



Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204

November 4, 2010
ES-214-2010
Gov Rel 9
Coyote Springs

Mr. Mark Fisher
Oregon Department of Environmental Quality
Eastern Region
475 NE Bellevue, Suite 110
Bend, Oregon 97701

**Re: Notice of Construction and Significant Permit Modification Application
Portland General Electric – Coyote Springs Plant, Combustion Turbine 1
Title V Operating Permit No.: 25-0031-TV-1**

Dear Mark:

Portland General Electric Company (PGE) is submitting this application for combustion turbine 1 (Unit 1) located at the Coyote Springs Plant in Boardman, Oregon. Below, please find PGE's regulatory applicability analysis, notice of construction application, and significant permit modification application for the Unit 1 upgrade project. This application also serves as PGE's new source performance standard (NSPS) 60-day notification in accordance with 40 CFR 60.7(4) which requires notice be made within 60 days or as soon as practical of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies. Unit 1 will be subject to 40 CFR 60, Subpart KKKK (Stationary Combustion Turbines) after the proposed modification in this application is implemented. As detailed below, the Unit 1 combustion turbine is currently subject to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines); however, the associated Heat Recovery Steam Generating (HRSG) and duct burner are not subject to any NSPS. Pursuant to § 60.4305(b), Unit 1 will be exempt from the requirements of NSPS Subpart GG following the proposed modification.

BACKGROUND

The Coyote Springs Plant is located at 200 Ullman Blvd in Boardman, Oregon and currently operates under Oregon Department of Environmental Quality (DEQ) Title V Operating and Acid Rain Permit No. 25-0031-TV-01. The permit covers the operation of two General Electric Model Frame 7FA combustion turbines, each with a HRSG unit that utilize natural gas fired duct burners to increase steam generation. The plant also operates a steam package boiler that provides supplemental steam when required.

PROJECT DESCRIPTION

PGE would like to perform upgrades on the Unit 1 combustion turbine that will result in increased unit output and efficiency and higher unit reliability. Based on these upgrades, natural gas usage for Unit 1 is expected to increase approximately 3.7% on an hourly basis. The upgrades to Unit 1 include a new compressor, turbine and casings with higher temperature combustion; abraded first stage seal for the power turbine; casing cooling system; new dry low NO_x combustion system; and upgrades to the control system processing hardware. The increased efficiency and output will be a result of a new compressor seal design which reduces leakage through the compressor. These upgrades will result in an increase in the hourly natural gas firing capability of Unit 1 and therefore hourly emissions; however, PGE is not requesting an increase in the annual Plant Site Emission Limits (PSELs).

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EMISSIONS INVENTORY

Table 1 below summarizes the small increases in hourly emissions from natural gas combustion in Unit 1 of sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC). Maximum hourly emissions of particulate matter (PM) and particulate matter less than 10 microns (PM₁₀) in Unit 1 have actually decreased slightly based on an updated emission factor. Table 2 shows the annual emissions both pre- and post-modification. As stated above, PGE is not requesting an increase in the PSELS. Detailed emission calculations are included as Attachment 1.

Table 1. Unit 1 Hourly Emissions (natural gas only)

Pollutant	Current (lbs/hr)	Proposed (lbs/hr)	Increase (lbs/hr)
PM/PM ₁₀	4.5	4.2	--
SO ₂	1.2	1.2	0.04
NO _x	30.0	31.1*	1.11
CO	51.0	52.9*	1.88
VOC	1.5	1.5	0.05

* The NO_x and CO hourly emissions shown in Table 1 are the maximum one-hour emissions from natural gas combustion in Unit 1 following the upgrade project. The hourly average emissions will continue to meet the permit limits of 30 lbs/hr (24-hour rolling average) for NO_x and 51 lbs/hr (8-hour rolling average) for CO following the project.

Table 2. Coyote Springs Plant Site Emission Limits/Netting Basis

Pollutant	Netting Basis (tons/yr)	Current PSEL (tons/yr)	Proposed PSEL (tons/yr)	Increase (tons/yr)
PM/PM ₁₀	48	48	48	0
SO ₂	0	39	39	0
NO _x	287	287	287	0
CO	452	452	452	0
VOC	0	39	39	0

REGULATORY APPLICABILITY ANALYSIS

Prevention of Significant Deterioration (Major New Source Review)

The Boardman area and Morrow County are currently designated as “attainment” for all criteria pollutants; therefore, the Coyote Springs Plant need not be evaluated in relation to Maintenance New Source Review (NSR) or Nonattainment NSR.¹ The Oregon Prevention of Significant Deterioration (PSD) permitting program (Major NSR) under OAR 340-224-0070 only applies to owners and operators of proposed federal major sources and major modifications at federal major sources. A fossil fuel fired steam electric plant with a heat input greater than 250 million British thermal units per hour (MMBtu/hr) is considered a federal major source if it has the potential to emit more than 100 tons of a regulated air pollutant.² The Coyote Springs Plant meets the criteria for a federal major source. A major modification is defined³ as any physical change or change of operation of a source that results in the following for any regulated air pollutant:

¹ OAR 340-224-0050 and OAR 340-224-0060

² OAR 340-200-0020(52)

³ OAR 340-200-0020(66)

(a) An increase in the PSEL by an amount equal to or more than the significant emission rate over the netting basis; and

(b) The accumulation of physical changes and changes of operation since baseline would result in a significant emission rate increase.

The Unit 1 upgrade project is not a construction of a new federal major source. Nor, as shown in Table 2, does the project constitute a “major modification” since there is no requested increase in the PSEL for any regulated air pollutant. Therefore, the Oregon PSD rules do not apply to this project.

New Source Performance Standards

Oregon DEQ has adopted the federal New Source Performance Standards (NSPS) found in 40 CFR Part 60 as referenced in OAR 340-238-0060. The Unit 1 combustion turbine is currently subject to 40 CFR Part 60 Subpart GG (Stationary Gas Turbines). The associated duct burner is not subject to any NSPS because the rated heat input capacity of the duct burner is less than 100 MMBtu/hr. In addition, the associated HRSG is not subject to any NSPS since it does not contain any internal burner. Subpart GG limits NO_x emissions from Unit 1 to 100 parts per million (ppm) at 15% O₂ (derived from the equation in 40 CFR 60.332(a)(1)) and SO₂ emissions are limited by a fuel sulfur content limit of 0.8% sulfur by weight (40 CFR 60.333(b)).

After completion of the Unit 1 upgrade project, Unit 1 will be subject to NSPS Subpart KKKK, Standards of Performance for Stationary Combustion Turbines. Subpart KKKK regulates stationary combustion turbines and HRSG with duct burners. Stationary combustion turbines regulated under Subpart KKKK are exempt from the requirements of Subpart GG.⁴ Subpart KKKK affects stationary combustion turbines constructed, modified, or reconstructed after February 18, 2005 with a heat input equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr) based on the higher heating value of the fuel. In order for the Unit 1 upgrade project to be considered a modification under 40 CFR 60.14(a), there must be a physical or operational change to the unit which results in an increase in the hourly emission rate of any pollutant regulated under Subpart KKKK (i.e., NO_x or SO₂). As shown in Table 1, there are small increases in hourly emissions from natural gas combustion of NO_x or SO₂ associated with the Unit 1 upgrade project; therefore, this project is considered a modification under NSPS.

Under Subpart KKKK, Unit 1 must comply with the natural gas based NO_x emission limit of 15 ppm at 15% O₂ or 0.43 lb/MWh output (40 CFR 60.4320) for new, modified, or reconstructed natural gas-fired turbines greater than 850 MMBtu/hr. Since Unit 1 combusts greater than 50% natural gas when compared to the volume of fuel oil combusted, Unit 1 must meet the applicable limit for natural gas-fired turbines.⁵ The SO₂ standard under Subpart KKKK is an emission limit of 0.060 lb/MMBtu heat input (40 CFR 60.4330) for each fuel burned. The Coyote Springs Plant will also comply with the monitoring requirements set forth in §60.4340 and §60.4365 and test methods and procedures set forth in §60.4405 and §60.4415 for Unit 1. The current Title V Operating Permit for the Coyote Springs Plant contains a BACT limit of 4.5 ppm at 15% O₂ of NO_x for Unit 1 which is more stringent than the limit required by Subpart KKKK.

National Emissions Standards for Hazardous Air Pollutants

Oregon DEQ has adopted the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) found in 40 CFR Part 63 as referenced in OAR 340-244-0220. NESHAP standards have been

⁴ 40 CFR 60.4305

⁵ 40 CFR 60.4325

established to control the emissions of hazardous air pollutants (HAP). NESHAP regulations establish Maximum Achievable Control Technology (MACT) standards for specific types of equipment located at a HAP major source. A HAP major source is a facility with a potential to emit 10 tons per year of a single HAP or 25 ton of a combination of HAPs. The Coyote Springs Plant is not a major source of HAPs; however, the facility is considered an area source. An area source is defined⁶ as any stationary source which has the potential to emit hazardous air pollutants but is not a major source of hazardous air pollutants.

