DEPARTMENT OF
ECOLOGY
State of Washington

TECHNICAL SUPPORT DOCUMENT FOR PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT

PERMIT NO: PSD-11-05

Puget Sound Energy
Fredonia Power Generating Station

Prepared by

Air Quality Program
Washington State Department of Ecology
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EXECUTIVE SUMMARY

Puget Sound Energy (PSE) proposes to expand the Fredonia Generating Station (FGS) located at 13085 Ball Road near Mt. Vernon, Washington, by adding one or two simple cycle combustion turbines. The proposed project will provide up to approximately 181–207 megawatts (MW) of additional generating capacity to meet future PSE system needs. The new combustion turbines will fire natural gas as the primary fuel with limited backup firing of ultra-low sulfur diesel (ULSD) fuel oil.

The Washington State Department of Ecology (Ecology) received the Prevention of Significant Deterioration (PSD) application for the project on February 23, 2011. Additional information was received on July 7, August 3, October 31, 2011, and February 14, 2012. Ecology determined the application to be complete on November 22, 2011. PSE submitted a final revised PSD modification and Notice of Construction (NOC) permit application (revision 3) dated June 7, 2012, which included all the revisions noted above in one package.

PSE requests approval to construct any one of the following four simple cycle combustion turbine options:

1. One (1) General Electric (GE) 7FA.05 frame turbine or a similar model, rated at approximately 207 MW.
2. One (1) GE 7FA.04 frame turbine or a similar model, rated at approximately 181 MW.
3. One (1) Siemens SGT6-5000F4 frame turbine or a similar model, rated at approximately 197 MW.
4. Two (2) 100 MW GE LMS100 high-efficiency aeroderivative turbines or similar models, with a combined rating of approximately 200 MW.

Ecology is allowing PSE to select the actual unit(s) to be installed after permit issuance. Ecology has included all the options in the permit. Only one option may be chosen and built. Air pollution control will include oxidation catalyst systems for the control of carbon monoxide (CO) and efficient combustion of inherently low polluting fuels (primarily use natural gas with limited firing on ULSD) to control emissions of particulate matter (PM) and sulfuric acid mist (H_2SO_4) .

The project also includes the installation of one (1) 600 kilowatt (kW) diesel-fired emergency standby generator and eight (8) new and two (2) replacement insulated circuit breakers, each of which contain up to 201 pounds (lb) of a sulfur hexafluoride (SF_6) dielectric.

The proposed project emissions for PM, PM less than 10 micrometers (μm) in diameter (PM_{10}), PM less than 2.5 μm in diameter ($PM_{2.5}$), H_2SO_4, and greenhouse gases (GHG) are above the PSD major modification thresholds for all four turbine options. The CO emissions from the Siemens SGT6-5000F4 option (Option 3 above) are also above the PSD major modification threshold. Therefore, a full technical review of the project for these NSR pollutants, including a Best Available Control Technology (BACT) analysis, and the project's effect on National Ambient Air Quality Standards (NAAQS), PSD increments, visibility, soils and vegetation, is required and included in this Technical Support Document (TSD).

The emissions of other air pollutants not subjected to PSD review will be covered in the Northwest Clean Air Agency (NWCAA) NOC approval for this project.

1. INTRODUCTION

1.1. The Permitting Process

1.1.1. The Prevention of Significant Deterioration Process

PSD permitting requirements in Washington State are established in Title 40, Code of Federal Regulations (CFR) § 52.21; Washington Administrative Code (WAC) 173-400-700 through 750; and the agreement for the delegation of the federal PSD regulations by the United States Environmental Protection Agency (EPA) to Ecology, dated November 17, 2011.

Federal and state rules require PSD review of all new or modified air pollution sources that meet certain criteria. The objective of the PSD program is to prevent significant adverse environmental impact from emissions into the atmosphere by a proposed new major source or major modification to an existing major source. The program limits degradation of air quality to that which is not considered "significant." It also sets up a mechanism for evaluating the effect that the proposed emissions might have on visibility, soils, and vegetation. PSD rules also require the utilization of BACT for certain new or modified emission units, which is the most effective air pollution control equipment and procedures that are determined to be available after considering environmental, economic, and energy factors.

