system. Pretreatment of the renewable feedstock primarily removes gummy and phosphorous contaminants before being processed in the RHT. As implied by its name, the RHT utilizes hydrogen to remove oxygen from bioseed oils and other renewable feedstocks. The refinery's existing and fully permitted hydrogen generating unit (HGU) will not be modified but will be more fully utilized to provide hydrogen for the RHT.

The most likely feedstock for the renewable fuel production facility (PTU and RHT) is imported soybean oil. Other sources include locally produced biofuel crops (such as camelina), vegetable oils (canola oil and distiller's corn oil). Used cooking oil, tallow, and other animal fats will also be considered, and may become equally viable renewable feedstocks for the RHT. The primary biofuels that will be produced by the RHT are renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (renewable LPG). Nine (9) existing petroleum storage tanks will be converted, and two (2) new tanks will be constructed to store renewable feedstocks and renewable fuels produced by PHR.

Pretreatment Unit (PTU)

The renewable PTU is designed to process 5,000 BPD of untreated renewable feedstock. The PTU utilizes high pressure (700 psia) steam and is comprised of feedstock tanks, a feed vacuum deaerator, reaction and mixing towers, and various feed filters, heat recovery exchangers and oil/water separators. Untreated renewable feedstock will be imported to the refinery via barge or isotainer and stored in four (4) tanks; two (2) existing vertical fixed-roof tanks, TK-602, TK-603, and two (2) new vertical fixed-roof tanks, TK-701 and TK-702. Untreated renewable feedstock, such as soybean oil, is vacuum dried and preheated to about 200 °F by waste heat and fed to the bottom of a high-pressure reactor.

A high-pressure package boiler (F2505) will be relocated from Par West (the former Chevron Hawaii Refinery) and recommissioned as SG1104 at Par East. It will be used to supply 700 psia steam and is described separately below. The steam is injected into the high-pressure extraction reactor (R-4101), where it mixes with the untreated renewable feedstock. The hot oil is transferred to the water wash tower (T-4101), where it rises up the column and cold water, added at the top, flows downward creating a counter-current flow of oil and water. The temperature, pressure, and time of contact between water and oil is controlled to allow water to remove (extract) gums, phosphorous, and other contaminants from the untreated renewable feedstock. The renewable feedstock exits the top of the column and goes through a coalescer to remove entrained water and the treated renewable feedstock is sent to the RHT via intermediate tankage. Water exiting the extraction column bottom is passed through a coalescer to remove oil carryover and other entrained impurities, before being discharged to an underground injection well. An additional pretreatment step may be required before injection of the non-toxic aqueous effluent from the PTU. Because the untreated and treated renewable feedstocks have no measurable amount of volatile organic compounds (VOCs) and hazardous air pollutants (HAPS), no significant air emissions are expected from the PTU and related renewable feedstock tanks.

Renewable Hydrotreater Unit (RHT) (Re-purposed Distillate Hydrotreater (DHT))

The RHT will be designed to process 4,000 BPD of treated renewable feedstock into renewable biofuels. Primary biofuels produced will be renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN) and renewable liquefied petroleum gas (Renewable LPG). The existing DHT consists primarily of a catalytic hydrotreating reactor, a charge heater, and a fractionation tower. The conversion of the DHT to the RHT includes modifying the existing reactor into an isomerization reactor, constructing a new larger catalytic hydrotreating reactor, and adding several new exchangers, pumps, towers, compressors, and a mixer. Existing vertical fixed-roof tank, TK-601, will be converted into treated feedstock storage and retrofitted with an internal floating-roof to protect its contents from exposure to air to mitigate corrosion. Five (5) existing vertical floating tanks, TK-401, TK-402, TK-403, TK-404, and TK-201, will also be converted to renewable biofuel storage tanks.

The amount of hydrogen needed to support the RHT will be nominally 3000 standard cubic feet (scf) per barrel of renewable feed, or about 10-13 MMSCF/day. Relative to the refinery's current baseline operation, the additional hydrogen required for the RHT will be produced by the Hydrogen Generating Unit (HGU). Hydrogen for the RHT may also be provided by the Catalytic Reforming Unit (CRU) when the HGU is not operating. The HGU will not be modified or expanded to support the operation of the RHT, however the existing design capacity of the HGU will be more fully utilized. Hydrogen from the HGU will be supplied to the RHT from a new compressor (C-3702) and hydrogen from the RHT will be recovered and routed back to the Distillate Hydrocracker (DHC) via existing compressors. Renewable LPG generated from the RHT would be used as the feedstock to the HGU. Alternatively, to further the State's goal that public utilities reduce GHG emissions, the renewable LPG may be sold as feedstock to the neighboring Synthetic Natural Gas (SNG) plant owned by Hawaii Gas.

The RHT will generate significantly less sulfur than the current DHT operation because, by comparison, there is relatively little sulfur in the renewable feedstock. Any sulfur removed by the RHT in form of sour off-gas will be routed to the existing Amine Treating Unit (ATU) and Sulfur Recovery Plant (SRP) along with sour off-gas from other refinery process units. The capacity of the ATU and SRP are adequate to handle the sulfur generated by and ultimately removed from the RHT.

High-Pressure (700 psia) Steam Generator (SG1104)

A new steam generator (SG1104) manufactured by Foster Wheeler will be relocated and installed principally to supply 700 psia steam to the high-pressure extraction reactor (R-4101) in the PTU. Excess steam may also be supplied to existing refinery operations. The Foster Wheeler package boiler (Model AG-5060, Serial No. 7414, National Board No 585) was built in 2007 and designed with 765 psi MAWP. It will be operated to produce about 75,000 lb/hr of 700 psi steam while operating at the design/permitted firing rate of 99 MMBtu/hr (HHV).

The relocated package boiler will normally be fired either on refinery fuel gas (RFG) or low sulfur distillate oil. The boiler has the capacity to be fired on both fuels simultaneously, but based on its historic use by Chevron, dual fuel mode of operation is expected to be uncommon. The boiler's annual fuel use and heat input has been limited in this permitting action to 551,880 MMBTU/year, which is the equivalent of an annual average firing rate of 63 MMBtu/hr. Although the boiler is projected to normally operate at about 35% of its Maximum Continuous Rating (MCR) to support operation of the PTU, at times, the full fired duty (i.e. 99 MMBTU/hr) and steam generating capacity of SG1104 will be utilized. The relatively new boiler has a Low NOx Burner (LNB) and was designed with a fully integrated and automated flue gas recirculation (FGR) system to control NOx emissions.

The relocated package boiler is the primary source of new air emissions associated with and required for the renewable fuels production facility. The package boiler, which in addition to having a FGR, is equipped with an economizer and super heater, was built in 2007 and is subject to New Source Performance Standard (NSPS) Subpart J which regulates SO2 emissions. However, because the refinery operates on a singular fuel gas system, which has been subject to NSPS Subpart Ja since 2019, the hydrogen sulfide content of the RFG used to fire SG1104 will be limited to no more than 230 mg/dscm (0.10 gr/dscf). This is equivalent to 162 ppm Subpart J limit and the more stringent Subpart Ja standard which limits the H2S content to no more than 60 ppm on an annual average basis. Because of the common fuel gas system, and as reflected by Title V permit condition, the SO2 concentration of the flue gas from SG1104 will be limited to no more than 20 ppm and average no more than 8 ppm on an annual basis while firing exclusively on RFG. Both the short term and long term SO2 concentration limits are expressed on dry basis (corrected to 0% excess air) and typically assured by monitoring the H2S content of the RFG because the boiler may be cofired.

Liquid fuel firing of the new high-pressure (700 psia) boiler is essential because the refinery's other two steam generators (SG1102 and SG1103) are low pressure (235 - 250 psia) and because there are intermittent shortages of RFG based on the type and composition of crude oil being refined. Additionally, SG1103 only burns RFG. To control SO2 emissions while firing SG1104 on distillate oil, the boiler would be restricted to burn only distillate oil with sulfur content limited to no more than 0.25% by weight. The limit on the sulfur content of the distillate fuel is not mandated by State or federal regulations but, is being proposed as an enforceable permit condition to cap or limit SO2 emissions. The sulfur content of the distillate oil will be sampled and analyzed by the refinery's lab at least once a week.

While NOx emissions from the 99 MMBTU/hr boiler are well controlled because it is equipped with FGR and a low NOx burner, principally to stay under the 40 TPY PSD threshold for the entire renewable fuels project, the use of distillate oil will be limited to 110,376 MMBtu/yr (equivalent to 788 thousand gallons per year) which is approximately 20% of the total heating value of the fuel (in terms of BTU's) that may be used to fire the boiler throughout the year, with the balance of heat input coming from RFG.

The limitation on the type of liquid fuel, distillate oil as defined by 40 CFR 60.41(c) (with a sulfur content of less 0.25%), and the amount of distillate oil (or more precisely the amount of heat from distillate oil) will have the combined effect of also limiting emissions of most criteria and non-criteria pollutants. Because the package boiler was built in 2007, it is also subject to NSPS Subpart Dc which also limits particulate matter (PM) emissions, but because the fuel use is being limited to RFG and clean burning low (<0.25%) sulfur distillate fuel, the PM emissions limit and many of the related requirements do not strictly apply. As explicitly provided by 40 CFR 60.43c(e)(4) because SG1104 will be fired on RFG or low sulfur distillate oil (< 0.5 wt%), it is not bound to the PM limits and testing requirements in NSPS Dc. Although this is true, PHR is proposing to voluntarily accept the 0.03 lb/MMBTU particulate emission limit set forth by 60.43c(e)(4) as an enforceable permit limit, to ensure that the 10 TPY PSD threshold for particulate matter is not exceeded. Without a stringent PM limit in place, the maximum potential-to-emit (PTE) particulate under the PSD analysis would have been projected and only limited by the 0.22 lb/MMBTU limit of NESHAPS Subpart DDDDD, for non-continental combustion sources, most of which burn a heavier mix of residual and distillate fuel.

Likewise, because the liquid fuel used to fire SG1104 will be limited to low sulfur distillate oil, which produces relatively little hazardous air pollutants (HAPS), the relocated package boiler will readily meet the CO and filterable PM emissions limits and national emission standards specified in NESHAPS Subpart DDDDD for non-continental steam generators (and process heaters) which burn liquid fuel. While the selection and restriction on fuel type severely limits the potential for metallic HAPS, the voluntary addition of a 0.03 lb/MMBTU PM limit, which is much more stringent than the 0.22 filterable PM limit specified for non-continental combustion, ensures that HAPS will be well controlled and that the PSD threshold for PM will not be encroached upon. With the 0.03 lb/MMBTU PM limit on SG1104 (which, as stated before, can fire low sulfur distillate oil), the potential to emit for PM emissions is less than 3 TPY. Additional details on the PSD determination are discussed and quantified in subsequent sections.

The location of the new renewable PTU and RHT is shown in Appendix A. Process Flow Diagrams for the renewable fuel production facility and the design specifications for the new steam generator are included in Appendix B.

Emission Estimates for Relocated and New Emission Sources

Distillate Oil and Fuel Gas Combustion in Relocated SG1104

Emissions from the relocated steam generator (SG1104) will occur at the stack described below.

Emission Point ID	24
UTM East (m)	594356
UTM North (m)	2356187
Elevation (m)	4.88
Height of Stack (m)	25.0
Temp (K)	300
Exit Velocity (m/s)	7.14
Diameter (m)	0.90

Peak, short-term hourly emissions rates (lb/hr) for the boiler are determined for each pollutant based on the fuel (either RFG or distillate oil) with the highest emission rate for that pollutant (at the max design operation rate of 99 MMBtu/Hr). The maximum total annual emission rate (TPY) for the boiler, for each pollutant was determined by multiplying the emission factor for each fuel (subject to the annual fuel use limit for that fuel) and then summing the two.

Distillate Oil Combustion

Hourly emissions for SG1104 while firing distillate oil are calculated by multiplying emission factors by the maximum design heat input capacity of 99 MMBtu/hr. Annual emission rates are calculated by multiplying the same emission factors by the fuel cap limit of 9,198 MMBtu/month based on a rolling 12-month average which is approximately equal to 12.6 MMBtu/hr of distillate fuel.

The physical properties of the distillate fuel used in emissions calculations are as follows:

HHV	= 140,000 Btu/gal, as provided in AP-42 Section 1.3 - Fuel Oil Combustion
Sulfur Content	= 0.25 wt% limit, proposed limit
Fd	= Dry Fuel Factor (SCF/ MMBtu) = 9190 SCF/ MMBtu, based on Part 60 Meth.19 & Part 75 Table 1

The emission factors for low-sulfur distillate oil are as follows:

CO	= 0.101 lb/MMBtu based on the MACT limit of 130 ppm at 3% O2
NH_3	= 0.8 lb/1000 gal, based on EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emission. Factor, Table 5-2, 8/94 (3.2 lb/MMscf).
Pb	= 0.000009 lb/MMBtu, based on AP-42, Table 1.3-10
NO_x	= 0.143 lb/MMBTU based AP42 Table 1.3-1 (20 lb/1000 gal) and an equivalent NOx limit of 130 ppm at 0% excess O2 proposed by the applicant along with fuel use limits to prevent from exceeding a PSD threshold.
SO_2	= 35.5 lb/1000 gal, based on AP-42, Table 1.3-10 and a proposed sulfur limit of 0.25 wt% in distillate oil.
VOC	= 0.2 lb/1000 gal, based on AP42 Table 1.3-3
PM_{Tot}	= 0.03 lb/MMBtu, proposed limit based on the NSPS Subpart Dc (and parallels NESHAPs Subpart JJJJJJ Table 1)
PM_{10}	= 0.03 lb/MMBtu, proposed limit based on the NSPS Subpart Dc (and parallels JJJJJJ Table 1)
$PM_{2.5}$	= 0.03 lb/MMBtu, proposed limit based on the NSPS Subpart Dc (and parallels NESHAPs Subpart JJJJJJ Table 1)
HCl	= 0.0011 lb/MMBtu based on MACT DDDDD Table 2.
Mercury	= 0.00000073 lb/MMBtu based on MACT DDDDD Table 2.
Total Greenhouse Gases (GHGs) CO2e	0.0163 lb/MMBtu (based 40 CFR 98 calculation methodologies, using standard emission factors for CO2, CH4 and NO2.
Other Individual HAPs	lb/MMBtu or lb/1000gal rates from rates from AP-42 Section 1.3 - Fuel Oil Combustion. Tables 1.3-1,2,3,6,8,10,14. May 2010. Uses factors for Distillate oil when available.

Based on the fuel use limitations and emission factors above, the potential emissions from operation of SG1104 on distillate oil are shown on permit application Form S-1 and calculations in Appendix C, Table C-2.

Fuel Gas Combustion

Hourly emission rates for SG1104 while firing on fuel gas are calculated by multiplying emission factors by the max design operation rate of 99 MMBtu/Hr. Annual emission rates are calculated by multiplying the same emission factors by the fuel cap limit of 36,792 MMBtu/month based on a rolling 12-month average or approximately equal to 50.4 MMBtu/hr of fuel gas.

While firing on RFG, the boiler will be subject to the NSPS J standard which limits the H2S in the fuel gas to no more than 162 ppm on volume basis for any 3-hour period, and because of the common fuel gas system the H2S will be limited to less than 60 ppm over a 365-day average. These limits along with a 98% combustion efficiency factor are used to determine the H2S slip and resulting emissions in Appendix C. Likewise, the new and closely aligned NSPS Ja standard for SO2 in flue gas (20 ppm on volume basis for any 3-hour period, and 8 ppm over a 365-day average) will be explicit permit limits and are used as the basis for emission estimates.

The physical properties of the RFG used in emissions calculations are as follows:

HHV	= Higher Heating Value (Btu/SCF) = 1595 Btu/SCF
Fd	= Dry Fuel Factor (SCF/ MMBtu) = 8622 SCF/ MMBtu

Note: Even though the Title V permit includes several references to a more typical heating value for RFG (1476 BTU/SCF) and a dry fuel factor of 8740 SCF/BTU, to be consistent with the air emissions modeling the physical properties of the RFG presented above were based on the two most recent years (2021-2022) of refinery lab analysis. Notably only the dry fuel factor (a near constant) is used to convert common concentration-based limits to equivalent lb/MMBTU emission factors through application of the generalized equation below.

$$\text{lb/MMBTU} = \frac{(\text{Pollutant PPM at 0\% excess O2}) * (\text{Pollutant MW}) * (\text{Fd SCF/MMBTU})}{(1{,}000{,}000) * (385.3\ \text{SCF/Mole})}$$

Because there is little variability in Fd factors for each category of gaseous or liquid fuel, the calculated or published lb/MMBTU emission factors do not vary much based on the composition of the RFG or the low sulfur oil (over time). Even though HHV of natural gas, propane and butane range from 1050 to 3225 BTU/SCF, in Method 19 of Appendix A-7 to Part 60 the EPA assigned a singular Fd factor of 8710 SCF/BTU for all three because the ratio of carbon to hydrogen in all of these gases is nearly the same. So, too, is the amount of flue gas from their combustion.

The emission factors for RFG used for estimating emissions for this project are as follows:

CO	= 0.095 lb/MMBtu based on the MACT limit of 130 ppm at 3% excess O2 and an average Fd factor of 8622 dscf/MMBtu
H_2S (3-hr)	= 0.00018 lb/MMBtu, NSPS Ja limit of 162 ppmv in RFG with 98% destruction efficiency upon combustion and 2% slip-by

NH_3	= 0.0020 lb/MMBtu, based on EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emission Factor, Table 5-2, 8/94 (3.2 lb/MMscf).
Pb	= 0.00000049 lb/MMBtu, based on EPA's Emission Estimation Protocol for Petroleum Refineries, version 3, April 2015, Table 4-3.
NO_x	= 0.051 lb/MMBtu, based on a NOx concentration limit of 50 ppm at 0% excess O2 proposed by the applicant along with fuel use limits to prevent from exceeding PSD threshold.
SO_2 (3-hr) (365-day)	= 0.029 lb/MMBtu, NSPS Ja limit of 20 ppmv in flue gas = 0.011 lb/MMBtu, NSPS Ja limit of 8 ppmv in flue gas (ppm limits are for dry flue gas, at 0% excess air)
VOC	= 0.0035 lb/MMBtu, based on AP-42, Table 1.4-1 boilers fired on natural gas (5.5 lb/MMSCF)
PM_{Tot}	= 0.00476 lb/MMBtu, based on AP-42, Table 1.4-1 for natural gas (7.6 lb/MMscf), includes filterable and condensable. (All PM assumed PM 2.5)
Total Greenhouse Gases (GHGs) CO2e	0.013 lb/MMBtu, based on 40 CFR 98 calculation methodologies, using 2021-2022 sample data for CO2 and standard emission factors for CH4 and NO2.
Individual HAPs	lb/MMBtu rates from EPA's International's Emission Estimation Protocol for Petroleum Refineries- Table 4-3.

Based on the fuel use limitations and emission factors above, the potential emissions from operation of SG1104 on RFG are shown on permit application form S-1 and calculations in Appendix C, Table C-2.

New Untreated Renewable Feedstock Tanks, TK-701 and TK-702

Two (2) new vertical fixed cone-roof tanks 701 and 702 will be constructed to store untreated renewable feedstock for the pretreatment unit. The 2 new heated tanks (TK-701 and TK-702) will be built in the same location that had been previously planned for permitted ethanol tanks (Tk-518 and Tk-519), which were never constructed.

Although the most likely option for feedstock is soybean oil, other options include seed oil, used cooking oil, and animal fats. Emissions from these tanks are considered insignificant because soybean oil, other seed oils and animal fats are all low volatility and essentially void of VOCs and HAPs. The Clean Air Branch affirmed this determination by issuing an insignificant activity approval letter (dated August 9, 2023) authorizing construction and operation of Tanks 701 and 702.

There are no significant emissions or controls required for the tanks because vegetable/seed oil/animal fat has low volatility and have no or negligible hazardous air pollutants (HAPs) present. Likewise, there are no applicable state or federal regulations for TK-701 and TK-702. Associated piping, pumps and filters to the tanks are also exempt from fugitive monitoring and requirements because they are free of VOCs and HAPs.

New RHT Fugitive Emissions

In addition to repurposing much of the existing DHT, a number of new vessels and towers, reactors and exchangers will be installed for the RHT. As with the DHT, miscellaneous sources of potential equipment leaks of VOC, including valves, pumps, pressure relief devices sampling connection systems, open-ended valves or lines, and flanges or other connectors in VOC service, will be subject to New Source Performance Standards (NSPS) Subpart GGGa. Unless not commercially available, all new valves in light hydrocarbon service will be Certified Low Leaking Technology (CLLT) valves or packed with Certified Low Leaking Packing to reduce VOC emissions. The leak threshold for fugitive emissions from pumps will be 2,000 ppm and the leak threshold from valves will be 100 ppm.

Detailed emissions calculations are provided in Appendix C. Calculations were based on the EPA Emission Estimation Protocol for Petroleum Refineries and an approximate count of components based on design plans. Potential emissions from the new fugitive sources are also shown on permit application form S-1.

The following correlation equations from Table 2-2 of the Emission Estimation Protocol for Petroleum Refineries (Version 3, April 2015) were used to determine VOC emissions from each component:

kg/hr/valve	= 0.00000229*(SV^0.746), where the screening value (SV) is 100 ppm based on the Certified Low Leak Technology (CLLT) limit.
kg/hr/pump	=0.0000503*(SV^0.61), where the SV is the monitoring leak threshold of 2,000 ppm
kg/hr/connector	=0.00000153*(SV^0.735), where the SV is the monitoring leak threshold of 500 ppm for connectors that will be monitored with valves
kg/hr/sample connection	=0.0000136*(SV^0.589), where the SV is the Standard leak threshold of 10,000 ppm for remaining sources (Except compressors)

The new compressors are excluded from the fugitive emissions calculations because they will be routed to the flare.

Annual VOC and speciated emissions were obtained by multiplying the hourly emission rate by 8760 hours per year. The total VOCs from the fugitive sources above were then speciated as individual HAP and non-HAP constituents following Table 2-7 concentration ratios for Hydrotreating/Hydrodesulfurization and the methodology in the Emission Estimation Protocol for Petroleum Refineries.

The potential emissions from fugitive emissions in the RHT are shown on permit application form S-1 and Appendix C, Table C-3. While not specified in the Emission Protocol, estimates for some additional pollutants are included in Table C-3 based on typical emission profiles from storage tanks at the refinery as well as Polycyclic Organic Matter expected to be proportional to naphthalene emissions.

New Biogenic CO2e Byproduct from RHT

In addition to producing a variety of renewable fuels, the RHT will also produce a relatively small (1,325 TPY) amount of biogenic CO2 byproduct which will pass to the refinery fuel gas system and released through various refinery fuel gas combustion sources. The additional emissions associated with the CO2 byproduct from the RHT are also captured in Form S-1 and Appendix C, Table C-1.

Additional Emissions from Increased or Alternative Utilization of Existing Sources

Effected Sources - Tanks

Eleven (11) tanks will be used to support the renewable fuel production facility, two (2) new, TK-701 and TK-701, and nine (9) existing, TK-201, TK-401, TK-402, TK-403, TK-404, TK-517, TK-601, TK-602, TK-603. The properties of the renewable feedstock and biofuel are compatible with the existing petroleum-based storage tanks they will be stored in. However, TK-601 will be retrofitted with an internal floating roof to protect the treated renewable feedstock from exposure to air for corrosion mitigation and not for regulatory reasons. Existing tank utilization will not increase and there are no emissions increases expected. New tanks 701 and 702 have no significant emissions, as described earlier under "New Emission Sources". Table 1 below lists all the tanks that will support the Renewable Fuel Production Facility with their current and future contents.

Table 1. RHT Tank Storage

Tank No.	Liquid Stored	
	Current	Future
TK-701	*new*	Untreated Renewable Feedstock
TK-702	*new*	Untreated Renewable Feedstock
TK-601	Fuel Oil	Treated Renewable Feedstock
TK-602	Fuel Oil	Untreated Renewable Feedstock
TK-603	HS Vaccum Resid	Untreated Renewable Feedstock
TK-517	Heavy Oil/Water	Heavy Oil/Water/ Transmix (Pipeline Interface-Diesel & Renewable Feedstock)
TK-401	Jet A	SAF/RD
TK-402	Jet A	SAF/RD
TK-403	Jet A	RD
TK-404	Jet A	RD
TK-201	Naphtha	RN

Effected Sources – Combustion Sources

H-3701 Potential Emission Increase from Actual to Design (PTE)

The RHT will directly utilize the existing feed heater H-3701 (for which PTE will now use the maximum safe design capacity).

The emissions factors for H-3701 are the same as those presented above for the combustion of RFG in SG1104, with the exception of NOx emissions, for which there is a different basis and limit.

NOx	= 0.040 lb/MMBtu based on design basis of 40 ppm at 0% excess O2 and an average Fd factor of 8622 dscf/MMBtu (as previously permitted). However, due to the increase to maximum safe design capacity (30 MMBtu/hr) the equivalent NOx emission limit requested is 1.24 lb/hr (vs 1.05 lb/hr currently specified on the permit). The limit was set as a mass rate because NOx concentrations are not as well controlled when firing the heater at low rates.

Based on the maximum safe design duty of 30 MMBTU/hr and the emission factors above, the potential emissions from operation of H-3701, are also shown on permit application form S-1 and in Appendix C, Table C-4.

Note: Although the PTE's have been calculated at the requested maximum design rate as required for the PSD assessment, the applicant is expecting H-3701 will be fired less as the RHT feed heater than it had historically been fired as the DHT feed heater.

H-2001 Projected Emission Increase from Actual to Max Permitted (PTE)

The new RHT will require more hydrogen to remove oxygen from the renewable feedstocks. Because the Catalytic Reforming Unit (CRU), which produces hydrogen as by-product of the reforming process, is already operated at near maximum rates, additional hydrogen for the RHT will be supplied by the Hydrogen Generation Unit (HGU).

In order to accommodate the product demand growth for hydrogen, the HGU will be more routinely operated at a rate of about 18 MMSCF/D and H-2001 will be fired at an estimated average rate of 132.8 MMBtu/hr. Because of the RHT, H-2001 will fire harder than normal which will lead to an increase in actual emissions from H-2001. Although H-2001 was designed and permitted for 172.8 MMBtu/Hr to accommodate peak (and future demand), the hydrogen reformer furnace is already effectively limited to a 12-month rolling average limit of 132.8 MMBTU/hr by an existing permit condition which limits the 12-month rolling average of RFG to 90,000 SCF/Hr. PHR is proposing to retain the existing PSD limits for NOx emissions and requests to list it as a heat input limit which equates to 132.8 MMBTU/hr instead of 90,000 SCF/hr.

