Oregon
Kate Brown, Governor

Department of Environmental Quality
Northwest Region
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Portland, OR 97232-4100
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August 30, 2019

Dan Luckett
Cascade Kelly Holdings, LLC
81200 Kallunki Road
Clatskanie OR 97016 2244

Re: Renewal of a Standard Air Contaminant Discharge Permit
Permit Number **05-0006-ST-01** Application Number's **028254 & 030372**

The Department of Environmental Quality has completed its review and public hearing of the application for the renewal of a Standard Air Contaminant Discharge Permit for Cascade Kelly Holdings, LLC dba Columbia Pacific Bio-Refinery, located at 81200 Kallunki Road in Clatskanie. Based on the information in the application, DEQ has issued the enclosed permit.

The effective date of the permit is the date it was signed by the regional Air Quality Manager.
The signature and date appear on the first page of the document. This permit is issued pursuant to Oregon Revised Statutes 468A and Oregon Administrative Rules (OAR) 340-14-005 through 340-14-050, and 216-0010 through 216-0100.

You may appeal conditions or limitations contained in the attached permit by applying to the Environmental Quality Commission, or its authorized representative, within twenty days from the date of this letter. Appeals are pursuant to ORS Chapter 183 and OAR Chapter 340, Division 14-025 (6). Appeal procedures are contained in OAR Division 11-005 through 11-140.

A copy of the current permit must be available at the facility at all times. Failure to comply with permit conditions may result in civil penalties. **You are expected to read the permit carefully and comply with all conditions** to protect the environment of Oregon.

If you have any questions, please contact David Graiver at 503-229-5690.

Sincerely,

Steven A. Dietrich

Steven A. Dietrich, Air Quality Manager
DEQ Northwest Region

Enclosure
Cc: HQ/AQ

State of Oregon Department of Environmental Quality

STANDARD
AIR CONTAMINANT DISCHARGE PERMIT

Department of Environmental Quality
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:

Cascade Kelly Holdings, LLC
dba Columbia Pacific Bio-Refinery
81200 Kallunki Road
Clatskanie, OR 97016

INFORMATION RELIED UPON:

Renewal Application No.: 028254
Date Received: 07/01/2015

Modification Application No.: 030372
Date Received: 10/18/2018

PLANT SITE LOCATION:

81200 Kallunki Road
Clatskanie, OR 97016

LAND USE COMPATIBILITY FINDING:

Approving Authority: Columbia County
Approval Date: 03/22/2000

PERMIT PREVIOUSLY ISSUED TO:

Cascade Grain Products, LLC

ISSUED BY THE DEPARTMENT OF ENVIRONMENTAL QUALITY

Steven A. Dietrich

Steven A. Dietrich, Northwest Region Air Quality Manager

8-30-19

Dated

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

Table 1 Code	Source Description	SIC (NAICS)
Part B, 57	Organic or inorganic chemical manufacturing and distribution with ½ or more tons per year emissions of any one criteria pollutant	2869 (325193)
Part C, 4	Sources that request a PSEL equal to or greater than the SER for a regulated pollutant.	

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1.0 GENERAL EMISSION STANDARDS AND LIMITS

1.1. **Visible Emissions**

The permittee must comply with the following visible emission limits from air contaminant sources other than fugitive emission sources, as applicable.

a. Opacity must be measured as a six-minute block average using EPA Method 9, a continuous opacity monitoring system (COMS) installed and operated in accordance with the DEQ Continuous Monitoring Manual or 40 CFR part 60, or an alternative monitoring method approved by DEQ that is equivalent to EPA Method 9.

b. Emissions from any air contaminant source must not equal or exceed 20% opacity.

1.2. **Particulate Matter Emissions**

The permittee must comply with the following particulate matter emission limits, as applicable:

a. Particulate matter emissions from any fuel burning equipment installed, constructed or modified on or after April 16, 2015 must not exceed 0.10 grains per dry standard cubic foot, corrected to 12% CO_2 or 50% excess air.

b. Particulate matter emissions from any fuel burning equipment installed, constructed, or modified on or after June 1, 1970 but before April 16, 2015 must not exceed 0.14 grains per dry standard cubic foot, corrected to 12% CO_2 or 50% excess air.

c. Particulate matter emissions from any air contaminant source installed constructed or modified after April 16, 2015 other than fuel burning equipment and fugitive emission sources must not exceed 0.10 grains per standard cubic foot.

d. Particulate matter emissions from any air contaminant source installed, constructed, or modified on or after June 1, 1970 but before April 16, 2015 other than fuel burning equipment and fugitive emission sources must not exceed 0.14 grains per dry standard cubic foot.

1.3. **Fugitive Emissions**

The permittee must take reasonable precautions to prevent fugitive dust emissions, as measured by EPA method 22, by:

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 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;
f. Promptly removing earth or other material that does or may become airborne from paved streets; and
g. Developing a DEQ approved fugitive emission control plan upon request by DEQ if the above precautions are not adequate and implementing the plan whenever fugitive emissions leave the property for more than 18 seconds in a six-minute period.

1.4. **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.

1.5. **Nuisance and Odors** The permittee must not cause or allow air contaminants from any source to cause a nuisance. Nuisance conditions will be verified by DEQ personnel.

1.6. **Fuels** The permittee must not use any fuel other than natural gas, propane, butane for production purposes. ASTM grade fuel oils may be used in emergency generator engines.

1.7. **Fuel Sulfur Content** [40 CFR 60.4207]

a. No. 2 Fuel Oil purchased on or after October 1, 2007, must not contain more than 500 ppm sulfur by weight; and
b. No. 2 Fuel Oil purchased on or after October 1, 2010, must not contain more than 15 ppm sulfur by weight.

1.8. **NSPS Subpart IIII** Emissions from:

a. EU69 and EU70 shall not exceed: [40 CFR 60.4205(b)]
   i. 6.4 g/kW-hr of NMHC + NOx
   ii. 3.5 g/kW-hr of CO
   iii. 0.20 g/kW-hr of PM
b. EU71 shall not exceed: [40 CFR 60.4205(c)]
   i. 10.5 g/kW-hr (7.8 g/hp-hr) of NMHC + NOx
   ii. 3.5 g/kW-hr (2.6 g/hp-hr) of CO
   iii. 0.54 g/kW-hr (0.40 g/hp-hr) of PM

1.9. **Operation of Pollution Control Devices and Processes** The permittee must operate and maintain air pollution control devices and emission reduction processes at the highest reasonable efficiency and effectiveness to minimize emissions. Air pollution control devices and components must be in operation and functioning properly at all times when the associated emission source is operating. (OAR 340-226-0120)

2.0 SPECIFIC PERFORMANCE AND EMISSION STANDARDS

2.1. **NSPS Subpart A - General Provision Requirements**

The permittee must comply with all applicable provisions of 40 CFR Subpart A, including but not limited to the following:

a. 40 CFR § 60.7 Notification and record keeping

i. § 60.7(a)(1) A notification of the date construction (or reconstruction as defined under §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

ii. § 60.7(a)(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

iii. § 60.7(b) The permittee must maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

iv. § 60.7(f) The permittee must maintain a file of all measurements and all other information as required by any Subpart, recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records.

v. § 60.7(g) If notification substantially similar to that in § 60.7(a) above (Condition 2.1.a.i) is required by a State (the DEQ), sending the EPA Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

b. 40 CFR § 60.8 Performance tests

i. §60.8(a) Within 60 days after achieving the maximum production rate at which each affected facility will be operated, but not later than 180 days after initial startup of such facility the permittee must conduct performance tests to determine compliance with the emissions standards of each applicable NSPS Subpart.

ii. §60.8(b) Performance tests must be conducted and data reduced in accordance with the test methods and procedures contained in each applicable NSPS Subpart or as otherwise approved pursuant to Subpart A.

c. See Condition 13.0 for reference/guidance to the applicability of the General Provisions to Subpart IIII.

2.2. **Product Loadout Flare**

a. 40 CFR 60.18: General control device requirements (CE21: Product Loadout Flare) [OAR 340-212-0120(1)]

i. The Product Loadout 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.

ii. The Product Loadout 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.

iii. The Product Loadout Flare must be operated at all times when emissions may be vented to it.

iv. The Product Loadout Flare must be operated only with the net heating value of the gas being combusted being 11.2 MJ/scm (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:

HT=Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas 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;

Ci=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

Hi=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.

v. The Product Loadout 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 2.2.a.iv above.

2.3. 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 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.

2.4. NSPS Subpart Kb - Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction or Modification Commenced after July 23, 1984

The permittee must comply with all applicable provisions of 40 CFR Subpart Kb, including but not limited to the following, for each affected storage vessel (TK6101, TK6102, TK6114). Note – refer to 40 CFR Subpart Kb and/or 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:

40 CFR 60.112b Standard for volatile organic compounds (VOC)

a. 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 0.75 psia but <11.11 psia or vessels ≥19,813 gallons but <39,890 gallons and containing a VOL with maximum true vapor pressure of at least 4.00 psia but <11.11 psia) as follows:

i. Each storage vessel must have a fixed roof in combination with an internal floating roof meeting the following specifications:

(a) 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.

(b) 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:

(1) 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.

(2) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(3) 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.

(c) 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.

(d) 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.

(e) 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.

(f) 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.

(g) 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.

(h) 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.

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

2.5. **NSPS Subpart VV - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry**

The permittee must comply with all applicable provisions and standards of 40 CFR Part 60, Subpart VV including but not limited to the following, (Note – refer to 40 CFR Subpart VV and/or Subpart A for definitions of terminology stated in this condition. The following summarizes the applicable requirements of Subpart VV, but is not intended to supersede the Subpart):

a. 40 CFR § 60.482-1 Standards: General:

i. The permittee must demonstrate compliance with the requirements of [§§60.482–1 through 60.482–10] for all equipment within 180 days of initial startup.

ii. Compliance with Conditions 2.5.a to 2.5.j [§§60.482-1 to 60.482–10] will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in Condition 5.3.a. [§60.485]

iii. Equipment that is in vacuum service is excluded from the requirements of Conditions 2.5.b to 2.5.j [§§60.482–2 to 60.482–10] if it is identified as required in Condition 6.3.a.iv(e) [§60.486(e)(5)]

b. 40 CFR § 60.482-2 Standards: Pumps in light liquid service:

i. Each pump in light liquid service:

(a) shall be monitored monthly to detect leaks by the methods specified in Condition 5.3.a.ii. [§60.485(b)] except as provided in Condition 2.5.a.iii. [§60.482–1(c)] and paragraphs iv, v, and vi of this section.

(b) shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

ii. Leak detection:

(a) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(b) If there are indications of liquids dripping from the pump seal, a leak is detected.

iii. Leak repair:

(a) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in Condition 2.5.i [§60.482–9].

(b) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

iv. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (i) above, provided the following requirements are met:

(a) Each dual mechanical seal system is:

(1) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(2) Equipment with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of Condition 2.5.j [§60.482–10]; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(b) The barrier fluid system is in heavy liquid service or is not in VOC service.

(c) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(d) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(e) Each sensor as described in paragraph (c) above is:

(1) checked daily or is equipped with an audible alarm, and

(2) the permittee determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) Detected leaks:

(1) If there are indications of liquids dripping from the pump seal or the sensor indicates failure of the seal system, the barrier fluid system, or both based on the criterion determined in paragraph (e) (2) above, a leak is detected.

(2) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in Condition 2.5.i [§60.482–9].

(3) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

v. Any pump that is designated, as described in Conditions 6.3.a.v(a) and 6.3.a.v(b) [§60.486(e)(1) and (2)], for no detectable emission, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs i, iii, and iv of this section if the pump:

(a) Has no externally actuated shaft penetrating the pump housing,

(b) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in Condition 5.3.a.iii [§60.485(c)], and

(c) Is tested for compliance with paragraph (b) of this section initially upon designation, annually, and at other times requested by the Administrator.

vi. If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of Condition 2.5.j [§60.482–10], it is exempt from paragraphs i through v of this section.

vii. Any pump that is designated, as described in Condition 6.3.a.iv(a) [§60.486(f)(1)], as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs i and iv(d) through iv(f) of this section if:

(a) The permittee demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph i of this section; and

(b) The permittee has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph iii of this section if a leak is detected.

c. 40 CFR § 60.482-3 Standards: Compressors:

i. Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere [except as provided in §60.482–1(c)], and paragraph viii and ix of this section.

ii. Each compressor seal system as required in paragraph i shall be:

(a) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(b) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of Condition 2.5.j [§60.482–10]; or

(c) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

iii. The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

iv. Each barrier fluid system as described in paragraph i shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

v. Each sensor as required in paragraph iv:

(a) shall be checked daily or shall be equipped with an audible alarm.

(b) The permittee shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

vi. If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph v(b) , a leak is detected.

vii. When a leak is detected:

(a) it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in Condition 2.5.i [§60.482–9].

(b) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

viii. A compressor is exempt from the requirements of paragraphs i and ii of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of Condition 2.5.j [§60.482–10], except as provided in paragraph ix of this section.

ix. Any compressor that is designated, as described in Conditions 6.3.a.iv(a) and (b) [§60.486(e) (1) and (2)], for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs i–ix if the compressor:

(a) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in Condition 5.3.a.iii [§60.485(c)]; and

(b) Is tested for compliance with paragraph (a) of this section initially upon designation, annually, and at other times requested by the Administrator.

d. 40 CFR § 60.482-4 Standards: Pressure relief devices in gas/vapor service

i. Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in Condition 5.3.a.iii [§60.485(c)].

ii. After each pressure release:

(a) the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in Condition 2.5.i [§60.482–9].

(b) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in Condition 5.3.a.iii [§60.485(c)].

iii. Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in Condition 2.5.j [§60.482–10] is exempted from the requirements of paragraphs i and ii of this section.

iv. Exemptions:

(a) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs i and ii of this section, provided the permittee complies with the requirements in paragraph (b) of this section.

(b) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in Condition 2.5.i [§60.482–9].

e. 40 CFR § 60.482-5 Standards: Sampling connection systems

i. Each sampling connection system shall be equipped with a closed-purged, closed-loop, or closed-vent system [except as provided in §60.482–1(c)]. Gases displaced during filling of the sample container are not required to be collected or captured.

ii. Each closed-purge, closed-loop, or closed-vent system as required in paragraph i. of this section shall comply with the requirements specified in paragraphs (a) through (d) of this section:

(a) Return the purged process fluid directly to the process line; or

(b) Collect and recycle the purged process fluid to a process; or

(c) Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of Condition 2.5.j [§60.482–10]; or

(d) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(1) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to, and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(2) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266; or

(3) A facility permitted, licensed, or registered by a State to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261.

iii. In situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs i and ii of this section.

f. 40 CFR §60.482-6 Standards: Open-ended valves or lines

i. Each open-ended valve or line:

(a) shall be equipped with a cap, blind flange, plug, or a second valve [except as provided in §60.482–1(c)].

(b) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

ii. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

iii. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph i at all other times.

iv. Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs i, ii, and iii of this section.

v. Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs i through iii of this section are exempt from the requirements of paragraphs i through iii of this section.

g. 40 CFR §60.482-7 Standards: Valves in gas/vapor service and in light liquid service

i. Each valve shall be monitored monthly to detect leaks by the methods specified in Condition 5.3.a.ii [§60.485(b)] and shall comply with paragraphs ii through v, except as provided in paragraphs vi, vii, and viii, Conditions 2.5.k and l [§60.483–1, 2], and as provided in Condition 2.5.a.iii [§60.482–1(c)].

ii. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

iii. Leak detection frequency:

(a) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(b) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

iv. When a leak is detected:

(a) it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in Condition 2.5.i [§60.482–9].

(b) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

v. First attempts at repair include, but are not limited to, the following best practices where practicable:

(a) Tightening of bonnet bolts;

(b) Replacement of bonnet bolts;

(c) Tightening of packing gland nuts;

(d) Injection of lubricant into lubricated packing.

vi. Any valve that is designated, as described in Condition 6.3.a.iv(b) [§60.486(e)(2)], for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph i of this section if the valve:

(a) Has no external actuating mechanism in contact with the process fluid,

(b) Is operated with emissions less than 500 ppm above background as determined by the method specified in Condition 5.3.a.iii [§60.485(c)], and

(c) Is tested for compliance with paragraph (b) of this section initially upon designation, annually, and at other times requested by the Administrator.

vii. Any valve that is designated, as described in Condition 6.3.a.v(a) [§60.486(f)(1)], as an unsafe-to-monitor valve, is exempt from the requirements of paragraph i if:

(a) The permittee demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph i, and

(b) The permittee adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

viii. Any valve that is designated, as described in Condition 6.3.a.v(b) [§60.486(f)(2)], as a difficult-to-monitor valve, is exempt from the requirements of paragraph i if:

(a) The permittee demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(b) The permittee designates less than 3.0 percent of the total number of valves as difficult-to-monitor, and

(c) The permittee follows a written plan that requires monitoring of the valve at least once per calendar year.

h. 40 CFR § 60.482-8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors

i. If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors, the permittee shall follow either one of the following procedures:

(a) The permittee shall monitor the equipment within 5 days by the method specified in [§60.485(b)] and shall comply with the requirements of paragraphs ii through iv of this section.

(b) The permittee shall eliminate the visual, audible, olfactory, or other indication of a potential leak.

ii. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

iii. When a leak is detected:

(a) it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in Condition 2.5.i [§60.482–9].

(b) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

iv. First attempts at repair include, but are not limited to, the best practices described under Condition 2.5.g.v.

i. 40 CFR§ 60.482-9 Standards: Delay of repair

i. Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.

ii. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

iii. Delay of repair for valves will be allowed if:

(a) The permittee demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(b) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with Condition 2.5.j [§60.482–10].

iv. Delay of repair for pumps will be allowed if:

(a) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(b) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

v. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

j. 40 CFR § 60.482-10 Standards: Closed vent systems and control devices.

i. The permittee must comply with the provisions of this section for all closed vent systems and control devices used to comply with provisions of this subpart.

ii. Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, whichever is less stringent.

iii. Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

iv. Flares used to comply with this subpart shall comply with the requirements of §60.18.

v. Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

vi. Except as provided in paragraphs vii through ix of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (a) and (b) below:

(a) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (1) and (2) below:

(1) Conduct an initial inspection according to the procedures in [§60.485(b)]; and

(2) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(b) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(1) Conduct an initial inspection according to the procedures in [§60.485(b)]; and

(2) Conduct annual inspections according to the procedures in [§60.485(b)].

vii. Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph viii of this section.