The PSD rules must be addressed when a company is adding a new emission unit or modifying an existing emission unit in an attainment or unclassifiable area. PSD rules apply to pollutants for which the area is classified as attainment or unclassifiable with the NAAQS. PSD rules are designed to keep an area with "good" air in compliance with the NAAQS. The distinctive requirements of PSD are BACT, air quality analysis (allowable increments and comparison with the NAAQS), and analysis of impacts of the project on visibility, vegetations, and soils.

1.1.2. The Notice of Construction Process

PSE Fredonia Expansion Project is subject to NOC permitting requirements under state of Washington regulations Chapters 173-400 and 173-460. The NWCAA is the permitting authority for all air emission regulatory requirements not included in PSD permitting. This includes the new source review (NSR) permitting of criteria pollutants that are not PSD-applicable, air toxics issues under federal MACT and state 173-460 WAC, and Title V permitting requirements. The procedure for issuing a NOC permit was established in Chapter 70.94 RCW.

WAC 173-400-110 NSR outlines the procedures for permitting criteria pollutants. These procedures are further refined in WAC 173-400-113 (requirements for new sources located in attainment or unclassifiable areas).

WAC 173-460-040 NSR supplements the requirements contained in Chapter 173-400 WAC by adding additional requirements for sources of toxic air pollutants (TAPs).

1.1.3. Federal Regulations Summary

This permit may not contain all the requirements included in the following summary. However, after the Title V and Acid Rain permits are issued, each of the following regulations will be addressed:

Prevention of Significant Deterioration	40 CFR 52.21
New Source Performance Standards (NSPS): Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	40 CFR 60, Subpart IIII
NSPS: Standards of Performance for Stationary Combustion Turbines	40 CFR 60, Subpart KKKK
NSPS Performance Specifications	40 CFR 60, Appendix B
NSPS Quality Assurance Procedures	40 CFR 60 Appendix F
Acid Rain Program	40 CFR 72
Sulfur Dioxide Allowance System	40 CFR 73
Continuous Emission Monitoring	40 CFR 75
Mandatory Greenhouse Gas Reporting	40 CFR 98

1.1.4. State Regulations Summary

This permit may not contain all the requirements included in the following summary. However, after the NOC, Title V, and Acid Rain permits are issued (by NWCAA), each of the following regulations will be addressed:

General Regulations for Air Pollution Sources	Chapter 173-400 WAC
Operating Permit Regulations	Chapter 173-401 WAC
Acid Rain Regulations	Chapter 173-406 WAC
Carbon Dioxide Mitigation Program	Chapter 173-407 WAC
Controls For New Sources of Toxic Air Pollutants	Chapter 173-460 WAC

1.2. Site and Project Description

1.2.1. Site Description

The FGS facility is located at 13085 Ball Road near Mount Vernon, Skagit County, Washington (see Figure 1). The site is on the south side of Ovenell Road, southwest of the Skagit Regional Bayview Airport, approximately 2.5 miles inland of Padilla Bay. The proposed project is not expected to increase the current footprint acreage of the site, which is approximately 40 acres.

The terrain surrounding the facility is essentially flat. The elevation of the facility is approximately 50 feet above mean sea level (MSL).

The FGS facility is located in a Class II area that is designated as "attainment or unclassifiable" for the purpose of PSD permitting for all pollutants.