Typically Achievable Control Technology (TACT)

OAR 340-226-0130 establishes Typically Achievable Control Technology (TACT) requirements for new or modified sources. TACT is an emission level (or a design, equipment, work practice, or operational standard) typically achieved by well controlled units of similar type and size of the proposed new equipment considering pollution prevention and other environmental impacts, energy impacts, cost effectiveness. TACT may also include emission control technologies typically applied to other types of units. In accordance with OAR 340-226-0130(2), a new or modified source must meet TACT if:

(a) The new or modified emissions unit is not subject to New Source Review requirements in OAR 340 division 224, an applicable Standard of Performance for New Stationary Sources in OAR 340 division 238, OAR 340-240-0110 through 340-240-0180, 340-240-0310(1), OAR 340-240-320 through 340-240-0430, or any other standard applicable only to new or modified sources in OAR 340 divisions 230, 234, 236, or 238 for the pollutant emitted...

Since a NSPS applies to Unit 1, TACT rules do not apply to this project.

Acid Rain Program

The Coyote Springs Plant is subject to the Acid Rain Rules pursuant to 40 CFR Part 72 through 78. Oregon DEQ has already issued the Acid Rain permit for this plant. The Unit 1 upgrade project does not affect the applicability of the Acid Rain program or the compliance status of Unit 1.

Title V

The Coyote Springs Plant is currently a major source of air pollutants and has already received a Title V Operating Permit from Oregon DEQ as required by OAR 340-218. The Coyote Springs Plant operates under Title V Operating and Acid Rain Permit No. 25-0031-TV-01.

Compliance Assurance Monitoring

The rules found in 40 CFR Part 64, and incorporated into Oregon's rules as OAR 340-212-0200 through OAR 340-212-0280, require compliance assurance monitoring (CAM) for emissions units with add-on control devices that would have uncontrolled potential emissions greater than 100 tons per year if the control device were not in place. Unit 1 currently has in place a Selective Catalytic Reduction (SCR) device for controlling emissions of NO_x. In accordance with OAR 340-212-0200(2)(a)(F), an emission limitation or standard for which an Oregon Title V Operating Permit specifies a continuous compliance determination method is exempt from the CAM rules. Therefore, CAM does not apply to Unit 1 or this project because the control device (SCR) is used to comply with NO_x limits for which the permit requires a continuous compliance demonstration method (in this case a continuous emission monitoring system (CEMS) to continually monitor NO_x emissions).

⁶ OAR 340-244-0020(4)

Continuous Emissions Monitoring

The Coyote Springs Plant currently maintains a CEMS on Unit 1 to monitor and record the exhaust concentration of NO_x in accordance with the NSPS and Acid Rain programs and to monitor compliance with the PSD NO_x emission limit. In addition, the plant operates a CEMS to monitor and record CO concentrations from Unit 1 to monitor compliance with the PSD CO emission limit.

NOTICE OF CONSTRUCTION APPLICATION

Pursuant to OAR 340-210-0215(2), a Notice of Construction application is required prior to making a physical change or change in operation of an existing stationary source that will cause an increase, on an hourly basis at full production, in any regulated pollutant emissions. As shown in Table 1, the Unit 1 upgrade project will result in an hourly increase of several criteria pollutants; therefore, Notice of Construction requirements apply. OAR 340-210-0225 identifies four distinct construction and modification types: Type 1, Type 2, Type 3, and Type 4. To be classified as a Type 2 change, the change must meet the following criteria:

- (a) Would not increase emissions above the Plant Site Emission Limit by more than the de minimis levels in OAR 340-200-0020 for sources required to have a permit;*
- (b) Would not increase emissions above the netting basis by more than or equal to the significant emissions rate;*
- (c) Would not increase emissions from any stationary source or combination of stationary sources by more than or equal to the Significant Emission Rate;*
- (d) Would not be used to establish a federally enforceable limit on the potential to emit; and*
- (e) Would not require a TACT determination under OAR 340-226-0130 or a MACT determination under OAR 340-244-0200.*

The Unit 1 upgrade project qualifies as a Type 2 change. Specifically, the project does not result in an increase in emissions by more than or equal to the significant emission rate, does not result in an annual increase in emissions from any stationary source, there are no federally enforceable limits on the plant's potential to emit being sought, and a TACT determination is not required. As a Type 2 change, Oregon DEQ must be notified prior to constructing or modifying the unit. However, as a Type 2 change, the project to upgrade Unit 1 is allowed to commence 60-days after Oregon DEQ receives this application.⁷ Please accept this application including the attached emission calculations (Attachment 1) and the Oregon DEQ Notice of Approval Application form – MD901 (included as a part of Attachment 2) as PGE's Notice of Construction application and notification for the Unit 1 upgrade project.

SIGNIFICANT PERMIT MODIFICATION

According to OAR 340-210-0250(1), the approval to construct does not provide approval to operate the constructed or modified stationary source. Type 2 changes may only be operated in accordance with OAR 340-218-0190(2) for Title V sources which includes permit modification requirements. Because the Unit 1 upgrade project triggers a modification of NSPS, the project is considered a Title I modification (under Section 111 of the Federal Clean Air Act). A permit modification that is defined as a Title I modification is classified as a Significant Modification⁸ under Oregon DEQ rules.

⁷ OAR 340-210-0240(1)(b)

⁸ OAR 340-218-0180

The current Title V Operating Permit contains requirements that are as or more stringent than those requirements contained in Subpart KKKK. Table 3 compares the requirements when firing natural gas.

Table 3. Permit Condition Comparison

Requirement	Current Permit	Subpart KKKK	Comments
NO _x Limit	4.5 ppmvd @ 15% O ₂ <i>Condition 13.a</i>	15 ppmvd @ 15% O ₂	Current permit limit is more stringent
NO _x Monitoring	CEMS <i>Condition 36</i>	CEMS	Equivalent
NO _x Performance Testing	Annual RATA <i>Condition 36</i>	Conduct performance test within 60-days after achieving the maximum production rate but no later than 180-days from initial startup	Annual RATA meets the performance testing requirements
SO ₂ Limit	0.8% sulfur content; pipeline grade natural gas only <i>Condition 16</i>	0.060 lb/MMBtu heat input	Equivalent (see SO ₂ Monitoring)
SO ₂ Monitoring	Demonstrate the fuel contains no more than 20 grains sulfur per 100 standard cubic foot <i>Condition 39.c</i>	Maintain contract or tariff sheet showing gas contains no more than 20 grains sulfur per 100 standard cubic foot	Equivalent
Startup Notification	--	Within 15-days of startup	EPA Notification Required
Performance Test Notification	State requirements are equivalent	30-days prior to testing	EPA Notification Required
Reporting	Semiannual	Semiannual	Equivalent

For a significant permit modification under OAR 340-218-0180 to be incorporated into an existing Title V Operating Permit, PGE must submit the permit application within one year of initial startup of the construction or modification unless prohibited by OAR 340-218-0190(2)(d) which states: "Where an existing Oregon Title V Operating Permit would prohibit such construction or change in operation, the owner or operator must obtain a permit revision before commencing operation." As shown in Table 3, the current permit already contains adequate requirements to address Subpart KKKK; as such, the proposed modification would not be prohibited. Therefore, pursuant to OAR 340-218-0190(2)(c), PGE is allowed one year after startup of the modification to submit the significant permit application to address the Title I modification. The significant permit modification application has been included with this notice of construction application to expedite the permitting process.

Modification Application

PGE requests that Oregon DEQ approve this significant permit modification application. Oregon DEQ Form MD906, as required for a significant modification application in accordance with OAR 340-218-0190(2)(c), is provided in Attachment 2. In addition, Oregon DEQ Forms DV201, EU501, CP701, and CP710 have also been included in Attachment 2 for Unit 1. An edited Title V Permit (red line changes), incorporating the requirements of Subpart KKKK, is provided in Attachment 3.

Subpart KKKK regulates emissions of SO₂ and NO_x. As stated above and illustrated in Table 3, the requirements in the existing permit are as stringent as the standards in Subpart KKKK. Based on the

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source type, fuels combusted, and the heat input and size of Unit 1, the NO_x emission limit for Unit 1 is 15 ppm corrected to 15% oxygen (or a NO_x concentration in excess of 0.43 lbs/MWh) calculated on a 30-day rolling average. The SO₂ emission limit is based on an emission factor of 0.060 lb/MMBtu heat input (sulfur content of 20 grain per 100 standard cubic feet). The NO_x emission limit only applies to Unit 1 when firing natural gas since natural gas is the primary fuel. However, the SO₂ emission limit applies to Unit 1 when firing both natural gas and fuel oil. PGE will use a CEMS in accordance with 40 CFR 60.4340(b) to demonstrate continuous compliance of NO_x emissions. PGE will also maintain tariff sheets that verify that the natural gas and/or fuel oil burned by the combustion turbine contain a total sulfur content of 20 grains per 100 standard cubic feet, or less, in accordance with 40 CFR 60.4365(a).

Please feel free to contact me with any questions regarding the information in this application at (503) 464-8519.