For most pollutants, the emissions factors for H-2001 are the same as those presented above for the combustion of RFG in SG1104, because both combustion sources are equipped with low and FGR. Whereas there is no NOx CEMS on SG1104 however, the hydrogen reformer furnace is equipped with a CEMS and subject to the consent decree. Therefore, emissions estimates for baseline TPY, baseline maximum lb/hr, and future maximum lb/hr (not expected to change) are based on actual CEMS data. Emissions for future/potential TPY are based on the on 365-day rolling limit of 50 ppm at 0% as specified by the Title V permit and the consent decree (equivalent to 0.051 lb/MMBtu).

Based on the full proposed heat input limits and the emission factors above, the potential and projected actual emissions increase from operation of H-2001, are also shown on permit application form S-1 and in Appendix C, Table C-5. Note that calculations of PTE minus baseline are conservatively higher than would be allowed by rule (40 CFR 52.21(b)41)(ii)(c)) which could further exclude the additional hydrogen product demand that the existing unit could have accommodate.

Feedstocks to the HGU will also increase, which generate an additional amount CO2 byproduct (36,769 TPY, 67% of which will be biogenic). Other refinery units will continue to operate and will not be affected. Potential emissions above baseline actuals for the affected units are shown on permit application form S-1 and in Appendix C, Table C-6.

Insignificant Addition of Transmix to Refinery Fuel Oil

As a result of the pipeline flush during the receipt of renewable feedstock from the barge harbor, a negligible amount of transmix (~20 BPD) composed of roughly 50% low sulfur diesel and 50% renewable feedstock may be blended into the current refinery fuel oil system for on-site combustion in fuel oil sources. There will be no increase in fuel oil consumption and no change to the fuel oil specification itself. Tank 517 (listed in Table 1) will be utilized for storage of this material.

Greenhouse Gas Emissions Reduction Plan

With increased utilization of existing combustion equipment there will be an increase in total direct GHG emissions. However, no change is needed to the CO_2e Emission Cap because all three (3) combustion sources described in this modification application were in existence in 2021 when the DOH issued the CO2e Emission Cap for the Par East and Par West Partnering Facilities (referenced below). GHG emission will increase modestly but, will remain below the cap. To reflect its relocation, the steam generator/boiler from Par West (F5205) will need to be removed from the Par West Permit (CSP 0088-01-C) and listed on the Par East Permit (CSP 0212-01-C), now as SG1104.

Partnering Facility	Permit No.	CO_2e Emission Cap	
		metric tons per calendar year	short tons per calendar year
Par East Refinery	CSP No. 0212-01-C	616,288	679,341
Par West Refinery	CSP No. 0088-01-C	292,549	322,480

The partnering facilities are compliant with the combined CO2e emissions cap and are expected to continue to be compliant with the emissions cap after the renewable fuel production facility commences operation. The steam generator/boiler may be relocated from Par West facility because operations there have been scaled back and steam is no longer needed to operate the tanks and equipment in the Effluent Treatment Plant. There are no updates to GHG control measures for direct emissions although, as previously described, some of the HGU emissions will be biogenic and will be exempt from the cap. Furthermore, it should be noted that the purpose of the project is to produce renewable fuels, thus emissions from supplies products reported under 40 CFR 98 Subpart MM (which represents well over 90% of emissions reported by the refinery under 40 CFR 98) will have a notable reduction in non-biogenic GHG emissions.

Rule Applicability

The rule applicability for existing equipment which will be utilized as part of the renewable fuel production facility is unchanged. The applicability of federal regulations on equipment that will be purchased, relocated, installed, and operated upon approval of this permit application are presented below. The applicability of State and Federal regulations which apply more broadly to all of the units and the refinery at large are summarized in permit application form C-1 Compliance Plan.

SG1104 Applicable Federal Regulations

The package boiler SG1104 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 Dc Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units; and
   iii. Subpart J, Standards of Performance for Petroleum Refineries

Subpart Dc emission limits for affected combustion sources burning liquid fuel.

Pollutant	NSPS Subpart Dc Maximum Emission Limits
SO2	0.50 lb/MMBtu or sulfur < 0.5 Wt%
PM	0.03 lb/ MMBTU (See note) Not applicable, if sulfur < 0.5 Wt%
Opacity	< 20 % (6 min ave.) except (*)

(*) The opacity limit is 27% for up to but not more than 6 minutes per hour.

(Auth.: 40 CFR §60.42c, §60.43c)

Notes:
1. Applicant is proposing a 0.25 wt% sulfur limit for liquid fuel.
   Applicant is proposing to utilize only RFG or low-sulfur distillate fuel to minimize opacity and to qualify for reduced monitoring requirements (§60.47c(c)).
2. In accordance with the exclusion set forth by §60.43c(e)(4), because only RFG and low sulfur distillate fuel will be used, SG1104 is not subject to the PM limits specified NSPS Subpart Dc. However, the applicant is nonetheless accepting the 0.03 lb/MMBTU limit on PM, specified in §60.43c(e)(1), as an enforceable permit condition to ensure significant PSD thresholds will not be exceeded.
3. Even though the EPA and the federal regulations recognize that the combustion of low sulfur distillate fuel does not normally generate appreciable particulate emissions, SG1104 will remain subject to the Subpart Dc opacity standard (40 CFR 60.43c(c)). While there is no categorical exemption from the Subpart Dc opacity limit for steam generators that use distillate fuel, the opacity monitoring requirements are somewhat relaxed. Pursuant to 40 CFR 60.47c(c), a Continuous Opacity Monitoring System

(COMS) is not required provided the refinery develops and follows an approved plan for controlling opacity as required by 40 CFR 60.47c(f)(3). As allowed by regulation and appropriate for low sulfur distillate fuel, PHR intends to submit a monitoring plan that will ensure that the opacity from exhaust stack of SG1104 normally remains less than 20% and continuously meets the standard set by NSPS Subpart Dc.

Subpart J emission limits for affected combustion devices burning RFG.

Pollutant	NSPS Subpart J Maximum Emission Limits
SO2 or H2S in RFG	< 20 ppm at 0% excess O2 (3-hr ave.) <162 ppm (3-hr ave.)

(Auth.: 40 CFR §60.104, §60.105)

Note: While Subpart J is applicable, applicant also will limit the 365-day average of SO2 < 8 ppm by limiting the 365-day average of H2S < 60 ppm because the RFG is sourced from a common system that complies with Subpart Ja.

SG1104 is not directly subject to the requirements of NSPS Ja because the boiler was constructed prior to the applicability date for Subpart Ja (May 14, 2007) and relocation of the boiler from Par West to Par East will not constitute reconstruction as a new source. Nonetheless, SG1104 will be held to the H2S and SOx limits of NSPS Subpart Ja because it will receive RFG from a common fuel gas system which includes amine treatment designed and operated to ensure that Ja standards will be met for other combustion devices (most notably H-3701). Elements from the Ja standards for combustion sources will be proposed as permit conditions by the applicant.

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.

SG1104 was built in 2007 and was originally designed and permitted for to be fired on low sulfur fuel oil (LSFO) or refinery fuel gas. Relocation of the steam generator from Par West (where the boiler was first permitted by Chevron) to Par East is not considered reconstruction, consequently the boiler remains subject to the Subpart DDDDD limits for boilers and process heaters which were existing prior to June 4, 2010.

Subpart DDDDD Emission limits for existing non-continental combustion sources burning liquid fuel.

Pollutant	MACT Subpart DDDDD Maximum Emission Limits
CO	130 ppmvd @ 3% excess O_2
Filterable PM (or TSM)	0.22 lb/MMBtu (or 0.00086 lb/MMBtu)
Hydrogen Chloride	1.1E-03 lb/MMBtu (based on liquid fuel testing)
Mercury	7.3E-07 lb/MMBtu (based on liquid fuel testing)

(Auth.: 40 CFR§63.7500 §63.7510, §63.7521)

Note: Subpart DDDDD emission limits (above) for non-continental combustion sources were established and intended to limit HAP emissions from the combustion of residual fuels or mixtures residual fuel and distillate fuel.

Note: Applicant is proposing to utilize only RFG or low (<0.25 wt%) sulfur distillate oil to comply with MACT Subpart DDDDD limits and minimize PM and HAP emissions. Because the applicant has elected to use low sulfur distillate fuel and has proposed a stringent 0.03 lb/MMBTU limit on PM emissions, the less stringent 0.22 lb/MMBTU limit specified under NESHAPS subpart DDDDD for existing non-continental sources has been rendered somewhat irrelevant.

PTU Applicable Federal Regulations

The renewable feedstock pretreatment unit (PTU) is subject to the provisions of the following federal regulations:

a. None

Note: The renewable PTU is not a refinery process unit nor is it directly connected to a refinery process unit. Feedstocks are limited to low volatility vegetable oil, waste cooking oils and animal fats (tallow). Applicant proposes to utilize filters, gravity phase separation and water/steam, (but no fossil fuels such as naphtha or hexane) to extract and remove contaminants from renewable feedstocks.

RHT Applicable Federal Regulations

The renewable hydrotreater (RHT) 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 Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007; and
   iii. Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006; and
   iv. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

b. 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAPS)
   i. Subpart A, General Provisions; and
   ii. Subpart FF, National Emission Standard for Benzene Waste Operations.

c. 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.

Note: All of the regulatory requirements above shown as applicable for RHT are already listed on the existing Title V permit as applicable to the DHT, which is to re-purposed.

Note: The regulatory requirements for repurposed 30 MMBtu/hr Feed Heater (H-3701), which will also become a key part of the RHT are already set forth in the Attachment II(O) of the existing Title V permit and will not be altered by this application.

Facility-wide Applicable Federal Regulations

The newly installed equipment for the Renewable Fuel Production Facility is subject to the provisions of the following facility-wide federal regulations:

a. 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):
   i. Subpart A, General Provisions; and
   ii. Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006; and
   iii. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

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.

c. 40 CFR Part 68, Chemical Accident Prevention Provisions

d. 40 CFR 98 Mandatory Greenhouse Gas Reporting:
   i. Subpart A, General Provision; and
   ii. Subpart C, General Stationary Fuel Combustion Sources; and
   iii. Subpart P, Hydrogen Production; and
   iv. Subpart Y, Petroleum Refineries; and
   v. Subpart MM, Suppliers of Petroleum Products.

Review of SOCMI Regulations

In addition to the regulations described above as applicable to the PTU and RHT, the regulations listed below for Synthetic Organic Chemical Manufacturing Industry (SOCMI) sources were reviewed. Although general provisions apply (by reference), no substantive requirements apply and no additional controls are required. The PTU and RHT are either categorically exempt from the following Part 60 NSPS federal regulations or – more commonly - the emission limits, standard and work practices do not directly apply to any of the new or modified equipment which is being installed for the renewable fuels project.

Subpart VVa 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

Subpart VVa standards are inapplicable to the PTU and RHT principally because they do not produce, as intermediate or final products, one or more of the chemicals listed in § 60.489. As result the PTU and RHT and do not meet the definition of a SOCMI process unit which is subject to regulation under Subpart VVa.

Only indirectly as consequence being cross referenced by Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, is RHT subject to some of the same standards for equipment leaks as those specified under Subpart VVa.

Subpart III Standards of Performance for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes

Subpart NNN Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations

Subpart RRR Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes

Subpart RRR standards are inapplicable to the PTU and RHT principally because there are no atmospheric vents to which the SOCMI standards would apply. In addition to renewable fuels which are normally liquids under standard conditions the RHT is going to make renewable propane and butane, which maybe either used as a feedstock to the HGU or sold to the neighboring SNG plant. Propane and butane are chemical products which are listed in § 60.707 and they are produced with the potential to be sold as a final product. However, there are no atmospheric vents from the PTU or RHT.

The PTU and RHT are either categorically exempt from the following Part 63 NESHAP regulations or more commonly the emission limits, standards and work practices do not apply to any of the new or modified equipment which is being installed for the renewable fuels project.

Subpart G National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater

Subpart H National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

Subpart FFFF National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing

Subpart GGGG National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production

Only steam is used as a solvent and as stripping gent to remove gums and other contaminates in the PTU (not a regulated solvent such as naphtha). The renewable facility is not producing vegetable oil, but rather the PTU is removing contaminates from raw vegetable and seed oils.

Proposed Changes to Title V Permit - General

The following sections of the CSP 0212-01-C should be revised to describe and represent the changes that are being proposed to accommodate the Renewable Fuel Production Facility more accurately:

1. Attachment II(I) Cogeneration Unit:
    a. Add SG1104 and associated limits and monitoring requirements
    b. Change section title to "Cogen and Steam Generators"
2. Attachment II(N) Petroleum Storage Tanks:
    a. Create a category for renewable feedstock tanks and add TK-701 and TK-702. While the CAB has already confirmed that storage of untreated renewable feedstocks in Tanks 701 and 702 are insignificant activities, to ensure their construction and operation is fully authorized, applicant would like to list them on the Title V permit.
    b. Change the equipment description for TK-601 to internal floating roof
    c. Remove Ethanol Tanks TK-518 and TK-519 from the permit.
3. Attachment II(O) Diesel Hydrotreater:
    a. Rename to Renewable Fuel Production Facility
    b. Add the following units: Renewable Pretreatment Unit (PTU), Renewable Hydrotreater (RHT), and Renewable Fuel Effluent Treatment (RET).
    c. Rename the DHT Feed Heater (H-3701) to RHT Feed Heater.
    d. Update equipment description DHT Feed Heater (H-3701) to 30 MMBtu/hr
    e. Increase the NOx limit to 1.24 lb/hr, accordingly
4. Attachment II(Q) Miscellaneous Process Units and Auxiliary Equipment:
    a. Change DHT to RHT
    b. Include SG1104 because it receives refinery fuel gas.
5. Attachment II(INSIG) Insignificant Activities:
    a. Include Tanks 701 and 702
6. Attachment II – GHG:
    a. Revise to include "SG1104 99 MMBTU/Hr Steam Generator (Boiler)." This naming convention is preferred for SG1102 and SG1103, as well.

Proposed Title V Operating Limits and Permit Conditions

In addition to the previously discussed applicable State and Federal requirements and general changes to the permit, below is an additional list of proposed operating and emission limits which are intended to limit emissions and, in some cases, are necessary to prevent potential emissions related to the entire the renewal fuels project from exceeding PSD thresholds, thereby creating a synthetic minor permit modification. The CSP 0212-01-C should be revised to reflect the following conditions:

A. Attachment II(I) Cogeneration Unit for SG1104:
   1. Fuel Usage and Specifications:
      - Fuel cap limit of 36,792 MMBtu/month based on a rolling 12-month average for RFG. Aside from RFG, any liquid fuel used to fire SG1104 will be limited to distillate oil with a maximum sulfur content of 0.25 wt% based on a rolling 30-day average and fuel cap limit of 9,198 MMBtu/month based on a rolling 12-month average.
   2. Sulfur Content of the Distillate Fuel:
      - Distillate fuel used to fire SG1104 shall be sampled and tested for sulfur content and verification of distillate properties at least once per week. Results shall be summarized and reported semi-annual. The use of distillate fuel shall be limited to 788 thousand gallons per rolling 12- month period.
   3. Air Pollution Control Equipment:
      - The flue gas recirculation system on SG1104 shall be in service whenever the package boiler is making steam and firing more than 15 MMBtu/hr or alternative criteria as specified by existing design criteria or by qualified third-party subject matter expert.
   4. Emission Limits for NOx:
      - While firing on distillate fuel, the NOx emissions from SG1104 shall be limited to 130 ppm at zero percent excess O2, based on a 3-hour average, when the FGR is in operation.
      - While firing on RFG, the NOx emissions from SG1104 shall be limited to 50 ppm at zero percent excess O2, based on a 3-hour average, when the FGR is in operation.
   5. Testing:
      - In addition to performance testing required by federal regulation, SG1104 shall be source tested for NOx emissions while firing on both fuels at least once per calendar year unless use of one of the two fuels in the prior calendar year represents less than 10% of the total heat input or 10% of the annual capacity factor.

B. Attachment II(G) Hydrogen Generating Unit:
   1. Maximum Fuel Consumption:
      - The heating value of the RFG used to fire H-2001 shall be limited to 96,973 MMBtu per /month over a rolling 12-month averaging period which is equivalent to a firing rate of 132.84 MMBTU/hr.

        This proposed limit would replace the existing fuel gas limit of 90,000 SCF/hr and the HHV of the RFG which is also listed on the permit (1476 BTU/SCF) to account for variability in the RFG. Like its predecessor, the monthly heat input limit is being retained to cap the annual PTE for the overall renewable fuel project which will require more hydrogen.

C. Attachment II(O) Diesel Hydrotreater:

1. Maximum Fuel Consumption:

    - The heating value of the RFG used to fire H-3701 shall be limited to 21,945 MMBtu per /month over a rolling 12-month averaging period which is equivalent to a firing rate of 30 MMBTU/hr.

      This proposed limit would represent an increased fuel gas limit from the previously permitted firing rate of the heater (25.6 MMBTU/hr). This monthly heat input limit allows for variability in the operation of the unit and RFG composition and will serve as a constraint on H-3701 for the overall renewable fuel project.

Emission Summary and PSD Applicability

The potential increase in emissions from the RHT project are compared to PSD significance levels in the table below. Emissions from new source SG1104, H-3701, and additional fugitive emissions associated with new equipment installed for the pretreatment unit and RHT are calculated as the difference between the Baseline Actual Emissions (BAE) and Potential to Emit (PTE) with fuel limit caps of 277 MMscf/yr of fuel gas and 788 Mgal/yr of distillate fuel on SG1104. Emission increases from existing sources H-2001 and HGU LPG feed are calculated as the difference between their Baseline Actual Emissions (BAE) and Projected Actual Emissions (PAE). The applicability of more stringent Subpart Ja sulfur limits to the entire RFG system are reflected in the estimates provided below.

PSD is not applicable because all calculations show that the PTE is less than the PSD significant thresholds for all pollutants.

Pollutant	**New SG-1104, Fugitives & Increased Utilization of Existing Sources (H-3701, H-2001 & HGU*)** **(TPY)**	**PSD Significance Level** **(TPY)**
CO	55.53	**100**
H_2S	0.03	**10**
Pb	0.0008	**0.6**
NO_X	35.79	**40**
SO_2	20.01	**40**
VOC	2.65	**40**
PM_{Total}	4.16	**25**
PM_{10}	4.16	**15**
$PM_{2.5}$	4.16	**10**
Fluorides	0.01	**3**
Sulfuric Acid Mist	0.28	**7**
Total Reduced Sulfur	0.10	**10**
GHG (CO_{2e})**	113,757	**75,000**

(*) GHG emissions associated with increased feed to and utilization of the HGU are not considered in PSD applicability.

(**) Per 40 CFR 52.21(b)(49)(iv)(b), pollutant GHG's are not subject to PSD regulation if there is not an increase of a regulated NSR pollutant.

Ambient Air Quality Analysis

Air quality dispersion modeling analysis of the proposed renewable fuel production facility demonstrate compliance of the existing facility with all applicable state and federal ambient air quality standards. The modeling methodology is described in the modeling analysis. The emission rates are based on the potential to emit emission rather than the project increase. Results of the analysis are provided in Appendix D.

Table 4-1 from the modeling analysis, excerpted below, presents the results of the modeling for CO (1-hr and 8-hr), NO2 (1-hr and Annual), H2S (1-hr), SO2 (1-hr, 3-hr, 24-hr, and Annual), PM10 (24-hr and Annual), and PM2.5 (24-hr and Annual). Impacts for all pollutants and applicable averaging periods are below the applicable standards.

Table 4-1. Modeled Impacts Summary

Pollutants	Averaging Periods	Predicted AERMOD Concentrations Basis	GLCmax	Background Calculations Basis	Background Values	Background + GLC max	Hawaii Standard		Federal Standard	
			(µg/m³)		(µg/m³)	(µg/m³)	(ppb)	(µg/m³)	(ppb)	(µg/m³)
CO	1-HR	H2H	69.99	H2H	1374.72	1444.72	9000	10310	35000	40096
	8-HR	H2H	31.37	H2H	458.24	489.61	4400	5041	9000	10310
NO_2	1-HR	maximum 98th percentile/H8H	55.70	3-year average of the 98th percentile	47.36	103.05			100	188
	ANNUAL	Maximum	4.13	3-year average of Annual Mean	6.27	10.41	40	76	53	100
H_2S	1-HR	H1H	0.13	H1H	7.73	7.86	25	35		
SO_2	1-HR	maximum 99th percentile/ H4H	34.75	3-year average of the 99th percentile	9.35	44.09			75	197
	3-HR	H2H	40.98	H2H	7.86	48.84	500	1310		
	24-HR	H2H	24.46	H2H	5.24	29.70	140	367		
	ANNUAL	Maximum	2.09	3-year average of Annual Mean	1.66	3.75	30	79		
PM_{10}	24-HR	H2H	2.96	H2H	46.00	48.96		150		150
	ANNUAL	Highest five-year average	0.41	3-year average of Annual Mean	12.67	13.07		50		
$PM_{2.5}$	24-HR	maximum 98th percentile/H8H	2.11	3-year average of the 98th percentile	7.60	9.71				35
	ANNUAL	Highest five-year average	0.41	3-year average of Annual Mean	3.70	4.11				9

Permit Application Forms

File/Application No.: 0212-01-C

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: Par Hawaii Refining, LLC

2. Facility Name (if different from the Company): Kapolei Refinery

3. Mailing Address: 91-325 Komohana St.

   City: Kapolei State: HI Zip Code: 96707-1713

   Phone Number: (808)

4. Name of Owner/Owner's Agent: Deaglan McClean

   Title: Vice President Phone: (808) 547-3841

   Mailing Address: 91-325 Komohana St.

   City: Kapolei State: HI Zip Code: 96707-1713

5. Plant Site Manager/Other Contact: Benton Widlansky

   Title: Environmental Manager Phone: (808) 547-3993

   Mailing Address: 91-325 Komohana St.

   City: Kapolei State: HI Zip Code: 96707-1713

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. 0212-01-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): Kapolei Refinery

City: Kapolei State: HI Zip Code: 96707-1713

UTM Coordinates (meters): East: 594327 North: 2356175.9

UTM Zone: ☐ 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: 2024

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): McClean (First): Deaglan (MI): ________

Title: Vice President Phone: (808) 547-3841

Mailing Address: 91-325 Komohana St.

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): Deaglan McClean

(Signature): [signature] Date: 03/21/2024

FOR AGENCY USE ONLY:
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.

See Form S1

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_X), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM_{10}). 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.

See Form S1

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.

See Form S1

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.

See Form S1

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.

See enclosed process flow diagram

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.

See enclosed plot plan and 100m radius map

D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

See enclosed description

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
(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		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No	Unit No	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
New Boiler (SG1104)																	
					Criteria Pollutants (CAPS):												
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	CO	630080	9.42E+00	2.10E+01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	H2S	7783064	1.78E-02	1.47E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	NH3	7664417	1.99E-01	4.43E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Lead	7439921	4.85E-05	1.08E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	NOx	NOX	5.10E+00	1.14E+01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	SO2	7446095	2.84E+00	2.53E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	VOC	VOC	3.41E-01	7.61E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Particulate Matter:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Total (Filterable + Condensable)	PM-PRI	4.72E-01	1.05E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Filterable	PM-FIL	1.18E-01	2.63E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Condensable	PM-CON	3.54E-01	7.89E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	PM10 (Filterable + Condensable)	PM10-PRI	4.72E-01	1.05E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	PM10 (Filterable)	PM10-FIL	1.18E-01	2.63E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	PM2.5 (Filterable + Condensable)	PM25-PRI	4.72E-01	1.05E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	PM2.5 (Filterable)	PM25-FIL	1.18E-01	2.63E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					PSD-Specific categories:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Fluorides	16984488	NA	NA	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Sulfuric Acid Mist	7664939	1.30E-01	1.16E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Total Reduced Sulfur	TRS	1.89E-02	4.20E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Greenhouse Gases (GHGs):									11.911			

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Total GHG (CO2e)	CO2e	1.26E+04	2.80E+04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					Individual Components:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Carbon Dioxide	124389	1.25E+04	2.79E+04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methane	74828	6.53E-01	1.46E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Nitrous Oxide	10024972	1.31E-01	2.91E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Hazardous Air Pollutants (HAPS):									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	1,3-Butadiene	106990			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	1,4-Dichlorobenzene(p)	106467	1.19E-04	2.65E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Acetaldehyde	75070	1.19E-03	2.65E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Acrolein	107028	1.68E-03	3.75E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Antimony	7440360	5.15E-05	1.15E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Arsenic	7440382	1.98E-05	4.42E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzene	71432	2.08E-04	4.64E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Beryllium	7440417	1.29E-05	2.87E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Biphenyl, 1,1-	92524			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Cadmium	7440439	1.09E-04	2.43E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Carbon disulfide	75150			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Carbonyl sulfide	463581			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Chlorine	7782505			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Chloroform	67663			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					Chromium:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Total Chromium	7440473	1.39E-04	3.09E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
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Stack No	Unit No	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)ᵇ	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Hexavalent Chromium	18540299	NA	NA	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Cobalt	7440484	8.12E-06	1.81E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Cumene	98828			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Dichloroethane, 1,2-	107062			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Diethanolamine	111422			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Ethyl benzene	100414	1.58E-03	3.53E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Ethylene glycol	107211			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Formaldehyde	50000	7.33E-03	1.63E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Hexane	110543	1.78E-01	3.97E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	m-Cresol	108394			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Hydrochloric acid	7647010			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Manganese	7439965	3.66E-05	8.17E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Mercury	7439976	2.48E-05	5.52E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methanol	67561			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methyl chloroform (1,1,1-Trichloroet	71556			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methyl isobutyl ketone	108101			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methyl tert butyl ether	1634044			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Naphthalene	91203	5.94E-05	1.32E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Nickel	7440020	2.08E-04	4.64E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Phenol	108952	3.96E-04	8.83E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

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Stack No	Unit No	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Phosphorus	7723140	6.34E-05	1.41E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Polychlorinated biphenyls (Aroclors)	PCBs			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Selenium	7782492	8.71E-05	1.94E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Styrene	100425			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Toluene	108883	3.27E-04	7.28E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Trimethylpentane, 2,2,4-	540841			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Xylenes	1330207	2.48E-03	5.52E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					HAPs - Polycylic Organic Matter (POM)									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Total Polycylic Organic Matter	POM	2.76E-05	6.15E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					Individual Components:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	2-Methylnapthalene	91576	2.38E-06	5.30E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	3-methylchloranthrene	56495	1.78E-07	3.97E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	7,12-dimethylbenz(a)anthracene	57976	1.58E-06	3.53E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Acenaphthylene	208968	6.44E-07	1.43E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Anthracene	120127	4.65E-07	1.04E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(a)anthracene	56553	2.18E-06	4.86E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(a)pyrene	50328	5.64E-06	1.26E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(b)fluoranthene	205992	2.67E-06	5.96E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(g,h,i)perylene	191242	1.29E-07	2.87E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(k)fluoroanthene	207089	1.68E-06	3.75E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Chrysene	218019	1.58E-07	3.53E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Dibenz(a,h)anthracene	53703	1.19E-07	2.65E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Fluoranthene	206440	2.87E-07	6.40E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Fluorene	86737	2.67E-07	5.96E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Indeno(1,2,3-cd)pyrene	193395	7.03E-06	1.57E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					PAH:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Phenanthrene	85018	1.68E-06	3.75E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Pyrene	129000	4.85E-07	1.08E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Non-HAPs:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	1,2,4- Trimethylbenzene	95636			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	2-Chloronaphthalene	91587			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Acenaphthene	83329	2.38E-07	5.30E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Barium	7440393	4.26E-04	9.49E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Benzo(e)pyrene	192972			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Copper	7440508	8.42E-05	1.88E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Cyclohexane	110827			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Ethane	74840	3.27E-01	7.28E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Fluorides	16984488	NA	NA	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Methyl ethyl ketone (2-Butanone)	78933			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Molybdenum	7439987	1.09E-04	2.43E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	n-Butane	106978	2.08E-01	4.64E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	n-pentane	109660	2.48E-01	5.52E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