(a) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(b) Repair shall be completed no later than 15 calendar days after the leak is detected.

viii. Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

ix. If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs vi(a) (1) and vi(b) of this section.

x. Any parts of the closed vent system that are designated, as described in paragraph xii(a) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs vi(a) (1) and vi(b) of this section if they comply with the requirements specified in paragraphs (a) and (b) of this section:

(a) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs vi(a) (1) or vi(b) of this section; and

(b) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

xi. Any parts of the closed vent system that are designated, as described in paragraph xii(b) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs vi(a) (1) and vi(b) of this section if they comply with the requirements specified in paragraphs (a) through (c) below:

(a) The permittee determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(b) The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(c) The permittee has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

xii. The permittee shall record the information specified in paragraphs (a) through (e) of this section:

(a) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(b) For each inspection during which a leak is detected, a record of the information specified in [§60.486(c)].

(c) For each inspection conducted in accordance with [§60.485(b)] during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(d) For each visual inspection conducted in accordance with paragraph vi(a) (2) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(e) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

xiii. Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

k. 40 CFR § 60.483-1 Alternative standards for valves—allowable percentage of valves leaking

i. An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

ii. The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(a) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487(d).

(b) A performance test as specified in paragraph iii of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(c) If a valve leak is detected, it shall be repaired in accordance with Conditions 2.5.g.iv and 2.5.g.v [§60.482–7(d) and (e)].

iii. Performance tests shall be conducted in the following manner:

(a) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in [§60.485(b)].

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

iv. Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent.

l. 40 CFR § 60.483-2 Alternative standards for valves—skip period leak detection and repair

i. The permittee may elect:

(a) to comply with one of the alternative work practices specified in paragraphs ii(b) and ii(c) below.

(b) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in [§60.487(d)].

ii. The permittee must:

(a) comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in Condition 2.5.g [§60.482–7].

(b) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(c) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(d) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in Condition 2.5.g [§60.482–7] but can again elect to use this section.

(e) The percent of valves leaking shall be determined by dividing the sum of valves found leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements of this section.

(f) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

m. 40 CFR § 60.484 Equivalence of means of emission limitation

i. Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

ii. Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(a) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(b) The Administrator will compare test data for the means of emission limitation to test data for the equipment, design, and operational requirements.

(c) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

iii. Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(a) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(b) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(c) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(d) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(e) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (d) .

(f) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

iv. An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

v. Following a request for determination of equivalence:

(a) the Administrator will publish a notice in the Federal Register and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(b) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the Federal Register.

(c) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the Clean Air Act.

vi. Manufacturers of equipment used to control equipment leaks of VOC:

(a) may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(b) The Administrator will make an equivalence determination according to the provisions of paragraphs ii, iii, iv, and v of this section.

2.6. **NSPS Subpart IIII (Emergency Generator Engines)** The permittee must comply with the following operational requirements for the emergency stationary compression ignition RICE EU69, EU70, and EU71:

a. The permittee must operate and maintain EU69, EU70, and EU71 that they achieve the emission standards as required in Condition 1.8 over the entire life of the engines. [40 CFR 60.4206]

b. The permittee must operate and maintain EU69, EU70, and EU71 according to the manufacturer's emission-related written instructions; [40 CFR 60.4211(a)(1)]

c. The permittee must change only those emission-related settings that are permitted by the manufacturer; [40 CFR 60.4211(a)(2)]

d. The permittee must meet the requirements of 40 CFR parts 89, 94 and/or 1068, as applicable; [40 CFR 60.4211(a)(3)]

e. The permittee must operate EU69 and EU70 according to the following requirements. In order for the engines to be considered emergency stationary ICE, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described below, is prohibited. If the permittee does not operate EU69 and EU70 according to the requirements below, the engines will not be considered an emergency engine and must meet all requirements for non-emergency engines. [40 CFR 60.4211(f)]

   i. There is no time limit on the use of EU69 and EU70 in emergency situations. [40 CFR 60.4211(f)(1)]

   ii. The permittee may operate EU69 and EU70 for any combination of the purposes specified in this Condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by this Condition counts as part of the 100 hours per calendar year allowed by this Condition. [40 CFR 60.4211(f)(2)]

      (a) EU69 and EU70 may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the permittee maintains records indicating that federal, state, or local standards require maintenance and testing of EU69 and EU70 beyond 100 hours per calendar year. [40 CFR 60.4211(f)(2)(i)]

iii. EU69 and EU70 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 2.6.e.ii. 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. [40 CFR 60.4211(f)(3)(i)]

f. If the permittee does not install, configure, operate, and maintain EU69 and EU70 according to the manufacturer's emission-related written instructions, or emission-related settings are changed in a way that is not permitted by the manufacturer, the permittee must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, the permittee must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after emission-related settings are changed in a way that is not permitted by the manufacturer. [40 CFR 60.4211(g)(2)]

2.7. **NESHAP Subpart ZZZZ (Emergency Generator Engines)** The permittee must comply with applicable requirements of 40 CFR 60 Subpart IIII for EU69, EU70, and EU71. [40 CFR 63.6590(c)]

2.8. **Limitation – Crude Oil Transloading** The permittee is prohibited from performing the transloading of crude oil under this permit. Crude oil transloading must be conducted under the authority of a separate ACDP.

2.9. **Approved Construction Activities** The permittee is pre-approved to make either of the following changes:

a. Construct and operate two new 4.5 million gallon internal floating roof storage tanks (TK6121 and TK6122)and operate two existing 3.8 million gallon internal floating roof tanks (TK6105 and TK6106) for storage of ethanol produced at the facility; OR

b. Refurbish and operate three 50,000-barrel (2,087,400 gallon) internal floating roof tanks (TK6201, TK6202, TK6203) and one 250,000-barrel (11,289,600 gallon) internal floating roof tank (TK6205) located at the adjacent Portland General Electric tank farm.

3.0 OPERATION AND MAINTENANCE REQUIREMENTS

3.1. **Scrubber Operation** The permittee must observe the following scrubber operation and maintenance requirements for the distillation vent scrubber (CE13) and the fermentation vent (CO_2) scrubber (CE14):

a. Each scrubber must be equipped with devices capable of continuously monitoring and recording the following operating parameters:

i. Scrubbing water temperature

ii. Scrubbing water flow rate

iii. Scrubber differential pressure

b. The scrubbing water temperature is to be determined based upon a three-hour rolling average of hourly temperatures.

i. When scrubbing water temperature is at or below 57°F, or the average level observed during the most recent DEQ approved source test, the permittee may use the demonstrated controlled VOC and HAP emission factors in Condition 12.0.

ii. When scrubbing water temperature is above 57°F, or the average level observed during the most recent DEQ approved source test, the permittee must use the reduced VOC and HAP emission factors in Condition 12.0.

iii. Upon collection of one year of scrubbing water temperature data after issuance of this permit, the permittee may request to have the requirement to continuously monitor scrubbing water temperature removed from the permit. The request must include:

A. A demonstration that the water temperature during performance testing represents the warmest annual water temperatures, and

B. That the tested operating conditions are adequately conservative to ensure compliance with the emission factors in Condition 12.0 of this permit.

c. The scrubbing water flow rates are to be determined based upon a one-hour block average of water flow rates for each scrubber.

d. Scrubbing water flow rate in the distillation scrubber must not drop below 49.9 gallons per minute or the average level observed during the most recent DEQ approved source test.

e. Scrubbing water flow rate in the fermentation scrubber must not drop below 74.5 gallons per minute or the average level observed during the most recent DEQ approved source test.

f. Chemical addition flow rate to the distillation scrubber must not drop below 1.40 gallons per hour or the average level observed during the most recent DEQ approved source test. The chemical addition flow rate and type of chemical added shall be measured and recorded daily.

g. Chemical addition flow rate to the fermentation scrubber must not drop below the average level observed during the most recent DEQ approved source test. The chemical addition flow rate and type of chemical added shall be measured and recorded daily. As of permit issuance, the fermentation scrubber was not tested with chemical addition.

3.2. **Baghouse/ Multi-clone/ Filter Operation and maintenance**

The permittee must observe the following baghouse/multiclone/filter operation and maintenance requirements:

a. Each baghouse, multiclone, and vent filter must be equipped with an operational pressure differential indicator.

b. The permittee must monitor and record the pressure differential of each baghouse, multiclone, and vent filter at least once per operating day.

c. The permittee must post the following operating differential pressure ranges, those observed during the most recent DEQ approved source test, or the design specifications if testing has not been conducted on each respective fabric filter baghouse, multiclone, and filter at the facility.

i. CE02: Grain (or Corn) Receiving Baghouse No. 2: 0.1" to 5" water

ii. CE07: Surge Bin No. 1 Vent Filters: 0.1" to 5" water

iii. CE08: Surge Bin No. 2 Vent Filters: 0.1" to 5" water

iv. CE09: Hammermill Baghouse No. 1: 0.1" to 5" water

v. CE10: Hammermill Baghouse No. 2: 0.1" to 5" water

vi. CE11: Hammermill Baghouse No. 3: 0.1" to 5" water

vii. CE12: Hammermill Baghouse No. 4: 0.1” to 5” water

viii. CE15: DDGS Reclaim Baghouse: 0.1” to 5” water

ix. CE16: DDGS Loadout Baghouse No. 1: 0.1” to 5” water

x. CE17: DDGS Loadout Baghouse No. 2: 0.1” to 5” water

xi. CE18: DDGS Loadout Baghouse No. 3: 0.1” to 5” water

xii. CE23: Grain (or Corn) Storage Bin No. 1 and 2 Baghouse: 0.1” to 5” water

xiii. CE24: Silo Reclaim Elevator Vent Filter: 0.1” to 5” water

xiv. CE25: DDGS Transfer Vent Filter: 0.1” to 5” water

xv. CE26: DDGS Bulkweigher Vent Filter: 0.1” to 5” water

xvi. CE27: DDGS Loadout Elevator Baghouse: 0.1” to 5” water

xvii. S10: Wheat Receiving and Transfer Baghouse: 0.1” to 5” water

xviii. S32: Wheat Milling Baghouse No. 1: 0.1” to 5” water

xix. S33: Wheat Milling Baghouse No. 2: 0.1” to 5” water

xx. S43: Gluten Packaging Baghouse: 0.1” to 5” water

xxi. S51: Gluten Dryer A Baghouse: 0.1” to 5” water

xxii. S52: Gluten Dryer B Baghouse: 0.1” to 5” water

d. The permittee must investigate and commence corrective action measures immediately after an observed excursion of the operating differential pressure range identified in Condition 3.2.c.

e. When replacing vent filters or fabric filter bags in any baghouse, the permittee may not substitute a bag or filter with lower control efficiency specifications than what was specified in the original system design specifications.

f. The permittee must keep readily accessible records documenting the original engineering design specifications for all baghouses, multiclones, filters, and associated fabric filter bags at the facility. These records must be kept for the life of the source.

3.3. **Regenerative Thermal Oxidizers (RTO)** At all times while DDGS or gluten is being dried, the permittee must maintain the temperature within the associated RTO(s) as follows:

a. RTO 1 (CE19) must be maintained at a minimum operating temperature of 1685° F (based on a one hour average) for at least a 0.5 second retention time unless an alternate temperature and/or time parameter has been demonstrated and approved by the DEQ as being equal or more effective;

b. RTO 2 (CE20) must be maintained at a minimum operating temperature of 1732° F (based on a one hour average) for at least a 0.5 second retention time unless an alternate temperature and/or time parameter has been demonstrated and approved by the DEQ as being equal or more effective;

c. If, based upon a one hour average, the operating temperature drops to more than 25°F below the temperature set point above, the permittee must immediately take action to return the temperature to the established operating range. The temperature falling below this emission action level is not a violation of this permit condition, however, it is a violation of this permit condition if the permittee fails to immediately take action to correct the operating temperature after it's fallen below the range.

3.4. **Device/ Process** The permittee must control Emission Units as described in the table below:

EP ID	Emission Unit(s)	Control Device
EP02	EU04: Grain Rail Dump Pit/Auger No. 2	CE02: Grain (or Corn) Receiving Baghouse No. 2
	EU05: Grain Conveyor No. 2	
	EU06: Grain Elevator No. 2	
EP07	EU15: Surge Bin No. 1	CE07: Surge Bin No. 1 Vent Filters
EP08	EU17: Surge Bin No. 2	CE08: Surge Bin No. 2 Vent Filters
EP07 or EP08	EU16: Scalper No. 1	CE07 or CE08
EP09	EU19: Hammermill No. 1	CE09: Hammermill Baghouse No. 1
EP10	EU20: Hammermill No. 2	CE10: Hammermill Baghouse No. 2
EP11	EU21: Hammermill No. 3	CE11: Hammermill Baghouse No. 3
EP12	EU22: Hammermill No. 4	CE12: Hammermill Baghouse No. 4

EP13	EU23: Slurry Tank	CE13: Distillation Process Scrubber
	EU24: Liquefaction Tank No. 1	
	EU25: Liquefaction Tank No. 2	
	EU26: Process Condensate Tank	
	EU27: Beer Column	
	EU28: Stripper	
	EU29: Rectifier	
	EU30: Evaporators	
	EU31: Whole Stillage Tank	
	EU32: Thin Stillage Tank	
	EU33: Syrup Tank	
	EU34: Centrifuge No. 1	
	EU35: Centrifuge No. 2	
	EU36: Centrifuge No. 3	
	EU37: Centrifuge No. 4	
	EU38: Molecular Sieve No. 1	
	EU39: Molecular Sieve No. 2	
	EU40: 200 Proof Condenser	
EP14	EU41: Yeast Tank No. 1	CE14: Fermentation (CO_2) Scrubber
	EU42: Yeast Tank No. 2	
	EU43: Fermenter No. 1	
	EU44: Fermenter No. 2	
	EU45: Fermenter No. 3	
	EU46: Fermenter No. 4	
	EU47: Fermenter No. 5	
	EU48: Fermenter No. 6	
	EU49: Fermenter No. 7	
	EU50: Beer Well	
EP15	EU51: DDGS Reclaim	CE15: DDGS Reclaim Baghouse
	EU76: Bulk Weigher Bucket Elevator	
EP16	EU52: DDGS Truck Load Spout No. 1	CE16: DDGS Loadout Baghouse No. 1

EP17	EU53: DDGS Truck Load Spout No. 2	CE17: DDGS Loadout Baghouse No. 2
EP18	EU54: DDGS Rail Loadout Spout	CE18: DDGS Loadout Baghouse No. 3
EP16, EP17, or EP18	EU79: DDGS Loadout Draft Conveyors 1 & 2	CE16, CE17, or CE18
EP19	EU55: DDGS Dryer No. 1	CE19: Regenerative Thermal Oxidizer No. 1
	EU56: DDGS Cooler No. 1	
	DRYERA: Gluten Dryer A	S51: Gluten Dryer A Baghouse, EU55, and CE19 in series*
	BURNERA: Gluten Dryer A Burner	
EP20	EU58: DDGS Dryer No. 2	CE20: Regenerative Thermal Oxidizer No. 2
	EU59: DDGS Cooler No. 2	
	DRYERA: Gluten Dryer A	S51: Gluten Dryer A Baghouse, EU58, and CE20 in series*
	BURNERA: Gluten Dryer A Burner	
*DRYERA must be routed to S51, EU55, and CE19 in series **OR** S51, EU58, and CE20 in series.		
EP21	EU61: Ethanol Loadout (Truck)	CE21: Product Loadout Flare (Truck/Rail)
	EU62: Ethanol Loadout (Rail)	
EP22	EU64: Marine Vessel Loadout	CE22: Vapor Recovery Unit
EP35		CE28: Vapor Combustion Unit
EP30	EU07: Transfer Conveyor No. 1	CE23: Grain (or Corn) Storage Bin No. 1 and 2 Baghouse
	EU08: Grain (or Corn) Storage Silo No. 1	
	EU10: Grain (or Corn) Storage Silo No. 2	
EP31	EU72: Storage Reclaim Belt Conveyor	CE24: Silo Reclaim Elevator Vent Filter
	EU73: Grain Elevator No. 3	
EP32	EU74: DDGS Transfer Conveyors	CE25: DDGS Transfer Vent Filter
	EU75: DDGs Transfer Bucket Elevator	
EP33	EU77: Bulkweigher	CE26: DDGS Bulkweigher Vent Filter
EP34	EU78: DDGS Bucket Elevator	CE27: DDGS Loadout Elevator Baghouse

S52	DRYERB: Gluten Dryer B	S52: Gluten Dryer B Baghouse
	BURNERB: Gluten Dryer B Burner	
S10	Wheat Receiving, Wheat Transfer	S10: Wheat Receiving and Transfer Baghouse
S32	Wheat Milling	S32: Wheat Milling Baghouse No. 1
S33	Wheat Milling	S33: Wheat Milling Baghouse No. 2
S43	Gluten Packaging	S43: Gluten Packaging Baghouse

3.5. **Fugitive Emission Control Plan** The permittee must submit a fugitive emission control plan within 60 days of request by DEQ. The plan must be implemented whenever fugitive emissions leave the property for more than 18 seconds in a six-minute period. The plan must be kept on site and be made available upon request.

3.6. **Standard Procedures for Marine Vessel Loading Events** During each marine vessel loading event the permittee must follow the standard procedures titled "Barge Loading," "Completion of Barge Loading" and "PIC Dock Operations Finishing a Barge," provided to DEQ under ACDP 05-0023-ST-01. This information must be re-submitted to DEQ any time modifications are made to procedures affecting the permittee's Vapor Collection System.

3.7. **Vapor Recovery Unit O&M** The permittee must operate and maintain the Vapor Recovery Unit (CE22) in accordance with manufacturer's specifications while the unit is the in-service VOC abatement device for marine vessel loading. A copy of the manufacturer's O&M specifications must be maintained on-site and available for inspection and reference.

3.8. **Vapor Combustion Unit O&M** The permittee must operate and maintain the Vapor Combustion Unit (CE28) in accordance with manufacturer's specifications while the unit is the in-service VOC abatement device for marine vessel loading. A copy of the manufacturer's O&M specifications must be maintained on-site and available for inspection and reference.

4.0 PLANT SITE EMISSION LIMITS

4.1. **Plant Site Emission Limits (PSEL)** The permittee must not cause or allow plant site emissions to exceed the following:

Pollutant	Limit	Units
PM	99	tons per year
PM_{10}	99	tons per year
$PM_{2.5}$	97	tons per year
SO_2	39	tons per year
NO_X	99	tons per year
CO	99	tons per year
VOC	90	tons per year
GHGs (CO_2e)	665,800	tons per year

4.2. **HAP PSEL** The permittee must not cause or allow plant site emissions from sources 05-0006 and 05-0023 combined to exceed 9 tons per year of any individual HAP.

4.3. **Annual Period** The annual plant site emissions limits apply to any 12-consecutive calendar month period.