Respectfully,



Ray Hendricks
Environmental Engineer

Attachments (3)

cc: Arya Behbehani-Divers
Gary Weidinger
USEPA, Region 10
Oregon DEQ – Business Office (with fee)

Attachment 1

Emission Calculations

Table 1
Combustion Turbine 1 (Natural Gas) Emissions - Current Operations
Combustion Turbine 1 Upgrade Project
Portland General Electric, Coyote Springs Plant

Pollutant	Emission Factor ⁽¹⁾	Hourly Emissions ^(a) (lbs/hr)	Annual Emissions ^(b) (tons/yr)
Criteria Pollutants			
PM/PM ₁₀	2.5 lbs/MMcf	4.5	18.3
SO ₂	0.64 lbs/MMcf	1.2	4.7
NO _x	16.7 lbs/MMcf	30.0	122.5
CO	28.4 lbs/MMcf	51.0	208.4
VOC	0.83 lbs/MMcf	1.5	6.1
Lead	--	--	--

Calculations:

(a) Hourly emissions (lbs/hr) = [maximum hourly fuel flow (MMcf/hr)] x [emission factor (lbs/MMcf)]

(b) Annual emissions (tons/yr) = [maximum annual fuel flow (MMcf/yr)] x [emission factor (lbs/MMcf)] / [2,000 lbs/ton]

Maximum hourly fuel flow (MMcf/hr) = 1.797 (c)

Maximum annual fuel flow (MMcf/yr) = 14,674 (d)

(c) Maximum hourly fuel flow (MMcf/hr) = [maximum hourly CT fuel flow (MMcf/hr)] + ([maximum hourly DB fuel flow (MMcf/hr)]

(d) Maximum annual fuel flow (MMcf/yr) = ([maximum hourly CT fuel flow (MMcf/hr)] x [CT operating hours (hrs/yr)]) + ([maximum hourly DB fuel flow (MMcf/hr)] x [DB operating hours (hrs/yr)])

Maximum hourly CT fuel flow (MMcf/hr) = 1.792 (2)

Maximum hourly DB fuel flow (MMcf/hr) = 0.005 (2)

CT operating hours (hrs/yr) = 8,166 (1)

DB operating hours (hrs/yr) = 8,166 (1)

Notes:

(1) Taken from the Title V (25-0031-TV-01) Review Report.

(2) The maximum hourly fuel usage estimates are based on average site conditions (14.55 psia; 55 degrees F; and 55% relative humidity).

Table 2
Combustion Turbine 1 (Oil) Emissions - Current Operations
Combustion Turbine 1 Upgrade Project
Portland General Electric, Coyote Springs Plant

Pollutant	Emission Factor ⁽¹⁾	Hourly Emissions ^(a) (lbs/hr)	Annual Emissions ^(b) (tons/yr)
Criteria Pollutants			
PM/PM ₁₀	2.42 lbs/1,000 gal	33.4	9.9
SO ₂	7.25 lbs/1,000 gal	100.0	29.7
NO _x	8.18 lbs/1,000 gal	112.9	33.5
CO	4.98 lbs/1,000 gal	68.7	20.4
VOC	0.21 lbs/1,000 gal	2.9	0.9
Lead	5.8E-05 lbs/MMBtu	0.1	0.03

Calculations:

(a) Hourly emissions (lbs/hr) = [maximum hourly fuel flow (gals/hr) / 1,000] x [emission factor (lbs/1,000-gal)]

Hourly emissions (lbs/hr) = [maximum hourly fuel flow (gals/hr)] x [heat value (Btu/gal) / 1,000,000 (Btu/MMBtu)] x [emission factor (lbs/MMBtu)]

(b) Annual emissions (tons/yr) = [maximum annual fuel flow (gals/yr) / 1,000] x [emission factor (lbs/1,000-gal)] / [2,000 lbs/ton]

Annual emissions (tons/yr) = [maximum annual fuel flow (gals/yr)] x [heat value (Btu/gal) / 1,000,000 (Btu/MMBtu)] x [emission factor (lbs/MMBtu)] / [2,000 lbs/ton]

Maximum hourly fuel flow (gals/hr) = 13,799 (1)

Maximum annual fuel flow (gals/yr) = 8,196,606 (c)

High heat value (Btu/gal) = 135,000 (1)

(c) Maximum annual fuel flow (gals/yr) = [maximum hourly fuel flow (gals/hr)] x [CT operating hours (oil) (hrs/yr)]

CT operating hours (oil) (hrs/yr) = 594 (1)

Notes:

(1) Taken from the Title V (25-0031-TV-01) Review Report.

**Table 3
Combustion Turbine 2 (Natural Gas) Emissions
Combustion Turbine 1 Upgrade Project
Portland General Electric, Coyote Springs Plant**

Pollutant	Emission Factor ⁽¹⁾	Hourly Emissions ^(a) (lbs/hr)	Annual Emissions ^(b) (tons/yr)
Criteria Pollutants			
PM/PM ₁₀ ⁽²⁾	2.25 lbs/MMcf	4.5	17.7
SO ₂	0.64 lbs/MMcf	1.3	5.0
NO _x ⁽³⁾	16.7 lbs/MMcf	33.2	131.1
CO ⁽³⁾	28.4 lbs/MMcf	56.5	223.0
VOC	0.83 lbs/MMcf	1.7	6.5
Lead	--	--	--

Calculations:

(a) Hourly emissions (lbs/hr) = [maximum hourly fuel flow (MMcf/hr)] x [emission factor (lbs/MMcf)]

(b) Annual emissions (tons/yr) = [maximum annual fuel flow (MMcf/yr)] x [emission factor (lbs/MMcf)] / [2,000 lbs/ton]

Maximum hourly fuel flow (MMcf/hr) = 1.990 (c)

Maximum annual fuel flow (MMcf/yr) = 15,704 (d)

(c) Maximum hourly fuel flow (MMcf/hr) = [maximum hourly CT fuel flow (MMcf/hr)] + ([maximum hourly DB fuel flow (MMcf/hr)]

(d) Maximum annual fuel flow (MMcf/yr) = ([maximum hourly CT fuel flow (MMcf/hr)] x [CT operating hours (hrs/yr)]) + ([maximum hourly DB fuel flow (MMcf/hr)] x [DB operating hours (hrs/yr)])

Maximum hourly CT fuel flow (MMcf/hr) = 1.69 (4)

Maximum hourly DB fuel flow (MMcf/hr) = 0.30 (4)

CT operating hours (hrs/yr) = 8,760 (4)

DB operating hours (hrs/yr) = 3,000 (4)

Notes:

(1) Taken from the Title V (25-0031-TV-01) Review Report.

(2) The PM/PM10 emission factor is based on a PGE engineering estimate.

(3) The NO_x and CO hourly emissions shown above are the maximum one-hour emissions from CT2. The hourly average emissions from CT2 will continue to comply with the Title V permit limits of 30 lbs/hr (24-hour rolling average) for NO_x and 51 lbs/hr (8-hour rolling average) for CO.

(4) The maximum hourly fuel usage estimates and operating hours were taken from the December 4, 2009 Significant Permit Modification application for the CT2 duct burner replacement project and are based on average site conditions (14.55 psia; 55 degrees F; and 55% relative humidity).

Table 4
Auxiliary Boiler (Natural Gas) Emissions
Combustion Turbine 1 Upgrade Project
Portland General Electric, Coyote Springs Plant

Pollutant	Emission Factor ⁽¹⁾	Hourly Emissions ^(a) (lbs/hr)	Annual Emissions ^(b) (tons/yr)
Criteria Pollutants			
PM/PM ₁₀	5.62 lbs/MMcf	3.9	17.1
SO ₂	0.64 lbs/MMcf	0.4	1.9
NO _x	48.4 lbs/MMcf	33.6	147.0
CO	39.8 lbs/MMcf	27.6	120.9
VOC	4.2 lbs/MMcf	2.9	12.8
Lead	--	--	--

Calculations:

(a) Hourly emissions (lbs/hr) = [maximum hourly fuel flow (MMcf/hr)] x [emission factor (lbs/MMcf)]

(b) Annual emissions (tons/yr) = [maximum annual fuel flow (MMcf/yr)] x [emission factor (lbs/MMcf)] / [2,000 lbs/ton]

Maximum hourly fuel flow (MMcf/hr) = 0.694 (1)

Maximum annual fuel flow (MMcf/yr) = 6,076 (1)

Notes:

(1) Taken from the Title V (25-0031-TV-01) Review Report.

Table 5
Maximum Annual Emissions - Current Operations
Combustion Turbine 1 Upgrade Project
Portland General Electric, Coyote Springs Plant

Emission Units	Maximum Annual Emissions					
	PM/PM ₁₀ (tons/yr)	SO ₂ (tons/yr)	NO _x (tons/yr)	CO (tons/yr)	VOC (tons/yr)	Lead (tons/yr)
Combustion Turbine 1 - Natural Gas	18.3	4.7	122.5	208.4	6.1	--
Combustion Turbine 1 - Oil	9.9	29.7	33.5	20.4	0.9	0.0
Combustion Turbine 2 - Natural Gas	17.7	5.0	131.1	223.0	6.5	--
Auxiliary Boiler -Natural Gas ⁽¹⁾	--	--	--	--	--	--
Maximum Annual Emissions	46	39	287	452	13	0.03
Annual Plant Site Emission Limits (PSEL)	48	39	287	452	39	--

Notes:

(1) As stated in the Title V Review Report, the auxiliary boiler annual emissions are not included in the totals since it is only operated in place of the combustion turbines.