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Location: 91-325 Komohana St., Kapolei, HI 96707
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Stack No	Unit No	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Perylene	198550			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Propane	74986	1.58E-01	3.53E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Propylene	115071	1.49E-02	3.31E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Vanadium	7440622	2.28E-04	5.08E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Refinery Fuel Gas Boilers (SCC 10200701)	2025 (Plan)	Zinc	7440666	2.87E-03	6.40E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	**Criteria Pollutants (CAPS):**				594356	594356				11.911		418.8722	
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	CO	630080	1.00E+01	5.60E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	H2S	7783064			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	NH3	7664417	5.66E-01	3.15E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Lead	7439921	8.91E-04	4.97E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	NOx	NOX	1.41E+01	7.88E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	SO2	7446095	2.51E+01	1.40E+01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	VOC	VOC	1.41E-01	7.88E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Particulate Matter:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Total (Filterable + Condensable)	PM-PRI	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Filterable	PM-FIL	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Condensable	PM-CON	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	PM10 (Filterable + Condensable)	PM10-PRI	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	PM10 (Filterable)	PM10-FIL	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	PM2.5 (Filterable + Condensable)	PM25-PRI	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	PM2.5 (Filterable)	PM25-FIL	2.97E+00	1.66E+00	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					PSD-Specific categories:									1.19E+01			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Fluorides	16984488	2.65E-02	1.48E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Sulfuric Acid Mist	7664939			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Total Reduced Sulfur	TRS			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Greenhouse Gases (GHGs):									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Total GHG (CO2e):	CO2e	1.62E+04	9.01E+03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					Individual Components:									11.911			

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Carbon Dioxide	124389	1.61E+04	8.98E+03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methane	74828	6.53E-01	3.64E-01	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Nitrous Oxide	10024972	1.31E-01	7.28E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Hazardous Air Pollutants (HAPS):									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	1,3-Butadiene	106990			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	1,4-Dichlorobenzene(p)	106467			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Acetaldehyde	75070	7.43E-04	4.14E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Acrolein	107028			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Antimony	7440360	3.71E-03	2.07E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Arsenic	7440382	3.96E-04	2.21E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzene	71432	1.51E-04	8.44E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Beryllium	7440417	2.97E-04	1.66E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Biphenyl, 1,1-	92524			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Cadmium	7440439	2.97E-04	1.66E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Carbon disulfide	75150			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Carbonyl sulfide	463581			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Chlorine	7782505			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Chloroform	67663	3.61E-03	2.01E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					Chromium									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Total Chromium	7440473	2.97E-04	1.66E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Hexavalent Chromium	18540299	2.97E-04	1.66E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Cobalt	7440484	4.26E-03	2.37E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Cumene	98828			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Dichloroethane, 1,2-	107062			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Diethanolamine	111422			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Ethyl benzene	100414	4.50E-05	2.51E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Ethylene glycol	107211			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Formaldehyde	50000	2.33E-02	1.30E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Hexane	110543			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	m-Cresol	108394			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Hydrochloric acid	7647010	1.09E-01	6.07E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
(Make as many copies of this page as necessary)

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Manganese	7439965	5.94E-04	3.31E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Mercury	7439976	7.23E-05	4.03E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methanol	67561			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methyl chloroform (1,1,1-Trichloroet	71556	1.67E-04	9.30E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methyl isobutyl ketone	108101			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methyl tert butyl ether	1634044			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Naphthalene	91203	7.99E-04	4.45E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Nickel	7440020	2.97E-04	1.66E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Phenol	108952			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Phosphorus	7723140	6.68E-03	3.73E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Polychlorinated biphenyls (Aroclors)	PCBs			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Selenium	7782492	1.49E-03	8.28E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Styrene	100425			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Toluene	108883	7.71E-05	4.30E-05	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Trimethylpentane, 2,2,4-	540841			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Xylenes	1330207	7.74E-04	4.32E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					HAPs - Polycylic Organic Matter (POM)									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Total Polycylic Organic Matter	POM	2.33E-03	1.30E-03	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Individual Components				594356	594356				11.911		418.8722	
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	2-Methylnapthalene	91576	7.85E-06	4.38E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	3-methylchloranthrene	56495			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	7,12-dimethylbenz(a)anthracene	57976			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Acenaphthylene	208968	1.79E-07	9.97E-08	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Anthracene	120127	8.63E-07	4.81E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(a)anthracene	56553	2.84E-06	1.58E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(a)pyrene	50328	1.49E-07	8.28E-08	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(b)fluoranthene	205992	1.05E-06	5.83E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(g,h,i)perylene	191242	1.60E-06	8.91E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(k)fluoroanthene	207089	1.05E-06	5.83E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Chrysene	218019	1.70E-06	9.46E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Dibenz(a,h)anthracene	53703	1.17E-06	6.50E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Fluoranthene	206440	3.39E-06	1.89E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Fluorene	86737	3.18E-06	1.77E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Indeno(1,2,3-cd)pyrene	193395	1.49E-06	8.28E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
					PAH:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Phenanthrene	85018	7.43E-06	4.14E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Pyrene	129000	2.97E-06	1.66E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
														11.911			
					Non-HAPs:									11.911			
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	1,2,4- Trimethylbenzene	95636			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	2-Chloronaphthalene	91587	1.59E-08	8.87E-09	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Acenaphthene	83329	1.49E-05	8.32E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Barium	7440393	1.20E-05	6.70E-06	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Benzo(e)pyrene	192972	6.15E-07	3.43E-07	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Copper	7440508	5.94E-04	3.31E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Cyclohexane	110827			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Ethane	74840			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Fluoride	16984488	2.65E-02	1.48E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Methyl ethyl ketone (2-Butanone)	78933			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Molybdenum	7439987			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	n-Butane	106978			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	n-pentane	109660			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Perylene	198550	7.85E-08	4.38E-08	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Propane	74986			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Propylene	115071			594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Vanadium	7440622	2.23E-02	1.24E-02	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
102	SG1104	Package Boiler Steam Generator #4	Distillate Oil Boilers (SCC 10200502)	2025 (Plan)	Zinc	7440666	3.96E-04	2.21E-04	594356	594356	25.0	u	0.904875	11.911	7.66	418.8722	N
so in previous Insignificant Modification																	
103	TS-701	TK701 Vegetable Oil Processing Holding Tank, Standing Loss	30201941	2024 (Plan)	VOC	VOC	No or negligibile emissions (see separate Insignifcant Activity Letter dated August 3, 2023)										
103	TW-701	TK701 Vegetable Oil Processing Holding Tank, Working Loss	30201941	2024 (Plan)	VOC	VOC	No or negligibile emissions (see separate Insignifcant Activity Letter dated August 3, 2023)										
104	TS-702	TK702 Vegetable Oil Processing Holding Tank, Standing Loss	30201941	2024 (Plan)	VOC	VOC	No or negligibile emissions (see separate Insignifcant Activity Letter dated August 3, 2023)										

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
104	TW-702	TK702 Vegetable Oil Processing Holding Tank, Working Loss	30201941	2024 (Plan)	VOC	VOC	No or negligibile emissions (see separate Insigniifcant Activity Letter dated August 3, 2023)										
New Fugitive Sources																	
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	**Criteria Pollutants (CAPS):**												
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	VOC	VOC	1.53E+03	7.63E-01									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)													
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	**Hazardous Air Pollutants (HAPS):**												
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	1,3-Butadiene	106990											
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Benzene	71432	5.64E+00	2.82E-03									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Biphenyl, 1,1-	92524	3.36E+00	1.68E-03									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Cumene	98828	1.07E+00	5.34E-04									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Ethyl benzene	100414	5.64E+00	2.82E-03									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Hexane	110543	2.90E+01	1.45E-02									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	m-Cresol	108394	1.53E-02	7.63E-06									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Methyl isobutyl ketone	108101	6.87E-01	3.43E-04									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Naphthalene	91203	3.81E+00	1.91E-03									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Phenol	108952	1.53E-02	7.63E-06									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Toluene	108883	2.59E+01	1.30E-02									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Trimethylpentane, 2,2,4-	540841	0.00E+00	0.00E+00									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Xylenes	1330207	2.90E+01	1.45E-02									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)													
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	**HAPs - Polycylic Organic Matter (POM)**												
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Total Polycylic Organic Matter	POM	7.78E-01	3.89E-04									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Individual Components:												
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Benzo(g,h,i)perylene	191242	5.68E-02	2.84E-05									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	PAH		7.21E-01	3.60E-04									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	**Non-HAPs:**												
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	1,2,4- Trimethylbenzene	95636	6.10E+00	3.05E-03									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Cyclohexane	110827	2.82E+01	1.41E-02									
	M1-M9	Fugitive Emissions	30600801 to 30600822	2025 (Plan)	Methyl ethyl ketone (2-Butanone)	78933	8.39E+00	4.20E-03									
CO2 Increases Passed Through Existing Fuel Gas System																	
					Greenhouse Gases (GHGs):												
		Biogenic RHT CO2 Byproduct Carryover (New) Releases through various Refinery Fuel Gas Combustion Sources	Gas-fired Process Heaters (SCC 30600104) Refinery Fuel Gas Boilers (SCC 10200701)		Carbon Dioxide	124389	3.03E+02	1.32E+03									
CO2 Increases Passed Through Existing HGU																	
					Greenhouse Gases (GHGs):												
14	HGU	Hydrogen Generation Unit *Biogenic* LPG Feed (New)	Hydrogen Generation Unit General (SCC 30601801)	1982	Carbon Dioxide	124389	5.60E+03	2.45E+04	594001.32	2356192.968	36.94176	u	2.19456	11.21664	42.42751336	432.95	N
14	HGU	Hydrogen Generation Unit *Non-Biogenic* LPG Feed (Increase)	Hydrogen Generation Unit General (SCC 30601801)	1982	Carbon Dioxide	124389	2.80E+03	1.23E+04	594001.32	2356192.968	36.94176	u	2.19456	11.21664	42.42751336	432.95	N
Existing FH2001 (PTE)																	
					Criteria Pollutants (CAPS):												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	CO	630080	1.26E+01	5.54E+01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	H2S	7783064	2.39E-02	3.87E-02	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum^a: NAD-83		STACK SOURCE PARAMETERS						
Stack No	Unit No	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)^b	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	NH3	7664417	2.67E-01	1.17E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Lead	7439921	6.51E-05	2.85E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	NOx	NOX	3.61E+01	3.00E+01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	SO2	7446095	3.81E+00	6.67E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	VOC	VOC	4.58E-01	2.01E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
					Particulate Matter:												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Total (Filterable + Condensable)	PM-PRI	6.33E-01	2.77E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Filterable	PM-FIL	1.58E-01	6.93E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Condensable	PM-CON	4.75E-01	2.08E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	PM10 (Filterable + Condensable)	PM10-PRI	6.33E-01	2.77E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	PM10 (Filterable)	PM10-FIL	1.58E-01	6.93E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	PM2.5 (Filterable + Condensable)	PM25-PRI	6.33E-01	2.77E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	PM2.5 (Filterable)	PM25-FIL	1.58E-01	6.93E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
					PSD-Specific categories:												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Fluorides	16984488	NA	NA	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Sulfuric Acid Mist	7664939	1.75E-01	3.06E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Total Reduced Sulfur	TRS	2.53E-02	1.11E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	**Greenhouse Gases (GHGs):**				594245.944	2356263.654	19.15058		1.955804	7.802499	23.44	480.3722	
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Total GHG (CO2e)	CO2e	1.69E+04	7.39E+04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Individual Components:				594245.944	2356263.654	19.15058		1.955804	7.802499	23.44	480.3722	

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Carbon Dioxide	124389	1.68E+04	7.36E+04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methane	74828	8.77E-01	3.84E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Nitrous Oxide	10024972	1.75E-01	7.68E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
					Hazardous Air Pollutants (HAPS):												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	1,3-Butadiene	106990			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	1,4-Dichlorobenzene(p)	106467	1.59E-04	6.98E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Acetaldehyde	75070	1.59E-03	6.98E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Acrolein	107028	2.26E-03	9.89E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Antimony	7440360	6.91E-05	3.03E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Arsenic	7440382	2.66E-05	1.16E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzene	71432	2.79E-04	1.22E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Beryllium	7440417	1.73E-05	7.56E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Biphenyl, 1,1-	92524			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Cadmium	7440439	1.46E-04	6.40E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Carbon disulfide	75150			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Carbonyl sulfide	463581			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Chlorine	7782505			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Chloroform	67663			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
					Chromium:												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Total Chromium	7440473	1.86E-04	8.15E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Hexavalent Chromium	18540299			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
(Make as many copies of this page as necessary)

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Stack No	Unit No	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)ᵇ	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Cobalt	7440484	1.09E-05	4.77E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Cumene	98828			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Dichloroethane, 1,2-	107062			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Diethanolamine	111422			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Ethyl benzene	100414	2.13E-03	9.31E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Ethylene glycol	107211			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Formaldehyde	50000	9.83E-03	4.31E-02	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Hexane	110543	2.39E-01	1.05E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	m-Cresol	108394			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Hydrochloric acid	7647010			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Manganese	7439965	4.92E-05	2.15E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Mercury	7439976	3.32E-05	1.45E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methanol	67561			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methyl chloroform (1,1,1-Trichloroet	71556			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methyl isobutyl ketone	108101			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methyl tert butyl ether	1634044			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Naphthalene	91203	7.97E-05	3.49E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Nickel	7440020	2.79E-04	1.22E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Phenol	108952	5.31E-04	2.33E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Phosphorus	7723140	8.50E-05	3.72E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N

EMISSIONS UNITS TABLE

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Polychlorinated biphenyls (Aroclors)	PCBs			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Selenium	7782492	1.17E-04	5.12E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Styrene	100425			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Toluene	108883	4.38E-04	1.92E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Trimethylpentane, 2,2,4-	540841			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Xylenes	1330207	3.32E-03	1.45E-02	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	**HAPs - Polycylic Organic Matter (POM)**				594245.944	2356263.654	19.15058		1.955804	7.802499	23.44	480.3722	
					Total Polycylic Organic Matter	POM	3.70E-05	1.62E-04									
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Individual Components:				594245.944	2356263.654	19.15058		1.955804	7.802499	23.44	480.3722	
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	2-Methylnapthalene	91576	3.19E-06	1.40E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	3-methylchloranthrene	56495	2.39E-07	1.05E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	7,12-dimethylbenz(a)anthracene	57976	2.13E-06	9.31E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Acenaphthylene	208968	8.63E-07	3.78E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Anthracene	120127	6.24E-07	2.73E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(a)anthracene	56553	2.92E-06	1.28E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(a)pyrene	50328	7.57E-06	3.32E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(b)fluoranthene	205992	3.59E-06	1.57E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(g,h,i)perylene	191242	1.73E-07	7.56E-07	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(k)fluoroanthene	207089	2.26E-06	9.89E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Chrysene	218019	2.13E-07	9.31E-07	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Dibenz(a,h)anthracene	53703	1.59E-07	6.98E-07	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Fluoranthene	206440	3.85E-07	1.69E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Fluorene	86737	3.59E-07	1.57E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Indeno(1,2,3-cd)pyrene	193395	9.43E-06	4.13E-05	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	PAH:				594245.944	2356263.654	19.15058		1.955804	7.802499	23.44	480.3722	
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Phenanthrene	85018	2.26E-06	9.89E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Pyrene	129000	6.51E-07	2.85E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
					Non-HAPs:												
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	1,2,4- Trimethylbenzene	95636			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	2-Chloronaphthalene	91587			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Acenaphthene	83329	3.19E-07	1.40E-06	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Barium	7440393	5.71E-04	2.50E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Benzo(e)pyrene	192972			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Copper	7440508	1.13E-04	4.95E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Cyclohexane	110827			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Ethane	74840	4.38E-01	1.92E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Fluorides	16984488	NA	NA	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Methyl ethyl ketone (2-Butanone)	78933			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Molybdenum	7439987	1.46E-04	6.40E-04	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	n-Butane	106978	2.79E-01	1.22E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	n-pentane	109660	3.32E-01	1.45E+00	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Perylene	198550			594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Propane	74986	2.13E-01	9.31E-01	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Propylene	115071	1.99E-02	8.73E-02	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Vanadium	7440622	3.06E-04	1.34E-03	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
14	FH2001	Hydrogen Reformer Heater	Gas-fired Process Heaters (SCC 30600104)	1982	Zinc	7440666	3.85E-03	1.69E-02	594245.944	2356263.654	19.15058	u	1.955804	7.802499	23.44	480.3722	N
Existing FH3701 (PTE)																	
					Criteria Pollutants (CAPS):												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	CO	630080	2.86E+00	1.25E+01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	H2S	7783064	5.40E-03	8.76E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	NH3	7664417	6.03E-02	2.64E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Lead	7439921	1.47E-05	6.45E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	NOx	NOX	1.24E+00	5.42E+00	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	SO2	7446095	8.61E-01	1.51E+00	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	VOC	VOC	1.04E-01	4.54E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Particulate Matter:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Total (Filterable + Condensable)	PM-PRI	1.43E-01	6.27E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Filterable	PM-FIL	3.58E-02	1.57E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Condensable	PM-CON	1.07E-01	4.71E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	PM10 (Filterable + Condensable)	PM10-PRI	1.43E-01	6.27E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	PM10 (Filterable)	PM10-FIL	3.58E-02	1.57E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	PM2.5 (Filterable + Condensable)	PM25-PRI	1.43E-01	6.27E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	PM2.5 (Filterable)	PM25-FIL	3.58E-02	1.57E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					PSD-Specific categories:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Fluorides	16984488	NA	NA	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Sulfuric Acid Mist	7664939	3.96E-02	6.93E-02	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Total Reduced Sulfur	TRS	5.73E-03	2.51E-02	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Greenhouse Gases (GHGs):												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Carbon Dioxide	124389	3.80E+03	1.66E+04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Methane	74828	1.98E-01	8.69E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Nitrous Oxide	10024972	3.97E-02	1.74E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Hazardous Air Pollutants (HAPS):												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	1,4-Dichlorobenzene(p)	106467	3.61E-05	1.58E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Acetaldehyde	75070	3.61E-04	1.58E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Acrolein	107028	5.11E-04	2.24E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Antimony	7440360	1.56E-05	6.85E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Arsenic	7440382	6.01E-06	2.63E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzene	71432	6.31E-05	2.77E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Beryllium	7440417	3.91E-06	1.71E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Cadmium	7440439	3.31E-05	1.45E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Chromium:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Total Chromium	7440473	4.21E-05	1.84E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N

Company Name: Par Hawaii Refining
Location: 91-325 Komohana St., Kapolei, HI 96707
(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		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum ᵃ: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp (K)	Capped (Y/N)
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Hexavalent Chromium	18540299	NA	NA	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Cobalt	7440484	2.47E-06	1.08E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Ethyl benzene	100414	4.81E-04	2.11E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Formaldehyde	50000	2.22E-03	9.74E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Hexane	110543	5.41E-02	2.37E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Hydrochloric acid	7647010			594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Manganese	7439965	1.11E-05	4.87E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Mercury	7439976	7.52E-06	3.29E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Naphthalene	91203	1.80E-05	7.90E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Nickel	7440020	6.31E-05	2.77E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Phenol	108952	1.20E-04	5.27E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Phosphorus	7723140	1.92E-05	8.43E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Selenium	7782492	2.65E-05	1.16E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Toluene	108883	9.92E-05	4.35E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Xylenes	1330207	7.52E-04	3.29E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					HAPs - Polycylic Organic Matter (POM)												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Total Polycylic Organic Matter	POM	8.38E-06	3.67E-05	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Individual Components:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	2-Methylnapthalene	91576	7.21E-07	3.16E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	3-methylchloranthrene	56495	5.41E-08	2.37E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	7,12-dimethylbenz(a)anthracene	57976	4.81E-07	2.11E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS					AIR POLLUTANT		AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum a: NAD-83		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)b	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Anthracene	120127	1.41E-07	6.19E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzo(a)anthracene	56553	6.61E-07	2.90E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzo(a)pyrene	50328	1.71E-06	7.51E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzo(b)fluoranthene	205992	8.12E-07	3.56E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzo(g,h,i)perylene	191242	3.91E-08	1.71E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Benzo(k)fluoroanthene	207089	5.11E-07	2.24E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Chrysene	218019	4.81E-08	2.11E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Dibenz(a,h)anthracene	53703	3.61E-08	1.58E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Fluoranthene	206440	8.72E-08	3.82E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Fluorene	86737	8.12E-08	3.56E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Indeno(1,2,3-cd)pyrene	193395	2.13E-06	9.35E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					PAH:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Phenanthrene	85018	5.11E-07	2.24E-06	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Pyrene	129000	1.47E-07	6.45E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
					Non-HAPs:												
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Acenaphthene	83329	7.21E-08	3.16E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Acenaphthylene	208968	1.95E-07	8.56E-07	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Barium	7440393	1.29E-04	5.66E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Copper	7440508	2.56E-05	1.12E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Ethane	74840	9.92E-02	4.35E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Molybdenum	7439987	3.31E-05	1.45E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N

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Stack No.	Unit No.	Equipment Name/Description & SCC number		Equipment Date	Regulated/Hazardous Air Pollutant Name	CAS #	#/HR	Tons/YR	East	North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m3/s)	Temp. (K)	Capped (Y/N)
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	n-Butane	106978	6.31E-02	2.77E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	n-pentane	109660	7.52E-02	3.29E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Propane	74986	4.81E-02	2.11E-01	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Propylene	115071	4.51E-03	1.98E-02	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Vanadium	7440622	6.91E-05	3.03E-04	594327	2356176	27.93	u	1.07	4.02	3.62	569	N
101*	FH3701	Hydrotreater Feed Heater	Gas-fired Process Heaters (SCC 30600104)	2019	Zinc	7440666	8.72E-04	3.82E-03	594327	2356176	27.93	u	1.07	4.02	3.62	569	N

a Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27
b Specify the direction of the stack exhaust as u = upward, d = downward, or h = horizontal

File No.: 0212-01-C

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}

[x] NO {If NO, complete items a, b, and c below}

a. Identify all applicable requirement(s) for which compliance is achieved.

For purposes of this Compliance Plan, Par has reviewed the Par Hawaii Refinery's most-recent annual Title V compliance certification and semi-annual Title V deviation reports to identify the applicable requirements to complete Parts 1.a and 1.b. (identification of applicable requirements for which compliance is achieved and identification of applicable requirements for which compliance is not achieved).

In order to identify the applicable requirements for which compliance is achieved, Par reviewed the most-recent semi-annual Title V deviation reports to identify applicable requirements for which either no deviations were reported or for which reported deviations have been resolved. Par identified the following applicable requirements for which either no deviations were reported or for which reported deviations have been resolved:

- *HAR Title 11, Chapters 60.1, 60.1-32, 60.1-38, 60.1-39, 60.1-40, 60.1-41, 60.1-42, 60.1-161, 60.1-174, 60.1-203, 60.1-204*
- *40 CFR 60 Subparts A, J, Ja, K, Ka, GG, IIII*
- *40 CFR 63 Subparts A, UUU, YYYY, ZZZZ, and DDDDD*
- *40 CFR 98 Subparts A, C, P, Y, and MM*

In the event that Par identifies additional deviations during the preparation if its Title V Annual Compliance Certification and Deviation Report, then Par will update this Form C-1: Compliance Plan , provided that deviation report is submitted while this application is pending. With regard to 40 CFR 68, Par conducts triennial audits as required by EPA's RMP rule; those audits often identify observations; Par is currently working to resolve observations identified by the auditors.

Provide a statement that the source is in compliance and will continue to comply with all such requirements.

In order to determine whether the source is in compliance with the requirements listed above, Par reviewed *the most-recent semi-annual Title V deviation reports to identify applicable requirements for which either no deviations were reported or for which reported deviations have been resolved. Par identified the applicable requirements listed above for which either no deviations were reported or for which reported deviations have been resolved*

Par implements a compliance management program designed to maintain compliance with all applicable requirements. As stated above, Par will supplement this version of Form C-1 to identify any noncompliance not listed in Part 1.b. below upon submittal of its next semi-annual Title V deviation report.

b. Identify all applicable requirement(s) for which compliance is NOT achieved.

In order to identify applicable requirements for which compliance is not achieved, Par reviewed the most-recent semi-annual Title V deviation reports to determine the applicable requirements for which deviations have been reported and for which reported deviations have not been resolved. Par identified the following applicable requirements for which deviations were reported and for which reported deviations have not been resolved, i.e applicable requirements for which noncompliance is ongoing:

- *40 CFR 60 Subparts Kb, VVa, GGGa and QQQ*
- *40 CFR 61 Subparts A and FF*
- *40 CFR 63 Subparts CC*
- *40 CFR 68*
- *CSP 0212-01-C, Consent Decree NOx Emission Limits*
- *CSP 0212-01-C, Consent Decree Requirement 99 for Certified Low-Leaking Valves*

Par has supplemented Part 1.b of Form C-1 in this revised application packet to identify any noncompliance per the July-December 2023 semi-annual Title V deviation report and removed any reported deviations which have been resolved.

