State of Oregon Department of Environmental Quality

STANDARD
AIR CONTAMINANT DISCHARGE PERMIT

Department of Environmental Quality
Eastern Region
475 NE Bellevue Dr., Suite 110
Bend, OR 97701
(541) 388-6146

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:

Portland General Electric Company
121 SW Salmon Street
Portland, OR 97204

INFORMATION RELIED UPON:

Application No.: 28833
Date Received: 11/2/16, 1/11/17

PLANT SITE LOCATION:

73334 Tower Road
Boardman, OR 97818

LAND USE COMPATIBILITY FINDING:

Pursuant to ORS 469, Oregon Department of Energy's Energy Facility Siting Council granted a Site Certificate in 2012 that determined that the land use complies with state-wide planning goals.

ISSUED BY THE DEPARTMENT OF ENVIRONMENTAL QUALITY

Mark W. Bailey
Mark W. Bailey, Eastern Region Air Quality Manager

SEP - 7 2022
Dated

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

Table 1 Code	Source Description	NAICS	SIC
Part B, 27	Electric Power Generation from Combustion	221112	4911
Part C, 4	Sources with PSEL greater than SER	NA	NA
Part C, 5	Sources with potential to emit more than 100 tons per year	NA	NA

Addendum No. 3
Complex Technical Modification
Significant changes to the ACDP are highlighted

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1.0 INTRODUCTION

1.1. Purpose

This permit modifies the previous ACDP which permitted construction of a combined cycle natural gas-fired electric generating plant (referred to as the Carty Plant) adjacent to the Boardman Power Plant in accordance with the Prevention of Significant Deterioration regulations contained in OAR 340-224-0070. This permit modifies the emissions of carbon monoxide (CO) and volatile organic compounds (VOC) from the turbine during startups and shutdowns. Additional analyses, including a Best Available Control Technology (BACT) determination and an air quality analysis was required for this emissions increase. After issuance, this permit will be rolled into the existing Title V Permit by administrative amendment. The Carty Plant consists of the following equipment:

a. Emissions unit CTEU1, natural gas-fired combustion turbine generator (Mitsubishi Industries M501G1 CTG) with duct burners operating in the combined cycle mode with a heat recovery steam generator (HRSG) and a steam turbine generator (STG);
b. Emissions unit ABEU2, auxiliary natural gas-fired boiler (91 million Btu/hr heat input, nominal capacity);
c. Emissions unit FWP1, diesel-fired water pump emergency engine (265 horsepower, nominal capacity); and
d. Cooling tower.

1.2. Procedural Requirement

Construction of the Carty Plant has been completed. This permit establishes new CO and VOC emission limits and associated compliance monitoring.

1.3. Relationship to Title V Permit

This permit is supplemental to Oregon Title V Operating Permit 25-0016-TV-01 that allows continued operation of the Boardman and Carty Plant. Upon issuance of this permit, the permittee must submit an administrative amendment to the Title V Permit incorporating the modified emission limits, emission factors, and monitoring.

1.4. Acid Rain Permit Application

Reserved.

1.5. Federal/State Enforceable Requirement

All conditions of this permit are federally enforceable, as that term applies for the Title V program, except Conditions 2.4 and 2.5.

2.0 GENERAL EMISSION STANDARDS AND LIMITS

2.1.	**Visible Emissions**	Emissions from any air contaminant source other than fugitive emission sources, must not equal or exceed 20% opacity. 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.
2.2.	**Particulate Matter Emissions**	The permittee must comply with the following particulate matter emission limits, as applicable: a. Particulate matter emissions from the Carty Auxiliary Boiler (ABEU2) must not exceed 0.10 grains per dry standard cubic foot, corrected to 12% CO_2 or 50% excess air. [OAR 340-228-0210(2)(c)] b. Particulate matter emissions from the Carty Turbine (CTEU1) and Fire Water Pump (FWP1) must not exceed 0.10 grains per standard cubic foot. [OAR 340-226-0210(2)(c)]
2.3.	**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. Installing adequate containment during sandblasting or other similar operations; f. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne; g. Promptly removing earth or other material that does or may become airborne from paved streets; and h. 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.
2.4.	**Particulate Matter Fallout**	The permittee must not cause or permit the deposition of any particulate matter larger than 250 microns in size at sufficient duration or quantity, as to create an observable deposition upon the real property of another person.

2.5. 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.

2.6. Fuels and Fuel Sulfur Content

a. If the permittee burns any of the fuels listed below, the sulfur content cannot exceed:
   i. 0.0015% sulfur by weight for ultra low sulfur diesel;
   ii. 0.3% sulfur by weight for ASTM Grade 1 distillate oil;
   iii. 0.5% sulfur by weight for ASTM Grade 2 distillate oil;

b. The permittee is allowed to use on-specification used oil as fuel which contains no more than 0.5% sulfur by weight. The permittee must obtain analyses from the marketer or, if generated on site, have the used oil analyzed, so that it can be demonstrated that each shipment of oil does not exceed the used oil specifications contained in 40 CFR Part 279.11, Table 1.

3.0 SPECIFIC PERFORMANCE AND EMISSION STANDARDS

3.1. CTEU1 – NO_x BACT Limit Nitrogen oxide emissions from CTEU1 must not exceed the following limits:

a. 2.0 ppmvd @ 15% O_2 as a 3-hour rolling average while operating at 60% of maximum load or greater;
b. 24 lbs/hr as a 3-hour rolling average that applies at all times, excluding periods of startup and shutdown; and
c. 150 lbs/hr as a 3-hour rolling average that applies at all times, including periods of startup and shutdown.

3.2. CTEU1 – NO_x NSPS Limit The permittee must not cause to be discharged into the atmosphere from CTEU1 any gases that contain nitrogen oxides (expressed as NO_2) in excess of 15 ppm corrected to 15% oxygen, in accordance with 40 CFR 60.4320(a). Emissions in excess of 15 ppm during periods of startup, shutdown and malfunction shall not be considered a violation in accordance with 40 CFR 60.8(c). However, for purposes of excess emission reports required by 40 CFR 60.7(c), an excess emission is any 30 unit operating day rolling average for all periods of unit operation, including startup, shutdown and malfunction in accordance with 40 CFR 60.4350(h) and 60.4375(a).

3.3. CTEU1 - SO_2 NSPS Limit The permittee must not cause to be discharged into the atmosphere from CTEU1 any gases that contain sulfur dioxide in excess of 0.060 lb/MMBtu-heat input in accordance with 40 CFR 60.4330(a)(2). The sulfur content of the fuels must be measured in accordance with Condition 59 of the Title V Permit.

3.4. CTEU1 – CO BACT Limit

Carbon monoxide emissions from CTEU1 must not exceed the following limits:

a. 2.0 ppmvd @ 15% O_2 as a 3-hour rolling average while operating at 60% of maximum load or greater;
b. 13 lbs/hr as a 3-hour rolling average that applies at all times, excluding periods of startup and shutdown;
c. 4,084 lbs per cold startup. A cold startup is defined as when the HP Turbine inlet metal temperature is less than or equal to 842°F. Startup begins when fuel is introduced to the turbine and ends when the turbine reaches 50% load.
d. 1,007 lbs per hot startup. A hot startup is defined as any startup when the HP Turbine inlet metal temperature is greater than 842°F. Startup begins when fuel is introduced to the turbine and ends when the turbine reaches 50% load;
e. 513 lbs per shutdown. A shutdown is defined as the ramp down from 50% load to cessation of fuel feed.
f. The permittee must conduct startup and shutdown operations in accordance with written procedures that minimize emissions during startups and shutdowns and also minimize the amount of time spent in startup and shutdown to the extent practicable.

3.5. CTEU1 – VOC BACT Limit

Volatile Organic Compound (VOC) emissions from CTEU1 must not exceed the following limits:

a. 1.0 ppmvd @ 15% O_2 as a 3-hour average while operating at 90% of maximum load or greater;
b. 3.6 lbs/hr as a 3-hour average that applies at all times, excluding periods of startup and shutdown; and
c. 1,004 lbs/hr during cold startups. A cold startup is defined as when the HP Turbine inlet metal temperature is less than or equal to 842°F. Startup begins when fuel is introduced to the turbine and ends when the turbine reaches 50% load.
d. 412 lbs/hr during hot startup. A hot startup is defined as any startup where the HP Turbine inlet metal temperature is greater than 842°F. Startup begins when fuel is introduced to the turbine and ends when the turbine reaches 50% load.
e. 315 lbs/hr during shutdown. A shutdown is defined as the ramp down from 50% load to cessation of fuel feed.
f. The permittee must conduct startup and shutdown operations in accordance with written procedures that minimize emissions during startups and shutdowns and also minimize the amount of time spent in startup and shutdown to the extent practicable.

3.6. CTEU1 Stack Height

The stack height must be at least 70 meters but no more than the Good Engineering Practice Stack Height

3.7.	**CTEU1 and ABEU2 – PM_{10} and H_2SO_4 BACT**	The permittee must burn only pipeline quality natural gas in the CTEU1 and ABEU2.
3.8.	**ABEU2 – NO_x BACT**	The permittee must install and operate low-NO_x burners and burn only pipeline quality natural gas in ABEU2. NO_x emissions must not exceed 4.5 lbs/hr.
3.9.	**ABEU2 – CO BACT**	Emissions of CO from ABEU2 must not exceed 2.13 lbs/hr as a three hour average, excluding periods of startup and shutdown.
3.10.	**ABEU2 – VOC BACT**	Emissions of VOC from ABEU2 must not exceed 0.14 lbs/hr as a three hour average, excluding periods of startup and shutdown.
3.11.	**ABEU2 – NESHAP (Part 63, Subpart DDDDD)**	a. The Carty auxiliary boiler (ABEU2) is a limited use boiler according to the definition in 40 CFR 63.7575. The permittee must maintain an annual capacity factor of no more than 10%. The annual capacity factor is the ratio of actual heat input to the auxiliary boiler during a calendar year and the potential heat input had the auxiliary boiler been operated for 8,760 hours/year at the maximum steady-state design heat input capacity. [40 CFR.7575]. b. The permittee must conduct a tune-up of the Carty auxiliary boiler (ABEU2) at least every 5 years as specified in 40 CFR 63.7540. [40 CFR 63.7500(c)]
3.12.	**FWP1 NSPS and BACT**	Emissions from the emergency fire pump diesel-fired engine must not exceed: a. 3 grams of NO_x per horsepower-hour; b. 0.15 gram of PM per horsepower-hour; c. 15 ppmw sulfur content of fuel d. 2.6 grams of CO per horsepower-hour; and e. 1.12 grams of VOC per horsepower-hour.
3.13.	**Boardman Coal Plant Emission Limitations**	Emissions from the adjacent Coal Plant must not exceed the following limits for any 12-month rolling period as measured in accordance with the Oregon Title V Operating Permit 25-0016-TV-01:

Pollutant	Limit
	12/31/20*
PM	0
PM_{10}	0
$PM_{2.5}$	0
SO_2	0
NO_x	0
CO	0
VOC	0
GHG (CO_2e)	0
*After this date the boiler will no longer burn coal and the allowable emissions from coal combustion will drop to zero.	

4.0 PLANT SITE EMISSION LIMITS

4.1. Plant Site Emission Limits (PSEL)

Pollutant	Limit (tons/yr)
PM	86
PM_{10}	71
$PM_{2.5}$	60
SO_2	39
NO_X	126
CO	294
VOC	195
H_2SO_4	16
Pb	0
GHGs (CO2e)	1,318,400

5.0 COMPLIANCE DEMONSTRATION AND SOURCE TESTING

5.1. Source Testing Requirements

Within 18 months of permit issuance the permittee must demonstrate CTEU1 is capable of operating in compliance with Conditions 3.5.a and 3.5.b by conducting a source test for VOC using the following test methods and procedures. The permittee must also conduct a source test to measure emissions of formaldehyde within 18 months of permit issuance. Unless the permittee can demonstrate to DEQ's satisfaction that representative sampling of VOC emissions during startups and shutdowns is not technically feasible, sampling of VOC emissions during startup and shutdown must be conducted within 18 months of permit issuance (unless otherwise approved by DEQ) in order to demonstrate compliance with Conditions 3.5.c, 3.5.d, and 3.5.e.

a. During steady-state operation conditions the VOC test must be conducted using EPA Methods 18 and 25A. The formaldehyde test method must be approved by DEQ prior to sampling. The performance test must include at least 3 test runs. The heat input (MMBtu/hr) must be measured during the test.

b. Subsequent steady-state VOC testing must be conducted annually (no more than 12 months after the previous VOC test) unless two consecutive test results are less than 75% of the limit in Condition 3.5.a, in which case testing will be every 5 years.

c. The test methods for sampling formaldehyde and VOC emissions during startup and shutdown must be approved by DEQ's Source Test Coordinator.

d. 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.

e. 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.

5.2. CTEU1 NO_x Monitoring Requirements

The permittee must certify, operate, maintain and record the output of a NO_x CEMS (consisting of a NO_x pollutant concentration monitor and an O_2 diluent monitor) with automated DAHS for measuring and recording NO_x concentration (ppm) and emissions rates (lb/million Btu, lb/MWh, and lb/hr) discharged to the atmosphere in accordance with 40 CFR 75.10(a)(2) and 75.12. [40 CFR 60.4345]

a. The data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm and lb/MMBtu, using the appropriate equation from method 19 in Appendix A of 40 CFR Part 60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly CO_2 concentration is less than 1.0 percent CO_2), a diluents cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations. [40 CFR 60.4350(b)]

b. The mass emissions rate in pounds per hour must be calculated as follows:

$$M_{NOx} = ER_{NOx} \times HI_g$$

Where,

M_{NOx} = Hourly mass of NO_x emissions from the combustion of pipeline natural gas, lb/hr.

ER_{NOx}= NO_x emission rate in lb/MMBtu as measured by the CEMS.

HI_g = Hourly heat input of pipeline natural gas, calculated using procedures in Appendix F of 40 CFR 75, in MMBtu/hr,

HI_g = $(Q_g \times GCV_g)/10000$;

Where, Q_g = fuel consumption in 100 scf/hr

GCV_g = gross calorific value of natural gas fuel in Btu/scf provided by the natural gas supplier on a monthly basis.

c. The mass emissions rate in pounds per megawatt hour from combustion turbine (CTEU1), if used for compliance, must be calculated as follows: [40 CFR 60.4350(f)]

$$E = (NO_x)_h * (HI)_h/P$$

Where,

E = Hourly NO_x emission rate, in lb/MWh

$(NO_x)_h$ = Hourly NO_x emission rate, in lb/MMBtu

$(HI)_h$ = Hourly heat input rate to the unit, in MMBtu/hr, measured using the fuel flow monitor

P = Gross energy output of the stationary combustion turbine system in MW

= $(Pe)_t + (Pe)_c + Ps + Po$

$(Pe)_t$ = Electrical or mechanical energy output of the combustion turbine in MW

$(Pe)_c$ = Elctrical or mechanical energy output (if any) of the steam turbine in MW

Ps = Useful thermal energy of the steam, measure relative to ISO conditions, not used to generate additional electric or mechanical output, in MW

= $Q * H/3.414 \times 10^6$ Btu/MWh

Q = Measure steam flow rate in lb/hr

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413×10^6 = conversion from Btu/h to MW.

Po = Other useful heat recovery, measure relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine

d. The permittee must ensure that all CEMS meet the equipment, installation and performance specifications in 40 CFR Part 75 Appendix A. [40 CFR 75.10(b)]

e. The permittee must ensure that all CEMS are in operation at all times that each affected facility combusts any fuel and that the following requirements are met: [40 CFR 75.10(d)]

   i. The permittee must ensure that each CEMS and component thereof is capable of completing a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute interval. The permittee must reduce all NO_x concentration and NO_x emissions rate data to 1-hour averages. The permittee must compute these averages from four or more data points equally spaced over each 1-hour period, except during periods when calibration, quality assurance, or maintenance activities pursuant to 40 CFR 75.21 and Appendix B of 40 CFR Part 75 are being performed. During these periods, a valid hour must consist of at least two data points separated by a minimum of 15 minutes. For combined monitoring systems (NO_x - diluent), the hourly average emission rate is valid only if the hourly average concentration from each of the component monitors is valid.

   ii. Failure of a NO_x CEMS to acquire the minimum number of data points comprising a valid hour, as specified in this condition, will result in the loss of such component data for the entire hour. The permittee must estimate and record emission or flow data for the missing hour by means of the automated DAHS, in accordance with 40 CFR Part 75 Subpart D.

   iii. Notwithstanding Condition ii, only quality assured data from the CEMS shall be used to identify excess emissions for the purposes of Condition 3.2. Periods where missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under Condition 7.3. [40 CFR 60.4350(d)]

f. The hourly average concentration of NO_x in parts per million, corrected to 15% oxygen, and emission rates in lb/hr, lb/MMBtu-heat input, and lb/MWh, must be recorded at the end of each clock hour that the combustion turbines are operating.

g. For the purposes of Condition 3.1.a, a 3-hour rolling average NO_x concentration is the arithmetic average of the average NO_x concentration measured by the CEMS for a given minute (corrected to 15% O_2) and the 179 minutes preceding the current minute, excluding periods of startup, shutdown and operation less than 60% of maximum load.

h. For the purposes of Condition 3.1.b, a 3-hour rolling average NO_x emission rate is the arithmetic average of the average NO_x emission rate measured by the CEMS for a given hour and the 2 hours preceding the current hour, excluding periods of startup and shutdown.

i. For the purposes of Condition 3.1.c, a 3-hour rolling average NO_x emission rate is the arithmetic average of the average NO_x emission rate measured by the CEMS for a given hour and the 2 hours preceding the current hour, including periods of startup and shutdown.

j. For the purposes of Condition 3.2, a 30-day rolling average NO_x emissions is the arithmetic average of all hourly NO_x emissions data in ppm measured by the CEMS for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_x emissions rates for the preceding 30 unit operating days if a valid NO_x emissions rate is obtained for at least 75 percent of all operating hours. [40 CFR 60.4380(h)]

k. The permittee must ensure that each CEMS and component thereof is capable of accurately measuring, recording and reporting data, and must not incur a full scale exceedance. [40 CFR 75.10(f)]

l. Whenever the permittee makes a replacement, modification or change in the certified CEMS, including the automated DAHS, that significantly affects the ability of the system to measure or record the NO_x emission rate, the permittee must recertify the CEMS or component in accordance with 40 CFR 75.20(b).

m. The permittee must operate, calibrate and maintain each CEMS used under the Acid Rain Program according to the quality assurance and quality control procedures in Appendix B of 40 CFR Part 75. [40 CFR 75.10(b) and 75.21(a)]

n. The permittee must ensure that all calibration gases used to quality assure the operation of the instrumentation required by this permit must meet the definition in 40 CFR 72.2. [40 CFR 75.21(c)]

o. If an out-of-control period occurs to a monitor or CEMS, the permittee must take corrective action and repeat the tests applicable to the “out-of-control parameter” in accordance with 40 CFR 75.24.

p. Whenever a valid hour of NO_x, emissions rate data have not been measured and recorded, the permittee must provide substitute data in accordance with 40 CFR 75.30 through 75.33.

q. If an out-of-control period occurs to a monitor or CEMS, the permittee must take corrective action and repeat the tests applicable to the "out-of-control parameter" in accordance with 40 CFR 75.24.

5.3. CTEU1 CO_2 Monitoring Requirements

In accordance with 40 CFR 60.4345(c), 75.10(a)(3)(ii), 75.13(b), and Appendix G of Part 75, the permittee must install, certify, operate, maintain and record the output of fuel flow meters and calculate the carbon dioxide emissions for each day of operation as follows:

$$W_{CO2} = (F_c \text{ x } H \text{ x } U_f \text{ x } MW_{CO2})/2{,}000$$

Where,

W_{CO2}	=	Daily mass of CO_2 emitted from combustion, tons/day
F_c	=	Carbon based F-factor, 1040 scf/MMBtu for natural gas;
H	=	Daily heat input in MMBtu, as reported in company records
U_f	=	1/385 scf CO_2/lb-mole at 14.7 psia and 68°F
MW_{CO2}	=	Molecular weight of carbon dioxide (44 lb/lbmole)

5.4. CTEU1 CO Monitoring Requirements

The permittee must certify, operate, maintain and record the output of a continuous emissions monitoring system (CEMS) for monitoring carbon monoxide emissions in accordance with the Department's Continuous Monitoring Manual.

a. The data acquisition and handling system must calculate and record the hourly CO emission rate in units of ppm, lb/hr, and lb/MMBtu. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly CO_2 concentration is less than 1.0 percent CO_2), a diluents cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations. During startup and shutdown the emissions must be calculated and recorded in units of lb/event. The HP Turbine metal inlet temperature at the beginning of startup will be recorded in the data acquisition and handling system.

b. The mass emissions rate in pounds per hour must be calculated as follows:

$$M_{CO} = ER_{CO} \text{ x } HI_g$$

Where,

M_{CO}	=	Hourly mass of CO emissions from the combustion of pipeline natural gas, lb/hr.
ER_{CO}	=	CO emission rate in lb/MMBtu as measured by the CEMS.

HI_g = Hourly heat input of pipeline natural gas, calculated using procedures in appendix F of 40 CFR 75, in MMBtu/hr,

$HI_g = (Q_g \times GCV_g)/10000$;

Where, Q_g = Fuel consumption in 100 scf/hr

GCV_g = Gross calorific value of natural gas fuel in Btu/scf provided by the natural gas supplier on a monthly basis.

c. The mass emissions in pounds per event for startups and shutdowns must be calculated as follows:

$$M_{CO(event)} = \sum ER_{CO(min)} \times HI_{g(min)}$$

Where,

$M_{CO(event)}$ = Total mass of CO emissions during a given startup or shutdown period, lb/event.

$ER_{CO(min)}$ = Minute-average CO emission rate in lb/MMBtu as measured by the CEMS.

$HI_{g(min)}$ = Minute-average heat input of pipeline natural gas during the event, in MMBtu.

d. The hourly average concentration of CO in parts per million, corrected to 15% oxygen, and emission rates in lb/hr and lb/MMBtu-heat input must be recorded at the end of each clock hour that the combustion turbine is operating. Emissions of CO in pounds per event must be recorded at the end of each event.

e. For the purposes of Condition 3.4.a, a 3-hour rolling average CO concentration is the arithmetic average of the average CO concentration measured by the CEMS for a given minute (corrected to 15% O_2) and the 179 minutes preceding the current minute, excluding periods of startup, shutdown and operation less than 60% of maximum load

f. For the purposes of Condition 3.4.b, a 3-hour rolling average CO emission rate is the arithmetic average of the average CO emission rate measured by the CEMS for a given hour and the 2 hours preceding the current hour, excluding periods of startup and shutdowns.

g. For the purposes of Conditions 3.4.c, 3.4.d, and 3.4.e, emissions are calculated as the sum of the 1-minute average CO emissions during the startup or shutdown period.

5.5. VOC Compliance Assurance Monitoring

The permittee must monitor emissions of CO using the CEMS as an indication of good combustion and proper operation of the catalytic oxidizer. For an excursion of the CO concentration the permittee must take corrective action as expeditiously as practical. An excursion is defined here as a 3-hour average CO concentration (excluding startups and shutdowns) that is greater than the maximum CO concentration measure during the most recent VOC compliant source test run. An excursion of the CO concentration is not necessarily a violation of the VOC limit.

5.6. FWP1 Certification

a. The permittee must operate and maintain the FWP1 internal combustion engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer. The permittee may only change those settings that are permitted by the engine manufacturer. [40 CFR 60.4211(a)]

b. The permittee must comply with the emission limits in Condition 3.12 by utilizing an engine certified to the emission standards. The engine must be installed and configured according to the manufacturer's specifications. [40 CFR 60.4211(c)]

c. The permittee must install a non-resettable hour meter prior to startup of the engine. [40 CFR 60.4209(a)]

5.7. PSEL Compliance Monitoring

a. The permittee must demonstrate compliance with the PSEL for each 12-consecutive calendar month period, based on the following calculation for each pollutant except for plant-wide GHG emissions, and NOx and CO emissions from the turbine: (Note: This permit contains only emission factors associated with the Carty Plant.)

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

where:

E = pollutant emissions (ton/yr);

EF = pollutant emission factor (see Condition 0);

P = process production (see Condition 13.0)

b. Compliance with the PSEL for NO_x and CO emissions from the turbine is determined for each 12-consecutive calendar month period based on the sum of all emissions from the CTEU1 during the period, as measured in accordance with Conditions 5.2 and 5.4. These values are added to the NO_x and CO emissions from all other emissions units to determine PSEL compliance.

5.8. 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 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.	**General Recordkeeping Requirements**	a. The permittee must comply with the General Recordkeeping Requirements provided in the Title V Permit. b. The permittee must maintain the records specified in Conditions 5.2, 5.3, 5.4 and 5.7 as well as associated CEMS QA/QC activities for the Carty Plant. c. The permittee must keep records of the number and duration of each cold startup, hot startup and shutdown, as well as the CO emissions measured by the CEMS during each event.
6.2.	**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).
6.3.	**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.
6.4.	**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.	**General Reporting Requirements**	The permittee must comply with the Reporting Requirements in the Title V permit.
7.2.	**Initial Compliance Report**	The permittee must submit an initial compliance report for demonstrating compliance with the emission limits in Conditions 3.4, and 3.5 within 45 days of completing the initial performance test.
7.3.	**NSPS Semi-Annual Excess Emissions Reports**	The permittee must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown and malfunction.

7.4.	**Annual/Semi-Annual Report**	The permittee must submit semi-annual and annual reports in accordance with the Title V permit. The annual report must also include a listing of the number and duration of each startup and shutdown for each month and the measured CO emissions during startup and shutdown each month.
7.5.	**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.
7.6.	**Startup and Shutdown procedures**	Within 60 days of permit issuance the permittee must submit the Carty startup and shutdown plans to DEQ for review and approval.
7.7.	**Notice of Frequent Startups**	The permittee must notify DEQ if the Carty turbine has 150 or more startups during a consecutive 12-month period. The notification shall occur within 14 days of the 150th startup and include the type (hot or cold), number and duration of each startup each month as well as the emissions for each month of the previous 12 month period as calculated in accordance with Condition 5.7. The permittee shall also schedule a test for VOC emissions during startup of the Carty turbine no later than 90 days after the 150th startup, unless otherwise approved by DEQ. The VOC testing must be in accordance with Condition 5.1.

8.0 ADMINISTRATIVE REQUIREMENTS

8.1.	**Title V Permit Modification**	The permittee must submit an application for an administrative Title V permit modification to incorporate the applicable requirements of this permit no later than 45 days after issuance of this permit.

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 and 3 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 5 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 4 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 4 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:

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

10.2. Permit Coordinator The permittee must submit all notices and applications that do not include payment to the Eastern Region's Permit Coordinator:

DEQ – Eastern Region
475 NE Bellevue Dr., Suite 110
Bend, OR 97701
541-388-6146

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

DEQ – Eastern Region
475 NE Bellevue Dr., Suite 110
Bend, OR 97701
541-388-6146

10.4. Web Site Information about air quality permits and DEQ's regulations may be obtained from the DEQ web page at www.deq.state.or.us

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 (CARTY ONLY)

Emissions Device or Activity	Pollutant	Emission Factor (EF)	EF Units	EF Reference
CTEU1	PM, PM_{10}, $PM_{2.5}$	5.03E-03	lb/MMBtu	Manufacturer Estimate
	SO_2	3.0	lb/MMft^3	Fuel sulfur content
	NO_x	CEMS	--	--
	CO	CEMS	--	--
	VOC Normal ops Cold start Hot start Shutdown	 2.10E-03 1,003.84 412.15 315.2	 lb/MMBtu lb/hr lb/hr lb/hr	 AP-42 Table 3.1-2a Manufacturer Estimate Manufacturer Estimate Manufacturer Estimate
	H_2SO_4	1.46	lb/MMft^3	31.6% of SO_2 conversion
	GHG	117.1	lb/MMBtu	40 CFR 98
ABEU2	PM, PM_{10}, $PM_{2.5}$	2.5	lb/MMft^3	DEQ form AQ-EF05
	SO_2	3.0	lb/MMft^3	Fuel sulfur content
	NO_x	50	lb/MMft^3	AP-42, Chapter 1.4
	CO	84	lb/MMft^3	AP-42, Chapter 1.4
	VOC	5.5	lb/MMft^3	AP-42, Chapter 1.4
	GHG	117.1	lb/MMBtu	40 CFR Part 98

13.0 PROCESS/PRODUCTION RECORDS

Emissions Device or Activity	Process or Production Parameter	Frequency
CTEU1	Heat input (MMBtu)	hourly
	Natural gas burned (MMft^3)	hourly
	Hours in cold startup, hot startup and shutdown	per event
ABEU2	Natural gas burned (MMft^3)	hourly

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
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2e	Carbon Dioxide Equivalent
DEQ	Oregon Department of Environmental Quality
dscf	dry standard cubic foot
EPA	US Environmental Protection Agency
FCAA	Federal Clean Air Act
Gal	Gallon(s)
GHG	Greenhouse Gas
gr/dscf	grains per dry standard cubic foot
HAP	Hazardous Air Pollutant as defined by OAR 340-244-0040
I&M	Inspection and Maintenance
lb	Pound(s)
MMBtu	Million British thermal units
NA	Not Applicable
NESHAP	National Emissions Standards for Hazardous Air Pollutants
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	parts per million
PSD	Prevention of Significant Deterioration
PSEL	Plant Site Emission Limit
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
scf	standard cubic foot
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
Year	A period consisting of any 12-consecutive calendar months

State of Oregon
Department of Environmental Quality

STANDARD AIR CONTAMINANT DISCHARGE PERMIT REVIEW REPORT

Portland General Electric - Boardman
73334 Tower Road
Boardman, OR 97818

Source Information:

SIC	4911
NAICS	221112

Source Categories (Table 1 Part, code)	B-27, C-4, C-5
Public Notice Category	III

Compliance and Emissions Monitoring Requirements:

FCE	X
Compliance schedule	
Unassigned emissions	
Emission credits	
Special Conditions	X

Source test [date(s)]	18 months after issuance
COMS	
CEMS	X
PEMS	
Ambient monitoring	

Reporting Requirements

Annual report (due date)	3/1
Quarterly report (due dates)	

Monthly report (due dates)	
Excess emissions report	X

Air Programs

Synthetic Minor (SM)	
SM -80	
NSPS (list subparts)	Dc, IIII, KKKK
NESHAP (list subparts)	YYYY, ZZZZ, DDDDD
Part 68 Risk Management	X

CAO	X
NSR	
PSD	X
TACT	
Other (specify)	

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PERMITTING

PERMITTEE IDENTIFICATION

1. Portland General Electric Company (PGE) owns and operates an electric power generation facility located on Tower Road near Boardman, Oregon. The facility includes a coal-fired steam generating boiler, which is no longer operating, and a natural gas-fired combined cycle turbine. Construction of the combined-cycle natural gas turbine, which is also called the Carty Generating Station, was initially permitted by this PSD permit issued on 12/29/10. Construction of the turbine has since been completed and operation has begun under a Title V Permit (25-0016-TV-01) issued on 8/9/16.

PERMITTING ACTION

2. The proposed permit is a modification of the PSD permit. The modification is required to update the Carbon Monoxide (CO) and Volatile Organic Compound (VOC) emission factors to reflect the manufacturer's estimates of emissions during startup. The increase in emissions will require a Best Available Control Technology (BACT) analysis for both CO and VOC emissions. The permit will also modify the requirements related to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (Subpart KKKK). Since the coal-fired boiler has ceased operation, emissions associated with the coal boiler will be removed from the PSEL.

   A separate permit application was submitted on 1/30/17 for an expansion of the Carty Plant involving additional gas-fired turbines, but that application was subsequently withdrawn.

3. PGE has been determined to be an existing source for the purposes of Cleaner Air Oregon in accordance with OAR 340-245-0020 because construction had commenced on this facility prior to November 16, 2018. As an existing source the permittee is required to perform a risk assessment in accordance with OAR 340-245-0050, and demonstrate compliance with the Risk Action Levels for an "Existing Source" in OAR 340-245-8010 Table 1 when called in by DEQ. PGE has not been called in and therefore, has not performed a risk assessment but will perform a risk assessment when called in by DEQ.

OTHER PERMITS

4. The facility is currently operating under Oregon Title V Operating Permit 25-0016-TV-01 and must continue to comply with the provisions of the Title V permit. This permit is being issued to increase the Plant Site Emission Limit (PSEL) for CO and VOC emissions, establish BACT limits on the Carty Plant CO and VOC emissions, and add appropriate monitoring. Once this permit is issued, the permittee must submit an application to revise the Title V permit to incorporate the applicable requirements of this permit.

ATTAINMENT STATUS

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

SOURCE DESCRIPTION

OVERVIEW

6. The PGE facility includes a 584 megawatt (MW) coal-fired electric generating unit, which is no longer operating and is being decommissioned, and a 440 MW combined cycle natural gas-fired electric generating unit. The natural gas fired unit (Carty Plant) includes a combustion turbine, duct burners, heat recovery steam generator (HRSG) and steam turbine/generator. The Carty turbine also has a dry low-NO_x burner, Selective Catalytic Reduction (SCR) with ammonia injection to reduce NO_x emissions, and a catalytic oxidizer to reduce emissions of CO and VOC. In addition to the electric generating unit, the Carty Plant has a cooling tower, natural gas-fired auxiliary boiler used to produce steam during startup of the electric generating unit and a fire water pump engine for emergency situations.

7. No physical changes or changes in the method of operation have been made to the facility since the last permit action other than the termination of coal boiler operation.

PROCESS AND CONTROL DEVICES

8. Existing air contaminant sources at the facility consist of the following:

   a. Boardman Plant: The 584 megawatt (MW) coal plant began construction in 1975 and began operation in 1980. A single 6,400 MMBtu/hr Foster Wheeler pulverized coal-fired boiler provided steam to a single Westinghouse turbine generator. Operation of the coal-fired boiler ceased in October 2020. A small Combustion Engineering oil-fired package boiler provided startup steam.
   b. Carty Generating Station: The facility includes a 440 MW combined cycle natural gas-fired electric generating unit. Components include a combustion turbine (Mitsubishi Industries M501G1), duct burners, heat recovery steam generator, steam turbine/generator, a cooling tower, 26 MMBtu/hr natural gas-fired auxiliary boiler used to produce steam during start up, and a 315 hp fire water pump engine for emergency situations (limit 100 hr/yr for reliability testing and maintenance). The turbine has a dry low-NO_x burner, Selective Catalytic Reduction (SCR) with ammonia injection to reduce NO_x emissions and a catalytic oxidizer to reduce emissions of CO and VOC.