**Table 6
Combustion Turbine 1 (Natural Gas) Emissions - Post Modification
Combustion Turbine 1 Upgrade Project
Portland General Electric, Coyote Springs Plant**

Pollutant	Emission Factor ⁽¹⁾	Hourly Emissions ^(a) (lbs/hr)	Annual Emissions ^(b) (tons/yr)
Criteria Pollutants			
PM/PM ₁₀ ⁽²⁾	2.25 lbs/MMcf	4.2	17.7
SO ₂	0.64 lbs/MMcf	1.2	5.0
NO _x ⁽³⁾	16.7 lbs/MMcf	31.1	131.5
CO ⁽³⁾	28.4 lbs/MMcf	52.9	223.6
VOC	0.83 lbs/MMcf	1.5	6.5
Lead	--	--	--

Calculations:

(a) Hourly emissions (lbs/hr) = [maximum hourly fuel flow (MMcf/hr)] x [emission factor (lbs/MMcf)]

(b) Annual emissions (tons/yr) = [maximum annual fuel flow (MMcf/yr)] x [emission factor (lbs/MMcf)] / [2,000 lbs/ton]

Maximum hourly fuel flow (MMcf/hr) = 1.863 (c)

Maximum annual fuel flow (MMcf/yr) = 15,744 (d)

(c) Maximum hourly fuel flow (MMcf/hr) = [maximum hourly CT fuel flow (MMcf/hr)] + ([maximum hourly DB fuel flow (MMcf/hr)]

(d) Maximum annual fuel flow (MMcf/yr) = ([maximum hourly CT fuel flow (MMcf/hr)] x [CT operating hours (hrs/yr)]) + ([maximum hourly DB fuel flow (MMcf/hr)] x [DB operating hours (hrs/yr)])

Maximum hourly CT fuel flow (MMcf/hr) = 1.858 (4)

Maximum hourly DB fuel flow (MMcf/hr) = 0.005 (4)

CT operating hours (hrs/yr) = 8,450 (5)

DB operating hours (hrs/yr) = 8,450 (5)

Notes:

(1) Taken from the Title V (25-0031-TV-01) Review Report.

(2) The PM/PM10 emission factor is based on a PGE engineering estimate.

(3) The NO_x and CO hourly emissions shown above are the maximum one-hour emissions from natural gas combustion in CT1 following the upgrade project. The hourly average emissions from CT1 will continue to comply with the Title V permit limits of 30 lbs/hr (24-hour rolling average) for NO_x and 51 lbs/hr (8-hour rolling average) for CO following the project.

(4) Based on the CT1 upgrade project, natural gas usage should increase approximately 3.7% on an hourly basis. The maximum hourly fuel usage estimates have been increased based on average site conditions (14.55 psia; 55 degrees F; and 55% relative humidity).

(5) For the combustion of natural gas in CT1, 8,450 hours of operation are adequate for typical operation.

**Table 7
Combustion Turbine 1 (Oil) Emissions - Post Modification
Combustion Turbine 1 Upgrade Project
Portland General Electric, Coyote Springs Plant**

Pollutant	Emission Factor ⁽¹⁾	Hourly Emissions ^(a) (lbs/hr)	Annual Emissions ^(b) (tons/yr)
Criteria Pollutants			
PM/PM ₁₀	2.42 lbs/1,000 gal	33.4	2.7
SO ₂	7.25 lbs/1,000 gal	100.0	8.0
NO _x	8.18 lbs/1,000 gal	112.9	9.0
CO	4.98 lbs/1,000 gal	68.7	5.5
VOC	0.21 lbs/1,000 gal	2.9	0.2
Lead	5.8E-05 lbs/MMBtu	0.1	0.01

Calculations:

(a) Hourly emissions (lbs/hr) = [maximum hourly fuel flow (gals/hr) / 1,000] x [emission factor (lbs/1,000-gal)]

Hourly emissions (lbs/hr) = [maximum hourly fuel flow (gals/hr)] x [heat value (Btu/gal) / 1,000,000 (Btu/MMBtu)] x [emission factor (lbs/MMBtu)]

(b) Annual emissions (tons/yr) = [maximum annual fuel flow (gals/yr) / 1,000] x [emission factor (lbs/1,000-gal)] / [2,000 lbs/ton]

Annual emissions (tons/yr) = [maximum annual fuel flow (gals/yr)] x [heat value (Btu/gal) / 1,000,000 (Btu/MMBtu)] x [emission factor (lbs/MMBtu)] / [2,000 lbs/ton]

Maximum hourly fuel flow (gals/hr) = 13,799 (1)

Maximum annual fuel flow (gals/yr) = 2,207,840 (c)

High heat value (Btu/gal) = 135,000 (1)

(c) Maximum annual fuel flow (gals/yr) = [maximum hourly fuel flow (gals/hr)] x [CT operating hours (oil) (hrs/yr)]

CT operating hours (oil) (hrs/yr) = 160 (2)

Notes:

(1) Taken from the Title V (25-0031-TV-01) Review Report.

(2) For the combustion of oil in CT1, 160 hours of operation are adequate for potential emergency situations.

Table 8
Maximum Annual Emissions - Post Modification
Combustion Turbine 1 Upgrade Project
Portland General Electric, Coyote Springs Plant

Emission Units	Maximum Annual Emissions					
	PM/PM ₁₀ (tons/yr)	SO ₂ (tons/yr)	NO _x (tons/yr)	CO (tons/yr)	VOC (tons/yr)	Lead (tons/yr)
Combustion Turbine 1 - Natural Gas (Post Modification)	17.7	5.0	131.5	223.6	6.5	--
Combustion Turbine 1 - Oil (Post Modification)	2.7	8.0	9.0	5.5	0.2	0.01
Combustion Turbine 2 - Natural Gas	17.7	5.0	131.1	223.0	6.5	--
Auxiliary Boiler - Natural Gas ⁽¹⁾	--	--	--	--	--	--
Maximum Annual Emissions	38	18	272	452	13	--
Annual Plant Site Emission Limits (PSEL)	48	39	287	452	39	--

Notes:

(1) As stated in the Title V Review Report, the auxiliary boiler annual emissions are not included in the totals since it is only operated in place of the combustion turbines.

Attachment 2

DEQ Application Forms

FOR DEQ ONLY
DATE REC'D NOV 16 2010
AMT. REC'D B,115 ⁰⁰
CHECK # 692198

ER

Print Form

Significant Permit Modification Application

**FORM MD906
Answer Sheet**

Facility name: PGE - Coyote Springs Plant Permit Number: 25-0031-TV-01

Part A

1.	Contact Person: Name	Ray Hendricks
	Title	Environmental Engineer
	Phone number	(503) 464-8519
	e-mail address	ray.hendricks@pgn.com
	Fax number	(503) 464-8527
2.	Describe the change: PGE is performing upgrades on the Unit 1 combustion turbine that will result in increased unit output and efficiency and higher unit reliability. Please refer to the cover letter for details on the project.	
3.	Date change will take effect:	March 2011
4.	Applicable requirements (describe and attach appropriate forms)	NSPS, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines
5.	Change in emissions	Increase in hourly emissions; PSEIs will remain the same
6.	Does the change involve construction of any new stationary sources or modifications to existing stationary sources	Yes
7.	Construction permit incorporation [yes/no]	Yes
	Type of construction/modification change	Type 2
	If Type 3 or 4 change, enhanced permitting procedures used [yes/no]	No
	Construction, purpose [describe]	Please see #2 (above)
	Changes in operating conditions [describe]	Please see attached forms (EU501)

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DEQ
Eastern Region Bend

Significant Permit Modification Application

**FORM MD906
Answer Sheet**

8. Attached Form Series EU500, DV200, CD300, and CP700, as appropriate

Statement of Certification:

Based on information and belief formed after reasonable inquiry, the statements and information in this document and any attachments are true, accurate and complete.

Gary Weidinger

Plant Manager

Name of Responsible Official

Title of Responsible Official



11/9/10

Signature of Responsible Official

Date

Part B

Pollutant	Emissions increase or decrease (tons/yr)	PSEL (tons/yr)	
		Before change	After change
No requested changes			
In PSELs			

Attach form ED605.