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>

Below is a Detailed Schedule of Compliance for all of the applicable requirements identified above for which compliance is not achieved:

Emission Unit	*Applicable Requirement*	*Corrective Action Plan*	*<u>Expected Date Of Completion</u>*
Miscellaneous Emissions Sources - Oily Water Sewer	*40 CFR § 60.692-3*	*Par is redesigning the Stainless Steel Sump (SSS) to include additional emissions control.*	*6/30/2024*
DHC Heaters H601,	*Consent Decree*	*Par is in discussions with EPA*	*Updated plan*

H602, H603	*and CSP 0212-01-C II(D)C.5*	*to determine corrective actions. Oxygen concentrations are minimized, and alternative limits are currently being sought.*	*expected by April 2024*
VDU Heater H175	*Consent Decree and CSP 0212-01-C II(C)C.4*		
VBK Heater H901	*Consent Decree and CSP 0212-01-C II(F)C.5.a*		
Miscellaneous Emissions Sources – PSM/RMP	*CSP 0212-01-C II(Q)B.7*	*2021 PSM/RMP open audit finding: develop a schedule and go back to previous PHAs to ensure instrumentation and control devices indicated as safeguards are included in the maintenance program.*	*3rd Party PSM/RMP Compliance Audit scheduled for week of March 11, 2024*
Various Continuous Emissions Monitoring Systems (CEMS)	*Various*	*Periods of downtime for the associated Continuous Emissions Monitoring Systems (CEMS) are reported separately in routine quarterly or semi-annual downtime and excess emissions reports. However, Par is including this activity in this deviation report out of an abundance of caution.*	*Corrective actions are completed as described in routine reports.*

This Compliance Schedule does NOT include applicable requirements for which Par has reported deviations, but for which Par has already completed corrective actions as of the date of this revised application. Par is in discussions with EPA Region 9 regarding additional items identified during a February 2023 inspection to determine compliance status and any remaining corrective actions. Par may decide to report additional deviations based on the outcome of those discussion that are not included in this application.

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:

Applicable Requirement	Effective Date	Currently in Compliance?
40 CFR 60 Subpart Dc, Applicable to the new boiler (SG1104)	*Upon SG1104 Startup*	*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:

Expected Date of

Description of Proposed Action/Steps to Achieve Compliance	Achieving Compliance
Source will be compliant upon startup	*Upon SG1104 Startup*

Provide a statement that the source on a timely basis will meet all these applicable requirements:

The source will meet all applicable requirements on a timely basis.

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:

Description of Remedial Action and Explanation	Expected Date of Completion
NA	*NA*

2. Compliance Progress Reports:

   a. If a compliance plan is being submitted to remedy a violation, complete the following information:

      Frequency of Submittal: *6 months* (less than or equal to 6 months) Beginning Date: Following Permit Issuance

   b. Date(s) that the Action described in (1)(b) was achieved:

Remedial Action	Date Achieved
NA	*NA*

   c. Narrative description of why any date(s) in (1)(b) was not met, and any preventive or corrective measures taken in the interim:

      NA

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): *McClean* (First): *Deaglan* (MI):

Title: *Vice President* Phone: *(808) 547-3841*

Mailing Address: *91-325 Komohana St.*

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): *Deaglan McClean*

(Signature): ______________________ Date: 03/21/2024

Facility Name: *Par Hawaii Refining, LLC, Par East Refinery*

Location: *91-325 Komohana St., Kapolei, HI 96707*

Permit Number: *CSP No. 0212-01-C*

FOR AGENCY USE ONLY

File/Application No.: ____________

Island: ____________

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: **3/30/2026**

2. Emissions Unit No./Description: **Renewable Hydrotreater (RHT) with Package Boiler Steam Generator (SG1104)**

3. Identify the applicable requirement(s) that is/are the basis of this certification:

   - **40 CFR 60 Subpart A General Provisions**
   - **40 CFR 60 Subpart Dc Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units**
   - **40 CFR 60 Subpart J Standards of Performance for Petroleum Refineries**
   - **40 CFR 60 Subpart Ja Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011**
   - **40 CFR 60 Subpart GGGa Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries**
   - **40 CFR 60 Subpart QQQ Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems**

   - **40 CFR 61 Subpart A General Provisions**
   - **40 CFR 61 Subpart FF Standards of Benzene Waste Operations**

   - **40 CFR 63 Subpart A General Provisions**
   - **40 CFR 63 Subpart CC NESHAPS for HAPs from Petroleum Refineries**
   - **40 CFR 63 Subpart DDDDD NESHAPS for Industrial/Commercial/Institutional Boilers and Process Heaters**

   - **40 CFR 98 Subpart A General Provisions**
   - **40 CFR 98 Subpart C General Stationary Fuel Combustion Sources**
   - **40 CFR 98 Subpart P Hydrogen Production**
   - **40 CFR 98 Subpart Y Petroleum Refineries**
   - **40 CFR 98 Subpart MM Suppliers of Petroleum Products**

4. Compliance status:

a. Will the emissions units be in compliance with the identified applicable requirement(s)?

   X YES ? NO

b. If YES, will compliance be continuous or intermittent?

   X Continuous ? Intermittent

c. If NO, explain.

5. Detailed below are 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. This will include detailed descriptions of the methods used to determine compliance if appropriate (e.g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.).

Proposed methods for determining compliance forthe new RHT and SG1104 are detailed in the enclosed proposed permit additions to the current permit (CSP 0212-01-C) special conditions. In addition:

- **A site-specific Opacity Monitoring Plan will be created for SG1104 per 40 CFR 60.47c(f) for approval by the agency. The plan will include procedures and criteria to establish and monitor the sulfur content of the distillate fuel to ensure it does not exceed 0.25 wt% based on a rolling 30-day average, Method 9 monitoring, and demonstrate that the distillate fuel complies with the specification under the definition of distillate oil in in § 60.41c.**
- **The Par Fuel Monitoring and Analysis Plan for Hg and HCl emissions compliance required by 40 CFR 63.7521 will updated to includethe distillate fuel used in SG1104.**
- **Par's GHG Monitoring Plan will be updated to include fuel metering of SG1104 and other meters, as required.**

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

The RHT and SG-1104 will not be subject to the CAM rule.

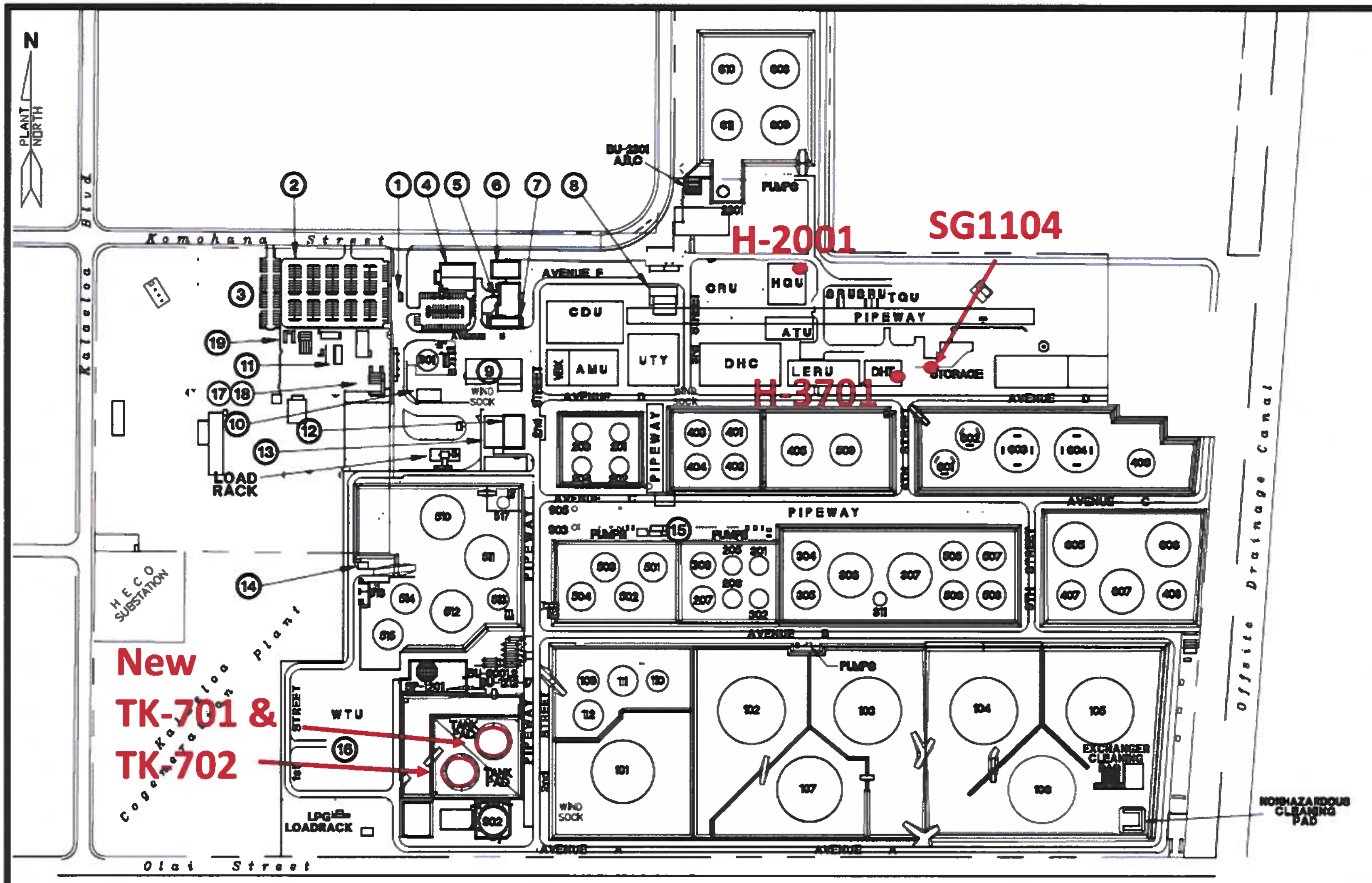
b. If YES, identify the requirements and the provisions being taken to achieve compliance:

c. If NO, describe below which requirements will not be met:

FOR AGENCY USE ONLY:
File/Application No.:
Island:
Date Received:

Appendix A – Location Plots

Renewable Fuel Facility Plot Plan



LEGEND

1. MAIN GATE AND SECURITY GUARD HOUSE
2. MAIN PARKING
3. CONTRACTOR PARKING
4. ADMIN. BLDG.
5. FIRE HOUSE, FIRST AID
6. PROCESS CTRL. HOUSE
7. LAB
8. DCS BUILDING
9. MAINT. BLDG.
10. FAB SHOP
11. MAINT. SHUTDOWN/ PLANNING TRAILER
12. PURCHASING
13. WAREHOUSE
14. FTP CTRL. HOUSE
15. TKF PUMP HOUSE
16. WTU CTRL. HOUSE
17. MAINT. SHUTDOWN TRAILERS
18. I&E SHUTDOWN TRAILERS
19. INSPECTION TRAILERS

3	2/9/10	JMM	GENERAL UPDATE	MJT
4	2/3/20	HOT	GENERAL UPDATE	MH
2	11/1/05	JMM	GENERAL UPDATE	JXM

Par Hawaii Refining

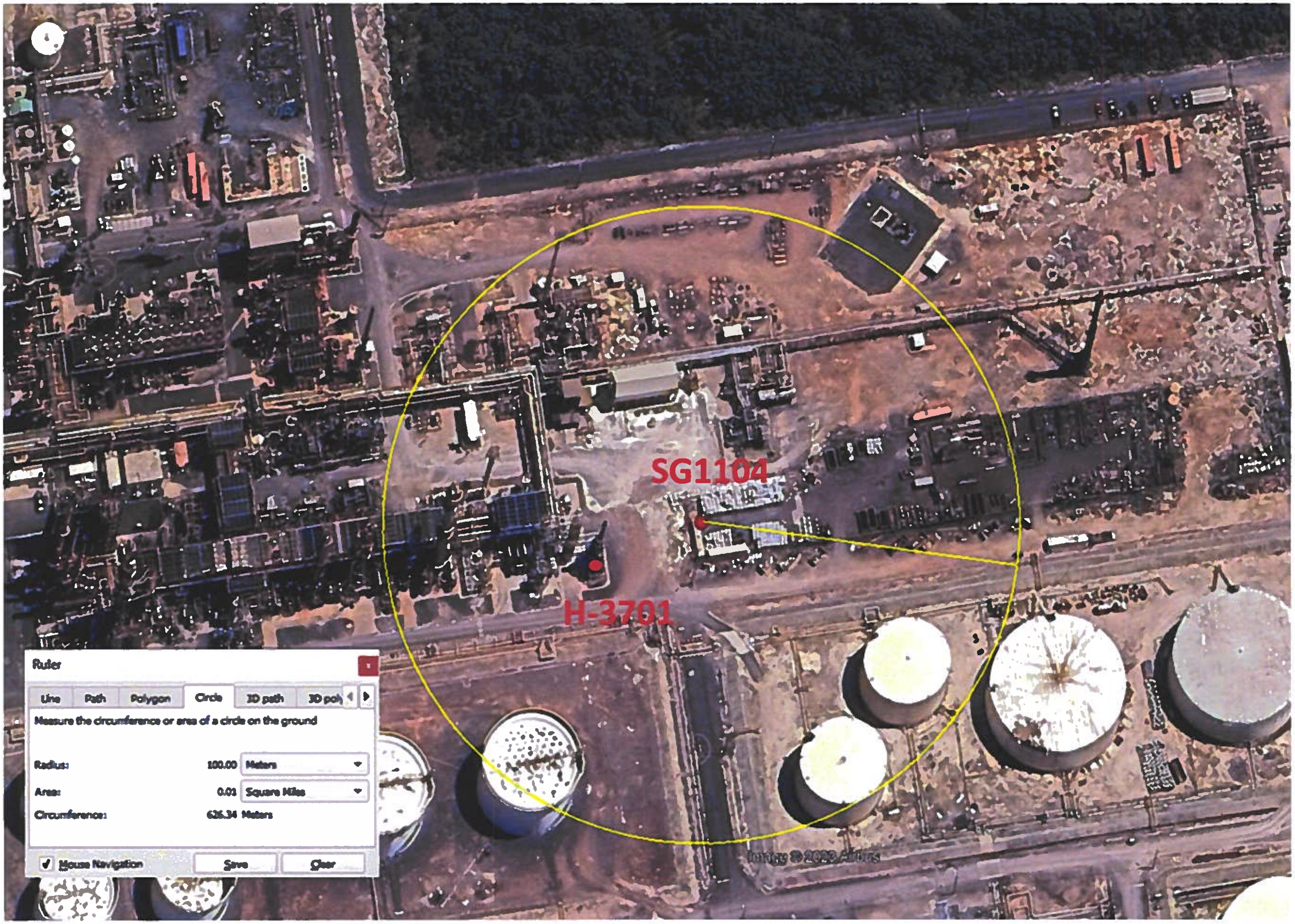
91-325 KOMOHANA STREET
KAPOLEI, HAWAII 96707
TELEPHONE (808) 547-3111

010 — GENERAL
GENERAL ENGINEERING

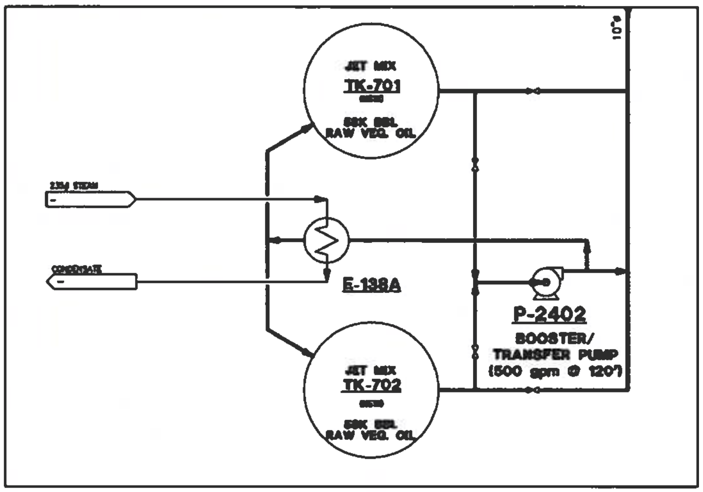
REFINERY GENERAL MAP

DESIGN	JMM	SCALE: NONE	PROJECT NO.: —
DATE	5/29/98	DRAWING NO.: A-010-C-57	REV.: 4
CHECKED			
OPERATIONS			
APPROVED			

100 meter radius – Contained within facility fenceline



TK701/702 Pad Locations



SG1104
Relocated from Par West

Appendix B – Boiler Design Specifications

	DESIGN AND FABRICATION OF STEAM GENERATORS **DATA SHEET**	**U-2M9S1** **PAGE 1 OF 9**

Facility Name/Location: Chevron Hawaii
Item Name: Boiler #5 and Boiler #6 Purchaser Project Number: ______
Item Tag Number: F-5205 and F-5206 Purchase Order Number: ______
Supplier: FOSTER WHEELER Supplier Project Number: 410-118786-01

GENERAL

Number of Units Required TWO (2)
Service: ☒ Power Boiler ☐ CO Boiler ☐ Other: ______ Type Operation: ☒ Continuous ☐ Intermittent
Type: ☒ Shop Assembled Package Boiler ☐ Field Erected Style: ☒ 'D' ☐ Cross Drum
MCR Steam Capacity: pph/Boiler 75,000 Steam Press, psig 600 Steam Temp, °F 625
☐ Peak Rating Required, pph ______ Hr/day ______ Hr/yr ______ Min Design Metal Temp, °F 10
Supply: ☒ Material and Shop Fabrication ☒ Delivery to Site ☐ Site Installation/Erection

SYSTEM REQUIREMENTS

Superheater:
☒ Drainable SH ☒ Attemperator/Desuperheater, Type: ☒ Spray ☐ SH Bypass Mixing ☐ Steam Drum Surface
Superheater Vent Design Flow Rate: ≥20 %MCR Flow at 50 100% Normal Oper Press ☒ Vent Silencer
Superheater Tube/Header Material: ☐ CS/CS ☒ T11/P11 ☐ T12/P12 ☒ Other Seamless
Evaporator:
☒ Natural Circulation ☐ Forced/Assisted Circulation
Boiler Blowdown (BD), % BFW 2-5 ☐ Manual BD Control By ______ ☒ Auto BD Control By Cond.
Economizer:
☐ Bare Tube Economizer ☒ Fintube Economizer ☒ Sootblower Required
Fans:
Qty of fans: Forced Draft ONE/UNIT Induced Draft ______ FGR Induced Other ______
☒ General Purpose Fans ☐ Special Purpose Fans (API 673) ☒ Fans Shop Performance Tested
Fan Drives: ☒ Motor for FD FAN Note 1-2 ☐ Steam Turbines for ______
Air Preheater:
☐ APH Required Type: ☐ Regenerative ☐ Recuperative ☐ Cold Air Bypass ☐ Steam Preheater
Boiler Instruments/Controls:
Drum Level Control: ☒ 3-Element ☐ 2-Element
Supply: ☒ All Insts and Controls ☐ Wetted Insts Only ☒ Non-Return/Stop Valve ☒ BFW Control/NR Valves
Burner System:
No. of Burners ONE Minimum Turndown Ratio: Note 1-3 :1 ☒ NFPA BMS by others
Burner Type: ☐ Mfr Std ☒ $LoNO_x$ ☐ Ultra-$LoNO_x$ ☒ Flue Gas Recirculation ☐ Internal ☒ External
Emission Monitoring/Control:
☒ EPA Stack Sampling Connections ☒ Extractive Flue Gas Sampling Connection
☐ Continuous Emission Monitors (CEM), Model Mfr ______
Mfr to Supply Analyzer For: ☐ NO_x ☐ CO ☒ O_2 ☒ Combustibles ☐ Particulates
☐ Selective Catalytic Recovery (SCR) System
Stack Height, ft 82 Minimum Stack Exit Velocity, fps 7.29 (FRG at min fire)

FOSTER WHEELER LIMITED
CERTIFIED FOR CONSTRUCTION
DATE April 12/08 BY [signature]

No.	Date	Revision	By	Apvd
2	3.28.07	Client comments added	LL	
1	3.7.07	FWL first issue	LL	
0	6.28.06	Issue For Purchase	RHW	MCW

12/99

BOILER FEEDWATER

☐ Boiler Feedwater Corrosive To Copper Alloys

Boiler Feedwater Characteristics			Ion Constituents			Drum Water Chemical Treatment
'M' Alkalinity		SEE	Chloride,	ppm_w		☐ Chelants
'P' Alkalinity		PROCESS	Silica,	ppm_w		☐ Phosphate
pH		DESIGN	Phosphate,	ppm_w		☐ Coordinated Phosphate
Turbidity	NTU	BASIS	Sulfate,	ppm_w		☐ Congruent Phosphate
Tds	ppm_w		Sulfite,	ppm_w		☐ Sodium Sulfite
Hardness	ppm_w		Iron,	ppm_w		☐ Hydrazine or Equivalent

CO BOILER PROCESS GAS DATA

Flow Rate (Wet), pph ______ Entrained Catalyst/Coke, Tons/Day ______

		Normal	Maximum	Minimum	Composition:
Temperature: °F:					(See Fuel Data, Page 3)
Pressure, psig:					

UTILITY DATA FOR AUXILIARY EQUIPMENT AND INSTRUMENTS

Economic Evaluation Factor: $/$10^6$ Btu/hr (HHV) ______

Steam Data For Turbine Drivers:

Inlet Pressure, psig ______ Inlet Temperature, °F ______ Exhaust Pressure, psig ______

Steam Data For Soot blowers:

Inlet Pressure, psig 600 Inlet Temperature, °F 625

Air Data:

Instrument Pressure, psig: 60

Pneumatic Drives (If Used For Emergency Drive, Such As Air Preheater Drive) Pressure, psig: ______

Electrical Data:

	Motors	Lights
Volts:	460	120
Cycles:	60	60
Phase:	3	1

Type Enclosure: TEFC, CL1, Div 2, Grps B, C and D (both motors and lights)

Cooling Water Data:

Supply Temperature, °F 80 Max Return Temperature, °F 110

Max. Allowable Δ p, psi 20 Supply Press., psig ~~150~~ 80

SUPPLEMENTARY INFORMATION

NOTE 1-2. FANS TO BE PER API 560

NOTE 1-3. TURNDOWN SHOULD BE 10:1 FOR REFINERY FUEL GAS, 8:1 FOR FUEL OIL

FUEL

Combustion Type: ☐ Gas ☐ Oil ☒ Combination ☒ Other DUAL FUEL–RFG & LSFO

Fuel Type	Gas	Fuel Type	Oil
Description	REF. FUEL	Description	FUEL OIL
Molecular Weight	SEE	H/C Ratio (wt)	SEE
Pressure (Available), psig	PROCESS	Pressure (Available), psig	PROCESS
Temperature, °F	DESIGN	Temperature, °F	DESIGN
Specific Gravity (Ref 60 °F Dry Air)	BASIS	API Gravity (60°/60°)	BASIS
Density (at Press/Temp), lb/ft^3		Density (at Press/Temp), lb/ft^3	
Chemical Heat Content (HHV), Btu/scf		Chemical Heat Content (HHV), Btu/lb	
Chemical Heat Content (LHV), Btu/scf		Chemical Heat Content (LHV), Btu/lb	
		Viscosity at °F ______	
Composition		at °F ______	
Hydrogen (H_2), %		Conradson Carbon No.	
Methane (C1), %		Atomizing Media	
Ethane (C2), %			
Ethylene (C2e), %		**Constituent Analysis**	
Propane (C3), %		Fixed Nitrogen (N), ppm	
Propylene (C3e), %		Vanadium (V), ppm	
Butane (C4), %		Nickel (Ni), ppm	
Pentane (C5), %		Sodium (Na), ppm	
Hexane (C6), %		Potassium (K), ppm	
Nitrogen (N_2), %		Sulfur (S), % wt	
Water (H_2O), %		Water (H_2O), % wt	
Carbon Monoxide (CO), %		Solid Carbon (C), % wt	
Carbonyl Sulfide (COS), %		Total Ash (), % wt	
Carbon Dioxide (CO_2), %			
Hydrogen Sulfide (H_2S), %		**Ultimate Analysis (Dry)**	
Sulfur (S), %		Hydrogen (H), % wt	
Sulfur Dioxide (SO_2), %		Carbon (C), % wt	
Ammonia (NH_3), %		Sulfur (S), % wt	
______		Nitrogen (N), % wt	
______		Oxygen (O), % wt	
		______	

	DESIGN AND FABRICATION OF STEAM GENERATORS DATA SHEET	U-2M9S1 PAGE 4 OF 9

1	MANUFACTURER PREDICTED PERFORMANCE DATA					
2	Section Data: Note: Complete For Each Performance Analysis Boiler Output % MCR 100 (RFG)					
3	**Steam Generator Section Water Side**	NRV	SH	Evap	Econ	BFW CV
4	Flow Rate (at Section Outlet), pph	75,000	71,703	75,000	76,531	76,531
5	Pressure (Outlet), psig	600	635	688	693	800
6	Pressure (Inlet), psig	620	688	688	713	720
7	Temperature (Outlet), °F	625	675	504	383	250
8	Temperature (Inlet), °F	625	504	504	250	250
9	Enthalpy (Outlet), Btu/hr ($x10^6$)	97.77	97.77	90.17	27.36	16.83
10	Enthalpy (Inlet), Btu/hr ($x10^6$)	97.77	90.17	27.36	16.83	16.83
11	Design Pressure, psig	745	745	745	745	745
12	Design Temperature, °F	650	843	604	408	250
13	Specific Heat (Avg), Btu/lb-°F	0.641	0.793	0.981	1.032	1.011
14	Fouling Factor, hr-ft^2-°F/Btu		0.054	0.079		
15	**Mechanical**					
16	Heating Service, ft^2		431	3,053	6771	
17	Tube Type (ERW/Seamless)		Seamless	Seamless	Seamless	
18	Tube (Diameter X Min Thickness), in. x in.		1.5x0.150	2x.135	2 x 0.150	
19	Tube Length, ft		15.23	9	12	
20	Tube Material (ATSM No.)		SA213-T11	SA-192	SA-192	
21	Tube Spacing (CL to CL) in.		~ 4.0	3.5	4.5	
22	Tube Pitch, (CL to CL) in.		2.5	3.5	4.5	
23	Type Arrangement (Square, Triangular)		square	square	square	
24	Number of Tubes Transverse to Flow No.		6	11	12	
25	Number of Tubes In Direction of Flow No.		12	47	17	
26	Fins (No./Height/Thickness) (No./in./in.)		N/A	N/A	2/.75/.105	
27	Fin Material (ASTM No.)		N/A	N/A	CS	
28	Weight (Hydro), lb		See Evap	228,000	35,000	
29	Weight (Shipping), lb		See Evap	180,000	32,000	
30	Weight (Operating), lb		See Evap	212,000	35,000	
31	Fill Volume (Hydro), gal		79	5762	380	
32	Fill Volume (Operating), gal		N/A	4910	380	
33						
34	**Steam Generator Section Gas Side**	Furnace	SH	BO Bank	Econ	Stack
35	Flow Rate, pph	95,229	95,229	95,229	95,229	85,025
36	Pressure (Outlet), in. H_2O	3.63	3.06	1.68	0.67	0
37	Pressure (Inlet), in. H_2O	10.05	3.63	3.06	1.68	0.67
38	Temperature (Outlet), °F	2070	1666	757	350	350
39	Temperature (Inlet), °F	N/A	1995	1666	757	350
40	Enthalpy (Outlet), Btu/hr	590	457	182	70	70
41	Enthalpy (Inlet), Btu/hr	943	566	457	182	70
42	Design Pressure, in. H_2O	30	25	25	25	0.76
43	Design Temperature, °F	N/A	N/A	N/A	750	750
44	Specific Heat (Avg.), Btu/hr-°F	0.33	0.323	0.297	0.277	0.267
45	Fouling Factor, hr-ft^2-°F /Btu				0.001	N/A
46	Gas Velocity (Outlet), fps	115	69.53	50.7	26.94	70.4