5.0 COMPLIANCE DEMONSTRATION AND SOURCE TESTING

5.1. **NSPS Subpart Dc Testing Requirements** There are no applicable testing requirements for Subpart Dc affected facilities that are fired exclusively with natural gas.

5.2. **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. § 60.113b Testing and procedures.

i. After installing the control equipment required to meet Condition 2.4.a.i[§60.112b(a)(1)] (permanently affixed roof and internal floating roof), the permittee must:

(a) 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.

(b) 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 7.3.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.

(c) For vessels equipped with a double-seal system as specified in Condition 2.4.a.i(b)(2) [§60.112b(a)(1)(ii)(B)]:

(1) Visually inspect the vessel as specified in paragraph (d) of this section at least every 5 years; or

(2) Visually inspect the vessel as specified in paragraph (b) of this section.

(d) 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 (b) and (c) (2) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (c) (1) of this section.

(e) Notify the DEQ in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a) and (d) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (d) 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.

5.3. **NSPS Subpart VV Testing Requirements**

The permittee must perform testing in accordance with the provisions of 40 CFR § 60.485.

a. § 60.485 Test methods and procedures

i. In conducting the performance tests required in Subpart A §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

ii. The owner or operator shall determine compliance with the standards in Conditions 2.5.a through j, 2.5.k through l, and 2.5.m [§§60.482, 60.483, and 60.484] as follows:

(a) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used:

(1) Zero air (less than 10 ppm of hydrocarbon in air); and

(2) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

iii. The permittee shall determine compliance with the no detectable emission standards in Conditions 2.5.b.v, 2.5.c.ix, 2.5.d, 2.5.g.vi, and 2.5.j.v [§§60.482–2(e), 60.482–3(i), 60.482–4, 60.482–7(f), and 60.482–10(e)] as follows:

(a) The requirements of paragraph ii above shall apply.

(b) Method 21 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

iv. The permittee shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(a) Procedures that conform to the general methods in ASTM E260–73, 91, or 96, E168–67, 77, or 92, E169–63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(b) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(c) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (a) and (b) of this section shall be used to resolve the disagreement.

v. The permittee shall demonstrate that an equipment is in light liquid service by showing that all the following conditions apply:

(a) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.

(b) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(c) The fluid is a liquid at operating conditions.

vi. Samples used in conjunction with paragraphs iv and v of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

5.4. **Source Testing Requirements**

The permittee must perform the following source tests within 60 days of achieving the maximum production rate at which the facility will be operated, but not later than 180 days after startup following permit issuance, unless an extension is approved by the DEQ:

a. The permittee must conduct a source test of the Grain Receiving baghouse stack (EP02), Wheat Receiving and Transferring baghouse stack (S10), Wheat milling baghouse stacks (S32 & S33), Gluten Dryer B baghouse stack (S52), and Gluten Packaging baghouse stack (S43) to demonstrate that their particulate (PM) emissions are in compliance with Condition 1.2 and to verify emission factors used to determine compliance with the PSELs of Condition 4.1. The following parameters must be monitored and recorded during the source tests:

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

ii. quantity of material processed and rate in tons/hr;

iii. pressure drop across the baghouse;

iv. grain loading in gr/dscf;

v. report emission rate in lbs/hr and lbs/ton of material processed.

b. The permittee must conduct a source test of the Fermentation (CO_2) Vent Scrubber stack (EP14) exhaust gas to verify wheat and corn based ethanol emission factors used to determine compliance with the PSELs of Condition 4.1. Exhaust gas at the outlet of the scrubber is to be tested for VOC, acetaldehyde, acrolein, formaldehyde, and methanol emissions. The following parameters must be monitored and recorded during the source test:

i. Type (i.e., corn or wheat) and quantity of mash charged to the fermentation tanks;

ii. the pressure drop across the scrubber;

iii. flow rate of scrubber water;

iv. temperature of scrubber water;

v. quantity and type of chemical addition;

vi. beer production rate of fermentation process in gal/hr;

vii. 200 proof ethanol production rate of the process in gal/hr;

viii. the source test report must identify the mass emission rate measured during the test expressed lbs/hr and in lbs/10^3 gallons EtOH produced.

ix. the source test report must provide a calculation of the mass emission rate of acetaldehyde, acrolein, formaldehyde, and methanol measured during the test expressed lbs/hr and in lbs/10^3 gallons EtOH produced.

c. The permittee must conduct a source test of the Distillation Vent Scrubber stack (EP13) exhaust gas to verify wheat and corn based ethanol emission factors used to determine compliance with the PSELs of Condition 4.1. Exhaust gas at the outlet of the scrubber is to be tested for VOC emissions, acetaldehyde, acrolein, formaldehyde, and methanol emissions. The following parameters must be monitored and recorded during the source test:

i. Type (i.e., corn or wheat) and quantity of beer distilled;

ii. the pressure drop across the scrubber;

iii. flow rate of scrubber water;

iv. temperature of scrubber water;

v. ethanol production rate of distillation process in gal/hr;

vi. quantity and type of chemical addition;

vii. 200 proof ethanol production rate of the process in gal/hr;

viii. the source test report identify the mass emission rate measured during the test expressed lbs/hr and in lbs/10^3 gallons EtOH produced.

ix. the source test report must provide a calculation of the mass emission rate of acetaldehyde, acrolein, formaldehyde, and methanol measured during the test expressed lbs/hr and in lbs/10^3 gallons EtOH produced.

d. The permittee must conduct a source test of the exhaust gas of DDGS Dryer No. 1/regenerative thermal oxidizer (RTO) No. 1 (EP19) while receiving exhaust from the Gluten Dryer A Baghouse (S51) and DDGS Dryer No. 2/RTO No. 2 (EP20) to demonstrate that their particulate (PM) emissions are in compliance with Condition 1.2 and to verify emission factors used to determine compliance with the PSELs of Condition 4.1. Stack exhaust emissions must be tested for PM, NO_X, CO, VOC, and acetaldehyde emissions. During the source test the following parameters must be monitored and recorded:

   i. DDGS production rates in tons/hr;

   ii. Wheat gluten production rate in tons/hr;

   iii. thermal oxidizer operating temperature;

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

   v. concentrations and emission rates of PM, NO_X, CO and VOCs; with pollutant mass emission rates expressed as lbs/hour when processing wheat gluten and DDGS;

   vi. concentrations and emission rates of PM, NO_X, CO and VOCs; with pollutant mass emission rates expressed as lbs/hour and in lbs/ton DDGS when processing only DDGS;

   vii. the source test report must provide a calculation of the mass emission rate of acetaldehyde measured during the test expressed as lbs/hr when processing wheat gluten and DDGS.

   viii. the source test report must provide a calculation of the mass emission rate of acetaldehyde measured during the test expressed as lbs/hr and in lbs/ton DDGS when processing only DDGS.

e. The permittee must conduct a source test of the exhaust gas of Gluten Dryer B Baghouse (S52) to demonstrate that their particulate (PM) emissions are in compliance with Condition 1.2 and to verify emission factors used to determine compliance with the PSELs of Condition 4.1. Stack exhaust emissions must be tested for PM, VOC, and acetaldehyde emissions. During the source test the following parameters must be monitored and recorded:

   i. wheat gluten production rate in tons/hr;

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

iii. concentrations and emission rates of PM, VOCs and acetaldehyde; with pollutant mass emission rates expressed as lbs/hour and lbs/ton wheat gluten; and

iv. the source test report must provide a calculation of the mass emission rate of acetaldehyde measured during the test expressed as lbs/hr and lbs/ton wheat gluten.

f. The permittee must conduct a performance test for the Rail and Truck Product Loadout Flare (EP21) as specified in Conditions 2.1.b.

g. The permittee must conduct a source test of stack exhaust gas of one of the four Utility Boilers (EP23, 24, 25, or 26) to verify emission factors used to determine compliance with the PSELs of Condition 4.1. Stack exhaust emissions must be tested for NO_X and CO emissions. During the source test the following parameters must be monitored and recorded:

i. Boiler steaming rate in lbs steam/hour;

ii. ft^3 natural gas combusted;

iii. opacity readings on the exhaust stack following the procedures of EPA Method 9;

iv. concentrations and emission rates of NO_X and CO; with pollutant mass emission rates expressed as lbs/hour and lbs/$MMft^3$ natural gas combusted.

h. The permittee must conduct a source test of the Marine Vessel Loadout VCU (EP35) to verify emission factors used to determine compliance with the PSELs of Condition 4.1. Stack exhaust emissions must be tested for VOC emissions (as mass) and acetaldehyde.

i. If the permittee controls Marine Vessel Loadout emissions with the VRU (EP22), the permittee must conduct a source test of the VRU (EP22) within 6 months of restarting VRU operations to verify emission factors used to determine compliance with the PSELs of Condition 4.1. Stack exhaust emissions must be tested for VOC emissions (as mass) and acetaldehyde.

j. A source test of the VRU or VCU conducted for Source 05-0023 when transloading ethanol will fulfill the requirement to conduct a source test for the EU under this permit.

k. During the source test the permittee must monitor and record the following parameters:

i. Ethanol loading rate in gal/hr;

ii. Carbon bed cycle time for the VRU;

iii. Combustion chamber temperature for the VCU;

iv. Concentration and emission rate of VOC and acetaldehyde with pollutant mass emission rates expressed as lbs/hour and lbs/10^3 gallons loaded.

l. All tests must be conducted in accordance with DEQ's Source Sampling Manual and the approved pretest plan. The pretest plan must be submitted at least 30 days in advance and approved by the Regional Source Test Coordinator. Test data and results must be submitted for review to the Regional Source Test Coordinator within 60 days unless otherwise approved in the pretest plan.

Tested Pollutant	**Reference Test Method***
PM	EPA Method 5 Oregon Method 5 or 8 (high vol)
NO_X	EPA Method 7E
CO	EPA Method 10 Note: Method 10 shall be modified to include improved quality assurance procedures of Method 6C - contact DEQ's Source Test Coordinator for details.
VOC	EPA Method 18, 25, 25A, or 320 (Method 18 based on NCASI Method CI/WP-98.01) • Method must be optimized/calibrated to ethanol
Opacity	EPA Method 9

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

m. 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.

n. The permittee must perform Stack tests for the Fermentation and Distillation Scrubbers (EP14 and EP13):

i. During the 3rd calendar quarter (i.e., July, August, or September); and

ii. The test must take place over one full fermentation cycle.

5.5. **PSEL Compliance Monitoring** The permittee must demonstrate compliance with the PSEL for each 12-consecutive calendar month period based on the following calculation for each pollutant:

$$E = \Sigma(EF \times P)/2000 \text{ lbs}$$

where:

E = pollutant emissions (ton/yr);
EF = pollutant emission factor (see Condition 12.0);
P = process parameter (see Condition 12.0)

5.6. **Emission Factors** The permittee must use the default emission factors provided in Condition 12.0 for calculating pollutant emissions, unless alternative emission factors are approved by DEQ. The permittee may request in writing 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.

6.0 RECORDKEEPING REQUIREMENTS

6.1. **NSPS Subpart Dc** The permittee must comply with all applicable recordkeeping requirements of 40 CFR Subpart Dc

a. The permittee must record and maintain records of the amount of natural gas combusted during each operating day; [40 CFR 60.48c(g)(1)]

b. The permittee must record and maintain records of the amount of natural gas 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)]

6.2. **NSPS Subpart Kb** The permittee must comply with all applicable recordkeeping requirements of 40 CFR Subpart Kb:

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 0.51 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. Available data on the storage temperature may be used 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 §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).

   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 §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 2.4.a 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 5.2.a.i(a) , 5.2.a.i(b) , 5.2.a.i(c) , and 5.2.a.i(d) (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).

6.3. **NSPS Subpart VV** The permittee must comply with all applicable recordkeeping requirements of 40 CFR Subpart VV:

a. 40 CFR 60.486 Recordkeeping requirements

i. When each leak is detected as specified in Conditions 2.5.b, 2.5.c, 2.5.g, 2.5.h, and 2.5.l [§§60.482–2, 60.482–3, 60.482–7, 60.482–8, and 60.483–2], the following requirements apply:

(a) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(b) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in Condition 2.5.g.iii [§60.482–7(c)] and no leak has been detected during those 2 months.

(c) The identification on equipment except on a valve, may be removed after it has been repaired.

ii. When each leak is detected as specified in Condition s 2.5.b, 2.5.c, 2.5.g, 2.5.h, and 2.5.l [§§60.482–2, 60.482–3, 60.482–7, 60.482–8, and 60.483–2], the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(a) The instrument and operator identification numbers and the equipment identification number.

(b) The date the leak was detected and the dates of each attempt to repair the leak.

(c) Repair methods applied in each attempt to repair the leak.

(d) "Above 10,000" if the maximum instrument reading measured by the methods specified in Condition 5.3.a.i [§60.485(a)] after each repair attempt is equal to or greater than 10,000 ppm.

(e) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(f) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(g) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(h) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(i) The date of successful repair of the leak.

iii. The following information pertaining to the design requirements for closed vent systems and control devices described in Condition 2.5.j [§60.482–10] shall be recorded and kept in a readily accessible location:

(a) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(b) The dates and descriptions of any changes in the design specifications.

(c) A description of the parameter or parameters monitored, as required in Condition 2.5.j.v [§60.482–10(e)], to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(d) Periods when the closed vent systems and control devices required in Conditions 2.5.b, 2.5.c, 2.5.d, and 2.5.e [§§60.482–2, 60.482–3, 60.482–4, and 60.482–5] are not operated as designed, including periods when a flare pilot light does not have a flame.

(e) Dates of startups and shutdowns of the closed vent systems and control devices required in Conditions 2.5.b, 2.5.c, 2.5.d, and 2.5.e [§§60.482–2, 60.482–3, 60.482–4, and 60.482–5.]

iv. The following information pertaining to all equipment subject to the requirements in Conditions 2.5.a to 2.5.j [§§60.482–1 to 60.482–10] shall be recorded in a log that is kept in a readily accessible location:

(a) A list of identification numbers for equipment subject to the requirements of this subpart.

(b) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of Conditions 2.5.b.v, 2.5.c.ix, and 2.5.g.vi [§§60.482–2(e), 60.482–3(i) and 60.482–7(f)]. The designation of such equipment shall be signed by the owner or operator.

(c) A list of equipment identification numbers for pressure relief devices required to comply with Condition 2.5.d [§60.482–4].

(d) The dates of each compliance test as required in Conditions 2.5.b.v, 2.5.c.ix, 2.5.d, and 2.5.g.vi [§§60.482–2(e), 60.482–3(i), 60.482–4, and 60.482–7(f)].

(1) The background level measured during each compliance test.

(2) The maximum instrument reading measured at the equipment during each compliance test.

(e) A list of identification numbers for equipment in vacuum service.

v. The following information pertaining to all valves subject to the requirements of Conditions 2.5.g.vii and 2.5.g.viii [§60.482–7(g) and (h)] and to all pumps subject to the requirements of Condition 2.5.b.vii [§60.482–2(g)] shall be recorded in a log that is kept in a readily accessible location:

(a) A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.

(b) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

vi. The following information shall be recorded for valves complying with Condition 2.5.1 [§60.483–2]:

(a) A schedule of monitoring.

(b) The percent of valves found leaking during each monitoring period.

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

(a) Design criterion required in Conditions 2.5.b.iv(e) and 2.5.c.v(b) [§§60.482–2(d)(5) and 60.482–3(e)(2)] and explanation of the design criterion; and

(b) Any changes to this criterion and the reasons for the changes.

viii. The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480(d):

(a) An analysis demonstrating the design capacity of the affected facility,

(b) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(c) An analysis demonstrating that equipment is not in VOC service.

ix. Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

x. The provisions of §60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

6.4. **Operation and Maintenance** The permittee must maintain the following records related to the operation and maintenance of the plant and associated air contaminant control devices:

	Monitored Parameter	Monitoring Frequency
a.	Quantity (MM ft^3) of natural gas combusted in the boilers (EU65-68).	Monthly
b.	Quantity (tons) of corn received.	Each Occurrence
c.	Number of hours of operation of the Grain (or Corn) Receiving Baghouse #2 (CE02).	Monthly
d.	Number of hours of operation of the Grain (or Corn) Storage Bins #1 and #2 Baghouse (CE23).	Monthly
e.	Number of hours of operation of the Silo Reclaim Elevator Vent Filter (CE24).	Monthly
f.	Number of hours of operation of the Surge Bin No. 1 Vent Filters (CE07).	Monthly
g.	Number of hours of operation of the Surge Bin No. 2 Vent Filters (CE08).	Monthly
h.	Number of hours of operation of the Hammermill Baghouse #1 (CE09).	Monthly
i.	Number of hours of operation of the Hammermill Baghouse #2 (CE10).	Monthly
j.	Number of hours of operation of the Hammermill Baghouse #3 (CE11).	Monthly
k.	Number of hours of operation of the Hammermill Baghouse #4 (CE12).	Monthly
l.	Number of hours of operation of the DDGS Transfer Vent Filter (CE25).	Monthly
m.	Number of hours of operation of the DDGS Reclaim Baghouse (CE15).	Monthly
n.	Number of hours of operation of the DDGS Bulkweigher Vent Filter (CE26).	Monthly
o.	Number of hours of operation of the DDGS Loadout Elevator Baghouse (CE27).	Monthly
p.	Number of hours of operation of the DDGS Loadout Baghouse No. 1 (CE16).	Monthly
q.	Number of hours of operation of the DDGS Loadout Baghouse No. 2 (CE17).	Monthly

r.	Number of hours of operation of the DDGS Loadout Baghouse No. 3 (CE18).	Monthly
s.	Quantity (tons) of DDGS produced	Monthly
t.	Quantity (gallons) of denaturant received into storage.	Each Receipt
u.	Quantity (gallons) of 200 proof ethanol produced.	Monthly
v.	Quantity (gallons) of denatured ethanol produced.	Monthly
w.	Number of hours of operation of the Product Loadout Flare (CE21).	Monthly
x.	Quantity (gallons) of ethanol loaded onto rail cars.	Monthly
y.	Quantity (gallons) of ethanol loaded onto trucks.	Monthly
z.	Number of hours of operation of the Cooling Towers.	Monthly
aa.	Quantity (tons) of WDGS produced (as final product).	Monthly
bb.	Using the compliance calculation procedures from Condition 5.5., perform a calculation of emissions to demonstrate compliance with the rolling 12-month PSEL and HAP limitations of Condition 4.1. (HAP emission calculations must be performed using source specific HAP emission factors developed from DEQ approved source test results. Once HAP emission factors become available, retroactive HAP emission calculations must be performed beginning with the commencement of plant operation.)	Monthly
cc.	Monitor the temperature of the scrubbing solution in the distillation process scrubber (CE13) to demonstrate compliance with Condition 3.1 (based on 3-hour rolling average).	Continuously During All Hours Of Operation
dd.	Monitor the temperature of the scrubbing solution in the fermentation (CO_2) scrubber (CE14) to demonstrate compliance with Condition 3.1 (based on 3-hour rolling average).	Continuously During All Hours Of Operation
ee.	Monitor the amount of time (in hours) the temperature of the scrubbing solution in the distillation process scrubber (CE13) exceeds the limits of Condition 3.1.	Monthly
ff.	Monitor the amount of time (in hours) the temperature of the scrubbing solution in the fermentation (CO_2) vent scrubber exceeds the limits of Condition 3.1.	Monthly
gg.	Monitor the operating temperature of each thermal oxidizer (CE19 and CE20) to demonstrate compliance with Condition 3.3.	Continuously During All Hours Of Operation
hh.	Quantity (MM ft^3) of natural gas combusted in each fuel combusting unit.	Monthly

ii.	Monitor the Product Loadout Flare (Truck/Rail) (CE21) for presence of a pilot flame.	Continuously During All Hours Of Operation
jj.	Maintain a record of the control efficiency specifications of all fabric filter bags replacement orders.	Each Order Placement or Order Receipt
kk.	Monitor and record the differential operating pressure across each fabric filter baghouse, multiclone, and vent filter control device.	Daily during operation
ll.	Record major maintenance performed on air pollution control equipment.	Each Occurrence
mm.	Record parameters necessary to calculate emissions from Tank roof landings	Each Occurrence
nn.	Quantity (tons) of wheat received	Each Occurrence
oo.	Number of hours of operation of the Wheat Receiving and Transfer Baghouse (S10)	Monthly
pp.	Number of hours of operation of the Wheat Milling Baghouse #1 (S32)	Monthly
qq.	Number of hours of operation of the Wheat Milling Baghouse #2 (S33)	Monthly
rr.	Number of hours of operation of the Gluten Packaging Baghouse (S43)	Monthly
ss.	Number of hours of operation of the Wheat Starch Surge Tank Bin Vent (S40)	Monthly
tt.	Number of hours of operation of the Gluten Surge Tank Bin Vent (S41)	Monthly
uu.	Number of hours of operation of the Wheat Starch Tank Bin Vent (S42)	Monthly
vv.	Number of hours of operation of the Gluten Dryer A Baghouse (S51)	Monthly
ww.	Number of hours of operation of the Gluten Dryer B Baghouse (S52)	Monthly
xx.	Number of hours of operation of the Emergency Use Engines (EUs 69, 70, 71)	Monthly

6.5. **Excess Emissions** The permittee must maintain records of excess emissions 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. If there is an ongoing excess emission caused by an upset or breakdown, the permittee must cease operation of the equipment or facility no later 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).