Notice of Approval Application

Facility name: PGE - Coyote Springs Plant Permit Number: 25-0031-TV-01

Part A

1.	Contact Person:	Name	Ray Hendricks
		Title	Environmental Engineer
		Phone number	(503) 464-8519
		e-mail address	ray.hendricks@pgn.com
		Fax number	(503) 464-8527
2.	Describe the proposed change: PGE is performing upgrades on the Unit 1 combustion turbine that will result in increased unit output and efficiency and higher unit reliability. Please refer to the cover letter for details on the project.		
3.	Type of change from OAR 340-210-0225:	Type 2	
4.	Date operation to begin:	March 2011	
5.	Increase in hourly emissions? (yes/no) If yes, complete Part B and attach documentation.	Yes	
6.	Increase in annual PSEL by more than the de minimus level? (yes/no) If yes, this is the wrong form. Instead, submit an application for a Construction of Standard ACDP.	No	
7.	Will the change be subject to any requirements not already addressed in the permit? If yes, list the new requirements by rule citation.	Yes - NSPS; Subpart KKKK	

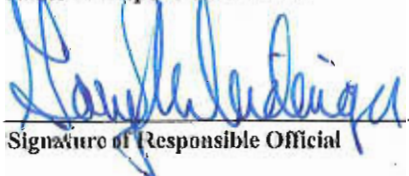
- 8. Attach DV200 forms, if appropriate
- 9. Attach CD300 forms, if appropriate
- 10. Attach a Land Use Compatibility Statement, if required.

Statement of Certification:

Based on information and belief formed after reasonable inquiry, the statements and information in this document and any attachments are true, accurate and complete.

Gary Weldinger

Name of Responsible Official


Signature of Responsible Official

Plant Manager

Title of Responsible Official

11/9/10
Date

Part B

Device/process	Pollutant	Potential Emissions (lb/hr)	
		Before change	After change
Unit 1	PM/PM10	4.5	4.2
	SO2	1.2	1.2
	NOx	30.0	31.1
	CO	51.0	52.9
	VOC	1.5	1.5

Provide documentation below or attach the information to this form.

See the included application for detailed emission calculations. The hourly calculations above for Unit 1 only include emissions from natural gas combustion.

Maximum hourly emissions of particulate matter (PM) and particulate matter less than 10 microns (PM10) have actually decreased slightly based on an updated emission factor. The emission factor was developed based on PGE engineering calculations.

The NOX and CO hourly emissions shown above are the maximum one-hour emissions from natural gas combustion in CT1 following the upgrade project. The hourly average emissions from CT1 will continue to comply with the Title V permit limits of 30 lbs/hour (24-hour rolling average) for NOX and 51 lbs/hour (8-hour rolling average) for CO following the project.

Device\Process Form
Miscellaneous Process

FORM DV201
Answer Sheet

Facility name: PGE - Coyote Springs Plant Permit Number: 25-0031-TV-01

1.	Device name and ID number or label	CT1.DV
2.	Date installation/construction commenced	September 19, 1994
3.	Date installed	September 29, 1995
4.	Special control requirements? [if yes, describe]	Yes - SCR to control NOx emissions
5.	Description of process: Combustion Turbine 1 (CT1.EU) is a General Electric Model Frame 7FA with an original rated capacity of 1,925.2 MMBtu/hour heat input. The turbine was designed to burn natural gas at a rate of 1.797 million cubic feet per hour or No. 2 distillate fuel oil at a rate of 13,799 gallons per hour. A Selective Catalytic Reduction (SCR) device is used to control nitrogen oxides emissions. The combustion turbine is used for electric power generation. In addition, the exhaust gases are used in a heat recovery steam generator (HRSG) to generate steam to power a steam turbine generator. There is also a small natural gas fired duct burner that is used to increase the temperature of the exhaust gases from the combustion turbine before entering the HRSG. The rated capacity of the duct burner is 50 MMBtu/hour heat input at a fuel rate of 4,915 cubic feet of natural gas per hour. The proposed modification would increase the hourly natural gas usage by the turbine by approximately 3.7% on an hourly basis (based on average site conditions).	
6.	Continuous or batch process? [if batch, maximum batches per hour]	Continuous

7. Raw material usage: [for EACH raw material used, enter]:

Material	Maximum design capacity (lbs/batch or lbs/hr)
Hourly Natural Gas (CT1)	1.858 MMcf/hr
Hourly Natural Gas (Duct Burners)	0.005 MMcf/hr
Natural Gas (Total Hourly)	1.863 MMcf/hr
Natural Gas (Total Annual)	15,744 MMcf/yr

8. Production data: [for EACH product, enter]:

Product	Maximum design capacity (lbs/batch or lbs/hr)
Not Applicable	

9. Attach any additional information necessary to describe this process and its operating and usage parameters, both short-term and annual.

Emissions Unit Summary

**FORM EU501
Answer Sheet**

Facility name: PGE - Coyote Springs Plant Permit Number: 25-0031-TV-01

1.	Emissions Unit name and ID number or label	Coyote Springs Unit 1 (CT1.EU)
2.	Emissions Unit description	Combustion Turbine
3.	Operating Scenario ID number	OS1

4. Emission devices, processes, and control devices:

Device/process ID(s) from DV2XX	Control Device ID(s) from CD3XX
CT1.DV	SCR.CD1

5. Pollutants/Emissions:

Pollutant	PSEL Component from ED605
PM/PM10	48 tpy
SO2	39 tpy
NOx	287 tpy
CO	452 tpy
VOC	39 tpy

Table 6: Applicable Requirements (next page)

Emissions Unit Summary

6. Applicable Requirements:

Applicable Requirement Citation	Parameter/ Pollutant	Limit/Standard/ Requirement	Currently in Compliance?	Current Monitoring Method	Proposed Monitoring Method
OAR 340-208-0110(2)	Visible Emissions	20% opacity	Yes	VE observ. (oil); fuel recordkeeping (natural gas)	no change
OAR 340-226-0210(1)(b)	PM/PM10	0.1 gr/dscf	Yes	VE observ. (oil); fuel recordkeeping (natural gas)	no change
1995 ACDP Condition 3	PM/PM10 (natural gas)	4.5 lb/hr	Yes	Fuel Recordkeeping	no change
1995 ACDP Condition 4	NOx (natural gas)	4.5 ppm at 15% O2	Yes	CEMS	no change
1995 ACDP Condition 4	NOx (natural gas)	30 lb/hr	Yes	CEMS	no change
1995 ACDP Condition 5	CO (natural gas)	15 ppm at 15% O2	Yes	CEMS	no change
1995 ACDP Condition 5	CO (natural gas)	51 lb/hr	Yes	CEMS	no change
40 CFR 60.4320(a)	NOx	15 ppm at 15% O2 or 0.43 lb/MWh	New Condition	New Condition	CEMS
40 CFR 60.4330 (a)(2)	SO2	0.060 lb/MMBtu - heat input (fuel sulfur content)	New Condition	New Condition	Fuel Recordkeeping
1995 ACDP Condition 3	PM/PM10 (fuel oil)	33 lb/hr	Yes	Periodic ST and VE observations	no change
1995 ACDP Condition 4	NOx (fuel oil)	15 ppm at 15% O2	Yes	CEMS	no change
1995 ACDP Condition 4	NOx (fuel oil)	113 lb/hr	Yes	CEMS	no change
1995 ACDP Condition 5	CO (fuel oil)	20 ppm at 15% O2	Yes	CEMS	no change
1995 ACDP Condition 5	CO (fuel oil)	69 lb/hr	Yes	CEMS	no change
OAR 340-228-0100	Distillate Oil Sulfur Content (fuel oil)	0.5% by weight	Yes	Fuel Recordkeeping	no change

**FORM CP701
Answer Sheet**

Continuous Monitoring Systems

Facility name:	PGE - Coyote Springs Plant	Permit Number:	25-0031-TV-01
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1. Continuous monitors:

Emissions Unit ID	Pollutant/parameter	Sample location	Limit or Standard(s)	Averaging Time	Program
CT1.EU	NOx - Natural Gas	Unit 1 stack	4.5 ppm @ 15% O2	24-hour rolling ave.	1995 ACDP Condition 4
CT1.EU	NOx - Natural Gas	Unit 1 stack	30 lb/hr	24-hour rolling ave.	1995 ACDP Condition 4
CT1.EU	NOx - Fuel Oil	Unit 1 stack	15 ppm at 15% O2	24-hour rolling ave.	1995 ACDP Condition 4
CT1.EU	NOx - Fuel Oil	Unit 1 stack	113 lb/hr	24-hour rolling ave.	1995 ACDP Condition 4
CT1.EU	NOx	Unit 1 stack	15 ppm at 15% O2 or 0.43 lb/MWh	30-day rolling ave.	NSPS (40 CFR 60.4320(a))
CT1.EU	CO - Natural Gas	Unit 1 stack	15 ppm at 15% O2	8-hour rolling ave.	1995 ACDP Condition 5
CT1.EU	CO - Natural Gas	Unit 1 stack	51 lb/hr	8-hour rolling ave.	1995 ACDP Condition 5
CT1.EU	CO - Fuel Oil	Unit 1 stack	20 ppm at 15% O2	8-hour rolling ave.	1995 ACDP Condition 5
CT1.EU	CO - Fuel Oil	Unit 1 stack	69 lb/hr	8-hour rolling ave.	1995 ACDP Condition 5