DESIGN AND FABRICATION OF STEAM GENERATORS

DATA SHEET

MANUFACTURER PREDICTED PERFORMANCE DATA (CONT)

General Physical Data		Supplemental Data
Total Furnace Volume, ft^3	1602	
Total Projected Radiant Surface, ft^2	1100	
Effective Projected Radiant Surface, ft^2	829	
Cross-sectional Furnace Area, ft^2	79.6	
Steam Drum/Mud Drum Separation (CL-CL), ft	12.5	
Steam Drum ID, in.	48	
Steam Drum Length (head weld to head weld), ft	22.66	
Steam Drum Vol. Between Norm & Min Oper Level ft^3	20	
Steam Drum Thickness, in.	2.625	
Steam Drum Corrosion Allowance, in.	0.125	
Steam Drum Material, ASTM No.	SA-516 GR 70	
Mud Drum ID, in.	24	
Mud Drum Length (head weld to head weld), ft	22.66	
Mud Drum Thickness, in.	1.375	
Mud Drum Corrosion Allowance, in.	0.125	
Mud Drum Material, ASTM No.	SA-516 GR 70	
Stack Exit Height Above Grade, ft	82	
Stack Exit Velocity, fps	70.4	
Stack Diameter Bottom/Top, in./in.	36/36	
Stack Material/Thickness, ASTM No./in.	A36/0.3125	
Stack Internal Coating Insul/Thick, Type/in.	N/A	
Stack External Coating-Insul/Thick, Type/in.	Inorganic Zinc	
Design Pressure, in. H_2O	0.76	
Design Temperature, °F	750	
Specific Heat (Avg.), Btu/hr-°F		
Fouling Factor, hr-ft^2°F/Btu		
Gas Velocity (Outlet), fps		

	DESIGN AND FABRICATION OF STEAM GENERATORS DATA SHEET	U-2M9S1 PAGE 6 OF 9

MANUFACTURER PREDICTED PERFORMANCE DATA (CONT)

	Performance Data (RFG)				
Boiler Output	Peak N/A	MCR	75% MCR	50% MCR	10% MCR
Boiler Efficiency (HHV), %		84.22	85.02	85.55	86.52
Radiation (Setting Losses), %		0.594	0.750	1.157	5.70
Mfr Margin, %		1.00	1.00	1.00	1.00
Steam Purity (TDS), ppm_w		1.00	1.00	1.00	1.00
Sulfur Dew Point, °F					
Circulation Ratio, Maximum	:1	:1	:1	:1	:1
Circulation Ratio, Average	:1	:1	:1	:1	:1
Circulation Ratio, Minimum	:1	:1	:1	:1	:1
Boiler Blowdown, %		2.00	2.00	2.00	2.00
Fuel Gas Consumption, pph		5001	3715	2462	486
Fuel Gas Chemical Heat, Btu/lb		19393	19393	19393	19393
Fuel Gas Sensible Heat, Btu/hr					
Fuel Oil Consumption, pph					
Fuel Oil Chemical Heat, Btu/hr					
Fuel Oil Sensible Heat, Btu/hr					
Alternate Fuel Consumption, pph					
Alternate Fuel Chemical Heat, Btu/hr					
Alternate Fuel Sensible Heat, Btu/hr					
Total Combustion Air, pph		80024	59440	39396	9467
Excess Air, %		15	15	15	40
O_2 in Flue Gas (Wet), % Vol		2.46	2.46	2.46	5.47
O_2 in Flue Gas (Dry), % Vol		2.92	2.92	2.92	6.31
Combustion Air Sensible Heat, Btu/hr					
Heat Available To Furnace (Total), MBtu/hr		96.98	72.04	47.74	9.42
Heat Available To Furnace, Volume, Btu/ft^3		60,536	44,968	29,800	5,883
Heat Available To Proj. Rad. Surf., Btu/ft^2		88,164	65,494	43,402	8,568
Heat Available To EPRS, Btu/ft^2		116,984	86,904	57,591	11,369
Heat Available To X-Sectional Area MBtu/ft^2		1.218	0.905	0.599	0.118
Flue Gas [FGR] Recirculation Flow, pph		10,203	7,579	5,022	1,194
FGR Pressure at Fan Inlet, in. H_2O		0.67	0.37	0.16	0.1
FGR Temperature at Burner, °F		350	318	297	258
FGR Sensible Heat, Btu/hr		70	58	56	44

DESIGN AND FABRICATION OF STEAM GENERATORS

DATA SHEET

UTILITIES REQUIRED BY AUXILIARY EQUIPMENT

	Electrical				Steam			Air		Cooling
	Qty Units	Bhp Each	Volts/ Phase	kW Total	Qty Units	Bhp Each	Total Consump (Mlb/hr)	Instr (scfm)	Other (scfm)	Water (gpm)
FD Fan Dr	2	125	460/3	93						
ID Fan Dr										
APH Dr										
FGR Fan Dr										
Other (List)										
Lighting		-			-	-	-	-	-	-
Totals										

Notes:

	DESIGN AND FABRICATION OF STEAM GENERATORS DATA SHEET	U-2M9S1 PAGE 8 OF 9

MANUFACTURER PREDICTED PERFORMANCE DATA (CONT)

	Performance Data (LSFO)				
Boiler Output	Peak N/A	MCR	75% MCR	50% MCR	12.5% MCR
Boiler Efficiency (HHV), %		86.18	86.9	86.98	88.43
Radiation (Setting Losses), %		0.594	0.750	1.157	4.5
Mfr Margin, %		1.00	1.00	1.00	1.00
Steam Purity (TDS), ppm_w		1.00	1.00	1.00	1.00
Sulfur Dew Point, °F (5% conversion)		280	280	280	267
Circulation Ratio, Maximum	:1	:1	:1	:1	:1
Circulation Ratio, Average	:1	:1	:1	:1	:1
Circulation Ratio, Minimum	:1	:1	:1	:1	:1
Boiler Blowdown, %		2.00	2.00	2.00	2.00
Fuel Gas Consumption, pph					
Fuel Gas Chemical Heat, Btu/hr					
Fuel Gas Sensible Heat, Btu/hr					
Fuel Oil Consumption, pph		5063	3765	2508	617
Fuel Oil Chemical Heat, Btu/lb		18,720	18,720	18,720	18,720
Fuel Oil Sensible Heat, Btu/hr					
Alternate Fuel Consumption, pph					
Alternate Fuel Chemical Heat, Btu/hr					
Alternate Fuel Sensible Heat, Btu/hr					
Total Combustion Air, pph		83,082	61,783	41,162	13,628
Excess Air, %		15	15	15	55
O_2 In Flue Gas (Wet), % Vol		2.54	2.54	2.54	6.95
O_2 In Flue Gas (Dry), % Vol		2.87	2.87	2.87	7.71
Combustion Air Sensible Heat, Btu/hr					
Heat Available To Furnace (Total), MBtu/hr		94.74	70.48	46.95	11.55
Heat Available To Furnace, Volume, Btu/ft^3		59,160	43,995	29,310	7,209
Heat Available To Proj. Rad. Surf., Btu/ft^2		88,886	64,073	42,686	10,500
Heat Available To EPRS, Btu/ft^2		114,324	85,019	56,640	13,932
Heat Available To X-Sectional Area MBtu/ft^2		1.19	0.885	0.589	0.145
Flue Gas [FGR] Recirculation Flow, pph		10,577	7865	5240	2,743
FGR Pressure at Fan Inlet, in. H_2O		0.72	0.39	0.18	0.02
FGR Temperature at Burner, °F		349	320	298	259
FGR Sensible Heat, Btu/hr		68	57	55	33

MANUFACTURER PREDICTED PERFORMANCE DATA (CONT)

	Performance Data (LCO)				
Boiler Output	Peak N/A	MCR	75% MCR	50% MCR	12.5% MCR
Boiler Efficiency (HHV), %		85.46	86.11	86.68	87.71
Radiation (Setting Losses), %		0.594	0.750	1.157	4.5
Mfr Margin, %		1.00	1.00	1.00	1.00
Steam Purity (TDS), ppm_w		1.00	1.00	1.00	1.00
Sulfur Dew Point, °F (5% conversion)		260	260	260	245
Circulation Ratio, Maximum	:1	:1	:1	:1	:1
Circulation Ratio, Average	:1	:1	:1	:1	:1
Circulation Ratio, Minimum	:1	:1	:1	:1	:1
Boiler Blowdown, %		2.00	2.00	2.00	2.00
Fuel Gas Consumption, pph					
Fuel Gas Chemical Heat, Btu/hr					
Fuel Gas Sensible Heat, Btu/hr					
Fuel Oil Consumption, pph		5,054	3761	2491	615
Fuel Oil Chemical Heat, Btu/lb		18,909	18,909	18,909	18,909
Fuel Oil Sensible Heat, Btu/hr					
Alternate Fuel Consumption, pph					
Alternate Fuel Chemical Heat, Btu/hr					
Alternate Fuel Sensible Heat, Btu/hr					
Total Combustion Air, pph		85,210	63,373	41,980	13,911
Excess Air, %		15	15	15	55
O_2 in Flue Gas (Wet), % Vol		2.53	2.53	2.53	6.91
O_2 in Flue Gas (Dry), % Vol		2.88	2.88	2.88	7.73
Combustion Air Sensible Heat, Btu/hr					
Heat Available To Furnace (Total), MBtu/hr		95.58	71.12	47.10	11.63
Heat Available To Furnace, Volume, Btu/ft^3		59,664	44,392	29,402	7,259
Heat Available To Proj. Rad. Surf., Btu/ft^2		86,893	64,651	42,820	10,571
Heat Available To EPRS, Btu/ft^2		115,298	85,786	56,818	14,026
Heat Available To X-Sectional Area $MBtu/ft^2$		1.201	0.893	0.592	0.146
Flue Gas [FGR] Recirculation Flow, pph		12	12	12	12
FGR Pressure at Fan Inlet, in. H_2O		0.75	0.42	0.18	0.02
FGR Temperature at Burner, °F		348	322	299	259
FGR Sensible Heat, Btu/hr		68	57	55	33

Appendix C – Potential-To-Emit Estimate

Table C-1: Applicability Demonstration	New Sources (PTE)				Existing Sources (PTE - Baseline)					PSD Major Mod Det.			Sig Permit Modification Det.			
	Relocated Boiler (SG1104) TPY	New Tanks (TK701 & TK702) TPY (Zero Increase; See Letter))	New CO2 byproduct stream TPY (Biogenic)	New Fugitive Components TPY	Exising DHT Heater H-3701 TPY	Current Tanks TPY (Zero Increase; See Text))	HGU LPG Feed TPY (Biogenic Portion)	Increase in HGU LPG Feed TPY (Non-Biogenic Portion)	Existing HGU Heater H-2001 TPY	Proposed PTE - Baseline Actual TPY	PSD Triggered?	Significance Level TPY	Increase in H-3701 PTE TPY	Proposed Project PTE - Current PTE TPY	Sig Mod?	Threshold TPY
Criteria Air Pollutants (CAPS)																
CO	26.60				5.96				22.97	55.53	N	100	1.88	28.47	Y	25
Hydrogen sulfide	0.01				0.00				0.02	0.03	N	10	0.00	0.02	N	2.5
NH3	0.76				0.13				0.48	1.37			0.04	0.80	N	2
Lead	6.05E-04				3.07E-05				1.18E-04	0.0008	N	0.6	0.0000	0.0006	N	0.15
NOx	19.25				2.58				13.97	35.79	N	40	0.81	20.06	Y	10
SO2	16.52				0.72				2.77	20.01	N	40	0.23	16.75	Y	10
VOC	0.84			0.76	0.22				0.83	2.65	N	40	0.07	1.67	N	10
Particulate Matter:																
Total (Filterable + Condensable)	2.71				0.30				1.15	4.16	N	25	0.09	2.80	N	6.25
Filterable	1.92				0.07				0.29	2.28			0.02	1.94		
Condensable	2.44				0.22				0.86	3.53			0.07	2.51		
PM10 (Filterable + Condensable)	2.71				0.30				1.15	4.16	N	15	0.09	2.80	N	3.75
PM10 (Filterable)	1.92				0.07				0.29	2.28			0.02	1.94		
PM2.5 (Filterable + Condensable)	2.71				0.30				1.15	4.16	N	10	0.09	2.80	Y	2.5
PM2.5 (Filterable)	1.92				0.07				0.29	2.28			0.02	1.94		
PSD-Specific Categories																
Fluorides	1.48E-02									0.01	N	3		0.01	N	0.75
Sulfuric Acid Mist	1.16E-01				3.29E-02				1.27E-01	0.28	N	7	0.01	0.13	N	1.75
Total Reduced Sulfur	4.20E-02				1.19E-02				4.60E-02	0.10	N	10	0.00	0.05	N	2.5
Greenhouse Gases (GHGs)																
Total GHG (CO2e):	37,048		1,325		7,950		24,513	12,256	30,665	113,757	Y	75,000	2,504	40,877	Y	10,000
Individual Components:																
Carbon Dioxide	36,894		1,325		7,915		24,513	12,256	30,530	113,433			2,493	40,712		
Methane	1.82E+00				4.13E-01				1.59E+00	3.83			0.13	1.95		
Nitrous Oxide	3.64E-01				8.26E-02				3.19E-01	0.77			0.03	0.39		
Hazardous Air Pollutants (HAPS)	5.22E-01			0.05	1.23E-01				4.74E-01	1.17			3.87E-02	0.61	Y	0.25

Table C-2: Future Boiler Potential To Emit	99.0 MMBtu/hr		441,504 MMBtu/yr		277 MMscf/yr		99.0 MMBtu/hr		110,376 MMBtu/yr		788 1000 gal/yr		551,880 MMBtu/yr	
	Fuel Gas						Diesel						Max	
	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr (Highest of 2 Fuels)	Max TPY (Sum of 2 Fuels)
Criteria Air Pollutants (CAPS)														
CO	130	ppm	Assume (10)	9.51E-02	9.42	21.00	130	ppm	(10)	1.01E-01	1.00E+01	5.60	10.04	26.60
Hydrogen sulfide	162	ppm in fuel	(2) 3hr	1.80E-04	1.78E-02	1.47E-02							0.02	0.01
	60	ppm in fuel	(2) ann	6.65E-05									0.00	0.00
NH3	2.01E-03	lb/MMBtu	(3)	2.01E-03	0.20	0.44	8.00E-01	lb/1000 gal	(13)	5.71E-03	5.66E-01	0.32	0.57	0.76
Lead	4.90E-07	lb/MMBtu	(1)	4.90E-07	4.85E-05	1.08E-04	9.00E+00	lb/10^12Btu	(12)	9.00E-06	8.91E-04	0.00	0.00	0.00
NOx	50	ppm	(11)	0.051	5.10	11.36	2.00E+01	lb/1000 gal	(12)	1.43E-01	1.41E+01	7.88	14.14	19.25
SO2	20	ppm	(4) 3hr	0.029	2.84	2.53	35.500	lb/1000 gal	(12)	2.54E-01	2.51E+01	13.99	25.10	16.52
	8	ppm	(4) ann	0.011										
VOC	3.45E-03	lb/MMBtu	(8)	0.00345	0.34	0.76	2.00E-01	lb/1000 gal	(12)	1.43E-03	1.41E-01	0.08	0.34	0.84
Particulate Matter:														
Total (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.47	1.05	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	2.71
Filterable	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.12	0.26	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	1.92
Condensable	3.57E-03	lb/MMBtu	(8)	3.57E-03	0.35	0.79	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	2.44
PM10 (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.47	1.05	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	2.71
PM10 (Filterable)	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.12	0.26	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	1.92
PM2.5 (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.47	1.05	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	2.71
PM2.5 (Filterable)	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.12	0.26	3.00E-02	lb/MMBtu	(14)	3.00E-02	2.97E+00	1.66	2.97	1.92

Table C-2: Future Boiler Potential To Emit	Fuel Gas						Diesel						Max	
	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr (Highest of 2 Fuels)	Max TPY (Sum of 2 Fuels)
PSD-Specific categories														
Fluorides							3.75E-02	lb/1000 gal	(12)	2.68E-04	2.65E-02	1.48E-02	2.65E-02	0.01
Sulfuric Acid Mist	1.32E-03	lb/MMBtu	(5) 3 hr	1.32E-03	1.30E-01	1.16E-01							0.13	0.12
	5.26E-04	lb/MMBtu	(5) ann	5.26E-04										
Total Reduced Sulfur	1.90E-04	lb/MMBtu	(9)	1.90E-04	1.89E-02	0.04							0.02	0.04
Greenhouse Gases (GHGs)														
Total GHG (CO2e):	5.77E+01	kg/MMBtu	(7)	1.27E+02	12,574	28,037	7.42E+01	kg/MMBtu	(7)	1.63E+02	16,164	9,011	16,163.77	37,047.73
Individual Components:														
Carbon Dioxide	5.75E+01	kg/MMBtu	(6)	1.26E+02	12,518	27,914	7.40E+01	kg/MMBtu	(7)	1.63E+02	16,108	8,980	16,108.49	36,893.66
Methane	3.00E-03	kg/MMBtu	(7)	6.60E-03	6.53E-01	1.46	3.00E-03	kg/MMBtu	(7)	6.60E-03	6.53E-01	0.36	0.65	1.82
Nitrous Oxide	6.00E-04	kg/MMBtu	(7)	1.32E-03	1.31E-01	0.29	6.00E-04	kg/MMBtu	(7)	1.32E-03	1.31E-01	0.07	0.13	0.36
Hazardous Air Pollutants (HAPS)														
1,3-Butadiene														
1,4-Dichlorobenzene(p)	1.20E-06	lb/MMBtu	(1)	1.20E-06	1.19E-04	2.65E-04							1.19E-04	2.65E-04
Acetaldehyde	1.20E-05	lb/MMBtu	(1)	1.20E-05	1.19E-03	2.65E-03	1.05E-03	lb/1000 gal	(12)	7.50E-06	7.43E-04	4.14E-04	1.19E-03	3.06E-03
Acrolein	1.70E-05	lb/MMBtu	(1)	1.70E-05	1.68E-03	3.75E-03							1.68E-03	3.75E-03
Antimony	5.20E-07	lb/MMBtu	(1)	5.20E-07	5.15E-05	1.15E-04	5.25E-03	lb/1000 gal	(12)	3.75E-05	3.71E-03	2.07E-03	3.71E-03	2.18E-03
Arsenic	2.00E-07	lb/MMBtu	(1)	2.00E-07	1.98E-05	4.42E-05	4.00E+00	lb/10^12Btu	(12)	4.00E-06	3.96E-04	2.21E-04	3.96E-04	2.65E-04
Benzene	2.10E-06	lb/MMBtu	(1)	2.10E-06	2.08E-04	4.64E-04	2.14E-04	lb/1000 gal	(12)	1.53E-06	1.51E-04	8.44E-05	2.08E-04	5.48E-04
Beryllium	1.30E-07	lb/MMBtu	(1)	1.30E-07	1.29E-05	2.87E-05	3.00E+00	lb/10^12Btu	(12)	3.00E-06	2.97E-04	1.66E-04	2.97E-04	1.94E-04
Biphenyl, 1,1-														
Cadmium	1.10E-06	lb/MMBtu	(1)	1.10E-06	1.09E-04	2.43E-04	3.00E+00	lb/10^12Btu	(12)	3.00E-06	2.97E-04	1.66E-04	2.97E-04	4.08E-04
Carbon disulfide														
Carbonyl sulfide														
Chlorine														
Chloroform							5.10E-03	lb/1000 gal	(12)	3.64E-05	3.61E-03	2.01E-03	3.61E-03	2.01E-03
Chromium:														
Total Chromium	1.40E-06	lb/MMBtu	(1)	1.40E-06	1.39E-04	3.09E-04	3.00E+00	lb/10^12Btu	(12)	3.00E-06	2.97E-04	1.66E-04	2.97E-04	4.75E-04

Table C-2: Future Boiler Potential To Emit	Fuel Gas					
	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY
Hexavalent Chromium						
Cobalt	8.20E-08	lb/MMBtu	(1)	8.20E-08	8.12E-06	1.81E-05
Cumene						
Dichloroethane, 1,2-						
Diethanolamine						
Ethyl benzene	1.60E-05	lb/MMBtu	(1)	1.60E-05	1.58E-03	3.53E-03
Ethylene glycol						
Formaldehyde	7.40E-05	lb/MMBtu	(1)	7.40E-05	7.33E-03	1.63E-02
Hexane	1.80E-03	lb/MMBtu	(1)	1.80E-03	1.78E-01	3.97E-01
m-Cresol						
Hydrochloric acid						
Manganese	3.70E-07	lb/MMBtu	(1)	3.70E-07	3.66E-05	8.17E-05
Mercury	2.50E-07	lb/MMBtu	(1)	2.50E-07	2.48E-05	5.52E-05
Methanol						
Methyl chloroform (1,1,1-Trichloroethane)						
Methyl isobutyl ketone						
Methyl tert butyl ether						
Naphthalene	6.00E-07	lb/MMBtu	(1)	6.00E-07	5.94E-05	1.32E-04
Nickel	2.10E-06	lb/MMBtu	(1)	2.10E-06	2.08E-04	4.64E-04
Phenol	4.00E-06	lb/MMBtu	(1)	4.00E-06	3.96E-04	8.83E-04
Phosphorus	6.40E-07	lb/MMBtu	(1)	6.40E-07	6.34E-05	1.41E-04
Polychlorinated biphenyls (Aroclors)						
Selenium	8.80E-07	lb/MMBtu	(1)	8.80E-07	8.71E-05	1.94E-04
Styrene						
Toluene	3.30E-06	lb/MMBtu	(1)	3.30E-06	3.27E-04	7.28E-04
Trimethylpentane, 2,2,4-						
Xylenes	2.50E-05	lb/MMBtu	(1)	2.50E-05	2.48E-03	5.52E-03

Table C-2: Future Boiler Potential To Emit	Fuel Gas					
	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY

HAPs - Polycylic Organic Matter (POM)

Total Polycylic Organic Matter:	2.79E-07	lb/MMBtu	(1), Sum	2.79E-07	2.76E-05	6.15E-05
Individual Components:						
2-Methylnapthalene	2.40E-08	lb/MMBtu	(1)	2.40E-08	2.38E-06	5.30E-06
3-methylchloranthrene	1.80E-09	lb/MMBtu	(1)	1.80E-09	1.78E-07	3.97E-07
7,12-dimethylbenz(a)anthracene	1.60E-08	lb/MMBtu	(1)	1.60E-08	1.58E-06	3.53E-06
Acenaphthylene	6.50E-09	lb/MMBtu	(1)	6.50E-09	6.44E-07	1.43E-06
Anthracene	4.70E-09	lb/MMBtu	(1)	4.70E-09	4.65E-07	1.04E-06
Benzo(a)anthracene	2.20E-08	lb/MMBtu	(1)	2.20E-08	2.18E-06	4.86E-06
Benzo(a)pyrene	5.70E-08	lb/MMBtu	(1)	5.70E-08	5.64E-06	1.26E-05
Benzo(b)fluoranthene	2.70E-08	lb/MMBtu	(1)	2.70E-08	2.67E-06	5.96E-06
Benzo(g,h,i)perylene	1.30E-09	lb/MMBtu	(1)	1.30E-09	1.29E-07	2.87E-07
Benzo(k)fluoroanthene	1.70E-08	lb/MMBtu	(1)	1.70E-08	1.68E-06	3.75E-06
Chrysene	1.60E-09	lb/MMBtu	(1)	1.60E-09	1.58E-07	3.53E-07
Dibenz(a,h)anthracene	1.20E-09	lb/MMBtu	(1)	1.20E-09	1.19E-07	2.65E-07
Fluoranthene	2.90E-09	lb/MMBtu	(1)	2.90E-09	2.87E-07	6.40E-07
Fluorene	2.70E-09	lb/MMBtu	(1)	2.70E-09	2.67E-07	5.96E-07
Indeno(1,2,3-cd)pyrene	7.10E-08	lb/MMBtu	(1)	7.10E-08	7.03E-06	1.57E-05
PAH						
Phenanthrene	1.70E-08	lb/MMBtu	(1)	1.70E-08	1.68E-06	3.75E-06
Pyrene	4.90E-09	lb/MMBtu	(1)	4.90E-09	4.85E-07	1.08E-06

Table C-2: Future Boiler Potential To Emit	Fuel Gas					
	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY

Non-HAPs

1,2,4- Trimethylbenzene						
2-Chloronaphthalene						
Acenaphthene	2.40E-09	lb/MMBtu	(1)	2.40E-09	2.38E-07	5.30E-07
Barium	4.30E-06	lb/MMBtu	(1)	4.30E-06	4.26E-04	9.49E-04
Benzo(e)pyrene						
Copper	8.50E-07	lb/MMBtu	(1)	8.50E-07	8.42E-05	1.88E-04
Cyclohexane						
Ethane	3.30E-03	lb/MMBtu	(1)	3.30E-03	3.27E-01	7.28E-01
Fluoride						
Methyl ethyl ketone (2-Butanone)						
Molybdenum	1.10E-06	lb/MMBtu	(1)	1.10E-06	1.09E-04	2.43E-04
n-Butane	2.10E-03	lb/MMBtu	(1)	2.10E-03	2.08E-01	4.64E-01
n-pentane	2.50E-03	lb/MMBtu	(1)	2.50E-03	2.48E-01	5.52E-01
Perylene						
Propane	1.60E-03	lb/MMBtu	(1)	1.60E-03	1.58E-01	3.53E-01
Propylene	1.50E-04	lb/MMBtu	(1)	1.50E-04	1.49E-02	3.31E-02
Vanadium	2.30E-06	lb/MMBtu	(1)	2.30E-06	2.28E-04	5.08E-04
Zinc	2.90E-05	lb/MMBtu	(1)	2.90E-05	2.87E-03	6.40E-03

Diesel Properties

0.25 % Sulfur
140,000 Btu/Gal (12)
9190 Diesel Fd Factor (dSCF/MMBtu), Part 75 Table 1

Refinery Fuel Gas Properties

1,595 RFG Heat Content (Btu/scf)
8622.193886 RFG Fd Factor (dSCF/MMBtu)