6.6. **Complaint Log** The permittee must maintain a log of all written complaints and complaints received via telephone that specifically refer to air pollution concerns associated to the permitted facility. The log must include a record of the permittee's actions to investigate the validity of each complaint and a record of actions taken for complaint resolution.

6.7. **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.

7.0 REPORTING REQUIREMENTS

7.1. **Excess Emissions** The permittee must notify DEQ of excess emissions events if the excess emission is of a nature that could endanger public health.

a. Such 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 10.0 by email, telephone, facsimile, or in person.

b. If the excess emissions occur during non-business hours, the permittee must notify DEQ by calling the Oregon Emergency Response System (OERS). The current number is 1-800-452-0311.

c. The permittee must also submit follow-up reports when required by DEQ.

7.2. **NSPS Subpart Dc** There are no applicable Subpart Dc specific reporting requirements for affected facilities that are exclusively natural gas fired.

7.3. **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 5.2.a.i(b) 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 5.2.a.i(c) 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 5.2.a.i(c)(2) [§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 §61.112b(a)(1) or §60.113b(a)(3)] and list each repair made.

c. Provide notification to the EPA Administrator and DEQ in writing, in accordance with the criteria stated in Condition 5.2.a.i(e) , prior to the filling or refilling of each storage vessel for which an inspection is required by Conditions 5.2.a.i(a) and 5.2.a.i(d) a.

7.4. **NSPS Subpart VV** The permittee must submit the following Subpart VV specific reports/notifications to the EPA Administrator and DEQ, as applicable:

a. 40 CFR §60.487 Reporting requirements:

i. The permittee shall submit semiannual reports to the EPA Administrator and DEQ beginning six months after the initial startup date.

ii. The initial semiannual report shall include the following information:

(a) Process unit identification.

(b) Number of valves subject to the requirements of Condition 2.5.g [§60.482–7], excluding those valves designated for no detectable emissions under the provisions of Condition 2.5.g.vi [§60.482–7(f)].

(c) Number of pumps subject to the requirements of Condition 2.5.b [§60.482–2], excluding those pumps designated for no detectable emissions under the provisions of Condition 2.5.b.v [§60.482–2(e)] and those pumps complying with Condition 2.5.g.vi [§60.482–2(f)].

(d) Number of compressors subject to the requirements of Condition 2.5.c [§60.482–3], excluding those compressors designated for no detectable emissions under the provisions of Condition 2.5.c.ix [§60.482–3(i)] and those compressors complying with Condition 2.5.c.viii [§60.482–3(h)].

iii. All semiannual reports shall include the following information, summarized from the information in Condition 6.3.a [§60.486]:

(a) Process unit identification.

(b) For each month during the semiannual reporting period,

(1) Number of valves for which leaks were detected as described in Conditions 2.5.g.ii or 2.5.l [§60.482(7)(b) or §60.483–2],

(2) Number of valves for which leaks were not repaired as required in Condition 2.5.g.iv(a) [§60.482–7(d)(1)],

(3) Number of pumps for which leaks were detected as described in Conditions 2.5.b.ii and 2.5.b.iv(f) (1) [§60.482–2(b) and (d)(6)(i)],

(4) Number of pumps for which leaks were not repaired as required in Conditions 2.5.b.iii(a) and 2.5.b.iv(f) (2) [§60.482–2(c)(1) and (d)(6)(ii)],

(5) Number of compressors for which leaks were detected as described in Condition 2.5.c.vi [§60.482–3(f)],

(6) Number of compressors for which leaks were not repaired as required in Condition 2.5.c.vii(a) [§60.482–3(g)(1)], and

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

(c) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(d) Revisions to items reported according to paragraph ii. above if changes have occurred since the initial report or subsequent revisions to the initial report.

iv. If the permittee elects to comply with the provisions of Conditions 2.5.k or 2.5.l [§§60.483–1 or 60.483–2], they shall notify the Administrator and DEQ of the alternative standard selected 90 days before implementing either of the provisions.

v. The permittee shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the EPA Administrator and DEQ of the schedule for the initial performance tests at least 30 days before the initial performance tests.

7.6 Annual Report

For each year this permit is in effect, the permittee must submit to the DEQ by February 15 two (2) copies of the following information for the previous calendar year:

a. A compliance status summary with the conditions of the permit.

b. Plant operating parameters:

i. Quantity (tons) of corn received for processing.

ii. Quantity (MM ft^3) of natural gas combusted in the boilers.

iii. Quantity (MM ft^3) of natural gas combusted facility-wide.

iv. Quantity (tons) of DDGS produced.

v. Quantity (tons) of wetcake produced as final product.

vi. Quantity (gallons) of 200 proof ethanol produced.

vii. Quantity (gallons) of denatured ethanol produced.

viii. Quantity (gallons) of ethanol loaded onto railcars.

ix. Quantity (gallons) of ethanol loaded onto trucks.

x. Quantity (tons) of wheat received for processing.

xi. Quantity (tons) of gluten produced as final product.

c. A summary of the rolling 12-month PSEL and HAP (acetaldehyde) pollutant emission rate calculations determined each month in accordance with Condition 6.4.bb.

d. Records of all planned and unplanned excess emissions events.

e. Summary of complaints relating to air quality received by permittee during the year.

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

g. List major maintenance performed on pollution control equipment.

h. Hours of operation for each emergency use engine (EUs 69, 70, 71).

7.5. **Greenhouse Gas Registration and Reporting** If the calendar year emission rate of greenhouse gases (CO_2e) is greater than or equal to 2,756 tons (2,500 metric tons), the permittee must register and report its greenhouse gas emissions with DEQ in accordance with OAR 340-215.

7.6. **Notice of Change of Ownership or Company Name** The permittee must notify DEQ in writing using a Departmental "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.

7.7. **Construction or Modification Notices** The permittee must notify DEQ in writing using a Departmental "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 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.

8.0 ADMINISTRATIVE REQUIREMENTS

8.1. **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) copies of the application must be submitted to the DEQ Permit Coordinator listed in Condition 10.0.

8.2.	**Permit Modifications**	Application for a modification of this permit must be submitted within **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.

9.0 FEES

9.1.	**Annual Compliance Fee**	The permittee must pay the annual fee specified in OAR 340-216-8020, Table 2, Part 2 for a Standard ACDP on **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 4 of the table will be assessed as appropriate.**
9.2.	**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 3(a) with an application for changing the ownership or the name of the company.
9.3.	**Special Activity Fees**	The permittee must pay the special activity fees specified in OAR 340-216-8020, Table 2, Part 3 (b through k) with an application to modify the permit.

10.0 DEQ CONTACTS / ADDRESSES

10.1.	**Business Office**	The permittee must submit payments for invoices, applications to modify the permit, and any other payments to DEQ's Business Office: Department of Environmental Quality Accounting / Revenue 700 NE Multnomah St., Suite 600 Portland, Oregon 97232
10.2.	**Permit Coordinator**	The permittee must submit all notices and applications that do not include payment to the Northwest Region's Permit Coordinator: 700 NE Multnomah St., Suite 600 Portland, OR 97232
10.3.	**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: Northwest Region 700 NE Multnomah St., Suite 600 Portland, OR 97232

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

11.0 GENERAL CONDITIONS AND DISCLAIMERS

11.1.	**Permitted Activities**	This permit allows the permittee to discharge air contaminants from processes and activities related to the air contaminant source(s) listed on the first page of this permit until this permit expires, is modified, or is revoked.
11.2.	**Other Regulations**	In addition to the specific requirements listed in this permit, the permittee must comply with all other legal requirements enforceable by DEQ.
11.3.	**Conflicting Conditions**	In any instance in which there is an apparent conflict relative to conditions in this permit, the most stringent conditions apply.
11.4.	**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.
11.5.	**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.
11.6.	**Permit Availability**	The permittee must have a copy of the permit available at the facility at all times.
11.7.	**Open Burning**	The permittee may not conduct any open burning except as allowed by OAR 340, division 264.
11.8.	**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.
11.9.	**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.

11.10. **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: i. A timely and complete application for renewal or for an Oregon Title V Operating Permit has been submitted, or ii. 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.
11.11. **Permit Termination, Revocation, or Modification**	DEQ may modify or revoke this permit pursuant to OAR 340-216-0082 and 340-216-0084.

12.0 EMISSION FACTORS

Process and EP ID	Pollutant	Monitoring Parameter (P)	Emissions Factor (EF)	Emissions Factor Units	Reference
Boilers (EP23-EP26)	$PM/PM_{10}/PM_{2.5}$	MM ft^3 of natural gas combusted	2.5	lbs/MM ft^3	DEQ Form AQ-EF05
	SO_2	MM ft^3 of natural gas combusted	1.7	lbs/MM ft^3	DEQ Form AQ-EF05
	NO_X	MM ft^3 of natural gas combusted	22.4	lbs/MM ft^3	Design Spec (06/30/2015 Application)
	CO	MM ft^3 of natural gas combusted	12.2	lbs/MM ft^3	Design Spec (06/30/2015 Application)
	VOC	MM ft^3 of natural gas combusted	5.5	lbs/MM ft^3	DEQ Form AQ-EF05
	GHGs (CO_2e)	MM ft^3 of natural gas combusted	120,142	lbs/MM ft^3	40 CFR 98, Tables A-1, C-1, C-2
Emergency Generator Engine (non-emergency use) (EU 69)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.730	lb/hr	40 CFR 89.112 (NSPS IIII)
	SO_2	Hours of operation	0.027	lb/hr	AP-42 Table 3.4-1
	NO_X	Hours of operation	23.4	lb/hr	40 CFR 89.112 (NSPS IIII)
	CO	Hours of operation	12.8	lb/hr	40 CFR 89.112 (NSPS IIII)
	VOC	Hours of operation	23.4	lb/hr	40 CFR 89.112 (NSPS IIII)
	GHGs (CO_2e)	Hours of operation	2,543	lb/hr	40 CFR 98 Tables A-1, C-1, C-2

Process and EP ID	Pollutant	Monitoring Parameter (P)	Emissions Factor (EF)	Emissions Factor Units	Reference
Emergency Generator Engine (non-emergency use) (EU 70)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.961	lb/hr	40 CFR 89.112 (NSPS IIII)
	SO_2	Hours of operation	0.035	lb/hr	AP-42 Table 3.4-1
	NO_X	Hours of operation	30.8	lb/hr	40 CFR 89.112 (NSPS IIII)
	CO	Hours of operation	16.8	lb/hr	40 CFR 89.112 (NSPS IIII)
	VOC	Hours of operation	30.8	lb/hr	40 CFR 89.112 (NSPS IIII)
	GHGs (CO_2e)	Hours of operation	3,347	lb/hr	40 CFR 98 Tables A-1, C-1, C-2
Fire Pump Engines (non-emergency use) (EU71)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	.355	lb/hr	40 CFR 89.112
	SO_2	Hours of operation	0.820	lb/hr	AP-42 Table 3.3-1
	NO_X	Hours of operation	6.91	lb/hr	40 CFR 89.112
	CO	Hours of operation	2.30	lb/hr	40 CFR 89.112
	VOC	Hours of operation	6.91	lb/hr	40 CFR 89.112
	GHGs (CO_2e)	Hours of operation	458	lb/hr	40 CFR 98 Tables A-1, C-1, C-2
Material Handling:					
Grain Receiving Baghouse #2 (EP02)	$PM/PM_{10}/PM_{2.5}$	Grain Received	1.12E-04	lbs/ton	10/06/2008 Stack Test
Grain Storage Bin #1 and 2 Baghouse (EP30)	$PM/PM_{10}/PM_{2.5}$	Grain Received	4.30E-05	lbs/ton	10/06/2008 Stack Test
Surge Bin #1 Vent Filters (EP07)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.034	lbs/hr	06/30/2015 Application
Surge Bin #2 Vent Filters (EP08)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.034	lbs/hr	06/30/2015 Application
Hammermill Baghouse #1 (EP09)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.26	lbs/hr	06/30/2015 Application
Hammermill Baghouse #2 (EP10)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.26	lbs/hr	06/30/2015 Application
Hammermill Baghouse #3 (EP11)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.26	lbs/hr	06/30/2015 Application
Hammermill Baghouse #4 (EP12)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.26	lbs/hr	06/30/2015 Application

Process and EP ID	Pollutant	Monitoring Parameter (P)	Emissions Factor (EF)	Emissions Factor Units	Reference
DDGS Reclaim Baghouse (EP15)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.11	lbs/hr	06/30/2015 Application
DDGS Loadout Baghouse #1 (EP16)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.086	lbs/hr	06/30/2015 Application
DDGS Loadout Baghouse #2 (EP17)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.086	lbs/hr	06/30/2015 Application
DDGS Loadout Baghouse #3 (EP18)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.13	lbs/hr	06/30/2015 Application
Silo Reclaim Elevator Vent Filter (EP31)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.10	lbs/hr	12/13/2018 e-mail
DDGS Transfer Vent Filter (EP32)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.077	lbs/hr	12/13/2018 e-mail
DDGS Bulkweigher Vent Filter (EP33)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.043	lbs/hr	12/13/2018 e-mail
DDGS Loadout Elevator Baghouse (EP34)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.090	lbs/hr	12/13/2018 e-mail
Wheat Receiving and Transfer Baghouse (S10)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	1.29	lbs/hr	10/05/2018 e-mail
Wheat Milling Baghouse #1 (S32)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	2.14	lbs/hr	10/05/2018 e-mail
Wheat Milling Baghouse #2 (S33)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	2.14	lbs/hr	10/05/2018 e-mail
Gluten Packaging Baghouse (S43)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.64	lbs/hr	10/05/2018 e-mail
Wheat Starch Surge Tank Bin Vent (S40)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.13	lbs/hr	10/05/2018 e-mail
Gluten Surge Tank Bin Vent (S41)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.13	lbs/hr	10/05/2018 e-mail
Wheat Starch Tank Bin Vent (S42)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	0.21	lbs/hr	10/05/2018 e-mail
Uncaptured Emissions from Material Handling:					
Grain Receiving	PM	Tons Grain Received	0.0035	lbs/ton	AP-42 Table 9.9.1-1 with 90% Capture
	PM_{10}	Tons Grain Received	0.00078	lbs/ton	
	$PM_{2.5}$	Tons Grain Received	0.00013	lbs/ton	
DDGS Loadout	PM	Tons DDGS Loaded	0.00033	lbs/ton	AP-42 Table 9.9.1-2 with 90% Capture
	PM_{10}	Tons DDGS Loaded	0.00008	lbs/ton	
	$PM_{2.5}$	Tons DDGS Loaded	0.00008	lbs/ton	

Process and EP ID	Pollutant	Monitoring Parameter (P)	Emissions Factor (EF)	Emissions Factor Units	Reference
DDGS Storage	PM	Tons DDGS Loaded	0.00033	lbs/ton	AP-42 Table 9.9.1-2 with 90% Capture
	PM_{10}	Tons DDGS Loaded	0.00008	lbs/ton	
	$PM_{2.5}$	Tons DDGS Loaded	0.00008	lbs/ton	
Distillation Vent Scrubber (corn based ethanol production) (EP13)	VOC	Gallons of ethanol Produced	0.0121 (99.9% Control)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	1.60 (90% Control)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	16.0 (Uncontrolled)	lbs/10^3 gallons	11/19/08 Test
	Single HAP: Acetaldehyde	Gallons of ethanol Produced	0.00165 (Controlled)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	0.0471 (Uncontrolled)	lbs/10^3 gallons	11/19/08 Test assuming 65% CE
Fermentation (CO_2) Vent Scrubber (corn based ethanol production) (EP14)	VOC	Gallons of ethanol Produced	0.0963 (99.9% Control)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	5.52 (90% Control)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	55.2 (Uncontrolled)	lbs/10^3 gallons	11/19/08 Test
	Single HAP: Acetaldehyde	Gallons of ethanol Produced	0.0304 (Controlled)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	0.0869 (Uncontrolled)	lbs/10^3 gallons	11/19/08 Test assuming 65% CE
	GHGs (CO_2e)	Gallons of ethanol Produced	6.29	lbs/gal	Mass Balance

Process and EP ID	Pollutant	Monitoring Parameter (P)	Emissions Factor (EF)	Emissions Factor Units	Reference
Distillation Vent Scrubber (wheat based ethanol production) (EP13)	VOC	Gallons of ethanol Produced	0.0121 (99.9% Control)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	1.60 (90% Control)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	16.0 (Uncontrolled)	lbs/10^3 gallons	11/19/08 Test
	Single HAP: Acetaldehyde	Gallons of ethanol Produced	0.00165 (Controlled)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	0.0471 (Uncontrolled)	lbs/10^3 gallons	11/19/08 Test assuming 65% CE
Fermentation (CO_2) Vent Scrubber (wheat based ethanol production) (EP14)	VOC	Gallons of ethanol Produced	0.0963 (99.9% Control)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	5.52 (90% Control)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	55.2 (Uncontrolled)	lbs/10^3 gallons	11/19/08 Test
	Single HAP: Acetaldehyde	Gallons of ethanol Produced	0.0304 (Controlled)	lbs/10^3 gallons	11/19/08 Test
		Gallons of ethanol Produced	0.0869 (Uncontrolled)	lbs/10^3 gallons	11/19/08 Test assuming 65% CE
	GHGs (CO_2e)	Gallons of ethanol Produced	6.29	lbs/gal	Mass Balance
For all Scrubbers: Use 90% Control or Uncontrolled VOC EFs and Uncontrolled Acetaldehyde EFs in accordance with Condition 3.1.b.ii.					