COMPLIANCE HISTORY

9. The facility was inspected on 8/24/16, 8/30/18 and 3/10/21 and found to be in compliance with permit conditions.

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

11. No enforcement actions have been taken against this source since the last permit renewal.

EMISSIONS

12. Proposed PSEL information for the entire facility:

Pollutant	Baseline Emission Rate (tons/yr)	Netting Basis			Plant Site Emission Limits (PSEL)		
		Previous (tons/yr)	Coal Boiler (ton/yr)	Proposed (tons/yr)	Previous PSEL (tons/yr)	Proposed PSEL (tons/yr)	PSEL Increase (tons/yr)
PM	1,056	1,101	1,015	86	1,101	86	-1,015
PM_{10}	1,056	1,101	1,015	86	1,086	71	-1,015
$PM_{2.5}$	--	848	787	61	847	60	-787
SO_2	30,450	9,502	6,700	3	9,525	39	-9,486
NO_x	17,762	5,961	5,836	126	5,961	126	-5,836
CO	767	8,881	8,881	294	8,980	294	-8,686
VOC	92	92	92	195	116	195	79
GHG (CO_2e)	5,670,500	5,670,500	4,351,900	1,318,400	6,796,100	1,318,400	-5,477,700
H_2SO_4	--	16	0	16	16	16	0
Pb	0.17	0.17	0.17	0	0.17	0	-0.17

a. The **baseline emission rate** for all pollutants except greenhouse gas equals the coal plant potential to emit during the baseline period (1977-1978) because the coal plant was permitted to construct and operate during the baseline period but had not begun operations. [OAR 340-222-0051(1)(c)] A baseline emission rate will not be established for $PM_{2.5}$. [OAR 340-222-0048(3)] For greenhouse gas the baseline period is 2010 in accordance with OAR 340-222-0048(1)(b) since this period includes the date the permit allowing construction of the Carty Plant was issued. Selecting this period allows the potential to emit greenhouse gas from the Carty Plant to be included in the baseline PSEL since the PSD permit was issued in 2010. [OAR 340-222-0051(1)(c)] The maximum greenhouse gas emissions from the coal plant occurred from April 2003 through March 2004, but the Carty Plant was not permitted during this period and would not be included in the greenhouse gas baseline. A baseline emission rate for H_2SO_4 was not included since all sulfur from the coal plant was assumed to be emitted as SO_2 rather than SO_4. The baseline emission rate was established in previous permitting actions and there is no new information that effects the previous determination.

b. The **netting basis** is defined as the baseline emission rate minus any emission reductions required by rule, order or permit condition, minus any unassigned PSEL emission reductions, minus any emission credit transfers, plus any emission increases through NSR/PSD approvals. [OAR 340-222-0046(3)] During the previous Title V Permit period two PSD permits were approved that affected the netting basis. These PSD actions included an increase in CO emissions from the coal boiler due to upgrades to the low-NO_x technologies, and an increase in PM, PM_{10}, $PM_{2.5}$, NO_x, and CO emissions due to the initial Carty PSD permit. These values are included in the previous netting basis since the netting increase is included in the current Title V Permit.

   In the regional haze regulations PGE agreed to cease burning coal no later than 12/31/20. The regulation also stipulates that on the date the boiler ceases to burn coal the netting basis and PSEL associated with the coal-fired boiler must be reduced to zero. [OAR 340-223-0030(1)(e)] The boiler ceased to burn coal in October 2020. The netting basis and PSEL for the coal-fired boiler have been reduced to zero in this permit.

c. The **previous PSEL** is the PSEL contained in the current Title V permit which was issued on 8/9/16.

d. The **proposed PSEL** is similar to the previous PSEL except the coal boiler emissions have been removed. In addition, the emissions of CO and VOC are increased in this permit action due to a correction of startup and shutdown emissions at the Carty turbine. Details of the PSEL calculations are contained in the Emission Detail Sheets in Appendix A. The PSEL for SO_2 is set at the generic PSEL since the potential emissions are less than SER. [OAR 340-222-0041(1)]

e. A comparison of the netting basis in the current permit minus the coal-boiler emissions to the proposed PSEL is shown below.

Pollutant	Current Netting Basis Minus Coal Plant Emissions	Proposed PSEL
PM	86	86
PM_{10}	86	71
$PM_{2.5}$	61	60
SO_2	3	39
NO_x	126	126
CO	1	294
VOC	1	195
GHG (CO_2e)	1,318,400	1,318,400
H_2SO_4	16	16

SIGNIFICANT EMISSION RATE ANALYSIS

13. The proposed PSEL is equal to or less than the netting basis for all pollutants except CO and VOC. The PM_{10} and $PM_{2.5}$ emissions decreased due to changes in the way emissions were calculated and do not necessarily represent an actual decrease in emissions of those pollutants. The increase in SO_2 emissions is due to installation of the Carty turbine, but the increase is less than the Significant Emission Rate (SER). Emissions of NO_x and H_2SO_4 are unchanged. In the 12/29/10 PSD Permit which allowed construction of the Carty facility, emissions of CO and VOC were estimated to be less than the SER. Therefore, a PSD analysis for these emissions was not performed at that time. This permit incorporates new emissions information which results in an increase in CO and VOC emissions greater than the SER. As a result, this permit modifies the original PSD permit to include a PSD analysis for CO and VOC emissions from the Carty facility. A summary of the proposed PSEL increases over the Netting Basis is shown in the following table.

Pollutant	SER	Requested Increase Over Previous Netting Basis[1]	Increase Due to Utilizing Capacity that Existed in Baseline Period	Increase Due to Physical Changes or Changes in Method of Operation
PM	25	0	0	0
PM_{10}	15	-15	-15	0
$PM_{2.5}$	10	-1	-1	0
SO_2	40	36	0	36
NO_x	40	0	0	0
CO	100	293	0	293
VOC	40	194	0	194
GHG (CO_2e)	75,000	0	0	0
H_2SO_4	10	0	0	0
Pb	0.6	0	0	0

1. Excluding coal boiler emissions

PSD REQUIEMENTS

14. **Best Available Control Technology (BACT)** means an emission limitation based on the maximum degree of reduction of each air contaminant subject to regulation which would be emitted from any proposed major source or major modification which, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, is achievable for such source. In no event may the application of BACT result in emissions of any air contaminant that would exceed the emissions allowed by an applicable new source performance standard (NSPS) or any standard for hazardous air pollutant (NESHAP). If an emission limitation is not feasible, a design, equipment, work practice, or operational standard, or combination thereof, may be required. Such standard

must, to the degree possible, set forth the emission reduction achievable and provide for compliance by prescribing appropriate permit conditions. [OAR 340-200-0020(17)]

The Environmental Protection Agency's (EPA) "top-down" evaluation process specifies that all available control technologies be ranked in descending order of control effectiveness. The most stringent, or "top", alternative is examined first. That alternative is established as BACT unless it is demonstrated that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on. EPA maintains a clearinghouse of RACT/BACT/LAER Controls (RBLC) to assist permitting authorities in making determinations for a specific source.

BACT limits for emissions of PM/PM_{10}, NO_x, and H_2SO_4 mist were determined in the original Carty PSD permit issued on 12/26/10 and will not be re-evaluated in this permit modification. Based on the corrected emissions estimate, CO and VOC emissions from the Carty turbine, auxiliary boiler, and fire water pump (CO and VOC emitting activities at the Carty facility) are subject to a PSD BACT analysis.

15. A BACT analysis is done on a case-by-case basis and is performed using a top-down method as outlined in EPA's NSR Workshop Manual. This method includes:
    - Identifying all potential control technologies;
    - Eliminate technically infeasible options;
    - Rank the remaining control technologies based on control effectiveness;
    - Evaluate the most effective controls based on a case-by-case consideration of energy, environmental, and economic impacts;
    - Select BACT.

<u>Carty Turbine BACT analysis</u>

16. EPA maintains a database of BACT determinations for a wide variety of emission units. This database, along with a database maintained by the California Air Resources Board, was reviewed to determine recent BACT determinations for large natural gas-fired turbines.

    Thermal oxidation, catalytic oxidation, and good design/operation of the combustion unit are all potential methods for reducing both CO and VOC emissions.

    According to EPA's database, thermal oxidation has not been applied to any combustion turbine. Thermal oxidizer efficiency depends on the emission source, chamber temperature, residence time, and inlet concentrations. Based on the temperature of the Carty combustion turbine exhaust, supplemental firing would be required to raise the exhaust temperature to appropriate levels for the thermal oxidation system to work effectively. Thermal oxidizers are not typically applied to combustion sources to control emissions.

Catalytic oxidation can remove about 20% more VOC emissions and 80% to 94% more CO emissions than good combustion practices alone. Therefore, catalytic oxidation will be ranked as the most effective control over good combustion practices and is considered BACT.

The Carty combustion turbine currently includes catalytic oxidation. This equipment can be used for catalytic oxidation of both CO and VOC emissions. The Carty facility can operate at various loads, both with and without the duct burner operating in the HRSG. These different operating conditions can impact the level of catalytic oxidation control. The proposed level of control for the Carty facility is shown in the table below. This draft permit was first sent out for public comment from January 23, 2018 through April 30, 2018. At that time, the BACT limit was proposed to be 3.2 ppm for CO and 2.0 ppm for VOC. After additional changes to the permit the draft was again sent out for public notice from September 8, 2021 through December 17, 2021 with proposed BACT limits of 2.0 ppm for CO and 1.5 ppm for VOC. After further review DEQ has decided to set the BACT limits at 2.0 ppm for CO and 1.0 ppm for VOC. The new limits are based on review of existing and newer turbines that have come on-line.

Pollutant	Control	Operating Condition	Proposed BACT Limit	Compliance Method
CO	Catalytic Oxidation	>60% load	2.0 ppmvd @ 15% O_2 (3-hr rolling average)	CEMS
		All loads excluding startup and shutdown	13 lb/hr (3-hr rolling average)	CEMS
		Cold startup	4,084 lb/startup	CEMS, follow recommended procedures, minimize startup time
		Hot startup	1,007 lb/startup	
		Shutdown	513 lb/shutdown	
VOC		90-100% load	1.0 ppmvd @ 15% O_2	Source test and 3-hour average
		All loads excluding startup and shutdown	3.6 lb/hr	Source test and 3-hour average
		Cold startup	1,004 lb/hr	Follow recommended procedures, minimize startup time. Monitor CO CEMS
		Hot startup	412 lb/hr	
		Shutdown	315 lb/hr	

Some of the more recent determinations in the EPA and CARB database are shown below. This table was updated after the second public notice to include BACT determinations after 6/30/17. For some permits a separate limit was set for duct firing versus non-duct firing operation. A few BACT determinations also included limits on emissions during startup/shutdown.

Date	Facility	Engine Rating	CO Limit (@15% O_2)	VOC Limit (@15% O_2)	Averaging Time	Startup/Shutdown Conditions
6/7/21	Shady Hills Energy, FL	385 MW	6.5 ppmvd	--	30 day avg	Follow manufacturer's procedures
3/17/21	NRG Cedar Bayou, TX	689 MW	4.0 ppmvd	1.0 ppmvd	3-hr avg	--
1/7/21	LBWL Erickson Sta, MI	667 MMBtu/hr	4.0 ppmvd	3.0 ppmvd	24-hr avg	CO: 389 lb/hr including SU/SD
11/9/20	APC Plant Barry, AL	774 MW	0.005 lb/MMBtu	0.003 lb/MMBtu	3-hr avg	--
8/13/20	Alaska Gasline Devel, AK	576 MMBtu/hr	5.0 ppmvd	0.0022 lb/MMBtu	3-hr avg	--
1/6/20	FG LA LLC, LA	2222 MMBtu/hr	4.0 ppmvd	4.0 ppmvd		
11/26/19	Indeck Niles, LLC, MI	3421 MMBtu/hr	4.0 ppmvd	4.0 ppmvd	24-hr avg	CO: 3,537 lb/hr any SU/SD, 500 hr/yr
8/21/19	Thomas Township Energy, MI	625 MW	2.0 ppmvd	0.004 lb/MMBtu	24-hr average	CO: 2,106 lb/hr including SU/SD
6/27/19	Big Cajun 1, LA	120 MW	25 ppm	--	3-hr average	--
12/31/18	Jackson Energy Ctr., IL	3864 MMBtu/hr	2.0 ppmvd	--	3-hr average	CO: 483.5 lb/hr any SU/SD
9/18/18	Brooke County Power Plant, WV	462.5MW	2.0 ppmvd	2.0 ppmvd	--	CO: 310 lb/hot SU, 350 lb/warm SU, 950 lb/cold SU, 125 lb/SD VOC: 28 lb/hot SU, 30 lb/warm SU, 87 lb/cold SU, 28 lb/SD
8/27/18	Renaissance Energy, PA	3580 MMBtu/hr	--	1.4 ppmvd	--	--
7/30/18	Three Rivers Energy, IL	3474 MMBtu/hr	2.0 ppmvd	--	3-hour avg	CO: 1,522 lb/hr (3-hr avg) SU
7/30/18	New Covert Generating Facility, MI	410 MW	2.0 ppmvd	1.0 ppmvd	24-hr average	CO: 1,164 lb/hr any SU/SD
7/27/18	Shady Hills Combined Cycle Facility, FL	385 MW	4.3 ppmvd	--	3-hr average	--
7/16/18	Belle River Power Plant, MI	575 MW	0.0045 lb/MMBtu	0.0026 lb/MMBtu	24-hr average	CO: 791.5 lb/hr any SU/SD
6/29/18	Marshall Energy Center, MI	500 MW	4.0 ppmvd	4.0 ppmvd	24-hr average	CO: 788.6 lb/hr any SU/SD 300 hr/yr
4/26/18	Novi Energy,VA	4107 MMBtu/hr	1.8 ppmvd	2.0 ppmvd	3-hr average	CO: 36 lb/hot SU, 397 lb/warm SU, 434 lb/cold SU, 184 lb/SD

Date	Facility	Engine Rating	CO Limit (@15% O_2)	VOC Limit (@15% O_2)	Averaging Time	Startup/Shutdown Conditions
						VOC: 34 lb/hot SU, 34 lb/warms SU, 37 lb/cold SU, 56 lb/SD
4/19/18	Harrison Power, OH	3231 MMBtu/hr	2.0 ppmvd	2.0 ppmvd	24-hr average	CO: 35.4 ton/yr any SU/SD VOC: 42.5 ton/yr any SU/SD
3/30/18	Montgomery County Power Station, TX	2635 MMBtu/hr	2.0 ppmvd	2.0 ppmvd	3-hr average	CO: 8,000 lb/hr VOC: 2,000 lb/hr
3/27/18	Harrison County Power Plant, WV	3496 MMBtu/hr	2.0 ppmvd	2.0 ppmvd	--	CO:120 lb/hot SU, 155 lb/warm SU, 790 lb/cold SU, 124 lb/SD VOC: 9 lb/hot SU, 10 lb/warm SU, 55 lb/cold SU, 26 lb/SD
3/21/18	Seminole Generating Station, FL	415 MW	--	2.0 ppmvd	--	--
2/1/18	TVA Johnsonville, TN	1339 MMBtu/hr	2.0 ppmvd	--	30-day average	CO: 1760 lb/SU, 22 lb/SD
11/17/17	Filer City Station, MI	1935 MMBtu/hr	4.0 ppmvd	--	24-hr avg	CO: 1,580 lb/event any SU/SD
11/7/17	Long Ridge Energy, OH	3600 MMBtu/hr	2.0 ppmvd	2.0 ppmvd	--	CO: 140.7 lb/hr hot, 449.4 lb/hr warm, 538.6 lb/hr cold, 162.7 lb/hr SD VOC: 185.9 lb/hr hot, 225.1 lb/hr warm, 224.7 lb/hr cold, 97 lb/hr SD
10/23/17	Guernsey Power Station, OH	3516 MMBtu/hr	2.0 ppmvd	2.0 ppmvd	--	CO: 133 lb/hot SU, 161.5 lb/warm SU, 791.6 lb/cold SU, 139.6 lb/SD VOC: 13.7 lb/hot SU, 16.5 lb/warm SU, 55.9 lb/cold SU, 34.9 lb/SD
9/27/17	Oregon Energy Center, OH	3055 MMBtu/hr	2.0 ppmvd	2.0 ppmvd	--	CO: 436 lb/hr hot, 496 lb/hr warm, 526 lb/hr cold, 150 lb/hr SD VOC: 59.6 lb/hr hot, 60.1 lb/hr warm, 64.4 lb/hr cold, 62.8 lb/hr SD
9/7/17	Trumbull Energy Center, OH	3025 MMBtu/hr	2.0 ppmvd	2.0 ppmvd	--	CO: 436 lb/hr hot, 496 lb/hr warm, 526 lb/hr cold, 159 lb/hr SD

Date	Facility	Engine Rating	CO Limit (@15% O_2)	VOC Limit (@15% O_2)	Averaging Time	Startup/Shutdown Conditions
						VOC: 59.6 lb/hr hot, 60.1 lb/hr warm, 64.4 lb/hr cold, 67.9 lb/hr SD
6/30/17	Killingly Energy Center, CT	550 MW, 2639 MMBtu/hr	(1.7 lb/MMBtu)	1.6 ppmvd	1-hour block	--
4/28/17	Gaines County Power Plant, TX	426 MW	2.0 ppmvd	3.5 ppmvd	3-hour average	--
1/4/17	Indeck Niles, MI	4161 MMBtu/hr	4.0 ppm (24.7 lb/hr)	4.0 ppmvd	24-hour average	CO: 3537 lb/hr any SU/SD
12/5/16	Holland Public Works, MI	162 MW, 554 MMBtu/yr	4.0 ppmvd (5.31 lb/hr)	4.0 ppmvd	24-hour average	CO: 247.3 lb/hr SU, 551.3 lb/hr SD
9/2/16	CPV Fairview Energy, PA	3338 MMBtu/hr	2.0 ppmvd	1.5 ppmvd	--	--
8/31/16	St. Charles Power, LA	3625 MMBtu/hr	2.0 ppmvd	2.0 ppmvd	3-hour avg	--
7/19/16	Middlesex Energy Center, NJ	380 MW, 3,462 MMBtu/hr	2.0 ppmvd (18.1 lb/hr)	2.0 ppmvd (10.3 lb/hr)	3-hr rolling avg. 3 test runs	--
6/17/16	Greensville Power Station, VA	533 MW, 3,227 MMBtu/hr	1.6 ppmvd	1.4 ppmvd	3-hr rolling avg. (CO) 3 test runs (VOC)	CO: 1771 lb/hot SU, 3316 lb/warm SU, 6944 lb/cold SU
4/19/16	TVA Johnsonville Cogeneration, TN	1,339 MMBtu/hr	1800 lb/MW-hr	--	12-month rolling avg	--
3/24/16	Apex Neches Station, TX	231 MW	4.0 ppm	2.0 ppm	hourly avg	--
3/9/16	Okeechobee Energy Center, FL	350 MW, 3,096 MMBtu/hr	4.3 ppmvd	2.0 ppmvd	3-hr avg	--
3/8/16	Decordova II Power, TX	231 MW	4.0 ppm	2.0 ppm	--	--
11/30/15	CPV Towantic, CT	402 MW, 2,544 MMBtu/hr	1.7 ppmvd	2.0 ppmvd	1 hr block	CO: 242 lb/hr and SU, 121 lb/hr SD VOC: 37 lb/hr any SU, 60 lb/hr SD

Date	Facility	Engine Rating	CO Limit (@15% O_2)	VOC Limit (@15% O_2)	Averaging Time	Startup/Shutdown Conditions
11/13/15	Mattawoman Energy, MD	286 MW	2.0 ppmvd	1.9 ppmvd	3-hr block avg	CO: 1216 lb/hot SU, 1461 lb/warm SU, 1772 lb/cold SU, 156 lb/SD VOC: 207 lb/hot SU, 258 lb/warm SU, 301 lb/cold SU, 63 lb/SD
11/4/15	FGE Eagle Pines, TX	321 MW	2.0 ppm	2.0 ppm	3-hr avg block	--
10/8/15	Comanche Power, OK	308 MW	0.0785 lb/MMBtu[3]	--	3-hr avg	CO: 1077 lb/SU, 364 lb/SD
10/2/15	Lon C. Hill Power, TX	195 MW	2.0 ppm	2.0 ppm	24-hr avg	--
6/18/15	Eagle Mountain Power, TX	210 MW	2.0 ppm	2.0 ppm	24-hr avg	--
4/1/15	Colorado Bend II Power, TX	337 MW	4.0 ppmvd	4.0 ppmvd	3-hr avg.	--
3/31/15	Cedar Bayou Station, TX	187 MW	15.0 ppmvd	--	--	--
12/19/14	SR Bertron Electric, TX	240 MW	4.0 ppmvd	1.0 ppmvd	1-hr avg	--

Emissions of CO and VOC during startup are anticipated to make a significant contribution to overall emissions. In establishing the PSEL (a 12-month rolling average) the permittee assumed the following.

Event	Number of Events per Year	Hours per year	CO Emissions per Event (lbs)	VOC Emissions per Event (lbs)	Average CO Emission Rate (lb/hr)	Average VOC Emission Rate (lb/hr)
Cold Startup	80	273.6	4084	3433	1194	1004
Hot Startup	80	104	1007	536	774	412
Shutdown	160	80	513	158	1025.7	315

Carty Turbine CO BACT Emission Limit Analysis

17. BACT determinations listed in the EPA clearinghouse for the past 10 years for units with duct firing and catalytic oxidation range from 1.6 ppmvd CO to 25 ppmvd CO. A review of the Bay Area Air Quality Management District (BAAQMD) BACT guidance indicates a 4.0 ppmvd limit for natural gas combined-cycle turbines while the San Joaquin Valley Air Pollution Control District (SJVAPCD) lists 6.0 ppmv as a CO emission limit achieved in practice and 4.0 ppmv as technologically feasible. A review of the lower emitting plants indicates differences between these facilities and Carty. The permit for the Novi Energy, VA was later invalidated. Two of the facilities with lower limits use generations of turbine design that are later than Carty (Mitsubishi-Hitachi M501J for Greensville and GE 7HA for CPV Towantic). These turbines have better fuel premixing and operate at higher temperatures than Carty, which helps reduce the amount of CO formed. The turbines at Carty have already been installed and installing these next generation turbines would require replacing the existing Carty turbine and not just a retrofit. Also, the Carty turbine has an existing BACT limit for NO_x and changing the combustion system to minimize CO could adversely affect compliance with the existing NO_x limit. In addition, many of the lower CO limits are applicable only for turbine operations at loads 90% or greater, where Carty will operate down to 60% load. The remaining facilities either have similar CO limits to Carty (2 ppm) or have limits of 4 ppm or greater.

PGE initially proposed a CO limit of 3.2 ppmvd at 15% O_2 as a 3-hour rolling average as BACT. DEQ requested a review of Carty operating data to determine if there was data indicating that a site-specific BACT limit of 2.0 ppmvd was inappropriate. Carty reviewed operating records from 2017 through 2020 and found no reason the limit should not be set at 2.0 ppm. This level is equivalent to the lowest BACT determinations for other similar generation, similarly sized turbines. DEQ agrees that this limit is an appropriate BACT emission limit. The secondary CO BACT limit of 13 lb/hr as a 3-hr rolling average, excluding periods of startup and shutdown is also appropriate. This pound per hour limit represents the maximum firing rate with a 2.0 ppmvd CO limit.

During times of startup and shutdown the 2.0 ppm and 13 lb/hr CO BACT emission limit will not apply. During these times stable combustion and operating temperatures have not been achieved and temperatures are not optimal for efficient operation of the catalytic oxidizer. Emissions during startup and shutdown can be substantial. Based on information provided by the manufacturer, CO emissions during a cold startup could be as high as 4,084 lb/event, during a hot startup emission could be 1,006.5 lb/event, and during shutdown emissions could be 512.8 lb/event. Since startup and shutdown can make a major contribution to the total amount of CO emissions, DEQ believes it is appropriate to set BACT limits during startup and shutdown. DEQ has determined that a BACT startup and shutdown emission limit based on total CO emissions during those periods is appropriate to capture the emission during the startup and shutdown period and to distinguish between a cold startup, hot startup, and a shutdown. The permit will contain a limit on CO emissions of 4,084 lb/cold startup, 1,007 lb/hot startup, and 513 lb/shutdown, in accordance with the manufacturer's estimates. Startup would be defined as the initiation of combustion in the turbine and ends when the turbine reaches a determined load. The permittee has expressed concern that the load point at which startup is complete may fluctuate over time under different operating conditions. The permittee proposed that startup end when the turbine CO emissions were at 20.6 lb/hr (a previous BACT limit) or less for 30 consecutive minutes. Since the emission limits during startup are greater than steady-state operations, DEQ desires the amount of time spent in startup be minimized in order to minimize emissions. A review of startup definitions in PSD permits issued by other states indicates 50% load is a common endpoint for the definition of a startup. DEQ will define the end of startup to be 50% load. If PGE can provide data indicating that this definition is too restrictive, a permit modification can be requested to change the limit. A cold startup would be defined as any startup where the high pressure turbine inlet metal temperature is less than or equal to 842°F while a hot startup would be a re-start where the high pressure turbine inlet metal temperature is greater than 842°F. This will minimize the number of hot starts that would otherwise be classified as cold starts.

The permittee will be required to conduct startup and shutdown operations in accordance with written procedures that minimize emissions during startups and shutdowns and also minimize the amount of time spent in startup or shutdown. Records indicating compliance with the written procedures will be kept.

Carty Turbine VOC BACT Analysis

18. BACT determinations listed in the EPA clearinghouse for the past 10 years for units with duct firing and catalytic oxidation range from 1.0 ppmvd VOC to 4.0 ppmvd VOC. A review of the Bay Area Air Quality Management District (BAAQMD) and the San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT guidance indicates a 2.0 ppmvd VOC limit for natural gas cogeneration turbines. The permittee initially proposed a VOC limit of 2.0 ppmvd at 15% O_2 as a 3-hour rolling average as BACT. PGE later indicated that a limit of 1.5 ppmvd at 15% O_2 could be maintained when operating at 90% or greater turbine load. In response to comments received during the

second public comment period, DEQ did a closer examination of VOC BACT determinations and found that a 1.0 ppmvd at 15% O_2 VOC limit had been established and demonstrated at a turbine similar to Carty (same make and model). DEQ can find no reason to reject this level of control as a BACT limit at Carty. Therefore, the VOC BACT limit in the permit will be changed to 1.0 ppmvd at 15% O_2 when the turbine is operating at 90% load or greater. PGE proposed the limit be established as a 3-hour rolling average. However, DEQ feels that a 3-hr average on the VOC limit is more appropriate than a 3-hour rolling average due to the fact that compliance with the limit will be demonstrated by 3 1-hour stack tests rather than by CEMS. If VOC emissions were measured continuously with a CEMS a rolling average would be appropriate. Using stack testing as a compliance method will not produce sufficient data to determine a rolling average. Since CO emissions are often a an indicator of good combustion and proper operation of the catalytic oxidizer, the CO CEMS will be used to provide confidence that VOC emissions are well controlled on an on-going basis. The secondary VOC BACT limit of 3.6 lb/hr (mass emissions at 1.0 ppmvd) as a 3-hr average is also appropriate.

During times of startup and shutdown the 1.0 ppm and 3.6 lb/hr VOC BACT limits will not apply. During these times stable combustion and operating temperatures have not been achieved and temperatures are not optimal for efficient operation of the catalytic oxidizer. The turbine vendor supplied average VOC emission estimates of approximately 1,004 lb/hr during each cold startup, 412 lb/hr during each hot startup, and 315 lb/hr during each shutdown. Establishing a pound per hour BACT limit rather than a pound per event is appropriate for VOC emissions since emissions are not continuously monitored. Compliance will be demonstrated by stack testing, and the variable duration of each event could make sampling over the entire period during three test runs difficult. Since startup and shutdown can make a major contribution to the amount of VOC emissions, DEQ believes it is appropriate to set limits during startup and shutdown. The permit will contain a limit on VOC emissions for cold startup of 1,004 lb/hr, for hot startup 412 lb/hr, and for shutdown 315 lb/hr.

For VOC compliance during startups and shutdowns, the permittee will be required to conduct startup and shutdown operations in accordance with written procedures that minimize emissions during startups and shutdowns and also minimize the amount of time spent in startup or shutdown.

Carty Auxiliary Boiler BACT analysis

19. The EPA database of BACT determinations was reviewed to determine recent CO and VOC BACT determinations for natural gas fired boilers with less than 100 MMBtu/hr heat input used for startup of turbines. The results are shown below.

Date	Facility	Boiler Rating	CO Limit	VOC Limit	Averaging Time
6/7/21	Shady Hills, FL	60 MMBtu/hr	0.080 lb/MMBtu	--	--

Date	Facility	Boiler Rating	CO Limit	VOC Limit	Averaging Time
1/7/21	LBKL Erickson, MI	50 MMBtu/hr	50 ppm	0.30 lb/hr	1-hour
11/9/20	APC – Plant Barry	90.5 MMBtu	0.037 lb/MMBtu	0.0040 lb/MMBtu	--
8/13/20	Alaska Gasline Development, AK	32 MMBtu/hr	0.087 lb/MMBtu	0.0057 lb/MMBtu	3-hour
7/23/20	Nucor Steel, KY	28 MMBtu/hr	0.082 lb/MMBtu	0.0054 lb/MMBtu	--
4/23/20	Chevron Chemical, TX	100 MMBtu/hr	50 ppmvd @3% O_2	0.0054 lb/MMBtu	--
1/8/20	Phillips 66 Sweeny, TX	90 MMBtu/hr	--	0.0054 lb/MMBtu	--
9/27/19	Northstar Bluescope Steel, OH	88 MMBtu/hr	0.070 lb/MMBtu (6.16 lb/hr)	(0.48 lb/hr)	--
8/21/19	Thomas Township Energy, MI	80 MMBtu/hr	0.037 lb/MMBtu (2.96 lb/hr)	0.0054 lb/MMBtu (0.43 lb/hr)	--
12/31/18	Jackson Energy, IL	96 MMBtu/hr	0.037 lb/MMBtu (3.55 lb/hr)	--	3-hour
8/27/18	Renaissance, PA	88 MMBtu/hr	0.055 lb/MMBtu (4.84 lb/hr)	--	--
7/30/18	CPV 3 Rivers, IL	96 MMBtu/hr	3.6 lb/hr	0.1 lb/hr	3-hour
7/27/18	Shady Hills, FL	60 MMBtu/hr	0.08 lb/MMBtu (4.8 lb/hr)	--	--
6/29/18	Marshall Energy, MI	61.5 MMBtu/hr	0.08 lb/MMBtu (4.92 lb/hr)	0.004 lb/MMBtu (0.25 lb/hr)	--
4/19/18	Harrison Power, OH	44.55 MMBtu/hr 80 MMBtu/hr	1.67 lb/hr 2.48 lb/hr	0.16 lb/hr 0.248 lb/hr	--
3/7/18	Harrison County, WV	77.8 MMBtu/hr	2.88 lb/hr	0.62 lb/hr	--
12/4/17	Dania Beach Energy, FL	99.8 MMBtu/hr	0.08 lb/MMBtu (7.98 lb/hr)	--	--
11/7/17	Long Ridge, OH	26.8 MMBtu/hr	0.99 lb/hr	0.13 lb/hr	--
9/27/17	Oregon Energy, OH	37.8 MMBtu/hr	2.08 lb/hr	0.23 lb/hr	--
9/7/17	Trumbull Energy, OH	37.8 MMBtu/hr	2.08 lb/hr	0.23 lb/hr	--
3/23/17	Midwest Fertilizer, IN	70 MMBtu/hr	2.556 lb/hr	0.378 lb/hr	3-hour
12/05/16	Holland Public Works, MI	83.5 MMBtu/hr	0.077 lb/MMBtu (6.43 lb/hr)	0.008 lb/MMBtu (0.67 lb/hr)	
9/2/16	CPV Fairview, PA	92.4 MMBtu/hr	0.037 lb/MMBtu (3.42 lb/hr)	0.004 lb/MMBtu (0.37 lb/hr)	3 runs
7/19/16	Middlesex Energy Center, NJ	97.5 MMBtu/hr	3.61 lb/hr	0.488 lb/hr	3-hr average
3/10/16	Sewaren Generating Station, NJ	80 MMBtu/hr	2.88 lb/hr	0.32 lb/hr	3-hr average

Date	Facility	Boiler Rating	CO Limit	VOC Limit	Averaging Time
3/9/16	Okeechobee Clean Energy Center, FL	99.8 MMBtu/hr	0.08 lb/MMBtu (7.98 lb/hr)	--	3-hr average
11/13/15	Mattawoman Energy, MD	42 MMBtu/hr	0.037 lb/MMBtu (1.55 lb/hr)	0.003 lb/MMBtu (0.13 lb/hr)	3-hr average
6/18/15	Eagle Mountain Power, TX	73.3 MMBtu/hr	50 ppm	4.0 ppm	3-hr/1-hr average

For small boilers such as the Carty auxiliary boiler, control of CO and VOC emissions is typically achieved through good combustion practices. All of the BACT determinations in the EPA clearinghouse indicated good combustion as the best control. For CO the BACT limits range from 0.99 lb/hr to 8.0 lb/hr. The application proposed CO emissions when using good combustion practices for the Carty auxiliary boiler as 2.13 lb/hr. For VOC emissions the past BACT limits range from 0.1 lb/hr to 0.67 lb/hr. The proposed VOC emissions when using good combustion practices for the Carty auxiliary boiler is 0.14 lb/hr. The auxiliary boiler went through BACT for PM/PM_{10} and NO_x during the 2010 PSD permit. The current BACT analysis must be done cautiously to avoid a limit that would violate a previous BACT determination. For example, in many combustion systems a decrease in CO and VOC emissions (which are often due to incomplete combustion) could result in an increase in NO_x emissions (due to operation at a higher temperature). DEQ will establish a BACT limit based on the existing auxiliary boiler operating with good combustion. DEQ agrees that 2.13 lb CO/hr and 0.14 lb VOC/hr as a 3-hr average are appropriate levels of BACT control for the existing Carty auxiliary boiler. Since the auxiliary boiler operates for a limited amount of time (247 hr/yr) no compliance tests will be required.

