OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY

STANDARD

AIR CONTAMINANT DISCHARGE PERMIT

Northwest Region
700 NE Multnomah St., Suite 600
Portland, OR 97232

This permit is being issued in accordance with the provisions of ORS 468A.040 and based on the land use compatibility findings included in the permit record.

ISSUED TO:

NEXT Renewable Fuels Oregon, LLC
11767 Katy Freeway, Suite 705
Houston, TX 77079

INFORMATION RELIED UPON:

Application No.: 32808
Date Received: 12/24/2020

PLANT SITE LOCATION:

Port Westward Industrial Park
Township 8N, Range 4W, Sections 22 & 23
(-Site address - TBD)
Clatskanie, OR 97016

LAND USE COMPATIBILITY FINDING:

Approving Authority: Columbia County
Approval Date: 03/23/2022

ISSUED BY THE DEPARTMENT OF ENVIRONMENTAL QUALITY

Melissa Hovey
Melissa Hovey (Aug 30, 2022 08:12 PDT)

Melissa Hovey, Northwest Region Air Quality Manager

Aug 30, 2022
Date

Source(s) Permitted to Discharge Air Contaminants (OAR 340-216-8010):

Table 1 Code	Source Description	SIC/NAICS
Part B, 57	Organic or inorganic industrial chemical manufacturing	2869/325199

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1.0 DEVICE, PROCESS AND POLLUTION CONTROL DEVICE (PCD) IDENTIFICATION

The devices, processes, and pollution control devices regulated by this permit are the following:

Devices and Processes Description	Device ID	Pollution Control Device Description	PCD ID	Emission Point ID
77.5 MMBtu/hr NG fired Boiler	Boiler 1	SCR and Oxidation Catalyst	SCR-BLR	BOILER
77.5 MMBtu/hr NG fired Boiler	Boiler 2			
35.2 MMBtu/hr NG Fired Ecofining Unit Trains-Feed Heater 1	ECO1F	SCR and Oxidation Catalyst	SCR-ECO1	ECO1
5.3 MMBtu/hr NG Fired Ecofining Unit Trains-Isomerization Heater 1	ECO1I			
35.2 MMBtu/hr NG Fired Ecofining Unit Trains-Feed Heater 2	ECO2F	SCR and Oxidation Catalyst	SCR-ECO2	ECO2
5.3 MMBtu/hr NG Fired Ecofining Unit Trains-Isomerization Heater 2	ECO2I			
35.2 MMBtu/hr NG Fired Ecofining Unit Trains-Feed Heater 3	ECO3F	SCR and Oxidation Catalyst	SCR-ECO3	ECO3
5.3 MMBtu/hr NG Fired Ecofining Unit Trains-Isomerization Heater 3	ECO3I			
700 MMBtu/hr NG and PSA Tail Gas Fired Hydrogen Plant	H2HTR	SCR and Oxidation Catalyst	SCR-H2HTR	H2HTR
125 MMBtu/hr NG Fired Jet Fractionator	JETFRAC	SCR and Oxidation Catalyst	SCR-JF	JETFRAC
Pretreatment Train 1-BE Day Tank	1BEDAY1	High-Efficiency Filter Bag	FB-1BEDAY1	FB-1BEDAY1
Pretreatment Train 1-BE Day Tank	1BEDAY2	High-Efficiency Filter Bag	FB-1BEDAY2	FB-1BEDAY2

Devices and Processes Description	Device ID	Pollution Control Device Description	PCD ID	Emission Point ID
Pretreatment Train 1-Bleaching Earth Silo	1BESV1	High-Efficiency Filter Bag	FB-1BESV1	FB-1BESV1
Pretreatment Train 1-Bleaching Earth Silo	1BESV2	High-Efficiency Filter Bag	FB-1BESV2	FB-1BESV2
Pretreatment Train 1-Bleaching Earth Silo	1BESV3	High-Efficiency Filter Bag	FB-1BESV3	FB-1BESV3
Pretreatment Train 1-Filter Aid Day Tank	1FADT	High-Efficiency Filter Bag	FB-1FADT	FB-1FADT
Pretreatment Train 1-Filter Aid Dry Silo	1FASV1	High-Efficiency Filter Bag	FB-1FASV1	FB-1FASV1
Pretreatment Train 2-BE Day Tank	2BEDAY1	High-Efficiency Filter Bag	FB-2BEDAY1	FB-2BEDAY1
Pretreatment Train 2-BE Day Tank	2BEDAY2	High-Efficiency Filter Bag	FB-2BEDAY2	FB-2BEDAY2
Pretreatment Train 2-Bleaching Earth Silo	2BESV1	High-Efficiency Filter Bag	FB-2BESV1	FB-2BESV1
Pretreatment Train 2-Bleaching Earth Silo	2BESV2	High-Efficiency Filter Bag	FB-2BESV2	FB-2BESV2
Pretreatment Train 2-Bleaching Earth Silo	2BESV3	High-Efficiency Filter Bag	FB-2BESV3	FB-2BESV3
Pretreatment Train 2-Filter Aid Day Tank	2FADT	High-Efficiency Filter Bag	FB-2FADT	FB-2FADT
Pretreatment Train 2-Filter Aid Dry Silo	2FASV1	High-Efficiency Filter Bag	FB-2FASV1	FB-2FASV1
Pretreatment Train 3-BE Day Tank	3BEDAY1	High-Efficiency Filter Bag	FB-3BEDAY1	FB-3BEDAY1
Pretreatment Train 3-BE Day Tank	3BEDAY2	High-Efficiency Filter Bag	FB-3BEDAY2	FB-3BEDAY2
Pretreatment Train 3-Bleaching Earth Silo	3BESV1	High-Efficiency Filter Bag	FB-3BESV1	FB-3BESV1
Pretreatment Train 3-Bleaching Earth Silo	3BESV2	High-Efficiency Filter Bag	FB-3BESV2	FB-3BESV2
Pretreatment Train 3-Bleaching Earth Silo	3BESV3	High-Efficiency Filter Bag	FB-3BESV3	FB-3BESV3
Pretreatment Train 3-Filter Aid Day Tank	3FADT1	High-Efficiency Filter Bag	FB-3FADT1	FB-3FADT1

Devices and Processes Description	Device ID	Pollution Control Device Description	PCD ID	Emission Point ID
Pretreatment Train 3-Filter Aid Day Tank	3FADT2	High-Efficiency Filter Bag	FB-3FADT2	FB-3FADT2
Pretreatment Train 3-Filter Aid Day Tank	3FADT3	High-Efficiency Filter Bag	FB-3FADT3	FB-3FADT3
Pretreatment Train 3-Filter Aid Dry Silo	3FASV1	High-Efficiency Filter Bag	FB-3FASV1	FB-3FASV1
Pretreatment Train 3-Filter Aid Dry Silo	3FASV2	High-Efficiency Filter Bag	FB-3FASV2	FB-3FASV2
Pretreatment Train 3-Filter Aid Dry Silo	3FASV3	High-Efficiency Filter Bag	FB-3FASV3	FB-3FASV3
5.25 MMGal Animal Fats Storage Tank	ANIFATS1	None		ANIFATS1
5.25 MMGal Animal Fats Storage Tank	ANIFATS2	None		ANIFATS2
5.25 MMGal Animal Fats Storage Tank	ANIFATS3	None		ANIFATS3
16,000 Gal Citric Acid Storage Tank	CACID1	None		CACID1
16,000 Gal Citric Acid Storage Tank	CACID2	None		CACID2
Cooling Tower	CT01	Ultra-high Efficiency Drift Eliminator		CT01
Cooling Tower	CT02	Ultra-high Efficiency Drift Eliminator		CT02
2,000 hp Compression Ignition Emergency Engine	EGEN1	Tier IV Certified		EGEN1
2,000 hp Compression Ignition Emergency Engine	EGEN2	Tier IV Certified		EGEN2
410 hp Compression Ignition Fire Water Pump Engine	EPUMP	Tier IV Certified		EPUMP
Flare with 1.4 MMBtu/hr pilot	FLARE	None		FLARE

Devices and Processes Description	Device ID	Pollution Control Device Description	PCD ID	Emission Point ID
630,000 Gal Hydrocarbon Slop Storage Tank	HCS	Internal Floating Roof		HCS
Acid Gas Regenerator Unit and Sour Water Stripper	AGRU & SWS	18 MMBtu/hr NG Fired Thermal Oxidizer, Baghouse with Dry Sorbent Injection, SCR and Oxidation Catalyst (in series)	TO-INCIN, SBH-INCIN, and SCR-INCIN	INCIN
Fugitive Equipment Leaks	LEAK	Leak Detection and Repair		LEAK
Renewable Diesel Product Loadout (Rail & Truck)	LOAD	1.7 MMBtu/hr NG Fired Vapor Combustion Unit	VCU1	VCU1
420,000 Gal Oil Water Separator Slop Tank	OWS	Internal Floating Roof		OWS
9.45 MMGal Swing RD/RJ Storage Tank	RD/RJ1	Internal Floating Roof		RD/RJ1
9.45 MMGal RD Product Storage Tank	RD1	None		RD1
9.45 MMGal RD Product Storage Tank	RD2	None		RD2
9.45 MMGal RD Product Storage Tank	RD3	None		RD3
2.1 MMGal Swing RJ/RN Storage Tank	RN/RJ1	Internal Floating Roof		RN/RJ1
2.1 MMGal Swing RJ/RN Storage Tank	RN/RJ2	Internal Floating Roof		RN/RJ2
2.1 MMGal Swing RJ/RN Storage Tank	RN/RJ3	Internal Floating Roof		RN/RJ3
5.25 MMGal Vegetable Oils Storage Tank	VEGOIL1	None		VEGOIL1
5.25 MMGal Vegetable Oils Storage Tank	VEGOIL2	None		VEGOIL2

Devices and Processes Description	Device ID	Pollution Control Device Description	PCD ID	Emission Point ID
5.25 MMGal Vegetable Oils Storage Tank	VEGOIL3	None		VEGOIL3
Wastewater Treatment System	WWT	None		WWT

2.0 GENERAL EMISSION STANDARDS AND LIMITS

2.1. Visible Emissions

The permittee must comply with the following visible emission limits from air contaminant sources other than fugitive emission sources, as applicable. Opacity must be measured as a six-minute block average using EPA Method 9.

a. Emissions Points BOILER, ECO1, ECO2, ECO3, H2HTR, JETFRAC, 1BEDAY1, 1BEDAY2, 1BESV1, 1BESV2, 1BESV3, 1FADT, 1FASV1, 2BEDAY1, 2BEDAY2, 2BESV1, 2BESV2, 2BESV3, 2FADT, 2FASV1, 3BEDAY1, 3BEDAY2, 3BESV1, 3BESV2, 3BESV3, 3FADT, 3FADT2, 3FADT3, 3FASV1, 3FASV2, 3FASV3, CT01, CT02, EGEN1, EGEN2, EPUMP, FLARE, INCIN, and WWT must not equal or exceed 20% opacity; and [OAR 340-208-0110(3)(b) and (4)]

b. Any devices or processes installed, constructed, or modified on or after April 16, 2015, must not equal or exceed 20% opacity. [OAR 340-208-0110(3)(b) and (4)]

2.2. Fugitive Emissions

a. In no case may the permittee allow fugitive dust emissions to leave the property of a source for a period or periods totaling more than 18 seconds in a six-minute period. Fugitive emissions must be measured by EPA method 22 with the minimum observation time of six minutes;

b. At least monthly, the permittee must conduct a six (6) minute visible emission survey of the property boundary downwind from the fugitive emissions sources using EPA Method 22. The person conducting this survey does not have to be EPA Method 9 certified. However, the individual should be trained and knowledgeable with respect to the general procedures for determining the presence of visible emissions. For purposes of this survey, excessive fugitive emissions are considered to be any visible emissions that leave the plant site boundaries. No monitoring is required if the entire facility is shut down; and [OAR 340-208-0210]

   i. If visible fugitive emissions are detected at the property boundary for more than 5% (18 seconds) of the survey time, the permittee must take corrective action which includes the following:

A. Using, where possible, water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;
B. Applying water or other suitable chemicals on unpaved roads, materials stockpiles, and other surfaces which can create airborne dusts;
C. Enclosing (full or partial) materials stockpiles in cases where application of water or other suitable chemicals are not sufficient to prevent particulate matter, including dust, from becoming airborne;
D. Installing and using hoods, fans, and fabric filters to enclose and vent the handling of dusty materials;
E. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne; and
F. Promptly removing earth or other material that does or may become airborne from paved streets.

ii. If no visible fugitive emissions are detected at the property boundary or visible fugitive emissions are detected for less than or equal to 5% (18 seconds) of the survey time for three consecutive months, the permittee may conduct visible emission surveys quarterly rather than monthly. If visible fugitive emissions are detected at the property boundary during the quarterly surveys, the surveys must be conducted monthly; and

iii. The permittee must record the results of the EPA Method 22 tests and the corrective action taken in a log.

c. If requested by DEQ, the permittee must:

i. Prepare and submit a fugitive emission control plan within 60 days of the request;

ii. Implement the DEQ approved plan whenever fugitive emissions leave the property for more than 18 seconds in a six-minute period; and

iii. Keep the plan on site and make the plan available upon request. [OAR 340-208-0210]

2.3. Particulate Matter Emissions

The permittee must comply with the following particulate matter emission limits. For fuel burning equipment that burns fuels other than wood, emission results are corrected to 50% excess air.

a. Particulate matter emissions from Boiler 1, Boiler 2, ECO1F, ECO1I, ECO2F, ECO2I, ECO3F, ECO3I, H2HTR, and JETFRAC must not exceed 0.10 grains per dry standard cubic foot. [OAR 340-228-0210(2)(c)].

b. Particulate matter emissions from 1BEDAY1, 1BEDAY2, 1BESV1, 1BESV2, 1BESV3, 1FADT, 1FASV1, 2BEDAY1, 2BEDAY2, 2BESV1, 2BESV2, 2BESV3, 2FADT, 2FASV1, 3BEDAY1, 3BEDAY2, 3BESV1, 3BESV2, 3BESV3, 3FADT, 3FADT2, 3FADT3, 3FASV1, 3FASV2, 3FASV3, CT01, CT02, EGEN1, EGEN2, EPUMP, FLARE, INCIN, SBH-INCIN, WWT, AGRU, and SWS must not exceed 0.10 grains per standard cubic foot. [OAR 340-226-0210(2)(c)]

c. Non-fugitive particulate matter emissions from processes listed in OAR 340-226-0300 must not exceed the process weight emission standards shown in Table 1 of OAR 340-226-0310.

d. Particulate matter emissions from any fuel burning equipment (except solid fuel burning devices that have been certified under OAR 340-262-0500) that is installed, constructed or modified on or after April 16, 2015, must not exceed 0.10 grains per dry standard cubic foot, corrected to 50% excess air. [OAR 340-228-0210(2)(c)]

e. Particulate matter emissions from any device or process (other than fugitive emissions sources and fuel burning equipment) that is installed, constructed or modified after April 16, 2015, must not exceed 0.10 grains per dry standard cubic foot. [OAR 340-226-0210(2)(c)]

2.4. Particulate Matter Fallout

The permittee must not cause or permit the deposition of any particulate matter larger than 250 microns in size at sufficient duration or quantity, as to create an observable deposition upon the real property of another person. [OAR 340-208-0450]

2.5. Nuisance and Odors

The permittee must not cause or allow the emission of odorous or other fugitive emissions so as to create nuisance conditions off the permittee's property. Nuisance conditions will be verified by DEQ personnel. [OAR 340-208-0300]

2.6. Complaint Log

The permittee must maintain a log of all complaints received by the permittee in person, in writing, by telephone or through other means that specifically refer to air pollution, odor, or nuisance concerns associated with the permitted facility. Documentation must include: [OAR 340-214-0114]

a. The date the complaint was received;

b. The date and time the complaint states the condition was present;

c. A description of the pollution or odor condition;

d. The location of the complainant/receptor relative to the plant site;

e. The status of plant operation or activities during the complaint's stated time of pollution or odor condition; and

f. A record of the permittee's actions to investigate the validity of each complaint and a record of actions taken for complaint resolution.

2.7. Fuels and Fuel Sulfur Content

a. The permittee must not use any fuels other than natural gas, propane, butane, process off gas, Pressure-swing Absorption (PSA) Tail Gas, or any of the ASTM grade fuel oils listed below. The sulfur content cannot exceed:

i. 0.0015% sulfur by weight for ultra-low sulfur diesel;
ii. 0.3% sulfur by weight for ASTM Grade 1 distillate oil; [OAR 340-228-0110]
iii. 0.5% sulfur by weight for ASTM Grade 2 distillate oil; [OAR 340-228-0110]

b. The permittee is allowed to use renewable diesel which is registered as a motor vehicle fuel or fuel additive under 40 Part 79 and meets the requirements of the ASTM D975 or D396. [OAR 340-228-0130(2)]

3.0 SPECIFIC PERFORMANCE AND EMISSION STANDARDS

3.1. NSPS Subpart A - General Provision Requirements

The permittee must comply with all provisions of 40 CFR 60 Subpart A – NSPS General Provisions, as applicable, adopted herein by reference.

3.2. Flare Operational Requirements - NSPS Subpart A

The permittee must comply with 40 CFR 60.18: General control device requirements (FLARE) [OAR 340-226-0120(1)]

a. FLARE must be designed for and operated with no visible emissions as determined by EPA Method 22, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours;
b. FLARE must be operated with a pilot flame present at all times, as determined by using a thermocouple or other equivalent device to detect the presence of a flame;
c. FLARE must be operated at all times when emissions may be vented to it;
d. FLARE must be operated only with the net heating value of the gas being combusted being 11.2 MJ/scum (300 Btu/scf) or greater. The net heating value is determined as follows:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

where:

H_T= Net heating value of the sample, MJ/scm; where the net enthalpy per mole of off gas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

K = Constant, $1.740 \times 10^{-7} \left(\frac{1}{\text{ppm}}\right) \left(\frac{\text{g mole}}{\text{scm}}\right) \left(\frac{\text{MJ}}{\text{kcal}}\right)$

where the standard temperature for $\left(\frac{\text{g mole}}{\text{scm}}\right)$ is 20°C;

C_i= Concentration of sample component “i” in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946–77 or 90; and

H_i= Net heat of combustion of sample component "i", kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382–76 or 88 or D4809–95 if published values are not available or cannot be calculated.

e. FLARE must be designed and operated with an exit velocity less than the velocity as determined by the following method:

V_{max}= 8.706+0.7084 (H_T)

V_{max}= Maximum permitted velocity, m/sec

8.706= Constant

0.7084=Constant

H_T= The net heating value as determined in paragraph 3.2.d above.

3.3. NSPS Subpart Dc – Small Industrial-Commercial-Institutional Steam Generating Units Requirements

The permittee must comply with all applicable provisions and standards of 40 CFR Part 60, Subpart Dc. All affected Steam Generating Units associated with this permit action, Boiler 1 and Boiler 2, are fired exclusively with natural gas and as such, there are no applicable emission standards for which these Steam Generating Units fall subject under this Subpart.

3.4. NSPS Subpart Kb - Standards of Performance for Volatile Organic Liquid (VOL) Storage Vessels for Which Construction, Reconstruction or Modification Commenced after July 23, 1984

The permittee must comply with all applicable provisions of 40 CFR 60 Subpart Kb, including but not limited to the following, for each affected storage vessel (RN/RJ1, RN/RJ2, and RN/RJ3) (Note – refer to 40 CFR 60 Subpart Kb and Subpart A for definitions of terminology stated in this condition). The following summarizes the applicable requirements of Subpart Kb, but is not intended to supersede the Subpart:

a. 40 CFR 60.112b Standard for volatile organic compounds (VOC)
   i. The permittee must equip each fixed-roof storage vessel that is subject to this standard (vessels ≥39,890 gallons that contain a VOL with maximum true vapor pressure of at least 5.2 kPa (0.75 psia) but <76.6 kPa (11.12 psia) or vessels ≥75 m^3 (19,813 gallons) but <151 m3 (39,890 gallons) and containing a VOL with maximum true vapor pressure of at least 27.6 kPa (4.0 psia) but <76.6 kPa (11.12 psia) as follows:
      A. Each storage vessel must have a fixed roof in combination with an internal floating roof meeting the following specifications:
         1. 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;

2. Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:
    a. A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal).
    A liquid-mounted seal means a foam or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank;
    b. Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous; or
    c. A mechanical shoe seal.
    A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.
3. Each opening in a non-contact 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;
4. 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;
5. 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 leg supports;
6. 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;
7. 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 90 percent of the opening;
8. 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; and

9. Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

3.5. NSPS Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

The permittee must comply with all applicable provisions of 40 CFR 60 Subpart IIII, including but not limited to the following, for each affected compression ignition reciprocating internal combustion engine (Note – refer to 40 CFR 60 Subpart IIII and Subpart A for definitions of terminology stated in this condition. The following summarizes the applicable requirements of Subpart IIII, but is not intended to supersede the Subpart):

a. Emission Limitations: The permittee must not allow emissions from EGEN1 or EGEN2 to equal or exceed the following: [40 CFR 60.4205(b)]
   i. 6.4 g/kW-hr of non-methane hydrocarbons (NMHC) + nitrogen oxides (NOX);
   ii. 3.5 g/kW-hr of carbon monoxide (CO); and
   iii. 0.20 g/kW-hr of particulate matter (PM).
b. Emission Limitations: The permittee must not allow emissions from EPUMP to equal or exceed the following: [40 CFR 60.4205(c) and 40 CFR 60 Subpart IIII Table 4]
   i. 4.0 g/kW-hr of non-methane hydrocarbons (NMHC) + nitrogen oxides (NO_X); and
   ii. 0.20 g/kW-hr of particulate matter (PM).
c. The permittee must demonstrate compliance with Conditions 3.5.a and b by purchasing engines certified by the manufacturer to meet the emissions standards. [40 CFR 60.4211(c)]
d. Fuel Sulfur Content: When using diesel fuel in EGEN1, EGEN2, or EPUMP, the permittee must use only diesel fuel with no more than 0.0015% sulfur by weight and must contain a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent. [40 CFR 60.4207(b)]
e. Metering: The permittee must install a non-resettable hour meter on EGEN1, EGEN2, and EPUMP prior to startup of each. [40 CFR 60.4209(a)]
f. Labeling: Each stationary emergency engine must have a permanent label stating that the engine is for stationary emergency use only. [40 CFR 60.4210(f) and Table 5 of Subpart IIII]
g. Operation Limits: The permittee must operate EGEN1, EGEN2, and EPUMP in accordance with the following operational limitations:
   i. The permittee must operate and EGEN1, EGEN2, and EPUMP such that they achieve the emission standards as required in Conditions 3.5.a and 3.5.b over the entire life of the engines; [40 CFR 60.4206]
   ii. The permittee must operate and maintain EGEN1, EGEN2, and EPUMP according to the manufacturer's emission-related written instructions; [40 CFR 60.4211(a)(1)]
   iii. The permittee must change only those emission-related settings that are permitted by the manufacturer; [40 CFR 60.4211(a)(2)]
   iv. There is no time limit on the use of EGEN1, EGEN2, and EPUMP in emergency situations; [40 CFR 60.4211(f)(1)]

v. EGEN1, EGEN2, and EPUMP may be operated for the purpose of maintenance checks and readiness testing for a maximum of 100 hours per calendar year, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. The permittee must maintain documentation of the recommendation; [40 CFR 60.4211(f)(2)]

vi. EGEN1, EGEN2, and EPUMP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in Condition 3.5.g.v. The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity; and [40 CFR 60.4211(f)(3)]

vii. Except as provided in Condition 3.5.g.vi and for maintenance checks and readiness testing, the permittee is prohibited from using EGEN1, EGEN2, and EPUMP for any non-emergency use including but not limited to peak shaving, emergency demand response, and/or generation of income from the sale of power. To perform such activity the permittee must first obtain a modified permit in accordance with Condition 11.2 or a separate permit for power generation that appropriately addresses and allows this activity.

h. Recordkeeping: The permittee must keep records of the hours of operation of EGEN1, EGEN2, and EPUMP that is recorded through a non-resettable hour meter. The permittee must document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation used for maintenance checks and readiness testing. [40 CFR 60.4214(b)]

3.6. NESHAP (40 CFR 61) Subpart A - General Provision Requirements

The permittee must comply with all provisions of 40 CFR 61 Subpart A – NESHAP General Provisions, as applicable, adopted herein by reference.