2. Quality Assurance Plans:

a.	Has a quality assurance plan been written for each continuous monitoring system described above?	Yes
b.	If yes, was the QAP submitted to the Department for review and approval (enter date)?	Submitted to USEPA per Part 75
c.	If no to either a or b, when will the QAP be written and submitted to the Department for review and approval?	NA

Attachment 3

Edited Title V Permit (Red-Line Changes)

**OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY
OREGON TITLE V OPERATING PERMIT AND ACID RAIN PERMIT
SIGNIFICANT PERMIT MODIFICATION**

Eastern Region
475 NE Bellevue Dr., Suite 110
Bend, OR 97701
Telephone (541) 388-6146

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 Number: 23913
Received: 12/16/09

PLANT SITE LOCATION:

Coyote Springs Plant
200 Ullman Blvd.
Boardman, OR 97818

LAND USE COMPATIBILITY STATEMENT:

Issued by: City of Boardman
Dated: 09/05/91

ISSUED BY THE DEPARTMENT OF ENVIRONMENTAL QUALITY

Linda Hayes-Gorman,
Eastern Region Air Quality Manager

Date

Nature of Business: Electric Power Generation – natural gas or distillate fired, 25 MW or more
Standard Industrial Code (SIC): 4911
Acid Rain Program Identification: Plant Name: Coyote Springs
State: Oregon
ORIS code: 07350
NADB#: CTG1 and CTG2

RESPONSIBLE OFFICIAL		ACID RAIN DESIGNATED REPRESENTATIVE		FACILITY CONTACT PERSON	
Title:	Plant Manager	Name:	Ray Hendricks	Name:	Ray Hendricks
		Title:	Designated Representative	Title:	Environmental Engineer
				Phone:	(541) 464-8519

5. The permittee must not cause or allow air contaminants from any source to cause a nuisance. Nuisance conditions will be verified by Department personnel. [OAR 340-208-0300]
6. The permittee must not cause or permit the emission 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. The Department will verify that the deposition exists and will notify the permittee that the deposition must be controlled. [OAR 340-208-0450]
7. At all times, including periods of startup, shutdown, and malfunction, the permittee must, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. [40 CFR 60.11(d), 60.4333(a), and 60.12 incorporated by reference]
8. The permittee must comply with the risk management plan (RMP) submitted to EPA and all other applicable Part 68 requirements. The permittee must certify compliance with the requirements of Part 68 as part of the semi-annual compliance certification required by Condition 51. [40 CFR Part 68]

Table 2. Emissions Units Specific Emission Limits and Standards

EU ID	Applicable Requirement	Condition Number	Pollutant/Parameter	Limit/Standard	Monitoring Requirements	
					Method	Condition No.
CT1.EU, CT2.EU and AB.EU	1995 ACDP Condition 16	9	Operating modes	See condition for fuel restrictions	Recordkeeping	31
CT1.EU and CT2.EU	340-208-0110(2)	10	Visible emissions	20% opacity, 3 min. in 60 min.	VE observations while burning oil; Fuel recordkeeping while burning natural gas	32
	340-226-0210(1)(b)	11.a	PM/PM ₁₀	0.1 gr/dscf	Periodic ST and VE observations while burning oil; Fuel recordkeeping while burning natural gas	31 and 32
	1995 ACDP Condition 3	11.b	PM/PM ₁₀ natural gas	4.5 lbs/hr/unit	Fuel recordkeeping	31
	1995 ACDP Condition 4	13.a	NO _x /natural gas	4.5 ppm at 15% O ₂	CEMS	36
	1995 ACDP Condition 4	13.a	NO _x /natural gas	30 lbs/hr/unit	CEMS	36
	1995 ACDP Condition 5	15.a	CO/natural gas	15 ppm at 15% O ₂	CEMS	38
	1995 ACDP Condition 5	15.a	CO/natural gas	51 lbs/hr/unit	CEMS	38
	40 CFR 60.4320(a)	14.b	NO _x	15 ppm or 0.43 lb/MWh	CEMS	36
40 CFR 60.4330(a)(2)	14.d	SO ₂	0.060 lb/MMBtu heat input	Recordkeeping	40	

EU ID	Applicable Requirement	Condition Number	Pollutant/Parameter	Limit/Standard	Monitoring Requirements	
					Method	Condition No.
CT1.EU	1995 ACDP Condition 3	11.c	PM/PM ₁₀ /fuel oil	33 lb/hr	Periodic ST and VE observations	24 and 32
	340-228-0100	12	Distillate oil sulfur content	0.5% by weight	NA	34
	1995 ACDP Condition 4	13.b	NO _x / fuel oil	15 ppm at 15% O ₂	CEMS	36
	1995 ACDP Condition 4	13.b	NO _x /fuel oil	113 lbs/hr/unit	CEMS	36
	40 CFR 60.332(a)(1)	14.a	NO_x	100 ppm at 15% O₂	CEMS	36
	1995 ACDP Condition 5	15.b	CO/#2 fuel oil	20 ppm at 15% O ₂	CEMS	38
	1995 ACDP Condition 5	15.b	CO/#2 fuel oil	69 lbs/hr/unit	CEMS	38
	40 CFR 60.333(b)	+	Fuel sulfur content	0.8% by weight	Recordkeeping	34 and 39
CT2.EU	40 CFR 60.4320(a)	14.b	NO_x	15 ppm or 0.43 lb/MWh	CEMS	36
	40 CFR 60.4330(a)(2)	14.d	SO₂	0.060 lb/MMBtu heat input	Recordkeeping	40
AB.EU	340-208-0110(2) and (3)(a)	10	Visible emissions	20% opacity, 3 min. in 60 minutes	Fuel recordkeeping	31
	340-228-0210(1)(b)	17	PM/PM ₁₀	0.1 gr/dscf @ 50% excess air	Fuel recordkeeping	31
	40 CFR 60.42(a)(1)	18	PM	0.10 lb/mmBtu	Fuel recordkeeping	31
	40 CFR 60.42(a)(2)	16	Visible emissions	20% opacity, 6 min. avg.	Fuel recordkeeping	31
	40 CFR 60.44(a)(1) and 60.44b(a)(1)	19	NO _x	0.20 lb/mmBtu	Recordkeeping or CEMS	40

9. The permittee must only operate the combustion turbines (CT1.EU and CT2.EU) and auxiliary boiler (AB.EU) as follows: [1995 ACDP Condition 16]
 - 9.a. The permittee must only burn natural gas or ASTM #2 fuel oil in combustion turbine 1 (CT1.EU).
 - 9.b. The permittee must only burn natural gas in combustion turbine 2 (CT2.EU).
 - 9.c. The permittee must only burn natural gas in the auxiliary boiler (AB.EU).

10. The permittee must not cause or allow the emissions of any air contaminant into the atmosphere from the combustion turbines (CT1.EU and CT2.EU) and auxiliary boiler (AB.EU), for a period or periods aggregating more than three minutes in any one hour which is equal to or greater than 20% opacity,

excluding uncombined water. [OAR 340-208-0110(2) and 340-208-0110(3)(a)]

The permittee is not required to monitor visible emissions from the combustion turbines (CT1.EU and CT2.EU) and auxiliary boiler (AB.EU) while burning natural gas. The permittee is required to monitor visible emissions from combustion turbine CT1.EU while burning fuel oil in accordance with Condition 32. [See also Condition 26.]

11. The permittee must not cause or allow the emission of particulate matter from the combustion turbines (CT1.EU and CT2.EU) in excess of:
 - 11.a. For each combustion turbine (CT1.EU and CT2.EU), 0.1 grains per dry standard cubic feet [OAR 340-226-0210(1)(b)]; and
 - 11.b. For each combustion turbine (CT1.EU and CT2.EU), 4.5 pounds per hour while burning natural gas [1995 ACDP Condition 3]; and
 - 11.c. For combustion turbine 1 (CT1.EU), 33 pounds per hour while burning ASTM #2 fuel oil. [1995 ACDP Condition 3]

Particulate matter emissions are measured in accordance with Condition 24 and monitored in accordance with Condition 32.

12. The permittee must not use any ASTM Grade 2 distillate oil containing more than 0.5 percent sulfur by weight. [OAR 340-228-0110(2)]
13. The permittee shall not cause or allow the emission of nitrogen oxides from the combustion turbines (CT1.EU and CT2.EU) in excess of:
 - 13.a. For each combustion turbine (CT1.EU and CT2.EU), 4.5 ppm corrected to 15% oxygen and 30 pounds per hour as a 24-hour rolling average while burning natural gas; or
 - 13.b. For combustion turbine 1 (CT1.EU), 15 ppm corrected to 15% oxygen and 113 pounds per hour as a 24-hour rolling average while burning ASTM #2 fuel oil.