<u>Carty Fire Water Pump BACT analysis</u>

20. The EPA database of BACT determinations was reviewed to determine recent BACT determinations for small (<500 hp) diesel-fired engines. The results are shown below:

Date	Facility	Engine Rating	CO Limit	VOC Limit
8/27/21	El Paso-Newman Power, TX	74 kW	NSPS	NSPS
6/7/21	Shady Hills Energy, FL	347 hp	3.5 g/kW-hr	--
3/26/21	Agrium-Kenai Nitrogen, AK	2.7 MMBtu/hr	0.95 lb/MMBtu	0.36 lb/MMBtu
3/17/21	Big River Steel, AR	2700 kW	3.5 g/kW-hr	1.55 g/kW-hr
2/18/21	Shell Polymers Monaca, PA	unknown	0.5 g/hp-hr	--
1/7/21	LBWL Erickson Sta, MI	315 hp	2.6 g/hp-hr	--
8/13/20	Alaska Gasline Development, AK	250 hp	3.3 g/hp-hr	0.19 g/hp-hr
7/23/20	Nucor Steel, KY	440 hp	2.61 g/hr-hr	--
6/24/19	Chickahominy Power, VA	Unknown	2.6 g/hp-hr	0.11 g/hp-hr
12/31/18	Jackson Energy, IL	420 hp	2.6 g/hp-hr	
12/21/18	LBWL Erickson Sta., MI	315 hp	2.6 g/hp-hr	3.0 g/hp-hr[1]

Date	Facility	Engine Rating	CO Limit	VOC Limit
12/21/18	PTTGCA Petrochemical, OH	402 hp	2.6 g/hp-hr	3.0 g/hp-hr[1]
9/23/18	Toyota Motors, TX	214 kW	2.7 hp-hr	0.14 g/hp-hr
7/27/18	Shady Hills Energy, FL	347 hp	2.6 g/hp-hr	
7/16/18	Belle River, MI	399 hp	2.6 g/hp-hr	0.13 lb/hr
6/29/18	Marshall Energy, MI	300 hp	2.6 g/hp-hr	0.75 lb/hr
5/2/18	Plaquemines Plt1, LA	375 hp	2.6 g/hp-hr	3.0 g/hp-hr[1]
4/26/18	Novi C4GT, VA	315 hp	2.6 g/hp-hr	
4/19/18	Harrison Power, OH	320 hp	2.6 g/hp-hr	3.0 g/hp-hr[1]
2/23/18	Steel Dynamics, IN	150 hp	2.3 g/hp-hr	1.134 g/hp-hr
2/9/18	Ironunits LLC, OH	250 hp	2.6 g/hp-hr	
12/4/17	Dania Beach Energy, FL	422 hp	2.6 g/hp-hr	
10/23/17	Guernset Power, OH	410 hp	2.6 g/hp-hr	3.0 g/hp-hr[1]
9/27/17	Oregon Energy, OH	300 hp	2.6 g/hp-hr	0.24 lb/hr
9/7/17	Trumbull Energy, OH	300 hp	2.6 g/hp-hr	0.24 lb/hr
6/30/17	Donlin Gold, AK	252 hp	2.5 g/hp-hr	--
4/19/17	Pallas Nitrogen, OH	460 hp	2.6 g/hp-hr	0.14 g/hp-hr
1/4/17	Indeck Niles, MI	260 hp	2.6 g/hp-hr	0.64 lb/hr
12/20/16	Topchem Pollock, LA	225 hp	2.6 g/hp-hr	--
12/5/16	Holland Public Works,MI	165 hp	3.7 g/hp-hr	0.47 lb/hr
9/23/16	South Field Energy, OH	311 hp	2.6 g/hp-hr	0.25 lb/hr
9/2/16	CPV Fairview, PA	422 hp	2.6 g/hp-hr	--
8/31/16	St.Charles, LA	282 hp	2.6 g/hp-hr	3.0 g/hp-hr[1]
7/19/16	Middlesex Energy Center, NJ	327 hp	1.87 lb/hr	0.117 lb/hr
6/17/16	Greensville Power Station, VA	376 bhp	2.6 g/hp-hr	3.0 g/hp-hr[1]
6/8/16	Beaumont Terminal, TX	Confidential	3.1 g/hr-hr	1.13 g/hp-hr
3/31/16	Rubart Sta., KS	197 hp	--	1.14 g/hp-hr
3/10/16	Sewaren Generating Station, NJ	360 hp	1.1 lb/hr	0.1 lb/hr
3/9/16	Okeechobee Clean Energy Ctr, FL	422 hp	2.6 g/hp-hr	--
12/8/15	Grain Processing Corporation, IN	425 hp	2.0 g/hp-hr	0.05 g/hp-hr
11/13/15	Mattawoman Energy Center, MD	305 hp	2.6 g/hp-hr	--
1/23/15	Exxon Point Thomson, AK	490 hp	2.6 g/hp-hr	1.13 g/hp-hr
1/8/15	Tinker AFB, OK	300 hp	--	0.15 g/hp-hr

1. Limit is an NSPS limit for combined NO_x and non-methane hydrocarbon

For small engines such as the Carty fire water pump, control of CO and VOC emissions is typically achieved through proper maintenance of the engine. All of the BACT determinations in the EPA clearinghouse indicated proper maintenance as the best control for these pollutants. The BACT limit cannot be greater than the NSPS limit of 2.6 g/hp-hr for CO and 3.0 g/hp-hr for VOC. The BACT limit of 2.6 g CO/hp-hr is appropriate for the fire pump. A VOC emission limit of 1.12 g/hp-hr was proposed. These limits are similar to the NSPS limits and the emission factors in AP-42. Since the pump only operates during emergencies and occasionally for testing and maintenance, no compliance tests will be required.

21. An **ambient air quality analysis** is required for the increases in CO and VOC emissions. An ambient air quality analysis for CO was conducted by the permittee in accordance with OAR 340-225-0050 through 0070 based on a modeling protocol submitted to DEQ. The CO analysis evaluated impacts in Class I and Class II areas within range of the Carty facility. Class I areas are national parks and wilderness areas designated by Congress. Class II areas are areas that are unclassified or in attainment with national ambient air quality standards. There are no direct ambient air quality standards for VOC. However, VOC emissions contribute to the formation of ozone, which does have an ambient air quality standard. The ambient air quality analysis for VOC will be discussed later in this Review Report.

The CO emissions analysis provides a conservative estimate of the ambient concentrations due to the Carty Plant's emissions using approved dispersion models. The CO emissions from the Carty Plant were first modeled to determine if the impacts were greater than significant impact level (SIL) for CO. If the impact is greater than the SIL, additional analyses would be required. The first analysis would evaluate the emissions from the Carty plus emissions from surrounding sources to determine if the combined impacts will exceed a PSD increment. PSD increments are established by EPA to prevent significant deterioration of air quality. The second analysis would evaluate whether the emissions from Carty plus background ambient concentrations could exceed a national ambient air quality standard. For Class I areas, there are additional requirements for determining if the emissions will have an adverse impact on visibility or contribute significantly to nitrogen or sulfur deposition.

PGE provided a CO emissions analysis with the permit modification application. The 2015 version of EPA's AERMOD software (version 15181) was used to determine the ambient CO concentrations due to operation of the Carty facility. On-site meteorological data collected from 4/1/12 through 3/31/13, supplemented with cloud cover and wind data from the Hermiston airport and Spokane upper air data were used in the model along with local terrain data. Several operating scenarios were modeled to determine the worst case ambient impacts. These scenarios included variable ambient temperatures (20°F, 55°F, and 90°F), variable operating loads, 60%, 75%, 100%, and 100% with duct burner), as well as periods of turbine startup. The worst case scenario was determined to be during startup at 20°F ambient temperature. The resulting ambient impact at the worst case scenario is compared to the SIL to determine if additional analysis is required. The results are summarized below.

Pollutant	Maximum Modeled Concentration (µg/m^3)	Significant Impact Level (µg/m^3)
CO (8-hr average)	179	500
CO (1-hr average)	2,300	2,000

The maximum predicted 8-hour concentration is 179 µg/m^3 and occurs adjacent to the facility. The modeled concentration is less than the significant impact level. Therefore, no additional analysis is required for this standard. In addition, OAR 340-224-0070(1)(a)(B) allows exemption from the requirement for pre-construction monitoring if the modeled 8-hour average CO concentration is less than 575 μg/m^3. No pre-construction monitoring is required for CO emissions.

The maximum predicted 1-hour CO concentration is 2,300 μg/m^3 and occurs at a ridge top approximately 10 km southeast of the facility. The modeled 1-hour average CO concentration is greater than the significant impact level. Therefore, additional analysis is required for this standard. CO emissions from 15 permitted sources in the area, including sources near Boardman and Hermiston, were added to the CO emissions from the PGE coal-fired boiler and the Carty plant to determine the combined impact of CO emissions on the ambient airshed. In addition, the ambient background CO concentration was added to the combined modeled impact for comparison against the ambient air quality standards. The results are shown below:

Pollutant	**Modeled Combined Concentration (μg/m^3)**	**Background Concentration (μg/m^3)**	**Total Concentration (μg/m^3)**	**National Ambient Air Quality Standard (μg/m^3)**
CO (1-hr average)	1,422	1,015	2,437	40,000

The predicted CO concentration is well below the National Ambient Air Quality Standard (NAAQS). There are no PSD increment standards for CO emissions. Based on this analysis, emissions from the Carty facility, including the effect of increased startup emissions, will not have an adverse impact on the environment.

22. As mentioned previously, emissions of VOC can contribute to ozone formation. In accordance with OAR 340-224-0070(1)(a)(A) the permittee must submit an analysis of ambient air quality in the area. Any net increase of 100 tons/yr or more of VOC from a source requires an ambient impact analysis including the gathering of ambient ozone monitoring data. [OAR 340-224-0070(1)(a)(B)(vi)] DEQ and Washington Department of Ecology are currently studying ozone concentrations in the Columbia Basin area. Ambient monitoring was conducted at the Hermiston Airport about 28 miles (45 kilometers) NE of the Carty plant. The results of the monitoring are summarized below.

Year	**Ozone (ppb)**	**Standard**
2009	61	70 ppb[2]
2010	63	
2011	58	
2012	68	
2013	62	
2014	64	
2015	70	
2016	63	
2017[1]	73	

Year	Ozone (ppb)	Standard
2018[1]	60	
2019	59	
2020	56	

1. Wildfires these years could have elevated the ambient ozone readings.
2. The ambient ozone standard was changed from 75 ppb to 70 ppb in October 2015

DEQ considers the collected data to be representative and conservative. No additional ozone monitoring will be required. However, the independent study of ozone in the area by DEQ and Washington Dept. of Ecology will continue. Currently it has been determined large point sources of NO_x and VOC likely make a contribution to ozone formation, however, there is no evidence these are solely responsible for elevated ozone in the airshed. T-COPS-Final-Report-12-2017.pdf (bfcog.us). (http://bfcog.us/wp-content/uploads/2018/03/T-COPS-Final-Report-12-2017.pdf)

Ambient impacts from a facility are typically determined using approved air quality models which predict the ambient concentration of a pollutant due to emissions from the facility. This ambient concentration is compared to the National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increments. There are no ambient standards (NAAQS or PSD increments) for VOC. However, VOC is a precursor that leads to formation of ozone, which does have an ambient standard. In accordance with OAR 340-224-0520(2)(a) the ozone impact area for the Carty facility is calculated to be:

$$D = (Q/40) \times 30 \text{ km}$$

Where:

D	=	Ozone impact distance in km;
Q	=	Larger of NO_x or VOC emission increase over netting basis
	=	194 ton/yr for VOC (0 ton/yr for NO_x).

The resulting ozone impact distance is 146 km. The Carty facility is approximately 190 km from the nearest designated ozone area (Portland ozone air quality maintenance area). Therefore, the Carty facility is not considered to have an impact on the Portland ozone air quality maintenance area.

In April 2019 EPA issued "Guidance on the Development of Modeled Emissions Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program" (EPA-454/R-19-003). Although not legally required for PSD compliance or approval, DEQ conducted a MERPs analysis of Carty VOC emissions to determine the impact on ambient ozone concentrations. The analysis indicated emissions from Carty make an insignificant contribution to ozone concentrations in the area. DEQ believes the proposed VOC emissions from Carty are acceptable.

TITLE V MAJOR SOURCE APPLICABILITY

23. 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. After removal of emissions from the coal plant this facility remains a major source of criteria pollutants, but drops from a major to a minor source of HAP emissions. The basis for this determination can be found in the Emission Detail Sheets in Attachment A.

HAZARDOUS AIR POLLUTANTS

24. When the coal boiler emissions are removed, this facility is an area source (not major) source of hazardous air pollutants (HAP). The HAP emissions detail is provided at the end of this report. Provided below is a summary of the HAP emissions.

Pollutant	Potential to Emit (ton/yr)
Acetaldehyde	0.45
Acrolein	0.07
Benzene	0.13
Ethylbenzene	0.36
Formaldehyde	8.00
Hexane	0.02
Polycyclic Aromatic Hydrocarbons (PAH)	0.03
Propylene oxide	0.33
Toluene	1.46
Xylenes	0.72
Total	**11.6**

Only compounds with emissions greater than 0.02 tons/yr are listed.

CLEANER AIR OREGON

25. The 2016 Cleaner Air Oregon Toxic Air Contaminant emissions inventory for this source can be found on this website: 25-0016-TV-01_ATEI_2016.PDF (state.or.us) (https://www.deq.state.or.us/AQPermitsonline/25-0016-TV-01_ATEI_2016.PDF). This inventory includes emissions from the coal boiler during 2016.

26. PGE has not been called in and therefore, has not performed a risk assessment.

TOXICS RELEASE INVENTORY

27. The Toxics Release Inventory (TRI) is a federal program that tracks the management of certain toxic chemicals that may pose a threat to human health and the environment, over which DEQ has no regulatory authority. It is a resource for learning about toxic chemical releases and pollution prevention activities reported by certain industrial facilities. Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA) created the TRI Program. In general, chemicals covered by the TRI Program (https://www.epa.gov/toxics-release-inventory-tri-program/tri-listed-chemicals) are those that cause:
(1) Cancer or other chronic human health effects;
(2) Significant adverse acute human health effects; or
(3) Significant adverse environmental effects.

28. There are currently over 650 chemicals covered by the TRI Program. Facilities that manufacture, process or otherwise use these chemicals in amounts above established levels must submit annual TRI reports on each chemical.

29. DEQ has copied this information from EPA's TRI website and does not guarantee the accuracy of this information. This data includes emissions from the coal boiler.

Chemical Name	Media	Units	2020	2019	2018	1999
1,2,4-TRIMETHYLBENZENE	AIR STACK	Pounds	1	1	14	NR
AMMONIA	AIR STACK	Pounds	2351	4142	4728	NR
BARIUM COMPOUNDS	AIR FUG	Pounds	1.4	1	11	5
BARIUM COMPOUNDS	AIR STACK	Pounds	.2	NR	NR	8500
COPPER COMPOUNDS	AIR FUG	Pounds	1	1	.8	5
COPPER COMPOUNDS	AIR STACK	Pounds	6	13	343	290
DIOXIN AND DIOXIN-LIKE COMPOUNDS	AIR STACK	Grams	.003362	.005119	.0032	NR
HYDROCHLORIC ACID	AIR STACK	Pounds	NR	NR	NR	74000
HYDROGEN FLUORIDE	AIR STACK	Pounds	NR	NR	NR	51000
LEAD COMPOUNDS	AIR FUG	Pounds	.01	.01	.0093	NR
LEAD COMPOUNDS	AIR STACK	Pounds	.3	1	1	NR

Chemical Name	Media	Units	2020	2019	2018	1999
MANGANESE COMPOUNDS	AIR FUG	Pounds	NR	NR	NR	5
MANGANESE COMPOUNDS	AIR STACK	Pounds	NR	NR	NR	460
MERCURY COMPOUNDS	AIR STACK	Pounds	3	13	8	NR
N-HEXANE	AIR STACK	Pounds	74	107	86	NR
SULFURIC ACID	AIR STACK	Pounds	NR	25067	NR	28000
VANADIUM COMPOUNDS	AIR FUG	Pounds	NR	NR	NR	NR
VANADIUM COMPOUNDS	AIR STACK	Pounds	NR	NR	NR	NR
ZINC COMPOUNDS	AIR FUG	Pounds	NR	NR	NR	5
ZINC COMPOUNDS	AIR STACK	Pounds	NR	NR	NR	260

ADDITIONAL REQUIREMENTS

NSPS APPLICABILITY

30. There are several New Source Performance Standards (NSPS) applicable to this facility. These standards are addressed in the current Title V Permit and are summarized below. No new standards are applicable as a result of this modification.

   a. Subpart D - Standards for fossil-fuel-fired steam generators applied to the coal fired boiler, but are no longer applicable since the coal boiler ceased operation.
   b. Subpart Dc - Standards for small industrial-commercial-institutional steam generating units apply to the Carty Plant Auxiliary Boiler. However, there are no emission standards associated with units that burn only natural gas.
   c. Subpart Y - Standards for coal preparation and processing plants applied to the coal processing equipment but is no longer applicable since coal is not handled.
   d. Subpart IIII – Standards for stationary compression ignition internal combustion engines apply to the Carty and Boardman fire pump engines. This standard includes a particulate matter emission limit, a combined NO_x and non-methane hydrocarbon (NMHC) limit, and a limit on fuel sulfur content. The engines should be certified, installed and configured in accordance with the regulation. Since the engines are used on a limited basis non-resettable hour meters will be used to track engine usage.

e. Subpart KKKK – Standards for stationary combustion turbines apply to the Carty Plant turbine. This regulation includes limits on NO_x emissions and on the sulfur content of the fuel burned in the turbine. The current permit has two NO_x limits (15 ppm at 15% O_2 and 54 ng/J of useful output) and requires compliance with the more stringent limit. However, the regulation actually allows compliance with either limit, not the more stringent limit. The permittee has elected to comply with the 15ppm at 15% O_2 limit and has requested that the other limit, with associated monitoring, recordkeeping and reporting, be removed from the permit.

f. Subpart UUUUa – Emission guidelines for greenhouse gas emissions from existing electric utility generating units could have applied to the coal-fired boiler since it commenced construction prior to January 8, 2014. However, the boiler stopped burning coal in 2020 and a state plan for the emission guideline is no longer required. This emission guideline is applicable only to units that burn coal for more than 10.0% of the average annual heat input during the 3 previous calendar years. [40 CFR 60.5775a(b)(3)] Therefore, this emission guideline is not applicable to the Carty facility, which burns only natural gas.

g. Since the Carty Plant turbine is regulated under Subpart KKKK it is exempt from the requirements of Subpart GG. Since the Carty duct burners are regulated under Subpart KKKK they are exempted from the requirements of Subpart Dc. [40 CFR 60.4305(b)]

<u>NESHAPS/MACT APPLICABILITY</u>

31. There are several National Emission Standards for Hazardous Air Pollutants (NESHAP) applicable to this facility. These standards are addressed in the current Title V Permit and are summarized below. No new standards are applicable as a result of this modification.

a. Subpart YYYY – Standards for stationary combustion turbines apply to the Carty turbine. The turbine is considered a new turbine (constructed after January 14, 2003). In accordance with 40 CFR 63.6095(d) the facility must comply with the initial notification requirements of this regulation, but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. Initial notification was submitted on 10/21/16.

b. Subpart ZZZZ – Standards for stationary reciprocating internal combustion engines apply to the Carty and Boardman fire pump engines, and the Boardman emergency generator. The Carty and Boardman fire pump engines will comply with Subpart ZZZZ by meeting the requirements of the NSPS (Subpart IIII). No further requirements from Subpart ZZZZ apply to these engines. [40 CFR 63.6590(c)]

c. Subpart DDDDD – Standards for industrial, commercial, and institutional boilers and process heaters at major sources of HAP applies to the Carty auxiliary boiler. The auxiliary boiler is considered to be limited use because it will have federally enforceable conditions that limit the average annual capacity factor (ratio of actual heat input to potential heat input at 8760 hr/yr) to no more than 10%. [40 CFR 63.7575] As a limited use boiler, the unit is not subject to the emission limits, energy assessment requirements, or operating limits in the Subpart DDDDD. The boiler is required to complete a tune-up every 5 years. [40 CFR 63.7500(c)] The initial notification of startup of the Carty auxiliary boiler was received on 6/21/16.

d. Subpart UUUUU – Standards for coal- and oil-fired electric utility steam generating units applied to the coal-fired boiler, but is no longer applicable.

e. The cooling tower is not subject to Subpart Q because chromium-based water treatment chemicals are not used. [40 CFR 63.400(a)]

GREENHOUSE GAS REPORTING APPLICABILITY

32. OAR Chapter 340 Division 215 is applicable to the source because emissions of greenhouse gases exceed 2,500 metric tons (2,756 short tons) of CO_2 equivalents per year.

RACT APPLICABILITY

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

COMPLIANCE ASSURANCE MONITORING

34. OAR 340-212-0200 requires sources that are subject to Title V, subject to an emission limitation or standard, uses a control device to achieve compliance with the limitation or standard, and has pre-control potential emissions equal or greater than 100 tons/yr to have a compliance assurance monitoring review. Emissions of NO_x, CO and VOC from the Carty turbine could be subject to this review for this permit modification. However, OAR 340-212-0200(2)(a)(F) exempts pollutants that have a continuous compliance determination method. Since there are CEMS to measure NO_x and CO compliance, the review does not apply to these pollutants. A review is required for VOC emissions from the turbine. All other emission points covered by this permit underwent a CAM review in previous permitting actions.

The Compliance Assurance Monitoring (CAM) review is to provide a reasonable assurance of compliance with the emission limit (BACT VOC limit). The monitoring serves as an indicator of emission control performance, but does not have to be a direct measurement of compliance for that pollutant. The VOC BACT limit was established based on the assumption of good combustion practices and proper operation of a catalytic oxidizer. These criteria were also the basis of establishing the CO BACT limit. In addition to measuring compliance with the CO BACT limit, the CO CEMS provides a reliable indicator of good combustion efficiency and proper operation of the catalytic oxidizer. During each run of the VOC compliance source test the permittee will monitor the CO emissions as indicated by the CO CEMS. The maximum CO value for any completed test run that is compliant for VOC emissions shall be established as the VOC action level. If the action level is exceeded the permittee will take action to reduce the concentration of CO in the exhaust.

SOURCE TESTING

PRIOR TESTING RESULTS

35. The results of the source tests on the coal fired boiler since the last permit action are listed below. The coal-fired boiler is no longer operating.

Test Date	Gross Load (MW)	Fuel Usage (tons/hr)	Opacity (%)	PM Emissions (lb/MMBtu)[1]	HCl Emissions (lb/MMBtu)[2]
7/7/15	596	319	3	0.0060 0.0044 gr/dscf 0.17 lb/ton coal	2.3E-04
10/15/15	599	326	2.5	0.0063	6.3E-05
1/7/16	602	329	4	0.0090	2.7E-04
6/29/16	601	326	3	0.0060	1.1E-04
8/22/16	603	326	3.4	0.0033 0.0046 gr/dscf 0.19 lb/ton coal	8.1E-05
10/11/16	600	334	3.8	0.0034	5.0E-05
1/10/17	608	345	5.1	0.0037	1.7E-04
Q2 2017	Boiler did not operate. No test required this quarter				
8/23/17	601	330	3.0	0.0053 0.0104 gr/dscf 0.39 lb/ton coal	6.3E-04
Q4 2017	Boiler did not operate. No test required this quarter				
Q1 2018	Boiler did not operate. No test required this quarter				
6/21/18	604	329	2.8	0.00094	2.0E-04
8/22/18	599	333	2.0	0.0022 0.0030 gr/dscf 0.11 lb/ton coal	
8/20/19[3]		300		0.00706 0.0087 gr/dscf 0.35 lb/ton coal	

1. PM limits are 0.030 lb/MMBtu, 0.10 gr/dscf, and 0.66 lb/ton coal.
2. HCl limit is 2.0E-03 lb/MMBtu.
3. This test has not been reviewed by DEQ yet.

36. A compliance test was conducted on the Carty turbine on 8/31/16. The results are shown below. The Carty CEMS for NO_x and CO were initially certified in August 2016 and have passed a Relative Accuracy Test Audit (RATA) every year since.

Turbine Load	Pollutant	Results	Limit
423 MW 3010 MMBtu/hr Duct burner ON	PM	<0.00067 gr/dscf 0.0017 lb/MMBtu	0.14 gr/dscf 0.00503 lb/MMBtu
	NO_x	1.7 ppmdv @ 15% O_2 19.3 lb/hr 0.046 lb/MW-hr	2.0 ppmdv @ 15% O_2 24 lb/hr 0.43 lb/MW-hr
	CO	<0.2 ppmvd <0.9 lb/hr	2.0 ppmvd[1] 13 lb/hr[1]
	SO_2	2.8E-04 lb/MMBtu	0.060 lb/MMBtu
	Ammonia	0.99 ppmv 2.8 lb/hr	--
	Formaldehyde	<0.03 ppmv <0.2 lb/hr	--

1. Limit is proposed for this permit and is not currently applicable.

PROPOSED TESTING

37. This permit will require additional testing on the Carty turbine to demonstrate compliance with the VOC BACT emission limits and to verify the VOC emission factor.

PUBLIC NOTICE

38. Pursuant to OAR 340-216-0066(4)(b)(C), modification of Standard Air Contaminant Discharge Permits require public notice in accordance with OAR 340-209-0030(3)(d), 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 permittee has requested that this ACDP modification be incorporated into the Title V Permit via an administrative amendment in accordance with OAR 340-218-0150(1)(h), which requires this permit action undergo the same public notice procedures as a Title V Significant Permit Modification. **An initial public notice was issued on Jan. 23, 2018 and a public hearing held on Feb. 22, 2018. The comment period ended on Apr. 30, 2018. Many comments were received during that time. In response to those comments some changes were been made to the permit. These changes include more stringent BACT limits as well as a review of BACT determinations made since the public comment period. The definition of cold startup and hot startup was also clarified. The permit was also modified after the first public notice period to remove regulations and limit pertaining to the coal-fired boiler, which is no longer operating. Due to the changes made, DEQ opted to open a second public comment**

period and receive additional comments. The second public comment period was opened from Sept. 8, 2021 through Dec. 17, 2021. A second public hearing was conducted virtually (on Zoom) on Nov. 9, 2021. Comments from both public comment periods have been considered and responses are attached. The proposed permit will now be sent to EPA for a 45-day review period.

DW:ww

ATTACHMENT A: EMISSION DETAIL SHEETS

TOTAL EMISSIONS

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	NO_x (tons/yr)	CO (tons/yr)	VOC (tons/yr)	H_2SO_4 (tons/yr)	GHG (tons CO_2e/yr)	Pb (tons/yr)
Boardman Plant - main boiler[a]	--	--	--	--	--	--	--	--	--	--
Boardman Plant – auxiliary boiler	0.05	0.03	0.01	1.8	0.5	0.1	0.005	0	564.5	0
Boardman Plant - fugitives	27.9	13.2	2.3	1	1	1	1	0	0	0
Boardman Plant - Total	**28.0**	**13.3**	**2.3**	**2.8**	**1.5**	**1.1**	**1.0**	0	**564.5**	**0**
Carty Plant - combustion turbine	56.6	56.6	56.6	22.6	124.0	291.9	193.6	16.1	1,316,469	
Carty Plant - auxiliary boiler	0.02	0.02	0.02	0.03	0.5	0.8	0.05		1,136	
Carty Plant - fire water pump	0.003	0.003	0.003	0.016	0.244	0.053	0.019		9.0	
Carty Plant - cooling tower	1.1	1.1	1.1							
Circuit Breaker – SF_6 (Carty)									2.8	
Circuit Breaker – SF_6 (Grassland)									231.8	
Carty Plant - Total	**57.7**	**57.7**	**57.7**	**22.7**	**124.7**	**292.7**	**193.7**	**16.1**	**1,317,849**	
Totals	**85.7**	**71.0**	**60.0**	**25.4**	**126.2**	**293.9**	**194.7**	**16.1**	**1,318,413**	**0**

a. The Boardman Plant main boiler (coal boiler) has ceased operation and its emissions are removed from the PSEL in this permit.

BOARDMAN PLANT EMISSIONS

Unit/Device	Process or Throughput		********** PM **********			************ PM_{10} ************			*********** $PM_{2.5}$ ***********		
			Emission Factor		Emissions	Emission Factor		Emissions	Emission Factor		Emissions
	Rate	Units	Rate	Units	(tons/yr)	Rate	Units	(tons/yr)	Rate	Units	(tons/yr)
Particulate Matter											
Main Boiler – NA[a]											
Auxiliary Boiler - oil	50	kgal/yr	2	lb/kgal	0.05	1	lb/kgal	0.03	0.25	lb/kgal	0.01
Coal Storage Pile	1,000,000	ft^2/yr	0.024	lb/ft^2	11.9	0.012	lb/ft^2	6.0	1.79E-03	lb/ft^2	0.9
Coal Yard Bull-Dozer Activity	3,500	hr/yr	2.78	lb/hr	4.9	2.09	lb/hr	3.7	0.06	lb/hr	0.1
Unpaved Road Vehicle Traffic	20,000	VMT/yr	1.01	lb/VMT	10.1	0.26	lb/VMT	2.6	0.03	lb/VMT	0.3
Aggregate Insignificant Activity											
Coal yard conveyor system	3.68E+07	ton/yr	1.33E-05	lb/ton	0.24	6.29E-06	lb/ton	0.12	9.52E-07	lb/ton	0.02
Fly ash handling system	441,504	ton/yr	3.14E-03	lb/ton	0.69	1.10E-03	lb/ton	0.24	1.10E-03	lb/ton	0.24
In-plant coal handling system	16,863,000	ton/yr	8.65E-09	lb/ton	7.29E-05	4.09E-09	lb/ton	3.45E-05	6.20E-10	lb/ton	5.22E-06
Paved road vehicle traffic	55,000	VMT/yr	3.87E-03	lb/VMT	0.11	7.75E-04	lb/VMT	0.02	1.90E-04	lb/VMT	0.01
AI Total					1.0			0.38			0.27
Total					**28.0**			**13.3**			**2.3**

a. OAR 340-223-0030(1)(e) requires the PSEL be reduced to zero on the date the boiler permanently ceases burning coal.

BOARDMAN PLANT EMISSIONS (cont.)

Pollutant	Process or Throughput		Emission Factor		Emissions
	Rate	Units	Rate	Units	(tons/yr)
CO - Main boiler[a]	--		--		--
- Aux boiler	50	kgal/yr	5	lb/kgal	0.1
NO_x - Main boiler[a]	--		--		--
-Aux boiler	50	kgal/yr	20	lb/kgal	0.5
SO_2 - Main boiler[a]	--		--		--
- Aux boiler	50	kgal/yr	71	lb/kgal	1.8
VOC - Main boiler[a]	--		--		--
- Aux boiler	50	kgal/yr	0.2	lb/kgal	0.005
Pb- Main boiler[a]	--		--		--
Pb - Aux Boiler	50	kgal/yr	1.24E-03	lb/kgal	0.00003
GHG - Main boiler[a]					
GHG -Aux Boiler					
CO_2	50	kgal/yr	22,501	lb/kgal	562.53
CH_4	50	kgal/yr	22.82	lbCO_2e/kgal	0.57
N_2O	50	kgal/yr	54.40	lbCO_2e/kgal	1.36
Total GHG - Aux boiler (CO_2e)					**564.5**

a. OAR 340-223-0030(1)(e) requires the PSEL be reduced to zero on the date the boiler permanently ceases burning coal.

BOARDMAN EMISSION FACTORS AND EMISSIONS DOCUMENTATION

Auxiliary Boiler Emissions:

The emission factors for the auxiliary boiler are from AP-42 Tables 1.3-1, 6 and 10, with the assumption of 0.5% sulfur content of the oil. The greenhouse gas (GHG) emission factors are from 40 CFR 98 Tables C-1 and C-2 with the global warming potentials from Table A-1 (1 for CO_2, 25 for CH_4, and 298 for N_2O).

Coal Pile Wind Erosion Emission Estimate:

Particulate emissions from the coal pile are going to be variable from one year to the next depending on meteorological conditions and coal stocking policies. Using Section 13.2.5 from the 2006 (latest) edition of AP-42, the emission factor for a typical meteorological year of wind speeds (1988) was calculated using the following assumptions:

- Although there are five coal storage piles, they have similar geometry. All of the piles have height to base ratios less than 0.2 so a flat pile is assumed for calculations.
- Using conservative estimates the piles will have similar disturbance frequencies (about once per week).
- Total surface area of the coal pile will vary through the year but will average about 1,000,000 square feet (based on previous survey data).
- Because of the bulldozer operations, the threshold friction velocity will be comparable to a coal pile with scraper tracks (0.62 m/s from AP-42 Table 13.2.5-2).
- 1988 meteorological data from the Pendleton Weather Station were used for wind speeds. Wind speed measurement height was 7 meters. (http://cdo.ncdc.noaa.gov/qclcd/QCLCD)

AP-42 Section 13.2.5 uses a calculation which is based on summing individual erosion potentials over the course of a year. Each event is dependent on the fastest mile of wind observed during each disturbance interval.

$$EF = k\sum_{i=1}^{N} P_i$$

Where: EF = emission factor in g/m^2 per year
K = particle size multiplier, 1.0 for PM, 0.5 for PM_{10}, 0.075 for $PM_{2.5}$
N = number of disturbance periods per year
P_i = erosion potential for the ith period.

From AP-42 Section 13.2.5 Equation 3, for each disturbance:

$$P = 58(u^* - u_t)^2 + 25(u^* - u_t)$$

Where: P = erosion potential in g/m^2, P = 0 if $u^* \leq u_t$

u^* = friction velocity in m/sec
u_t = threshold friction velocity in m/sec (0.62 m/sec)

Accounting for the 7 meter height of the wind gage, the friction velocity is calculated by Equation 4 of AP-42 Section 13.2.5

$$u^* = (0.053)(1.05)u_7^+$$

Where: u^+_7 = fastest wind mile for disturbance period measured at 7 meters

Based on these equations, for an emission event to occur during the disturbance period the measured wind speed must be:

$$u_7^+ > \frac{\left(0.62\frac{m}{s}\right)}{(0.053)(1.05)} = 11.14\frac{m}{s}\ or\ 25\ mph$$

Meteorological data for 1988 had 25 one week intervals with the potential for measureable emission events. Calculating the individual erosion potentials and summing yields an annual emission factor of 116.59 g/m^2 (0.024 lb/ft^2) for PM, 58.30 g/m^2 (0.012 lb/ft^2) for PM_{10} and 8.74 g/m^2 (0.002 lb/ft^2) for $PM_{2.5}$. It should be noted that these calculations do not take into account the fact that the site boundary is approximately one mile east of the pile and a substantial portion of these calculated emissions will be deposited within the Boardman facility property.

Bulldozer Operation Emissions Estimate:

Particulate matter emissions from the bulldozer operations were calculated using the equation found in AP-42 Table 11.9-1:

$$EF = \frac{78.4s^{1.2}}{M^{1.3}}$$

Where: EF =emission factor, lb/operating hour
s = silt content, 2.2% from AP-42 Table 13.2.4-1
M = coal moisture content, 27% from 1994 Boardman coal analysis

AP-42 Table 11.9-1 also included scaling factors to determine the percentage of particulate that is PM_{10} (75%) and $PM_{2.5}$ (2.2%). It should be noted that these calculations do not take into account the fact that the site boundary is approximately one mile east of the pile and a substantial portion of these calculated emissions will be deposited within the Boardman facility property.

Unpaved Roads Emissions Estimate:

From AP-42 Section 13.2.2, Equations 1a and 2 are combined to estimate fugitive emissions from unpaved roads at an industrial site with occasional natural mitigation (rain).

$$EF = k(s/12)^a(W/3)^b\left(\frac{365-P}{365}\right)$$

Where: EF =emission factor lb/vehicle mile travelled (VMT)
k = empirical constant; 4.9 for PM, 1.5 for PM_{10}, and 0.15 for $PM_{2.5}$
s = surface material silt content; 5.1% from AP-42 Table 13.2.2-1
a = empirical constant; 0.7 for PM, 0.9 for PM_{10}, and 0.9 for $PM_{2.5}$
W = average vehicle weight of all vehicles on road; 3 tons
b = empirical constant; 0.45 for PM, PM_{10}, and $PM_{2.5}$
P = number of days in a year with at least 0.01 inches precipitation; 90 days.

The emission factor also includes an assumption of 50% control due to dust suppression on the unpaved roads.