3.7. NESHAP (40 CFR 61) Subpart FF – Benzene Waste Operations

The permittee must comply with all applicable provisions of 40 CFR 61 Subpart FF, including but not limited to the following (Note – refer to 40 CFR 61 Subpart FF and Subpart A for definitions of terminology stated in this condition). The following summarizes the applicable requirements of Subpart FF, but is not intended to supersede the Subpart:

a. The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows: [40 CFR 61.342(a)]

i. Wastes must be included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent; [40 CFR 61.342(a)(1)]

ii. The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent; [40 CFR 61.342(a)(2)]

iii. Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility; and [40 CFR 61.342(a)(3)]

iv. The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in Conditions 3.7.c.i and ii: [40 CFR 61.342(a)(4)]

b. The permittee shall determine the total annual benzene quantity from facility waste by the following procedure: [40 CFR 61.355(a)]

i. For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in Condition 3.7.a, the permittee shall:

A. Determine the annual waste quantity for each waste stream using the procedures specified in Condition 3.7.c;

B. Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in 3.7.d; and

C. Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.

ii. Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to 3.7.c.iii.

c. For purposes of the calculation required by Condition 3.7.b, the permittee shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in Conditions 3.7.c.i through iii, by one of the methods given in Conditions 3.7.c.iv through vi. [40 CFR 61.355(b)]

i. The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper;

ii. The determination of annual waste quantity for wastes that are received at hazardous waste treatment, storage, or disposal facilities from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility;

iii. The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in Condition 3.7.b.i.C for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the initial startup report, required under Condition 10.4.a, the permittee shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs;

iv. Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility;

v. Use the maximum design capacity of the waste management unit; or

vi. Use measurements that are representative of maximum waste generation rates.

d. For the purposes of the calculation required by Condition 3.7.b the permittee shall determine the flow-weighted annual average benzene concentration in a manner that meets the requirements given in Condition 3.7.d.i using either of the methods given in Conditions 3.7.d.ii or iii. [40 CFR 61.355(c)]

i. The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:

A. The determination shall be made at the point of waste generation except for:

1. The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper;

2. The determination for wastes that are received from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility; and

3. The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in Conditions 3.7.d.ii or iii. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in Condition 3.7.b.i.C for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.

B. Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration;

C. Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination - to reduce the benzene concentration;

D. The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in Conditions 3.7.d.i.A.1 through 3; and

E. For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.

ii. ***Knowledge of the waste.*** The permittee shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under Condition 3.7.d.iii shall be used to resolve the disagreement; or

iii. Measurements of the benzene concentration in the waste stream in accordance with the following procedures:

A. Collect a minimum of three representative samples from each waste stream. Where feasible, samples shall be taken from an enclosed pipe prior to the waste being exposed to the atmosphere;

B. For waste in enclosed pipes, the following procedures shall be used:

1. Samples shall be collected prior to the waste being exposed to the atmosphere in order to minimize the loss of benzene prior to sampling;
2. A static mixer shall be installed in the process line or in a by-pass line unless the owner or operator demonstrates that installation of a static mixer in the line is not necessary to accurately determine the benzene concentration of the waste stream;
3. The sampling tap shall be located within two pipe diameters of the static mixer outlet;
4. Prior to the initiation of sampling, sample lines and cooling coil shall be purged with at least four volumes of waste;
5. After purging, the sample flow shall be directed to a sample container and the tip of the sampling tube shall be kept below the surface of the waste during sampling to minimize contact with the atmosphere;
6. Samples shall be collected at a flow rate such that the cooling coil is able to maintain a waste temperature less than 10 °C (50 °F);
7. After filling, the sample container shall be capped immediately (within 5 seconds) to leave a minimum headspace in the container; and

8. The sample containers shall immediately be cooled and maintained at a temperature below 10 °C (50 °F) for transfer to the laboratory.

C. When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of benzene prior to sampling; and

D. Each waste sample shall be analyzed using one of the following test methods for determining the benzene concentration in a waste stream:

1. Method 8020, Aromatic Volatile Organics, in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in 40 CFR 61.18);
2. Method 8021, Volatile Organic Compounds in Water by Purge and Trap Capillary Column Gas Chromatography with Photoionization and Electrolytic Conductivity Detectors in Series in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in 40 CFR 61.18);
3. Method 8240, Gas Chromatography/Mass Spectrometry for Volatile Organics in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in 40 CFR 61.18);
4. Method 8260, Gas Chromatography/Mass Spectrometry for Volatile Organics: Capillary Column Technique in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in 40 CFR 61.18);
5. Method 602, Purgeable Aromatics, as described in 40 CFR 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA methods; or
6. Method 624, Purgeables, as described in 40 CFR 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method.

E. The flow-weighted annual average benzene concentration shall be calculated by averaging the results of the sample analyses as follows:

$$\overline{C} = \frac{1}{Q_t} \times \sum_{i=1}^{n} (Q_i)(C_i)$$

Where:

C = Flow-weighted annual average benzene concentration for waste stream, ppmw.

Q_t = Total annual waste quantity for waste stream, kg/yr (lb/yr).

n = Number of waste samples (at least 3).

Q_i = Annual waste quantity for waste stream represented by C_i, kg/yr (lb/yr).

C_i = Measured concentration of benzene in waste sample i, ppmw.

e. If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in Condition 3.7.b, the permittee must comply with applicable requirements of 40 CFR 61, Subpart FF.

3.8. NESHAP (40 CFR 63) Subpart A - General Provision Requirements

The permittee must comply with all provisions of 40 CFR 63 Subpart A – NSPS General Provisions, as applicable, adopted herein by reference.

3.9. NESHAP (40 CFR 63) Subpart ZZZZ – Emergency Engines

The permittee must comply with applicable requirements of 40 CFR 60 Subpart IIII for Emergency Generator Engines and Fire Water Pump Engine. [40 CFR 63.6590(c)]

4.0 OPERATION AND MAINTENANCE REQUIREMENTS

4.1. Operation of Pollution Control Devices and Processes

The permittee must operate and ensure proper functioning of all air pollution control devices and components at all times when the associated emission source is operating. [OAR 340-226-0120]

4.2. Operation and Maintenance for Emergency Stationary RICE

The permittee must comply with the following requirements for Emergency Generator Engines and Fire Water Pump Engine: [OAR 340-226-0100]

a. At all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions;
b. Change oil and filter every 500 hours of operation or annually, whichever comes first, or utilize an oil analysis program as described in 40 CFR 63.6625(i);
c. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;
d. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary;
e. During periods of startup, minimize the engine’s time spent at idle and minimize the engine’s startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply;
f. The permittee must install a non-resettable hour meter on each emergency stationary RICE prior to operation, if one is not already installed;
g. The permittee must not operate EGEN1, EGEN2, or EPUMP for non-emergency purposes during plant startup commissioning or during the plant annual shutdown;
h. The permittee may operate EGEN1 and EGEN2 for non-emergency purposes only between the hours of 10:00 a.m. and 4:00 p.m.; and

i. The permittee must not operate both EGEN1 and EGEN2 for non-emergency purposes on any single calendar day.

4.3. Highest and Best Practicable Treatment and Control

The permittee must provide the highest and best practicable treatment and control of air contaminant emissions in every case so as to maintain overall air quality at the highest possible levels, and to maintain contaminant concentrations, visibility reduction, odors, soiling, and other deleterious factors at the lowest possible levels as provided below. [OAR 340-226-0100]

a. The permittee must control emissions from ECO1F, ECO1I, ECO2F, ECO2I, ECO3F, and ECO3I with Selective Catalytic Reduction (SCR) and Oxidation Catalyst.
    i. The permittee must operate the SCR and Oxidation Catalyst with appropriate ammonia injection rates at all times that the exhaust gas and catalyst temperatures meet the specifications of the SCR and Oxidation Catalyst device manufacturer;
    ii. Each SCR must be equipped with devices capable of continuously monitoring and recording the following operating parameters:
        A. Ammonia injection rate;
        B. Gas temperature at catalyst inlet; and
        C. Pressure difference across the catalyst.
    iii. Each Oxidation Catalyst must be equipped with devices capable of continuously monitoring and recording the following operating parameters:
        A. Gas temperature at catalyst inlet; and
        B. Pressure difference across the catalyst.
    iv. The permittee must continuously monitor and record the SCR and Oxidative Catalyst operating parameters identified in Conditions 4.3.a.ii and iii;
    v. The permittee must maintain the SCR and Oxidation Catalyst operating parameters identified in Conditions 4.3.a.ii and iii within the manufacturer's design operating ranges;
    vi. The permittee must investigate and commence corrective action measures immediately after an observed excursion of any operating parameter range identified in Condition 4.3.a.v; and
    vii. The permittee must correct the problem as soon as practicable, but no later than 10 calendar days from the date of discovery.
b. The permittee must control emissions from Boiler 1, Boiler 2, H2HTR, and JETFRAC with SCR and Oxidation Catalyst.
    i. The permittee must operate the SCR and Oxidation Catalyst with appropriate ammonia injection rates at all times that the exhaust gas and catalyst temperatures meet the specifications of the SCR and Oxidation Catalyst device manufacturer;
    ii. Each SCR must be equipped with devices capable of continuously monitoring and recording the ammonia injection rate;
    iii. Each Oxidation Catalyst must be equipped with devices capable of continuously monitoring and recording the following operating parameters:
        A. Gas temperature at catalyst inlet; and
        B. Pressure difference across the catalyst.

iv. The permittee must continuously monitor and record the SCR and Oxidation Catalyst operating parameters identified in Conditions 4.3.b.ii and iii;

v. The permittee must maintain the SCR and Oxidation Catalyst operating parameters identified in Conditions 4.3.b.ii and iii within the manufacturer's design operating ranges;

vi. The permittee must investigate and commence corrective action measures immediately after an observed excursion of any operating parameter range identified in Condition 4.3.b.v; and

vii. The permittee must correct the problem as soon as practicable, but no later than 10 calendar days from the date of discovery.

c. The permittee must control emissions from 1BEDAY1, 1BEDAY2, 1BESV1, 1BESV2, 1BESV3, 1FADT, 1FASV1, 2BEDAY1, 2BEDAY2, 2BESV1, 2BESV2, 2BESV3, 2FADT, 2FASV1, 3BEDAY1, 3BEDAY2, 3BESV1, 3BESV2, 3BESV3, 3FADT, 3FADT2, 3FADT3, 3FASV1, 3FASV2, and 3FASV3 with Filtration Units.

i. Each filtration unit must be equipped with an operational pressure differential indicator;

ii. The permittee must continuously monitor and record the pressure differential of each filtration unit;

iii. The permittee must follow the manufacturer's design operating differential pressure ranges for each respective filtration unit at the facility;

iv. The permittee must investigate and commence corrective action measures immediately after an observed excursion of the operating differential pressure range identified in Condition 4.3.c.iii;

v. The permittee must correct the problem as soon as practicable, but no later than 10 calendar days from the date of discovery;

vi. When replacing filters or fabric filter bags in any filtration unit, the permittee may not substitute a bag or filter with lower control efficiency specifications than what was specified in the original system design specifications; and

vii. The permittee must keep readily accessible records documenting the original engineering design specifications for all filtration units at the facility. These records must be kept for the life of the source.

d. The permittee must control emissions from LOAD with a vapor combustion unit.