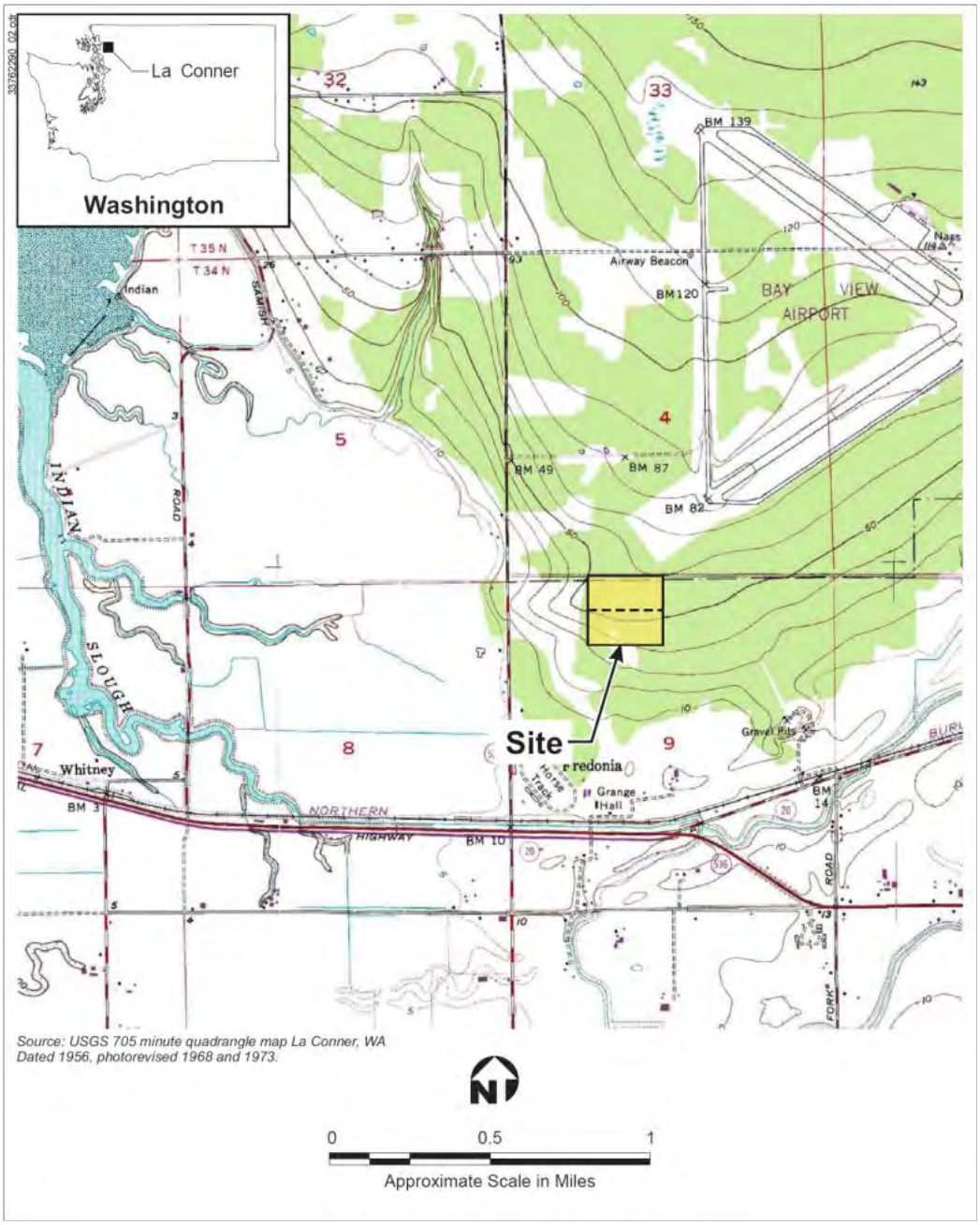

Figure 1. The FGS facility location map

(Source: PSE's PSD application 2nd revision, received July 7, 2011)

1.2.2. Project Description

PSE owns and operates the FGS facility. The existing FGS facility consists of two Westinghouse W501D simple cycle combustion generators, and two Pratt & Whitney Model FT-8 Twin Pac simple cycle combustion turbines. All four turbines are permitted to use either natural gas or distillate fuel. Natural gas is normally used; distillate fuel is infrequently used as a backup fuel. The Westinghouse turbines (Units 1and 2) have a base load rating of 104 MW each, and the Pratt & Whitney turbines (Units 3 and 4) have a base load rating of 54 MW each.

The project will utilize either one (1) or two (2) combustion turbines operating in simple cycle (peaking) mode. PSE proposes to interconnect the new unit(s) to the adjacent FGS substation, which is the nearest connection point to PSE's electrical grid. The purpose of the new generating unit(s) will be to provide additional power generation capacity (totaling approximately 181-207 MW, depending on the unit(s) selected after permit issuance) to help meet future PSE system needs using locally available fuels. No physical change or changes in method of operation will occur to the existing FGS units.

The combustion turbines will fire natural gas as the primary fuel with limited backup firing of ULSD (0.0015% sulfur) No. 2 distillate (ULSD) fuel oil. Natural gas will be delivered to the site by the adjacent transmission pipeline owned by Cascade Natural Gas. ULSD is planned as backup fuel, stored on-site in an existing 100,000-barrel tank. Backup fuel oil will be used to continue serving PSE's electrical load when natural gas supply is curtailed by the pipeline supply company, or is not reasonably available to be received at the facility. Historically this has happened, but it is a rare occurrence.