Aggregate Insignificant Emissions Estimate:

I. **Coal Yard Coal Handling:** The coal yard coal handling system is designed to provide coal to the in-plant coal handling system. It consists of a railcar dumper, a conveyor system, and two "stacker/reclaimers". Several different fueling scenarios are available to provide coal to the plant. Coal can be delivered directly to the plant from the railcars via the conveyor system or it can be conveyed from the railcar dumper and "stacked out" on the storage pile to be "reclaimed" and delivered to the plant at a later time. The maximum number of transfers under any of the fueling scenarios is twelve. Particulate emissions are controlled by a water based foam and chemical binder application which is sprayed on the coal during coal transfer at the dumper, "stacker/reclaimer" #2, and/or the last conveyor transfer point. This type of dust suppression material is designed to provide control through the entire conveyor system. According to data supplied by the vendor, Betz Water Management Group, the material provides 90% reduction of fugitive particulate emissions.

From AP-42 Section 13.2.4 the emission factor for each transfer or drop can be calculated as:

$$EF = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}\left(\frac{100-C}{100}\right)$$

Where: EF = emission factor (lb/ton transfer)
k = particle size multiplier; 0.74 for PM, 0.35 for PM_{10}, 0.053 for $PM_{2.5}$
U = mean wind speed; 9 mph from meteorological data

M = material moisture content; 27% from monthly as-fired coal analysis
C = control efficiency; 90%

II. **In-plant Coal Handling:** The in-plant coal handling system is designed to receive coal from the coal yard coal handling system and deliver it to the pulverizer silos. The system consists of a distribution bin and two conveyor systems which each feed four pulverizer silos. The silos are in series and the conveyor system has splitters which can direct coal into the silo, send it on to the next silo, or do both. Each coal transfer point is enclosed. Particulate emission control is accomplished by separate dust collectors on each conveyor system. Each dust collection system draws air from inside the coal transfer enclosures and discharges the air outside the building through baghouses. The design collection efficiency is 99.9% for both baghouses.

From AP-42 Section 13.2.4 the emission factor for each transfer or drop can be calculated as:

$$EF = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}\left(\frac{100-C}{100}\right)$$

Where: EF = emission factor (lb/ton transfer)
k = particle size multiplier; 0.74 for PM, 0.35 for PM_{10}, 0.053 for $PM_{2.5}$
U = mean wind speed; 1.1 mph from the Boardman Plant Data Book
M = material moisture content; 27% from monthly as-fired coal analysis
C = control efficiency; 99.9%

III. **Fly Ash Handling:** The fly ash handling system is designed to deliver fly ash from the electrostatic precipitator to storage and subsequently transfer the ash to vehicles for on-site disposal or transporting off-site for use in making concrete. The system is an enclosed pneumatic transfer system with a storage dome, large storage silo, and two smaller holding silos. There are four dust collection systems with baghouses which serve to collect ash at each of the ash transfer points. The baghouses are rated at a 99.9% control efficiency.

The emission factor calculation for drop transfers is not applicable to a pneumatic transfer system. The characteristics of fly ash are similar to dry cement, so AP-42 Section 11.12 “Concrete Batching” was used to estimate emission factors. From Table 11.12-2 of AP-42 the uncontrolled emissions for pneumatic unloading of cement supplements to elevated silos is 3.14 lb/ton for PM and 1.10 lb/ton for PM_{10}.

It was conservatively assumed that the $PM_{2.5}$ emissions are similar to PM_{10} emissions. The 99.9% control efficiency is applied to these emission factors.

IV. **Paved Roads:** There are approximately 4 miles of paved roads on the plant site with a wide variety of vehicular traffic. The most significant vehicular traffic can be broken into three categories:

a. Light vehicles including plant and employee transportation. These vehicles have an average weight of 3 tons and constitute 49% of traffic (27,000 miles/yr).
b. Ash haul trucks average 27 tons and constitute 42% of traffic on paved roads (23,000 miles/yr).
c. Water wagon is used to haul water for dust suppression in the ash disposal pit. This vehicle averages 38 tons and constitutes 9% if paved road traffic (5,000 miles/yr).

The average vehicle weight based on the amount of travel for each type of vehicle is 16.22 tons. From AP-42 Section 13.2.1 the emission factor for paved roads can be calculated as follows:

$$EF = k(sL)^{0.91}W^{1.02}(1 - {}^{P}/_{4N})$$

Where: EF = emission factor, lb/VMT
k = particle size multiplier; 0.011 for PM, 0.0022 for PM_{10}, 0.00054 for $PM_{2.5}$
sL = road surface silt loading; 0.015 g/m^2 AP-42 Section 13.2.1
W = average weight of vehicles traveling the roads; 16.22 tons
P = number of days in a year with at least 0.01 inches precipitation; 90 days
N = number of days in the averaging period; 365 days

CARTY COMBUSTION TURBINE

Annual Hours of Operation 7840 hr/yr (920 hours of outage)
Average Hourly Heat Input 2868 MMBtu/hr
Hourly Gas Usage 2.81 MMcf/hr
Cold Startups (80) 273.6 hr/yr
Hot Startups (80) 104 hr/yr
Shutdowns (160) 80 hr/yr

Pollutant	Process or Throughput		Emission Factor		Emissions
	Rate	Units	Rate	Units	(tons/yr)
$PM/PM_{10}/PM_{2.5}$	**22,485,120**	**MMBtu/yr**	**5.03E-03**	**lb/MMBtu**	**56.6**
CO - Normal Operation	21,172,723	MMBtu/yr	4.46E-03	lb/MMBtu	47.3
- Cold Startup	273.6	hr/yr	1,194	lb/hr	163.3
- Hot Startup	104.0	hr/yr	774	lb/hr	40.3
- Shutdown	80.0	hr/yr	1,025.7	lb/hr	41.0
Total CO					**291.9**
NO_x - Normal Operation	21,172,723	MMBtu/yr	7.37E-03	lb/MMBtu	78.0
- Cold Startup	273.6	hr/yr	145.6	lb/hr	19.9
- Hot Startup	104.0	hr/yr	237.5	lb/hr	12.4
- Shutdown	80.0	hr/yr	344	lb/hr	13.8
Total NO_x					**124.0**
SO_2	**22,030**	**MMcf/yr**	**3.0**	**lb/MMcf**	**22.6**
VOC - Normal Operation	21,172,723	MMBtu/yr	2.10E-03	lb/MMBtu	22.2
- Cold Startup	273.6	hr/yr	1,003.84	lb/hr	137.3
- Hot Startup	104.0	hr/yr	412.15	lb/hr	21.4
- Shutdown	80.0	hr/yr	315.2	lb/hr	12.6
Total VOC					**193.6**
H_2SO_4	**22,030**	**MMcf/yr**	**1.46**	**lb/MMcf**	**16.1**
GHG - CO_2	22,485,120	MMBtu/yr	117.0	lb/MMBtu	1,315,111
- CH_4 (CO_2e)	22,485,120	MMBtu/yr	5.51E-02	lb/MMBtu	619.6
- N_2O (CO_2e)	22,485,120	MMBtu/yr	6.57E-02	lb/MMBtu	738.6
Carty-SF_6	1.21E-04	ton/yr	22,800	lb CO_2e/lb SF_6	2.8
Grassland – SF_6	1.02E-02	ton/yr	22,800	lb CO_2e/lb SF_6	231.8
Total GHG (CO_2e)					**1,316,703.4**

COMBUSTION TURBINE EMISSION FACTOR DOCUMENTATION

The PM, PM_{10} and $PM_{2.5}$ emission factors as well as the estimates of CO, NO_x, and VOC emissions during startup and shutdown were provided by the manufacturer. The CO emission factor during normal operation assumes the exhaust gas concentration of CO is 2.0 ppm at standard temperature and pressure, corrected to 15% oxygen (the proposed BACT limit). The NO_x emission factor during normal operation assumes the exhaust gas concentration of NO_x is 2 ppm at standard temperature and pressure, corrected to 15% oxygen (current BACT limit). The SO_2 emission factor assumes the sulfur content of natural gas is 30 ppm but 31.6% of the SO_2 formed is converted to SO_4 which becomes H_2SO_4. The VOC emission factor is from AP-42 Table 3.1-2a. The greenhouse gas emission factors are from 40 CFR 98 Tables C-1 and C-2. There are two circuit breakers, each containing 24.25 lbs of SF_6 at the Carty facility. There are also three circuit breakers at the Grassland Switchyard that contain 1,355.84 lbs of SF_6 each. The circuit breakers are assumed to leak SF_6, a greenhouse gas, at an annual rate of 0.5% by weight. As a result, 0.24 lbs of SF_6 leak from the two Carty breakers each year, and 20.34 lbs of SF_6 leak from the three Grassland Switchyard breakers. The global warming potential of SF_6 is 22,800.

CARTY AUXILIARY BOILER

Annual Hours of Operation	751 hr/yr (during turbine startup)
Hourly Heat Input	26 MMBtu/hr
Hourly Gas Usage	0.025 MMcf/hr

Pollutant	Process or Throughput		Emission Factor	Units	Emissions (tons/yr)
	Rate	Units			
$PM/PM_{10}/PM_{2.5}$	19.0	MMcf/yr	2.5	lb/MMcf	0.02
SO_2	19.0	MMcf/yr	3.0	lb/MMcf	0.03
NO_x	19.0	MMcf/yr	50	lb/MMcf	0.48
CO	19.0	MMcf/yr	84	lb/MMcf	0.80
VOC	19.0	MMcf/yr	5.5	lb/MMcf	0.05
GHG - CO_2	19,406	MMBtu/yr	117.0	lb/MMBtu	1,135
- CH_4 (CO_2e)	19,406	MMBtu/yr	0.055	lb/MMBtu	0.53
- N_2O (CO_2e)	19,406	MMBtu/yr	0.066	lb/MMBtu	0.64
Total GHG (CO_2e)					1,136

CARTY AUXILIARY BOILER EMISSION FACTOR DOCUMENTATION

The Carty auxiliary boiler is used for turbine startup. The emission factors for PM, PM_{10} and $PM_{2.5}$ come from DEQ's table of emission factors (Form AQ-EF05). The SO_2 emission factor assumes a natural gas sulfur content of 30 ppm which is all converted to SO_2 emissions. The NO_x and CO emission factors come from AP-42 Table 1.4-1 and VOC emission factor from AP-42 Table 1.4-2. The greenhouse gas emission factors are from 40 CFR 98 Tables C-1 and C-2.

CARTY FIRE WATER PUMP

Annual Hours of Operation 50 hr/yr (for routine testing)
Horse-Power Output 315 hp-hr
Heat Input 2.21 MMBtu/hr

Pollutant	Process or Throughput		Emission Factor		Emissions (tons/yr)
	Rate	Units	Rate	Units	
$PM/PM_{10}/PM_{2.5}$	15,750	hp-hr/yr	3.31E-04	lb/hp-hr	0.003
SO_2	15,750	hp-hr/yr	2.05E-03	lb/hp-hr	0.016
NO_x	15,750	hp-hr/yr	3.10E-02	lb/hp-hr	0.244
CO	15,750	hp-hr/yr	6.68E-03	lb/hp-hr	0.053
VOC	15,750	hp-hr/yr	2.47E-03	lb/hp-hr	0.019
GHG - CO_2	110.5	MMBtu/yr	163.1	lb/MMBtu	9.0
- CH_4 (CO_2e)	110.5	MMBtu/yr	0.165	lb/MMBtu	0.009
- N_2O (CO_2e)	110.5	MMBtu/yr	0.394	lb/MMBtu	0.022
Total GHG (CO_2e)					9.0

FIRE WATER PUMP EMISSION FACTOR DOCUMENTATION

The PM, PM_{10} and $PM_{2.5}$ emission factor is set at the regulatory limit found in 40 CFR 60.4205(c). The emission factors for SO_2, NO_x, CO and VOC are from AP-42 Table 3.3-1. The greenhouse gas emission factors are from 40 CFR 98 Tables C-1 and C-2.

CARTY COOLING TOWER

Fugitive particulate emissions from the cooling tower are calculated based on the water circulation rate, total dissolved solids and drift loss according to the following equation.

$$E = k * Q * TDS * d * \rho$$

Where: E = particulate emissions, lb/hr
k = constant to convert units; 6.0E-07
Q = cooling water circulation rate; 85,000 gpm
TDS = total dissolved solids in cooling water; 1,200 ppm
d = drift loss; 0.0005%
ρ = density of water; 8.34 lb/gal.

The resulting emissions are (6.0E-07) * 85,000 * 1,200 * 0.0005 * 8.34 = 0.26 lb/hr.
For year-round operation (8760 hr/yr) this is equal to 1.1 ton/yr

Hazardous Air Pollutants

Pollutant	Carty Gas Turbine 22,044 MMscf/yr 22,485,120 MMBtu/yr			Carty Auxiliary Boiler 22.04 MMscf/yr 22,477 MMBtu/yr			Total
	Emission Factor[a]		Emissions (ton/yr)	Emission Factor[b]		Emissions (ton/yr)	Emissions (ton/yr)
Acetaldehyde	4.0E-05	lb/MMBtu	0.45				0.45
Acrolein	6.4E-06	lb/MMBtu	0.07				0.07
Benzene	1.2E-05	lb/MMBtu	0.13	2.1E-03	lb/MMscf	2.0E-05	0.13
1,3 Butadiene	4.3E-07	lb/MMBtu	0.005				0.005
Dichlorobenzene				1.2E-03	lb/MMscf	1.1E-05	1.1E-05
Ethylbenzene	3.2E-05	lb/MMBtu	0.36				0.36
Formaldehyde	7.1E-04	lb/MMBtu	7.98	7.5E-02	lb/MMscf	7.1E-04	8.00
Hexane				1.8	lb/MMscf	0.017	0.02
Naphthalene	1.30E-06	lb/MMBtu	0.015	6.1E-04	lb/MMscf	5.8E-06	0.02
PAH							
Acenaphthene				1.8E-06	lb/MMscf	1.7E-08	1.7E-08
Acenaphthylene				1.8E-06	lb/MMscf	1.7E-08	1.7E-08
Anthracene				2.4E-06	lb/MMscf	2.3E-08	2.3E-08
Benzo(a)anthracene				1.8E-06	lb/MMscf	1.7E-08	1.7E-08
Benzo(b,j,k)pyrene				1.2E-06	lb/MMscf	1.1E-08	1.1E-08
Benzo(g,h,i)perylene				1.2E-06	lb/MMscf	1.1E-08	1.1E-08
Chrysene				1.8E-06	lb/MMscf	1.7E-08	1.7E-08
Fluoranthene				3.0E-06	lb/MMscf	2.9E-08	2.9E-08
Fluorene				2.8E-06	lb/MMscf	2.7E-08	2.7E-08
Indeno(1,2,3-cd)pyrene				1.8E-06	lb/MMscf	1.7E-08	1.7E-08
Napthalene (also a HAP)	1.30E-06	lb/MMBtu	0.015	6.1E-04	lb/MMscf	5.8E-06	0.02
Phenanthrene				1.7E-05	lb/MMscf	1.6E-07	1.6E-07
Pyrene				5.0E-06	lb/MMscf	4.8E-08	4.8E-08
Total PAH	2.2E-06	lb/MMBtu	0.025			6.2E-06	0.03
Propylene Oxide	2.9E-05	lb/MMBtu	0.33				0.33
Toluene	1.3E-04	lb/MMBtu	1.46	3.4E-03	lb/MMscf	3.2E-05	1.46
Xylenes	6.4E-05	lb/MMBtu	0.72				0.72
Arsenic				2.0E-04	lb/MMscf	1.9E-06	1.9E-06
Beryllium				1.2E-05	lb/MMscf	1.1E-07	1.1E-07
Cadmium				1.1E-03	lb/MMscf	1.1E-05	1.1E-05
Chromium				1.4E-03	lb/MMscf	1.3E-05	1.3E-05
Cobalt				8.4E-05	lb/MMscf	8.0E-07	8.0E-07
Lead				5.0E-04	lb/MMscf	4.8E-06	4.8E-06
Manganese				3.8E-04	lb/MMscf	3.6E-06	3.6E-06
Mercury				2.6E-04	lb/MMscf	2.5E-06	2.5E-06
Nickel				2.1E-03	lb/MMscf	2.0E-05	2.0E-05

Pollutant	Carty Gas Turbine 22,044 MMscf/yr 22,485,120 MMBtu/yr			Carty Auxiliary Boiler 22.04 MMscf/yr 22,477 MMBtu/yr			Total
	Emission Factor[a]		Emissions (ton/yr)	Emission Factor[b]		Emissions (ton/yr)	Emissions (ton/yr)
Selenium				2.4E-05	lb/MMscf	2.3E-07	2.3E-07
Total HAP							**11.6**
Maximum Single HAP							8.0

a. Emission factors from AP-42 Table 3.1-3
b. Emission factors from AP-42 Table 1.4-3, 1.4-4

ATTACHMENT B: RESPONSE TO COMMENTS

Please see attached document…

Attachment B: Response to Comments PGE – Carty Permit

DEQ received numerous public comments during the two public comment periods opened for this permit modification. The first public notice period ran from January 23, 2018, through April 30, 2018. DEQ held an in-person hearing on February 22, 2018. After the first comment period, DEQ made several changes to the permit including more stringent BACT limits and additional VOC testing. DEQ decided to open a second public comment period from September 8, 2021, through December 17, 2021. DEQ held a second public hearing on November 9, 2021. Due to concerns about COVID impacts on vulnerable communities, this hearing was held online (virtual). The comments received during these comment periods have not been combined in a single table, but the comment responses to each comment period is provided in separate tables. Due to the length of many comments, a summary of each relevant comment has been provided next to DEQ's response.

Many of the comments received were essentially the same letter either submitted individually or in the form of a petition with multiple people attaching their name to the letter. Many of these people added personal comments either expressing their opinion about the facility, describing the impact emissions would have on them, or urging DEQ to reject the permit and shutdown the Carty facility. DEQ is grateful for these comments and for the efforts of environmental interest groups in reaching out to involve individuals that might not normally comment on these permit actions, including some disadvantaged communities. Over 2,100 people commented during the 2021 public notice period. About 84% of these individuals identified as being from Oregon, while the remainder were from other states and from countries as far away as England and Croatia. About 10 of the comments were from individuals living in zip codes within 62 miles of the facility.

Many of the comments misunderstood the purpose and scope of this permit modification. A correction of the estimates for potential emission of CO and VOC during startup and shutdown of the Carty turbine triggered a Prevention of Significant Deterioration analysis for those pollutants. The PSD analysis and the proposed permit modification dealt only with CO and VOC emissions and no other pollutants. The potential emissions increase was not due to any recent physical change at the facility nor was it due to any change in the way the facility was operated, such as allowing more frequent startups and shutdowns. The major source PSD requirements require a modification of the ACDP (this modification) to establish new emission limits and monitoring requirements. Actual operation of the facility is allowed under a separate Title V permit, and the appropriate conditions from this ACDP modification will be incorporated into the Title V Operating Permit under a separate action. Denial of this ACDP modification will not cause this facility to cease operation. This ACDP modification changes the way CO and VOC emissions are calculated during startups and shutdowns, ensures the Best Available Control Technology (BACT) is applied to the increased emissions during startup and shutdown as well as during steady-state operation, and also ensures the emissions will not cause a violation of the ambient air quality standards.

Due to the volume and length of comments received, DEQ has summarized the relevant comments and given a response to the issues raised. The following comments were received during the 2021 comment period. Numerous comments were received after the comment period closed. The majority of these comments were identical to those received during the comment period and are addressed in the response.

Name	Type of Comment
Edmark	Email from Kristin Edmark, received 10/29/21
Zehava	Email from Angela Zehava of Portland, received 11/9/21

Name	Type of Comment
Dougherty	Email from Laurie Dougherty of Salem, received 11/9/21. Dougherty also gave oral comments during the public hearing on 11/9/21
Maffei	Email from Jennifer Maffei of Portland, received 11/26/21
Sampson-Kruse	Oral comments from Cathy Sampson-Kruse, received 11/9/21
Davis	Oral comments from Daniel Davis, Vice Chair of Rogue Valley Transit District, received 11/9/21
Wallace	Oral comments from Willa Wallace from Pendleton, received 11/9/21
Pommier	Oral comments from Madeline Pommier, received 11/9/21
Murphy	Oral comments from Kate Murphy of Columbia Riverkeeper, received 11/9/21
Talik	Oral comments from John Talik, received 11/9/21
Stevens	Oral comments from Laura Stevens of the Sierra Club, received 11/9/21
Saylor	Oral comments from Erin Saylor of Columbia Riverkeeper, received 11/9/21
Chipman	Oral comments from Kyle Chipman of Portland, received 11/9/21
Dugan	Oral comments from Allyson Dugan of Portland, received 11/9/21. Dugan also submitted written comments in an email received 12/9/21 and a second email received 12/16/21
Serres	Oral comments from Daniel Seres of Columbia Riverkeeper, received 11/9/21
Daniel	Oral comments from Chad Daniel of Umatilla County, received 11/9/21
Gordon	Email from Diana Gordon of Washougal, WA, received 12/13/21
Thorpe	Email from Jan Thorpe of Portland, received 12/13/21
Meisenhelter	Email from Diana Meisenhelter, received 12/14/21
Sierra, et.al	These comments were essentially a common letter, submitted either collectively or individually, with personal variations added by some commenters: Email from Noah Rott representing Sierra Club, received 12/15/21. Email contained a spreadsheet containing input from **953** individuals. Email from Michael Heumann representing the Metropolitan Alliance for Common Good Climate Change and Environmental Justice Team and its 23 member organizations, received 12/15/21. Email from Dineen O'Rourke representing 350PDX, Power Past Fracked Gas, received 12/17/21. Comments from **306** people. Email from Richard Allen of Trout Lake, WA, received 12/17/21 Email from Mimi Maduro of Mosier, OR, received 12/17/21 Email from Luanne Mierow of Beavercreek, OR, received 12/17/21 Email from Cathy Lewis-Dougherty of Lake Oswego, received 12/17/21 Email from Sandra Joos of Portland, received 12/17/21 Email from Bill Kirkland of Portland, received 12/17/21 Email from Den Wichar of Vancouver, WA, received 12/17/21 Email from Constance Coleman of Portland, received 12/17/21 Email from James Minick of Lyle, WA, received 12/17/21 Email from David Berger of Lyle, WA, received 12/17/21 Email from Judith McLean of Portland, received 12/17/21 Email from Rob Parker of Portland, received 12/17/21 Email from Abigail Corbet of Portland, received 12/17/21 Email from Jon Nystrom of Portland, received 12/17/21 Email from Barbara Coleman of Portland, received 12/17/21 Email from Dawn Snider of Portland, received 12/17/21 Email from James Loacker of Manzanita, OR, received 12/17/21

Name	Type of Comment
	Email from Martha Goetsch of Portland, received 12/17/21 Email from Kate Murphy representing Columbia Riverkeeper, received 12/17/21. Included spreadsheet containing input from **914** people Email from Jeff Malmquist of Portland, received 12/17/21 Email from Michelle Asivido of Gresham, received 12/17/21 Email from Fuji Kreider of La Grande, received 12/17/21 Email from David Grant of Medford, received 12/17/21 Email from Steve Cummins of Santa Clara, CA, received 12/17/21 Email from Mike Demshki of Corbett, OR, received 12/17/21 Email from Carol Clark of Portland, received 12/17/21 Email from Stephen Gerould of Portland, received 12/17/21 Email from Julie Stream of Vancouver, WA, received 12/17/21 Email from Yehudah Winter of Portland, received 12/17/21
Houston	Email from Jynx Houston of Portland, received 12/15/21
Turner	Email from Ann Turner of Portland, received 12/16/21
NEDC	Email from Dan Polkow representing Northwest Environmental Defense Center, received 12/17/21
Orem	Email from Frank Orem of Lake Oswego, received 12/17/21
CTUIR	Email from Audie Huber, containing a letter from Eric J. Quaempts representing the Confederated Tribes of the Umatilla Indian Reservation (CTUIR), received 12/17/21
Tsongas	Email from Theodora Tsongas of Portland, received 12/17/21
Partners	Email from Kate Murphy on behalf of Columbia Riverkeeper, Friends of the Columbia Gorge, Sierra Club, Oregon Physicians for Social Responsibility, 350 PDX, Breach Collective, Oregon Just Transition Alliance, Power Past Fracked Gas, Rogue Climate, Oregon Conservancy Foundation, Cedar Action, No Methanol 360, Cascadia Climate Action Now, Lower Columbia Stewardship Community, and Braided River Campaign, received 12/17/21
Brewer	Email from Roger Brewer of Portland, received 12/17/21
Earthrise	Email from James Saul of Earthrise Law Center at Lewis & Clark Law School on behalf of Columbia Riverkeeper, Friends of the Columbia Gorge, 350PDX, and Northwest Environmental Defense Center. Also contained analysis by consultant Ranajit Sahu. Received 12/17/21

2021 Comment Summary and Response

Comment	DEQ Response
PGE needs to take seriously the transition to clean energy and invest in energy created by wind, solar, geothermal, tidal actions, etc. (*Edmark*)	The transition to other ways of generating energy is beyond the scope and authority of this permitting action, which reviews the natural gas turbine at Carty. Thank you for your comment.
Most Oregonians ascribe droughts to climate change and feel government should limit greenhouse gas emissions. (*Edmark*)	This permit action does not allow any increase in greenhouse gas emissions. DEQ is working within its authority to address climate change in its recently passed Climate Protection Program.
An increase in emissions directly conflicts with Governor Brown's Executive Order 20-04 (*Edmark*)	DEQ's response to Governor Brown's Executive Order 20-04 has been posted on DEQ's website. (State of Oregon: Governor Kate Brown - Carbon Policy Executive Order) At this time the response does not include any actions that would impact this permitting action.
Technology is available to greatly decrease discharge during the starting up process. Clark PUD is considering upgrades at the River Road facility including installation of GE DLN 2.6. (*Edmark*)	DEQ reviewed the permit for Clark PUD's River Road facility. The emission controls are similar to PGE's (catalytic oxidation). The permitted CO limits are about three times the limit proposed for PGE and there is no limit on CO or VOC emissions during startup. The technology at Clark PUD is similar to the technology currently in use at PGE-Carty.
Carty will be phased out during the next decade. Increases are not needed. Methane is dangerous and accelerates global warming. (*Edmark*)	The proposed modification does not allow an increase in fuel use or change the way the facility is operated. The modification will not allow an increase in greenhouse gas emissions
Indigenous people living nearby oppose the increased VOC and CO levels which pose health risks. (*Edmark*)	Federal and State regulations require an analysis of any significant increases in pollutants to ensure federal air quality standards are not exceeded. These standards were established to protect public health (OAR 340-202-0050(1)). DEQ's analysis found that the impacts of the proposed emission increase at PGE are well below the national standards that are set to protect public health. More information on this analysis is discussed in the permit review report. During the permit drafting process, DEQ met with representatives of the nearby Confederated Tribes of the Umatilla Indian Reservation (CTUIR) to discuss the proposed permit changes and analysis of potential air quality impacts. DEQ would be happy to provide additional information about air quality standards upon request.
Allow no compromise. The enormous increase makes it appear PGE is looking for a compromise similar to the tactic used in lawsuits. Methane is not a bridge fuel and needs to be discontinued soon. (*Edmark*)	DEQ has applied the same regulations and stringency that applies to all sources. No compromise has been made. DEQ does not have authority to require natural gas (methane) use be discontinued.
Commenter is suspicious of new information from manufacturer that led	The proposed permit requires emissions testing in order to confirm the information provided by the manufacturer. The

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to this emission increase. Concerned that VOC emissions are only tested annually by a company hired by PGE. PGE could hide emissions when not testing. Also concerned that DEQ is not reviewing the data itself, but relying on representations made by PGE. (*Zehava*)	test plan and results will be thoroughly reviewed by DEQ. DEQ reviews all reports submitted by PGE and will conduct on-site inspections where all relevant data is available for DEQ review. In addition, most reports submitted by PGE have a certification statement that could result in criminal prosecution of responsible officials if reports are falsified.
CO and VOC emissions will contribute to ground-level ozone which is harmful to health and degrade air quality and visibility in the Gorge. (*Dougherty*)	Analysis using EPA-approved methods indicate CO and VOC emissions will not adversely impact human health or the environment in the Gorge. The Regional Haze program, which is used to address visibility issues in the Gorge, does not require additional analysis from this source.
Climate change is real. Climate change creates conditions, such as increased temperatures and stagnant air, which will result in increased formation of ground-level ozone. DEQ needs to take a holistic approach that includes the effect of climate change on local pollution. (*Dougherty*)	DEQ appreciates the comment. Current regulations do not incorporate the impact of climate change on ozone formation. DEQ will continue to monitor actual ozone concentrations in areas of concern. Additional action will be taken if concentrations exceed the ambient air quality standards.
PGE needs to dig deeper to find solutions. Spewing more harmful pollutants into the air affecting vulnerable communities, directly impacting human health, and recklessly ignoring the urgency of our current climate crisis is not the answer. I urge DEQ to make decisions in line IPCC reduction targets, construct rules and regulations without loopholes, and hold first line communities in highest consideration. (*Maffei*)	DEQ's analysis shows the proposed increase in emission limits remain within air quality standards that are set to protect public health, including the health of vulnerable communities. The proposed permit modification does not increase greenhouse gas emission limits. The rulemaking process is separate from the permit writing process. This permit must implement existing rules and regulations.
PGE must stop their air pollution. It's time for the State to stand up and stop them. (*Sampson-Kruse*)	Thank you for your comment.
The length of startups and shutdowns sounds anomalous to me. I will contact DEQ for more information so I can comment further. (*Davis*)	Thank you for your comment. DEQ is willing to informally discuss the permit and the reasons behind the permit conditions with the public upon request.
Agrees with concerns expressed by CTUIR. VOC creates smog which causes respiratory health problems, made worse by COVID. We need cleaner air, not more pollution. (*Wallace*)	Thank you for your comment. DEQ's analysis shows VOC emissions from Carty will not have a significant adverse impact on air quality in the area. Emission limits remain within air quality standards that are set to protect public health.
Oregon House Bill 2021 set a timetable for PGE to eliminate emissions by 2040 including an 80% reduction within the next eight years. How can we be raising	HB 2021 requires retail electricity providers to reduce greenhouse gas emissions associated with electricity sold to Oregon consumers by 80% in 2030 and 100% by 2040. This permit does not allow an increase or decrease in greenhouse

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any emission levels given this House Bill? (*Pommier*)	gas emissions. It deals only with CO and VOC emissions, which are not regulated by EPA or DEQ as a greenhouse gases.
It falls to DEQ to protect our communities from pollution threats and say no to proposals that may cause harm. Concerned about the potential negative public health impacts of CO and VOC. VOCs are a precursor to ozone formation, which has negative health impacts. Use of fracked gas has extremely negative impacts on the environment and health. Take aggressive action to protect our communities from further negative impact. Counting on DEQ to make the right decision in line with Oregon's ambitious climate goals. (*Murphy*)	Thank you for your comment. The potential health impacts of CO and VOC have been addressed in the ambient air quality analysis, which shows air quality will remain within levels set to protect public health. This permit does not propose any increase to greenhouse gas pollutants that contribute to climate change. Denial of this modification would not stop emissions of greenhouse gas pollutants from this facility. Rather, denial of this modification would allow PGE to continue to use emission calculations during startup and shutdown that may not be representative of actual emissions. Denial would also allow PGE to operate without short-term limits on CO and VOC emissions; and will not increase VOC monitoring at the facility.
I still have concerns about the limits and emissions that will happen from Carty and concerns about air quality in the Columbia Gorge. I'm concerned about PGE mismanagement and improper planning. We must hold PGE to higher levels of scrutiny. Monitoring of VOC will not be sufficient for the operation of the plant. The permit should not be approved before more testing is done on startup. We need to be focusing and prioritizing carbon reductions, not increasing permits that allow this. PGE must do more to assess more options to lower pollution levels. (*Talik*)	DEQ has evaluated the proposed emission limit increases and determined they have an insignificant adverse impact on air quality in the Columbia Gorge. DEQ can only address environmental and regulatory impacts of the proposed changes. DEQ has completed this review prior to proposing this modification and PGE has met all regulatory environmental requirements. DEQ anticipates correcting the emissions estimates in future permits based on the testing required in this permit. DEQ has reviewed the options to lower pollution levels and is requiring the Best Available Control Technology be used at this facility.
Concerned about limits and increases with current data. PGE should lower pollution levels based on actual operation emissions. PGE must pursue their options before being allowed any pollution. Concerned about PGE mismanagement and improper planning. Investigate additional BACT. Limit cold startups. Assess all options to lower emissions based on actual operation. VOC monitoring is not sufficient. Should use established VOC monitoring rather than relying on correlating VOC to CO emissions. DEQ should be responsible for respiratory health	Just prior to placing the proposed permit on public notice DEQ reviewed the latest BACT determinations on EPA's clearinghouse and determined that the proposed limits are acceptable. There is currently no site-specific VOC emission data for this facility. The VOC monitoring proposed in the permit is intended to provide data that can be used to establish the PSEL based on actual data. DEQ does not intend to establish a CO correlation to determine the quantity of VOC emissions. Rather, DEQ intends to establish a CO action level which will be indicative of poor combustion or catalytic oxidizer failure which can be used to determine that VOC controls are not performing optimally. As mentioned in a response elsewhere, a continuous VOC emission monitor was not deemed

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services for frontline communities. (*Talik*)	appropriate and the CO action level is consistent with VOC monitoring done on gas turbines in other states.
Pollution harms our lungs, our people, and our environment. Oregonians have spoken against it. We want clean air and healthy communities, not increased hospital visits for increased smog days. PGE is apparently running this baseload power plant as dispatchable energy to make more money. Deny the permit. (*Stevens)*	Thank you for your comments. PGE has not requested a change in the allowed number of startups and shutdowns since the initial permit in 2010. DEQ has determined that the impact on ozone (smog) formation will be insignificant.
For the CO BACT determination the review report suggests DEQ did not actually review Carty's operating record itself, but relied on PGE's word with respect to the CO emissions it can achieve. The fact that this data was not produced as part of a recent records request further indicates DEQ does not have this data and has not reviewed it. DEQ should review this data itself and make it available for public review. (*Saylor*)	The comment is correct. DEQ did not review data from Carty's CO CEMS to establish the CO BACT limit. PGE initially proposed a CO BACT limit of 3.2 ppm. During its review, DEQ found that a CO BACT limit of 2.0 ppm was consistently established for similar turbines. DEQ informed PGE that it would establish the BACT limit as 2.0 ppm unless PGE could demonstrate that the 2.0 ppm limit was inappropriate for their site. PGE reviewed their CEMS data from 2017 through 2020 and found no justification that a CO limit of 2.0 ppm would be inappropriate. DEQ was not looking to establish 2.0 ppm or any other limit based on this data, only to verify that the 2.0 ppm limit independently determined as BACT was appropriate. Since the CEMS data was not reviewed to establish the actual BACT limit, it is not part of the permitting record.
The data provided by DEQ undermines the agency's assertion that there is a correlation between Carty CO and VOC emissions. PGE is required to test VOC emission just once per year, but this time period is not reflective of the range of conditions under which Carty will operate. So DEQ is flying blind with respect to Carty's actual emissions. (*Saylor*)	DEQ has never tried to assert or infer that there is a correlation between CO and VOC emissions. In both the CO and VOC BACT analysis it was determined that good combustion followed by catalytic oxidation was the Best Available Control Technology. CO emissions can be directly monitored by the Continuous Emission Monitoring System (CEMS). DEQ has determined that a VOC CEMS is inappropriate for this facility. The CO CEMS can provide a reasonable assurance that there is good combustion and that the catalytic oxidizer is operating properly. The annual VOC tests will demonstrate the level of VOC emissions when there is good combustion and catalytic oxidation. The value from the CO CEMS during the VOC test is used as an indicator of the combustion system and catalytic oxidizer performance during the VOC test. The CO CEMS value measured during the VOC test is used as an action level. If this action level (as measured by the CO CEMS) is exceeded during normal operations, it is an indicator that the combustion and catalytic oxidizer are not operating as efficiently as they were during the VOC test and the permittee must take action to improve combustion or in the operation of the catalytic oxidizer. Thus, the intent is not to