i. The permittee must design and configure the exhaust stacks of the VCU system to comply with EPA's Test Method 1 and appropriately equipped with sample ports for sample and velocity traverses while source testing;

ii. The permittee must install a temperature monitoring system to continuously monitor and record the operating temperature in the combustion zones of the VCU system;

iii. The permittee must maintain the operating temperature of the VCU system at or above the average operating temperature recorded during the most recent approved source test at which compliance was demonstrated. Prior to source testing the operating temperature of the VCU system must be above 1,500°F;

iv. The permittee must investigate and commence corrective action measures immediately after an observed excursion of the temperature range identified in Condition 4.3.d.iii;

v. The permittee must correct the problem as soon as practicable, but no later than 10 calendar days from the date of discovery; and

vi. The permittee must equip the VCU system with a process interlock that halts product loading during VCU system malfunction or upset condition events.

e. The permittee must control emissions from AGRU and SWS with TO-INCIN, SBH-INCIN, and SCR-INCIN, in series.

i. TO-INCIN:

A. The permittee must install:

1. A temperature monitoring system to continuously monitor and record the operating temperature in the combustion zones of TO-INCIN; and

2. Audible and visual alarms linked to the temperature monitoring system.

B. The permittee must maintain the operating temperature of the TO-INCIN system at or above the average operating temperature recorded during the most recent approved source test at which compliance was demonstrated. Prior to source testing the operating temperature of the TO-INCIN must be above 1,500°F;

C. The audible and visual alarms must trigger automatically upon the operating temperature of the TO-INCIN system being below the average operating temperature recorded during the most recent approved source test or 1,500°F if source testing has not yet been conducted;

D. The permittee must investigate and commence corrective action measures immediately after an observed excursion of the temperature range identified in Condition 4.3.e.i.B; and

E. The permittee must correct the problem as soon as practicable, but no later than 10 calendar days from the date of discovery.

ii. SBH-INCIN:

A. SBH-INCIN must be equipped with:

1. An operational pressure differential indicator; and

2. A device capable of measuring the sorbent injection rate.

B. The permittee must monitor and record the pressure differential for SBH-INCIN at least once per operating day;

C. The permittee must continuously monitor and record and sorbent injection rate for SBH-INCIN;

D. The permittee must follow the manufacturer’s design operating differential pressure ranges and sorbent injection rate for SBH-INCIN;

E. The permittee must investigate and commence corrective action measures immediately after an observed excursion of the operating differential pressure range or sorbent injection rate identified in Condition 4.3.e.ii.D;

F. The permittee must correct the problem as soon as practicable, but no later than 10 calendar days from the date of discovery;

G. When replacing filters or fabric filter bags in SBH-INCIN, the permittee may not substitute a bag or filter with lower control efficiency specifications than what was specified in the original system design specifications; and

H. The permittee must keep readily accessible records documenting the original engineering design specifications for all filtration units at the facility. These records must be kept for the life of the source.

iii. SCR-INCIN

A. SCR-INCIN must be equipped with an SCR and an Oxidation Catalyst;

B. The permittee must operate the SCR and Oxidation Catalyst with appropriate ammonia injection rates at all times that the exhaust gas and catalyst temperatures meet the specifications of the SCR and Oxidation Catalyst device manufacturer;

C. The SCRs must be equipped with devices capable of continuously monitoring and recording the following operating parameters:

1. Ammonia injection rate;
2. Gas temperature at catalyst inlet; and
3. Pressure difference across the catalyst.

D. The Oxidation Catalyst must be equipped with devices capable of continuously monitoring and recording the following operating parameters:

1. Gas temperature at catalyst inlet; and
2. Pressure difference across the catalyst.

E. The permittee must continuously monitor and record the SCR and Oxidation Catalyst operating parameters identified in Conditions 4.3.e.iii.C and D;

F. The permittee must maintain the SCR and Oxidation Catalyst operating parameters identified in Conditions 4.3.e.iii.C and D within the manufacturer's design operating ranges;

G. The permittee must investigate and commence corrective action measures immediately after an observed excursion of any operating parameter range identified in Condition 4.3.e.iii.F; and

H. The permittee must correct the problem as soon as practicable, but no later than 10 calendar days from the date of discovery.

f. The permittee must control emissions from HCS, OWS, and RD/RJ1 with internal floating roofs;

i. Each internal floating roof must meet the specifications of Condition 3.4.a;
ii. The permittee must inspect each tank in accordance with Condition 6.2; and
iii. The permittee must maintain records in accordance with Condition 9.2.

g. During startup, shutdown, and emergency situation the permittee must control process gases associated with ECO1F, ECO1I, ECO2F, ECO2I, ECO3F, ECO3I, JETFRAC, H2HTR, AGRU and SWS with FLARE.

h. The permittee must take corrective action to return to highest and best practicable treatment and control upon exceeding any of the following action levels:

i. 5 ppm NO_x at 3% O_2 from the Boiler 1 and Boiler 2 combined stack, BOILER;
ii. 5 ppm NO_x at 3% O_2 from H2HTR; and

iii. 5 ppm NO_x at 3% O_2 from JETFRAC;

i. The exceedance of an action level is not considered a violation of an emission limit in this permit but failure to take corrective action is a violation. [OAR 340-226-0120(2)(d)]

4.4. Process Leak Detection Program

The permittee must implement a process component leak detection program that at a minimum includes the following performance requirements:

a. Quarterly, the permittee must monitor all process associated pipes, ductwork, connectors, valves/flanges, pumps and compressors to for leaks by complying with the following inspection and repair protocol:
   i. The permittee must perform an inspection of the facility's product receipt, loading and vapor collection associated components in volatile organic liquid product service;
   ii. The permittee must perform quarterly inspections by evaluating the components using Method 21;
   iii. The permittee must record each detection of a leak. A leak is detected whenever a measured concentration of 5,000 ppm or greater is detected;
   iv. The permittee must attempt to correct components identified to have recognized leaks within 5 calendar days. If components cannot be repaired with the first attempt the permittee must tag and log the component, noting the date of the identified leak;
   v. The permittee must repair leaking components within 15 days;
   vi. The permittee must report leaking components that are not repairable within the 15-day period to DEQ by 5:00 p.m. of the 15th day by phone, fax or e-mail. The report must identify the leaking component(s), the anticipated alternate repair period and the justification for an extended repair period;
   vii. Leaking components that are taken out of service by isolation and bypass are not required to be reported to DEQ as required by Condition 4.4.a.vi; and
   viii. DEQ may require submission of an excess emission report in accordance with Condition 10.1 for reported leaking components.

4.5. Continuous Emissions Monitoring

a. In addition to operating all CEMS and CPMS in accordance with the manufacturer's instructions, the permittee must operate all CEMS and CPMS in accordance with a quality assurance plan approved by and on file with the Department.

b. The permittee must monitor NO_x and O_2 emissions from emissions points BOILER, H2HTR, and JETFRAC by calibrating, maintaining, and recording the output of a CEMS in accordance with DEQ's Continuous Monitoring Manual.

i. Each CEMS must continuously monitor and record the concentration of NO_x and O_2 emissions on a wet or dry basis discharged into the atmosphere. [Continuous Monitoring Manual]

ii. Each CEMS must consist of subsystems for sample extraction, conditioning, detection, analysis, and data recording/processing. [Continuous Monitoring Manual]

iii. Each CEMS must meet the requirements of 40 CFR 60 Appendix B (performance specifications) and Appendix F (QA/QC procedures). [Continuous Monitoring Manual]

iv. The CEMS must be capable of measuring emission levels under normal conditions and under periods of short-duration peaks of high concentrations.

A. The permittee may either use a single NO_X analyzer with a dual range (low-and high-scales) or two separate NO_X analyzers connected to a common sample probe and sample interface. Two separate NO_X analyzers connected to separate probes and sample interfaces may be used if RATAs are passed on both ranges.

B. For dual-range units, when the reading goes above the full-scale measurement value of the lower range, the higher-range operation must be started automatically.

v. As an alternative to Condition 4.5.b.iv, the permittee may use a default high range value of 100 ppm when the low scale NO_x range is exceeded. The assumed 100 ppm high range value must be utilized for each unit operating hour in which the full-scale of the low range NO_X analyzer is exceeded.

vi. The CEMS spans must be: [Continuous Monitoring Manual and 40 CFR 60 – Appendix B]

A. 10 ppm for NO_x low-scale;

B. 100 ppm for NO_x high-scale; and

C. 25% for oxygen

vii. Each CEMS must complete a minimum of one cycle of sampling and analyzing for each successive 15-minute period. [Continuous Monitoring Manual]

viii. NO_x concentrations must be corrected to 3% oxygen.

ix. Relative Accuracy Test Audits (RATAs):

A. For purposes of RATA testing the emission action level values in Condition 4.3.g may be used as the applicable standard when emissions are below 50% of the emission action level.

B. The first CEMS data accuracy assessment must be a RATA [40 CFR 60 Appendix F, Procedure 1]

c. The permittee must install, certify, operate, calibrate, maintain, and record the output of fuel flow meters for natural gas to Boiler 1, Boiler 2, JETFRAC, and H2HTR in accordance with the manufacturer's instructions and 40 CFR Part 75, Appendix D.

d. The permittee must install, certify, operate, calibrate, maintain, and record the output of a fuel flow meter for PSA Tail gas to H2HTR in accordance with the manufacturer's instructions and 40 CFR Part 75, Appendix D.

5.0 PLANT SITE EMISSION LIMITS

5.1. Plant Site Emission Limits (PSEL)

The permittee must not cause or allow plant site emissions to exceed the following: [OAR 340-222-0040 and/or OAR 340-222-0041]

Pollutant	Limit	Units
PM	27	tons per year
PM_{10}	27	
$PM_{2.5}$	27	
SO_2	39	
NO_X	39	
CO	99	
VOC	70	
H_2S	9	
GHGs (CO_2e)	1,152,905	
GHGs (CO_2e) excluding biomass CO_2	436,938	

5.2. Annual Period

The annual plant site emissions limits apply to any 12-consecutive calendar month period. [OAR 340-222-0035]

6.0 COMPLIANCE DEMONSTRATION

6.1. NSPS Subpart Dc Testing Requirements

There are no applicable testing requirements for Boiler 1 or Boiler 2 under NSPS Subpart Dc.

6.2. NSPS Subpart Kb Testing Requirements

The permittee must perform testing of each storage tank subject to Subpart Kb in accordance with 40 CFR 60.113b:

a. After installing the control equipment required to meet Condition 3.4.a.i.A. of the permit [40 CFR 60.112b(a)(1)] (permanently affixed roof and internal floating roof), the permittee must:

   i. Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL.
   If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

   ii. For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in Condition 10.3.a. of the permit [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 company will take that will assure that the control equipment will be repaired, or the vessel will be emptied as soon as possible.

   iii. For vessels equipped with a double-seal system as specified in Condition 3.4.a.i.A.2.b. of the permit [40 CFR 60.112b(a)(1)(ii)(B)]:

      A. Visually inspect the vessel as specified in paragraph 6.2.a.iv. of this section at least every 5 years; or

      B. Visually inspect the vessel as specified in paragraph 6.2.a.ii. of this section.

   iv. 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 vessel is emptied and degassed. 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 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs 6.2.a.ii. and 6.2.a.iii.B. of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph 6.2.a.iii.A. of this section.

   v. Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs 6.2.a.i. and 6.2.a.iv. of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph 6.2.a.iv. of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. 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 Administrator at least 7 days prior to the refilling.