Emission Factor References

1. RTI International's Emission Estimation Protocol for Petroleum Refineries- Table 4-3. Criteria pollu Filterable PM determined by subtraction of Condensable PM from from Primary PM. Total POM is
2. 40 CFR 60 NSPS Subpart Ja H2S in fuel limits: 162 ppmv 3hr and 60 ppmv 365day, assumes 2% H2S
3. EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emiss. Factor, Table 5-2, 8/94
4. 40 CFR 60 NSPS Subpart Ja SO2 in flue gas limits: 20 ppmv (dry, 0% O2) 3hr and 8 ppmv (dry, 0% C
5. Sulfuric Acid Mist based on conversion from SO2
6. Carbon content in RFG averaged from event-based lab sample data used for GHG reporting
7. GHG Emission factors from Tables C-1 and C-2 of 40 CFR 98. Global warming potentials from Table
8. AP-42 Section 1.4 - Natural Gas Combustion.
9. Total Sulfur/H2S Ratio Factor = 1.060 max spec; 0.01 Total Sulfur (as H2S)
10. Boiler MACT DDDDD Standard for liq. Fuel
11. Equivalent of Ja Standard for forced draft process heater (50 ppm)
12. EPA AP-42 Section 1.3 - Fuel Oil Combustion. May 2010.
13. EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emiss. Factor, Table 5-2, 8/94
14. PM from NSPS Dc (Same as Table 1 to Subpart JJJJJ of Part 63), presuming any PM constituent co

Table C-3: Future Fugitive Sources Potential To Emit

New Fugitive Components				VOC Emissions			
Class	Chemical State	Count	Reference	kg/hr/source	EF	lb/yr	TPY
VALVE		160	Conservative 20% addition to DHT (large than default 100 per	7.11E-05	(1)	219	0.11
PUMP	LT. LIQUID	0	(Exclude) Replacing existing pump P3703A/B with larger pump P3703C/D. No plan to reuse existing at this time.	0.00E+00	NA	0	0.00
PUMP	HEAVY LIQUID	1	1 new multi-renewable product transfer pump for renewable diesel and/or SAF	5.19E-03	(1)	100	0.05
PUMP	HEAVY LIQUID	0	(Exclude) P3701A- changed from fresh diesel to swing between	0.00E+00	NA	0	0.00
PUMP	HEAVY LIQUID	0	(Exclude) P3701B- changed from fresh diesel to recycle diesel.	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	P3701C – new treated veg oil	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	2 new raw veg oil feed pump to pretreat unit	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	2 new boiler feed water pump	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	3 new veg oil pumps, swing between untreated and pretreated	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	2 pretreat veg oily water pump around pump	0.00E+00	NA	0	0.00
PUMP	Non-HC (TVP 0)	0	1 raw veg oil transfer pump in tank farm	0.00E+00	NA	0	0.00
Compressors		0	(Exclude; Routing to Flare) C2503 Product Compressor (Previously OOS)	1.61E+00	(2)	0	0.00
Compressors		0	(Exclude; Routing to Flare) New C-3702 Makeup H2 Compressor; Emission factor reduced by 90% because 90+% H2 purity	1.61E-01	(2)	0	0.00
Compressors		0	(Exclude; Routing to Flare) New C-3703 Recycle H2 Compressor; Emission factor reduced by 85% because 85% H2 purity	2.41E-01	(2)	0	0.00
CONNECTORS		320	Assumes 2 per valve	1.47E-04	(1)	909	0.45
OPEN-ENDED LINE		0	No OELS	1.44E-03	(1)	0	0.00
SAMPLING CONNECTIONS		5	Estimate	3.09E-03	(1)	297	0.15
Total		486				1,526	0.76

	Emission Factor	Emission Factor Units	Emission Factor Reference	Max lb/hr	Max TPY
Criteria Air Pollutants (CAPS)					
VOC			(1) Calculation Above	1,526	0.76
Hazardous Air Pollutants (HAPS)					
1,3-Butadiene	0	lb/lb VOC	(3)	0	0
Benzene	0.0037	lb/lb VOC	(3)	6	0.002822
Biphenyl, 1,1-	0.0022	lb/lb VOC	(3)	3	0.001678
Cumene	0.0007	lb/lb VOC	(3)	1	0.000534
Ethyl benzene	0.0037	lb/lb VOC	(3)	6	0.002822
Hexane	0.019	lb/lb VOC	(3)	29	0.014493
m-Cresol	0.001%	of Tank VOCs	(4)	0	7.63E-06
Methyl isobutyl ketone	0.05%	of Tank VOCs	(4)	1	0.000343
Naphthalene	0.0025	lb/lb VOC	(3)	4	0.001907
Phenol	0.001%	of Tank VOCs	(4)	0	7.63E-06
Toluene	0.017	lb/lb VOC	(3)	26	0.012968
Trimethylpentane, 2,2,4-	0	lb/lb VOC	(3)	0	0
Xylenes	0.019	lb/lb VOC	(3)	29	0.014493
HAPs - Polycylic Organic Matter (POM)					
Total Polycylic Organic Matter:			(4) Sum of below	1	0.000389
Individual Components:					
Benzo(g,h,i)perylene	1.49E-02	Ratio	(5)	0	2.84E-05
PAH	1.89E-01	Ratio	(5)	1	3.60E-04
Non-HAPs					
1,2,4- Trimethylbenzene	4.00E-03	lb/lb VOC	(3)	6	0.003051
Cyclohexane	1.85%	of Tank VOCs	(4)	28	0.014112
Methyl ethyl ketone (2-Butanone	0.55%	of Tank VOCs	(4)	8	0.004195

Emission Factor References

1. NMOC value for fugitives (except compressor) from Table 2-2 Correlation Equation of Emission Estimation Protocol for Petroleum Refineries (Version 3, April 2015) and the following screening values:
   - Certified Low Leak Technology (CLLT) limit of 100 ppm for valves
   - Monitoring leak threshold of 500 ppm for connectors that will be monitored with valves
   - Monitoring leak threshold of 2,000 ppm for pumps
   - Standard leak threshold of 10,000 ppm for remaining sources (Except compressors)
2. NMOC value for compressor from Table 2-3 of Emission Estimation Protocol for Petroleum Refineries (Version 3, April 2015).
3. Calculated ratio of WFi/WFVOC from Table 2-7. Concentration of HAP in Refinery Process Unit Streams (Emission Estimation Protocol for Petroleum Refineries (Version 3))
4. Though not identified in the Emission Protocol, conservatively added based on typical profile of Tank VOC emissions at the refinery.
5. Also not identified in the Emission Protocol. Conservatively added based on typical ratio of PAH and Benzo(g,h,i)perylene in Sara 312 reporting

Table C-4: H-3701 Actual Increase	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Baseline		Current PTE		Future PTE		Future PTE - Baseline		Future PTE - Current PTE	
					15.8 MMBtu/hr		26 MMBtu/hr		30 MMBtu/hr		14.3 MMBtu/hr			
					Max lb/hr	Max TPY	Max lb/hr	Max TPY*	Max lb/hr	Max TPY*	Max lb/hr	Max TPY	Max lb/hr	Max TPY
Criteria Air Pollutants (CAPS)														
CO	130	ppm	Assume (10)	9.51E-02	1.50	6.57	2.43	10.65	2.86	12.53	1.36	5.96	0.43	1.88
Hydrogen sulfide	162 60	ppm in fuel ppm in fuel	(2) 3hr (2) ann	1.80E-04 6.65E-05	2.83E-03	4.60E-03	4.59E-03	7.45E-03	5.40E-03	8.76E-03	2.57E-03	4.17E-03	8.09E-04	1.31E-03
NH3	2.01E-03	lb/MMBtu	(3)	2.01E-03	0.03	0.14	0.05	0.22	0.06	0.26	0.03	0.13	0.01	0.04
Lead	4.90E-07	lb/MMBtu	(1)	4.90E-07	7.73E-06	3.38E-05	1.25E-05	5.49E-05	1.47E-05	6.45E-05	7.00E-06	3.07E-05	2.21E-06	9.66E-06
NOx	40	ppm	(11)	4.12E-02	0.65	2.84	1.05	4.61	1.24	5.42	0.59	2.58	0.19	0.81
SO2	20 8	ppm ppm	(4) 3hr (4) ann	0.029 0.011	0.45	0.79	0.73	1.28	0.86	1.51	0.41	0.72	0.13	0.23
VOC	3.45E-03	lb/MMBtu	(8)	3.45E-03	0.05	0.24	0.09	0.39	0.10	0.45	0.05	0.22	0.02	0.07
Particulate Matter														
Total (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.08	0.33	0.12	0.53	0.14	0.63	0.07	0.30	0.02	0.09
Filterable	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.02	0.08	0.03	0.13	0.04	0.16	0.02	0.07	0.01	0.02
Condensable	3.57E-03	lb/MMBtu	(8)	3.57E-03	0.06	0.25	0.09	0.40	0.11	0.47	0.05	0.22	0.02	0.07
PM10 (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.08	0.33	0.12	0.53	0.14	0.63	0.07	0.30	0.02	0.09
PM10 (Filterable)	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.02	0.08	0.03	0.13	0.04	0.16	0.02	0.07	0.01	0.02
PM2.5 (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.08	0.33	0.12	0.53	0.14	0.63	0.07	0.30	0.02	0.09
PM2.5 (Filterable)	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.02	0.08	0.03	0.13	0.04	0.16	0.02	0.07	0.01	0.02
PSD-Specificcategories														
Fluorides														
Sulfuric Acid Mist	1.32E-03 5.26E-04	lb/MMBtu lb/MMBtu	(5) 3 hr (5) ann	1.32E-03 5.26E-04	2.08E-02	0.04	3.36E-02	0.06	3.96E-02	0.07	1.88E-02	0.03	5.92E-03	0.01
Total Reduced Sulfur	1.90E-04	lb/MMBtu	(9)	1.90E-04	3.00E-03	0.01	4.87E-03	0.02	5.73E-03	0.03	2.72E-03	0.01	8.57E-04	0.00
Greenhouse Gases (GHGs)														
Total GHG (CO2e)	5.77E+01	kg/MMBtu	(7)	1.27E+02	2,003	8,773	3,246	14,219	3,818	16,723	1,815	7,950	572	2,504
Individual Components														
Carbon Dioxide	5.75E+01	kg/MMBtu	(6)	1.26E+02	1,994	8,735	3,232	14,157	3,801	16,650	1,807	7,915	569	2,493
Methane	3.00E-03	kg/MMBtu	(7)	6.60E-03	1.04E-01	0.46	1.69E-01	0.74	1.98E-01	0.87	9.43E-02	0.41	2.97E-02	0.13
Nitrous Oxide	6.00E-04	kg/MMBtu	(7)	1.32E-03	2.08E-02	0.09	3.37E-02	0.15	3.97E-02	0.17	1.89E-02	0.08	5.94E-03	0.03
Hazardous Air Pollutants (HAPS)														
1,3-Butadiene														
1,4-Dichlorobenzene(p)	1.20E-06	lb/MMBtu	(1)	1.20E-06	1.89E-05	8.29E-05	3.07E-05	1.34E-04	3.61E-05	1.58E-04	1.71E-05	7.51E-05	5.40E-06	2.37E-05
Acetaldehyde	1.20E-05	lb/MMBtu	(1)	1.20E-05	1.89E-04	8.29E-04	3.07E-04	1.34E-03	3.61E-04	1.58E-03	1.71E-04	7.51E-04	5.40E-05	2.37E-04
Acrolein	1.70E-05	lb/MMBtu	(1)	1.70E-05	2.68E-04	1.17E-03	4.35E-04	1.90E-03	5.11E-04	2.24E-03	2.43E-04	1.06E-03	7.65E-05	3.35E-04
Antimony	5.20E-07	lb/MMBtu	(1)	5.20E-07	8.20E-06	3.59E-05	1.33E-05	5.82E-05	1.56E-05	6.85E-05	7.43E-06	3.26E-05	2.34E-06	1.03E-05
Arsenic	2.00E-07	lb/MMBtu	(1)	2.00E-07	3.15E-06	1.38E-05	5.11E-06	2.24E-05	6.01E-06	2.63E-05	2.86E-06	1.25E-05	9.00E-07	3.94E-06
Benzene	2.10E-06	lb/MMBtu	(1)	2.10E-06	3.31E-05	1.45E-04	5.37E-05	2.35E-04	6.31E-05	2.77E-04	3.00E-05	1.31E-04	9.45E-06	4.14E-05
Beryllium	1.30E-07	lb/MMBtu	(1)	1.30E-07	2.05E-06	8.98E-06	3.32E-06	1.46E-05	3.91E-06	1.71E-05	1.86E-06	8.14E-06	5.85E-07	2.56E-06
Biphenyl, 1,1-														
Cadmium	1.10E-06	lb/MMBtu	(1)	1.10E-06	1.73E-05	7.60E-05	2.81E-05	1.23E-04	3.31E-05	1.45E-04	1.57E-05	6.89E-05	4.95E-06	2.17E-05
Carbon disulfide														
Carbonyl sulfide														
Chlorine														
Chloroform														
Chromium														
Total Chromium	1.40E-06	lb/MMBtu	(1)	1.40E-06	2.21E-05	9.67E-05	3.58E-05	1.57E-04	4.21E-05	1.84E-04	2.00E-05	8.76E-05	6.30E-06	2.76E-05
Hexavalent Chromium														

Table C-4: H-3701 Actual Increase	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Baseline 15.8 MMBtu/hr		Current PTE 26 MMBtu/hr		Future PTE 30 MMBtu/hr		Future PTE - Baseline 14.3 MMBtu/hr		Future PTE - Current PTE	
					Max lb/hr	Max TPY	Max lb/hr	Max TPY*	Max lb/hr	Max TPY*	Max lb/hr	Max TPY	Max lb/hr	Max TPY
Criteria Air Pollutants (CAPS)														
CO	130	ppm	Assume (10)	9.51E-02	1.50	6.57	2.43	10.65	2.86	12.53	1.36	5.96	0.43	1.88
Hydrogen sulfide	162 60	ppm in fuel ppm in fuel	(2) 3hr (2) ann	1.80E-04 6.65E-05	2.83E-03	4.60E-03	4.59E-03	7.45E-03	5.40E-03	8.76E-03	2.57E-03	4.17E-03	8.09E-04	1.31E-03
NH3	2.01E-03	lb/MMBtu	(3)	2.01E-03	0.03	0.14	0.05	0.22	0.06	0.26	0.03	0.13	0.01	0.04
Lead	4.90E-07	lb/MMBtu	(1)	4.90E-07	7.73E-06	3.38E-05	1.25E-05	5.49E-05	1.47E-05	6.45E-05	7.00E-06	3.07E-05	2.21E-06	9.66E-06
NOx	40	ppm	(11)	4.12E-02	0.65	2.84	1.05	4.61	1.24	5.42	0.59	2.58	0.19	0.81
SO2	20 8	ppm ppm	(4) 3hr (4) ann	0.029 0.011	0.45	0.79	0.73	1.28	0.86	1.51	0.41	0.72	0.13	0.23
VOC	3.45E-03	lb/MMBtu	(8)	3.45E-03	0.05	0.24	0.09	0.39	0.10	0.45	0.05	0.22	0.02	0.07
Particulate Matter:														
Total (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.08	0.33	0.12	0.53	0.14	0.63	0.07	0.30	0.02	0.09
Filterable	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.02	0.08	0.03	0.13	0.04	0.16	0.02	0.07	0.01	0.02
Condensable	3.57E-03	lb/MMBtu	(8)	3.57E-03	0.06	0.25	0.09	0.40	0.11	0.47	0.05	0.22	0.02	0.07
PM10 (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.08	0.33	0.12	0.53	0.14	0.63	0.07	0.30	0.02	0.09
PM10 (Filterable)	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.02	0.08	0.03	0.13	0.04	0.16	0.02	0.07	0.01	0.02
PM2.5 (Filterable + Condensable)	4.76E-03	lb/MMBtu	(8)	4.76E-03	0.08	0.33	0.12	0.53	0.14	0.63	0.07	0.30	0.02	0.09
PM2.5 (Filterable)	1.19E-03	lb/MMBtu	(8)	1.19E-03	0.02	0.08	0.03	0.13	0.04	0.16	0.02	0.07	0.01	0.02
PSD-Specificcategories														
Fluorides														
Sulfuric Acid Mist	1.32E-03 5.26E-04	lb/MMBtu lb/MMBtu	(5) 3 hr (5) ann	1.32E-03 5.26E-04	2.08E-02	0.04	3.36E-02	0.06	3.96E-02	0.07	1.88E-02	0.03	5.92E-03	0.01
Total Reduced Sulfur	1.90E-04	lb/MMBtu	(9)	1.90E-04	3.00E-03	0.01	4.87E-03	0.02	5.73E-03	0.03	2.72E-03	0.01	8.57E-04	0.00
Greenhouse Gases (GHGs)														
Total GHG (CO2e):	5.77E+01	kg/MMBtu	(7)	1.27E+02	2,003	8,773	3,246	14,219	3,818	16,723	1,815	7,950	572	2,504
Individual Components:														

					Baseline		
					15.8 MMBtu/hr		
Table C-4: H-3701 Actual Increase	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Ma
Carbon Dioxide	5.75E+01	kg/MMBtu	(6)	1.26E+02	1,994	8,735	3
Methane	3.00E-03	kg/MMBtu	(7)	6.60E-03	1.04E-01	0.46	1.6
Nitrous Oxide	6.00E-04	kg/MMBtu	(7)	1.32E-03	2.08E-02	0.09	3.3

Hazardous Air Pollutants (HAPS)

1,3-Butadiene							
1,4-Dichlorobenzene(p)	1.20E-06	lb/MMBtu	(1)	1.20E-06	1.89E-05	8.29E-05	3.0
Acetaldehyde	1.20E-05	lb/MMBtu	(1)	1.20E-05	1.89E-04	8.29E-04	3.0
Acrolein	1.70E-05	lb/MMBtu	(1)	1.70E-05	2.68E-04	1.17E-03	4.3
Antimony	5.20E-07	lb/MMBtu	(1)	5.20E-07	8.20E-06	3.59E-05	1.3
Arsenic	2.00E-07	lb/MMBtu	(1)	2.00E-07	3.15E-06	1.38E-05	5.1
Benzene	2.10E-06	lb/MMBtu	(1)	2.10E-06	3.31E-05	1.45E-04	5.3
Beryllium	1.30E-07	lb/MMBtu	(1)	1.30E-07	2.05E-06	8.98E-06	3.3
Biphenyl, 1,1-							
Cadmium	1.10E-06	lb/MMBtu	(1)	1.10E-06	1.73E-05	7.60E-05	2.8
Carbon disulfide							
Carbonyl sulfide							
Chlorine							
Chloroform							
Chromium:							
Total Chromium	1.40E-06	lb/MMBtu	(1)	1.40E-06	2.21E-05	9.67E-05	3.58
Hexavalent Chromium							

Table C-4: H-3701 Actual Increase	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Baseline		Current PTE		Future PTE		Future PTE - Baseline		Future PTE - Current PTE	
					15.8 MMBtu/hr		26 MMBtu/hr		30 MMBtu/hr		14.3 MMBtu/hr			
					Max lb/hr	Max TPY	Max lb/hr	Max TPY*	Max lb/hr	Max TPY*	Max lb/hr	Max TPY	Max lb/hr	Max TPY
Cobalt	8.20E-08	lb/MMBtu	(1)	8.20E-08	1.29E-06	5.66E-06	2.10E-06	9.18E-06	2.47E-06	1.08E-05	1.17E-06	5.13E-06	3.69E-07	1.62E-06
Cumene														
Dichloroethane, 1,2-														
Diethanolamine														
Ethyl benzene	1.60E-05	lb/MMBtu	(1)	1.60E-05	2.52E-04	1.11E-03	4.09E-04	1.79E-03	4.81E-04	2.11E-03	2.29E-04	1.00E-03	7.20E-05	3.15E-04
Ethylene glycol														
Formaldehyde	7.40E-05	lb/MMBtu	(1)	7.40E-05	1.17E-03	5.11E-03	1.89E-03	8.28E-03	2.22E-03	9.74E-03	1.06E-03	4.63E-03	3.33E-04	1.46E-03
Hexane	1.80E-03	lb/MMBtu	(1)	1.80E-03	2.84E-02	1.24E-01	4.60E-02	2.02E-01	5.41E-02	2.37E-01	2.57E-02	1.13E-01	8.10E-03	3.55E-02
m-Cresol														
Hydrochloric acid														
Manganese	3.70E-07	lb/MMBtu	(1)	3.70E-07	5.84E-06	2.56E-05	9.46E-06	4.14E-05	1.11E-05	4.87E-05	5.29E-06	2.32E-05	1.67E-06	7.30E-06
Mercury	2.50E-07	lb/MMBtu	(1)	2.50E-07	3.94E-06	1.73E-05	6.39E-06	2.80E-05	7.52E-06	3.29E-05	3.57E-06	1.56E-05	1.13E-06	4.93E-06
Methanol														
Methyl chloroform (1,1,1-Trichloroethane)														
Methyl isobutyl ketone														
Methyl tert butyl ether														
Naphthalene	6.00E-07	lb/MMBtu	(1)	6.00E-07	9.46E-06	4.14E-05	1.53E-05	6.72E-05	1.80E-05	7.90E-05	8.57E-06	3.76E-05	2.70E-06	1.18E-05
Nickel	2.10E-06	lb/MMBtu	(1)	2.10E-06	3.31E-05	1.45E-04	5.37E-05	2.35E-04	6.31E-05	2.77E-04	3.00E-05	1.31E-04	9.45E-06	4.14E-05
Phenol	4.00E-06	lb/MMBtu	(1)	4.00E-06	6.31E-05	2.76E-04	1.02E-04	4.48E-04	1.20E-04	5.27E-04	5.72E-05	2.50E-04	1.80E-05	7.89E-05
Phosphorus	6.40E-07	lb/MMBtu	(1)	6.40E-07	1.01E-05	4.42E-05	1.64E-05	7.17E-05	1.92E-05	8.43E-05	9.15E-06	4.01E-05	2.88E-06	1.26E-05
Polychlorinated biphenyls (Aroclors)														
Selenium	8.80E-07	lb/MMBtu	(1)	8.80E-07	1.39E-05	6.08E-05	2.25E-05	9.85E-05	2.65E-05	1.16E-04	1.26E-05	5.51E-05	3.96E-06	1.74E-05
Styrene														
Toluene	3.30E-06	lb/MMBtu	(1)	3.30E-06	5.20E-05	2.28E-04	8.43E-05	3.69E-04	9.92E-05	4.35E-04	4.72E-05	2.07E-04	1.49E-05	6.51E-05
Trimethylpentane, 2,2,4-														
Xylenes	2.50E-05	lb/MMBtu	(1)	2.50E-05	3.94E-04	1.73E-03	6.39E-04	2.80E-03	7.52E-04	3.29E-03	3.57E-04	1.56E-03	1.13E-04	4.93E-04

HAPs - Polycylic Organic Matter (POM)

Total Polycylic Organic Matter:	2.79E-07	lb/MMBtu	(1), Sum	2.79E-07	4.39E-06	1.92E-05	7.12E-06	3.12E-05	8.38E-06	3.67E-05	3.98E-06	1.74E-05	1.25E-06	5.49E-06
Individual Components:														
2-Methylnapthalene	2.40E-08	lb/MMBtu	(1)	2.40E-08	3.78E-07	1.66E-06	6.13E-07	2.69E-06	7.21E-07	3.16E-06	3.43E-07	1.50E-06	1.08E-07	4.73E-07

Table C-4: H-3701 Actual Increase	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Baseline		
					15.8 MMBtu/hr		
					Max lb/hr	Max TPY	Ma
3-methylchloranthrene	1.80E-09	lb/MMBtu	(1)	1.80E-09	2.84E-08	1.24E-07	4.6
7,12-dimethylbenz(a)anthracene	1.60E-08	lb/MMBtu	(1)	1.60E-08	2.52E-07	1.11E-06	4.0
Acenaphthylene	6.50E-09	lb/MMBtu	(1)	6.50E-09	1.03E-07	4.49E-07	1.6
Anthracene	4.70E-09	lb/MMBtu	(1)	4.70E-09	7.41E-08	3.25E-07	1.2
Benzo(a)anthracene	2.20E-08	lb/MMBtu	(1)	2.20E-08	3.47E-07	1.52E-06	5.6
Benzo(a)pyrene	5.70E-08	lb/MMBtu	(1)	5.70E-08	8.99E-07	3.94E-06	1.4
Benzo(b)fluoranthene	2.70E-08	lb/MMBtu	(1)	2.70E-08	4.26E-07	1.87E-06	6.9
Benzo(g,h,i)perylene	1.30E-09	lb/MMBtu	(1)	1.30E-09	2.05E-08	8.98E-08	3.3
Benzo(k)fluoroanthene	1.70E-08	lb/MMBtu	(1)	1.70E-08	2.68E-07	1.17E-06	4.3
Chrysene	1.60E-09	lb/MMBtu	(1)	1.60E-09	2.52E-08	1.11E-07	4.0
Dibenz(a,h)anthracene	1.20E-09	lb/MMBtu	(1)	1.20E-09	1.89E-08	8.29E-08	3.0
Fluoranthene	2.90E-09	lb/MMBtu	(1)	2.90E-09	4.57E-08	2.00E-07	7.4
Fluorene	2.70E-09	lb/MMBtu	(1)	2.70E-09	4.26E-08	1.87E-07	6.9
Indeno(1,2,3-cd)pyrene	7.10E-08	lb/MMBtu	(1)	7.10E-08	1.12E-06	4.90E-06	1.8
PAH							
Phenanthrene	1.70E-08	lb/MMBtu	(1)	1.70E-08	2.68E-07	1.17E-06	4.3
Pyrene	4.90E-09	lb/MMBtu	(1)	4.90E-09	7.73E-08	3.38E-07	1.2

Table C-4: H-3701 Actual Increase	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Baseline 15.8 MMBtu/hr		
					Max lb/hr	Max TPY	Ma
Non-HAPs							
1,2,4- Trimethylbenzene							
2-Chloronaphthalene							
Acenaphthene	2.40E-09	lb/MMBtu	(1)	2.40E-09	3.78E-08	1.66E-07	6.1
Barium	4.30E-06	lb/MMBtu	(1)	4.30E-06	6.78E-05	2.97E-04	1.1
Benzo(e)pyrene							
Copper	8.50E-07	lb/MMBtu	(1)	8.50E-07	1.34E-05	5.87E-05	2.1
Cyclohexane							
Ethane	3.30E-03	lb/MMBtu	(1)	3.30E-03	5.20E-02	2.28E-01	8.4
Fluoride							
Methyl ethyl ketone (2-Butanone)							
Molybdenum	1.10E-06	lb/MMBtu	(1)	1.10E-06	1.73E-05	7.60E-05	2.8
n-Butane	2.10E-03	lb/MMBtu	(1)	2.10E-03	3.31E-02	1.45E-01	5.3
n-pentane	2.50E-03	lb/MMBtu	(1)	2.50E-03	3.94E-02	1.73E-01	6.3
Perylene							
Propane	1.60E-03	lb/MMBtu	(1)	1.60E-03	2.52E-02	1.11E-01	4.0
Propylene	1.50E-04	lb/MMBtu	(1)	1.50E-04	2.37E-03	1.04E-02	3.8
Vanadium	2.30E-06	lb/MMBtu	(1)	2.30E-06	3.63E-05	1.59E-04	5.8
Zinc	2.90E-05	lb/MMBtu	(1)	2.90E-05	4.57E-04	2.00E-03	7.4