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	determine VOC emissions using the CO CEMS, which would indeed infer a correlation. This approach is consistent with EPA's Compliance Assurance Monitoring (CAM) regulations.
The AP-42 emission factors DEQ relied on are outdated and likely undercalculate Carty's emissions. The formaldehyde emissions, which are VOCs, are just slightly below the major HAP source threshold. It's likely a CEMS will more accurately reflect startup emissions and will show that Carty is, in fact, a major source of HAP emissions. (*Saylor*)	The section of AP-42 that DEQ used for the formaldehyde emission factor was last reviewed by EPA in April 2000, which is relatively recent. EPA rates the emission factors in AP-42 based on the quality of data used to derive the factors. The formaldehyde emission factor DEQ used is found in Table 3.1-3 of AP-42 and has a rating of A or excellent. The formaldehyde emission factor is based on uncontrolled emissions. EPA data indicates a catalytic oxidizer can reduce formaldehyde emissions by up to 90%. The formaldehyde estimate in the permit uses the uncontrolled emission factor, while actual emissions pass through a catalytic oxidizer control. As a result, the formaldehyde emission factor used in the permit likely overcalculates the formaldehyde emissions. DEQ will require a test to verify formaldehyde emissions from the turbine. In the permit the requirements of 40 CFR 63, Subpart YYYY are applied to the Carty turbine. This subpart is applicable to turbines located at a <u>major source of HAP emissions</u>. (40 CFR 63.6085) In other words, DEQ already considers the Boardman facility to be a major source of HAP emissions and this permit does nothing to change that status.
Concerned about the negative health the emissions will have on surrounding communities. VOC emissions lead to ozone formation, a respiratory irritant. This will lead to increased ER visits and hospital admissions exacerbated by COVID complications. More troubling would be the increase in climate change events. Denying this permit would be in line with DEQ's climate protection program to reduce greenhouse gas emissions in Oregon. (*Chipman*)	DEQ's analysis shows the proposed increase in VOC emission limits remain within air quality standards set to protect public health. DEQ has evaluated the impact of VOCs on ozone formation and determined the VOCs from this facility will not have a significant impact on ozone formation in the area. Covered emissions under DEQ's climate protection program do not include emissions from "an electric power generating plant with a total nominal electric generating capacity greater than or equal to 25 megawatts". (OAR 340-271-0110(5)(b)(B)(viii)) Since the Carty facility generates 415 megawatts, its emissions are not regulated by the Climate Protection Program. This modification does not increase greenhouse gas emission limits. Denying this permit would not result in a decrease in greenhouse gas emissions.
Can you clarify if the Carty 1 permit is permit for the specific Carty 1 facility, or did the permit cover the entire site including the Boardman plant? (*Dugan*)	EPA requires that if two facilities 1) are the same type of facility (same standard industrial classification code or SIC); 2) have common ownership; and 3) are located adjacent and contiguous to each other, they should be treated as a single source for permitting. This is done to prevent companies from breaking large facilities into smaller units with separate

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	permits in order to avoid regulations applicable to larger sources. Since the Boardman coal plant and the Carty natural gas facility met all these criteria, they were considered a single source and regulated under a single permit in accordance with state and federal rules.
Has PGE assessed all options to lower pollution levels with operation of the Carty Plant? (*Dugan*)	PGE proposed emission limits associated with the Best Available Control Technology (BACT) in its application. DEQ determined more stringent (lower) limits on CO and VOC emissions were achievable and appropriate and has included these lower limits in the proposed permit.
Can PGE limit cold startups, which are particularly polluting events. (*Dugan*)	Not every cold startup event is the same. DEQ reviewed CO emissions during cold startups over a 21 month period and found emissions ranged from 1,900 lbs CO to 3,700 lbs CO (the proposed limit is 4,084 lbs CO per cold startup). Rather than limit the number of cold startups, DEQ is requiring PGE "conduct startup and shutdown operations in accordance with written procedures that minimize emissions during startups and shutdowns and also minimize the amount of time spent in startup and shutdown" (Proposed Permit Condition 3.4.f). Failure to follow these procedures would be a violation of the permit.
Has PGE investigated Best Available Control Technology that could reduce VOC and CO pollution? Have these findings been confirmed by an expert outside of PGE? (*Dugan*)	Yes. Items 14 through 20 of the review report discuss the Best Available Control Technology review. The BACT review submitted by PGE was reviewed by DEQ, updated to include more recent BACT determinations by other states. For some limits, the values established by DEQ are more stringent than those proposed by PGE.
What is the risk if the permit is denied from a power production standpoint or an energy standpoint? (*Dugan*)	DEQ reviews emissions and their impact on the environment. Analysis of the risks to the energy market is beyond the purview of DEQ.
Why are so many startups and shutdowns needed? Is PGE running the plant in a different way than planned (as a peaker plant rather than base-load)? (*Dugan*)	Carty operation depends on several factors, including: the need for power, availability of renewable power, and economy (power can be purchased elsewhere for less money than it costs to run Carty). In addition, the plant will occasionally shutdown for malfunctions and maintenance. A peaker plant would be expected to have more startups and shutdowns than a base-load plant. The number of assumed startups and shutdowns has not changed since DEQ initially permitted the facility in 2010 and is not proposed to be changed in this modification. DEQ has no evidence that PGE is running the plant in a different way than planned.
Will DEQ insist on continuous monitoring of emissions and reporting frequently enough (e.g., daily) to protect the vicinity against upward trends in pollutants. Can and would DEQ insist upon operating and maintenance	PGE is required to continuously monitor CO, CO_2, and NO_x emissions. EPA has indicated that continuous VOC emission monitors can provide only a relative measure of total mass of a mixture of organic gases rather than an accurate quantification. Therefore, continuous VOC monitoring is not required for Carty. Records are kept for the continuous monitors to demonstrate compliance with

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adjustments by PGE if such trends are detected? (*Dugan*)	permit limits. If emissions exceed the permit limits PGE would be cited for a violation and required to take any action required to reduce emissions below the permit limits.
What mitigations is DEQ considering to compensate for the higher level of emissions? (*Dugan*)	Due to the higher level of emissions, DEQ is imposing new emission limits and requiring additional testing, monitoring, recordkeeping and reporting. No other mitigating actions are required by DEQ regulations.
When and how did Mitsubishi give out the original expected emission levels and then the updated levels? Do they have any financial exposure here? (*Dugan*)	The original emissions estimates were contained in the initial permit application for Carty which was received on 12/24/09. In 2016 PGE was investigating installation of an additional turbine similar to the one currently operating. As part of the bid for the additional turbine Mitsubishi provided an updated emission estimate for startups and shutdowns. Since the existing Carty turbine is similar to the proposed new turbine they were looking at, PGE notified DEQ that the emissions for the existing turbine would need to be modified. On 11/2/16 PGE submitted a permit modification application to incorporate the new values. Determination of financial exposure is beyond the scope of this permit action.
Can you share the dates (with duration) on which PGE ran their gas turbine? (*Dugan*)	Initial startup of the Carty plant occurred on 6/21/16. There have been multiple startups and shutdowns since that time. PGE maintains records of each startup and shutdown and of monitored parameters when operating. The annual reports for PGE available on DEQ's website give an indication of turbine operation. For example, in 2021 the turbine operated for 7,509 hours during the year over 313 days. The records that PGE maintains are available for review by DEQ, but are not required to be reported in the current permit. However, Condition 7.4 of the proposed permit will require reporting of the number and duration of startups and shutdowns during each month. These reports will be available on DEQ's website when the permit is implemented.
Hold PGE to lower pollution levels based on actual operation emissions and available options. PGE is currently only testing for CO emissions and then back calculating VOC emissions, which is not reliable. Knowing current CO and VOC emissions is crucial for reviewing this request. Once actual operating data are available DEQ can better assess all options for PGE. Should institute continuous emission monitoring, request implementation of approve solar facility or request funding for respiratory health services in the community. (*Dugan*)	DEQ is not allowing use of CO emission data to back calculate VOC emissions. VOC emissions are currently estimated based on a combination of EPA's compilation of emission factors, and manufacturer's estimates for emissions during startups and shutdown. The permit requires site-specific testing to determine actual VOC emissions. In the future, the emissions estimate in the PSEL will be updated based on the VOC test data and DEQ guidance. While DEQ would like to base initial emissions estimates on actual, on-site emission data, operations to collect these actual data cannot occur until a permit based on "best-estimated emissions" is issued. DEQ will update the emissions estimates as better data is acquired. DEQ does not have authority to require facilities to install solar equipment or fund community services.

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I support the comments of those opposed to the permit. We've identified specific reasons why the proposed permit is off the mark. (*Serres*)	Thank you for your comment.
I don't believe anyone desires to harm the environment or intentionally do things not in favor of Mother Nature. We all may disagree on how to do things in our local communities. Where is the outrage for visual pollution of windmills and the carbon footprint they actually leave in their production. I support the PGE modification as do the majority of Eastern Oregon residents that I talk to. (*Daniel*)	Thank you for your comments.
It is vital to hold fracked gas power plants like Carty to higher standards. Reduce pollution, not increase it. (*Gordon*)	Thank you for your comment. Carty will be held to the same standards as other natural gas turbines.
Not in favor of proposal (*Thorpe*)	Thank you for your comment.
Knows that CTUIR has concerns about health issues from these emissions. Environmental Justice issue not only for tribes but substantial Lantinx population and low-income frontline communities. Area already impacted by air quality advisories. Should be using BACT to reduce emissions and limit startups and shutdowns. (*Meisenhelter*)	DEQ has reached out to CTUIR and local Hispanic groups to discuss the permit, answer questions, and encourage comments. EPA-approved methods were used to assess health and environmental impacts of the emissions increase and no adverse impacts were predicted. The current permit has no short-term limits on CO and VOC emissions while the proposed permit has limits based on the Best Available Control Technology.
DEQ should not allow PGE to increase harmful carbon monoxide and VOC pollution due to public health impacts. (*Sierra, et.al.*)	Regulations require an analysis of any significant increases in pollutants to ensure federal ambient air quality standards are not exceeded. These standards were established to protect both public health and public welfare (OAR 340-202-0050(1)). As discussed in the review report, using EPA-approved methodologies, DEQ found that the impacts of the proposed emission increase at PGE are well below the national standards and should not have significant health impacts.
Pollution increases would affect air quality near the facility and in the Columbia River Gorge National Scenic Area, which already experience haze and other air quality problems. Studies should be done on the potential impact of smog-forming pollution on the gorge and nearby communities. (*Sierra, et.al.*)	A comprehensive study on air quality, including haze in the Columbia River Gorge was conducted in 2011 https://www.swcleanair.gov/docs/ColumbiaRiverGorge/ColumbiaGorgeAirStrategyDocument-Final.pdf. DEQ has identified haze-contributing sources in the Gorge and, after reviewing many options, has determined that the most effective approach to mitigate and improve haze conditions in the Gorge is through the federally-mandated Regional Haze Program. DEQ has defined the "Round 2 Regional Haze Pollutants" as sulfur dioxide (SO_2), particulate matter

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	less than 10 microns in diameter (PM_{10}), and nitrogen oxides (NO_x) (OAR 340-223-0020(2)). VOC emissions are not included in the Regional Haze analysis. The proposed increases at PGE do not include pollutants DEQ defines as Regional Haze Pollutants.
Fracked gas is not a climate-friendly energy alternative. Negative health impacts – from extraction, through transport, to combustion – disproportionately burden frontline communities. (*Sierra, et.al*)	DEQ realizes the concerns of fracking in production of natural gas. However, actions and emissions occurring during gas production and transportation are beyond the scope of this permitting action. The proposed changes will not result in the increased combustion of natural gas nor increase the emissions of greenhouse gases. In addition, denial of this permit modification will not reduce the amount of gas consumed at the plant nor decrease greenhouse gas emissions. This modification only establishes emission limits and monitoring for CO and VOC emissions.
Assess all options for holding PGE to lower pollution levels. The proposed limits during startup and shutdown still result in a massive increase in smog-forming pollution. This is unacceptable. (*Sierra, et.al*)	The permit includes establishment of Best Available Control Technology (BACT) limits on CO and VOC which represent the lowest emissions achievable on a consistent basis for this facility. DEQ has evaluated the impact of VOCs on ozone (smog) formation and determined the VOCs from this facility will not have a significant impact on ozone formation in the area.
In the midst of a climate emergency we need to focus on reducing emissions. DEQ's current plan to exempt fracked gas power plants like Carty from its "Climate Protection Program" means DEQ should be doing more to rein in pollution. (*Sierra, et.al*)	The applicability and exemptions in DEQ's Climate Protection Program were addressed in a separate rulemaking and are beyond the scope of this permit action. This permit action will not result in an emission increase of any regulated greenhouse gases.
Urge DEQ to never allow increased air pollution. No more gas plants. (*Houston*)	Thank you for your comment. Using approved regulatory methods, DEQ has determined that the emissions increase will not cause an adverse impact to health or the environment.
Allowing PGE to increase CO and VOC is a public health issue. Almost 40% of the Morrow County population is Latinx. Clearly an environmental justice issue. (*Turner*)	The 2014-2018 American Community Survey (ACS) of the Census Bureau indicates that within a 15-mile radius of the facility (which includes the towns of Boardman and Ione) there is a population of 4,020, 45% of which are people of color (mostly Latinx). DEQ agrees that environmental justice is a concern. DEQ reached out to the Confederated Tribes of the Umatilla Indian Reservation (CTUIR) and local Latinx groups during the comment period, with information in both Spanish and English. For the 2021 public hearing, DEQ provided English-Spanish interpretation of the information presentation, questions and answers, and public comments. DEQ did its best to reach out to and invite comment from diverse communities during the public notice.

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Burning fossil fuels affects our health not only by causing air pollution but by releasing greenhouse gases. Extraction of gas burned at Carty is primarily done by fracking. Though not done in Oregon, communities located close to fracking wells are at health risk. With the passage of HB2021, PGE is required to move to renewable sources. It makes no sense to allow PGE to increase pollutants. DEQ must protect our climate. (*Turner*)	This permit only regulates activities occurring within the plant site boundary and not upstream in the supply chain. The permit accounts for greenhouse gas emissions generated within the footprint of the facility. When rule-making addressing HB2021 has passed the Environmental Quality Commission, DEQ will incorporate the applicable requirements into the permit in accordance with established procedures.
Ozone from combustion is known to cause premature mortality, even at levels below current standards. There is much we don't know about actual CO and VOC levels emitted by Carty. DEQ must require that PGE submit more actual CO emissions data and require a Continuous Emissions Monitoring System (CEMS) for VOC and lower the VOC BACT limit. PGE admits there is no data to support the correlation between CO and VOC levels. (*Turner*)	DEQ is required to ensure compliance with the current National Ambient Air Quality Standards (NAAQS) which are intended to be protective of human health and the environment. Any standards more stringent than the current standards would need to be approved by rulemaking before they could be incorporated into the permit. Actual emissions data collected so far during Carty's operation may not fully represent all the permitted operating scenarios. For example, the turbines could operate at 50% load for extended periods, but so far has mostly operated near full load. The permit limits need to encompass all permitted operating scenarios. Therefore, actual data may not be appropriate for establishing future operating conditions. DEQ has determined that VOC CEMS, while possible, have reliability and representativeness issues. DEQ has not, and will not, attempt to determine VOC emission based on CO levels. DEQ may however, use CO as an indicator of good combustion and proper catalytic oxidizer operation, which are also key factors for VOC formation.
The choice of control technology for the turbine will not strictly adhere to the BACT emission limits. The permit lists a 1.5 ppmvd CO limit while operating at 60% load or greater while the review report states the limit should be 1.5 ppmvd while operating at 90% load or greater. The permit should be modified to reflect the correct standard. (*NEDC*)	DEQ agrees that there was an inconsistency between the review report and the permit. The intent was to apply the BACT limit at turbine loads of 90% or greater. The permit has been modified to reflect the 90% load or greater limit reflected in the review report.
It is clear that the VOC control technology for the turbine is not sufficient to meet the emission limitations. DEQ should choose a control technology that would meet the emissions limitations. (*NEDC*)	DEQ disagrees that the VOC control technology (good combustion and catalytic oxidation) is not sufficient to meet the permitted emission limitation. Similar controls have been installed on similar turbines in other facilities and the similar permitted limitations have been met.
Thermal oxidation is dismissed as BACT because it would require supplemental firing and is not typically applied to	While PGE may propose BACT controls, DEQ is ultimately responsible to review and determine the appropriate level of control. DEQ has reviewed the information submitted by

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combustion sources. While the BACT analysis may be technically compliant, NEDC requests PGE more thoroughly describe its decision-making process in choosing its control technology. (*NEDC*)	PGE, as well as determinations made by other states and has determined there is generally sufficient information for DEQ to determine the appropriate control technology.
The deadline for conducting the initial compliance test is 18 months from permit issuance. NEDC requests a shorter deadline between 6 to 12 months because this modification resulted from PGE's inability to demonstrate compliance with their CO and VOC initial permitted emission limitations. NEDC requests that DEQ more adequately define when PGE may request an extension for its compliance requirements. (*NEDC*)	There is no issue with PGE's ability to demonstrate compliance with their CO and VOC initial permitted emission limits. The initial CO limit was 99 tons/yr, and compliance has been demonstrated every month. There was no initial VOC limit in the permit other than the PSEL which is a limit not only on the turbine, but all emission units at the facility, combined. A period of 18 months from permit issuance is a typical allowance for testing in most permits in order to allow time to hire a testing contractor, develop a site-specific test plan that must be approved by DEQ, and schedule a date for testing. Frequently, the test is conducted much sooner than the 18 month deadline. The allowance for an extension on testing during startup testing is because most EPA approved test methods are designed to be conducted at steady-state operation. During startup, the emission unit is not operating at steady-state and some deviations to the test method may need to be agreed upon. In addition, a series of startup events that are representative of worst-case emissions is desired. That may necessitate scheduling the test at a time when multiple cold-starts can be accomplished, which may take some time.
NEDC seeks inclusion of the specific source sampling procedures DEQ will require in order to approve a test plan. (*NEDC*)	Approval of source test plans typically follow DEQ's Source Sampling Manual, which specifies the available options for sampling procedures. There are many options in testing that are acceptable but should be agreed upon prior to testing. DEQ prefers that these details be worked out as conditions of test plan approval rather than specifying them in the permit so that the permit does not have to be modified every time there is a deviation in the testing protocol.
Section 5.5 of the permit includes a definition of excursion of the CO concentration that excludes startup and shutdown emissions. This is troubling since the permit modification is due to higher emissions during startup and shutdown. NEDC seeks a more comprehensive definition of excursion which includes startup and shutdown emissions. (*NEDC*)	Condition 5.5 of the permit, which is labeled "VOC Compliance Assurance Monitoring" states that CO CEMS data are to be used as "an indication of good combustion and proper operation of the catalytic oxidizer." Good combustion and proper operation of the catalytic oxidizer are the control technologies behind the BACT limit. Note that CO CEMS data will <u>not</u> be used to directly determine VOC emissions. During startup and shutdown good combustion is not typically achieved due to transient temperatures and flowrate variations. Proper operation of the catalytic oxidizer does not occur during startup because flue gas temperatures are below the optimal temperature for oxidizing VOC emissions. In other words, periods of startup and shutdown are by their very nature not conducive to good

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	combustion and proper operation of the catalytic oxidizer. In addition, the CO value that defines an excursion, will be established based on the 3-hour average CO concentration during steady-state operation (excluding startups and shutdowns). Compliance with the VOC limits during startup and shutdown will be determined by assuring that all startups and shutdowns are conducted in accordance with written procedures that minimize emissions and the time spent under startup and shutdown conditions.
Section 5.8 allows use of alternative emission factors, instead of default emission factors in Condition 12.0. The use of alternative emission factors gives an overabundance of deference to DEQ. NEDC requests that DEQ specify the minimum requirements these alternative factors will have to meet and what DEQ's approval would be based on. PGE must show reasoning for its choice of alternative emission factors. (*NEDC*)	Oregon regulations (OAR 340-222-0051(4)) allow actual emissions used in determining compliance with the PSEL to be calculated using data that is considered valid and representative, regardless of the PSEL compliance requirements specified in a permit. This condition, which is now standard in all ACDPs, reflects this rule and allows alternative emission factors. It is up to DEQ, as the regulating authority to determine if the data (emission factors) are valid and representative.
Increasing emission limits will disproportionately impact environmental justice communities in the area. Relaxing or removing recordkeeping and reporting requirements may have a similar effect. PGE has not chosen to replace the Boardman coal plant with renewable energy. Fracked gas power plants like Carty are subject to less enforcement than other plants because fracked gas power plants are exempt from DEQ's Climate Protection Program. (*NDEC*)	The proposed emission increases have been evaluated and determined not to have an adverse impact on any communities in the area. Reporting and recordkeeping requirements have increased with this permit and have not been relaxed or removed. As referred to in the comment, emissions from electric power generating plants with a generating capacity greater than 25 MW are not covered in DEQ's Climate Protection Program (OAR 340-271-0110(5)(b)(B)(viii)) Changes to the Climate Protection Program are beyond the scope of this permit action.
DEQ's commenting and public notice hearing procedures during the COVID-19 pandemic have lacked equitable accessibility. Hearings have been conducted remotely rather than in person. This technological requirement disproportionately limits the ability to join these meetings for low-income and other at risk communities. Not everyone has access to a computer. The public could benefit from more public hearings at various days and times. DEQ could also provide access through platforms other than virtual hearings. (*NEDC*)	DEQ has endeavored to provide equitable access during the public notice period of this permit. This is the second public notice period for this permit action. The first public notice period was 1/23/18 through 2/27/18, prior to the pandemic. An in-person hearing was held on 2/22/18 and the comment period was extended to 4/30/18. DEQ met with CTUIR, in-person, to explain the proposed modification and later received comments from CTUIR. After the first comment period, the BACT limits were made more stringent and additional VOC testing was added. Though not required by rule, DEQ opted to open a second public comment period from 9/8/21 through 10/18/21 and to host a second public hearing. The comment period was later extended to 12/17/21 with a virtual hearing on 11/9/21. Again, DEQ met with CTUIR on conference call to discuss the changes. DEQ also

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	conducted direct outreach to several community groups and local government leaders that serve a diverse population. A request was made to have Spanish interpretation services during the virtual hearing, which DEQ provided. The hearing and associated information meeting were conducted via a Zoom videoconferencing platform, which is accessible via computer and smartphone, and was also accessible via telephone if computer connection was not available. The cumulative comment period for this permit action has been 197 days with both an in-person hearing and a virtual hearing. DEQ has tried to provide information on the permit modification to all communities and to ensure equitable access for public input.
NEDC has concerns that the Boardman Coal Plant was replaced by Carty in 2010. The permit modifications were only requested after DEQ and PGE failed to correctly anticipate higher emissions than originally permitted for. These errors could have significant effects on the health and wellness of Oregonians. (*NEDC*)	It is not within DEQ's purview to determine whether the generating capacity of the Carty facility was intended to replace the generating capacity of the coal plant. However, from an environmental standpoint, the emission reductions at the coal plant were not used to off-set the emission increases due to Carty. In the ambient air quality analysis DEQ assumed both the coal plant and Carty were operating at the same time since from 2016 through 2020 the two plants actually could operate at the same time. In the initial Carty permit DEQ was aware and accounted for greater emissions during startup and shutdown (an extra 19.7 tons of CO and 46.1 tons of NOx). However, the magnitude of emissions during this period for CO and VOC were not anticipated by either DEQ or PGE.
Clear that level of emissions from Carty are unknown. Inappropriate to make changes until emissions for actual operational patterns are known and additional mitigations considered. DEQ should set an appropriate period for emission measurements then mitigate any increase by enhancing capture of emissions, funding respiratory care for residents of Boardman area, constructing the approved solar facility, process of continual measurement and mitigation to hold the line on impacts. (*Orem*)	When drafting new permits DEQ uses the best emissions information available to issue a permit that allows operation to start. Once operating, testing provides site-specific emissions data that can be used to either verify the initial emissions estimate or to improve the emission estimate. DEQ guidance requires use of site-specific data, when available, to estimate emissions. If representative source-specific data cannot be obtained, information from equipment vendors is used. DEQ hopes to improve the emissions estimates as more test data is collected. Many of the mitigation measures discussed in the comment are outside DEQ's regulatory authority.
None of the CTUIR comments in 2018 appear to have been taken into account. CTUIR stands by those prior comments and reiterated them for this comment period. PGE should bear the costs of keeping their facility's emissions within the existing permit limits. (*CTUIR*)	DEQ apologizes for the confusion. DEQ received the comments in 2018 and will respond to both the 2018 and 2021 comments prior to a final determination on the permit. DEQ typically responds to comments at the time a permitting decision is made. DEQ elected not to issue a separate response to the 2018 comments period so that all comments could be evaluated in light of the final proposed permit.

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The manufacturer of the generator made material errors in the specifications of the turbine. We note there was a dispute between PGE and the contractor regarding the plant contracted for and what was delivered resulting in a settlement of all claims for lack of performance. PGE should resolve their claims against the manufacturer and contractor over plant construction rather than alter the permit issued for Carty. (*CTUIR*)	DEQ understands there were issues between PGE and the contractor responsible for engineering, procurement, and construction of the Carty facility. However, DEQ has no information connecting these construction issues with the proposed permit modification. DEQ cannot use its permitting authority to encourage or require any settlement between PGE and the contractor.
PGE received a permit for a "base load" facility that they are operating essentially as a "peaking" facility, dramatically increasing emissions based on their operations. The entirety of the original permit's emissions exceedances may be resolved by plant operations minimizing startups and shutdowns. (*CTUIR*)	The initial and current permit for Carty includes a PSEL calculation allowance for 80 cold startups, 80 hot startups, and 160 shutdowns (see page 47 of the review report for the current Title V permit). The assumed number of startups and shutdowns remains unchanged in the proposed permit. In other words, the proposed permit does not allow an increase in startups and shutdowns, which would indicate a transition from a base-load facility to a peaking unit. Conversely, denial of this modification will not reduce the number of allowed startups and shutdowns. Based on compliance determinations for the current permit there have been no emissions exceedances occurring.
The equations provided by the manufacturer for emissions are not reliable and should not be used to calculate actual emissions of VOCs. An adequate testing regime must be in place to determine that Carty's emissions do not exceed permitted levels. To meet these levels a catalytic oxidation unit should be required for VOC destruction. (*CTUIR*)	DEQ seeks to use reliable information in determining emissions. DEQ Internal Management Directive (IMD number AQ.00.020) describes the procedures DEQ employs when using emission factors to calculate emissions for permitted sources. The IMD requires DEQ to "Use all site-specific source test data whenever available, even if it is only one test, provided that it is representative of the process during the time period under consideration." It later states "If representative source-specific data cannot be obtained, emissions information from equipment vendors, particularly emission performance guarantees or actual test data from similar equipment is typically a better source of information for permitting decisions". The proposed permit includes a testing regime that will provide data to update the emission factors used in the PSEL during permit renewal. The reduction in VOC emissions due to the catalytic oxidizer has been included in the emissions estimates.
The proposed VOC limit for Carty will make it the single largest VOC source in the Boardman area. Even though CTUIR has been assured by DEQ that actual emissions will be far less than this limit, there is no certainty or guarantee that this will be the case. Permitting this level of	During the 20 month period from October 2016 through June 2018 PGE recorded 15 cold startups (43 hours, 49 minutes in duration), 13 hot startups (26 hours, 6 minutes in duration), and 28 shutdowns (13 hours, 23 minutes in duration). The proposed permit assumes during a 12 month period there will be 80 cold startups (273 hours, 36 minutes in duration), 80 hot startups (104 hours in duration), and 160

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VOC increase without hard data on current conditions or potential impacts, cumulatively and to local people, communities and the environment is inappropriate and unreasonable. (*CTUIR*)	shutdowns (80 hours in duration). The number and duration of actual startups and shutdowns during the 20 month period studied were much less than the permit assumed number and duration of startups and shutdowns. Based on this information it can be assumed that, in general, the number of actual startups and shutdowns will be less than the number assumed in the emissions calculations and, therefore, that the actual emissions will be far less than the limit. DEQ has used the best available information and methods to determine that, even at worst-case emissions, the impacts of the emissions will not adversely impact the community or environment. Hard data on current conditions will not reflect the impact of these future worst-case conditions, nor would it provide information that could be used in the impact analysis.
CTUIR supports the requirement to track and report emissions associated with startups and shutdowns, and to test to verify VOC emissions. However, CTUIR believes a CEMS should be required for VOC. Such systems exist and are economically achievable for plants such as Carty. Lacking verifiable data and arbitrarily setting VOC emissions based on questionable equations or suspect specifications from the manufacturer is particularly ill-advised before knowing both the environmental impacts and actual emissions based on defensible measurements. A CEMS would provide empirical and verifiable monitoring data, which DEQ must have to ensure permit compliance. (*CTUIR*)	Section 1.2.2 of EPA's Performance Specification 8 for VOC CEMS indicates, "In most emission circumstances, most VOC monitors can provide only a relative measure of the total mass or volume concentration of a mixture of organic gases, rather than an accurate quantification". DEQ has not required VOC CEMS on any other natural gas-fired turbine in the state and has not found any use for these types of facilities in other states. DEQ has determined the source tests required by the proposed permit, coupled with Compliance Assurance Monitoring for the CO CEMS on the catalytic oxidizer performance will be adequate to determine VOC compliance.
The reason given for the permit modification is a change in specifications from the turbine manufacturer but CTUIR understands the plant was built by a contractor who was replaced by PGE mid-way through construction, which may have also played a factor in the increase. A pollution source should be authorized for specific emission levels and held to those standards. Allowing retroactive revision of a permit is a classic case of bait-and-switch and should only be allowed based on clear data of the facility. PGE should identify	As far as DEQ is aware, the turbine manufacturer's update of CO and VOC emissions have nothing to do with any actions by the construction contractor. The emissions update was received from the manufacturer as part of a bid package to install an identical turbine as part of now abandoned expansion plans. The use of data from an identical, uninstalled turbine means construction/installation issues did not play a part in the requested increase. It should also be noted that the Carty CO and NO_x standards in the current permit are a 99 ton/year limit on CO emissions from the turbine (Condition 66) and the plant-wide limits in the PSEL (Condition 88). DEQ guidance allows use of manufacturer's data when site-specific data are unavailable. Site-specific data for VOC

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the necessary data to justify this change, which data do not appear in the application. (*CTUIR*)	emissions during startup have not been collected, but is required in this modification. Site-specific emissions test data will be used by DEQ to modify the PSEL in future permit actions. DEQ is satisfied with the conservative emission estimates provided for this permit.
CTUIR was unable to identify any monitoring data within the public record for this permit action. Such information is critical in evaluating the statements made by PGE and the manufacturer. The change in manufacturer's data and plant construction deviances should also be studied carefully. If actual emissions are far below the proposed limits, why is it necessary to modify their permit to allow increased emissions. PGE should be held to the standard adopted in the existing permit, or should re-initiate the permitting process. (*CTUIR*)	Monitoring data from the CO CEMS is being recorded and kept at the facility. Those data are available for review by DEQ upon request, but are not required to be submitted other than a summary of annual emissions to show compliance with the existing PSEL. Monitoring to show compliance with short-term limits (hourly basis or 3-hour average) is required only for NOx emissions in the current permit. (Condition 64) Continuous monitoring of CO emissions is required but the permit limit is a long-term limit (99 ton/yr – Condition 66) The proposed permit will require additional monitoring to demonstrate compliance with the new shorter-term limits. The emission limits in the proposed permit reflect potential operations rather than past or actual operations. Emissions estimates are established based on current DEQ guidance for establishing emission factors. When facilities need to increase emission above their existing permit, Oregon regulations require the permit be modified rather than initiating a new permit process.
CTUIR is aware that ozone levels are high in the Hermiston/Tri-Cities area. Ozone is a significant problem that contributes to a multitude of health problems. DEQ indicates VOC emissions will make an insignificant contribution to ozone concentrations in the area. However, there are an increasing number of energy developments, agricultural and other operations having significant impacts on air quality in and around Boardman. Currently there exist no agricultural air quality regulations for operations that can have more than a hundred thousand cows. These operations are significant emitters of VOC. (*CTUIR*)	DEQ is also aware of elevated ozone levels in the Hermiston/Tri-Cities area. Based on EPA accepted analysis methods (MERP), DEQ does not believe Carty will contribute significantly to that ozone problem. Oregon regulations (OAR 340-200-0030(1)(a)) exempt agricultural operations from DEQ's air quality regulations. This permit cannot address issues with Confined Animal Feeding Operations (CAFO).
In 2020 Carty did not employ the maximum number of startups and shutdowns and their emissions were far below the proposed limits. The minimization of startups and shutdowns should be continued to keep the facility in compliance with the current limits.	It is not just the number of startups that is driving emissions higher in the proposed permit, but also the estimate of emissions during each startup, based on the manufacturer's estimates. The current permit allows 80 cold startups, but assumes VOC emissions during that startup period are no greater than VOC emissions when the turbine is operating a full load and the catalytic oxidizer is at full efficiency,

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Relying only on PGE's informal assurances that emissions will always be less than authorized in its permit still creates too much risk that significantly higher amounts of VOC may be released solely on chosen operations of the plant with no outside or independent oversight or repercussions. (*CTUIR*)	which would amount to 20.6 lbs VOC for each cold start or 1,648 lb lbs VOC in a year for 80 cold starts. The manufacturer has indicated that each cold start could actually emit up to 3,400 lbs VOC. In other words, emissions from one cold start using the new emission factor would exceed the amount of emissions allowed for 80 cold starts under the current PSEL. Therefore, limiting the number of startups alone will not keep emissions below the current PSEL. DEQ maintains oversight to ensure compliance with the permit conditions and will take enforcement actions when violations occur.
It is premature to amend the permit without a particularized and careful analysis of the amount, timing, distribution, and impacts of the current and proposed increased VOC releases from the facility. Ozone concentrations have been high at the Hermiston monitor with an exceedance in 2017, which was speculated to be due to the contribution of wildfires. Since wildfires will increase with climate change ozone is a concern. (*CTUIR*)	Ozone in the Hermiston area continues to be a concern, and DEQ continues to watch the situation closely. DEQ used the EPA-approved Modeled Emission Rates for Precursors (MERPs) program (Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program | US EPA) to demonstrate that Carty's contribution to ozone formation is insignificant. Addressing the impact of climate change on ozone formation is beyond the scope of this permit.
The Boardman area has been subject to increased VOC sources. It is reasonable to expect that VOCs will continue to rise and without a comprehensive study of VOCs in this area, regulatory measures to reduce these impacts will not be possible. (*CTUIR*)	Requirements for a multi-source, comprehensive study of VOC emissions in the area is beyond the scope of regulatorily required actions for this permit.
Inclusion of the coal plant emission reductions renders the emissions limits in the PSEL difficult to understand. It is at best confusing and at worst potentially misleading. The total proposed increase from Carty alone is from 24 to 195 tons VOC per year. Due to the reductions from the coal plant the increase appears to be only 79 tons. By combining the increase from Carty and the decrease from the coal plant the net effect appears to be much smaller than it actually is. (*CTUIR*)	DEQ regrets the confusion. In the first public notice only the Carty increases were addressed in the permit. By the time the second public notice was issued the coal plant had closed and the regulations in place at the time required the PSEL be reduced on the day the coal boiler ceased operation. It was not DEQ's intent to obscure the emissions increase and tried to clarify the impact of each action in the public notice.
Modifications are not based on actual monitoring data but calculated using an inaccurate formula about relationship of CO and VOC. Why would DEQ allow PGE to solve a technical deficiency in its	The proposed VOC emission limits are not based on actual monitoring data because those data are not available. The current VOC limits are not calculated based on a formula founded on the relationship of CO and VOC emissions but are estimates based on a combination of EPA data and

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operating system that would result in increased health problems in already vulnerable and adversely impacted people. DEQ must consider the environmental injustices inherent in PGE's proposal. It is not acceptable to increase limits without knowing how much is emitted. DEQ should require PGE monitor VOC emissions before allowing any increase in emissions. (*Tsongas*)	manufacturer's estimates. As better, representative data becomes available the emissions estimate will be updated in accordance with DEQ guidelines.
DEQ needs to comply with Executive Order 20-04 directing State agencies to curb GHG emissions. Increase in warming will increase ozone production. (*Tsongas*)	DEQ's response to Governor Brown's Executive Order 20-04 has been posted. (State of Oregon: Governor Kate Brown - Carbon Policy Executive Order) At this time the response does not include any actions that would impact this permitting action.
Serious concern about the request for CO and VOC increases, both of which have serious health and environmental impacts that could affect air quality in the Columbia River Gorge National Scenic Area. VOCs are a precursor to low-level ozone formation (smog). There are frequent air stagnation advisories and alerts. When first proposed in 2018 numerous environmental and community-based organizations expressed concerns about the proposed emission increases and BACT determination. These comments were largely (or completely) ignored and we are asked to comment on a proposed permit that presents virtually identical threats to the one proposed three years ago. (*Partners*)	The permitting action placed on public notice in 2018 is the same permitting action recently placed on public notice. As a result of comments received in 2018 DEQ found that lower BACT limits were appropriate and increased monitoring and recordkeeping was required. The CO limits were lowered from 3.2 ppm to 2.0 ppm and VOC limits were lowered from 2.0 ppm to 1.0 ppm. The number of VOC tests was increased from 1 to 5 during the permit term and better recordkeeping of startups and shutdowns was required. Due to these changes, DEQ opted to allow a second public comment period. No comments from 2018 were ignored. All comments from 2018 and 2021 will be responded to prior to any action on the permit. We regret any confusion this additional public comment period may have created.
Since Carty was initially approved, multiple studies have demonstrated the cradle-to-grave climate change impacts of fracked gas. Negative health impacts associated with fracked gas disproportionately burden frontline, environmental justice communities. Oregon House Bill 2021 sets ambitious goals for reducing greenhouse gas emissions from the electricity sector. PGE must eliminate greenhouse gas emissions from its electricity by 2040 and has committed to tripling its use of	DEQ's permits, only address emissions within the plant-site boundary and do not address emissions upstream in the gas production line. This permit modification mainly addresses the impacts of increasing the factors used to calculate emissions of CO and VOC. This proposed permit modification does not allow increased combustion of natural gas and does not increase emissions of greenhouse gases. Denying this permit will not cause Carty to stop operations, reduce operations, or decrease emissions of greenhouse gases. This permit modification will allow increases in the annual emissions of CO and VOC, but will place new, more stringent, limits on the short-term emissions of CO and VOC.