6.3. PSEL Compliance Monitoring using Emission Factors

The permittee must calculate the emissions for each 12-consecutive calendar month period based on the following calculation for each pollutant except as provided in Conditions 6.5, 6.6, and 6.7: [OAR 340-222-0080]

$$E = \Sigma(EF \times P) \times 1 \text{ ton}/2000 \text{ pounds}$$

where:

E = pollutant emissions (tons/year);

Σ = symbol representing "summation of";

EF = pollutant emission factor (see Condition 15.0);

P = process/production (see Condition 16.0)

6.4. Emission Factors

The permittee must use the default emission factors provided in Condition 15.0 for calculating pollutant emissions unless alternative emission factors are approved in writing by DEQ. The permittee may request or DEQ may require using alternative emission factors provided they are based on actual test data or other documentation (e.g., AP-42 compilation of emission factors) that has been reviewed and approved by DEQ. [OAR 340-222-0080]

6.5. Greenhouse Gas Emissions

The permittee must calculate greenhouse gas emissions in metric tons and short tons for each 12-consecutive calendar month period to determine compliance with the GHG PSEL by using the following: [OAR 340-215-0040]

a. DEQ Fuel Combustion Greenhouse Gas Calculator;https://www.oregon.gov/deq/FilterDocs/ghgCalculatorFuelCombust.xlsx;

b. EPA emission quantification methodologies as prescribed in 40 CFR Part 98 subparts E through UU;

c. https://ccdsupport.com/confluence/display/help/Optional+Calculation+Spreadsheet+Instructions; or

d. An alternative calculation method approved in writing by DEQ.

6.6. Mass Balance

The permittee must calculate the VOC emissions for each 12 consecutive calendar month period based on the following formula: [OAR 340-222-0080]

$$E_{VOC\text{-}A} = [\sum(C_x \text{ x } D_x \text{ x } K_x)] - W_x] \text{ x } 1 \text{ ton/2000 pounds}$$

where:

$E_{VOC\text{-}A}$	=	Annual VOC emissions in tons
C	=	Material usage for the period in gallons
D	=	Material density in pounds per gallon
K	=	VOC concentration in pounds of VOC per pound of material, expressed as a decimal
x	=	Subscript x represents a specific material
W	=	Weight of VOC shipped offsite in pounds

6.7. NO_x CEMS

The permittee must calculate the NO_x emissions from Boiler 1, Boiler 2, JETFRAC, and H2HTR for each 12 consecutive calendar month period based on the following formulas: [OAR 340-222-0080]

$$E = \Sigma[C \text{ x } K_1 \text{ x } F_d \text{ x } H \text{ x } K_2] \text{ x } 1 \text{ ton/2000 pounds}$$

where:

E	=	Emission unit pollutant emissions (tons/year);
Σ	=	symbol representing “summation of”;
C	=	Average hourly NO_x concentrations at 3% O_2 (ppmvd);
K_1	=	Constant for converting ppm to lb/scf = $1.194 \text{ x } 10^{-7}$
F_d	=	EPA Method 19 value (8,710 dscf/MMBtu for natural gas, site specific F factor for PSA tail gas)
H	=	Emission unit hourly heat input (MMBtu)
K_2	=	Oxygen Correction Factor (20.9)/(20.9-3) = 1.17

6.8. PSEL Compliance Monitoring

The permittee must demonstrate compliance with the PSEL by totaling the emissions from all devices and processes calculated under Conditions 6.3, 6.5, 6.6, and 6.7. [OAR 340-222-0080]

7.0 SOURCE TESTING

7.1. Source Testing Requirements

The permittee must perform the following source tests within sixty (60) days after first reaching the maximum capacity, but not more than 180 days after the start-up of operations of each unit, unless an extension is approved by DEQ in writing: [OAR 340-212-0120]

a. The permittee must conduct an initial source test of emission points BOILER, ECO1, ECO2, ECO3, H2HTR, and JETFRAC to verify CO emission factors used to determine compliance with the PSELs of Condition 5.1;
   i. Following the initial test, the permittee must conduct source tests of EPs BOILER, ECO1, ECO2, ECO3, H2HTR, and JETFRAC to verify CO emission factors used to determine compliance with the PSELs of Condition 5.1 at least once every five calendar years.
      A. The EPs may either all be tested in the same calendar year, or subsets may be tested in different years and then retested not less than every five years thereafter; and
      B. Subsequent testing of each EP must be at least 12 months after the EP was last tested.
   ii. During the CO source tests of EPs BOILER, ECO1, ECO2, ECO3, H2HTR, and JETFRAC the following parameters must be monitored and recorded:
      A. Opacity readings on the exhaust stacks following the procedures of EPA Method 9;
      B. Type and quantity of fuel combusted in MMcf/hr;
      C. Oxidation Catalyst operating parameters; and
      D. Concentrations and emission rates of CO in pounds/hour and pounds/MMcf of fuel input.

b. The permittee must conduct an initial source test of EPs ECO1, ECO2, and ECO3 to verify NO_x emission factors used to determine compliance with the PSELs of Condition 5.1;
   i. Following the initial test, the permittee must conduct source tests of EPs ECO1, ECO2, and ECO3 to verify NO_x emission factors used to determine compliance with the PSELs of Condition 5.1 at least once every three calendar years.
      A. The EPs may either all be tested in the same calendar year, or subsets may be tested in different years and then retested not less than every five years thereafter; and
      B. Subsequent testing of each EP must be at least 12 months after the EP was last tested.
   ii. During the NO_x source tests of EPs ECO1, ECO2, and ECO3 the following parameters must be monitored and recorded:
      A. Opacity readings on the exhaust stack following the procedures of EPA Method 9;
      B. Type and quantity of fuel combusted in MMcf/hr;
      C. SCR operating parameters; and

D. Concentrations and emission rates of NOx in pounds/hour and pounds/MMcf of fuel input.

c. The permittee must conduct a source test of VCU1 to verify VOC emission factors used to determine compliance with the PSELs of Condition 5.1;

i. Following the initial test, the permittee must conduct a source test of VCU1 to verify VOC emission factors used to determine compliance with the PSELs of Condition 5.1 at least once every five calendar years;

ii. Subsequent testing of VCU1 must be at least 12 months after VCU1 was last tested; and

iii. During the source test, the following parameters must be monitored and recorded:

A. Opacity readings on the exhaust stack following the procedures of EPA Method 9;

B. Quantity (in gallons) of renewable diesel loaded;

C. VCU1 operating parameters; and

D. Outlet concentrations and emission rates in pounds/hour and pounds/Mgal of renewable diesel loaded.

d. The permittee must conduct a source test of EP INCIN to verify PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, CO, NO_x, and H_2S emission factors used to determine compliance with the PSELs of Condition 5.1 and to determine Sulfuric Acid emission rates;

i. Following the initial test, the permittee must conduct a source test of EP INCIN to verify to verify PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, CO, NO_x, and H_2S emission factors used to determine compliance with the PSELs of Condition 5.1 and to determine Sulfuric Acid emission rates at least once every five calendar years;

ii. Subsequent testing of EP INCIN must be at least 12 months after EP INCIN was last tested; and

iii. During the source test of EP INCIN, the following parameters must be monitored and recorded:

A. Opacity readings on the exhaust stack following the procedures of EPA Method 9;

B. Acid gas flow rate from the amine regeneration unit and sour water stripper unit;

C. H_2S content of the acid gas;

D. Type and quantity of fuel combusted in MMcf/hr;

E. TO-INCIN operating temperature;

F. SBH-INCIN operating parameters;

G. SCR operating parameters;

H. Oxidation Catalyst operating parameters;

I. Grain loading and emission rates of PM in gr/dscf and pounds/hour;

J. Concentrations and emission rates of H_2S, SO_2, and Sulfuric Acid in ppm and pounds/hour; and

K. Concentrations and emission rates of VOC, CO, and NO_x in pounds/hour and lb/MMcf fuel input.

e. All tests must be conducted in accordance with DEQ's Source Sampling Manual and the approved source test plan. The source test plan must be submitted at least 30 days in advance and approved by the Regional Source Test Coordinator. The source test report must be submitted to the Regional Source Test Coordinator within 60 days of the test unless otherwise approved in the source test plan;

Tested Pollutant	Reference Test Method*
$PM/PM_{10}/PM_{2.5}$	DEQ Method 5
NOx	EPA Method 7E
CO	EPA Method 10
VOC	EPA Method 18 or 25A
SO_2	EPA Method 6C
H_2S	EPA Method 15
Sulfuric Acid Mist	EPA CTM 13B
Opacity	EPA Method 9

*Substitution of alternative test methods must be pre-approved by the DEQ.

f. Only regular operating staff may adjust the combustion system or production processes and emission control parameters during the source test and within two hours prior to the source test. Any operating adjustments made during the source test, which are a result of consultation with source testing personnel, equipment vendors or consultants, may render the source test invalid; and

g. Unless otherwise specified by permit condition or DEQ approved source test plan, all compliance source tests must be performed as follows:

  i. At least 90% of the design capacity for new or modified equipment;

  ii. At least 90% of the maximum operating rate for existing equipment; or

  iii. At 90% of the normal maximum operating rate for existing equipment. For purposes of this permit, the normal maximum operating rate is defined as the 90th percentile of the average hourly operating rates during a 12 month period immediately preceding the source test. Data supporting the normal maximum operating rate must be included with the source test report.

8.0 SPECIAL CONDITIONS

8.1. Emergency Engine Emission Limits

The permittee must ensure that EGEN1, EGEN2, and EPUMP are certified by the manufacturer to meet EPA Tier 4 emissions standards. [OAR 340-226-0100]

8.2. Rail and Truck Loadout

The permittee must loadout only renewable diesel at the truck and rail loadouts.

9.0 RECORDKEEPING REQUIREMENTS

9.1. NSPS Dc

The permittee must comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart Dc:

a. The permittee must record and maintain records of the type and quantity of fuel combusted during each operating day; [40 CFR 60.48c(g)(1)]
b. The permittee must record and maintain records of the type and quantity of fuel combusted during each calendar month; or [40 CFR 60.48c(g)(2)]
c. The permittee must record and maintain records of the total amount of records of the total amount of each steam generating unit fuel delivered to that property during each calendar month. [40 CFR 60.48c(g)(3)]

9.2. NSPS Kb

The permittee must comply with all applicable monitoring and recordkeeping requirements of 40 CFR Subpart Kb (see 40 CFR 60.116b Monitoring of operations and 40 CFR 60.115b Reporting and recordkeeping requirements).

a. The permittee must keep readily accessible records showing the dimensions of each Subpart Kb subject storage vessel and an analysis showing the capacity of the storage vessel. **These records must be kept for the life of the respective source;**
b. For each Subpart Kb subject storage vessel, either with a design capacity greater than or equal to 39,890 gallons storing a liquid with a maximum true vapor pressure greater than or equal to 0.5 psi or with a design capacity greater than or equal to 19,813 gallons but less than 39,890 gallons storing a liquid with a maximum true vapor pressure greater than or equal to 2.2 psi, the permittee must maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period;
c. The permittee may use available data on the storage temperature to determine the maximum true vapor pressure as determined below:
    i. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service;
    ii. For refined petroleum products the vapor pressure may be obtained by the following:
        A. Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see 40 CFR 60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s); and

B. The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

iii. For non-petroleum liquids, the vapor pressure:

A. May be obtained from standard reference texts, or

B. Determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see 40 CFR 60.17); or

C. Measured by an appropriate method approved by the Administrator; or

D. Calculated by an appropriate method approved by the Administrator.

d. After installing the control equipment required to meet Condition 3.4.a.i. of the permit [40 CFR 60.112b(a)(1)] (permanently affixed roof and internal floating roof), the permittee must keep a record of each inspection performed as required by permit Conditions 6.2.a.i., 6.2.a.ii., 6.2.a.iii., and 6.2.a.iv. (as applicable). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

9.3. NESHAP (40 CFR 61) Subpart FF

The permittee shall maintain records that identify each waste stream at the facility subject to this subpart and indicate whether or not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition, the permittee shall maintain the following records: [40 CFR 61.356(b)]

a. For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity; and [40 CFR 61.356(b)(1)]

b. For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with Condition 3.7.c.iv, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with Condition 3.7.c.iv, the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with Condition 3.7.b.i.C. [40 CFR 61.356(b)(5)]