Overall, the project includes the following emission sources:

- One (1) or two (2) simple cycle combustion turbine generators
- Emergency generator
- Switchyard circuit breakers

1.2.2.1. Simple Cycle Combustion Turbine Options

The proposed project includes installation of one or two of the following high-efficiency simple cycle combustion turbine(s):

- One (1) GE 7FA.05 frame turbine or a similar model, approximately 207 MW.
- One (1) GE 7FA.04 frame turbine or a similar model, approximately 181 MW.
- One (1) Siemens SGT6-5000F4 frame turbine or a similar model, approximately 197 MW.
- Two (2) 100 MW GE LMS100 aeroderivative turbines or similar models, totaling approximately 200 MW.

Any proposed turbine option will have a combination of gas turbine combustion controls, selective catalytic reduction (SCR), and an oxidation catalyst installed to minimize emissions from the project.

PSE Fredonia has proposed to restrict annual fuel usage to reduce potential annual emissions from each unit. All their calculations are based on hours for the purpose of analysis only. The permit conditions are based on equivalent fuel usage, which will be explained in detail in Section 2.2.1.4.

Annual operating hours (excluding start-up and shutdown (SUSD) hours) are assumed to be 2,280 hours per year (hr/yr) for frame turbines (GE 7FA.05, GE 7FA.04 and Siemens SGT6-5000F4) and 2,880 hr/yr for each of the two GE LMS100 aeroderivative turbines. ULSD will only be fired for a maximum of 336 hours per turbine in any consecutive 12 months, subject to the restrictions on annual operating hours.

In order to minimize emissions during SUSD, the number of starts per year per unit will be limited to 144 starts on natural gas and 14 starts on backup distillate for frame turbines (GE7FA.05, GE 7FA.04 and Siemens SGT6-5000F4), and to 240 starts on natural gas and 14 starts on backup distillate for each of the two GE LMS100.

1.2.2.2. Emergency Generator

The project includes one nominal 600 kW diesel standby generator (Caterpillar C18, or equivalent) to supply the new units' critical electrical loads in the event power could not be back fed from either the site's 230 kV or 115 kV transmission systems. The turbine(s) would be supplied with a 125 voltage direct current (VDC) battery bank to supply a critical 120 voltage alternating current (VAC) Essential Power Bus through an inverter or directly from a 125 VDC Essential Power Bus. Examples of devices needing Essential Power from one or both of these sources would be the facility's Distributed Control System (DCS), protective relays and a direct current (DC) driven emergency lube oil pump.

In the event of a transmission system failure and blackout of the facility, the 125 VDC and 120 VAC Essential Power Buses could be kept energized for a period of time from the 125 VDC battery bank. However, the turbine units have the potential to expend the battery's power quickly since they have large, heavy components, such as rotor bearings, that require lubrication during turbine spin down (and while at rest to prevent seizing). The lubrication oil flow is provided by large electrically driven lubricating pumps. To prevent damage to these components during a transmission system failure, an emergency generator is needed to provide power to back up the batteries.

Manufacturer required reliability testing and maintenance operations for the emergency generator are expected to occur one hour per week, or 52 hours per year. It is estimated that emergency use will not exceed 223 hours, for a total of up to 275 hours of emergency generator operation annually.

1.2.2.3. Switchyard

The project's proposed new 230 kV switchyard will include eight new circuit breakers filled with sulfur hexafluoride (SF_6), a gaseous dielectric fluid commonly used in power system circuit breakers. In addition to these eight breakers accommodating the new equipment, there will be two other new breakers installed to replace some existing units. A small amount of the GHG pollutant SF_6 is emitted from switchyard breakers as a result of unavoidable leakage. Therefore, these 10 breakers are included in emission calculations due to their predicted GHG emissions. Although specific models have not been identified, PSE expects that Mitsubishi 200-SFMT-40E or 200-SFMT-63F breakers (or similar) will be used.