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clean energy by 2030. It is critical to take aggressive action to reduce emissions from fossil fuels to quickly decarbonize the energy system. DEQ should deny the permit modification and ensure limits on the dangerous emissions at Carty. (*Partners*)	
We need less pollution, not more. (*Brewer*)	Thank you for your comment.
This proposed permitting decision appears to be nearly identical to the proposed permit DEQ put forth for public comment in 2018. DEQ has provided no explanation for why that permit was never finalized or how this current permit is different from the one the agency put forth in 2018. (*Earthrise*)	The permitting action placed on public notice in 2018 is the same permitting action recently placed on public notice. As a result of comments received in 2018 DEQ did not issue that proposed permit but did not deny the permit either. After further review, DEQ found that lower BACT limits were appropriate and increased the monitoring and recordkeeping requirements. The CO BACT limits were lowered from 3.2 ppm to 2.0 ppm and VOC BACT limits will be lowered from 2.0 ppm to 1.0 ppm. The number of VOC tests was increased from a single initial test to annual testing and better recordkeeping of startups and shutdowns was required. Due to these changes, DEQ opted to allow a second public comment period to occur for this permit modification. All comments from 2018 and 2021 will be responded to prior to any action on the permit. We regret any confusion the allowance for a second public hearing and comment period may have created.
Commenters filed public records requests pertaining to the permit modification during both the initial public notice period and the current comment period. Neither of the responses to the requests included direct information from PGE's engineer or the turbine's manufacturer describing why the prior estimates of CO and VOC emissions were incorrect or how the newly proposed emissions are more reliable. DEQ should not rely on PGE's word for it. Considering neither PGE nor DEQ have much data regarding Carty's actual emissions, DEQ must take a very hard look at the emission factors to ensure they are accurate and that the permit includes as many emissions controls as possible. (*Earthrise*)	DEQ's Internal Management Directive (IMD) number AQ.00.020 (emission factor guidance for NSR regulated Pollutants (oregon.gov)) was used in establishing the emission factors used to establish the PSELs for this modification. Part of that guidance indicates that, for PSEL calculation, emission factors based on site-specific test data should be used. The IMD further directs that if representative source-specific data cannot be obtained, emissions information from equipment vendors can be used. DEQ acknowledges use of equipment vendor data to establish the worst case startup/shutdown emission factors to calculate annual NO_x and CO emissions over the proposed operating range in the current permit. Both NO_x and CO emissions have been monitored by a CEMS since the facility began operation. There has been no required monitoring or testing for VOC emissions until the proposed permit. The IMD indicates site specific data should be used whenever available, provided that it is representative of the process during the time period under consideration. The current permit does not define periods of startup and shutdown, nor does it distinguish the difference between cold starts and hot starts. The proposed permit

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	provides these definitions in Conditions 3.4 and 3.5 and requires annual reporting of the number and duration of each startup and shutdown in Condition 7.4. This reported data will help DEQ determine average representative conditions during startup and shutdown which can then be properly used in an analysis of existing NO_x and CO CEMS data and to establish conditions for a VOC test. The PSEL emission factors in the proposed permit will be updated in future permit renewals as site-specific test data becomes available. DEQ will rely on the manufacturer provided data until site-specific, representative data can be obtained.
DEQ continues to reject lower, identified BACT levels for CO. DEQ should review the facility's emissions data and BACT analysis with a critical eye towards setting the lowest achievable limit. DEQ may have relied on PGE to self-assess what CO BACT limits the facility could meet rather than reviewing Carty's data itself. Does the data show that Carty can meet a lower BACT limit? Can Carty adjust its operating practices and/or install additional control technology that would allow it to meet a lower BACT limit? The commenter strongly urges DEQ to review Carty's data itself rather than rely on a PGE review. (*Earthrise*)	Based on PGE's application DEQ initially proposed a 3.2 ppm limit on CO emissions. After the first public comment period, DEQ re-reviewed data from EPA's BACT clearinghouse and determined 2.0 ppm appeared to be a more appropriate BACT limit. On 8/6/2019 DEQ sent an email to PGE stating, "With so many states setting CO limits of 2.0 ppm it is difficult to dismiss this level of control. Does PGE have some rationale why the CO BACT limit should not be set at 2.0 ppmvd?" PGE responded by pointing to the unique load requirements for Carty as PGE transitioned to a greater portfolio of renewable sources. PGE also proposed that a lower CO BACT limit might be acceptable if a longer averaging time (like 24-hours) were used. DEQ responded that if a 2.0 ppm CO limit based on a 3-hour average were too restrictive, DEQ would need to see sufficient data to justify this fact. Carty has operated for more than 28,000 hours since initial startup of the facility. PGE reviewed the 1-minute CO CEMS data and could find no data to support a less stringent limit or a longer averaging time. In other words, DEQ established the proposed 2.0 ppm CO BACT limit in a manner consistent with other BACT determinations, which involves a review of BACT determinations made in other, similar facilities. DEQ then asked PGE if there was some site-specific reason this limit could not be met at Carty. The CEMS data review was not used to establish the new BACT limit, but was used to assure that a less stringent limit was not appropriate.
DEQ should require PGE to meet a VOC BACT limit of 1.0 ppmvd. The permit identifies a facility that has equipment that is nearly identical to Carty, the New Covert facility in Michigan. New Covert has a VOC BACT limit of 1.0 ppmvd. DEQ provides no explanation for why Carty cannot meet the same 1.0 ppmvd BACT limit. The commenter strongly	DEQ has reviewed the permit, statement of basis, and source test data for the New Covert facility in Michigan. This facility has a VOC BACT limit of 1.0 ppmvd as a 24-hour average. Although the turbines at New Covert and Carty are not identical, they are similar enough that DEQ agrees that the same BACT limit should be applicable. Testing at the New Covert facility indicates that 1.0 ppm as a 24-hour VOC limit can be complied with on a consistent basis.

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encourages DEQ to review its analysis of the New Covert facility and justify why the VOC BACT limit should not be 1.0 ppmvd. (*Earthrise*)	Therefore, DEQ will change the VOC BACT limit to be 1.0 ppmvd @ 15% O_2 as a 3-hour average while operating at a 90% of maximum load or greater. DEQ notes that this is a shorter (more stringent) averaging time that found in the New Covert permit, and that the minimum operating load for the limit is increased from 60% to 90% of maximum load.
DEQ should require PGE to install a CEMS for VOC emissions. DEQ cannot assume that CO emissions are an adequate indicator of VOC emissions at Carty. There is little correlation between CO and VOC emissions at Carty and DEQ has no technical basis to assume that a correlation exists. The only way to truly evaluate the VOC emissions at the facility is to require PGE install a CEMS to track VOC emissions on a continuous basis, including during startup events. The commenter understands that PGE would be the first electric generating facility in Oregon to install a VOC CEMS and that these systems are not fool-proof. Since, neither DEQ nor PGE has a clear sense of what the overall VOC emissions are at the facility under the unproven assumption that there is a correlation between CO and VOC emissions, they are flying blind. Stack testing is a snapshot of emissions at a given point in time and does not provide adequate assurance that Carty is in continuous compliance. OAR 340-212-0210(1)(b) requires a reasonable assurance of ongoing compliance with emission limitations. At a minimum DEQ should require PGE lease a VOC CEMS for a period of time to evaluate whether such a system would be a worthwhile investment and provide a far better sense of what Carty's actual VOC emissions are. (*Earthrise*)	The commenter misunderstands DEQ's intent on using the CO CEMS to assure compliance with the VOC BACT limit. DEQ does not intend to use CO emissions as measured by the CEMS to calculate the VOC emissions. The commenter is correct in asserting that this type of correlation has not been established. The heading for Condition 5.5 of the permit is "VOC Compliance Assurance Monitoring". Compliance Assurance Monitoring (CAM) is an EPA requirement DEQ has implemented in OAR 340-212-0200 through 0280. EPA states the purpose of CAM is to "Provide a reasonable assurance of compliance with applicable requirements of the Clean Air Act <u>that rely on pollution control equipment to achieve compliance</u>. Monitoring is conducted to determine that <u>control measures</u>, once installed or otherwise employed, are properly operated and maintained so that they continue to achieve a level of control that complies with applicable requirements". (Emphasis added) A review of EPA's RACT/BACT/ LAER Clearinghouse (RBLC) indicates that the most universal technology used to control both CO and VOC emissions is good combustion control and use of catalytic oxidation. The permit clearly states that for VOC emissions the use of CO CEMS data is as "an indication of good combustion and proper operation of the catalytic oxidizer" and not as a method to directly calculate VOC emissions. The permit establishes the CO CEMS data as the indicator of emission <u>control performance</u> as required in OAR 340-212-0210(1)(a) and the CO value during a compliant VOC test as the designated condition that reflects the <u>proper operation and maintenance of the control device</u> and provides a reasonable assurance of ongoing compliance as required in OAR 340-212-0210(1)(b). Section 1.2.2 of EPA's Performance Specification 8 for VOC CEMS indicates, "In most emission circumstances, most VOC monitors can provide only a relative measure of the total mass or volume concentration of a mixture of organic gases, rather than an accurate quantification". DEQ has not required VOC CEMS, either permanent or temporary, on any other natural gas-fired turbine in the state and has not found its use in other states. DEQ believes the VOC monitoring in the proposed permit is adequate to

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	provide a reasonable assurance of compliance under the CAM rules.
DEQ is likely underestimating Carty's HAP emissions. DEQ relies on the poor quality emission factors in AP-42. Some of the emissions estimates rely on very few data points and rely on faulty assumptions. Given the margin of error and potential for high formaldehyde emissions during startup and shutdown events, Carty is very likely a major source of Hazardous Air Pollutants (HAP) and DEQ should treat it as such. (*Earthrise*)	While the proposed Air Contaminant Discharge Permit (ACDP) addresses the PSD impacts of the emission factor corrections, Carty along with the now-closed coal burning boiler currently operate under authority of a Title V Permit. The Title V Permit treats Carty as part of a source that is a major source of HAP emissions. That means that Carty currently is treated as a major source of HAP emissions and operates under all the requirements that would be applicable to a major source of HAP. This permit does nothing to change that designation nor the applicability of any HAP related rules. DEQ understands the limitations of emission factors found in AP-42. The HAP emission factors for natural gas turbines range from good (an A rating for pollutants such as Benzene and Formaldehyde) to poor (a D rating for 1,3-butadiene and propylene oxide). As mentioned in the comment, formaldehyde is potentially the most significant HAP emitted. That is why DEQ included a requirement to conduct a site-specific test for formaldehyde emissions within 18 months of permit issuance. (Condition 5.1) DEQ will continue to treat PGE as a major source of HAP emissions until formaldehyde emissions are tested.
PGE must reduce its GHG PSEL or subject the facility to PSD review, including a BACT analysis for GHG. Since the last time this permit modification was out for public comment the climate crisis has deepened considerably. Other State initiatives have taken significant steps in reducing GHG emissions, including Executive Order 20-04 and DEQ's Climate Protection Program. Carty is currently the fourth largest contributor of GHG in the state. There is no excuse for DEQ not to regulated Carty's GHG to the fullest extent possible. DEQ has an obligation to either reduce Carty's PSEL for GHG to 75,000 ton/yr or conduct a full BACT analysis for GHG as required by PSD. (*Earthrise*)	DEQ understands the increasing importance of climate change. This permit modification does not address any physical changes to the facility or changes to the method of operation that will increase GHG emissions. The initial PSD permit for Carty which was issued on 12/29/10 was the permit that allowed construction of Carty. In accordance with OAR 340-222-0048(4) GHG emissions were added to the permit on 9/25/12. This permit established GHG baseline emission rate. The proposed permit removes GHG emissions associated with the coal boiler from both the baseline emission rate and PSEL. PSD is required when the accumulation of emission increases since baseline are equal to or greater than the Significant Emission Rate (SER). Item 12 of the review report indicates that the GHG emissions (proposed PSEL) are the same as the baseline GHG emissions (proposed netting basis). Therefore, no reduction in GHG emissions or PSD analysis for GHG is required for this permit modification.
PGE has failed to submit the required analysis of potential impacts to visibility in the Columbia River Gorge National Scenic Area and to visibility and other air quality related values in Class I areas,	Carty is located about 84 kilometers from the Columbia River Gorge National Scenic Area. Both the Federal Land Managers and DEQ's Regional Haze Program use a ratio of emissions (Q) to distance (d) as a screening tool to determine if additional AQRV and visibility impacts are

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the required deposition modeling for receptors in Class I areas and the National Scenic Area; and the required analysis of impairment to visibility, soils and vegetation. Carty's current operations are already affecting visibility in the National Scenic Area and Class I areas. The proposed massive increases in CO and VOC could further affect these sources. Because PGE has failed to submit the analyses and modeling, the application must be denied. (*Earthrise*)	required. The Regional Haze Program only looks at PM_{10}, SO_2, and NO_x emissions as contributors to regional haze. The Federal Land Managers only look at PM_{10}, SO_2, NO_x, and H_2SO_4 emissions. The visibility impacts of these pollutants was addressed in a previous permit action. Neither group looks at the contribution of VOC emissions to visibility. Therefore, a visibility analysis due only to VOC emissions is typically not performed. However, if, for comparison, VOC emissions were included in this group of haze-causing pollutants, the highest value for Q (combined PM_{10}, SO_2, NO_x, and VOC emissions) would be 413 tons giving a Q/D value of 4.92. If Q/D is less than or equal to 10 the Federal Land Managers allow a presumptive no adverse impact determination. For DEQ's Regional Haze Program a Q/D less than 5.00 is not subject to the program. Thus, even when VOC emissions are included in the visibility screening analysis (which is not required), the Q/D value is less than the threshold for additional analysis. DEQ used the EPA-approved Modeled Emission Rates for Precursors (MERPs) program (Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program | US EPA) to demonstrate that Carty's contribution to ozone formation in the area is insignificant.
The significant change in VOC emissions requires review and approval by the Oregon Energy Facility Siting Council (EFSC) in the form of an amendment to the energy site certificate, to specifically evaluate potential impacts to visibility in designated protected areas. Unless and until EFSC issues such a site certificate amendment, DEQ cannot authorize PGE to exceed the previously established limits. If DEQ allowed PGE to do so it would be in violation of applicable state law. (*Earthrise*)	In making its original determination, Section IV.F.1.d of the 6/29/12 final order EFSC relied on the 12/29/10 ACDP that indicated Carty would not have an adverse impact on air quality and an insignificant impact on visibility to determine that Carty would not have significant adverse visual impacts on any protected area. The proposed permit modification does not change DEQ's determination and thus should have no impact on the EFSC determination.
PGE is required by law to seek EFSC approval to amend the site certificate in order to design, construct, or operate Carty in a manner different than the description in the site certificate if the proposed change could result in a significant adverse impact that was not addressed in an earlier order and the	The decision on the need for an amendment to the site certificate is up to EFSC and outside DEQ's authority. However, the changes proposed in the ACDP do not involve any change in the design, construction, or operation of the facility different from what is currently permitted. The modification simply changes the emissions estimates when operating as currently allowed.

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impact affects a resource or interest protected by an applicable law. (Earthrise)	In Section IV.J.1.c of the 6/29/12 Final Order, EFSC in responding to a comment that the Council has a responsibility to ensure that the Gorge air is protected from new sources of air pollution indicated: "The Council is not authorized to determine compliance with regulatory programs that have been delegated to another state agency by the federal government (ORS 469.503(3)). Air quality issues are under the jurisdiction of the Oregon Department of Environmental Quality and cannot be decided on by the Council." DEQ infers this to mean EFSC intentionally did not directly evaluate plume visibility or other ambient air quality impacts but left the analysis to DEQ.
DEQ must coordinate with EFSC to ensure EFSC evaluates and decides whether the proposed increases in the previously established VOC emissions will comply with the applicable law, including EFSC's standards and requirements for protecting visibility within designated Protected Areas. Any allowance to increase current VOC emissions without a corresponding EFSC review and amendment to the site certificate would be in violation of state law. (*Earthrise*)	DEQ has contacted Oregon Dept. of Energy to ensure they are aware of the changes proposed in this permit. The EFSC will decide if any changes are needed to the site certificate.
There is no information in the public record from the turbine manufacturer (Mitsubishi), PGE's consultants (Sargent and Lundy) or the catalytic oxidizer vendor (unknown) supporting: (i) why the prior CO and VOC estimates were incorrect; and (ii) how the proposed CO and VOC estimates are more reliable and correct. If DEQ has this information, it should provide it for the public record. If not, then DEQ should not rely on statements from PGE about the revised emissions without underlying documents from the vendors. (*Earthrise - Sahu*)	DEQ relies on permittees to provide accurate information during the application process as well as when certifying compliance with the permit conditions. Each application for permit modification contains a statement of certification from a responsible official stating, in part: "I have reviewed this application and all supporting documentation in their entirety and to the best of my knowledge, information, and belief formed after reasonable inquiry, the statements and information contained herein are true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and/or imprisonment for knowing violations". DEQ evaluates the proposed changes to ensure they comply with all applicable regulations. DEQ has determined that the information provided with the modification application is sufficient to incorporate all applicable requirements.
The definition of startup (i.e., when exactly startup ends) and shutdown (i.e., when shutdown begins) and how these should be verified using process monitoring, recordkeeping, and reporting is not consistent or complete in the proposed permit. End of startup should	The use of percent load is not confusing or unusual in defining turbine operations. Condition 61.a of the current Title V Permit establishes a NO_x limit "while operating at 60% of the maximum load or greater." The facility's operating system measures and records sufficient information to determine % operating load at any given time. The 50% load level was chosen because it was the

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be spelled out as a MW limit instead of a vague percentage of load since the load in question is not defined. Also, the basis for temperature distinction of cold and hot starts is not discussed in the record. There is no discussion of where exactly this temperature will be measured and how it will be recorded and reported. (*Earthrise - Sahu*)	lowest operating load modeled to show compliance with the ambient air quality standards. The permittee wants the flexibility to operate the turbines at partial load so that they don't have to burn the maximum amount of natural gas in the turbine when they need only a fraction of the electrical generating capacity. The 50% load represents the lowest steady-state turbine operation expected. During the previous public notice period, the permit defined a cold start as one where the turbine had been down for more than 12 hours and a hot start as one where the turbine had been down for less than 12 hours. In other States, facilities either added a third category (warm starts) or used different downtimes (4 or 8 hours) to define the different type of startups. DEQ believes these values are somewhat arbitrary since ambient temperatures could have an impact on startup behavior. PGE suggested the temperature threshold to distinguish between cold starts and hot starts based on observations during actual startups. PGE noticed a difference in CO emissions during startups that began with high pressure turbine temperatures greater than 842°F and less than 842°F. The temperature will be monitored and recorded at the same location used during PGE's review, which allows the operating system to flag what kind of startup is occurring and keep records of each type of startup.
Since Carty has been in operation for several years, CO CEMS data for that time period should be available. The public record does not contain any of the CEMS data for CO which are required to be monitored under the current permit. DEQ makes some statements about what this data might indicate, relying on PGE's review of that data. The establishment of a BACT limit would be informed by the CO CEMS data, collected under various operating conditions including startup and shutdown. CO CEMS data and the performance of the turbine/oxidation catalyst that affect the CO emissions are directly useful and relevant. DEQ should obtain, analyze and provide that data in the public record. For example, as part of the BACT determination it is directly relevant to see the actual CO concentrations that have been achieved under various loads. (*Earthrise - Sahu*)	DEQ agrees that Carty presents a unique situation where actual, site-specific operating data from the CO CEMS – data that would normally only be used to determine compliance with permit limits - is available to inform the determination of a BACT emission limit. However, the proposed BACT CO limits encompass a wider operating envelope than has been measured during actual operations so far. The proposed CO BACT limit is applicable when the turbine is operating at 60% loads or greater. PGE has requested that it be permitted to operate at less than full load for extended periods in order to have flexibility in responding to variable power demands. Most of the CO CEMS data collected so far represents a period when the turbines were operating at higher loads. In addition, the actual emissions measured by the CO CEMS during startup and shutdown so far do not necessarily represent worst-case conditions that would occur in the future. The BACT limits are intended to be applicable over the entire permitted operating envelope and not just the envelope demonstrated to date. While the CEMS data may be useful in approximating the normal operating emissions, using the data to extrapolate emissions outside the previously demonstrated operating

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	range or even establishing an upper limit to emissions can be difficult.
DEQ repeatedly makes statements indicating that monitoring of CO emissions would be sufficient to provide assurances for VOC emissions, i.e., that CO is a proper surrogate for VOC emissions. However, DEQ does not support this crucial assumption at all. Given the complexities of modern turbines and the presence of an oxidation catalyst there is no reason to assume that a correlation between CO and VOC exists – much less that it is robust enough for CO to act as a surrogate for VOC. Carty daily emission reports from the public record were cited as evidence that DEQ's premise of consistency and correlation between CO and VOC emissions is simply invalid. (*Earthrise - Sahu*)	DEQ does not assume or infer that there is a direct correlation between CO and VOC emissions. DEQ does not intend to use data from the CO CEMS to estimate VOC emissions. It is common engineering judgement that poor/incomplete combustion leads to increases in both CO and VOC emissions. It is also a common engineering assumption that catalytic oxidation can reduce CO and VOC emissions. The stated purpose of VOC Compliance Assurance Monitoring in Condition 5.5 of the proposed permit is to use CO CEMS data "as an indication of good combustion and proper operation of the catalytic oxidizer". There is no attempt to establish a relationship between CO and VOC emissions or to infer that CO emissions below a certain level will ensure VOC emissions below a corresponding level. The attempt is to ensure good combustion and proper operation of the catalytic oxidizer. This compliance assurance monitoring is intended to be employed only during steady-state operation of the turbine and not during startups and shutdowns. The emissions data referred to by the commenter comes from the Daily Mass Emissions Reports generated by the Carty operating system and is used to show compliance with the current Title V Permit. These reports were requested by DEQ during a compliance inspection and were specifically selected to focus on emissions during startups and shutdowns. The current Title V permit requires CO emissions to be reported as measured by the CO CEMS while the VOC emissions in this report are calculated by multiplying the turbine heat input (million Btu) by an emission factor (lb/million Btu) from AP-42, Table 3.1-2a. The VOC emission factor was derived from turbines operating at high load (≥80%), steady-state, and uncontrolled (no catalytic oxidation). The data values the commenter referred to as evidence for a lack of CO and VOC emissions correlation represents a comparison of actual CO emissions (measured by CEMS) and VOC emissions that are calculated using factors that are admittedly unrepresentative of the operating conditions for which the factors are valid (lower operating loads). DEQ agrees with the commenter that any attempt to establish a correlation between the CO and VOC emissions listed in those data sheets would be inappropriate. DEQ did not attempt and has no plans to attempt a correlation that will used the CO CEMS data to estimate VOC emissions.
It is essential to require a VOC CEMS for the turbine. Any short-term testing a	DEQ agrees that stack testing provides only a short-term demonstration of compliance. That is part of the reason that

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via stack tests is incapable of providing assurances for continuous compliance and since such testing is required only during periods of steady-state operation, they cannot cover the non-steady-state periods during startup and shutdown. Further, identifying a "representative" startup or shutdown event is not realistic. For these reasons, DEQ should require the use of VOC CEMS. Compliance assurance with BACT and startup/shutdown emission limits can only be done using CEMS since other methods of compliance assurance are not valid. DEQ could require CEMS for a representative period of time such as 1 year to evaluate the relationship, if any, between CO and VOC under all load conditions. (*Earthrise - Sahu*)	since the last public notice DEQ has proposed increasing testing for VOC from a single initial test to annual testing. DEQ is also requiring PGE to work with DEQ on establishing protocols to conduct VOC testing during startup and identifying what test conditions would be representative. As for determining continuous compliance EPA has established in 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) which has been adopted by DEQ in OAR 340-212-0200 through 0280. CAM is intended to provide monitoring at emission units where monitoring requirements are inadequate to determine continuous compliance. This approach uses parameters associated with a control device that ensure the controls are operating properly, such as pressure drop across a baghouse. If the parameter goes outside a specified range, action must be taken to return the parameter to the specified range. In this instance, CO concentrations (as measured by the CO CEMS) are monitored to ensure the catalytic oxidizer is working properly. An action level is established as the average CO concentration measured during a VOC stack test where the VOC emissions are in compliance with the permit conditions. (Permit Condition 5.5) The assumption is that if the catalytic oxidizer was operating well enough to keep the VOC emissions in compliance at the given CO concentration during the test, then as long as the CO concentration stays below the action level there is reasonable assurance that the catalytic oxidizer is operating properly and that VOC emissions are being controlled. The permit does not require CO monitoring for VOC CAM during startup and shutdown because catalytic oxidizer cannot be expected to operate properly at the temperatures and flow rates that occur during these operating periods. DEQ will not require installation of a VOC CEMS.
DEQ's determination of BACT appears to rely solely and exclusively on information from EPA's RACT/BACT/LAER Clearinghouse (RBLC). While this is a resource that can be used, just relying on it alone is not an appropriate way to conduct BACT analyses. BACT is not just what has been achieved elsewhere – it is what can be achieved, cost effectively, on a case-by-case basis. Previous BACT determinations can inform the process but cannot be the only basis upon which BACT determinations should be made.	DEQ agrees with the comments provided. DEQ does rely on information in EPA's RBLC as well as a database maintained by the California Air Resources Board (CARB) to determine what BACT determinations have been made in the recent past. DEQ also looks at the PSD permits issued by other states for additional details beyond the clearinghouse information. The comment is correct that a BACT analysis is a case-by-case determination. The establishment of a BACT determination and the comparison with other BACT limits must take into account several factors: the emissions value (i.e., 2.0 ppmvd @ 7% O_2); the design and size of the turbine (simple cycle vs combined cycle and large vs small turbine); the operating conditions for the limit (many limits

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The analysis requires a determination of what levels can be technologically achieved and then conduct a cost evaluation which can point to the lowest emissions level that is cost effective. (*Earthrise - Sahu*)	apply only at operating loads greater than 90% while others apply at loads greater than 60%, some limits also depend on size and operating status of duct burners); and the averaging times (some limits are 1-hr averages others are 3-hr or 8-hr or 24-hr, etc.). In reviewing the RBLC and CARB databases DEQ often reviewed the actual permits of the more stringent BACT determinations to ascertain these details, since they are not clearly listed in the databases. DEQ also reviewed compliance determination tests where available to determine what emission levels can consistently be achieved over the life of the equipment. The cost evaluation is typically done if the lowest technologically achievable control level is not selected. DEQ believes it has selected the lowest technological control level that can be achieved for the given design and operation of this facility.
DEQ noted that some lower CO BACT determinations were dismissed because the facilities had not begun operation and demonstrated the lower emissions. This includes the Novi Energy facility in VA. This is improper. The fact that a different agency made a proper determination of BACT is consequential regardless of the reasons the units have not begun operations. (*Earthrise - Sahu*)	DEQ agrees that the fact that a different agency made a proper determination of BACT is consequential. Most of the proper BACT determinations reviewed had CO limits equal to or greater than the limits proposed for Carty, meaning those States had determined that the more stringent limits were not appropriate. Those limits more stringent than the Carty proposal were reviewed. Details of the Novi Energy facility were unavailable because the permit was invalidated by VA DEQ (DEQ Invalidates Air Permit in Charles City County | News Releases | Virginia DEQ) The remaining more-stringent BACT limits are applicable at 90% turbine load or greater, while the Carty limit is applicable at 60% load or greater. Since Carty has the ability to operate at reduced loads for extended periods, DEQ feels the 60% load restriction is appropriate and warrants an emission limit greater than that which would apply only above 90% load. DEQ regrets review report language that lead the commenter to believe that emissions demonstration was the only factor used to establish its BACT determination.
DEQ rejected two lower CO BACT limits because the limits were for newer generations of turbine design that have better fuel premixing and operate at higher temperatures than Carty which helps reduce CO formation. There is no detail in the permit record that these newer turbines produce statistically significant and lower CO emissions than Carty. A 2016 stack test demonstrated that Carty had lower emissions than those allowed for the newer generation plants. (*Earthrise - Sahu*)	DEQ notes that BACT determinations can vary, even for identical equipment. For example, the Greensville Power Station turbine, which is similar to Carty, has a CO BACT limit of 1.6 ppmvd while a BACT determination 2½ years later for an identical turbine at Jackson Energy Center has a CO BACT limit of 2.0 ppmvd. The same can be said of the CPV Towantic CO BACT determination which was 1.7 ppmvd while a few months earlier the same type of turbine at Colorado Bend II Power had a CO BACT of 4.0 ppmvd. The point being that proper BACT determinations can have some variation. Newer generations of turbines are typically more efficient with better combustion controls. This permit modification deals with an existing turbine that was permitted in 2010

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	and installed in 2016. The turbines mentioned in the comment that had lower BACT limits were for newer generation turbines installed after the Carty turbine. Upgrades to existing turbines to make them perform like newer turbines without replacing the entire turbine may not be possible. In addition, there is an existing BACT limit for NO_x emissions that could be affected if changes to the combustors are made. DEQ considers the replacement of the existing turbine with a later generation turbine and specifying a new turbine be installed as a BACT determination is a redesign of the source and not within the scope of BACT.
DEQ indicated the proposed BACT limit is similar to the BACT limits established at other facilities. The BACT standard is not one where the limit is set similar to what other BACT determination may have been. (*Earthrise - Sahu*)	DEQ did not intend the use of the word similar to represent the process used to establish a specific BACT limit, but rather establish that the independent, site-specific determination of the CO BACT limit for Carty is comparable to BACT determinations made by other agencies elsewhere.
The review report makes clear that DEQ did not review Carty's own CO CEMS data to determine what levels of CO Carty was already achieving in order for that data to inform its BACT determination. It is not clear if Carty could consistently meet CO levels lower than the proposed BACT limit. These data would have been important since no one other than Carty has reviewed the CO CEMS data. (*Earthrise - Sahu*)	The current Title V Operating Permit requires recording of the hourly CO emission rates from the turbine. (Title V Condition 67) DEQ has reviewed selected data from the CO CEMS in order to evaluate compliance with the Title V Permit. DEQ has not used the CO CEMS data to directly establish a BACT limit. Past turbine operations do not necessarily represent the full-range of turbine operations allowed in the permit. The proposed BACT limit is applicable at turbine loads greater than or equal to 60% and the value is averaged over 3 hours. The current CO CEMS data represents 1 hour emissions averages and has limited data at lower operating loads. DEQ feels the existing CO CEMS data, while useful as a broad indicator of future compliance, is insufficient to allow a direct establishment of a BACT limit over the operating conditions and averaging times proposed.
The 2.0 ppm BACT limits excludes periods of startup and shutdown even though DEQ admits emissions during these periods can be substantial. DEQ establishes separate mass limits for CO during startup and shutdown using emissions data and startup profiles provided by the manufacturer. The exact manufacturer's supporting data for these limits should be provided in the record. (*Earthrise - Sahu*)	While DEQ requested and would have appreciated use of supporting data from the manufacturer for estimates of startup and shutdown emissions, DEQ noted that a nearly identical turbine at the New Covert Generating facility has a 1,164 lb CO/hr limit during any startup or shutdown, which is comparable to the 1,194 lb CO/hr value used only for cold starts at Carty. Based on the similarity of the data for an identical turbine, DEQ will accept the value as provided by the permittee as representative and sufficient to establish a site-specific BACT limit for Carty.
The permit indicates that startups and shutdowns must be conducted in accordance with written procedures.	Condition 7.6 of the proposed permit requires the permittee to submit the Carty startup and shutdown plans to DEQ for review and approval within 60 days of permit issuance. The