These limits do not apply during startup and shutdown if Department approved procedures are followed for the startup and shutdown. Nitrogen oxide emissions must be measured in accordance with Condition 36. [1995 ACDP Condition 4]

14. New Source Performance Standards (NSP) for the combustion turbines are as follows:
 - 14.a. ~~The permittee must not cause to be discharged into the atmosphere from combustion turbine 1 (CT1.EU) any gases which contain nitrogen oxides in excess of 100 ppm corrected to 15% oxygen in accordance with 40 CFR 60.332(a)(1). Emissions in excess of 100 ppm during periods of startup, shutdown, and malfunction shall not be considered a violation in accordance with 40 CFR 60.8(e). However, for purposes of the excess emissions reports required in 40 CFR 60.7(c), an hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_x concentration exceeds 100 ppm in accordance with 40 CFR 60.334 (j)(1)(iii). Nitrogen oxides emissions must be measured in accordance with Condition 36.~~
 - 14.b. The permittee must not cause to be discharged into the atmosphere from the combustion turbines (CT1.EU and CT2.EU) any gases that contain nitrogen oxides (expressed as NO₂) in excess of 15 ppm corrected to 15% oxygen or 0.43lbs/MWh, whichever is greater, 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 start-up, shutdown, and malfunction in accordance with 40 CFR 60.4350(h) and 60.4375(a). Nitrogen oxides emissions must be measured in accordance with Condition 36.

- 14.c. ~~The sulfur content of any fuel burned in the combustion turbine 1 (CT1.EU) must not exceed 0.8% by weight. [40 CFR 60.333(b)] When burning natural gas, the permittee must use only pipeline grade natural gas. The sulfur content of the fuels must be measured in accordance with Condition 34 for fuel oil and Condition 39 for natural gas.~~
- 14.d. The permittee must not cause to be discharged into the atmosphere from the combustion turbines (CT1.EU and CT2.EU) 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 34 for fuel oil and Condition 39 for natural gas.~~
15. The permittee must not cause or allow the emission of carbon monoxide from the combustion turbines (CT1.EU and CT2.EU) in excess of:
- 15.a. For each combustion turbine (CT1.EU and CT2.EU), 15 ppm corrected to 15% oxygen and 51 pounds per hour as an 8-hour rolling average while burning natural gas; or
- 15.b. For combustion turbine 1 (CT1.EU), 20 ppm corrected to 15% oxygen and 69 pounds per hour as an 8-hour rolling average while burning ASTM #2 fuel oil.
- These limits do not apply during startup and shutdown if Department approved procedures are followed for the startup and shutdown. Carbon monoxide emissions must be measured in accordance with Condition 38. [1995 ACDP Condition 5]
16. The permittee must not cause to be discharged into the atmosphere from the auxiliary boiler (AB.EU) any gases which exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity in accordance with 40 CFR 60.42(a)(2). Emissions in excess of 20 percent opacity during periods of startup, shutdown, and malfunction shall not be considered a violation in accordance with 40 CFR 60.8(c).
- The permittee is not required to monitor visible emissions from the auxiliary boiler (AB.EU) while burning natural gas. [See also Condition 26.]
17. The permittee must not cause or allow the emission of particulate matter from the auxiliary boiler (AB.EU) in excess of 0.1 grains per dry standard cubic feet, corrected to 50% excess air. [OAR 340-228-0210(1)(b)]
- The permittee is not required to monitor particulate matter emissions from the auxiliary boiler (AB.EU) while burning natural gas. [See also Condition 26.]
18. The permittee must not cause or allow the emission of particulate matter from the auxiliary boiler (AB.EU) in excess of 0.10 pounds per million Btu heat input. [40 CFR 60.42(a)(1)] Emissions in excess of 0.10 pound per million Btu heat input during periods of startup, shutdown, and malfunction shall not be considered a violation in accordance with 40 CFR 60.8(c).
- The permittee is not required to monitor visible emissions from the auxiliary boiler (AB.EU) while burning natural gas. [See also Condition 26.]
19. The permittee must not discharge any gases from the auxiliary boiler (AB.EU) which contain nitrogen oxides in excess of 0.20 pound per million Btu heat input based on a 30-day rolling average. [40 CFR 60.44(a)(1) and 60.44b(a)(1). Nitrogen oxide emissions are measured in accordance with Condition 40.

Insignificant Activities Emission Limits and Standards

20. The Department acknowledges that insignificant emissions units (IEUs) identified by rule as either categorically insignificant activities or aggregate insignificant emissions as defined in OAR 340-200-0020 exist at facilities required to obtain an Oregon Title V Operating Permit. IEUs must comply with all applicable requirements. In general, the requirements that could apply to IEUs are incorporated as follows:

- 20.a. OAR 340-208-0110 (20% opacity)
- 20.b. OAR 340-226-0210 (0.1 gr/dscf for non-fugitive, non-fuel burning equipment)
- 20.c. OAR 340-226-0310 (process weight limit for non-fugitive, non-fuel burning process equipment)
- 20.d. OAR 340-228-0210 (0.1 gr/dscf corrected to 12% CO₂ or 50% excess air for fuel burning equipment)

Unless otherwise specified in this permit or an applicable requirement, the Department is not requiring any testing, monitoring, recordkeeping, or reporting for the particulate matter and visible emissions limits and standards that apply to insignificant emission units, including categorically insignificant activities and aggregate insignificant emissions. However, if testing were performed for compliance purposes, the permittee would be required to use the test methods identified in the definitions of "opacity" and "particulate matter" in OAR 340-208-0010 and perform the testing in accordance with the Department's Source Sampling Manual.

PLANT SITE EMISSION LIMITS

21. The plant site emissions must not exceed the following limits for each 12 consecutive month period: [OAR 340-222-0040 through OAR 340-222-0043]

Pollutant	Annual PSEL (tons/yr)	Monitoring Requirements	
		Method	Condition Number
PM/ PM ₁₀	48	Recordkeeping	41
CO	452	CEM and recordkeeping	41
NO _x	287	CEM and recordkeeping	41
SO ₂	39	FSA	41
VOC	39	Recordkeeping	41

EMISSION FEES

22. Emission fees will be based on the Plant Site Emissions Limits, unless the permittee elects to report actual emissions for one or more permitted processes/pollutants. If the permittee reports actual emissions for one or more permitted processes/pollutants, the permitted emissions for the remaining permitted processes/pollutants will be based on the following table: [OAR 340-220-0090]

Emission Source Description	ES/Process Code [DEQ]	PM ₁₀	SO ₂	NO _x	VOC
Combustion turbine 1 (gas)	PS-1/P-1	17.7 18.3	5.0 4.7	131 123	6.5 6.4
Combustion turbine 1 (oil)	PS-1/P-2	2.7 9.9	8.0 29.7	9.0 33.5	0.2 0.9
Combustion turbine 2 (gas)	PS-2/P-1	17.7 49.7	5	131	6.5
Auxiliary boiler	PS-3/P-1	17.1	1.9	147	12.8
Aggregate insignificant emissions	FS-1/P-1	1	1	1	1

TESTING REQUIREMENTS

The testing conditions in this section are based on OAR 340-212-0120 and 340-218-0050(3)(a); unless otherwise specified.

23. Unless otherwise specified in this permit, the permittee must conduct all testing in accordance with the Department's Source Sampling Manual and 40 CFR 60.8, where applicable.

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 60.334 and 60.4345]

36.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 O₂ concentration exceeds 19.0 percent O₂ (or the hourly CO₂ concentration is less than 1.0 percent CO₂), a diluents cap value of 19.0 percent O₂ or 1.0 percent CO₂ (as applicable) may be used in the emission calculations. [40 CFR 60.4350(b)]

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

$$M_{\text{NO}_x} = \text{ER}_{\text{NO}_x} \times \text{HI}_g$$

Where,

M_{NO_x} = Hourly mass of NO_x emissions from the combustion of pipeline natural gas, lb/hr.
 ER_{NO_x} = 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,
 $\text{HI}_g = (Q_g \times \text{GCV}_g) / 10000$;
 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.

36.c. The mass emissions rate in pounds per megawatt hour ~~from combustion turbine 2(CT2.EU)~~ must be calculated as follows: [40 CFR 60.4350(f)]

Where,

$E = (\text{NO}_x)_h * (\text{HI})_h / P$

E = hourly NO_x emission rate, in lb/MWh
 $(\text{NO}_x)_h$ = hourly NO_x emission rate, in lb/MMBtu
 $(\text{HI})_h$ = 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
 $= (\text{Pe})_t + (\text{Pe})_c + \text{Ps} - \text{Po}$
 $(\text{Pe})_t$ = electrical or mechanical energy output of the combustion turbine in MW
 $(\text{Pe})_c$ = electrical 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
 $= Q * H / 3.414 \times 10^6 \text{ Btu/MWh}$
 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 $3.413 \times 10^6 =$ 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.