2. PSD APPLICABILITY REVIEW

2.1. Overview and Permitting History

The existing facility is a major PSD stationary source per 40 CFR § 52.21(b)(1)(i), and operates under Permit No. PSD-01-04, issued on July 18, 2003, by Ecology and Permit No. X82-09, issued on August 23, 1982, and amended on October 24, 1995, by EPA Region 10. Under WAC 173-400-720 through 750, a project proposed at an existing major stationary source is subject to PSD review if the project either is a "major modification" to an existing "major stationary source," or is a major stationary source unto itself.

Unless otherwise exempted by applicable regulation, a change to an existing major stationary source is a major modification if the change results in both a significant emissions increase and a significant net emissions increase at the source. "Significant emissions increase" means that the emissions increase for any regulated PSD pollutant is greater than the PSD Significant Emission Rate (SER) threshold for that regulated pollutant.

The proposed FGS Expansion Project will require a PSD permit if both the project's emissions increase and the net contemporaneous emissions increase caused by the project exceed any PSD SERs of any NSR pollutant, including GHGs. The proposed simple cycle generating units to be located at the Fredonia site are new units. In accordance with the requirements of 40 CFR 52.21(a)(2), these emission increases associated with the new units is based on their potential to emit (PTE). Also, as addressed in the regulation, their baseline actual emissions are zero.

2.2. Emissions Calculation

The maximum capacity was examined by PSE for each of the emission units based on worst-case operating scenarios and emission calculations details are presented below, by following three air emission source types:

- Simple cycle combustion turbine generator(s), for which four equipment options are being considered by PSE:

  - One (1) GE 7FA.05 frame turbine or a similar model.
  - One (1) GE 7FA.04 frame turbine or a similar model.
  - One (1) Siemens SGT6-5000F4 frame turbine or a similar model.
  - Two (2) GE LMS100 aeroderivative turbines or a similar model.
- A 600 kW emergency generator (Caterpillar with Model C18 ATAAC Tier 2 engine (approximately 890 brake horsepower (bhp)), or similar make and model).
- Substation breakers containing SF_6.

2.2.1. Simple Cycle Combustion Turbine Generator(s)

2.2.1.1. Standard Peaking Mode Emissions

The combustion turbine manufacturers provided emission rate data for all criteria pollutants (except lead, whose emission factor is from EPA's "Compilation of Air Pollutant Emission Factors," commonly referred to as AP-42) during normal operation for three different ambient temperatures (7°F, 51°F, and 88°F). These temperatures are representative of the range of expected conditions at the PSE Fredonia facility.

As a peaking facility, the combustion turbines to be installed at this project are capable of extended operation at a broad load range as follows:

a. GE 7FA.05 option: 50 to 100 percent load when fired on either natural gas or ULSD.
b. GE 7FA.04 option: 50 to 100 percent load when fired on either natural gas or ULSD.
c. Siemens SGT6-5000F4 option: 60 to 100 percent load when fired on natural gas and 70 to 100 percent load when fired on ULSD.
d. GE LMS100 option: 30 to 100 percent load when fired on natural gas and 75 to 100 percent load when fired on ULSD.

"Normal operation" has been defined as all operating modes within the above load ranges, for which the permit limits can be achieved using gas turbine combustion controls, SCR, and an oxidation catalyst. Under normal operating conditions, all four of the potential combustion turbines will emit between 2.5 and 5 parts per million (ppm) nitrogen oxides (NO_X) and between 4 and 12 ppm CO (after the BACT determination, PSE accepted Ecology's request to lower CO concentration to 8 ppm from 12 ppm. Section 3.4 discusses the CO BACT analysis), depending on the turbine and fuel used.

Potential annual emissions for the new unit(s) are based on worst-case operating scenarios estimated by PSE from forecast load requirements; an ambient temperature, pressure, and

relative humidity of 51°F, 14.68 psia and 75%, respectively; a maximum annual average natural gas sulfur content of 2.25 gr/100 scf;[1] and a maximum ULSD sulfur content of 15 ppmw. On a pollutant-by-pollutant basis, worst-case maximum operation on other loads other than 100% is included in the annual emission estimates *only if* pollutant emissions (on a lb/hr basis) under mixed loads are higher than emissions under full load. In addition, the worst-case maximum of 336 hr/yr (consecutive or nonconsecutive) firing on backup ULSD is included in the annual emission estimates *only if* pollutant emissions (on a lb/hr basis) on ULSD are higher than emissions on natural gas. Table 1 shows emission rates due to normal operation of the combustion turbines.