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However, no written procedures could be found in the permit record. (*Earthrise - Sahu*)	startup and shutdown procedures will be reviewed at that time.
DEQ's rejection of prior, lower BACT determinations simply because projects were cancelled is improper. (*Earthrise - Sahu*)	During the 2021 public comment period DEQ re-examined many of the VOC BACT determinations at other facilities and determined that a site-specific VOC limit of 1.0 ppmvd was appropriate. This value is reflective of the lowest VOC emissions for all facilities reviewed. The proposed permit has been modified to reflect a 1.0 ppmvd BACT limit for VOC.
DEQ's rejection of units with lower VOC limits simply because they were later generation turbines is improper because DEQ did not establish how these later generation turbines, via design always and consistently produce statistically lower VOC levels than the Carty turbine. (*Earthrise - Sahu*)	After re-evaluation DEQ has established a VOC limit of 1.0 ppm as BACT. This represents the lowest value found for the facilities reviewed.
DEQ noted that the New Covert Generating facility, which has a similar turbine to Carty, was able to comply with a 1.0 ppm VOC BACT limit after modifications were made to the turbine. Whatever modification was made to the New Covert turbine can clearly be done at Carty. DEQ has no basis to disregard the New Covert BACT limit. (*Earthrise - Sahu*)	DEQ agrees with the comment. The proposed BACT limit has been set at 1.0 ppmv, the same limit as the New Covert facility, but with a more stringent averaging time (3-hour average rather than 24-hour average at New Covert).
DEQ relies on CO CEMS to provide assurances for VOC emissions and only requires a rare stack test for compliance assurance. CO is not a proper surrogate for VOC emissions and therefore, the CO CEMS will provide no confidence as to the turbine's VOC emissions. (*Earthrise - Sahu*)	As mentioned in prior responses, the CO CEMS is used to provide assurance of proper operation of the catalytic oxidizer, which is critical to reduce VOC emissions. This approach is in accordance with EPA's Compliance Assurance Monitoring (CAM) policy which is designed for large emission units that rely on control device equipment to achieve compliance. DEQ has no intention of using the CO CEMS to directly or indirectly determine the quantity of VOC emissions.
DEQ establishes separate VOC limits during startup and shutdown that are based on information provided by the manufacturer. The exact manufacturer's supporting data should be provided. (*Earthrise - Sahu*)	While DEQ requested and would have appreciated use of manufacturer's supporting data, DEQ believes the estimate to be conservative (worst-case) and actual emissions will be lower. There is limited independent data on VOC emissions during startups and shutdowns. DEQ has accepted the provided data and has shown that there are no adverse impacts due to these emissions.
Carty is a major source of hazardous air pollutants (HAP) and DEQ has improperly classified it as an area source. The HAP emissions estimates rely on	While the proposed modification indicates HAP emissions from Carty are less than the major source threshold for HAP, the current Title V operating permit treats the facility

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AP-42 emission factors. There are significant issues that make these factors unreliable. The AP-42 factors are based on just a handful of measurements that are only valid when the turbine is operating at 80% load or greater. Formaldehyde emissions (estimated at Carty to be 8 tons/yr) are only slightly less than the major source threshold of 10 tons/yr. A 20% margin is not sufficient to assure that Carty is not a major source of HAP. In the AP-42 background document, the data used to establish the AP-42 factor for formaldehyde confirms that only 2 data points were used to derive the emission factor for formaldehyde. Thus, the formaldehyde emission factor is not reliable. Due to the deficiencies noted in the comment, formaldehyde emissions would be greater than 10 tons/yr, making Carty a major source of HAP. (*Earthrise - Sahu*)	as a major source of HAP emissions due to emissions from the coal plant. DEQ is aware of the limitations with AP-42 emission factors. The comment noted that AP-42 background data has only 2 data points, with an average emission factor of 3.60E-04 lb/MMBtu to represent formaldehyde emissions for units controlled by a CO catalyst. The comment did not highlight the 22 data points AP-42 has, with average emissions of 3.12E-03 lb/MMBtu, for uncontrolled formaldehyde emissions. This indicates a potential 10-fold decrease in formaldehyde emissions due to catalytic oxidation when compared with uncontrolled emissions. The factor DEQ used to calculate formaldehyde emissions came from Table 3.1-3 of AP-42. The header to this table indicates that these factors represent uncontrolled emissions. Thus, the 8 tons/yr of formaldehyde emissions calculated by DEQ assume no catalytic oxidation and is based on an emission factor with more than 2 data points. Since Carty has a catalytic oxidizer, the actual formaldehyde emissions will be much less than the 8 tons/yr used in the HAP summary table. Similar reductions in other actual HAP emissions due to the catalytic oxidizer can be expected. Until site-specific testing can prove otherwise, DEQ will continue to treat this source as a major source of HAP emissions.
Condition 2.3 of the permit requires the permittee to take reasonable precautions to prevent fugitive dust emissions and lists several measures to address fugitive dust. None of the measures listed are enforceable as written, unaccompanied by any practical means of verification of not only the extent of fugitive dust emissions but also how they can be prevented. (*Earthrise - Sahu*)	The language of the condition comes from Oregon regulations, OAR 340-208-0210. Clarifying language is included and will continue to be in the Title V Permit which clarifies the monitoring (using EPA Method 22 to determine any visible emissions leaving the plant-site boundaries for more than 18 seconds in a 6-minute period), the required action (contain the source of emissions by watering, sweeping, etc.), and the recordkeeping of all actions taken to address fugitive emissions.

In 2018 several people requested that a second public hearing for the Carty modification be held in Portland for those living in that area that wanted to public comment on the permit. DEQ denied the request and reminded those that asked for the Portland hearing that written comments would receive the same weight as oral comments received at the hearing.

Name	Type of Comment
Perry	Email from Gilbert and Clare Perry of Beaverton, OR, received 2/21/18
Onasch	Email from Carole Onasch, received 2/21/18
Neal	Oral comments from Gary Neal of the Port of Morrow given during the public hearing 2/22/18
Spofferd	Oral comments from Cathy Spofferd of Portland given during the public hearing 2/22/18
Horner	Oral comments from Mike Horner of Climate Action Coalition given during the public hearing on 2/22/18
Dreier	Oral comments from Ted Drier of Portland given during the public hearing 2/22/18
Clark	Oral comments from Andrew Clark of Pendlton given during the public hearing 2/22/18
Little	Oral comments from Chuck Little of Hermiston given during the public hearing 2/22/18
Russell	Oral comments from Don Russell, Morrow County Commissioner given during the public hearing 2/22/18.
Erickson	Email from Charles Erickson, received 2/26/18. Mr. Erickson submitted a second comment on 3/5/18.
Lackner	Email from William Lackner representing the Clam Diggers Association of Oregon, received 2/26/18
Dlugonski	Letter from Melba Dlugonski of Portland, received 2/27/18
Schaeffer	Email from Katy Schaeffer of Montesano, WA, received 3/9/18
Hodiak	Email from Diane Hodiak of Bend, received on 3/11/18
ODOE	Email from Maxwell Woods representing Oregon Dept. of Energy, received 3/14/18
Sundermann	Letter from Kathryn Sundermann, received 3/21/18
Riverkeeper, et.al	These comments were essentially a common letter, submitted either collectively by Columbia Riverkeepr or individually, with some personal variations collected from 1,056 commenters. Comments were also collected by Oregon for Social Responsibility from approximately 100 individuals
Arcana	Email from Judith Arcana of Portland, received 3/27/18
Todd	Email from Judy Todd of Portland, received 3/27/18
Brannan	Email from Michael Brannan of Beaverton, received 3/28/18
Bachhuber	Email from Stephan Bachhuber of Portland, received 3/30/18
Alman	Email from Kris Alman, received 4/17/18
Postcards	Postcards received from 20 individuals opposing the proposed increase at Carty
Muller	Letter from Katherine Muller, received 4/26/18
CTUIR	Email from Audie Huber representing the Confederated Tribes of the Umatilla Indian Reservation (CTUIR), received 4/27/18
Merritt	Email received from Regna Merritt representing Oregon Physicians for Social Responsibility, received 4/30/18
Plunkett	Email from Jim Plunkett of Portland, received 4/30/18
McKinlay	Email from Bonnie McKinlay of Portland, received 4/30/18
Earthrise	Email from Kathryn Roberts of Earthrise Law Center at Lewis & Clark Law School on behalf of Columbia Riverkeeper, Friends of the Columbia Gorge, 350PDX, Climate Action Coalition, Columbia Gorge Climate Action Network, Greater Hells Canyon Council, Green Energy Institute, Northwest Environmental Defense Center, Oregon Natural Desert Association, Oregon Physicians for Social Responsibility, Sierra Club, and Stop Fracked Gas PDX, received 4/30/18

2018 Comment Summary and Response

Comment	DEQ Response
Opposed to any increase in emissions. (*Perry*)	Thank you for your comment.
Increase in emissions will increase haze and smog and have adverse health impacts. (*Onasch*)	DEQ has determined that the emissions will not significantly contribute to any exceedance of the health based ambient air quality standards.
PGE is using Best Available Control Technology (BACT). More plants are starting and stopping more often because of renewable energy projects that are on the system. (*Neal*)	Thank you for your comment.
Concerned about the impact of CO and VOC and opposed to the permit. (*Spofferd)*	Thank you for your comment.
Concerned about increased haze that would be formed in the Columbia Gorge and health impacts of VOC. Something has gone very wrong at Carty whether due to initial miscalculation, faulty construction, or running the plant in a way it wasn't designed to run. I ask that you require a root cause analysis to determine where the problem lies. Portland rate-payers should be able to weigh on this in an organized way. Consider having a hearing in Portland. (*Horner*)	DEQ has conducted an analysis that indicates the impact of the facility on health and visibility in the area will not be significant. DEQ believes the plant is properly constructed and operated. The cause of the increase is a correction of emissions estimates from the manufacturer. There has been no change in the design or operation of the plant associated with this permit modification. DEQ declined the request to have a hearing in Portland.
DEQ's analysis fails to adequately assess the impact of smog forming pollution on the Columbia River Gorge. Also concerned about the adverse public health impact of increased CO and VOC emissions. The addition of a major VOC source will make health event more likely. (*Dreier)*	DEQ has conducted an analysis that indicates the impact of the facility on health and visibility in the gorge will not be significant.
There are many questions regarding the adequacy of monitoring and recording. The permittee is required to calculate facility-wide emissions and submit an emissions report semiannually. On-site inspections will be conducted to assure compliance. Data included in the review report ends in 2014. DEQ should provide the results of any monitoring that has already occurred at Carty and not rely on stale information. (*Dreier*)	DEQ has added more testing and monitoring requirements to the proposed permit and believes the monitoring and recordkeeping requirements are sufficient to determine compliance. The review report contains all source test data that has been reviewed and approved by DEQ since the last permit action and was updated since the public notice to include test results up through 2019. The CEMS monitoring CO and NO_x emissions from Carty was initially certified in 2016 and records of this monitoring are kept on-site and are not typically included in the review report. These records are reviewed during on-site inspections. A review of emissions monitoring at the facility during a recent inspection

Comment	DEQ Response
	indicated the facility was in compliance with the current permit and that this modification is necessary.
PGE should be limited in how often it can operate the Carty plant because it produced more carbon monoxide and VOC than originally anticipated. Increasing the pollution limit will increase the operation of the Carty plant resulting in higher levels of greenhouse gas pollution than if the plant were held to its current limits for carbon monoxide and VOC. (*Dreier*)	The proposed permit increases the factors used to calculate emissions, but does not increase the number of startups and shutdowns currently allowed. The proposed modification does not allow longer hours or operation or result in more combustion of natural gas. There is also no proposed increase in the emissions of greenhouse gases. Due to the emission factor increase there will be a potential increase in carbon monoxide and VOC emissions. However, DEQ has determined that the increase will have an insignificant impact on ambient air quality.
DEQ would be setting a disturbing precedent if it allows PGE to dramatically increase pollution levels so soon after the plant has gone into operation. Can any plant come forward and claim faulty information and then request permission to increase its emissions? DEQ has failed to assess all options for holding PGE to lower pollution levels. DEQ should 1) Hold PGE to correct annual pollution limits for CO and VOC; 2) Limit startup and shutdown events; 3) Particularly limit cold startup events; 4) Investigate additional best available control technologies that could reduce CO and VOC pollution, including restrictions on how PGE operates the facility. Request hearings in Portland. (*Dreier*)	It would be equally disturbing for DEQ to ignore information that emissions when operating as currently permitted could be greater than anticipated. PGE has not requested any change in operations (no change in hours of operation, fuel use, or number of startups) or made any other change to the facility that caused the increased emission limit. The initial permit assumed a certain number of startups and shutdowns and that value has not changed with this permit modification. DEQ encourages facilities to report any updated information that will help to more accurately quantify emissions. Based on the emission factors contained in the current permit, PGE is in compliance with the current permit emission limits. This modification will change the emission factors for CO and VOC based on the latest information from the turbine manufacturer. This change in emission factors is driving the increased permit limit. Before granting the increased permit limit DEQ reviewed and implemented the best available control technology and conducted the appropriate analyses to ensure the increase would not have a significant adverse impact to the ambient air quality. DEQ has determined that PGE can continue to operate as currently permitted with the new emission factors and still meet all applicable environmental regulations without restrictions on operation.
Those of us that live in Eastern Oregon have a great appreciation for the air we breathe. In 2017 PGE kept emissions to 50% of the permit, so why are they requesting an increase of 3.7 times? The emissions increase is an extraordinary request worth very serious examination. Ask DEQ to exercise authority vigorously and effectively. (*Clark*)	Thank you for your comment. Permits are written to cover the range of foreseeable operations. While past years may have had low emissions, those emissions occurred because the facility only operated 50-60% of the time. Since PGE is asking for authority to operate up to 100% of the time, the permit must be written to assume emissions when operating 100% of the time.
I support PGE's request. I don't see a problem modifying the permit. (*Little*)	Thank you for your comment.

Comment	DEQ Response
I live in the area. We get prevailing winds that blow from east to west (from Carty to the Gorge) about 21 days a year, primarily in the winter. The rest of the time the primary factor for haze in the Columbia River Gorge is unregulated motor vehicle emissions from the Portland Metro area. PGE got poor initial information from the manufacturer and now wants to use real numbers. (*Russell*)	Thank you for your comment. In its analysis of ambient impacts due to the Carty plant, actual meteorological data (wind speed and direction) at the PGE site, supplemented with data from the Hermiston airport and Spokane upper-air data were used with local terrain data to determine the ambient air impacts.
The permit should be denied if it allows self-monitoring. In the past, coal tar pitch from aluminum plants has been applied to the coal pile and burned with the coal. Coal tar pitch is a hazardous waste that should not be combusted. There are also allegations that the stack scrubbers are turned off at night. Was the coal plant initially permitted and then mothballed so that PGE could operate a dirtier plant in the future when clean air standards would be stricter? The public should be informed of the plant's dark history that affects public health. (*Erickson, Lackner)*	Since DEQ cannot be on-site at every facility every day, it relies to a certain extent on self-monitoring. DEQ routinely reviews monitoring records to ensure they are complete and accurate. Issues at the coal plant are beyond the scope of this permit modification. However, DEQ routinely monitors operational records at the coal plant to ensure all air pollution control equipment is working when the plant is operational. DEQ has found no indication that hazardous waste is being burned at the coal plant. Carbon bake plant ESP residue, an aluminum plant waste, was used at the coal plant in the past to suppress dust on the coal piles and limited to no more than 1800 tons per year. However, an inspection in 1994 indicated this substance was no longer being used and has not been used since. A review of monitoring during on-site inspections indicates pollution control equipment is not turned off at night, but operates continuously.
How many tons of coal tar pitch from aluminum plants were dumped and burned at the coal plant? Which plants did the pitch come from? Did the aluminum plants falsify disposal records? How many days did PGE operate while illegally burning pitch? How many nights did PGE operate without stack scrubbers? Were annual reports to EPA falsified involving the burning of pitch? How did pitch burning affect public health? How much did DEQ fine PGE for illegally burning coal pitch? Why was PGE allowed to burn pitch after it was brought to the attention of OR PUC? A coal plant operator developed throat polys. Was this related to burning pitch? How many others developed polyps? (*Erickson*)	As mentioned above, ESP residue from an aluminum plant was temporarily used to suppress dust from the coal piles more than 28 years ago. It has not been used since that time and will not be used in the future since the coal plant has ceased operation. DEQ has no indications that hazardous waste was burned in the coal boiler. No enforcement action was taken. This permit action is only for CO and VOC emissions from the natural gas fired turbine adjacent to the coal plant. Any actions dealing with the now-closed coal plant are beyond the scope of this permit action.
Opposed to continued operation of the coal plant. The amount of	The coal plant is no longer operating. However, DEQ notes that during the last several years of operation mercury

Comment	DEQ Response
methylmercury, arsenic and cyanide discharged by the coal fired power plant is unacceptable. The impact on razor clams and other shellfish should be investigated. (*Lackner*)	controls were installed at the coal plant in accordance with federal regulations resulting in a significant decrease in mercury emissions. An investigation of impacts on clams and shellfish due to coal plant emissions is beyond the scope of this permit modification.
Must decrease, not increase the use of fossil fuel and decrease pollution, permitted or not. PGE should commit to renewable energy, DEQ could hold the line here to encourage such change. (*Dlugonski*)	This permit does not allow an increase in natural gas usage. Requiring use of renewable energy at this facility is beyond the scope of this permit action.
PGE is supporting fracked gas which consumes millions of gallons of water and due to methane leaks may be dirtier than coal. It could lead to an expansion of pipelines in Oregon. (*Schaeffer*)	Fracking is a procedure that occurs at the natural gas extraction area. This occurs at some distance from the facility. Regulating off-site activities is beyond the scope if this permit action.
Hold PGE to current annual pollution limits. Limit startup and shutdown events. Investigate additional control technologies including restrictions on how PGE operates its facility. Study the impact of smog forming pollution on the Gorge and nearby communities. (*Schaeffer*)	DEQ has evaluated the Best Available Control Technologies for this facility and will require them in this permit. The increase in emissions has been evaluated and determined not to have a significant impact on ambient air quality in the Gorge and nearby communities.
Carbon dumping will cost taxpayers more money and threaten the health and welfare of communities throughout Oregon. Stop this new permit (*Hodiak*)	The proposed modification will not allow an increase in greenhouse gas emissions. The emissions will not significantly impact the ambient air quality in the area.
Clarified some statements relating to the Site Certificate issued by the Energy Facility Siting Council (EFSC). Indicated all matters related to siting of energy facilities as well as state and local permits included in and governed by the Site Certificate are the responsibility of EFSC and ODOE. All matters related to federally-delegated permits, such as this PSD permit and the Title V Permit are the responsibility of DEQ. ODOE takes no position regarding issues outside its jurisdiction. (*ODOE*)	Thank you for your comments. The clarifications related to EFSC and the site certificate have been made to the permit.
PGE has failed to demonstrate that the new pollution levels will protect air quality and public health near the facility and in the Columbia River Gorge. Please hold PGE to current annual pollution limits. (*Sundermann*)	Using EPA-approved methods, DEQ has determined that emissions from Carty will not significantly impact the ambient air quality limits in the Gorge and surrounding areas.

Comment	DEQ Response
The increase in emissions is excessive, unacceptable for a newer plant. The health impacts of these pollutants are serious. PGE should operate efficiently and within the current permit limits. (*Riverkeeper, et.al.*)	DEQ agrees that the increase in emissions is significant and that these pollutants can, at sufficient concentrations, cause serious health effects. Any time there is a significant increase in emissions DEQ is required to conduct an analysis to ensure there are no adverse impacts. DEQ has followed these requirements in drafting this permit. The analysis indicates that the impact of the emissions increase on the ambient concentration of these pollutants is insignificant.
DEQ should determine the potential impact of increases in pollution on visibility in the Columbia River Gorge National Scenic Area and public health in nearby communities. (*Riverkeeper, et.al.*)	DEQ's efforts on regional haze can be found on our website https://www.oregon.gov/deq/aq/Pages/Haze.aspx which includes impacts on the Columbia Gorge. The Regional Haze Program only looks at PM_{10}, SO_2, and NO_x emissions as contributors to regional haze. The Federal Land Managers only look at PM_{10}, SO_2, NO_x, and H_2SO_4 emissions. The visibility impacts of these pollutants was addressed in a previous permit action. The increase in VOC emissions will not significantly change that analysis.
PGE should limit startup and shutdown events. If these events would push PGE over its annual pollution limits then startups should be limited. (*Riverkeeper, et.al)*	The proposed permit does not increase the number or duration of startups and shutdowns allowed in the current permit. Based on the estimates of potential emissions during a single cold startup, PGE could only have a handful of cold starts before exceeding the current annual limits, which would severely restrict operations as the company transitions to other renewable energy sources.
DEQ should investigate additional Best Available Control Technology (BACT) limits, including operating restrictions that will reduce CO and VOC emissions. (*Riverkeeper, et.al.*)	DEQ follows federal guidelines in determining BACT. This includes an analysis that requires the best control options for a given facility as determined following the top-down procedures established by EPA.
With an 800% increase in smog-forming VOC and a three-fold increase in CO, Carty will produce more than twice as much smog-forming VOC pollution than the coal plant. I urge DEQ to reject PGE's proposal. (*Arcana, Todd, Brannan*)	Thank you for your comment. DEQ has determined that the emissions increase will have an insignificant impact on ambient air quality.
Oppose expanding pollution limits because of the effect it will have on air quality in the Columbia River Gorge. Limit cold starts and shutdowns. Hold to current limits. (*Bachhuber*)	Thank you for your comment. DEQ has determined that the increased emissions will not have a significant impact on air quality in the Gorge.
Deny PGE's request for three-fold increase in carbon monoxide and eight-fold increase in VOC from Carty. Carty has been mire with controversy. The construction contractors filed for bankruptcy and PGE completed	Thank you for your comment. Many of the issues raise in this comment are outside the scope of activities regulated by this permit.

Comment	DEQ Response
construction at an increased price tag. Carty just met a deadline to become operational in 2016. Contractors have raised safety allegations. (*Alman*)	
The release of greenhouse gases lead to climate change and is damaging to health and the environment. An increase of CO_2 emissions is a threat that will create climate feedback loops that cannot be reversed. 1-9% of all natural gas produced escapes into the atmosphere from various points along the natural gas supply line, adding to the amount of GHG (methane) in the atmosphere. No new fossil fuel infrastructure should be built. The increased emissions of CO can react with hydroxyl radicals in the atmosphere, reducing the abundance of hydroxyl radicals available to oxidize the more potent GHG, methane. Thus, CO emissions can indirectly result in a decrease in the reduction of methane in the atmosphere, thus increasing global warming. (*Alman*)	DEQ acknowledges the contribution of GHG to climate change. Permits issued by DEQ can only consider emissions within the Carty plant site boundary and not emissions of methane off-site (at the wellhead or along the pipeline). While there may be a potential for CO to affect the reduction of ambient methane, current regulations do not quantify this effect. EPA has not promulgated a global warming potential for CO. Lacking appropriate protocols to determine the impact, the effect of CO on GHG retention in the atmosphere will not be considered at this time.
Oregon utilities must comply with the State's GHG emission reduction goals found in 2009 SB101. GHG emissions from electricity consumed in Oregon are still well above the target goals. PGE should be limited in how often it operates Carty to keep it within the current limits for CO and VOC. (*Alman*)	Thank you for the comment. SB 101 was applicable to the public utility commission and had no applicable requirements for DEQ.
Hold the line on pollution limits from Carty. (*Postcards*)	Thank you for your comments.
Wonder if the original permit was filed in good faith. The fact that PGE requested a huge increase in emissions within two months of the plant becoming operation suggests they may have deliberately underestimated emissions in the original permit. DEQ should investigate the circumstances behind the pollution problems at Carty. Repeated comments from the *Riverkeeper* letter. (*Muller*)	Thank you for your comments. DEQ has no reason to believe the emissions estimates in the original permit were intentionally underestimated. The startup and shutdown emissions estimates were similar to estimates at other natural gas turbines in the area.
Increasing the emissions of VOC into the Columbia River Gorge unnecessarily impacts a vital natural resource of	DEQ understands the importance of the Columbia River Gorge to CTUIR. Based on information from the manufacturer there are no technological fixes that can be

<table>
<tr><th>Comment</th><th>DEQ Response</th></tr>
<tr><td>significance to the Confederated Tribes of the Umatilla Indian Reservation (CTUIR), the region and the nation. The public was promised a plant emitting less pollution, only to have pollution increases at the end of the process. PGE should bear the cost to undertake the technological fixes needed to bring their facility into compliance with the current permitted annual emission limits. (CTUIR)</td><td>made to keep emissions below the current PSEL. The current PSEL contains assumptions on the type and number of startups and shutdowns that can occur. Those assumptions have not changed. What has changed is the estimate of actual emissions of CO and VOC during the currently allowed startups and shutdowns. This is not due to any physical changes or changes in the method of operation at the facility, but is a correction based on manufacturer's estimates. DEQ agrees that the increase in emissions is significant and has included conditions in the permit that limits emissions associated with startup and shutdown activities and requires increased monitoring. DEQ hopes to use the data collected during this monitoring to adjust the PSEL in the future to better reflect actual emissions during these events.</td></tr>
<tr><td>The facility was represented before the Public Utility Commission of Oregon as a baseload facility. This permit seeks to allow Carty to operate as a peaking plant with frequent startup and shutdown events. VOC and CO emissions are much higher than steady state operations. Reducing the number of shut downs and startups will decrease the emissions of VOC and CO. (CTUIR)</td><td>The site certificate issued for Carty by the Oregon Dept. of Energy makes no distinction of Carty being a baseload or peaking plant. The original permit issued by DEQ did not designate the facility as either baseload or peaking unit. This permit modification maintains the operating scenario, including the number of startups and shutdowns, contained in the initial permit. DEQ agrees that reducing the number of startups and shutdowns will decrease the emissions of VOC and CO. However, PGE has demonstrated it can comply with all applicable standards and regulations under its proposed operating scenario.</td></tr>
<tr><td>The fact that PGE is reporting much higher emission factors after issuance of the initial permit creates the perception that the community has been subject to a bait-and-switch scheme. It is difficult to believe that the turbine manufacturer and the permittee were not aware that startup and shutdown emissions differed from steady state levels. For example, PSD permitting on the Grays Harbor turbines shows the awareness of different startup/shutdown emissions. DEQ should prepare an internal database of key operating assumptions and parameters used in permitting facilities such as Carty. The database can be used in future permitting to determine typical upper and lower bound on key process parameters to compare with future proposed values to identify those that are outside of the normal range. Scrutiny should be placed on the non-standard</td><td>During initial permitting in 2010 PGE and DEQ were aware that emissions of some pollutants are greater during periods of startup and shutdown. Some of these differences are reflected in the PSEL detail sheets of the initial PSD (and current) permit. The manufacturer (Mitsubishi) and PGE's consultant (Sargent & Lundy) provided new estimates of emissions during startup and shutdown that were greater than those used in the initial PSD (2010) permit, as the example in the table below shows.

<table>
<tr><td>Pollutant</td><td>2010 Permit (lb/cold start)</td><td>Proposed Permit (lb/cold start)</td></tr>
<tr><td>NO_x</td><td>498</td><td>498</td></tr>
<tr><td>CO</td><td>258</td><td>4083</td></tr>
<tr><td>VOC</td><td>--</td><td>3433</td></tr>
</table>

No change was proposed for NO_x emissions during a cold start, but CO startup estimates were increased and VOC emissions, which were not accounted for in 2010 was included in this modification. The magnitude of the corrections to startup emissions provided by the manufacturer was surprising, we believe, to all parties. The</td></tr>
</table>

Comment	DEQ Response
values and Permittees should be required to provide data to justify the values. (*CTUIR*)	startup/shutdown information was provided as part of an estimate of annual emissions (PSEL). Actual emissions of individual startup/shutdown events could vary based on ambient conditions, the hold load for HRSG warming, steam temperature matching, and other site-specific operational considerations and configurations. DEQ does not plan on developing a database of operating assumptions and parameters for different facilities since each facility may have different sizes and types of turbines and data collected for 2010 turbines may not be applicable to turbines permitted in 2030. However, DEQ will be looking closely at CEMS data and source test results to assess compliance and the accuracy and representativeness of the manufacturer's emissions estimates. If the manufacturer's estimates are over-inflated, DEQ may reduce the PSEL annual limits to better reflect actual emissions. If the manufacturer's estimates are again under-estimated, PGE will need to return to the PSD process to evaluate the difference in emissions.
Condition 3.3 of the proposed permit indicates that sulfur content of fuels must be measured in accordance with Condition 60 of the Title V Permit. Is Condition 60 the correct reference or should it be Condition 59? (*CTUIR*)	Permit condition 3.3 was modified to reflect the correct reference. Thank you for spotting the error.
DEQ must have oversight authority in the development of the test plans used to identify operating procedures. There also needs to be a well-defined set of Data Quality Objectives (DQO) to focus the development of the testing and quality assurance plans. Without oversight it is likely that factors other than minimizing emissions and startup/shutdown times will influence the development of startup and shutdown procedures. Add language to the permit to identify how the written procedures will be developed and what role DEQ will have in the process. The language should include the use of DQO to define the problem, goals, analytical approach, and acceptance criteria. (*CTUIR*)	Startup and shutdown procedures are typically developed based on manufacturer's recommendations on how to safely and efficiently conduct these operations. DEQ will require submittal and approval of startup and shutdown procedures. However, since the development of these procedures does not involve a testing regimen to establish minimization of emissions, the review of these procedures will not involve source testing with accompanying DQO, but will be a review of procedures to follow good combustion rules and minimize the time spent in startup or shutdown.
The largest portion of VOC emissions will likely occur during startup. Condition 5.1 indicates that there is a possibility that a test cannot be designed to accurately measure VOC emissions during startup and shutdown. If this is	Due to the magnitude of VOC emissions increase during startup, and the potential impact on permitting other natural gas turbines in the state, DEQ is greatly interested in obtaining valid emissions data during startup. DEQ's source test coordinator has many years of experience conducting and reviewing source tests at a wide variety of sources and

Comment	**DEQ Response**
the case, how will DEQ be able to prove that the facility is operating in a manner that is protective of the environment? The commenter has little confidence in the manufacturer's provided emission factors since the original values were so different from those currently proposed. Significant effort on the part of DEQ and the permittee is needed to ensure that an emissions test can be developed to measure VOC emission rates during startup and shutdown. DEQ should consider including CTUIR experts in the development of the VOC test plan and requiring public comment on the test plan. The permit should explicitly state that the emission factors measured during the source test will be used to adjust the emission factors used for PSEL compliance. (*CTUIR*)	regularly consults with experts at EPA. The test for VOC emissions during startup will likely be based on existing EPA protocols, modified to account for the transient nature of sampling conditions during the startup period. The EPA protocols have been widely reviewed by experts in the field and were subject to public review prior to inclusion in the Code of Federal Regulations (CFR). DEQ typically does not require external review or public notice of air quality test plans received by DEQ. That same procedure will be followed in this instance. However, the test plans and reports of test results are public documents that can be requested and viewed by the public.
The permit lacks a specific provision that requires the Permittee to update the VOC emission factors based on the results of source testing. (*CTUIR*)	DEQ's Internal Management Directive (IMD AQ.00.020 as found at https://www.oregon.gov/deq/Filtered%20Library/IMDemissionfactor.pdf.) requires permit writers to make corrections to the PSEL in accordance with the directive. This includes using the best estimate based on a hierarchy of data sources. Data from continuous emission monitors and source tests rank higher than data based on engineering judgements. In accordance with the IMD, DEQ plans to use the best, most representative source of data to determine emission factors in the future.
Is the current catalytic oxidizer optimized for both VOC and CO destruction or is it primarily designed for CO oxidation? Please consider requiring the permittee include an oxidation catalyst more suited for VOC destruction. (*CTUIR*)	Both VOC and CO catalytic oxidizers use proprietary mixes of platinum group metals and metal oxides as the catalyst and may operate in the same general temperature range. Some tweaks in the catalyst and oxidizer design may optimize performance for reducing CO vs VOC emissions. However, at baseline turbine operating conditions, which is the design criteria for catalytic oxidizers, the difference is not very great. A combined catalytic oxidizer for CO and VOC has been used at many other facilities and DEQ feels that is sufficient.
DEQ should consider the possibility of pre-heating the catalytic oxidizer to allow it to function more efficiently during startup periods. (*CTUIR*)	DEQ discussed the possibility of pre-heating the catalytic oxidizer with PGE during a recent inspection. Although the facility has an auxiliary boiler to provide thermal conditioning during startup, the heating is directed to the steam turbine to reduce the thermal stress on that equipment during startup. The facility is not designed to accommodate pre-heating of the catalytic oxidizer. In addition, it is not just

Comment	DEQ Response
	the catalyst temperature that impacts emissions during startup. The catalytic oxidizer was designed to operate most efficiently during steady-state operation. The exhaust flow and CO/VOC concentration at the oxidizer inlet are significantly different during startup/shutdown than it is during steady-state operation.
The commenter has little faith in the accuracy of the vendor's estimate of emissions during startups and shutdowns given the difference in the initial values and those in the proposed permit. DEQ should request the process data used by the manufacturer to estimate startup emissions and determine if the information is accurate. (*CTUIR*)	DEQ requested additional information from PGE about assumptions behind the startup and shutdown emissions. PGE indicated that the startup/shutdown emissions estimates came from the manufacturer (Mitsubishi) and a well-established power plant consultant (Sargent & Lundy). The emissions estimate used assumptions that were for a typical configuration. The emissions data were provided a part of an annual emissions estimate (to establish the PSEL) and actual emissions during startup/shutdown can vary based on ambient conditions, HRSG warming profile, steam temperature matching and other conditions that can vary from one startup to another. DEQ has decided to issue the permit which will require monitoring and testing of emission during startup and shutdown. DEQ will review the collected information and take any action deemed necessary.
Since the ozone levels in the Hermiston area are very near the non-attainment level, the increase in VOC emissions is of concern. The inability of DEQ to model the impacts of the increased VOC emissions on the ambient ozone concentration is of concern. DEQ should assess the technical feasibility of developing a region-scale atmospheric ozone model to help guide evaluation of NO_x and VOC emissions in the area. (*CTUIR*)	DEQ shares concern over the ozone concentrations in the Hermiston area. However, a region-scale atmospheric ozone study is beyond the scope of this permit. DEQ did perform a "Modeled Emission Rates for Precursors" (MERP) analysis in accordance with EPA guidance to determine the VOC impacts on ozone formation. This analysis indicated no significant adverse impact on ambient ozone concentration due to the Carty facility.
The detail sheet table is missing a designation for the units of each entry. Please add the units to each column. (*CTUIR*)	The summary table for total emissions lacked units. The units are tons per year. The remaining tables in the detail sheet have appropriate units. The Total Emissions table has been modified to include units. Thank you for catching this oversight.
More frequent startups, especially cold startups, are the cause of the emissions increases. The permit does not limit the startups that lead to these emissions increases. DEQ imposes a per hour limit asserting that this is the best PGE can do, when in fact PGE has stated that it can meet the pollution limits currently in place. PGE built the plant for large baseloads and is proposing to operate the	The permit calculates annual emissions based on a given number of startups and shutdowns during a 12-month period. The PSEL is based on those calculations. For CO compliance with the PSEL is determined by using a Continuous Emissions Monitoring System (CEMS) to directly measure CO emissions, including during startups and shutdowns. A CEMS is not required for VOC monitoring. For VOC compliance with the PSEL, monitoring the number of startup and shutdowns is required. If the assumed number of startups and shutdowns is