Process and EP ID	Pollutant	Monitoring Parameter (P)	Emissions Factor (EF)	Emissions Factor Units	Reference
DDGS Dryer System/ Regenerative Thermal Oxidizers #1 & #2 (each) <u>without</u> Gluten Dryer A Baghouse (S51) Exhaust (EP19 and 20)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	2.00	lb/hr	11/20/08 and 12/4/08 Performance Tests
	SO_2	Hours of operation	3.85	lbs/hr	Source Application and 11/20/08 and 12/4/08 Performance Test
	NO_X	Hours of operation	4.70	lbs/hr	11/20/08 and 12/4/08 Performance Test
	CO	Hours of operation	1.21	lbs/hr	11/20/08 and 12/4/08 Performance Test
	VOC	Tons of DDGS Produced	2.56	lbs/hr	11/20/08 and 12/4/08 Performance Test
	GHGs (CO_2e)	MM ft^3 of natural gas combusted	120,142	lbs/MM ft^3	40 CFR 98, Tables A-1, C-1, C-2
	Single HAP: Acetaldehyde	Hours of operation	0.36	lbs/hr	11/20/08 and 12/4/08 Performance Test

Process and EP ID	Pollutant	Monitoring Parameter (P)	Emissions Factor (EF)	Emissions Factor Units	Reference
Regenerative Thermal Oxidizers #1 & #2 (each) with Gluten Dryer A Baghouse (S51) Exhaust (EP19)	$PM/PM_{10}/PM_{2.5}$	Hours of Operation	2.16	lb/hr	11/20/08 and 12/4/08 RTO Test Data + Source Application
	SO_2	Hours of Operation	3.85	lb/hr	Source Application and 11/20/08 and 12/4/08 Performance Test + AP-42 Table 1.4-2
	NO_X	Hours of Operation	6.09	lb/hr	11/20/08 and 12/4/08 Performance Test + Source Application
	CO	Hours of Operation	3.53	lb/hr	11/20/08 and 12/4/08 Performance Test + AP-42 Table 1.4-1
	VOC	Hours of Operation	2.58	lb/hr	11/20/08 and 12/4/08 Performance Test + Source Application
	GHGs (CO_2e)	MM ft^3 of natural gas combusted	120,142	lbs/MM ft^3	40 CFR 98, Tables A-1, C-1, C-2
	Single HAP: Acetaldehyde	Hours of Operation	0.56	lb/hr	11/20/08 and 12/4/08 Performance Test + Source Application

Process and EP ID	Pollutant	Monitoring Parameter (P)	Emissions Factor (EF)	Emissions Factor Units	Reference
Gluten Dryer B Baghouse (S52)	$PM/PM_{10}/PM_{2.5}$	Hours of Operation	1.63	lb/hr	Source Application
	SO_2	Hours of Operation	0.017	lb/hr	AP-42 Table 1.4-2
	NO_X	Hours of Operation	1.62	lb/hr	Source Application
	CO	Hours of Operation	2.32	lb/hr	AP-42 Table 1.4-1
	VOC	Hours of Operation	0.82	lb/hr	Source Application
	GHGs (CO_2e)	MM ft^3 of natural gas combusted	120,142	lbs/MM ft^3	40 CFR 98, Tables A-1, C-1, C-2
	Single HAP: Acetaldehyde	Hours of Operation	0.05	lb/hr	Source Application
Equipment Leaks	VOC	Equipment leak emission rate constant	USEPA's Protocol for Equipment Leak Emission Estimates	lbs/yr	EPA-543/R-95-017
	Acetaldehyde	VOC Emissions	1.59%	VOC lbs/yr	1.59% Acetaldehyde
Ethanol, Denaturant, and Crude Oil Storage Tanks	VOC	Monitor gallons of throughput for respective 12-month period	Use TANKS software or AP-42 algorithms for 12-month emission rate calculation	tons/yr	TANKS software, AP-42 Section 7.1
	Acetaldehyde	VOC Emissions from ethanol storage	1.59%	VOC lbs/yr	1.59% Acetaldehyde

Process and EP ID	Pollutant	Monitoring Parameter (P)	Emissions Factor (EF)	Emissions Factor Units	Reference
Marine Vessel Loading – VCU (EP35)	VOC	Gallons ethanol loaded	8.82E-5	lbs/10^3 gal loaded	2015-2017 Source Tests
	Acetaldehyde	Gallons ethanol loaded	1.40E-6	lbs/10^3 gal loaded	1.59% Acetaldehyde content
	$PM/PM_{10}/PM_{2.5}$	Hours of Operation	0.33	lbs/hour	AP-42 Section 1.5
	SO_2	Hours of Operation	0.048	lbs/hour	AP-42 Section 1.5
	NO_x	Gallons ethanol loaded	3.50E-4	lbs/10^3 gal loaded	Manufacturer Guarantee
	CO	Gallons ethanol loaded	8.82E-5	lbs/10^3 gal loaded	Manufacturer Guarantee
	GHGs (CO_2e)	Gallons propane burned	12,587	lbs/10^3 gal propane burned	40 CFR 98, Tables A-1, C-1, C-2
Marine Vessel Loading – VRU (EP22)	VOC	Gallons ethanol loaded	3.38E-2	lbs/10^3 gal loaded	2008 and 2013 Source Tests
	Acetaldehyde	Gallons ethanol loaded	5.37E-4	lbs/10^3 gal loaded	1.59% Acetaldehyde content
Ethanol Loading – trucks & rail cars (flare)	VOC	Gallons loaded into rail cars	0.0092	lbs/10^3 gal loaded	AP-42, Section 5.2
	VOC	Gallons loaded into truck	0.19	lbs/10^3 gal loaded	AP-42, Section 5.2
	NO_X	Hours of flare operation	0.44	lbs/hr	AP-42, Table 13.5-1
	CO	Hours of flare operation	1.98	lbs/hr	AP-42, Table 13.5-2
	GHGs (CO_2e)	Hours of flare operation	966	lbs/hr	40 CFR 98, Table C-1 (ethanol)
	Acetaldehyde	Gallons loaded into rail cars	1.46E-4	lbs/10^3 gal loaded	1.59% Acetaldehyde content
	Acetaldehyde	Gallons loaded into truck	0.0031	lbs/10^3 gal loaded	1.59% Acetaldehyde content
Ethanol/Denaturant Storage Tank Roof Landings and Internal Cleanings	VOC	inputs to AP-42 and API calculations	Use AP-42, Section 7.1 and/or API Technical Report 2568	lbs/event	AP-42, Section 7.1, API TR 2568
Cooling Towers (corn ethanol processing)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	3.0	lbs/hr	12/13/2018 e-mail

Process and EP ID	Pollutant	Monitoring Parameter (P)	Emissions Factor (EF)	Emissions Factor Units	Reference
Cooling Towers (wheat ethanol processing)	$PM/PM_{10}/PM_{2.5}$	Hours of operation	1.5	lbs/hr	12/13/2018 e-mail
Wetcake Production/Storage	VOC	Tons wetcake produced	0.00833	lbs/ton	11/2004 DENCO Test
Haul Road Fugitives (Truck Traffic)	PM	Vehicle Miles Traveled (VMT)	0.34	lbs/VMT	AP-42 Section 13.2.1.1, December 13, 2018 e-mail
	PM_{10}	VMT	0.068	lbs/VMT	
	$PM_{2.5}$	VMT	0.017	lbs/VMT	

13.0 NSPS SUBPART IIII GENERAL PROVISIONS

Citation	Subject	Applicable to Subpart IIII	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	

Citation	Subject	Applicable to Subpart IIII	Explanation
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	

14.0 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
CE	Control Equipment
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
DDGS	dried distillers grain with solubles
DEQ	Oregon Department of Environmental Quality
Dscf	dry standard cubic foot
EP	emission point
EPA	US Environmental Protection Agency
EtOH	Ethanol
EU	emission unit
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
lb	pound(s)
MMBtu	million British thermal units
NA	not applicable
NESHAP	National Emissions Standards for Hazardous Air Pollutants
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
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 by volume (unless otherwise specified)
PSD	Prevention of Significant Deterioration
PSEL	Plant Site Emission Limit
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
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
VE	visible emissions
VOC	volatile organic compound
WDGS	wet distillers grain with solubles
year	A period consisting of any 12-consecutive calendar months

Standard AIR CONTAMINANT DISCHARGE PERMIT REVIEW REPORT

Department of Environmental Quality
Northwest Region

State of Oregon Department of Environmental Quality

Source Information:

SIC	2869
NAICS	325193

Source Categories (Table 1 Part, code)	B, 57 and C, 4
Public Notice Category	III

Compliance and Emissions Monitoring Requirements:

FCE	
Compliance schedule	
Unassigned emissions	
Emission credits	
Special Conditions	

Source test [date(s)]	X
COMS	
CEMS	
PEMS	
Ambient monitoring	

Reporting Requirements

Annual report (due date)	February 15
Semiannual report (due dates)	January 31 July 31

Monthly report (due dates)	
Excess emissions report	
Other (specify)	

Air Programs

Synthetic Minor (SM)	X
SM -80	
NSPS (list subparts)	Dc, Kb, VV, IIII
NESHAP (list subparts)	ZZZZ
Part 68 Risk Management	
CFC	

NSR	
PSD	
RACT	
TACT	X
Other (specify)	

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PERMITTING

PERMITTEE IDENTIFICATION

1. Cascade Kelly Holdings, LLC
dba Columbia Pacific Bio-Refinery
81200 Kallunki Road
Clatskanie, OR 97016

PERMITTING ACTION

2. The proposed permit is a combination of a modification to and renewal of an existing Standard Air Contaminant Discharge Permit (ACDP) that was issued on January 30, 2008, and revised on July 26, 2010, June 26, 2012, and April 21, 2015, and was originally scheduled to expire on December 1, 2012. The existing ACDP remains in effect until the ODEQ takes action on the renewal application because the permittee submitted a timely and complete application for renewal.

3. This permitting action only covers the ethanol production, storage, and shipping operations at CPBR. This includes marine loading of ethanol produced at CPBR. In accordance with Case No. AQ/AC-NWR-14-014, all oil storage, oil transloading, and ethanol transloading operations are covered under ACDP 05-0023-ST-01. Transloading refers to the process of transferring a shipment from one mode of transportation to another (e.g. transferring from truck or rail to barge) and includes intermediate storage between the transportation methods. The ethanol production, storage, and shipping operation is considered to a completely separate source from the transloading and oil storage operations with regards to Air permitting. However, the Marine Vessel Loadout equipment, Vapor Combustion Unit, Vapor Recovery Unit, and Storage Tanks TK6105 and TK6106 are regulated by both this ACDP and ACDP 05-0023-ST-01. Therefore, all emissions from crude oil transloading must be accounted for under ACDP 05-0023-ST-01except for HAPs, which must be considered from under this ACDP and ACDP 05-0023-ST-01 together (combined) for ensuring compliance with Condition 4.2 of this ACDP.

OTHER PERMITS

4. Other permits issued or required by the DEQ for this source include:
   - NPDES GEN12Z, and
   - ACDP 05-0023-ST-01, a Standard ACDP covering transloading and oil storage operations

ATTAINMENT STATUS

5. The source is located in an attainment area for all pollutants with a NAAQS.

6. The source is not located within 10 kilometers of any Class I Air Quality Protection Area.

SOURCE DESCRIPTION

OVERVIEW

7. The permittee operates an ethanol production facility. The facility will receive corn or wheat and process it to produce ethanol, gluten, and dry distillers grain with solubles (DDGS) (animal feed). The facility's design capacity for anhydrous ethanol production is 120,000,000 gallons annually when utilizing corn as a feedstock. When processing wheat, CPBR can produce only 60,000,000 gallons of anhydrous ethanol per year. Construction of the facility was completed on June 5, 2008.

8. The modifications relevant to this permit renewal consist of changes, as follows:
   a. Reflect the as-built facility configuration, (as detailed in paragraph 9.m, below)
   b. Incorporate minor changes completed under notices of intent to construct, and
   c. Allow for wheat as a feedstock as an alternative to corn, which will require installation of a new process train for wheat handling, as described in paragraph 9.l., below.

   These changes do not increase emissions associated with the facility above the previous plant site emission levels.

9. The following changes have been made to the facility since the last permit renewal:

   a. On July 28, 2008, the ODEQ received a Notice of Intent to Construct (NC) from CPBR to add chemical to the scrubbing solutions for enhanced VOC and HAP control (NC 23412). The ODEQ approved the project on September 10, 2008.

   b. On July 14, 2010, the ODEQ received a Non-technical ACDP modification application for a name change (Application #25018) from Cascade Grain Products, LLC to Cascade Kelly Holdings, LLC. The ODEQ issued the modification on July 26, 2010.

   c. On September 9, 2011, the ODEQ received an NC to construct a 192,000-gallon internal floating roof storage tank (TK-6114) to be used for storing denaturant (gasoline) (NC 26461). The ODEQ approved the project on September 12, 2011.

   d. On September 27, 2011, the ODEQ received an NC to construct a new syrup loadout skid and new (replacement) syrup tank (NC 26463). The ODEQ approved the project on September 27, 2011.

   e. On June 4, 2012, the ODEQ received a Simple Technical Modification application (Application #26864) to receive and transload up to 50 MMgal/yr of crude oil from railcars to barges. The ODEQ issued the modification on June 26, 2012.

f. On June 29, 2012, the ODEQ received an initial Title V application (application #26913) as required by the requirements of the greenhouse gas tailoring rule (GHG Tailoring Rule), which required sources that were major only for greenhouse gases (GHGs) to obtain Title V permits. However, on June 23, 2014 U.S. Supreme Court issued its decision in Utility Air Regulatory Group v. EPA, 134 S. Ct. 2427 (2014) ("UARG"). The Court held that EPA may not require a source to obtain a PSD or title V permit solely due to GHGs emissions. As such, CPBR was no longer required to obtain a Title V operating permit based on potential GHG emissions. A subsequent Standard ACDP renewal application was submitted on June 30, 2015 (see paragraph 9.j), and this application was officially withdrawn on July 1, 2015.

g. On January 25, 2013, the ODEQ received an NC to replace four pumps on their existing vapor recovery unit: 2 vacuum pumps, 1 supply pump, and 1 absorption tower recovery pump (NC 27172). The ODEQ approved the project on January 29, 2013.

h. On October 20, 2014, the ODEQ received an NC to install two 4.5 million-gallon denatured ethanol storage tanks with internal floating roofs (NC 27935). The project was approved by default on October 30, 2014, and formally approved by the ODEQ on November 6, 2014.

i. On April 13, 2015, the ODEQ initiated a Simple Technical Modification (Application #28127) to incorporate the settlement terms of Mutual Agreement and Final Order No. AQ/AC-NWR-14-014. The ODEQ issued the modification on April 21, 2015.

j. On July 1, 2015, The ODEQ received an air contaminant discharge permit renewal application (application #28254) rather than obtain a Title V operating permit for the facility because such a permit was no longer required by the GHG Tailoring Rule.

k. On August 1, 2017, the ODEQ received an addendum to the June 30, 215 ACDP renewal application. The addendum requested that the ACDP include an alternate operating scenario in which the facility may either (a) construct and operate the two new 4.5 million-gallon tanks authorized in NC 27935 and operate the two existing 3.8 million gallon tanks or (b) refurbish and operate three 50,000-barrel tanks and one 250,000-barrel tank at the adjacent Portland General Electric (PGE) tank farm. The ACDP contains language allowing CPBR to proceed with one of these options.

l. On October 18, 2018, the ODEQ received an ACDP Moderate Technical Modification application (Application #30372) to allow CPBR to produce ethanol from wheat and to construct associated handling and processing equipment for wheat feedstock and byproducts.

i. The previous permit included four corn hammermills and associated baghouses for processing corn. Those devices will remain in the permit to preserve the capability to produce corn-based ethanol. However, the facility is adding a wheat flour milling operation that will include a wheat receiving and transfer baghouse (S10) and wheat rolling mills with two wheat milling baghouses (S32 and S33). The wheat milling operation will be used in lieu of the corn milling process to produce wheat-based ethanol. Corn-based ethanol and wheat-based ethanol cannot be produced simultaneously with the facility configuration because CPBR is not able to simultaneously process the feedstock byproducts (e.g., DGS and gluten).

ii. CPBR will construct a wheat gluten manufacturing process. Similar to DDGS, this is a by-product of ethanol production when wheat is used. This process will include a wheat starch tank (S42), wheat starch surge tank (S40), gluten surge tank (S41), and gluten packaging operation with baghouse control (S43). Additionally, two natural gas fired ring dryers will be installed to dry wheat gluten (DRYERA and DRYERB). Each dryer can dry up to 8,036 lb/hr of material. Both gluten dryers will be controlled by baghouses (S51 and S52). The exhaust from Gluten Dryer A baghouse (S51) will be vented to the existing DDGS dryer and RTO system (EU55 and CE19 or EU58 and CE20) for additional emission control.

m. On October 18, 2018, the ODEQ received an NC (application# 030370) for CPBR to utilize storage tank TK6104, a 248,300-gallon denatured ethanol storage tank which is currently utilized and permitted at the ethanol plant (05-0006), at the transloading facility (source 05-0023). The storage tank would then be solely covered by the transloading facility permit because there are no plans to use it for ethanol production operations in the future.

n. The following reflect the as-built facility configuration:

i. add a baghouse (CE 23) for grain storage bins #1 and #2 and associated transfer conveyor.

ii. add a silo reclaim elevator vent filter (CE 24) and associated grain handling operations (EU 72 & 73).

iii. add a DDGS transfer system vent filter (CE 25) and associated DDGS handling operations (EU 74 & 75).

iv. add a DDGS bulkweigher (EU 77) and vent filter (CE 26).

v. add a DDGS bucket elevator (EU 78) and vent filter (CE 27).

vi. add DDGS loadout conveyors (EU 79). and

vii. add fugitive VOC emissions from loading ethanol product to marine vessels, railcars, and trucks.