The potential emissions from each turbine must also incorporate any emissions during SUSD operation. Section 2.2.1.2 discusses SUSD emissions, and Section 2.2.1.3 provides a summary of estimated potential pollutant emissions from the combustion turbine taking into account standard peaking and SUSD operation.

[1] For the pipeline sulfur content, seven years of daily total sulfur measurements (June 1, 2002 through March 8, 2010) for the Northwest Pipeline compressor station at Sumas, WA, were analyzed. The maximum 365-day rolling average was 1.10 gr/100 dscf (June 2009). Because an upward trend was observed in data for 2009 and preceding years, PSE assumed a worst-case future concentration of 2.00 gr/100 dscf for the Williams Northwest Pipeline to achieve a margin of safety for the Project's emission compliance. On top of that, 0.25 gr/100 dscf was added to account for worst-case odorant addition by local natural gas utility, Cascade Natural Gas, for a total of 2.25 gr/100 dscf for annual emission calculations.

Table 1. Estimated Maximum Emissions From Turbine(s), Excluding SUSD

Pollutant	Fuel	GE 7FA.05		GE 7FA.04		Siemens SGT6-5000F4		GE LMS100	
		lb/hr	tpy[3]	lb/hr	tpy[3]	lb/hr	tpy[3]	lb/hr	tpy[3]
NO_X	NG	19.40	26.27	16.80	22.88	19.70	25.67	16.20	27.20
	ULSD	44.10		39.00		38.80		33.80	
CO	NG	18.60	25.19	15.60	21.08	8.44	15.80[4]	12.40	18.43
	ULSD	42.30		35.20		45.20[4]		10.00	
VOC	NG	3.70	5.16	2.90	4.08	2.70	3.72	4.60	8.12
	ULSD	9.30		7.50		6.50		13.20	
$PM/PM_{10}/PM_{2.5}$	NG	36.00	41.46	36.80	42.22	26.70	31.68	27.20	43.84
	ULSD	38.50		38.40		34.10		53.40	
SO_2	NG	4.99	5.69	4.37	4.98	4.47	5.10	4.22	6.09
	ULSD	1.26		1.12		0.98		1.00	
H_2SO_4	NG	13.34	15.21	11.66	13.29	13.92	15.87	11.30	16.28
	ULSD	3.36		3.01		3.04		2.56	
Pb	NG	0	0.0053	0	0.0047	0	0.0045	0	0.0042
	ULSD	0.03		0.03		0.03		0.02	
CO_2	NG	246,140	301,048	215,297	264,485	243,583	289,816	208,389	313,752
	ULSD	367,860		328,669		315,797		284,399	
CH_4 as CO_2e[1]	3.43E-04 lb/MMBtu	2,124 MMBtu/hr	1	1,858 MMBtu/hr	1	2,102 MMBtu/hr	1	899 MMBtu/hr	1
N_2O as CO_2e[1]	8.12E-01 lb/MMBtu		1,966		1,720		1,946		2,103
GHG (as CO_2e)[2]	---	---	303,015	---	266,206	---	291,763	---	315,855

[1] The emission factors for CH_4 and N_2O are based on a review of PSE's reports to the NWCAA, Southwest Clean Air Agency (SWCAA), and Ecology regarding compliance with Chapter 173-407 WAC, "Carbon dioxide mitigation program for fossil-fueled thermal electric generating facilities," and related source test results. Values are for natural gas use only; EPA's AP-42 emission factors for these pollutants show non-detects for distillate use. Therefore, maximum potential emissions are based on natural gas use only. The values include the conversion to CO_2e using the individual Global Warming Potential (GWP) factors for each pollutant. GHG as CO_2e = emission factor (lb/MMBtu) × Fuel Use (MMBtu/hr) × Annual Maximum Operating Hours (hr)

[2] GHGs (as CO_2e) = CO_2 + N_2O as CO_2e + CH_4 as CO_2e

[3] PTE calculations: (a) If emission rates firing with ULS (ER ULSD) > emission rates firing with natural gas (ER NG):
PTE = ER NG x (Annual Max Op. Hr-Max Op. Hr on ULSD) + ER ULSD x Max Op. Hr on ULSD
(b) If ER ULSD < ER NG: PTE = ER NG x Annual Max Op. Hr

[4] A new CO mass rate under the 8 ppm BACT CO limit (Section 3.4) is equal to 30.1 lb/hr and corresponding annual CO emission is equal to 13.27 tpy.