9.4. Operation and Maintenance

The permittee must maintain the following records related to the operation and maintenance of the facility and associated air contaminant control devices: [OAR 340-214-0114]

a. Quantity (MMcf) of natural gas and PSA Tail Gas combusted in Boiler 1, Boiler 2, ECO1F, ECO1I, ECO2F, ECO2I, ECO3F, ECO3I, H2HTR, JETFRAC, FLARE, INCIN, VCU1, Monthly;
b. Hours of normal operation of Boiler 1, Boiler 2, ECO1F, ECO1I, ECO2F, ECO2I, ECO3F, ECO3I, H2HTR, and JETFRAC, Monthly;
c. Hours of startup and shutdown operation of Boiler 1, Boiler 2, ECO1F, ECO1I, ECO2F, ECO2I, ECO3F, ECO3I, H2HTR, and JETFRAC, Monthly;
d. Quantity (tons) of bleaching aid and filter aid received, Monthly;
e. Type and quantity (gallons) of materials received into and removed from storage tanks ANIFATS1, ANIFATS2, ANIFATS3, CACID1, CACID2, HCS, OWS, RD/RJ1, RD1, RD2, RD3, RN/RJ1, RN/RJ2, RN/RJ3, VEGOIL1, VEGOIL2, VEGOIL3, and WWT, Monthly;
f. Number of roof landings and internal cleaning events for each storage tank, Monthly;
g. Hours of operation of each Cooling Tower (CT01 and CT02), Monthly;
h. FLARE Operational Records;
    i. EPA Method 22 readings;
    ii. Flare pilot flame presence determinations;
    iii. Heating value determinations for gas being combusted by the flare, upon changes to gas composition;
    iv. Exit velocity determinations, initial and upon changes; and
    v. Number of hours of FLARE startup and shutdown operation, Monthly.
i. Hours of operation of the Acid Gas Regenerator Unit, Sour Water Stripper, and associated control system, Monthly;
j. Quantity (gallons) of renewable diesel loaded onto rail cars, Monthly;
k. Quantity (gallons) of renewable diesel loaded onto trucks, Monthly;
l. Quantity (gallons) of renewable diesel, renewable naphtha, and renewable jet fuel produced, Monthly;
m. Control device operational parameters as required in Condition 4.3;
n. Using the compliance calculation procedures from Conditions 6.3, 6.5, 6.6, and 6.7, perform a calculation of emissions to demonstrate compliance with the rolling 12-month PSEL limitations of Condition 5.1, Monthly;
o. Results of the quarterly leak detection evaluation required in Condition 4.4, Monthly:
    i. Date of inspection;
    ii. Findings – identification of leaking component, location, nature and severity (instrument reading) of each leak; or indicate no leaks;
    iii. Corrective action - for each detected leak record the corrective action performed and date of repair; and
    iv. Maintain a record of each leaking component report submitted to DEQ as required by Condition 4.4.a.vi.

p. Record major maintenance performed on air pollution control equipment. Each Occurrence;

q. Record parameters necessary to calculate emissions from Tank roof landings, Each Occurrence;

r. The following records for each emergency generator and fire pump engine (EGEN1, EGEN2, EPUMP): [OAR 340-214-0114]

  i. Date, start time, end time and hours of operation of each emergency stationary RICE that is recorded through the non-resettable hour meter;

  ii. Notification of the emergency situation; including what classified the operation as emergency;

  iii. Date, start time, end time and hours of non-emergency operation used for maintenance checks and readiness testing;

  iv. Records of operation and maintenance requirements in Condition 4.2.

s. The following records for the NO_x and O_2 CEMS:

  i. Records of routine observation checks;

  ii. Records of routine maintenance and adjustments;

  iii. Records of parts that are replaced;

  iv. Spare parts inventory for the CEMS;

  v. Records of CEMS calibrations;

  vi. Records of CEMS daily calibration drift;

  vii. Records of CEMS audits;

  viii. Records of corrective action taken to bring an “out-of- control” (40 CFR 60 Appendix F) CEMS into control;

  ix. Records of date and time when a CEMS is inoperative or “out-of-control” (40 CFR 60 Appendix F);

  x. The one-hour average NO_x and O_2 concentrations corrected to 3% O_2;

  xi. Hourly emission rates (lb/hr) of NO_x from EPs BOILER, JETFRAC, and H2HTR;

  xii. identification of the operating hours for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

  xiii. identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

  xiv. identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and

  xv. description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specification 2, 3, or 6 (40 CFR 60, Appendix B).

t. A copy of the CEMS/CPMS quality assurance plan approved by the Department.

9.5. Excess Emissions

a. The permittee must maintain the records of excess emissions listed below and as defined in OAR 340-214-0300 through 340-214-0340, recorded on occurrence. Typically, excess emissions are caused by process upsets, startups, shutdowns, or scheduled maintenance. In many cases, excess emissions are evident when visible emissions are greater than 20% opacity as a six-minute block average;

i. The date and time of the beginning of the excess emissions event and the duration or best estimate of the time until return to normal operation;
ii. The date and time the permittee notified DEQ of the event;
iii. The equipment involved;
iv. Whether the event occurred during planned startup, planned shutdown, scheduled maintenance, or as a result of a breakdown, malfunction, or emergency;
v. Steps taken to mitigate emissions and corrective action taken, including whether the approved procedures for a planned startup, shutdown, or maintenance activity were followed;
vi. The magnitude and duration of each occurrence of excess emissions during the course of an event and the increase over normal rates or concentrations as determined by continuous monitoring or best estimate (supported by operating data and calculations); and
vii. The final resolution of the cause of the excess emissions;

b. If there is an ongoing excess emission caused by an upset or breakdown, the permittee must immediately take action to minimize emissions by reducing or ceasing operation of the equipment or facility, unless doing so could result in physical damage to the equipment or facility, or cause injury to employees. In no case may the permittee operate more than 48 hours after the beginning of the excess emissions, unless continued operation is approved by DEQ in accordance with OAR 340-214-0330(4);
c. In the event of any excess emissions which are of a nature that could endanger public health and occur during non-business hours, weekends, or holidays, the permittee must immediately notify DEQ by calling the Oregon Emergency Response System (OERS). The current number is 1-800-452-0311;
d. If permittee anticipates that scheduled maintenance may result in excess emissions, the permittee must submit scheduled maintenance procedures used to minimize excess emissions to DEQ for prior authorization, as required in OAR 340-214-0320. New or modified procedures must be received by DEQ in writing at least 72 hours prior to the first occurrence of the excess emission event. The permittee must abide by the approved procedures and have a copy available at all times; and
e. The permittee must maintain a log of all excess emissions in accordance with OAR 340-214-0340(3).

9.6. Complaints

The permittee must maintain a log of all complaints received by the permittee in person, in writing, by telephone or through other means according to Condition 2.6. Documentation must include all information identified in Condition 2.6. [OAR 340-214-0114]

9.7. Retention of Records

Unless otherwise specified, the permittee must retain all records for a period of at least five (5) years from the date of the monitoring sample, measurement, report, or application and make them available to DEQ upon request. The permittee must maintain the two (2) most recent years of records onsite. [OAR 340-214-0114]

10.0 REPORTING REQUIREMENTS

10.1. Excess Emissions

a. The permittee must notify DEQ of excess emissions events if the excess emission is of a nature that could endanger public health. Initial notice must be provided as soon as possible, but never more than one hour after becoming aware of the problem. Notice must be made to the regional office identified in Condition 12.0 by email, telephone, facsimile, or in person; and
b. When required by DEQ, the permittee must also submit follow-up reports summarizing records of excess emissions as required in Condition 9.4.r.i within 15 days of the date of the event.

10.2. NSPS Dc

There are no applicable Subpart Dc specific reporting requirements for Boiler 1 and Boiler 2.

10.3. NSPS Subpart Kb

The permittee must submit the following Subpart Kb specific reports/notifications to the EPA Administrator and DEQ, as applicable:
a. If any of the conditions described in Condition 6.2.a.ii. of the permit [40 CFR 60.113b(a)(2)] are detected during the required annual visual inspection, a report shall be furnished to the Administrator and DEQ within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made;
b. After each inspection required by Condition 6.2.a.iii. of the permit [40 CFR 60.113b(a)(3)] 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 Condition 6.2.a.iii.B. [40 CFR 60.113b(a)(3)(ii)], a report shall be furnished to the EPA Administrator and DEQ within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the required specifications [of 40 CFR 60.112b(a)(1) or 40 CFR 60.113b(a)(3)] and list each repair made; and
c. Provide notification to the EPA Administrator and DEQ in writing, in accordance with the criteria stated in Condition 6.2.a.v., prior to the filling or refilling of each storage vessel for which an inspection is required by Conditions 6.2.a.i. and 6.2.a.iv.

10.4. NESHAP Subpart FF

a. The permittee shall submit to the Administrator by the initial startup a report that summarizes the regulatory status of each waste stream subject to Condition 3.7.a and is determined by the procedures specified in Condition 3.7.d to contain benzene. The report shall include the following information: [40 CFR 61.357(a)]
   i. Total annual benzene quantity from facility waste determined in accordance with Condition 3.7.b;
   ii. A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart;
   iii. For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:
      A. Whether or not the water content of the waste stream is greater than 10 percent;
      B. Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;
      C. Annual waste quantity for the waste stream;
      D. Range of benzene concentrations for the waste stream;
      E. Annual average flow-weighted benzene concentration for the waste stream; and
      F. Annual benzene quantity for the waste stream.
   iv. The information required in Conditions 10.4.a.i through 10.4.a.iii of this section should represent the waste stream characteristics based on current configuration and operating conditions. The permittee only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in 40 CFR 61.10(a).

b. If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the permittee shall submit to the Administrator a report that updates the information listed in Conditions 10.4.a.i through 10.4.a.iii whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more. [40 CFR 61.357(b)]

10.5. Annual Report

For each year this permit is in effect, the permittee must submit to DEQ by **February 15th** -two (2) paper copies and one (1) electronic copy of the following information for the previous calendar year. If February 15th falls on a weekend or Monday holiday, the permittee must submit their annual report on the next business day.

a. Operating parameters:

i. Quantity (MMcf) of natural gas and PSA Tail Gas combusted in Boiler 1, Boiler 2, ECO1F, ECO1I, ECO2F, ECO2I, ECO3F, ECO3I, H2HTR, JETFRAC, FLARE, INCIN, and VCU1;

ii. Hours of operation (both startup/shutdown and normal operations) of Boiler 1, Boiler 2, ECO1F, ECO1I, ECO2F, ECO2I, ECO3F, ECO3I, H2HTR, and JETFRAC;

iii. Quantity (tons) of bleaching aid and filter aid received;

iv. Type and quantity (gallons) of materials received into and removed from storage tanks ANIFATS1, ANIFATS2, ANIFATS3, CACID1, CACID2, HCS, OWS, RD/RJ1, RD1, RD2, RD3, RN/RJ1, RN/RJ2, RN/RJ3, VEGOIL1, VEGOIL2, VEGOIL3, and WWT;

v. Number of roof landings and internal cleaning events for each storage tank;

vi. Number of hours of operation of each Cooling Tower (CT01 and CT02);

vii. Number of hours of FLARE startup and shutdown operation;

viii. Number of hours of operation of the Acid Gas Regenerator Unit, Sour Water Stripper, and associated control system;

ix. Quantity (gallons) of renewable diesel loaded onto rail cars;

x. Quantity (gallons) of renewable diesel loaded onto trucks; and

xi. Quantity (gallons) of renewable diesel, renewable naphtha, and renewable jet fuel produced.

b. Calculations of annual pollutant emissions determined each month in accordance with Conditions 6.3, 6.5, 6.6, and 6.7.

c. Data Assessment Reports for the NO_x CEMS which at a minimum must contain: the information specified in 40 CFR 60 Appendix F, Procedure 1, Section 7: Reporting Requirements.

d. A brief summary listing the date, time, and the affected device/process for each excess emission that occurred during the reporting period.

e. Summary of complaints relating to air quality received by permittee during the year in accordance with Condition 9.4.r.i.

f. The following records for each emergency stationary RICE identified: [OAR 340-214-0114]

i. Hours of operation of each emergency stationary RICE that is recorded through the non-resettable hour meter;

ii. Hours of emergency operation; including what classified the operation as emergency; and

iii. Hours of non-emergency operation used for maintenance checks and readiness testing.

g. List permanent changes made in facility process, production levels, and pollution control equipment which affected air contaminant emissions.

h. List major maintenance performed on pollution control equipment.

i. Information as to whether there has been any changes in zoning within 1.5 kilometers of the source and, if so, whether that change increases the source risk; and

j. Documentation showing that, for any area that the source demonstrated in its risk assessment was not used in a manner allowed by the land use zoning applicable to the area, the area continues to not be used in the manner allowed by the land use zoning applicable to the area.