36.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)]

36.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)]

- 36.e.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.
- 36.e.ii. Failure of an 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.
- 36.e.iii. Notwithstanding condition 36.e.ii, only quality assured data from the CEMS shall be used to identify excess emissions for the purposes of condition 14.b. 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 53.b. [40 CFR 60.4350(d)]
- 36.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.
- 36.g. For purposes of condition 13, the 24-hour rolling average concentration of NO_x in parts per million, corrected to 15% oxygen, and emission rate in lb/hr must be calculated and recorded at the end of each clock hour (at the end of each clock hour, a new 24-hour average is calculated and recorded using the most recent hourly average and the previous twenty-three hourly averages). Emissions during periods of startup and shutdown are excluded from the 24-hour rolling average.
- ~~36.h. For the purposes of condition 14.a, a 4-hour rolling average NO_x concentration is the arithmetic average of the average NO_x concentration measured by the CEMS for a given hour (corrected to 15% O₂ and, if required under 40 CFR 60.335 (b)(1), to ISO standard conditions) and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour. [40 CFR 60.334(j)(1)(iii)(A)]~~
- 36.i. For the purposes of condition 14.b, a 30-day rolling average NO_x emissions is the arithmetic average of all hourly NO_x emissions data in ppm or lb/MWh 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)]
- 36.j. 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)]
- 36.k. 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).
- 36.l. 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)]
- 36.m. 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)]

39. A customized fuel gas monitoring schedule for sulfur, as hydrogen sulfide, as approved by EPA on December 8, 1993, must be conducted as follows: [modified 1995 ACDP Condition 19.b ~~and 40 CFR 60.334(h)(3)~~]
- 39.a. Sulfur fuel gas monitoring must be conducted semi-annually. Sampling must be conducted at the plant site, or as approved by the Department in advance.
- 39.b. Nitrogen monitoring is waived for pipeline quality natural gas, as there is no fuel-bound nitrogen and the free nitrogen does not contribute appreciably to NO_x emissions.
- 39.c. ~~The permittee may elect not to monitor the total sulfur content of the gaseous fuel combusted in combustion turbine 1 (CT1.EU) if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 CFR 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring.~~
- 39.d. The permittee must demonstrate compliance with Condition 14.d by providing a natural gas tariff sheet to the Department that verifies the natural gas burned in ~~the combustion turbines (CT1.EU and CT2.EU)~~ contains a total sulfur content of 20 grains per 100 standard cubic feet, or less, in accordance with 40 CFR 60.4365(a). A copy of the tariff sheet must be maintained on site and be available for Department review upon request.
40. If the natural gas annual capacity factor for the auxiliary boiler (AB.EU) exceeds 10%, the permittee must monitor the NO_x emissions in accordance with 40 CFR 60.48b(i). The permittee must record and maintain records of the amount of natural gas combusted during each day and calculate the annual capacity factor for each calendar quarter. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month. [40 CFR 60.49b(d)] The heat input that corresponds to 10% of the annual capacity factor for the auxiliary boiler (AB.EU) is 2.22x10⁵ million Btu/year.

Plant Site Emissions Monitoring: [OAR 340-222-0080]

41. The permittee must determine compliance with the Plant Site Emission Limits established in Condition 21 of this permit by conducting monitoring and calculations for each 12-month period in accordance with the following procedures, test methods, and frequencies:
- 41.a. The permittee must calculate emissions using the following formula, process parameters, and emission factors:

$$E = P_{eu} \times EF_{eu} \times K$$

Where,

- E = Pollutant emissions in lbs/month and tons/yr.
 P_{eu} = Process parameter identified in the table below;
 EF_{eu} = Emission factor identified for each emissions unit and pollutant in table below;
 K = Conversion constant: 1 lb/lb for daily and monthly emissions calculations; 1 ton/2,000 lbs for annual emissions calculations.

ES Description	Throughput Type [Units]	PM ₁₀	SO ₂	NO _x	CO	VOC	PB
Combustion turbine 1	Natural Gas [MILLION CUBIC FEET]	2.25 2.5	MB	CEMS	CEMS	0.83	
Combustion turbine 1	Distillate Oil [1000 GALLONS]	2.42	MB	CEMS	CEMS	0.21	5.8E-05 7.83E-03
Combustion turbine 2	Natural Gas [MILLION CUBIC FEET]	2.25 2.5	MB	CEMS	CEMS	0.83	
Auxiliary boiler	Natural Gas [MILLION CUBIC FEET]	5.62	0.64	48.4	39.8	4.2	

- 46.a. Monthly and annual amount of natural gas burned in the combustion turbines and auxiliary boiler by unit;
- 46.b. Monthly and annual amount of #2 fuel oil burned in combustion turbine 1 (CT1.EU);
- 46.c. Sulfur content of the #2 fuel oil burned in combustion turbine 1 (CT1.EU) (% by weight);
- 46.d. Sulfur content of the natural gas or records demonstrating that the natural gas meets the definition of natural gas in ~~40 CFR 60.331(u)~~ and 60.4420;
- 46.e. Heating value of the fuels;
- 46.f. Combustion turbine visible emission observation reports, if oil is burned;
- 46.g. Annual pollutant emissions for each 12 consecutive calendar month period;
- 46.h. Occurrence and length of downtime for all pollution control devices;
- 46.i. Excess emissions; and
- 46.j. NSPS records for the combustion turbines and auxiliary boiler in accordance with 40 CFR 60.7(b) and (f), including:
 - 46.j.i. Occurrence and duration of any startup, shutdown, or malfunction in operation;
 - 46.j.ii. Any malfunction of the air pollution control equipment; or
 - 46.j.iii. Any periods during which a continuous monitoring system or monitoring device is inoperative.

REPORTING REQUIREMENTS

The reporting conditions in this section are based on OAR 340-218-0050(3)(c); unless otherwise specified.

General Reporting Requirements

- 47. Excess Emissions Reporting The permittee must report all excess emissions as follows: [OAR 340-214-0300 through 340-214-0360]
 - 47.a. As soon as possible, but not later than 12 hours after the beginning of an excess emissions event, notify the Department of an excess emission event by phone, e-mail, or facsimile; and
 - 47.b. Within 15 days of the excess emissions event, submit a written report that contains the following information: [OAR 340-214-0340(1)]
 - 47.b.i. The date and time of the beginning of the excess emissions event and the duration or best estimate of the time until return to normal operation;
 - 47.b.ii. The date and time the owner or operator notified the Department of the event;
 - 47.b.iii. The equipment involved;
 - 47.b.iv. Whether the event occurred during planned startup, planned shutdown, scheduled maintenance, or as a result of a breakdown, malfunction, or emergency;
 - 47.b.v. Steps taken to mitigate emissions and corrective action taken, including whether the approved procedures for a planned startup, shutdown, or maintenance activity were followed;
 - 47.b.vi. The magnitude and duration of each occurrence of excess emissions during the course of an event and the increase over normal rates or concentrations as determined by continuous monitoring or best estimate (supported by operating data and calculations);
 - 47.b.vii. The final resolution of the cause of the excess emissions; and
 - 47.b.viii. Where applicable, evidence supporting any claim that emissions in excess of technology-based limits were due to any emergency pursuant to OAR 340-214-0360.
 - 47.c. In the event of any excess emissions which are of a nature that could endanger public health and occur during non-business hours, weekends, or holidays, the permittee must immediately notify the Department by calling the Oregon Accident Response System (OARs). The current number is 1-800-452-0311.
 - 47.d. If startups, shutdowns, or scheduled maintenance may result in excess emissions, the permittee must submit startup, shutdown, or scheduled maintenance procedures used to minimize excess

- except during periods of zero and span checks; and
- 53.b.vii. The excess emission reports required by Condition 53.b are only applicable to the following emissions units as follows:
- 53.b.vii.A. combustion turbine 1 (CT1.EU) for conditions 14.a and 14.c;
 - 53.b.vii.B. combustion turbine 2 (CT2.EU) for conditions 14.b and 14.d; and
 - 53.b.vii.C. auxiliary boiler (AB.EU), if a NO_x CEMS is required to be installed in accordance with Condition 40.
- 53.c. A quarterly report that includes the annual capacity factor for the auxiliary boiler (AB.EU) over the previous 12 months for each month in the calendar quarter. [40 CFR 60.49b(q)(1)] The report must be postmarked within 30 days following the last day of the calendar quarter. One copy of the report must be submitted to EPA and one copy to the Eastern Region office of the DEQ.
- 53.d. Notification at least 60 days prior to any physical or operational change which may increase the emission rate of any air pollutant to which a standard applies in accordance with 40 CFR 60.7(a)(4).

NON-APPLICABLE REQUIREMENTS

54. Non-applicable requirements:

- 54.a. The NESHAP for stationary combustion turbines (40 CFR Part 63, subpart YYYYY) is not applicable to this facility because it is not a major source of hazardous air pollutant emissions. Should this source become a major source of HAPs, subpart YYYYY will be applicable. [OAR 340-218-0110]
- ~~54.b. 40 CFR Part 60, subpart KKKK does not apply to combustion turbine 1 (CT1.EU) because the turbine was installed prior to the applicability date in the standard and the unit has not been modified. [40 CFR 60.14]~~
- 40 CFR Part 60, subparts Db and GG do not apply to **the combustion turbines (CT1.EU and CT2.EU)** because the **turbines are** subject to 40 CFR Part 60, subpart KKKK. [40 CFR 60.4305(b)]