PROCESS AND CONTROL DEVICES

10. Existing and *proposed (identified in italics)* air contaminant sources at the facility consist of the following:

EP ID	Emission Unit(s)	Control Device
EP02	EU04: 50,000 bushel (bu)/hr Grain Rail Dump Pit/Auger No. 2	CE02: 30,000 dscfm Grain (or Corn) Receiving Baghouse No. 2
	EU05: 50,000 bu/hr Grain Conveyor No. 2	
	EU06: 50,000 bu/hr Grain Elevator No. 2	
EP07	EU15: 6,259 ft^3 Surge Bin No. 1	CE07: 400 dscfm Surge Bin No. 1 Vent Filters
EP08	EU17: 513,227 bu Surge Bin No. 2	CE08: 400 dscfm Surge Bin No. 2 Vent Filters
EP07 or EP08	EU16: 7,500 bu/hr Scalper No. 1	CE07 or CE08
EP09	EU19: 77,000 lb/hr Hammermill No. 1	CE09: 6,000 dscfm Hammermill Baghouse No. 1
EP10	EU20: 77,000 lb/hr Hammermill No. 2	CE10: 6,000 dscfm Hammermill Baghouse No. 2
EP11	EU21: 77,000 lb/hr Hammermill No. 3	CE11: 6,000 dscfm Hammermill Baghouse No. 3
EP12	EU22: 77,000 lb/hr Hammermill No. 4	CE12: 6,000 dscfm Hammermill Baghouse No. 4
EP13	EU23: Slurry Tank	CE13: Distillation Process Scrubber
	EU24: Liquefaction Tank No. 1	
	EU25: Liquefaction Tank No. 2	
	EU26: Process Condensate Tank	
	EU27: Beer Column	
	EU28: Stripper	
	EU29: Rectifier	
	EU30: Evaporators	
	EU31: Whole Stillage Tank	
	EU32: Thin Stillage Tank	
	EU33: Syrup Tank	
	EU34: Centrifuge No. 1	
	EU35: Centrifuge No. 2	
	EU36: Centrifuge No. 3	

EP ID	**Emission Unit(s)**	**Control Device**
	EU37: Centrifuge No. 4	
	EU38: Molecular Sieve No. 1	
	EU39: Molecular Sieve No. 2	
	EU40: 200 Proof Condenser	
EP14	EU41: Yeast Tank No. 1	CE14: Fermentation (CO_2) Scrubber
	EU42: Yeast Tank No. 2	
	EU43: Fermenter No. 1	
	EU44: Fermenter No. 2	
	EU45: Fermenter No. 3	
	EU46: Fermenter No. 4	
	EU47: Fermenter No. 5	
	EU48: Fermenter No. 6	
	EU49: Fermenter No. 7	
	EU50: Beer Well	
EP15	EU51: 281 ton/hr DDGS Reclaim	CE15: 2,500 dscfm DDGS Reclaim Baghouse
	EU76: 330 ton/hr Bulk Weigher Bucket Elevator	
EP16	EU52: 281 ton/hr DDGS Truck Load Spout No. 1	CE16: 2,000 dscfm DDGS Loadout Baghouse No. 1
EP17	EU53: 281 ton/hr DDGS Truck Load Spout No. 2	CE17: 2,000 dscfm DDGS Loadout Baghouse No. 2
EP18	EU54: 350 ton/hr DDGS Rail Loadout Spout	CE18: 3,000 dscfm DDGS Loadout Baghouse No. 3
EP16, EP17, or EP18	EU79: 420 ton/hr (each) DDGS Loadout Draft Conveyors 1 & 2	CE16, CE17, or CE18
EP19	EU55: 97 MMBtu/hr Natural Gas Fired DDGS Dryer No. 1	CE19: 18 MMBtu/hr Natural Gas Fired Regenerative Thermal Oxidizer No. 1
	EU56: DDGS Cooler No. 1	
	DRYERA: 8,036 lb/hr Gluten Dryer A	*S51: 44,300 dscfm Gluten Dryer A Baghouse*, EU55, and CE19 in series*
	BURNERA: 28.1 MMBtu/hr Natural Gas Fired Gluten Dryer A Burner	

EP ID	Emission Unit(s)	Control Device
EP20	EU58: 97 MMBtu/hr DDGS Dryer No. 2	CE20: 18 MMBtu/hr Natural Gas Fired Regenerative Thermal Oxidizer No. 2
	EU59: DDGS Cooler No. 2	
	DRYERA: 8,036 lb/hr Gluten Dryer A	*S51: 44,300 dscfm Gluten Dryer A Baghouse*, EU58, and CE20 in series*
	BURNERA: 28.1 MMBtu/hr Natural Gas Fired Gluten Dryer A Burner	
*DRYERA must be routed to S51, EU55, and CE19 in series **OR** S51, EU58, and CE20 in series.		
EP21	EU61: 600 gal/min Ethanol Loadout (Truck)	CE21: 6.4 MMBtu/hr Product Loadout Flare (Truck/Rail)
	EU62: 1,200 gal/min Ethanol Loadout (Rail)	
EP22	EU64: Marine Vessel Loadout	CE22: Vapor Recovery Unit
EP35		CE28: Vapor Combustion Unit
EP23	EU65: 92.4 MMBtu/hr Boiler Natural Gas Fired No. 1	None
EP24	EU66: 92.4 MMBtu/hr Boiler Natural Gas Fired No. 2	None
EP25	EU67: 92.4 MMBtu/hr Boiler Natural Gas Fired No. 3	None
EP26	EU68: 92.4 MMBtu/hr Boiler Natural Gas Fired No. 4	None
EP27	EU69: 2,220 hp Diesel Fired Emergency Generator Engine No. 1	None
EP28	EU70: 2,922 hp Diesel Fired Emergency Generator Engine No. 2	None
EP29	EU71: 400 hp Diesel Fired Emergency Fire Pump Engine	None
EP30	EU07: 50,000 bu/hr Transfer Conveyor No. 1	CE23: 14,000 dscfm Grain (or Corn) Storage Bin No. 1 and 2 Baghouse
	EU08: 513,227 bu Grain (or Corn) Storage Silo No. 1	
	EU10: 513,227 bu Grain (or Corn) Storage Silo No. 2	
EP31	EU72: 8,000 bu/hr Storage Reclaim Belt Conveyor	CE24: 1,200 dscfm Silo Reclaim Elevator Vent Filter
	EU73: 8,000 bu/hr Grain Elevator No. 3	
EP32	EU74: 56 ton/hr DDGS Transfer Conveyors	CE25: 900 dscfm DDGS Transfer Vent Filter
	EU75: 56 ton/hr DDGs Transfer Bucket Elevator	
EP33	EU77: 195 ton/hr Bulkweigher	CE26: 500 dscfm DDGS Bulkweigher Vent Filter

EP ID	Emission Unit(s)	Control Device
EP34	EU78: 330 ton/hr DDGS Bucket Elevator	CE27: 2,100 dscfm DDGS Loadout Elevator Baghouse
S52	*DRYERB: Gluten Dryer B*	*S52: 44,300 dscfm Gluten Dryer B Baghouse*
	BURNERB: 28.1 MMBtu/hr Natural Gas Fired Gluten Dryer B Burner	
S10	*EU_S10: Wheat Receiving, Wheat Transfer*	*S10: 30,000 dscfm Wheat Receiving and Transfer Baghouse*
S32	*EU_S32: Wheat Milling*	*S32: 50,000 dscfm Wheat Milling Baghouse No. 1*
S33	*EU_S33: Wheat Milling*	*S33: 50,000 dscfm Wheat Milling Baghouse No. 2*
S40	*EU_S40: Wheat Starch Surge Tank*	*S40: 3,000 dscfm Wheat Starch Surge Tank Bin Vent*
S41	*EU_S41: Gluten Surge Tank*	*S41: 3,000 dscfm Gluten Surge Tank Bin Vent*
S42	*EU_S42: Wheat Starch Tank*	*S42: 5,000 dscfm Wheat Starch Tank Bin Vent*
S43	*EU_S43: Gluten Packaging*	*S43: 15,000 dscfm Gluten Packaging Baghouse*
FS02	FS02: Cooling Towers	None
TK6101	TK6101: 191,861-gallon 200 Proof Storage Tank	Internal Floating Roof
TK6102	TK6102: 191,861-gallon 200 Proof Storage Tank	Internal Floating Roof
TK6105	TK6105: 3.8-MMGal Denatured Ethanol Tank	Internal Floating Roof
TK6106	TK6106: 3.8-MMGal Denatured Ethanol Tank	Internal Floating Roof
TK6114	TK6114: 192,000-gallon Denaturant Storage Tank	Internal Floating Roof
TK6121	*TK6121: 4.5 million-gallon Denatured Ethanol Tank*	*Internal Floating Roof*
TK6122	*TK6122: 4.5 million-gallon Denatured Ethanol Tank*	*Internal Floating Roof*
TK6201	*TK6201: 50,000-barrel (2,087,400 gallon) Denatured Ethanol Tank (PGE Tank Farm)*	*Internal Floating Roof*
TK6202	*TK6202: 50,000-barrel (2,087,400 gallon) Denatured Ethanol Tank (PGE Tank Farm)*	*Internal Floating Roof*

EP ID	Emission Unit(s)	Control Device
TK6203	*TK6203: 50,000-barrel (2,087,400 gallon) Denatured Ethanol Tank (PGE Tank Farm)*	*Internal Floating Roof*
TK6205	*TK6205: 250,000-barrel (11,289,600 gallon) Denatured Ethanol Tank (PGE Tank Farm)*	*Internal Floating Roof*

CONTINUOUS MONITORING DEVICES

11. The facility has the following continuous monitoring devices:
    a. Regenerative Thermal Oxidizers: operating temperature
    b. Distillation process scrubber: scrubbing solution temperature, scrubbing solution flow rate.
    c. Fermentation (CO_2) scrubber: scrubbing solution temperature, scrubbing solution flow rate.
    d. Rail/Truck Product Loadout Flare: presence of a flame must be continuously monitored using a thermocouple or equivalent device.
    e. Baghouses and multiclones: pressure differential

COMPLIANCE

12. A file review on October 22, 2013, resulted in a violation stemming from CPBR's crude oil transloading activities resulting in it operating a new major source without obtaining the necessary permit. A pre-enforcement notice was sent to CPBR on January 10, 2014 (2014-PEN-95). This issue was resolved through Notice of Civil Penalty and Order, Case No. AQ/AC-NWR-14-014.

13. The facility was inspected on September 19, 2018, and found to be in compliance with permit conditions. However, the facility was not in operation and had not been in operation since January 9, 2009.

14. During the prior permit period there were no complaints recorded for this facility.

15. A Notice of Civil Penalty and Order, Case No. AQ/AC-NWR-14-014, was issued on March 27, 2014. This was resolved on January 31, 2015 by Mutual Agreement and Final Order No. AQ/AC-NWR-14-014, and resulted in the separation of the crude oil transloading operation into a separate Standard ACDP.

EMISSIONS

16. Proposed PSEL information:

Pollutant	Baseline Emission Rate (tons/yr)	Netting Basis		Plant Site Emission Limits (PSEL)		
		Previous (tons/yr)	Proposed (tons/yr)	Previous PSEL (tons/yr)	Proposed PSEL (tons/yr)	PSEL Increase (tons/yr)
PM	0	99	99	99	99	0
PM_{10}	0	99	99	99	99	0
$PM_{2.5}$	N/A	N/A	97	N/A	97	97
SO_2	0	0	0	39	39	0
NO_x	0	99	99	99	99	0
CO	0	0	0	99	99	0
VOC	0	51	51	90	90	0
GHG (CO_2e)	194,063	N/A	194,063	N/A	665,800	665,800
Single HAP	N/A	N/A	N/A	9	9	0

a. The facility is located in an area that is in attainment with the National Ambient Air Quality Standards for these pollutants. Although the facility is not a Federal Major Source, in its initial permitting action the permittee successfully complied with the New Source Review(NSR)/Prevention of Significant Deterioration (PSD) requirements of OAR 340-224-0010 through 340-224-0110 thereby providing the basis for the Netting Bases identified above. The Netting Bases are the starting point for determining a net significant emission rate increase for the NSR/PSD program.

b. The proposed PSEL represents the equivalent of the generic PSEL for SO_2 and CO as defined in OAR 340-222-0040.

c. $PM_{2.5}$ became a regulated pollutant in DEQ rules in May 2011 and is first being addressed in this permit renewal action. $PM_{2.5}$ represents a fraction of the PM and PM_{10} emitted by the permittee. A PSEL is being added for $PM_{2.5}$ in this permit action because the permittee can emit the pollutant at a rate greater than the de minimis emission level defined in OAR 340-200-0020. In accordance with OAR 340-222-0048(3) a baseline emission rate for $PM_{2.5}$ will not be established; a $PM_{2.5}$ netting basis is being established in this permit action in accordance with OAR 340-222-0046.

d. GHG became a regulated pollutant in DEQ rules in May 2011. The Baseline Period for GHG is defined to be any 12 consecutive calendar month period during the calendar years 2000 through 2010. Pursuant to OAR 340-200-0020(13)(b), the baseline emission rate for GHG is being added for the first time with this permit action. The permittee's facility was an existing source during this period and it therefore qualifies for GHG Baseline/Netting Basis emissions.

With the addition of the GHG baseline emission rate in this permit action, an associated netting basis quantity is also added. The permittee designated June 2008 – February 2009 (its only operational timeframe) as its representative Baseline year and basis for these emission rates. During this time period the facility emitted 194,063 short tons CO_2e (176,052 metric tonnes CO_2e).The PSEL is a federally enforceable limit on the potential to emit (PTE).

e. The permittee has the potential to emit acetaldehyde at a level that exceeds the major source threshold for Title V ($\geq$ 10 tons/yr). The permittee is accepting a PSEL (a federally enforceable operational limitation) to regulate/limit its individual HAP PTE to 9 tons per year. PTE for all individual HAPs other than acetaldehyde are considerably below the 10 ton threshold. A PSEL for combined HAPs is not included in the permit because the permittee's respective PTE is less than 80% of the HAP major source threshold (25 tons/yr), as shown in paragraph 22, below.

f. The HAP PSEL applies to emissions from sources 05-0006 and 05-0023 combined.

g. The previous PSELs for PM, PM10, SO2, NOx, CO, and VOC are the PSELs in the last permit.

SIGNIFICANT EMISSION RATE ANALYSIS

17. For each pollutant except for GHGs, the proposed Plant Site Emission Limit is less than the sum of the Netting Basis and the significant emission rate, thus no further air quality analysis is required. While the PSEL for GHGs is greater than the sum of the netting basis and significant emission rate, GHGs does not have a NAAQS and is not subject to PSD because PSD is not triggered for any other criteria pollutant.

TITLE V MAJOR SOURCE APPLICABILITY

18. A major source is a facility that has the potential to emit 100 tons/yr or more of any criteria pollutant or 10 tons/yr or more of any single HAP or 25 tons/yr or more of combined HAPs. This facility is not a major source of emissions.

19. A source that has potential to emit at the major source levels but accepts a PSEL below major source levels is called a synthetic minor (SM). When including the control requirements in the permit, this source no longer has the potential to emit at major source levels. Therefore, this source is a synthetic minor. Based on 2008 performance testing data and actual production rates, CPBR does not have actual emissions above 80% of any major source threshold.

CRITERIA POLLUTANTS

20. This facility is a synthetic minor source of criteria pollutant emissions.

21. CPBR's ethanol manufacturing facility as a whole is considered a 250 ton source;

meaning they would be considered a PSD major source if criteria pollutant emissions exceed 250 ton/yr.

The four boilers at CPBR have a combined capacity of 369.6 MMBtu/hr which makes them a nested PSD source under the category "fossil fuel boilers (or combination thereof) totaling more 250 million British thermal units per hour heat input" listed in OAR 340-200-0020 (66)(c)(A). Therefore, the four boilers are subject to 100 tpy threshold. The PTE of criteria pollutants from the boilers are all less than 100 tpy making the nested source a minor source for PSD. At this time there are no additional requirements due to having a nested source.

HAZARDOUS AIR POLLUTANTS

22. With regards to hazardous air pollutants, the definition of source only requires that the activities must be located on one or more contiguous or adjacent properties and that they are owned or operated by the same person or by persons under common control; being in the major industrial group is not used in HAP single source determination. The ethanol (05-0006) and transloading (05-0023) facilities are on adjacent properties and share the same owner, making them a single source of HAP.

23. The combined source is an area source of hazardous air pollutants. Provided below is a summary of the HAP emissions.

Hazardous Air Pollutant	05-0006 PTE (ton/year)	05-0023 PTE[1] (ton/year)	Combined PTE (ton/year)
Acetaldehyde[2, 3]	< 9	0.34	9
Acrolein[3]	0.19	<0.01	0.20
Formaldehyde[3]	1.17	0.01	1.18
Methanol[3]	0.66	0.04	0.70
n-Hexane	3.78	0.35	4.13
Other HAP	0.07	2.12	2.19
Total	14.86	2.86	17.72

[1]05-0023 PTE from supplemental application information (received July 16, 2019)
[2]The permitted acetaldehyde PTE is the PSEL
[3]Acetaldehyde, Acrolein, Formaldehyde, and Methanol are the main HAPs emitted from the ethanol fermentation process.

24. Although the source has the capacity to emit above the Title V major source threshold level for acetaldehyde, the permittee has elected not to obtain an Oregon Title V Operating Permit by requesting a PSEL below the major source threshold levels. The PSEL is a federally enforceable limit on PTE.