10.6. Greenhouse Gas Registration and Reporting

a. If the calendar year greenhouse gas emissions (CO_2e) are ever greater than or equal to 2,756 tons (2,500 metric tons), the permittee must annually register and report its greenhouse gas emissions with DEQ in accordance with OAR 340 division 215; and
b. If the calendar year greenhouse gas emissions (CO_2e) are less than 2,756 tons (2,500 metric tons) for three consecutive years, the permittee may stop reporting greenhouse gas emissions but must retain all records used to calculate greenhouse gas emissions for the five years following the last year that they were required to report. The permittee must resume reporting its greenhouse gas emissions if the calendar year greenhouse gas emissions (CO_2e) are greater than or equal to 2,756 tons (2,500 metric tons) in any subsequent calendar year.

10.7. Initial Startup Notice

The permittee must notify DEQ in writing of the date a newly permitted source is first brought into normal operation. The notification must be submitted no later than seven (7) days after the initial startup. [OAR 340-214-0110]

10.8. CEMS/CPMS Quality Assurance Plan

The permittee must develop and submit a Standard Operating Procedure and a Quality Assurance Plan for each type of CEMS and CPMS for each emission unit constructed under this permit. The plan must be submitted prior to the initial startup of the source.

10.9. Notice of Change of Ownership or Company Name

The permittee must notify DEQ in writing using a DEQ "Transfer Application Form" within 60 days after the following:

a. Legal change of the name of the company as registered with the Corporations Division of the State of Oregon; or
b. Sale or exchange of the activity or facility.

10.10. Construction or Modification Notices

The permittee must notify DEQ in writing using a DEQ "Notice of Intent to Construct Form," or other permit application form and obtain approval in accordance with OAR 340-210-0205 through 340-210-0250 and OAR 340-245-0060(4)(c) before:

a. Constructing, installing, or establishing a new stationary source that will cause an increase in any regulated pollutant emissions;

b. Making any physical change or change in operation of an existing stationary source that will cause an increase, on an hourly basis at full production, in any regulated pollutant emissions; or

c. Constructing or modifying any air pollution control equipment.

11.0 ADMINISTRATIVE REQUIREMENTS

11.1. Permit Renewal Application

The permittee must submit the completed application package for renewal of this permit **180 days prior to the expiration date**. Two (2) paper copies and one (1) electronic copy of the application must be submitted to the DEQ Permit Coordinator listed in Condition 12.2. [OAR 340-216-0040]

11.2. Permit Modifications

Application for a modification of this permit must be submitted at least 60 days prior to the source modification. When preparing an application, the applicant should also consider submitting the application 180 days prior to allow DEQ adequate time to process the application and issue a permit before it is needed. A special activity fee must be submitted with an application for the permit modification. The fees and two (2) copies of the application must be submitted to the DEQ Business Office.

11.3. Annual Compliance Fee

The permittee must pay the annual fees specified in OAR 340-216-8020, Table 2, Part 2 and 3 for a Standard ACDP by **December 1** of each year this permit is in effect. An invoice indicating the amount, as determined by DEQ regulations will be mailed prior to the above date. **Late fees in accordance with Part 5 of the table will be assessed as appropriate.**

11.4. Change of Ownership or Company Name Fee

The permittee must pay the non-technical permit modification fee specified in OAR 340-216-8020, Table 2, Part 4 with an application for changing the ownership or the name of the company.

11.5. Special Activity Fees

The permittee must pay the special activity fees specified in OAR 340-216-8020, Table 2, Part 4 with an application to modify the permit.

12.0 DEQ CONTACTS / ADDRESSES

12.1. Business Office

The permittee must submit payments for invoices, applications to modify the permit, and any other payments to DEQ's Business Office:

Oregon Dept. of Environmental Quality
Financial Services – Revenue Section
700 NE Multnomah St., Suite 600
Portland, Oregon 97232-4100

12.2. Permit Coordinator

The permittee must submit all notices and applications that do not include payment to the Permit Coordinator.

Oregon Dept. of Environmental Quality
NWR Air Quality Permit Coordinator
700 NE Multnomah St., Suite 600
Portland, OR 97232-4100
nwraqpermits@deq.state.or.us

12.3. Report Submittals

Unless otherwise notified, the permittee must submit all reports (annual reports, source test plans and reports, etc.) to DEQ's Region. If you know the name of the Air Quality staff member responsible for your permit, please include it:

Oregon Dept. of Environmental Quality
Northwest Region Air Quality Permits
700 NE Multnomah St., Suite 600
Portland, OR 97232-4100
nwraqpermits@deq.state.or.us

12.4. Web Site

Information about air quality permits and DEQ's regulations may be obtained from the DEQ web page at www.oregon.gov/deq/.

13.0 GENERAL CONDITIONS AND DISCLAIMERS

13.1. Permitted Activities

a. Until this permit expires or is modified or revoked, the permittee is allowed to discharge air contaminants from the following:

i. Processes and activities directly related to or associated with the devices/processes listed in Condition 1.0 of this permit;

ii. Any categorically insignificant activities, as defined in OAR 340-200-0020, at the source; and

iii. Construction or modification changes that are Type 1 or Type 2 changes under OAR 340-210-0225 that are approved by DEQ in accordance with OAR 340-210-0215 through 0250 if the permittee complies with all of the conditions of DEQ's approval to construct and all of the conditions of this permit.

b. Discharge of air contaminants from any other equipment or activity not identified herein is not authorized by this permit.

13.2. Other Regulations

In addition to the specific requirements listed in this permit, the permittee must comply with all other applicable legal requirements enforceable by DEQ.

13.3. Conflicting Conditions

In any instance in which there is an apparent conflict relative to conditions in this permit, the most stringent conditions apply. [OAR 340-200-0010]

13.4. Masking of Emissions

The permittee must not cause or permit the installation of any device or use any means designed to mask the emissions of an air contaminant that causes or is likely to cause detriment to health, safety, or welfare of any person or otherwise violate any other regulation or requirement. [OAR 340-208-0400]

13.5. DEQ Access

The permittee must allow DEQ's representatives access to the plant site and pertinent records at all reasonable times for the purposes of performing inspections, surveys, collecting samples, obtaining data, reviewing and copying air contaminant emissions discharge records and conducting all necessary functions related to this permit in accordance with ORS 468.095.

13.6. Permit Availability

The permittee must have a copy of the permit available at the facility at all times. [OAR 340-216-0020(3)]

13.7. Open Burning

The permittee may not conduct any open burning except as allowed by OAR 340, division 264.

13.8. Asbestos

The permittee must comply with the asbestos abatement requirements in OAR 340, division 248 for all activities involving asbestos-containing materials, including, but not limited to, demolition, renovation, repair, construction, and maintenance.

13.9. Property Rights

The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations.

13.10. Permit Expiration

a. A source may not be operated after the expiration date of the permit, unless any of the following occur prior to the expiration date of the permit: [OAR 340-216-0082]
    i. A timely and complete application for renewal of this permit or for a different ACDP has been submitted; or
    ii. A timely and complete application for renewal or for an Oregon Title V Operating Permit has been submitted, or
    iii. Another type of permit (ACDP or Oregon Title V Operating Permit) has been issued authorizing operation of the source.
b. For a source operating under an ACDP or Oregon Title V Operating Permit, a requirement established in an earlier ACDP remains in effect notwithstanding expiration of the ACDP, unless the provision expires by its terms or unless the provision is modified or terminated according to the procedures used to establish the requirement initially.

13.11. Permit Termination, Revocation, or Modification

DEQ may terminate, revoke, or modify this permit pursuant to OAR chapter 340 division 216. [OAR 340-216-0082].

14.0 CLEANER AIR OREGON GENERAL CONDITIONS AND DISCLAIMERS

14.1. Reassessment of Risk

a. The permittee must reassess, and submit to DEQ, the source risk for cancer, chronic noncancer, and acute noncancer risk in accordance with OAR 340-245-0050(7)(b)(C) by no later than 60 days after the following [OAR 340-245-0100(8)(a)(F)]:

i. Zoning changes approved and effective within 1.5 kilometers of the source that could increase risk; or

ii. Land use has changed in a way that could increase risk in any area in which land uses were excluded from the permittee's Cleaner Air Oregon risk assessment under OAR 340-245-0210(1)(a)(F) because such area was not used in a manner allowed by the applicable zoning.

b. The permittee must reassess, and submit to DEQ, the source risk for cancer, chronic noncancer, and acute noncancer risk in accordance with OAR 340-245-0050(7)(b)(C) based on any of the following:

i. The permittee becomes aware that corrections or additional information are needed to revise or update the original risk assessment [OAR 340-245-0100(8)(a)(H)];

ii. The permittee proposes to modify any physical feature of the source that was used as a modeling parameter in the risk assessment that may increase risk [OAR 340-245-0100(8)(a)(D)];

iii. A Risk Based Concentration in OAR 340-245-8010 Table 2 for a Toxic Air Contaminant that is emitted by this source has been added or the value lowered, leading to an increase in risk [OAR 340-245-0100(8)(b)(B)];

iv. Risk assessment procedures in division 245 change that may increase risk, or impact the implementation or effectiveness of the Risk Reduction Plan [OAR 340-245-0100(8)(b)(C)]; or

v. When notified in writing by DEQ that the permittee must update or correct its previous risk assessment based on new or additional information [OAR 340-245-0100(8)(b)].

14.2. Permit Modifications

a. When a revised risk assessment under condition 14.1, indicates this source no longer qualifies as a de minimis source under OAR 340-245-0050(7)(a)(A) or (B) the permittee must apply for a permit modification under OAR 340 Division 216 and submit fees as required under OAR 340-245-0100(8)(g) and Condition 12.1.

b. When notified in writing by DEQ that a modification under division 245 is required, the permittee must submit the necessary information required under OAR 340-245-0100(3) to DEQ 90 days after the date of the written notification. [OAR340-245-0100(8)(c)]

14.3. CAO Submittal Deadline Extensions

The permittee may request an extension for submittals required under Conditions 14.1 and 14.2 in accordance with OAR 340-245-0030(3) by submitting a written request no fewer than 15 days prior to the submittal deadline.