Refinery Fuel Gas Properties

1,595	RFG Heat Content (Btu/scf)
8,622	RFG Fd Factor (dSCF/MMBtu)

Emission Factor References

1. RTI International's Emission Estimation Protocol for Petroleum Refineries- Table 4-3. Criteria pollutants cons subtraction of Condensable PM from from Primary PM. Total POM is sum of individual components.
2. 40 CFR 60 NSPS Subpart Ja H2S in fuel limits: 162 ppmv 3hr and 60 ppmv 365day, assumes 2% H2S Slip, Rema
3. EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emiss. Factor, Table 5-2, 8/94
4. 40 CFR 60 NSPS Subpart Ja SO2 in flue gas limits: 20 ppmv (dry, 0% O2) 3hr and 8 ppmv (dry, 0% O2) 365day
5. Sulfuric Acid Mist based on conversion from SO2
6. Carbon content in RFG averaged from event-based lab sample data used for GHG reporting
7. GHG Emission factors from Tables C-1 and C-2 of 40 CFR 98. Global warming potentials from Table A-1 of 40
8. AP-42 Section 1.4 - Natural Gas Combustion.
9. Total Sulfur/H2S Ratio Factor = 1.060 max spec; 0.01 Total Sulfur (as H2S)
10. Boiler MACT DDDDD Standard for liq. Fuel
11. Design basis with Ultra Low Nox Burner (ULNB)

Table C-5: H-2001 Actual Increase (Fuel Burning)	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Baseline		Potential		Increase	
			MMBTU/rolling 12-mo	96973.2	77.72 MMBtu/hr		132.84 MMBtu/hr		55.12 MMBtu/hr	
					Max lb/hr	Max TPY	Max lb/hr	Max TPY*	Max lb/hr	Max TPY
Criteria Air Pollutants (CAPS)										
CO	130	ppm	Assume (10)	9.51E-02	7.39	32.39	12.64	55.36	5.24	22.97
Hydrogen sulfide	162	ppm in fuel	Assume (2) 3hr	1.80E-04	0.01	0.02	0.02	0.04	0.01	0.02
	60	ppm in fuel	Assume (2) ann	6.65E-05						
NH3	2.01E-03	lb/MMBtu	(3)	2.01E-03	0.16	0.68	0.27	1.17	0.11	0.48
Lead	4.90E-07	lb/MMBtu	(1)	4.90E-07	3.81E-05	1.67E-04	6.51E-05	2.85E-04	2.70E-05	1.18E-04
NOx	**Baseline (Using CEMS)**				36.1	16.0	36.1	30.0	0.00	14.0
	36.1	lb/hr	CEMS highest hour 2021-2022							
	16.0	TPY	CEMS Avg 2021-2022 (Annual Emiss Inv)							
	Potential									
	36.1	lb/hr	CEMS highest hour 2021-2022							
	60	ppm	(11) 30 day	6.18E-02						
	50	ppm	(11) ann	5.15E-02						
SO2	20	ppm	(4) 3hr	2.86E-02	2.23	3.90	3.81	6.67	1.58	2.77
	8	ppm	(4) ann	1.15E-02						
VOC	3.45E-03	lb/MMBtu	(8)	3.45E-03	0.27	1.17	0.46	2.01	0.19	0.83
Particulate Matter:										
Total (Filterable + Condensable)	0.005	lb/MMBtu	(8)	4.76E-03	0.37	1.62	0.63	2.77	0.26	1.15
Filterable	0.001	lb/MMBtu	(8)	1.19E-03	0.09	0.41	0.16	0.69	0.07	0.29
Condensable	0.004	lb/MMBtu	(8)	3.57E-03	0.28	1.22	0.47	2.08	0.20	0.86
PM10 (Filterable + Condensable)	0.005	lb/MMBtu	(8)	4.76E-03	0.37	1.62	0.63	2.77	0.26	1.15
PM10 (Filterable)	0.00119	lb/MMBtu	(8)	1.19E-03	0.09	0.41	0.16	0.69	0.07	0.29
PM2.5 (Filterable + Condensable)	0.005	lb/MMBtu	(8)	4.76E-03	0.37	1.62	0.63	2.77	0.26	1.15
PM2.5 (Filterable)	0.001	lb/MMBtu	(8)	1.19E-03	0.09	0.41	0.16	0.69	0.07	0.29
PSD-Specificcategories										
Fluorides										
Sulfuric Acid Mist	1.32E-03	lb/MMBtu	(5) 3 hr	1.32E-03	1.02E-01	0.18	1.75E-01	0.31	7.25E-02	0.13
	5.26E-04	lb/MMBtu	(5) ann	5.26E-04						
Total Reduced Sulfur	1.90E-04	lb/MMBtu	(9)	1.90E-04	1.48E-02	0.06	2.53E-02	0.11	1.05E-02	0.05
Greenhouse Gases (GHGs)										
Total GHG (CO2e):	5.77E+01	kg/MMBtu	(7)	1.27E+02	9,871	43,233	16,872	73,898	7,001	30,665
Individual Components:										
Carbon Dioxide	5.75E+01	kg/MMBtu	(6)	1.26E+02	9,827	43,043	16,798	73,573	6,970	30,530
Methane	3.00E-03	kg/MMBtu	(7)	6.60E-03	5.13E-01	2.25	8.77E-01	3.84	3.64E-01	1.59
Nitrous Oxide	6.00E-04	kg/MMBtu	(7)	1.32E-03	1.03E-01	0.45	1.75E-01	0.77	7.28E-02	0.32
Hazardous Air Pollutants (HAPS)					15.987	70.02				
1,3-Butadiene										
1,4-Dichlorobenzene(p)	1.20E-06	lb/MMBtu	(1)	1.20E-06	9.33E-05	4.08E-04	1.59E-04	6.98E-04	6.61E-05	2.90E-04
Acetaldehyde	1.20E-05	lb/MMBtu	(1)	1.20E-05	9.33E-04	4.08E-03	1.59E-03	6.98E-03	6.61E-04	2.90E-03
Acrolein	1.70E-05	lb/MMBtu	(1)	1.70E-05	1.32E-03	5.79E-03	2.26E-03	9.89E-03	9.37E-04	4.10E-03
Antimony	5.20E-07	lb/MMBtu	(1)	5.20E-07	4.04E-05	1.77E-04	6.91E-05	3.03E-04	2.87E-05	1.26E-04
Arsenic	2.00E-07	lb/MMBtu	(1)	2.00E-07	1.55E-05	6.81E-05	2.66E-05	1.16E-04	1.10E-05	4.83E-05
Benzene	2.10E-06	lb/MMBtu	(1)	2.10E-06	1.63E-04	7.15E-04	2.79E-04	1.22E-03	1.16E-04	5.07E-04
Beryllium	1.30E-07	lb/MMBtu	(1)	1.30E-07	1.01E-05	4.43E-05	1.73E-05	7.56E-05	7.17E-06	3.14E-05
Biphenyl, 1,1-										
Cadmium	1.10E-06	lb/MMBtu	(1)	1.10E-06	8.55E-05	3.74E-04	1.46E-04	6.40E-04	6.06E-05	2.66E-04
Carbon disulfide										
Carbonyl sulfide										

Table C-5: H-2001 Actual Increase (Fuel Burning)	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr	Max TPY*	Max lb/hr	Max TPY
Chlorine										
Chloroform										
Chromium:										
Total Chromium	1.40E-06	lb/MMBtu	(1)	1.40E-06	1.09E-04	4.77E-04	1.86E-04	8.15E-04	7.72E-05	3.38E-04
Hexavalent Chromium										
Cobalt	8.20E-08	lb/MMBtu	(1)	8.20E-08	6.37E-06	2.79E-05	1.09E-05	4.77E-05	4.52E-06	1.98E-05
Cumene										
Dichloroethane, 1,2-										
Diethanolamine										
Ethyl benzene	1.60E-05	lb/MMBtu	(1)	1.60E-05	1.24E-03	5.45E-03	2.13E-03	9.31E-03	8.82E-04	3.86E-03
Ethylene glycol										
Formaldehyde	7.40E-05	lb/MMBtu	(1)	7.40E-05	5.75E-03	2.52E-02	9.83E-03	4.31E-02	4.08E-03	1.79E-02
Hexane	1.80E-03	lb/MMBtu	(1)	1.80E-03	1.40E-01	6.13E-01	2.39E-01	1.05E+00	9.92E-02	4.35E-01
m-Cresol										
Hydrochloric acid										
Manganese	3.70E-07	lb/MMBtu	(1)	3.70E-07	2.88E-05	1.26E-04	4.92E-05	2.15E-04	2.04E-05	8.93E-05
Mercury	2.50E-07	lb/MMBtu	(1)	2.50E-07	1.94E-05	8.51E-05	3.32E-05	1.45E-04	1.38E-05	6.04E-05
Methanol										
Methyl chloroform (1,1,1-Trichloroethane)										
Methyl isobutyl ketone										
Methyl tert butyl ether										
Naphthalene	6.00E-07	lb/MMBtu	(1)	6.00E-07	4.66E-05	2.04E-04	7.97E-05	3.49E-04	3.31E-05	1.45E-04
Nickel	2.10E-06	lb/MMBtu	(1)	2.10E-06	1.63E-04	7.15E-04	2.79E-04	1.22E-03	1.16E-04	5.07E-04
Phenol	4.00E-06	lb/MMBtu	(1)	4.00E-06	3.11E-04	1.36E-03	5.31E-04	2.33E-03	2.20E-04	9.66E-04
Phosphorus	6.40E-07	lb/MMBtu	(1)	6.40E-07	4.97E-05	2.18E-04	8.50E-05	3.72E-04	3.53E-05	1.55E-04
Polychlorinated biphenyls (Aroclors)										
Selenium	8.80E-07	lb/MMBtu	(1)	8.80E-07	6.84E-05	3.00E-04	1.17E-04	5.12E-04	4.85E-05	2.12E-04
Styrene										
Toluene	3.30E-06	lb/MMBtu	(1)	3.30E-06	2.56E-04	1.12E-03	4.38E-04	1.92E-03	1.82E-04	7.97E-04
Trimethylpentane, 2,2,4-										
Xylenes	2.50E-05	lb/MMBtu	(1)	2.50E-05	1.94E-03	8.51E-03	3.32E-03	1.45E-02	1.38E-03	6.04E-03

Table C-5: H-2001 Actual Increase (Fuel Burning)	Emission Factor	Emission Factor Units	Emission Factor Reference	lb/MMBtu Equivalent Emission Factor	Max lb/hr	Max TPY	Max lb/hr	Max TPY*	Max lb/hr	Max TPY
HAPs - Polycylic Organic Matter (POM)										
Total Polycylic Organic Matter:	2.79E-07	lb/MMBtu	(1), Sum	2.79E-07	2.17E-05	9.48E-05	3.70E-05	1.62E-04	1.54E-05	6.73E-05
Individual Components:										
2-Methylnapthalene	2.40E-08	lb/MMBtu	(1)	2.40E-08	1.87E-06	8.17E-06	3.19E-06	1.40E-05	1.32E-06	5.79E-06
3-methylchloranthrene	1.80E-09	lb/MMBtu	(1)	1.80E-09	1.40E-07	6.13E-07	2.39E-07	1.05E-06	9.92E-08	4.35E-07
7,12-dimethylbenz(a)anthracene	1.60E-08	lb/MMBtu	(1)	1.60E-08	1.24E-06	5.45E-06	2.13E-06	9.31E-06	8.82E-07	3.86E-06
Acenaphthylene	6.50E-09	lb/MMBtu	(1)	6.50E-09	5.05E-07	2.21E-06	8.63E-07	3.78E-06	3.58E-07	1.57E-06
Anthracene	4.70E-09	lb/MMBtu	(1)	4.70E-09	3.65E-07	1.60E-06	6.24E-07	2.73E-06	2.59E-07	1.13E-06
Benzo(a)anthracene	2.20E-08	lb/MMBtu	(1)	2.20E-08	1.71E-06	7.49E-06	2.92E-06	1.28E-05	1.21E-06	5.31E-06
Benzo(a)pyrene	5.70E-08	lb/MMBtu	(1)	5.70E-08	4.43E-06	1.94E-05	7.57E-06	3.32E-05	3.14E-06	1.38E-05
Benzo(b)fluoranthene	2.70E-08	lb/MMBtu	(1)	2.70E-08	2.10E-06	9.19E-06	3.59E-06	1.57E-05	1.49E-06	6.52E-06
Benzo(g,h,i)perylene	1.30E-09	lb/MMBtu	(1)	1.30E-09	1.01E-07	4.43E-07	1.73E-07	7.56E-07	7.17E-08	3.14E-07
Benzo(k)fluoroanthene	1.70E-08	lb/MMBtu	(1)	1.70E-08	1.32E-06	5.79E-06	2.26E-06	9.89E-06	9.37E-07	4.10E-06
Chrysene	1.60E-09	lb/MMBtu	(1)	1.60E-09	1.24E-07	5.45E-07	2.13E-07	9.31E-07	8.82E-08	3.86E-07
Dibenz(a,h)anthracene	1.20E-09	lb/MMBtu	(1)	1.20E-09	9.33E-08	4.08E-07	1.59E-07	6.98E-07	6.61E-08	2.90E-07
Fluoranthene	2.90E-09	lb/MMBtu	(1)	2.90E-09	2.25E-07	9.87E-07	3.85E-07	1.69E-06	1.60E-07	7.00E-07
Fluorene	2.70E-09	lb/MMBtu	(1)	2.70E-09	2.10E-07	9.19E-07	3.59E-07	1.57E-06	1.49E-07	6.52E-07
Indeno(1,2,3-cd)pyrene	7.10E-08	lb/MMBtu	(1)	7.10E-08	5.52E-06	2.42E-05	9.43E-06	4.13E-05	3.91E-06	1.71E-05
PAH										
Phenanthrene	1.70E-08	lb/MMBtu	(1)	1.70E-08	1.32E-06	5.79E-06	2.26E-06	9.89E-06	9.37E-07	4.10E-06
Pyrene	4.90E-09	lb/MMBtu	(1)	4.90E-09	3.81E-07	1.67E-06	6.51E-07	2.85E-06	2.70E-07	1.18E-06
Non-HAPs										
1,2,4- Trimethylbenzene										
2-Chloronaphthalene										
Acenaphthene	2.40E-09	lb/MMBtu	(1)	2.40E-09	1.87E-07	8.17E-07	3.19E-07	1.40E-06	1.32E-07	5.79E-07
Barium	4.30E-06	lb/MMBtu	(1)	4.30E-06	3.34E-04	1.46E-03	5.71E-04	2.50E-03	2.37E-04	1.04E-03
Benzo(e)pyrene										
Copper	8.50E-07	lb/MMBtu	(1)	8.50E-07	6.61E-05	2.89E-04	1.13E-04	4.95E-04	4.69E-05	2.05E-04
Cyclohexane										
Ethane	3.30E-03	lb/MMBtu	(1)	3.30E-03	2.56E-01	1.12E+00	4.38E-01	1.92E+00	1.82E-01	7.97E-01
Fluoride										
Methyl ethyl ketone (2-Butanone)										
Molybdenum	1.10E-06	lb/MMBtu	(1)	1.10E-06	8.55E-05	3.74E-04	1.46E-04	6.40E-04	6.06E-05	2.66E-04
n-Butane	2.10E-03	lb/MMBtu	(1)	2.10E-03	1.63E-01	7.15E-01	2.79E-01	1.22E+00	1.16E-01	5.07E-01
n-pentane	2.50E-03	lb/MMBtu	(1)	2.50E-03	1.94E-01	8.51E-01	3.32E-01	1.45E+00	1.38E-01	6.04E-01
Perylene										
Propane	1.60E-03	lb/MMBtu	(1)	1.60E-03	1.24E-01	5.45E-01	2.13E-01	9.31E-01	8.82E-02	3.86E-01
Propylene	1.50E-04	lb/MMBtu	(1)	1.50E-04	1.17E-02	5.11E-02	1.99E-02	8.73E-02	8.27E-03	3.62E-02
Vanadium	2.30E-06	lb/MMBtu	(1)	2.30E-06	1.79E-04	7.83E-04	3.06E-04	1.34E-03	1.27E-04	5.55E-04
Zinc	2.90E-05	lb/MMBtu	(1)	2.90E-05	2.25E-03	9.87E-03	3.85E-03	1.69E-02	1.60E-03	7.00E-03

Refinery Fuel Gas Properties

1,595	RFG Heat Content (Btu/scf)
8622.193886	RFG Fd Factor (dSCF/MMBtu)

Emission Factor References

1. RTI International's Emission Estimation Protocol for Petroleum Refineries- Table 4-3. Criteria pollutants considered same as natural gas external combustion. Filterable PM determined by subtraction of Condensable PM from from Primary PM. Total POM is sum of individual components.
2. 40 CFR 60 NSPS Subpart Ja H2S in fuel limits: 162 ppmv 3hr and 60 ppmv 365day, assumes 2% H2S Slip, Remainder SO2
3. EPA Emission Factor (Non-AP42), Dev. & Selection of Ammonia Emiss. Factor, Table 5-2, 8/94
4. 40 CFR 60 NSPS Subpart Ja SO2 in flue gas limits: 20 ppmv (dry, 0% O2) 3hr and 8 ppmv (dry, 0% O2) 365day
5. Sulfuric Acid Mist based on conversion from SO2
6. Carbon content in RFG averaged from event-based lab sample data used for GHG reporting
7. GHG Emission factors from Tables C-1 and C-2 of 40 CFR 98. Global warming potentials from Table A-1 of 40 CFR 98.
8. AP-42 Section 1.4 - Natural Gas Combustion.
9. Total Sulfur/H2S Ratio Factor = 1.060 max spec; 0.01 Total Sulfur (as H2S)
10. Boiler MACT DDDDD Standard for liq. Fuel
11. Consent Decree/Permit Limit after installation of ULNB

Table C-6: HGU Increased Feedstock

RATIO 0.069223475 MT CO2 from LPG Fed /MMBtu RFG Burned

	Baseline		Increased Bio		Increased Fossil		Increased Total	
H2001 Firing	680799	MMBtu/yr	37	MMBtu/hr	18	MMBtu/hr	55	MMBtu/hr
Associated LPG Feed CO2	47127.29066	MT CO2/Year	2.5	MTCO2/hr	1.3	MTCO2/hr	3.8	MTCO2/hr
	Max lb/hr	Max TPY	Max lb/hr	Max TPY	Max lb/hr	Max TPY	Max lb/hr	Max TPY
CO2	11,836	51,840	5,597	24,513	2,798	12,256	8,395	36,769

Appendix D – Ambient Air Quality Model Analysis

AECOM

Air Quality Analysis
Par Hawaii Refining Kapolei Refinery
Renewal Hydrotreater Project Modeling

Prepared for:

Par Hawaii Refining
91-325 Komohana Street
Kapolei, HI 96707

Prepared by:

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February 2024

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1.0 INTRODUCTION

Par Hawaii Refining (Par) owns and operates a petroleum refinery in the Campbell Industrial Park located in the city of Kapolei, Hawaii. The refinery produces diesel and gasoline for Oahu and other neighboring islands.

The refinery plans to convert the existing distillate hydrotreater unit into a renewable hydrotreater unit (RHT). The RHT will process up to 61 million gallons per years of renewable feedstocks into renewable fuels such as renewable diesel (RD), sustainable aviation fuel (SAF), renewable naphtha (RN), and renewable liquefied petroleum gases (RLPGs). A pre-treatment facility will be constructed to treat raw feedstocks prior to processing in the RHT unit. The feedstock for the facility will be imported soybean oil, but other sources including biofuel crops, vegetable oils, used cooking oil, and other animal fats will also be used for production. The goal for the RHT project is to reduce the carbon intensity of liquid fuels in Hawaii and meet the increasing demand for low-carbon energy in the state of Hawaii.

This memo summarizes the methodology used to perform the air dispersion modeling analysis for this proposed project and documents the modeling results.

2.0 MODELING METHODOLOGY

AECOM conducted air dispersion modeling of emissions from the proposed RHT project at the facility. The analysis used the American Meteorological Society/ U.S. Environmental Protection Agency Regulatory (AERMOD) model (Version 23132).

AECOM used the Hawaii Department of Health (HDOH) recommended methodologies for modeling the impacts from the following pollutants and averaging periods: CO (1-hr and 8-hr), NO_2 (1-hr and Annual), H_2S (1-hr), SO_2 (1-hr, 3-hr, 24-hr, and Annual), PM_{10} (24-hr and Annual), and $PM_{2.5}$ (24-hr and Annual). In addition, ambient background concentrations from State of Hawaii Annual Summary Air Quality Data from 2019, 2020, 2021, and 2022 were added to the maximum ground level concentrations predicted by the model; the total concentration was compared to the applicable National Ambient Air Quality Standards (NAAQS) and Hawaii Ambient Air Quality Standards.

In terms of the air quality model methodology, the analysis was performed in compliance with the rules in the Health Department of Hawaii's Administrative Rules (HAR). In Chapter 11-60.1-12(a) of the HAR, it states that the requirements provided in the federal rule 40 CFR Part 51 Appendix W are acceptable when determining the type of air quality model needed to perform. This air quality model that will be submitted with this application complies with the criteria and recommended procedure stated in 40 CFR Part 51 Appendix W.

Table 2-1 and Table 2-2 each lists the source release parameters and emission rates used in this modeling analysis. The listed sources were modeled with maximum hourly emission rates (converted to g/s) for short-term averaging periods and average annual emission rates (converted to g/s) for annual periods. For each of these sources, the emissions rates are based on the potential to emit emission rather than the project increase to provide a more conservative model for the analysis of this application.

Table 2-1. Source Input Parameters

Source ID	Source Description	UTM East (m)	UTM North (m)	Base Elevation (m)	Temperature (K)	Stack Diameter (m)	Stack Height (m)	Exit Velocity (m/s)
14	FH2001 (Hydrogen Reformer Heater)	594,245	2,356,269	5.00	480.37	1.96	19.15	7.80
101	FH3701 Hydrotreater Feed Heater	594,325	2,356,179	5.00	569.32	1.07	27.93	4.02
102	SG1104 Steam Generator #4	594,356	2,356,187	5.00	418.87	0.90	25.20	11.91

Table 2-2. Modeled Emission Rates (g/s)

Source ID	CO 1-hr, 8-hr	H_2S 1-hr	NO_x 1-hr	NO_x Ann	SO_2 1-hr, 3-hr, 24-hr	SO_2 Ann	$PM_{10}/PM_{2.5}$ 24-hr	$PM_{10}/PM_{2.5}$ Ann
14	1.59E+00	3.01E-03	4.55E+00	8.62E-01	4.79E-01	1.92E-01	7.98E-02	7.98E-02
101	3.60E-01	6.81E-04	1.56E-01	1.56E-01	1.08E-01	4.34E-02	1.80E-02	1.80E-02
102	1.26E+00	2.24E-03	1.78E+00	5.54E-01	3.16E+00	4.75E-01	3.74E-01	7.79E-02

Five years (2017-2021) of meteorological data were processed using surface station data from Honolulu Airport (Station ID PHNL). Upper air data were collected from the National Weather Service (NWS) station located in LIHUE Airport (Station 22536). All meteorological raw data was processed using AERMET (Version 22112). 1-minute and 5-minute Automated Surface Observing System (ASOS) data from NWS surface station was processed by the subroutine, AERMINUTE, and used for processing. AERSURFACE (Version 20060) was used to process land cover, impervious, and tree canopy data obtained from the National Land Cover Database (NLCD) website to determine the surface characteristics for use in AERMET.

The rural dispersion option was selected based on an examination of the area surrounding the site. The dominant land use types are mostly rural that include common residential, undeveloped land, and water. Therefore, the site is best characterized as "rural" and the rural dispersion option is appropriate.

Terrain data (elevations and hill heights) were processed using AERMOD's terrain preprocessor, AERMAP (Version 18081). National Elevation Data (NED) files are uploaded to the processor, which then generates elevations and hill heights for all sources, buildings, and receptors.

The modeling analysis included consideration of building downwash effects, wherein the potential for emission discharges from a stack to become caught in the turbulent wakes of structures, was evaluated. The analysis used Building Profile Input Program (BPIP-Prime) (Version 04274) to generate wind direction-specific downwash dimensions from downwash structures. AERMOD considers direction-specific downwash using the PRIME algorithm as evaluated in the BPIP-Prime program.

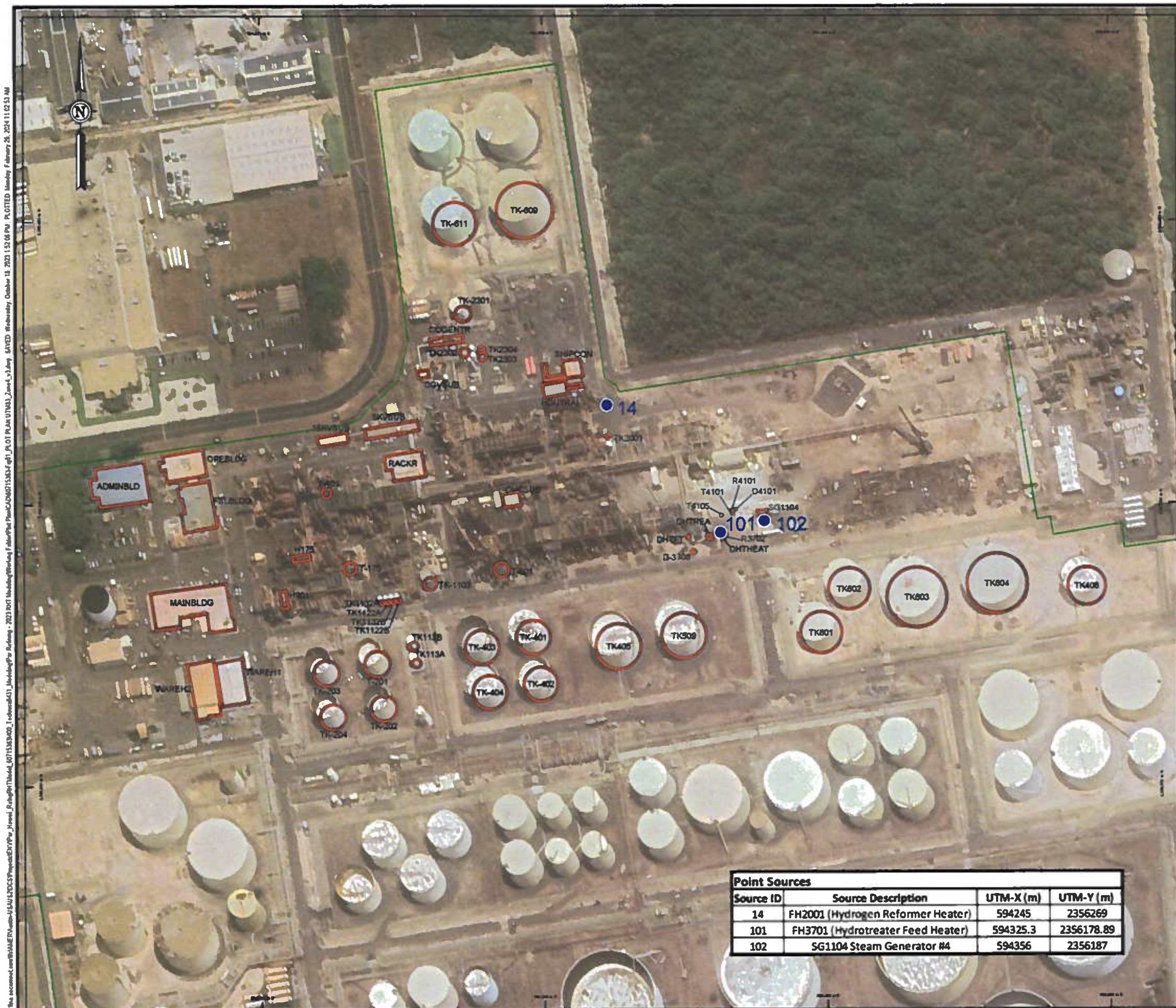
Figure 2-1 shows the plot plan of the modeled stacks, and the proposed structures overlaid the google aerial image.