ADDITIONAL REQUIREMENTS

NSPS APPLICABILITY

25. CPBR has EUs that are subject to Subpart Dc, "*Small Industrial, Commercial and Institutional Steam Generating Units*" which applies to each steam generating unit with a maximum design heat input capacity between 10 and 100 MMBtu/hr that commenced construction, modification, or reconstruction after June 9, 1989. EUs at CPBR that are subject to this subpart and the applicable decision points are listed in the table below:

EU ID	Capacity (MMBtu/hr)	Fuel	Construction Date
EU-65	92.4	Natural Gas	2007
EU-66	92.4	Natural Gas	2007
EU-67	92.4	Natural Gas	2007
EU-68	92.4	Natural Gas	2007

26. CPBR has EUs that are subject to Subpart Kb, "*Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*" which applies to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) (approx. 19,813 gallons) that is used to store volatile organic liquids (VOL), with certain exclusions based upon function, true vapor pressure of contents, design, or other regulatory requirements, for which construction, reconstruction, or modification is commenced after July 23, 1984. EUs at CPBR that are subject to this subpart and the applicable decision points are listed in the table below:

EU ID	Capacity (gal)	Control	Contents	Construction Date
TK6101	191,861	Internal Floating Roof	Anhydrous Ethanol	2007
TK6102	191,861	Internal Floating Roof	Anhydrous Ethanol	2007
TK6114	192,000	Internal Floating Roof	Denaturant	2011
TK6121	4,500,000	Internal Floating Roof	Denatured Ethanol	TBD
TK6122	4,500,000	Internal Floating Roof	Denatured Ethanol	TBD

EU ID	Capacity (gal)	Control	Contents	Reconstruction Date
TK6105	3,800,000	Internal Floating Roof	Denatured Ethanol	2007
TK6106	3,800,000	Internal Floating Roof	Denatured Ethanol	2007
TK6201	2,100,000	Internal Floating Roof	Denatured Ethanol	TBD
TK6202	2,100,000	Internal Floating Roof	Denatured Ethanol	TBD
TK6203	2,100,000	Internal Floating Roof	Denatured Ethanol	TBD
TK6205	10,500,000	Internal Floating Roof	Denatured Ethanol	TBD

Construction of TK6121 and 6122 was authorized under NC #27935. Construction of the tanks has not commenced as of permit issuance.

27. CPBR is subject to Subpart VV, "*Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006*" which applies to facilities in source group 28 (synthetic organic chemical manufacturers) that manufacture any of the chemicals listed in 40 CFR 60.489. CPBR manufactures ethanol, which is a listed chemical. Construction of CPBR commenced in June of 2006. There is no equipment in heavy liquid service at CPBR.

28. CPBR has EUs that are subject to 40 CFR Part 60, Subpart IIII, "*Stationary Compression Ignition Internal Combustion Engines*" which applies to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE). The EUs at CPBR are used for emergency power generation and fire suppression. EU-69, 70, and 71 are certified by the manufacturer to meet the applicable IIII emission limits. Specific parameters for each engine subject to this subpart are listed below:

EU ID	**Capacity (hp)**	**Displacement per cylinder (L)**	**Construction Date**	**Fuel**
EU-69	2,220	3.14	2007	Diesel
EU-70	2,922	3.76	2007	Diesel
EU-71	400	1.5	2007	Diesel

29. CPBR **is not** subject to 40 CFR Part 60, Subpart DD, "*Grain Elevators*" which applies to grain terminal and grain storage elevators. CPBR has two grain storage elevators with a total capacity of 1,026,454 bushels. CPBR does not meet the definition of "Grain storage elevator," and has a capacity below the "Grain terminal elevator" threshold of 2.5 million bushels.

NESHAPS/MACT APPLICABILITY

30. CPBR has EUs that are subject to 40 CFR Part 63, Subpart ZZZZ, "*Stationary Reciprocating Internal Combustion Engines*" which applies to existing, new, or reconstructed stationary RICE located at a major or area sources of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand. The EUs at CPBR are used for emergency power generation and fire suppression. CPBR will comply with the applicable requirements of this subpart by complying with NSPS Subpart IIII. Specific parameters for each engine subject to this subpart are listed below:

EU ID	**Capacity (hp)**	**Displacement per cylinder (L)**	**Construction Date**	**Fuel**
EU-69	2,220	3.14	2007	Diesel
EU-70	2,922	3.76	2007	Diesel
EU-71	400	1.5	2007	Diesel

31. CPBR **is not** subject to 40 CFR 63, Subpart JJJJJJ "*Industrial, Commercial, and Institutional Boilers at Area Sources*" which applies to the collection of all existing industrial, commercial, and institutional boilers within a subcategory located at an area source of HAP, and to each new or reconstructed industrial, commercial, or institutional boiler located at an area source of HAPs. The boilers at CPBR combust only natural gas, which makes them "gas-fired boilers" with respect to this subpart. Gas-fired boilers are considered an unaffected facility under this subpart.

32. CPBR **is not** subject to 40 CFR 63, Subpart VVVVVV "*Chemical Manufacturing Area Sources*" which applies owners and operators of chemical manufacturing process units (CMPUs) at area sources of HAPs. In order for a source to be subject to this standard, it must use as a feedstock, emit as byproduct or produce as a product one of the following HAPs: 1,3-butadiene, 1,3-dichloropropene, acetaldehyde, chloroform, ethylene dichloride, hexachlorobenzene, methylene chloride, quinoline, arsenic compounds, cadmium compounds, chromium compounds, lead compounds, manganese compounds, or nickel compounds. Additionally, the concentration of a target HAP must be greater than 0.1% for carcinogens and 1.0% for non-carcinogens in order to be subject. Acetaldehyde is present in process fluids at ethanol plants but it is not found in concentrations exceeding 0.1%.

RACT APPLICABILITY

33. The RACT rules are not applicable to this source because it is not in the Portland AQMA, Medford AQMA, or Salem-Keizer SKATS.

TACT APPLICABILITY

34. All emission units subject to TACT are required to utilize control devices that meet TACT requirements. The list of applicable emission units and corresponding control devices is displayed in the tables below. The PM EUs are all controlled by baghouses, which can capture upwards of 99% of all PM emissions. VOC emissions from the fermentation units at CPBR are controlled by a wet scrubber with option for chemical addition and VOC emissions from ethanol loadout and DDGS drying are controlled by combustion units (flare and RTO). Typical chemicals added to the scrubber water are ammonium bisulfate and sodium bisulfate which are used to enhance the capture of HAPs. The required controls are effective and commonly used in the ethanol production industry. Therefore, the controls listed in the table below satisfy TACT.

PM Emission Units	Control Device
EU04: Grain Rail Dump Pit/Auger No. 2	CE02: Grain (or Corn) Receiving Baghouse No. 2
EU19: Hammermill No. 1	CE09: Hammermill Baghouse No. 1
EU20: Hammermill No. 2	CE10: Hammermill Baghouse No. 2
EU21: Hammermill No. 3	CE11: Hammermill Baghouse No. 3
EU22: Hammermill No. 4	CE12: Hammermill Baghouse No. 4

PM Emission Units	Control Device
Wheat Receiving, Wheat Transfer	S10: Wheat Receiving and Transfer Baghouse
Wheat Milling	S32: Wheat Milling Baghouse No. 1
Wheat Milling	S33: Wheat Milling Baghouse No. 2

VOC Emission Units	Control Device
EU43: Fermenter No. 1	CE14: Fermentation (CO_2) Scrubber
EU44: Fermenter No. 2	CE14: Fermentation (CO_2) Scrubber
EU45: Fermenter No. 3	CE14: Fermentation (CO_2) Scrubber
EU46: Fermenter No. 4	CE14: Fermentation (CO_2) Scrubber
EU47: Fermenter No. 5	CE14: Fermentation (CO_2) Scrubber
EU48: Fermenter No. 6	CE14: Fermentation (CO_2) Scrubber
EU49: Fermenter No. 7	CE14: Fermentation (CO_2) Scrubber
EU50: Beer Well	CE14: Fermentation (CO_2) Scrubber
EU55: DDGS Dryer No. 1	CE19: Regenerative Thermal Oxidizer No. 1
EU58: DDGS Dryer No. 2	CE20: Regenerative Thermal Oxidizer No. 2
EU61: Ethanol Loadout (Truck)	CE21: Product Loadout Flare (Truck/Rail)
EU62: Ethanol Loadout (Rail)	CE21: Product Loadout Flare (Truck/Rail)

SOURCE TESTING

PRIOR TESTING RESULTS

35. The results of the source tests performed during the previous permit term are listed in Attachment A.

PROPOSED TESTING

36. The following emission points will be tested once during the permit term for the listed pollutants:

Emission Point	Pollutant(s)
EP02: Grain (or Corn) Receiving Baghouse No. 2	PM
EP13: Distillation Process Scrubber	VOC (mass), Acetaldehyde, Acrolein, Formaldehyde, Methanol
EP14: Fermentation (CO2) Scrubber	VOC (mass), Acetaldehyde, Acrolein, Formaldehyde, Methanol
EP19: Regenerative Thermal Oxidizer No. 1	PM, NOx, CO, VOC, Acetaldehyde
EP20: Regenerative Thermal Oxidizer No. 2	PM, NOx, CO, VOC, Acetaldehyde
EP21: Product Loadout Flare (Truck/Rail)	Per 40 CFR 60, Subpart A
EP22/EP35: Marine Vessel Loadout VRU/VCU	VOC (mass), Acetaldehyde

Emission Point	Pollutant(s)
EP23-26: Boiler No. 1, 2, 3, or 4	NOx, CO
S10: Wheat Receiving and Transfer Baghouse	PM
S32: Wheat Milling Baghouse No. 1	PM
S33: Wheat Milling Baghouse No. 2	PM
S43: Gluten Packaging Baghouse	PM
S52: Gluten Dryer B Baghouse	PM, VOC, Acetaldehyde

PUBLIC NOTICE

37. Pursuant to OAR 340-216-0066(4)(a)(A), issuance of Standard Air Contaminant Discharge Permits require public notice in accordance with OAR 340-209-0030(3)(c), which requires DEQ to provide notice of the proposed permit action and a minimum of 35 days for interested persons to submit written comments. The public hearing begins at 6:30 pm on July 24, 2019 at the Clatskanie Cultural Center in Clatskanie, OR. **The public notice was emailed/mailed on June 20, 2019 and the comment period will end on July 31, 2019 at 5 p.m.**

- During the public comment period, DEQ received 276 written comments, testimony from 37 individuals, and 812 names of persons supporting or opposing the proposed permit. Comments received during the public comment period as well as comments received at the public hearing are summarized in the attached document.

dg:pj
05-0006-rr-4.docx

Attachment A: Source Testing Results

Emission Point	Test Date	Production Rate	Pollutant	Measured Value
EP-02: Grain Receiving Baghouse No. 2	10/6/2008	419 ton/hr	PM	0.047 lb/hr
EP-30: Grain Storage Bin No. 1 and 2 Baghouse	10/6/2008	419 ton/hr	PM	0.018 lb/hr
EP-13: Distillation Process Scrubber	11/18/2008	9,100 gal EtOh/hr	VOC	0.11 lb/hr
EP-13: Distillation Process Scrubber	11/18/2008	9,100 gal EtOh/hr	VOC	99.9% CE
EP-13: Distillation Process Scrubber	11/18/2008	9,100 gal EtOh/hr	Acetaldehyde	< 0.015 lb/hr
EP-13: Distillation Process Scrubber	11/18/2008	9,100 gal EtOh/hr	VOC (Inlet)	146 lb/hr
EP-14: Fermentation (CO2) Scrubber	11/19/2008	9,870 gal EtOh/hr	VOC (Inlet)	545 lb/hr
EP-14: Fermentation (CO2) Scrubber	11/19/2008	9,870 gal EtOh/hr	VOC	0.95 lb/hr
EP-14: Fermentation (CO2) Scrubber	11/19/2008	9,870 gal EtOh/hr	VOC	99.9% CE
EP-14: Fermentation (CO2) Scrubber	11/19/2008	9,870 gal EtOh/hr	Acetaldehyde	0.30 lb/hr
EP-19: RTO No. 1	12/4/2008	21.8 ton DDGS/hr	PM	1.3 lb/hr
EP-19: RTO No. 1	12/4/2008	21.8 ton DDGS/hr	CO	1.5 lb/hr
EP-19: RTO No. 1	12/4/2008	21.8 ton DDGS/hr	NOx	3.7 lb/hr
EP-19: RTO No. 1	12/4/2008	21.8 ton DDGS/hr	VOC	5.1 lb/hr
EP-19: RTO No. 1	12/4/2008	21.8 ton DDGS/hr	Acetaldehyde	< 0.33 lb/hr
EP-20: RTO No. 2	11/20/2008	23.3 ton DDGS/hr	PM	2.7 lb/hr
EP-20: RTO No. 2	11/20/2008	23.3 ton DDGS/hr	CO	0.92 lb/hr
EP-20: RTO No. 2	11/20/2008	23.3 ton DDGS/hr	NOx	5.7 lb/hr
EP-20: RTO No. 2	11/20/2008	23.3 ton DDGS/hr	VOC	0.025 lb/hr
EP-20: RTO No. 2	11/20/2008	23.3 ton DDGS/hr	Acetaldehyde	< 0.38 lb/hr
EP-22: VRU	10/10/2008	3,550 gal/min	VOC	2.1 lb/hr

Emission Point	Test Date	Production Rate	Pollutant	Measured Value
EP-22: VRU	2/22/2013	3,000 bbl/hr	VOC (as propane)	6 lb/hr
EP-22: VRU	2/22/2013	4,200 bbl/hr	VOC (as propane)	9.3 lb/hr
EP-23: Boiler No. 1	10/6/2008	89.9 MMBtu/hr	CO	0.0 lb/hr
EP-23: Boiler No. 1	10/6/2008	89.9 MMBtu/hr	NOx	0.91 lb/hr
EP-35: VCU A	7/10/2017	2,928 gal/min	CO	0.0189 lb/hr
EP-35: VCU A	7/10/2017	2,928 gal/min	NOx	0.0391 lb/hr
EP-35: VCU A	7/10/2017	2,928 gal/min	VOC (as propane)	< 0.0035 lb/hr
EP-35: VCU A	10/19/2016	4,459 gal/min	CO	<0.0020 lb/hr
EP-35: VCU A	10/19/2016	4,459 gal/min	NOx	0.201 lb/hr
EP-35: VCU A	10/19/2016	4,459 gal/min	VOC (as propane)	<0.0115 lb/hr
EP-35: VCU A	8/14/2015	4,231 gal/min	CO	0.043 lb/hr
EP-35: VCU A	8/14/2015	4,231 gal/min	NOx	0.14 lb/hr
EP-35: VCU A	8/14/2015	4,231 gal/min	VOC (as propane)	0.098 lb/hr
EP-35: VCU B	7/10/2017	2,928 gal/min	CO	0.0059 lb/hr
EP-35: VCU B	7/10/2017	2,928 gal/min	NOx	0.0322 lb/hr
EP-35: VCU B	7/10/2017	2,928 gal/min	VOC (as propane)	< 0.0063 lb/hr
EP-35: VCU B	10/19/2016	4,459 gal/min	CO	0.0044 lb/hr
EP-35: VCU B	10/19/2016	4,459 gal/min	NOx	0.0254 lb/hr
EP-35: VCU B	10/19/2016	4,459 gal/min	VOC (as propane)	<0.0036 lb/hr
EP-35: VCU B	8/14/2015	4,231 gal/min	CO	0.0081 lb/hr
EP-35: VCU B	8/14/2015	4,231 gal/min	NOx	0.050 lb/hr
EP-35: VCU B	8/14/2015	4,231 gal/min	VOC (as propane)	0.00 lb/hr

State Of Oregon

Department of Environmental Quality

Subject: **Hearing Officer's Report and Response to Comments**

Date: **August 29, 2019**

Hearing Officer: **Steven Dietrich**

Company Name: **Cascade Kelly Holdings LLC, dba Columbia Pacific Bio-Refinery**

Permit No.: **05-0006-ST-01**

Application No.: **028254 and 030372**

Background

Cascade Kelly Holdings, LLC, applied to DEQ for a renewal of and modification to a Standard Air Contaminant Discharge Permit for an ethanol production plant at 81200 Kallunki Road, Clatskanie, Oregon. Cascade Kelly Holdings LLC, will do business as Columbia Pacific Bio-Refinery (CPBR or the permittee). CPBR can currently produce ethanol from corn, but its production facilities haven't operated since 2009. The modification will allow CPBR to construct equipment to produce ethanol from wheat (in addition to corn) and to recover wheat coproducts after fermentation. The maximum ethanol production capacity will be 120 million gallons per year when using corn as a feedstock and 60 million gallons per year when using wheat as a feedstock.

DEQ prepared a draft Air Contaminant Discharge Permit and proposed it for public review and comment in a public comment period from June 20, 2019, through July 31, 2019. In addition, DEQ held a public information meeting and public hearing for the proposed permit on July 24, 2019, at the Clatskanie Cultural Center in Clatskanie, Oregon.

This report and Response to Comments provides DEQ's responses to the public comments submitted during the comment period and public hearing.

Public Comment

DEQ received 276 written comments, testimony from 37 individuals, and 812 names of persons supporting or opposing the proposed permit. Comments received during the public comment period as well as comments received at the public hearing are summarized or stated below. DEQ responses follow each comment or group of comments. Most of the comments and the public input received by DEQ were focused around common concerns and perceptions. Where similar comments were provided by multiple persons, DEQ has summarized or grouped the comments/concerns. In some cases the commenters refer to "Global", "Global Partners", or "Global, LP" which is the controlling shareholder of Cascade Kelly Holdings, LLC.

A. Comments related to the Transloading and Ethanol Production facilities being separate sources of air pollution.

1. **Summarized Comment:** *DEQ should evaluate the cumulative effects of the ethanol and transloading facility; they should be treated as a single source.*

   DEQ Response: OAR 340-200-0020 (166) defines "Source" as: any building, structure, facility, installation or combination thereof that emits or is capable of emitting air contaminants to the atmosphere, is located on one or more contiguous or adjacent properties and is owned or operated by the same person or by persons under common control. The term includes all air contaminant emitting activities that belong to a single major industrial group, i.e., that have the same two-digit code, as described in the Standard Industrial Classification Manual, U.S. Office of Management and Budget, 1987, or that support the major industrial group. On July 26, 2012, ODEQ determined that the crude oil transloading operation was considered a separate source because the transloading operations do not support the ethanol facility's primary activity and because both operations fall under different SIC group classifications (51 vs 28). This point was repeated in the March 27, 2014, Notice of Civil Penalty Assessment and Order.

   With regards to hazardous air pollutants, the definition of source requires that the activities must be located on one or more contiguous or adjacent properties and that they are owned or operated by the same person or by persons under common control; being in the same major industrial group is not used in hazardous air pollutant single source determination. The ethanol and transloading facilities are on adjacent properties and share the same owner, making them a single source of hazardous air pollutants. During the public hearing DEQ became aware that the permit documents did not clearly identify that the combined facilities are an area source (i.e., minor source) of hazardous air pollutants. DEQ revised the hazardous air pollutant discussion and plant site emission limit language to make it clear that CPBR is an area source of hazardous air pollutants.