Comment	DEQ Response
plant to manage peak loads, turning it on and off frequently. DEQ should limit the number of turbine startups. (*Merritt*)	exceeded, the PSEL will also be exceeded, resulting in a violation. By limiting emissions in the PSEL and requiring the use of the proposed emissions factors to demonstrate compliance with the PSEL, the permit effectively limits long-term emissions during startup. PGE can meet the PSEL currently in place because it is not required to use the higher startup emission factors that the manufacturer says are representative in calculating compliance. This permit requires use of the higher emission factors.
The commenter reviewed the health impacts of CO and VOC and states that the permit fails to demonstrate that the proposed emission levels remain protective of public health. Public health should be the priority. No reference to impacts to human health is made in the proposed permit. (*Merritt*)	The permit contains all applicable federal standards (National Emission Standards for Hazardous Air Pollutants – NESHAP and New Source Performance Standards – NSPS) that are applicable to the facility. The permit also demonstrates using EPA-approved methods that emissions from the facility will not violate the applicable National Ambient Air Quality Standards (NAAQS) and PSD increments. These regulations and standards have been established to protect human health from criteria air pollutants. In addition, DEQ recently adopted rules under the Cleaner Air Oregon program that will evaluate a site-specific risk assessment of facilities subject to the rules. The PGE Carty facility is subject to these rules and will be evaluated under these rules at a later time.
I'd rather have higher utility rates than even dirtier air. Do not increase the pollution limit. Enforce the current permit. (*Plunkett)*	Thank you for your comment.
These cold starts increase air pollution. To grant the permit runs counter to DEQ's and PGE's mission statements. Deny the permit modification. (*McKinlay)*	Thank you for your comment.
The BACT analysis is fatally flawed. The BACT determination ranks as one of the most critical elements of the PSD program. PGE failed to provide complete information about the facility and a complete BACT analysis for each pollutant. The application provided a partial BACT analysis for VOC but provided no information as to a CO analysis. DEQ appears to have forgone reliance on anything PGE submitted and instead conducted the BACT analysis on its own. At a minimum DEQ should publish the entire search results of the RACT/BACT/LAER Clearinghouse (RBLC) database queried so as to enable	The title page of the permit indicates that the application was received on 11/2/16 and 1/11/17. The 11/2/16 application contained a request for a VOC increase and the associated VOC BACT analysis. In that 2016 application there was no anticipated CO emissions increase so it did not contain a CO BACT analysis. On 1/11/17 DEQ received an addendum to the application which discussed the CO emissions increase and the associated CO BACT analysis. Both the initial application and the addendum were used to draft the proposed permit. While DEQ independently reviewed the BACT analysis, the analysis was based on information submitted in the application, as well as a DEQ review of BACT determinations made after the application was submitted (as contained in EPA's BACT clearinghouse). The entire search results of the RBLC search are available can be accessed by the public on EPA's

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the public to assess any relevant permits that may be missing from the analysis and bring such information to DEQ's attention. (*Earthrise*)	website (https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information). Click on the search database link and from the process type menu select 15.210 for Large Combustion Turbines (>25 MW) – Combined Cycle – Natural Gas and run the search.
The BACT analysis is fatally flawed because DEQ failed to conduct a BACT analysis on all emission limits. The secondary BACT limits (13 lb CO/hr and 3.6 lb VOC/hr) do not appear to be derived through a BACT analysis since the review table only listed limits at a full operating load. DEQ must provide a rational basis for concluding the secondary limits are appropriate. The secondary limits are mass based (lb/hr) and there is no readily discernable conversion to the primary limits, which are concentration based (ppm), absent any variable like flow information which is not provided to the public. Absent the "top down" analysis these secondary limits cannot be considered BACT. (*Earthrise*)	Both the primary limits (in ppmv) and the secondary limits (in lbs/hr) are enforceable limits. The primary limits are the values used for comparison in the BACT analysis. The units of the primary limit (parts per million by volume on a dry basis, corrected to 15% oxygen, or ppmvd @15% O_2) provides a value that is more easily compared to the other turbines in the BACT analysis. The units of the primary limit compensate for any differences in exhaust gas temperatures, flowrates, excess combustion air, or moisture content that may exist from one turbine to another. The secondary limit is dependent on exhaust gas flow and composition and cannot be directly compared from one turbine to another. In this instance the secondary limit was calculated from the primary limit by assuming ideal gas behavior and EPA F-factors for natural gas. As DEQ has reduced the primary BACT limits, the secondary BACT limits were reduced accordingly.
The BACT analysis is fatally flawed because the BACT limits on startup and shutdown emissions did not go through the "top down" analysis either separately from the full load BACT analysis or as part of setting that limit. Rather, DEQ set the startup and shutdown limits in accordance with the manufacturer's estimates. DEQ reviewed other PSD determinations to determine that 50% load is a common endpoint for startup, but did not even do this cursory level of review for the emission limit. In fact, many of the startup and shutdown limits listed for other facilities are more stringent than the limits proposed for Carty. The emission limits proposed for startup and shutdown do not represent BACT. (*Earthrise*)	A traditional BACT analysis is difficult to apply to startups and shutdowns for several reasons. A comparison of startup and shutdown emissions between facilities is difficult due to differences in turbine capacity, burner configuration, assumed startup conditions, and startup definitions. A smaller turbine burns less fuel and will likely have lower emissions during startup. Even turbines of similar size may have different burner configurations that could affect startup emissions. A turbine required to have a dry low NO_x burner may not have the same CO and VOC startup emissions as a turbine without a dry low NO_x burner. A startup limit assuming a turbine is starting up in the winter when the ambient temperature is -10°F will be different than a limit established at a location where the temperature never drops below 50°F. Finally, some permits define startup as the period between ignition and steady-state (often undefined), while other permits define startup as the period between ignition and 60% load. Due to these differences, a reasonable comparison of startup/shutdown BACT emission limits at different facilities is difficult. While EPA allows establishment of a design, operating or equipment standard when limitations on the application of measurement techniques make the imposition of an emission standard infeasible, DEQ opted to establish an emission limit during

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	startup/shutdown knowing that measurement could be difficult. In DEQ's review of facilities in EPA's clearinghouse, none of the permits reviewed had performed a top down analysis to establish a BACT limit during startup and shutdown. Most simply stated that good combustion practices and minimization of startup time was BACT (without comparison to other facilities) and established an emission limit based the estimated emissions during these periods. This is similar to the approach taken by DEQ. PGE is required to conduct startup and shutdown operations in accordance with written procedures that minimize emissions (good combustion) and minimize the time spent in startup/shutdown. DEQ will review the startup and shutdown plan to ensure good combustion practices and minimization of startup time, and use the manufacturer's emissions estimate as a limit.
DEQ erred at Step 1 of the BACT analysis by not considering all potential controls. Specifically, DEQ must consider energy storage (use of batteries to reduce startups as demonstrated in an attachment to the comment), combustion optimization (no consideration of any other possible design of the combustion unit), limits on the frequency and duration of startups, defining a "warm" startup scenario that would have an emission limit more stringent than the cold startup scenario and reduce the number of events categorized as cold startups. The alternatives cannot be categorically determined to be redefining the source without a fully reasoned analysis of the facility's fundamental purpose. (*Earthrise*)	Use of energy storage (batteries) may be a scenario that could be considered in some instances for a facility that is designed and operated as a peaker plant (a facility that only operates when there is high energy demand). However, since the initial permit in 2010 this facility has been permitted on the assumption of 7840 hours or operation per year (see detail sheet for Carty Combustion Turbine in the review report). DEQ believes operating at steady-state conditions for 89.5% of the year is an indication that this facility was not designed and is not being permitted as just a peaking facility. The length of expected steady-state operation covers a greater period of time than most batteries could cover. DEQ believes that the option of energy storage would constitute a redefining of the source for this facility. Consideration of alternate turbine designs for an existing turbine with existing BACT limits is limited. As provided in the comment, several manufacturers have advertised "fast start" turbines available for the American market. A key feature of the turbine mentioned by the commenter (the Alstom GT26) is "sequential combustion" which allows it to "park" at very low loads while waiting for the command to ramp up to operating loads. DEQ does not consider this an acceptable approach for a couple of reasons. First, the previous BACT analysis for NO_x established limits that are attained through the use of low NO_x combustors in addition to selective catalytic reduction (SCR). Changing the turbine combustors from low NO_x to sequential combustion could violate the previous BACT determination for NO_x. Secondly, operating the turbine at a low "parking" level for an extended period of time is not a currently permitted operating scenario. During startup of a combined cycle

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	facility, the length of startup time, and subsequently the quantity of emissions, is driven more by the need to prevent thermal stress in the steam generator and steam turbine than it is by the need for a slow start of the natural gas combustion turbine. DEQ will review and evaluate the startup and shutdown plan to encourage efficiency during startup. The annual emission limits in the PSEL provide a mechanism to limit the number of startups in a given 12-month period. PGE did not provide data to support establishing a limit for a warm startup. A comparison of hot and warm startup definitions at other facilities indicates many of the startups defined as "warm" in other permits would fall under the "hot" startup category under the Carty permit, resulting in a more stringent emissions limit for those types of startup at Carty.
DEQ must consider good design separately from good combustion practices as part of its BACT analysis. Following the manufacturer's recommendations to properly run the unit as designed is inherently different than optimizing the design. Good design of a combustion unit should be considered in addition to pollution control like a catalytic oxidizer. (*Earthrise*)	DEQ agrees that good design and good combustion practices are two different methods of controlling emissions. Both can be important for minimizing emissions. In the initial 2010 PSD permit both good design and good operations were determined to be BACT for particulate and H_2SO_4 emissions. The good design was set in the earlier PSD permit and cannot be changed in this permit without invalidating the previous BACT determination. Since the design is set for this existing turbine, additional design considerations were not evaluated.
DEQ cannot lawfully constrain the BACT analysis to just the existing technology at the Carty plant. DEQ seems to assume that whatever configuration PGE had already installed must be sufficient for BACT. In fact, DEQ's ultimate BACT determination turned out to be no different and have no more stringent operating parameters than what PGE had in place prior to this permit modification. BACT may not be rendered meaningless merely because PGE erred in calculating emissions of CO and VOC in the initial PSD permit. DEQ is wrong to implicitly consider the costs of retrofitting controls to the Carty unit in order to rule out more efficient designs. Retrofitting costs are not relevant because PGE made the physical change (constructing Carty) before the current PSD modification and the current	BACT is defined as an "emissions limitation based on the maximum degree of reduction …" In reviewing and establishing BACT, DEQ did not pre-determine that the existing controls and operating parameters would be the final BACT limits. Although the control device (catalytic oxidizer) was installed when the facility was constructed, its presence was not required as a part of the initial BACT determination. The BACT determination of this modification would have required installation of a catalytic oxidizer even if one was not already present. This permit also established BACT emission limits that were not in place prior to this permit. DEQ did not explicitly or implicitly consider retrofitting costs in the BACT determination. In fact, the cost analysis portion of a BACT analysis was not employed in the determination of BACT for CO and VOC emissions since a cost analysis is necessary only when determining that the top level of control is inappropriate due to economic considerations. DEQ did not make this determination and used the top level of appropriate control based on a site-specific review.

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application seeks to relax an emission limit (99 ton/yr CO) that was previously relied on to avoid NSR in the initial PSD permit. Hence it is inappropriate to consider retrofitting costs since the emissions should have been subject to NSR in the initial permit. Even if retrofitting costs are considered they should not be included in Step 1 of the BACT analysis, and if they are properly considered in Step 3 of the BACT analysis is should not be an implicit consideration. Relevant information of the cost analysis should be provided in the administrative record. (*Earthrise*)	
DEQ removed every more stringent limit on a flawed basis. A demonstration of technical infeasibility should be clearly documented and show that technical difficulties would preclude successful use of the control option. Where a permitted limit has not yet been demonstrated in operation, the limit is still considered feasible if the technology is both available and applicable. DEQ did not follow this process, but eliminated *every* potential limit more stringent than that proposed by PGE without any analysis. In addition DEQ selectively included only a partial list of the more stringent limits possible. The analysis should be forward looking for emission reductions that are achievable, not merely what has been achieved in the past. Absent a reasoned, fact-based rationale for eliminating each more stringent limit, the presumption of technical feasibility requires these to be included in the remaining steps of the BACT analysis. (*Earthrise*)	In a December 21, 2006 decision EPA's Environmental Appeals Board held that "… a permit issuer's rejection of a more stringent emissions limit based on the absence of data showing that the more stringent rate has been consistently achieved over time is not a per se violation of the BACT requirements." But that the "permit issuer is obliged to adequately explain its rationale for selecting a less stringent emission limit, and that rationale must be appropriate in light of all evidence in the record." (*In re Newmont Nevada Energy Investment, LLC, TS Power Plant*, 12 E.A.D 429, 440 (EAB 2005)) Carty's review report stated that many of the more stringent limits were eliminated because they had not been demonstrated. The review report also refers to the Bay Area Air Quality Management District (BAAQMD) BACT Workbook that lists 4.0 ppm CO and 2.0 ppm VOC as the emission limits that have been achieved in practice for units with Catalytic Oxidation. The report also refers to the San Joaquin Valley Unified Air Pollution Control District (SJVAPCD) BACT Guideline 3.4.7 that lists 6.0 ppm CO (achieved in practice), 4.0 ppm CO (technologically feasible), 2.0 ppm VOC (achieved in practice), and 1.5 ppm VOC (technologically feasible). Based on this information and information gathered after the public comment period, which indicated a 1.0 ppm VOC limit had been achieved in practice, DEQ has decided to lower the VOC BACT limit from 2.0 ppm to 1.0 ppm.
DEQ erred by ignoring the most stringent limits from permits that are in currently in operation in setting BACT. Ranking emission limits by control effectiveness (percent removal) is necessary where DEQ intends to set the primary limit as a concentration-based	DEQ disagrees that ranking emission limits by percent removal is necessary for effective comparison and that a list for each pollutant containing control effectiveness, emission rate, and economic impact is required. In addition to the information supplied in the permit application, DEQ relied to a great deal on its own review of data contained EPA's BACT clearinghouse and the permits issued for those

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limit and other limits as a mass-based limit. Not all comparable concentration-based limits normalize to the same oxygen level which makes comparison difficult. For a fully transparent analysis a list should be prepared for each pollutant containing control effectiveness, emission rate, and economic impact. DEQ did not prepare a list to allow meaningful comparison between emission limits or conduct any form of comparison suggesting every control more stringent than the one proposed by PGE should be eliminated. Some of the facilities with more stringent limits are currently in commercial operation (West Deptford Power Station began operation in 2014 Chouteau Power in 2012, McDonough in 2012, Bartow in 2009, and West County in 2011). Some of these facilities in commercial operation have limits more stringent than those proposed for PGE. (*Earthrise*)	determinations. While the clearinghouse contains fields to input the control efficiency, compliance verification status (achieved in practice), emission limits and economic impact, these fields are rarely filled in with usable data, except for the emission limit data. Some of this information can be found in the permits issued for these determinations. The emission limit data in the clearinghouse often are given in different units that make comparison difficult without knowledge of the exhaust gas temperature, flow rate, and oxygen content. DEQ reviewed the actual PSD permits and review reports (or equivalent), where available. The information cited in the comment (percent removal and economic impact) was not consistently reported in the issued permits, indicating this information was not uniformly used in making BACT determinations in other states. By reviewing the permits, DEQ was able to determine that, in most cases, the pollutant concentrations were corrected to 15% oxygen, which allows a comparison on that basis. DEQ based its BACT determination on the available information. DEQ re-reviewed the facilities that the commenter indicated were currently in commercial operation. DEQ notes that the West Deptford facility has two phases. Phase I was permitted in 2009 and began operation in 2014 with BACT limits of 2.0 ppm for CO and 1.9 ppm (LAER) for VOC. Phase II, which was included in the application's table of BACT determinations and had more stringent limits was permitted in 2014 and was never constructed and is not in the current (2021) operating permit. DEQ reviewed the PSD permit for the Chouteau facility.(www.deq.ok.gov/wp-content/uploads/air-division/Permit_2007115-cp3.pdf page 29 of 51) and found a BACT limit of 8.0 ppm for CO but the permitted BACT limit for VOC was 5.27 lb/hr (no VOC limit in ppm) which is similar to the Carty secondary VOC BACT limit of 5.5. The McDonough facility has turbines that are similar to Carty. The McDonough turbines have a CO and VOC limit of 1.8 ppm, while Carty's limits are similar at 2.0 ppm for CO and 1.0 ppm for VOC. (http://permitsearch.gaepd.org/permit.aspx?id=PDF-VF-23280 Condition 3.3.9.c, d) The Bartow facility utilizes F-Class turbines (Siemens SGT6 501F) while Carty is a G-Class turbine (Mitsubishi M501G). F-Class turbines typically operate in the 170-230 MW range while G-Class turbines operate in the 275-350 MW range. Due to the difference in turbine class and heating rate, the limit at the Bartow facility would not be comparable to the turbine at Carty. The Bartow PSD limits are 7.6 ppmvd for

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	CO and 1.5 ppmvd for VOC. (http://arm-permit2k.dep.state.fl.us/psd/1030011/00002493.pdf see Condition 18) The limits at Carty are now more stringent (2.0 ppmvd for CO and 1.0 ppmvd for VOC) than Bartow. The West County facility uses a turbine similar to Carty (Mitsubishi M501G). The limits at this facility are 7.6 ppmvd for CO and 1.5 ppmvd for VOC. (http://arm-permit2k.dep.state.fl.us/psd/0990646/000020EA.pdf Condition 12) The limits at Carty are now more stringent than West County. While some BACT limits have been set slightly lower, DEQ has the discretion to set a higher limit to allow for a margin on compliance. EPA has stated that, "Permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis." (EAB Three Mountain Power, pg 53 https://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Decision~Date/AB23C9A533E3C3E88525706C004F2A79/$File/3mountpower.pdf page 53)
PGE's application apparently removes a control from BACT consideration because it was determined to be LAER. LAER determinations should be available for BACT purposes. The fact the projects were undertaken to comply with allegedly different legal requirements is not especially material to the issue of availability for BACT. (*Earthrise*)	DEQ agrees that LAER determination should be available for BACT purposes. DEQ did not remove facilities from consideration simply because the application stated they were LAER determinations.
DEQ did not account for all operating scenarios in setting emission limits. DEQ did not consider setting separate emission limits when the duct burners are not firing. By setting an emission limit for each operating scenario (with and without duct burners) the limit is both more accurate and more stringent. (*Earthrise*)	DEQ does not believe a separate BACT limit is necessary for operations when the duct burner is off. A BACT determination was made for the worst-case (highest emissions) condition when the duct burner is on. This determination concluded that good combustion practices and catalytic oxidation were BACT. Turning off the duct burner would not affect the technology determined to be BACT. At best, the difference in emission limit would reflect only the difference of turning the duct burner off, while maintaining the controls utilized when the duct burner is on. The difference in limit would not be due to any change in the level of control. A separate BACT limit for duct burner off operation will not result in more stringent control, it would merely reflect the operation described in the scenario (the duct burner is turned off). Many other facilities with duct burners have established only a single limit representative of duct burner-on operation and DEQ will do the same.

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DEQ did not assess requiring more stringent monitoring for VOC. DEQ correctly noted that setting a three hour rolling average is only appropriate if emissions are measured by a Continuous Emission Monitoring System (CEMS). However, rather than actually considering a more stringent monitoring of the emission limits, DEQ simply adopted a 3-hour averaging time. DEQ did not discuss whether a CEMS for VOC would be rejected for cost, energy, or other impacts as part of the BACT analysis. Because the monitoring has implications on the stringency of the BACT limit, the monitoring must be considered part of the BACT analysis. Use of a CO CEMS as a surrogate is possible, but DEQ must establish a variable adequately reflecting the surrogate relationship between the two pollutants to enable a determination of VOC compliance based on CO data. DEQ must rely on actual, site-specific data to establish the relationship between VOC and CO emissions. (*Earthrise*)	While it is appropriate to consider averaging time as part of the BACT analysis, monitoring costs have not typically been considered part of the analysis. In order to include monitoring costs as part of the BACT analysis DEQ would also need to include the cost of VOC testing used to monitor VOC emissions for the non-CEMS approach. DEQ will not include monitoring as part of the establishment of BACT limits. EPA has stated "VOC monitors can provide only a relative measure of the total mass or volume concentration of a mixture of organic gases, rather than an accurate quantification." (40 CFR 60, Appendix B, Performance Specification 8, Section 1.2.2) DEQ has determined that accurate long-term CEMS for VOC is not reliable and, therefore, did not consider a VOC CEMS to determine compliance with the BACT limit. DEQ believes that monitoring CO as a surrogate for VOC is appropriate as an indicator of good combustion and proper operation of the catalytic oxidizer, which minimize VOC emissions. However, as a direct measure of compliance with the VOC BACT limit, DEQ agrees that, absent a valid correlation between the CO concentration and VOC concentration, use of the CO CEMS to directly determine VOC emissions is inappropriate. The CO CEMS is used as a action parameter under the CAM rule. DEQ believes the stringency of the VOC monitoring is sufficient.
As a result of not incorporating a VOC CEMS or establishing an actual CO/VOC variable, the permit is devoid of any monitoring of VOC at Carty after the initial stack test. DEQ must require regular verification of compliance with the VOC emission limit. Compliance with the annual PSEL does not ensure compliance with Carty's VOC limit. DEQ must at least require annual verifications of Carty's VOC emissions via stack test. Carty must have emissions monitoring that meets the requirements of OAR 340-212-0200(1) (Compliance Assurance Monitoring) to provide a reasonable assurance of ongoing compliance (OAR 340-212-0200(1)(b)). (*Earthrise*)	DEQ agrees that a single initial source test is insufficient to determine on-going compliance with the VOC BACT limit. A review of PSD permits from other states indicates that most states require VOC testing at least every five years. The Oregon Title V Monitoring and Testing Guidance recommends gas turbines with uncontrolled VOC emissions greater than 100 tons/yr conduct annual source tests unless 2 consecutive tests results are less than 75% of the limit, in which case testing is every 5 years. Although the turbine includes VOC controls, DEQ will modify the permit to require testing in accordance with the guidance for uncontrolled units. DEQ agrees that a Compliance Assurance Monitoring (CAM) analysis should have been performed as part of the permit. The turbine is subject to an emission limit, it uses a control device (catalytic oxidizer) to achieve compliance, and has pre-control emissions greater than 100 ton/yr (OAR 340-212-0200(1). A section explaining the CAM determination was added to the review report before the second public notice period. DEQ will use the CO CEMS as CAM for VOC. It will not result in a direct measurement of

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	VOC emissions, but serves as a good indication that good combustion practices are being observed and that the catalytic oxidizer is operating.
PGE has failed to comply with the PSD requirements triggered by its greenhouse gas emissions. The increase in the greenhouse gas PSEL is well above the Significant Emission Rate for that pollutant. The 2010 ACDP admits that the increase in GHG emissions is greater than 75,000 tons/year (the SER for GHG) and under EPA's tailoring rule, the Carty Plant would be subject to PSD for GHG after January 2, 2011. Thus, where PGE is seeking a modification of its GHG PSEL in this permit modification, the current regulations apply to PGE's facility – either Boardman or Carty – for PSD of GHG emissions. (*Earthrise*)	GHG emission were included in the baseline emission rate and PSEL in a modification made to this PSD permit on 9/25/12. OAR 340-224-0010(1)(a)(B) indicates PSD is applicable for a major modification at an existing federal major source. OAR 340-224-0025(1)(a) indicates a major modification is a change in a source <u>since the baseline period</u> that meets the requirements in OAR 340-224-0025(2) which is a physical change or change in the method of operation where the PSEL or actual emissions exceed the netting basis by an amount that is greater than or equal to the significant emission rate (SER). In 2012 the baseline period for GHG was established as 2010 in accordance with OAR 340-222-0048(1)(b). The baseline emission rate is the actual emission rate during the baseline period (OAR 340-200-0020(16)). For the coal fired boiler this would be the actual GHG emissions in 2010. However, OAR 340-222-0051(2) indicates that for any source that had not begun normal operations during the baseline period, but was approved to construct and operate, actual emissions of the source or part of the source are equal to the potential to emit of the source. Since the Carty natural gas turbine was approved to construct and operate during the baseline period, the baseline emission rate for this part of the facility is set equal to the Carty facility's potential to emit GHG. There has been no change in Carty's potential to emit GHG since the baseline period. Therefore, the increase in GHG emissions since the baseline period during the first public comment period represented the difference between the coal plant's actual GHG emissions in the baseline period (2010) and the coal plant's permitted GHG emissions. The GHG increase was greater than the SER, but the increase was due to utilization of existing capacity of the coal boiler and not due to any physical changes or changes in the method of operation of the coal boiler. There have been no physical changes or changes in the method of operation of the Carty facility outside those that were permitted during the GHG baseline period. Prior to the second public comment period DEQ was required to remove the coal plant's emissions from the baseline emission rate and from the PSEL. As a result, the GHG baseline emission rate and the PSEL are the same. There has been no increase in GHG emissions since the baseline period and PSD is not triggered for this pollutant.
DEQ regulations preclude PGE from setting its proposed PSEL for GHG at its	As mentioned above, the Carty facility's baseline emission rate (and netting basis) was established as the potential to

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chosen level. PGE has not met the regulatory criteria that would allow DEQ to establish a PSEL greater than the netting basis until it has met the requirements of PSD, which would include a BACT analysis. (*Earthrise*)	emit in a 2012 permitting action. Since no physical changes or operational changes have been made to Carty since the baseline period, its current GHG PSEL remains at the potential to emit. Therefore, DEQ has determined, based on the regulations, that GHG emissions from Carty do not qualify as a major modification subject to PSD. The reduction in GHG netting basis from the previous permit is due to a lower estimated annual heat input to the Carty auxiliary boiler.
The existing capacity rationale is not supported and violates regulations to allow a PSEL increase well in excess of the significant emission rate. PGE asserts that the difference between the netting basis and the PSEL is due to use of the coal boiler capacity. DEQ does not provide any support from the regulations for this justification. PGE is attempting to game the regulations allowing the Carty Plant to escape PSD by using the Boardman plant as a scapegoat. For GHG emissions PGE patently chose 2010 as its baseline year intentionally so that all of the Carty Plant's potential to emit would continue to escape PSD and appear to subject the coal plant to PSD requirements if it operates at its full capacity. DEQ now seeks to justify allowing PGE to substantially increase its GHG emissions above the purposely chosen netting basis using its existing capacity rationale, suggesting the large difference between the netting basis and the proposed PSEL does not trigger PSD. (*Earthrise*)	As explained above, DEQ determined PSD was not applicable in accordance with the existing regulations. The GHG baseline period can be any consecutive 12 month period between 2000 and 2010. [OAR 340-222-0048(1)(b)] The baseline emission rate is the actual emissions during the baseline period. [OAR 340-200-0020(15)] Actual emissions include the potential to emit for any part of a source that had not begun normal operation during the baseline period but was approved to construct and operate prior to January 1, 2011. [OAR 340-222-0051(1)(c)] The portion of the GHG PSEL assigned to Carty has not changed since the baseline period. This becomes more evident now that coal boiler emissions have been removed from both the netting basis and the PSEL. The GHG PSEL increase shown during the previous public notice was due to the difference between actual GHG emissions from the coal plant in the baseline period and the desired (permitted) GHG PSEL for the coal plant. There was no physical or operational change at the coal plant that would be considered a major modification (OAR 340-224-0025(2)) and thus trigger major source PSD (OAR 340-224-0010(1)(a)(B)) and GHG emissions are not subject to State NSR (OAR 340-224-0010(2)(c)).
To comply with DEQ regulations, PGE must either reduce its GHG PSEL to the netting basis or subject the facility to PSD review, including a BACT analysis for GHG. If PGE relies on a 2010 baseline for its GHG emissions it must accept a PSEL equal to its netting basis. Alternatively, PGE may select an alternative baseline year which would set the netting basis for the Carty facility at zero and subject Carty to PSD requirements, including BACT. Since PGE is voluntarily reopening its 2010	In accordance with DEQ regulations, PGE is allowed to operate with emissions up to the current PSEL without being subject to major source PSD. With the coal boiler emissions now removed from the netting basis and PSEL it becomes clearer that the netting basis and the PSEL are the same. There is no need to reduce the PSEL to the netting basis because it is already equal to the netting basis. Since the regulations allow use of <u>any</u> 12 month period from 2000 through 2010 as the baseline period, DEQ cannot require certain periods to be excluded from that allowance.

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permit to increase emission levels, PGE may either maintain its 2010 GHG baseline period and reduce its proposed PSEL to a permissible level, or chose a different allowable GHG baseline period, excluding the Carty facility from the netting basis and meet all the NSR requirements for GHG emissions from the Carty unit. (*Earthrise*)	
PGE has failed to submit the required analysis of potential impacts to visibility in the Columbia River Gorge National Scenic Area. Pursuant to OAR 340-224-0070(3)(a)(B) a federal major source must comply with OAR 340-225-0070 which requires a visibility analysis on the Columbia Gorge National Scenic Area if it is affected by the source. PGE previously submitted a visibility analysis with its original Carty PSD application. Now, although proposing to increase VOC emissions, and despite the fact that VOC emissions are a known contributor to visibility impairment, PGE has failed to provide any visibility impact analysis. PGE must prepare and submit an analysis of visibility impacts using actual emissions data from Carty and also factor in the proposed increase in VOC emissions into modeling of potential impacts. (*Earthrise*)	In analyzing impacts to air quality related values (AQRV) such as visibility and deposition, DEQ consults with the appropriate federal land manager. In the "Federal Land Managers' Air Quality Related Values Work Group manual (2010 Revision), Section 3.2 www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf , the federal land managers indicate "the Agencies will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_x, PM_{10}, and H_2SO_4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions), divided by the distance (in km) from the Class I area (Q/D) is 10 or less. The Agencies would not request any further Class I AQRV impact analyses from such sources." (pg. 18-19) Although not a Class I area, the Columbia River Gorge National Scenic Area is afforded special protections that are, at times similar to Class I areas. DEQ notes that, although VOC emissions can lead to formation of ozone that can affect visibility, the federal land managers did not include VOC in the list of pollutants to consider in determining impacts to air quality related values. The pollutants that are included in the federal land managers' list were reviewed and analyzed in the initial PSD permit and will not be re-evaluated in this modification.
PGE's application for proposed increases in VOC emissions contains no discussion – let alone analysis of impacts to visibility and other air quality related values in Class I areas. PGE must submit an analysis of the proposal's impact to air quality related values, including visibility in Class I areas. The analysis should include actual emission data from Carty and factor in the proposed increases in VOC emissions. The analysis must also be shared with the Federal Land Managers. (*Earthrise*)	As discussed above, the federal land managers did not include VOC in the list of pollutants to be analyzed for AQRV impacts in Class I areas. DEQ does not believe this analysis is required for VOC emissions.

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Pursuant to OAR 340-225-0070(7) deposition modeling is required for receptors in Class I areas and the Columbia River Gorge National Scenic Area where visibility modeling is also required. The analysis should include actual emission data from Carty and factor in the proposed increases in VOC emissions. The analysis must also be shared with the Federal Land Managers. (*Earthrise*)	As discussed above, the federal land managers did not include VOC in the list of pollutants to be analyzed for AQRV impacts in Class I areas. DEQ does not believe this analysis is required for VOC emissions.
Pursuant to OAR 340-224-0070(3)(a)(B), PGE must provide an analysis of impairment to visibility, soils and vegetation that would occur as a result of the source or modification, and general commercial, residential, industrial and other growth associated with the source in Class I areas, the Columbia River Gorge National Scenic Area, as well as Class II and Class III areas. The analysis should include actual emission data from Carty and factor in the proposed increases in VOC emissions. (*Earthrise*)	As discussed above, the federal land managers did not include VOC in the list of pollutants to be analyzed for AQRV impacts in Class I areas. DEQ does not believe this analysis is required for VOC emissions.
DEQ erred in waiving the requirement for monitoring VOC for the ambient air quality analysis. DEQ erred in not requiring an adequate analysis to ensure VOC emissions from Carty do not cause a violation of the ozone standards. Regulations specifically require an ambient impact analysis, including ambient ozone monitoring. DEQ purports to use the general authority of relying solely on background data in lieu of monitoring. The analysis is deficient because regulations (OAR 340-224-0070(1)(a)(B)(vi)) permit representative data in lieu of specific monitoring only where the existing representative monitoring data shows maximum ozone concentrations are less than 50% of the ozone ambient air quality standards based on a full season of monitoring. The data used by DEQ does not show maximum concentrations are less than 50% of the standard, nor does it break	DEQ believes OAR 340-224-0070(1)(a)(A)(i) exempts facilities from ambient monitoring of VOC. There is no ambient air quality standards for VOC, only for ozone. In addition, OAR 340-224-0070(1)(a)(A)(vi) requires monitoring be done in accordance with 40 CFR Part 58, Appendix A. This regulation does not discuss VOC monitoring. As mentioned in the review report, OAR 340-224-0070(1)(a)(A)(vii) allows DEQ to use representative or conservative background concentration data in lieu of conducting preconstruction monitoring if the permittee can demonstrate that such data are adequate to determine that the facility would not cause or contribute to a violation of any ambient air quality standard or any applicable PSD increment. Due to the monitor's proximity to a more populated area (Hermiston) with higher vehicular traffic (I-84), DEQ believes the ozone measurements in Hermiston are higher (more conservative) than would be measured near the Carty facility. In addition, DEQ has ozone data from the Hermiston site from 2011 through 2020 (2020 Annual Report (oregon.gov) , page 76) The data are fairly consistent across this time period. Ozone concentrations were higher in Hermiston during 2017 and 2018, but this was attributed to

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down data to show concentration variations by season. The ozone standard is 75 ppb while the 2014 monitoring data shows a concentration of 64 ppb, well above 50% of the standard. In addition, data are supplied as a single concentration for an entire year and does not make any distinction based on seasonal variation. Thus, this data cannot be considered representative by DEQ and is not sufficient to waive the requirement to submit an analysis of the ambient air quality. DEQ has not provided any rationale as to why this data is sufficient given both the distance from the Carty facility (45 kilometers away) and the age of the data (4 to 9 years old). (*Earthrise*)	the numerous wildfires in the area that affected other monitors as well. Most of the maximum ozone concentrations are measured during the summer months when heat and sunlight are conducive to ozone formation. The maximum VOC emissions from Carty would be expected during a cold startup during the winter months when the turbine will take longer to heat up to steady state conditions. DEQ used the EPA-approved Modeled Emission Rates for Precursors (MERPs) program (Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program | US EPA) to demonstrate that Carty's contribution to ozone formation is insignificant. Although DEQ remains concerned about the elevated ozone levels in the Hermiston area, DEQ does not believe Carty will cause or contribute to a violation of the ambient ozone standards.