15.0 EMISSION FACTORS

Emissions device or activity	Pollutant	Emission Factor (EF)	EF units	EF Reference
Boiler 1 & 2	$PM/PM_{10}/PM_{2.5}$	5.98	lb/MMcf	Manufacturer Guarantee
	SO_2	0.6	lb/MMcf	AP-42 Table 1.4-2
	NO_x	0.84 (when CEMS not operational)	lb/hr (each)	Manufacturer Guarantee
	NO_x	7.12 (Startup and Shutdown when CEMS not operational)	lb/hr (each)	AP-42 Table 1.4-1
	CO	2.04	lb/hr (each)	Manufacturer Guarantee
	CO	5.98 (Startup and Shutdown)	lb/hr (each)	AP-42 Table 1.4-1
	VOC	5.5	lb/MMcf	AP-42 Table 1.4-2
ECO1F, ECO2F, ECO3F	$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMcf	AP-42 Table 1.4-2
	SO_2	0.6	lb/MMcf	AP-42 Table 1.4-2
	NO_x	0.21	lb/hr (each)	Manufacturer Guarantee
	NO_x	3.24 (Startup and Shutdown)	lb/hr (each)	AP-42 Table 1.4-1
	CO	0.50	lb/hr (each)	Manufacturer Guarantee
	CO	2.72 (Startup and Shutdown)	lb/hr (each)	AP-42 Table 1.4-1
	VOC	5.5	lb/MMcf	AP-42 Table 1.4-2

Emissions device or activity	Pollutant	Emission Factor (EF)	EF units	EF Reference
ECO1I, ECO2I, ECO3I	$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMcf	AP-42 Table 1.4-2
	SO_2	0.6	lb/MMcf	AP-42 Table 1.4-2
	NO_x	0.031	lb/hr (each)	Manufacturer Guarantee
	NO_x	0.49 (Startup and Shutdown)	lb/hr (each)	AP-42 Table 1.4-1
	CO	0.077	lb/hr (each)	Manufacturer Guarantee
	CO	0.41 (Startup and Shutdown)	lb/hr (each)	AP-42 Table 1.4-1
	VOC	5.5	lb/MMcf	AP-42 Table 1.4-2

Emissions device or activity	Pollutant	Emission Factor (EF)	EF units	EF Reference
H2HTR	$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMcf Natural Gas	AP-42 Table 1.4-2 with PSA gas composition
		1.0	lb/MMcf PSA gas	
	SO_2	0.6	lb/MMcf Natural Gas	AP-42 Table 1.4-2 with PSA gas composition
		0.08	lb/MMcf PSA gas	
	NO_x	4.53 (when CEMS not operational)	lb/hr	SCAQMD BACT assessment (with SCR control) for Air Liquide (March 2007).
	NO_x	64.3 (Startup and Shutdown when CEMS not operational)	lb/hr	AP-42 Table 1.4-1
	CO	5.52	lb/hr	SCAQMD BACT assessment (with SCR control) for Air Liquide (March 2007).
	CO	54.0 (Startup and Shutdown)	lb/hr	AP-42 Table 1.4-1
	VOC	5.5	lb/MMcf Natural Gas	AP-42 Table 1.4-2 with PSA gas composition
		0.73	lb/MMcf PSA gas	

Emissions device or activity	Pollutant	Emission Factor (EF)	EF units	EF Reference
JETFRAC	$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMcf	AP-42 Table 1.4-2
	SO_2	0.60	lb/MMcf	AP-42 Table 1.4-2
	NO_x	1.14 (when CEMS not operational)	lb/hr	SCAQMD BACT assessment (with SCR control) for Air Liquide (March 2007).
	NO_x	11.5 (Startup and Shutdown when CEMS not operational)	lb/hr	AP-42 Table 1.4-1
	CO	2.78	lb/hr	Manufacturer Guarantee
	CO	9.65 (Startup and Shutdown)	lb/hr	AP-42 Table 1.4-1
	VOC	5.5	lb/MMcf	AP-42 Table 1.4-2
1BEDAY1, 1BEDAY2, 1BESV1, 1BESV2, 1BESV3, 1FADT, 1FASV1, 2BEDAY1, 2BEDAY2, 2BESV1, 2BESV2, 2BESV3, 2FADT, 2FASV1, 3BEDAY1, 3BEDAY2, 3BESV1, 3BESV2, 3BESV3, 3FADT1, 3FADT2, 3FADT3, 3FASV1, 3FASV2, 3FASV3	PM	7.3E-04	lb/ton	AP-42 Table 11.12-2 with 99.9% Control
	$PM_{10}/PM_{2.5}$	4.7E-04	lb/ton	AP-42 Table 11.12-2 with 99.9% Control

Emissions device or activity	Pollutant	Emission Factor (EF)	EF units	EF Reference
ANIFATS1, ANIFATS2, ANIFATS3, CACID1, CACID2, HCS, OWS, RD/RJ1, RD1, RD2, RD3, RN/RJ1, RN/RJ2, RN/RJ3, VEGOIL1, VEGOIL2, VEGOIL3 Storage	VOC	Use TANKS software or AP-42 algorithms for 12-month emission rate calculation	tons/yr	TANKS software, AP-42 Section 7.1
Roof Landings and Internal Cleanings	VOC	Use AP-42, Section 7.1 and/or API Technical Report 2568	lbs/event	AP-42, Section 7.1, API TR 2568
WWT	VOC	0.012	ton/month	TOXCHEM version 4 4
	H_2S	0.017	ton/month	TOXCHEM version 4 4
CT01, CT02	PM	0.032	lb/hour	Derived in application
	PM_{10}	0.028	lb/hour	Derived in application
	$PM_{2.5}$	0.017	lb/hour	Derived in application
	VOC	0.84	lb/hour	Derived in application
EGEN1, EGEN2 (non-emergency operation)	$PM/PM_{10}/PM_{2.5}$	0.22	lb/hour	Derived in application.
	SO_2	0.019	lb/hour	Derived in application.
	NO_x	2.20	lb/hour	EPA Tier IV Emission Standards
	CO	11.5	lb/hour	EPA Tier IV Emission Standards

Emissions device or activity	Pollutant	Emission Factor (EF)	EF units	EF Reference
	VOC	0.62	lb/hour	EPA Tier IV Emission Standards
EPUMP (non-emergency operation)	$PM/PM_{10}/PM_{2.5}$	0.038	lb/hour	Derived in application.
	SO_2	5.0E-03	lb/hour	Derived in application.
	NO_x	0.27	lb/hour	EPA Tier IV Emission Standards
	CO	2.36	lb/hour	EPA Tier IV Emission Standards
	VOC	0.13	lb/hour	EPA Tier IV Emission Standards
FLARE (pilot)	$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMcf	AP-42 Table 1.4-2
	SO_2	0.6	lb/MMcf	AP-42 Table 1.4-2
	NO_x	100	lb/MMcf	AP-42 Table 1.4-1
	CO	84	lb/MMcf	AP-42 Table 1.4-1
	VOC	5.5	lb/MMcf	AP-42 Table 1.4-2
FLARE (startup)	$PM/PM_{10}/PM_{2.5}$	3.00	lb/hour	AP-42 Table 13.5-1
	SO_2	97.4	lb/hour	Input Gas Composition
	NO_x	46.9	lb/hour	AP-42 Table 13.5-1
	CO	43.5	lb/hour	Input Gas Composition
	VOC	455	lb/hour	AP-42 Table 13.5-2
	H2S	1.06	lb/hour	Gas analysis and FLARE control

Emissions device or activity	Pollutant	Emission Factor (EF)	EF units	EF Reference
FLARE (shutdown)	$PM/PM_{10}/PM_{2.5}$	1.75	lb/hour	AP-42 Table 13.5-1
	SO_2	56.8	lb/hour	Input Gas Composition
	NO_x	27.3	lb/hour	AP-42 Table 13.5-1
	CO	25.3	lb/hour	Input Gas Composition
	VOC	265	lb/hour	AP-42 Table 13.5-2
	H2S	0.62	lb/hour	Gas analysis and FLARE control
AGRU, SWS, TO-INCIN, SBH-INCIN, SCR-INCIN (EP INCIN)	$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMcf (INCIN natural gas input)	AP-42 Table 1.4-2
	SO_2	4.97	lb/hr	Manufacturer Guarantee
	NO_x	0.43	lb/hr	Manufacturer Guarantee
	CO	1.45	lb/hr	Manufacturer Guarantee
	VOC	13.8	lb/MMcf (INCIN natural gas input)	AP-42 Table 1.4-2 + 99.5% Inlet VOC Control
	H2S	0.32	lb/hr	Gas analysis and INCIN control
LOAD (VCU1 combustion)	$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMcf	AP-42 Table 1.4-2
	SO_2	0.6	lb/MMcf	AP-42 Table 1.4-2
	NO_x	50	lb/MMcf	AP-42 Table 1.4-1
	CO	84	lb/MMcf	AP-42 Table 1.4-1
	VOC	5.5	lb/MMcf	AP-42 Table 1.4-2

Emissions device or activity	Pollutant	Emission Factor (EF)	EF units	EF Reference
LOAD (VCU1 rail loadout)	VOC	6.61E-4	lb/Mgal	AP-42 Chapter 5.2 Equation 1; 98.7% capture and 98% control
LOAD (VCU1 truck loadout)	VOC	1.10E-3	lb/Mgal	AP-42 Chapter 5.2 Equation 1; 98.7% capture and 98% control
LEAK	VOC	2.06	ton/month	Preferred and Alternative Methods for Estimating Fugitive Emissions from Equipment Leaks Final Report published in November 1996
	H_2S	5.70E-3	ton/month	Process Gas Composition

16.0 PROCESS/PRODUCTION RECORDS

Emissions device or activity	Process or production parameter	Frequency
Boiler 1, Boiler 2, ECO1F, ECO1I, ECO2F, ECO2I, ECO3F, ECO3I, H2HTR, JETFRAC, FLARE (pilot), INCIN, VCU1	Quantity (MMcf) of natural gas and PSA Tail Gas combusted	Monthly
Boiler 1, Boiler 2, ECO1F, ECO1I, ECO2F, ECO2I, ECO3F, ECO3I, H2HTR, JETFRAC	Hours of operation (Both startup/shutdown and normal operation)	Monthly

Emissions device or activity	Process or production parameter	Frequency
1BEDAY1, 1BEDAY2, 1BESV1, 1BESV2, 1BESV3, 1FADT, 1FASV1, 2BEDAY1, 2BEDAY2, 2BESV1, 2BESV2, 2BESV3, 2FADT, 2FASV1, 3BEDAY1, 3BEDAY2, 3BESV1, 3BESV2, 3BESV3, 3FADT, 3FADT2, 3FADT3, 3FASV1, 3FASV2, and 3FASV3	Quantity (tons) of bleaching aid and filter aid received	Monthly
ANIFATS1, ANIFATS2, ANIFATS3, CACID1, CACID2, HCS, OWS, RD/RJ1, RD1, RD2, RD3, RN/RJ1, RN/RJ2, RN/RJ3, VEGOIL1, VEGOIL2, VEGOIL3, WWT	Type and quantity (gallons) of materials received into and removed from storage	Monthly
	Roof Landing and Internal Cleaning Events	Monthly
CT01, CT02	Hours of operation	Monthly
EGEN1, EGEN2, EPUMP	Hours of non-emergency operation	Monthly
FLARE	Hours of startup and shutdown operation	Monthly
AGRUSWS (INCIN, SBH-INCIN, and SCR-INCIN)	Number of hours of operation of the Acid Gas Regenerator Unit, Sour Water Stripper, and associated control system	Monthly
LOAD	Quantity (gallons) of renewable diesel loaded onto rail cars	Monthly
	Quantity (gallons) of renewable diesel loaded onto trucks	Monthly

17.0 ABBREVIATIONS, ACRONYMS, AND DEFINITIONS

ACDP	Air Contaminant Discharge Permit
ASTM	American Society for Testing and Materials
AQMA	Air Quality Maintenance Area
calendar year	The 12-month period beginning January 1st and ending December 31st
CAO	Cleaner Air Oregon
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
DEQ	Oregon Department of Environmental Quality
dscf	dry standard cubic foot
EPA	US Environmental Protection Agency
FCAA	Federal Clean Air Act
Gal	gallon(s)
GHG	greenhouse gas
gr/dscf	grains per dry standard cubic foot
HAP	Hazardous Air Pollutant as defined by OAR 340-244-0040
I&M	inspection and maintenance
lb	pound(s)
MMBtu	million British thermal units
NA	not applicable
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NG	Natural Gas
NO_X	nitrogen oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	oxygen
OAR	Oregon Administrative Rules
ORS	Oregon Revised Statutes
O&M	operation and maintenance
Pb	lead
PCD	pollution control device
PEMS	Predictive emission monitoring system
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in size
$PM_{2.5}$	particulate matter less than 2.5 microns in size
ppm	part per million
PSA	Pressure-swing Absorption
PSD	Prevention of Significant Deterioration
PSEL	Plant Site Emission Limit
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
scf	standard cubic foot
SCR	Selective Catalytic Reduction
SER	Significant Emission Rate
SIC	Standard Industrial Code
SIP	State Implementation Plan
SO_2	sulfur dioxide
Special Control Area	as defined in OAR 340-204-0070
TACT	Typically Achievable Control Technology
VE	visible emissions
VOC	volatile organic compound
year	A period consisting of any 12-consecutive calendar months