2. **Summarized Comment:** *(Amelia Ponti) This company should operate under the oversight of the Title V major pollutant permit. The activities at these facilities combined would be allowed to emit more than 10 tons of hazardous air pollutants, 1.44 tons from the transloading and nine tons from the ethanol facility. Therefore this is a major source and Title V permits are needed.*

   DEQ Response: Title V applicability is discussed in OAR 340-218-0020(1). In accordance with OAR 340-218-0020(3)(a), CPBR reduced its emissions to below Title V thresholds through limits contained in an air contaminant discharge permit. As discussed in the response to comment 1., DEQ revised the review report and permit to clarify that combined hazardous air pollutant emissions from the transloading and ethanol production facilities are below the applicable major source thresholds (10 tons per year of any individual hazardous air pollutant and 25 tons per year of combined hazardous air pollutants).

3. **Summarized Comment:** *DEQ received numerous comments requesting that DEQ not allow any equipment to be shared between the ethanol and transloading facilities.*

   DEQ Response: Air contaminant discharge permits are issued for a source. The definition of "source" takes three things into account: 1) common ownership; 2) Common two digit standard industrial classification code; 3) contiguous or adjacent. Because the transloading operation has a different two digit standard industrial classification code from ethanol manufacturing, the two operations are considered separate sources for permitting purposes. The fact that they use some of the same equipment doesn't change the fact that the tanks are used for two different operations and therefore belong to two different sources and in-turn two separate air contaminant discharge permits.

4. **Summarized Comment:** *DEQ received numerous comments claiming that CPBR will add equipment to the site under the ethanol permit and then transfer the equipment to the transloading facility in an effort to circumvent the permitting process for the transloading facility.*

   DEQ Response: CPBR is required to submit a notice of intent to construct for modifications to the ethanol and transloading facility in accordance with OAR 340-210-0205. Because the facilities are considered separate sources of air pollution the transfer of equipment from one to the other is considered a modification and is treated like new construction. OAR 340-210-0225 identifies the triggers involved for the various "types" of notice of intent to construct. A permit modification and subsequent public comment period is required if the notice of intent to construct qualifies as Type 3 or Type 4 and can be required for some Type 2 notice of intent to constructs. The transfer of TK6104 from the ethanol facility to the transloading facility occurred through a type 2 notice of intent to construct which did not require a permit modification and was approved by DEQ on October 23, 2018 (Application 30370). The notification process would have been identical if CPBR planned to install a new tank because the emissions from the tank qualified the project as a Type 2 notice of intent to construct.

5. **Summarized Comment:** *DEQ received several comments claiming that DEQ's definition of "transloading" in the review report does not account for storage of oil.*

   DEQ Response: The comment is referring to a specific sentence in Section 3 of the proposed review report. However, the sentence prior states "In accordance with Case No. AQ/AC-NWR-14-014, all oil storage, oil transloading, and ethanol transloading operations are covered under air contaminant discharge permit 05-0023-ST-01." Since CPBR first planned to transload oil (Simple Technical Permit Modification received on June 12, 2012, and approved on June 26, 2012), the DEQ and CPBR have included intermediate storage as a part of the transloading process. The paragraph was revised to clarify that storage is also included in the transloading process.

6. **Summarized Comment:** *DEQ received numerous comments requesting that Condition 2.8 be replaced with more specific language.*

DEQ Response: The condition is a result of Item 2 of the 2014 Mutual Agreement and Final Order (MAO) between the DEQ and CPBR; DEQ will issue a Department-initiated modification to air contaminant discharge permit 05-0006 withdrawing DEQ approval to allow CPBR conduct the crude oil transloading activity under that permit. The review report to the air contaminant discharge permit modification states "this Department initiated permit modification is issued under the authority of OAR 340-216-0084, and removes all allowances for crude oil transloading from the permit. The change added by Condition 2.4 of the addendum prohibits the facility from transloading any amount of crude oil." The condition was included as part of a DEQ-initiated modification that was issued on April 21, 2015, and requires CPBR to perform all oil transloading under the authority of air contaminant discharge permit 05-0023-ST-01. To add clarity to the condition and its intent the DEQ is revising the condition to read: The permittee is prohibited from performing the transloading of crude oil under this permit. Crude oil transloading must be conducted under the authority of a separate ACDP.

7. **Comment:** *(Center for Sustainable Economy, Columbia Riverkeeper, Envision Columbia County, Friends of the Columbia Gorge, Neighbors for Clean Air, and Northwest Environmental Defense Center) DEQ Has Not Assessed Potential Air Pollution Impacts From Handling Heavy Oil.*

   DEQ Response: CPBR is prohibited from transloading crude oil under the proposed ACDP. Emissions from oil handling and storage are accounted for under the transloading facility air contaminant discharge permit (05-0023-ST-01).

B. Comments related to oil trains

8. **Summarized Comment:** *DEQ received numerous comments requesting DEQ take actions that would result in it regulating fossil fuel extraction, shipment, or end-use [post-CPBR] related activities. The primary intentions of these comments were to promote climate change abatement, pollution prevention, and conservation of natural resources.*

   DEQ Response: DEQ's authority is defined within Oregon's Air Quality programmatic rules, most of which are contained in the EPA-approved State of Oregon Clean Air Act Implementation Plan which defines how the Clean Air Act is implemented in Oregon. Our air quality permitting action is confined to the CPBR stationary source's air contaminant emissions. When DEQ writes an Air Contaminant Discharge Permit it must include all applicable requirements of Oregon's Air Quality program in the respective permit. DEQ does not have authority to influence or regulate fossil fuel extraction, shipment, or end-use related activities in this permit action.

9. **Summarized Comment:** *DEQ received several comments requesting that DEQ deny the proposed permit because the production, shipping, and use of tar sands oil will exacerbate the current climate change crisis.*

   DEQ Response: DEQ's authority is defined within Oregon's Air Quality programmatic rules, most of which are contained in the EPA-approved State of Oregon Clean Air Act

Implementation Plan which defines how the Clean Air Act is implemented in Oregon. This air quality permitting action is confined to the CPBR stationary source's air contaminant emissions. When DEQ writes an Air Contaminant Discharge Permit it must include all applicable requirements of Oregon's Air Quality program in the respective permit. At the time of this permit action, as it pertains to these comments, CPBR is subject only to greenhouse gas monitoring and reporting requirements under the greenhouse gas program. The permit includes a site-specific plant site emission limit for greenhouse gas emissions in accordance with OARs 340-216-0066(3)(b) and 340-222-0041. DEQ does not have authority to influence or regulate fossil fuel extraction, shipment, or end-use related activities in this permit action. Any future new applicable greenhouse gases regulations adopted by the Environmental Quality Commission will be applied to this facility in the appropriate manner and as defined by rule. DEQ wrote the CPBR permit to appropriately address all applicable requirements to which it is subject and has made no changes to the permit in response to this comment.

10. **Summarized Comment:** *DEQ received numerous comments requesting DEQ regulate mobile sources (specifically trains, trucks, and barges) and mobile source activities associated with CPBR and its operations.*

    DEQ Response: DEQ's Air Quality program issues permits for stationary sources of air contaminant emissions. Trains and marine vessels are mobile sources. Emissions from trains, trucks, and marine vessels that come to or from the CPBR facility are defined in rule as "secondary emissions" [OAR 340-200-0020 (138)]. Secondary emissions are not taken into consideration when assessing a facility's "potential to emit" [OAR 340-200-0020 (100)] and are only considered as part of overall emissions for sources subject to the Major New Source Review provisions of OAR Chapter 340, Division 224. As stated in the review report, the facility is not subject to the Major New Source Review provisions because it is located in an area that is in attainment with all National Ambient Air Quality Standards and the requested plant site emission limits are less than the Federal Major Source threshold of 100 tons per year.

    DEQ's permitting action is confined to the equipment and activities of the CPBR stationary source that emit air contaminants. The permit proposed for issuance to CPBR is an Air Contaminant Discharge Permit; its content is specific to the regulatory requirements of DEQ's stationary source air quality program. While public health and safety is an element of DEQ's authoritative concern, our ability to address this is confined to our ability to regulate air contaminant emissions from the source under our regulatory authority. DEQ's authority in this permitting action is defined within the Oregon Administrative Rules. DEQ reviewed the CPBR facility's operations and design in a manner consistent with this defined regulatory authority. Our review did not find the facility's current or proposed operation to present an imminent danger to human health or the environment.

    The incidents in Mosier, Oregon, and Doon, Iowa, referred to by commenters were associated with oil train accidents. Although there are some Clean Air Act requirements related to emissions from the transportation sector, including in some instances, from trains, in general, DEQ does not have authority to regulate trains or railroad activities. Trains are regulated by the United States Department of Transportation Federal Railroad Administration and the Oregon Department of Transportation Rail Safety Division.

No applicable requirements associated with the Air Quality program pertain to the commenters' points of concern. The comments raise points and concerns outside of DEQ's authority and so, DEQ cannot act to deny or modify the permit as requested.

C. Comments related to CPBR's compliance with applicable regulations

11. **Summarized Comment:** *DEQ received numerous comments claiming that Global, LP has a poor record of safety and environmental compliance and should therefore not be granted a permit.*

    DEQ Response: It is DEQ's responsibility to write the proposed permit to address all Air Quality regulatory requirements that are applicable to the CPBR facility. To properly do so, the proposed permit must include appropriate and sufficient monitoring, recordkeeping, and reporting requirements to allow CPBR and DEQ to verify the company's compliance status. The ethanol production facility has not had any violations since the 2014 oil transloading violation, which is discussed in the review report.

12. **Summarized Comment:** *(Kristin Edmark) It is absolutely necessary that independent inspectors which allow oversight by concerned agencies/the public be allowed access to the facility to make certain that nothing at the facility is being used for oil transport. Self-oversight is worthless for this company with this track record.*

    DEQ Response: DEQ reviews all reports and notifications submitted by CPBR. The self-monitoring and reporting requirements in the permit are representative of the requirements for all air, water, and land permits issued by DEQ and the USEPA. DEQ staff also perform on-site inspections to ensure that CPBR is complying with all applicable permit requirements.

13. **Comment:** *(Kristin Edmark) There must be a clear/quick way of shutting the facility down when violations occur.*

    DEQ Response: Noncompliance with permit conditions is subject to DEQ enforcement. Enforcement actions and/or penalties are determined on a case by case basis by DEQ's Office of Compliance and Enforcement. If necessary, DEQ has the authority to revoke a source's air contaminant discharge permit in accordance with the provisions of OAR 340-216-0082(4).

D. Comments related to land use determinations

14. **Comment:** *(Thomas Gordon) The area where this facility is located is rated as "high seismicity" by the Oregon Department of Geology, DOGAMI.*

DEQ Response: A facility's seismic design is not a factor that DEQ considers as part of an air quality permitting decision. Seismic design considerations for this facility are generally addressed by Columbia County as part of its land use permitting and construction approval processes.

15. **Comment:** *(Center for Sustainable Economy, Columbia Riverkeeper, Envision Columbia County, Friends of the Columbia Gorge, Neighbors for Clean Air, and Northwest Environmental Defense Center) Global's Application Relies on an Outdated Land Use Compatibility Statement.*

    DEQ Response: The land use compatibility statement for the ethanol production facility is dated March 22, 2000, and is adequate for the proposed permit. CPBR submitted an updated land use compatibility statement for the transloading facility, which is dated March 30, 2017.

E. Comments related to future modifications at CPBR's facilities

16. **Summarized Comment:** *DEQ received numerous comments stating that any type of change in CPBR's lease, operation, and/or design should trigger the permitting process.*

    DEQ Response: OAR 340-210-0225 identifies the triggers involved for the various "types" of notice of intent to construct. A permit modification and subsequent public comment period is required if the notice of intent to construct qualifies as a Type 3 or Type 4 notice of intent to construct and can be required for some Type 2 notice of intent to constructs. DEQ cannot force a facility to submit a permit modification or require a public comment period for a Type 1 notice of intent to construct.

17. **Comment:** *(Kristin Edmark) All affected jurisdictions must be notified of any change.*

    DEQ Response: DEQ's public participation regulations are found in OAR 340-209. Public notification is required for only Category II, III, and IV permit actions.

18. **Summarized Comment:** *DEQ received numerous comments claiming that CPBR is attempting to piecemeal multiple small projects to avoid the permitting process.*

    DEQ Response: DEQ evaluates each notice of intent to construct to determine if the proposed project should be aggregated with previous changes at the facility.

F. Comments related to storage tanks

19. **Comment:** *(Paulette Lichatowich) The storage capacity numbers (of the PGE tank farm in the March 14, 2017, Agreement for Purchase of Storage Tanks and Real Property) do not match the applications submitted to ODEQ. The information of "at least 920,000 barrels of crude oil and ethanol" as stated in the agreement equates to 38,640,000 gallons of product which is 4,415,978 gallons in excess of the total tank storage listed in the air emission permits. Because, the scenario presented in the application depends on this purchase agreement, storage capacity numbers should add up.*

DEQ Response: The PGE tank farm consists of seven tanks with a combined volume of 1.15 million barrels (approximately 48.3 million gallons). Not all of these tanks will be used by the ethanol production facility. The proposed permit authorizes CPBR to utilize four of these tanks (approximately 16.8 million gallons) for ethanol storage. CPBR received authorization as part of a 2017 notice of intent to construct to construct the other three tanks (approximately 31.5 million gallons) for oil storage at the transloading facility.

20. **Summarized Comment:** *DEQ received several comments requesting that each storage tank in the permit should be limited to holding one specific liquid*

    DEQ Response: air contaminant discharge permits limit emissions from a source and provide all applicable monitoring, recordkeeping, and reporting so that the source can demonstrate compliance with the applicable limitations. CPBR has the authority to operate the storage tanks under several differing operational scenarios.

21. **Comment:** *(Daphne Wysham) Global Partners plans to use tanks purchased or leased from Portland General Electric (PGE) that are at least 45-50 years old, dating to the 1970s. Few regulations protect the public from these companies' decisions to use these aging, questionable ASTs (above ground storage tanks).*

    DEQ Response: There are no air rules or regulations that prevent CPBR from purchasing and refurbishing older tanks. ASTs are regulated by DEQ's Tanks Program, EPA's Spill Prevention, Control and Countermeasure Rule, State Fire Marshal's Office and/or Local Fire Departments.

22. **Summarized Comment:** *Above ground ethanol storage tanks should have the same requirements as underground storage tanks and must be inspected to ensure they are capable of safely storing ethanol.*

    DEQ Response: Placement, safety, and spill containment of above ground and underground storage tanks are not regulated by DEQ's Air Quality Division. The proposed air permit contains all applicable air regulations and requirements for the ethanol storage tanks. ASTs are regulated by DEQ's Tanks Program, EPA's Spill Prevention, Control and Countermeasure Rule, State Fire Marshal's Office and/or Local Fire Departments.

G. Other Comments

23. **Summarized Comment:** *DEQ received several comments endorsing the issuance of the proposed permit to CPBR. Many of these comments identified various economic benefits associated with the facility and job creation.*

    DEQ Response: DEQ acknowledges and appreciates the support for the proposed air contaminant discharge permit. None of the commenters endorsing DEQ's issuance of the proposed permit identified elements of the permit action that required change or re-evaluation. No further consideration by DEQ is necessary for this comment category.

24. **Comment:** *(Oregon Physicians for Social Responsibility) We are asking that the Oregon Department of Environmental Quality consider seriously the benefits of prevention and the precautionary principle in its deliberations about this and other proposed air quality permits to give attention to the cumulative impacts of adding/permitting another generator of air pollutants into an already seriously compromised air shed.*

    DEQ Response: Columbia County is currently classified as "attainment" with respect to all pollutants with an ambient air quality standard and DEQ is compelled to issue an air contaminant discharge permit to any source that meets all applicable requirements. The commenter provides no evidence to support the claim that the air shed is seriously compromised. With regards to Columbia County, DEQ monitors ozone and $PM_{2.5}$ in Columbia County at a rural monitoring site on Sauvie Island. The monitored pollutants are in attainment with the applicable ambient air quality standards. In 2010, DEQ required PGE to do Prevention of Significant Deterioration monitoring in Rainier for ozone, PM_{10}, and nitrogen dioxide. The results of the model indicated that the area was projected to be in attainment with applicable ambient air quality standards. Southwest Clean Air Agency in Washington monitors for $PM_{2.5}$ in Longview and demonstrates that this area is in attainment with the $PM_{2.5}$ ambient air quality standard.

25. **Summarized Comment:** *DEQ received numerous comments requesting the proposed permit be denied because CPBR hasn't produced ethanol since 2009 and does not plan to produce ethanol in the near future.*

    DEQ Response: DEQ does not have the authority to rescind or deny a permit simply because a source is not operating their facility. So long as the equipment is properly maintained CPBR has the right to renew and maintain their air contaminant discharge permit.

H. Conclusion

Based on the comments received during the public review process DEQ intends to issue the CPBR permit with the following noted revisions:

Review Report:

1. The third sentence in paragraph 3 now reads: Transloading refers to the process of transferring a shipment from one mode of transportation to another (e.g. transferring from truck or rail to barge) and includes intermediate storage between the transportation methods.
2. The following sentence was added to the end of paragraph 3: Therefore, all emissions from crude oil transloading must be accounted for under ACDP 05-0023-ST-01except for HAPs, which must be considered from under this ACDP and ACDP 05-0023-ST-01 together (combined) for ensuring compliance with Condition 4.2 of this ACDP.
3. Paragraph 9 now includes a discussion of the October 18, 2018, notice of intent to construct (application # 030370) which transfers TK6104 from the ethanol production facility to the transloading facility.

4. TK6104 was removed from the list of equipment in paragraphs 10 and 25.
5. Paragraph 16 now includes an additional subparagraph stating: The hazardous air pollutant plant site emission limit applies to emissions from sources 05-0006 and 05-0023 combined.
6. The "HAZARDOUS AIR POLLUTANTS" Section (paragraphs 22 and 23) was revised to clarify that the ethanol production and transloading facilities are a single source for hazardous air pollutant emissions.

Permit:

1. TK6014 was removed from Condition 2.4.
2. Condition 2.8 was revised to: The permittee is prohibited from performing the transloading of crude oil under this permit. Crude oil transloading must be conducted under the authority of a separate ACDP.
3. The hazardous air pollutant plant site emission limit was removed from Condition 4.1.
4. A new Condition (4.2.) was added which reads: The permittee must not cause or allow plant site emissions from sources 05-0006 and 05-0023 combined to exceed 9 tons per year of any individual hazardous air pollutant.
5. Condition 10.4. was revised to correct the Oregon DEQ web address.

DEQ would like to thank all individuals who took the time to review the proposed CPBR permit as well as those who attended the public hearing and/or submitted comments.