The basic receptor grid as shown in Figure 2-2 used for the modeling analysis was as follows:

- 25-meter spacing extending from the property line out to 300 meters;

- 100-meter spacing within 300 meters to 1 km of property line for any locations not covered by the 25-meter grid;
- 500-meter spacing within 1 km to 5 km of property line; and
- 1,000-meter spacing within 5 km to 10 km of property line.

Figure 2-1. Source and Downwash



Point Sources			
Source ID	Source Description	UTM-X (m)	UTM-Y (m)
14	FH2001 (Hydrogen Reformer Heater)	594245	2356269
101	FH3701 (Hydrotreater Feed Heater)	594325.3	2356178.89
102	SG1104 Steam Generator #4	594356	2356187

LEGEND

MODEL ID — 14 ● POINT SOURCE

WASHDOWN

PROPERTY BOUNDARY

70 0 70 140

SCALE IN METERS
(COORDINATE SYSTEM: UTM WITH NAD83 DATUM, ZONE 4, METERS)

SOURCE: BING IMAGERY SERVICES

AECOM

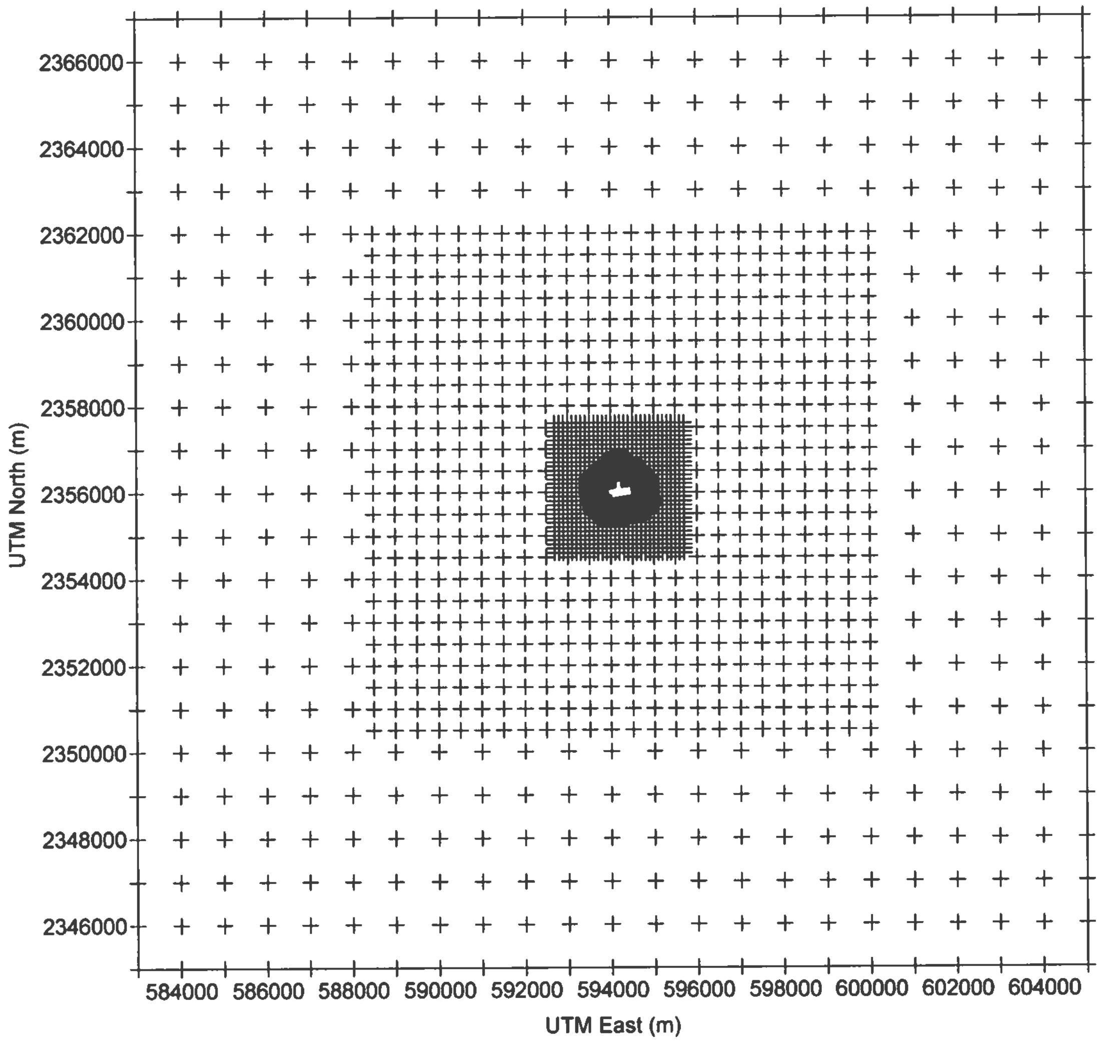
19219 KATY FREEWAY, SUITE 100
HOUSTON, TX 77094
PH (281) 646-2400
FAX (281) 646-2401

Title: SOURCE LOCATION MAP

Project: PAR REFINING - 2023 RHT MODELING
91-325 KOMOHANA STREET
KAPOLEI, HAWAII

Scale	Drawn by	Date	Client: PAR HAWAII REFINING		
As Noted	MS	2/26/2024			
	Chk'd by	Date	Project No.	File Name:	Figure No.
	CM	2/26/2024	60715363	60715363-Fig01_PLOT PLAN UTM83_Zone4_v3.dwg	-

Figure 2-2. Receptors Grid



3.0 Air Quality Data Summary

Representative monitoring data for CO, NO_2, H_2S, SO_2, PM_{10}, and $PM_{2.5}$ was required for use in this modeling analysis.

The published air monitoring data found in the Hawaii Air Quality Data books from 2020 to 2022 were used to determine the ambient background concentrations for the CO, SO_2, PM_{10}, and $PM_{2.5}$ in this modeling analysis. Due to less than 50% of the NO_2 data recovered in the 1st and 2nd quarters in 2022, the published air monitoring data found in the Hawaii Air Quality Data books from 2019 to 2021 were used to determine the ambient background concentrations for NO_2 in this modeling analysis. The selected monitoring stations are located at Kapolei/NCore (Oahu) and Leilani (Pahoa). The Kapolei / NCore monitoring station was selected to represent CO and SO_2 ambient background, the Kapolei monitoring station was selected to represent NO_2, PM_{10}, and $PM_{2.5}$ ambient background, and the Leilani monitoring station was selected to represent H_2S ambient background. The following tables summarize the air quality data used to determine ambient background concentrations in this modeling analysis. Please note, that the 2022 background concentration for 1-hr CO at the Kapolei/NCore monitor exceeds the 1-hr CO Hawai'i state standard of 9ppm. The 2022 air quality data report has explained that in the month of August there was a brush fire right next to the station that caused the elevated levels of CO.

Table 3-1: Kapolei / NCore Air Monitoring Station Location

Kapolei / NCore			
2052 Lauwiliwili St., Kapolei, Oahu			
UTM NAD 83 Zone 4N	Northing: 2,358,251.47 m	Easting: 594,516.6 m	Altitude: 17.9 m MSL

Table 3-2: Kapolei / NCore Air Monitoring Station 2020 – 2022 Data for CO and SO_2

Gas Pollutant	Averaging Time	2020 Maximum ($\mu g/m^3$)	2021 Maximum ($\mu g/m^3$)	2022 Maximum ($\mu g/m^3$)
SO_2	1-hour	24	10	7
	99th percentile	16	7	5
	3-hour	13	8	5
	24-hour	8	5	3
	Annual	3	2	1
CO	1-hour	1375	916	10883
	8-hour	458	458	1489

Table 3-3: Kapolei Air Monitoring Station 2019 – 2021 Data for NO_2

Gas Pollutant	Averaging Time	2019 Maximum ($\mu g/m^3$)	2020 Maximum ($\mu g/m^3$)	2021 Maximum ($\mu g/m^3$)
NO_2	1-hour	64	60	56
	98th percentile	53	49	40
	Annual	8	6	6

Table 3-4: Kapolei/ NCore Air Monitoring Station 2020 - 2022 Averaging SO_2 Background Concentrations

2020 - 2022 Averaging SO_2 Background Concentrations (µg/m³)		
SO_2	1-hour 99th percentile	9
	Annual	2

Table 3-5: Kapolei Air Monitoring Station 2019 - 2021 Averaging NO_2 Background Concentrations

2019 - 2021 Averaging NO_2 Background Concentrations (µg/m³)		
NO_2	1-hour 98th percentile	47
	Annual	6

Table 3-6: Kapolei Air Monitoring Station 2020 – 2022 Data for PM_{10}

PM_{10} (Highest four 24-hour averages in each year)								
2020			2021			2022		
µg/m³	Quarter	Valid/Possible (% complete)	µg/m³	Quarter	Valid/Possible (% complete)	µg/m³	Quarter	Valid/Possible (% complete)
43	4	Monthly Values Not Available	46	1	Monthly Values Not Available	48	4	Monthly Values Not Available
37	1	Monthly Values Not Available	34	2	Monthly Values Not Available	45	2	Monthly Values Not Available
26	4	Monthly Values Not Available	26	4	Monthly Values Not Available	38	2	Monthly Values Not Available
25	4	Monthly Values Not Available	22	2	Monthly Values Not Available	36	1	Monthly Values Not Available
Annual Average	µg/m³	Valid/Possible (% complete)	Annual Average	µg/m³	Valid/Possible (% complete)	Annual Average	µg/m³	Valid/Possible (% complete)
	12.3	343/366 (93.7%)		9.2	273/365 (74.8%)		16.5	351/365 (96.2%)

Table 3-7: Kapolei Air Monitoring Station 2020 – 2022 Data for $PM_{2.5}$

$PM_{2.5}$	2020		2021		2022	
24-hr	98th percentile	3-year average (2018-2020)	98th percentile	3-year average (2019-2021)	98th percentile	3-year average (2020-2022)
	6.9	6.9	6.0	6.3	9.3	7.6
Annual	Average	3-year average (2018-2020)	Average	3-year average (2019-2021)	Average	3-year average (2020-2022)
	3.4	2.9	3.0	2.7	4.7	3.7

Table 3-8: Leilani Air Monitoring Station Location

Leilani			
13-3441 Moku St., Pahoa			
UTM NAD 83 Zone 5Q	**Northing: 2,153,462.21 m**	**Easting: 298,896.84 m**	**Altitude: 229 m MSL**

Table 3-9: Leilani Air Monitoring Station 2020 – 2022 Data for H_2S

Gas Pollutant	Averaging Time	2020 Maximum ($\mu g/m^3$)	2021 Maximum ($\mu g/m^3$)	2022 Maximum ($\mu g/m^3$)
H_2S	**1-hour**	1-hour Values Not Available	8	5

4.0 Modeling Results and Conclusions

Proposed emissions of CO, NO_x, H_2S, SO_2, PM_{10}, and $PM_{2.5}$ from the project sources were modeled. The predicted maximum ground level concentrations (GLC_{max}) with the addition of background concentration are compared with NAAQS and Hawaii Ambient Air Quality Standards. Table 4-1 presents the results of the modeling for CO (1-hr and 8-hr), NO_2 (1-hr and Annual), H_2S (1-hr), SO_2 (1-hr, 3-hr, 24-hr, and Annual), PM_{10} (24-hr and Annual), and $PM_{2.5}$ (24-hr and Annual). Impacts for all pollutants and applicable averaging periods are below the applicable standards.

Table 4-1. Modeled Impacts Summary

Pollutants	Averaging Periods	Predicted AERMOD Concentrations Basis	GLCmax	Background Calculations Basis	Background Values	Background + GLC max	Hawaii Standard		Federal Standard	
			(μg/m³)		(μg/m³)	(μg/m³)	(ppb)	(μg/m³)	(ppb)	(μg/m³)
CO	1-HR	H2H	69.99	H2H	1374.72	1444.72	9000	10310	35000	40096
	8-HR	H2H	31.37	H2H	458.24	489.61	4400	5041	9000	10310
NO_2	1-HR	maximum 98th percentile/H8H	55.70	3-year average of the 98th percentile	47.36	103.05			100	188
	ANNUAL	Maximum	4.13	3-year average of Annual Mean	6.27	10.41	40	76	53	100
H_2S	1-HR	H1H	0.13	H1H	7.73	7.86	25	35		
SO_2	1-HR	maximum 99th percentile/ H4H	34.75	3-year average of the 99th percentile	9.35	44.09			75	197
	3-HR	H2H	40.98	H2H	7.86	48.84	500	1310		
	24-HR	H2H	24.46	H2H	5.24	29.70	140	367		
	ANNUAL	Maximum	2.09	3-year average of Annual Mean	1.66	3.75	30	79		
PM_{10}	24-HR	H2H	2.96	H2H	46.00	48.96		150		150
	ANNUAL	Highest five-year average	0.41	3-year average of Annual Mean	12.67	13.07		50		
$PM_{2.5}$	24-HR	maximum 98th percentile/H8H	2.11	3-year average of the 98th percentile	7.60	9.71				35
	ANNUAL	Highest five-year average	0.41	3-year average of Annual Mean	3.70	4.11				9

5.0 REFERENCES

EPA, 1985 — *Guideline for Determination of Good Engineering Stack Height (Technical Support Document for the Stack Height Regulation) (Revised)*, EPA-450/4-80-023R, June 1985, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711.

EPA, 1997 — Addendum to ISC3 User's Guide, The PRIME Plume Rise and Building *Downwash Model*. Schulman, L.L., D.G. Strimaitis, and J.S. Scire, 1997. Prepared for the Electric Power Research Institute, Palo Alto, CA., Earth Tech Document A287. A-99-05, II-A-12)

EPA, 2022 — *USER'S GUIDE FOR THE AMS/EPA REGULATORY MODEL –AERMOD*. EPA Publication No. EPA-454/B-22-007. Environmental Protection Agency, Research Triangle Park, NC., June 2022

EPA, 2016 — *User's Guide for the AMS/EPA Regulatory Model – AERMOD*. U.S. Environmental Protection Agency, Research Triangle Park, NC.

DOH, 1998 — *State Air Modeling Guidelines for Prevention of Significant Deterioration and Covered Source Permit Applications*. Department of Health, Clean Air Branch, Research Triangle Park, NC., December 7, 1998.

DOH, 2014 — *Amendment and Compilation of Chapter 11-60.1 Hawaii Administrative Rules*. State of Hawaii, Department of Health, Clean Air Branch, 2827 Waimano Home Road #130, HI., June 2014.

DOH, 2019 — *State of Hawaii Annual Summary 2019 Air Quality Data*. State of Hawaii, Department of Health, Clean Air Branch, 2827 Waimano Home Road #130, HI., July 2021.

DOH, 2020 — *State of Hawaii Annual Summary 2020 Air Quality Data*. State of Hawaii, Department of Health, Clean Air Branch, 2827 Waimano Home Road #130, HI., December 2021.

DOH, 2021 — *State of Hawaii Annual Summary 2021 Air Quality Data*. State of Hawaii, Department of Health, Clean Air Branch, 2827 Waimano Home Road #130, HI., December 2022.

DOH, 2022 — *State of Hawaii Annual Summary 2022 Air Quality Data*. State of Hawaii, Department of Health, Clean Air Branch, 2827 Waimano Home Road #130, HI., September 2023.

MAY - 6 2024

POSTMARK

MAY 3 - 2024

Par Hawaii

Certified Mail: 9489 0090 0027 6525 5232 11

May 2, 2024

Ms. Marianne Rossio, Manager
Hawaii Department of Health
Clean Air Branch
2827 Waimano Home Road
Hale Ola Building, Room 130
Pearl City, Hawaii 96782

Dear Ms. Rossio:

Subject:

Par Hawaii Refining, LLC: Petroleum Refinery, CSP No. 0212-01-C
Significant Permit Modification
Renewable Fuel Production Facility
Revised Steam Generating Boiler Equipment Number & Site-Specific Opacity Monitoring Plan

Dear Ms. Rossio:

On March 20, 2024, Par Hawaii Refining resubmitted an application packet for a significant modification to Covered Source Permit (CSP) No. 0212-010C, to construct a renewable fuel production facility by converting the Diesel Hydrotreater (DHT) to a Renewable Hydrotreater (RHT) and adding a renewable feedstock pretreatment unit (PTU) and high-pressure (700 psia) steam generating boiler to the refinery.

This letter is to inform you that the relocated steam generating boiler from Par West will retain its original equipment number, F5205, and will not be recommissioned to SG1104 as described in the application. Also enclosed is the site-specific opacity monitoring plan for F5205 required by 40 CFR 60.47c(f) for approval by the agency.

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.

If there are any questions concerning our request, please call Anna Chung at (808) 440-5576.

Sincerely,

Deaglan McClean
Vice President, Par Hawaii Refining

Enclosure
cc: Darin Lum Darin.Lum@doh.hawaii.gov

Chief, Permits Office, (Attention: Air-3)
Air Division, USEPA Region 9
75 Hawthorne Street
San Francisco, CA 94105

MD22102

CSP No. 0212-01-C
Par East Refinery

F5205 Site-Specific Monitoring Plan for Opacity Emissions

May 2, 2024

Par Hawaii Refining (PHR) proposes a Site-Specific Monitoring Plan for Opacity emissions from a High Pressure (700 psia) Steam Generator/Package Boiler (F5205) which will be installed as part of a new Renewable Fuel Production Facility at PHR's Par East Refinery. An existing package boiler originally constructed in 2007 will be relocated from the idled Par West Facility. The boiler was designed to use and previously operated using liquid fuel (<0.5 %wt sulfur) and/or refinery fuel gas (RFG). Once relocated, the high-pressure steam generator will burn either low sulfur (<0.25% wt) distillate oil and/or RFG.

The high-pressure steam generator is subject to 40 CFR 60 Subpart Dc which requires a Continuous Opacity Monitoring System (COMS) unless other conditions are met. PHR proposes a Site-Specific Monitoring Plan per 40 CFR 60.47c(f)(3) which, for a facility that either burns only RFG or fuels oils that contain no greater than 0.5 weight percent sulfur, allows for a monitoring plan approved by the permitting authority that includes "parameters and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard" instead of a COMS. Per 60.43c(c), the facility may not emit >20% opacity (6 minute average), except for one 6-minute period per hour of not more than 27% opacity. Additionally, the opacity standards in NSPS Dc do not apply during periods of startup, shutdown and malfunction per §60.11(c). This is less stringent than the Hawaii Administrative Rules (HAR) opacity standard which does not allow emissions >20% opacity (6 minute average), except during start-up, shutdown or equipment malfunction of not more than 60% opacity (for no more than six (6) minutes in any 60 minute period). Therefore, PHR will comply with the HAR opacity standard and proposes the following Alternative Monitoring Plan for F5205 per the conditions in ATTACHMENT II(I): SPECIAL CONDITIONS COGENERATION GAS TURBINE AND BOILERS, COVERED SOURCE PERMIT NO. 0212-01-C.

FUEL SPECIFICATIONS

Package Boiler F5205 shall be fired only on distillate oil with a sulfur content not to exceed 0.25% by weight or RFG with a hydrogen sulfide (H2S) content not to exceed 230 mg/dscm (0.10 gr/dscf), a total sulfur content (TS) not to exceed 258 ppm, and a H2S content not to exceed 162 ppmv determined hourly on a three-hour (3-hour) rolling average basis and not to exceed 60 ppmv determined daily on a 365 successive calendar day rolling average basis. The 0.25% weight distillate oil sulfur limit is based on a thirty-day (30-day) rolling average basis. The liquid fuel sulfur limit shall apply at all times, including periods of startup, shutdown, and malfunction.

FUEL CONSUMPTION

PHR shall operate and maintain non-resetting fuel meters for the continuous measurement and recording of the amount of distillate oil and RFG fired in the boiler. Daily, monthly, and rolling twelve-month records of distillate oil consumption and monthly and rolling twelve-month RFG consumption records for the boiler shall be maintained.

DISTILLATE OIL SAMPLING FOR SULFUR CONTENT

Distillate oil samples may be collected from the fuel tank for the boiler immediately after the fuel tank is filled and before any distillate oil is combusted. PHR shall analyze the distillate oil sample to determine the sulfur content of the distillate oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank is required upon filling. Results of the fuel analysis taken after each new supply of distillate oil is received shall be used as the daily value when calculating the thirty (30) day rolling average until the next supply is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.25 weight percent sulfur, PHR shall ensure that the sulfur content of subsequent distillate oil supplies is low enough to cause the thirty (30) day rolling average sulfur content to be 0.25 weight percent sulfur or less.

The sulfur content of the distillate oil for Package Boiler F5205 shall be tested in accordance with the most current ASTM Methods D129, D2622, D4294, D5453, or D7039 or other test methodologies with prior written approval from the Department and the U.S. EPA.

OPACITY AND VISIBLE EMISSIONS (VE)

Package Boiler F5205 shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during start-up, shutdown, or equipment malfunction, Package Boiler F5205 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.

Compliance with the opacity standard will be determined by monthly (calendar month) visible emissions (VE) observations in accordance with 40 CFR Part 60, Appendix A, Method 9 observations, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department and the US EPA, as similarly required for other heaters on this permit. 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.

NOTIFICATION AND REPORTING

Written reports will be submitted semi-annually as required in CSP 0212-01-C Attachment II(I), Section E.2.

From:	Chung, Anna
To:	Lum, Darin W C
Cc:	Widlansky, Benton
Subject:	[EXTERNAL] Par Hawaii Renewable Fuel Production Facility Permit Sig Mod - Possible WTU Expansion
Date:	Thursday, May 16, 2024 12:26:40 AM

Hi Darin,

We are planning to expand the Wastewater Treatment Unit (WTU) to accommodate the water from the Pretreatment Unit (PTU) before being discharged to an underground injection well. An additional aeration tank, new wet surface air cooler (WSAC) and two new blowers will be installed in the Activated Sludge Unit of the WTU. We would like to list some of the new equipment in the WTU section of the Title V permit although, they will not affect emissions or create new regulatory requirements. The Activated Sludge Unit is downstream of the air stripper and oil recovery system in the WTU so, there are no additional VOCs volatized in this unit. There are also no VOCs and HAPs expected in the PTU effluent because the untreated and treated renewable feedstocks have no measurable amount of volatile organic compounds (VOCs) and hazardous air pollutants (HAPs). The WSAC is not a cooling tower or heat exchanger per the definitions in 40 CFR 63 Subpart Q, National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers, and 40 CFR 63 Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, Heat Exchange Systems thus, it is not subject to those regulations.

<u>Proposed Permit & Permit Application Changes:</u>

1. Attachment II(J) Section A.1.3.ii Activated Sludge Units - add an aeration tank and change the description from <u>Two (2)</u> to <u>Three (3)</u> aeration tanks.

2. Revise the PTU project description in the Significant Modification Permit Application dated March 2024 as follows (revisions in red):

<u>Pretreatment Unit (PTU)</u>

The renewable PTU is designed to process 5,000 BPD of untreated renewable feedstock. The PTU utilizes high pressure (700 psia) steam and is comprised of feedstock tanks, a feed vacuum deaerator, reaction and mixing towers, and various feed filters, heat recovery exchangers and oil/water separators. Untreated renewable feedstock will be imported to the refinery via barge or isotainer and stored in four (4) tanks; two (2) existing vertical fixed-roof tanks, TK-602, TK-603, and two (2) new vertical fixed-roof tanks, TK-701 and TK-702. Untreated renewable feedstock, such as soybean oil, is vacuum dried and preheated to about 200 °F by waste heat and fed to the bottom of a high-pressure reactor.

A high-pressure package boiler (F2505) will be relocated from Par West (the former Chevron Hawaii Refinery) to the Par East Refinery. It will be used to supply 700 psia steam and is described separately below. The steam is injected into the high-pressure extraction reactor (R-4101), where it mixes with the untreated renewable feedstock. The hot oil is transferred to the water wash tower (T-4101), where it rises up the column and cold water, added at the top, flows downward creating a counter-current flow of oil and water. The temperature, pressure, and time of contact between water and oil is controlled to allow water to remove (extract) gums, phosphorous, and other contaminants from the untreated renewable feedstock. The renewable feedstock exits the top of the column and goes through a coalescer to remove entrained water and the treated renewable feedstock is sent to the RHT via intermediate tankage. Water exiting the extraction column bottom is passed through a coalescer to remove oil carryover and other entrained impurities. Further treatment to reduce the organic loading may be required if the water is to be discharged to an underground injection well. The refinery's existing Wastewater Treatment Unit (WTU) would be expanded, with an additional aeration tank, new wet surface air cooler (WSAC) and two new blowers to be installed in the non-oily wastewater section of the WTU. Because the untreated and treated renewable feedstocks have no measurable amount of volatile organic compounds (VOCs) and hazardous air pollutants (HAPS), no significant air emissions are expected from the PTU and related renewable feedstock tanks and effluent water.

Let me know if you have any questions.

Thanks,

Anna

Par Hawaii Refining
Anna S.P.T. Chung | Environmental Engineer
91-325 Komohana Street| Kapolei, HI 96707
Office VM:808-763-2016 or 808-440-5576 (refinery)| Mobile:808-726-3271 | achung@parpacific.com