2.2.1.2. SUSD Emissions

A simple cycle combustion turbine does not have a steam cycle like a combined cycle turbine, and, therefore does not have cool or cold water and boiler tubing to heat as part of the start-up sequence. Accordingly, start-up duration and quantity of emissions during start-up are unrelated to when the last shutdown occurred. The duration of SUSD for a combustion turbine in a simple cycle mode is relatively short, mostly related to bringing the turbine rotors up to speed, lighting the turbine burners, bringing the SCR and oxidation catalysts up to their minimum operating temperatures, and synchronizing the electric generator to the grid. As such, only one start-up duration is defined for each proposed turbine option for this project. Data was provided by each of the turbine vendors to quantify emissions during a start-up/shutdown event and its duration.

Since emissions from combustion turbines can be significantly higher during SUSD than during normal operation, they can represent a relatively substantial portion of the proposed project's total PTE and hence need to be accounted. During start-up, the turbines cannot initially operate in lean pre-mix mode, which results in higher emissions of some pollutants. A similar transition from lean pre-mix combustion to standard combustion occurs during shutdown, though the time involved is considerably shorter. In addition, the SCR catalyst is not effective until it reaches a minimum temperature of about 500°F. Even though an oxidation catalyst actually begins to reduce emission of CO as soon as the equipment is started, its rate of destruction is highly related with operating temperature. To account for this potential increase in emissions, a worst-case maximum number of SUSD on both natural gas and ULSD are included in the annual emission estimates for all pollutants.

Table 2 summarizes SUSD emissions and duration for each turbine. Potential lead (Pb) emissions during SUSD are not included in this table because they are less than 0.001 tons per year (tpy) for all options. Potential emissions of CH_4 and N_2O (GHG) during SUSD are also not included in Table 2 because emissions of those pollutants during SUSD are extremely low compared to standard operation. However, this contribution to the overall CO_2e is included in Table 3.

The number of start-ups and associated shutdowns per year per unit is limited to 144 of natural gas and 14 of backup distillate for frame turbines (GE 7FA.05, GE 7FA.04, and Siemens SGT6-5000F4), and to 240 of natural gas and 14 of backup distillate for each of the two GE LMS100 turbines.

Table 2. Baseline Actual Emissions (TPY)										
Options	SU/SD	Fuel	Duration (min)	Pollutant Emitted (lb/event/unit)						
				NO_X	CO	VOC	PM/ PM_{10}/ $PM_{2.5}$	CO_2	SO_2	H_2SO_4
GE 7FA.05	SU	Gas	30	31.5	209.6	5.9	9.2	69,717	10.4	5.8
		Oil	30	145.7	332.1	8.6	17	109,132	1.1	1.0
	SD	Gas	19	16	189	4.3	5.8	30,885	4.6	2.6
		Oil	17	79	196	6	9.6	44,157	0.4	0.4
	Annual Emission (tpy)			***5.0***	***32.4***	***0.8***	***1.3***	***8,316***	***1.1***	***0.6***
GE 7FA.04	SU	Gas	30	43.1	106.4	6.5	6	70,823	10.1	8.0
		Oil	30	168.1	140.1	5	17.4	108,102	1.1	1.0
	SD	Gas	14	31	90	4.8	4.4	28,819	4.2	3.2
		Oil	14	107	95	2	8.4	44,110	0.4	0.4
	Annual Emission (tpy)			***7.3***	***15.8***	***0.9***	***0.9***	***8,240***	***1.0***	***0.8***
Siemens SGT6-5000F4	SU	Gas	35	92.4	1,347	154.2	4.8	81,663	11.0	7.2
		Oil	38	146.2	1,462	162.2	15.6	99,757	1.0	1.0
	SD	Gas	17	45	443	50	2.4	41,460	5.4	3.6
		Oil	19	90	709	76	10	61,518	0.7	0.6
	Annual Emission (tpy)			***11.5***	***144.1***	***16.4***	***0.7***	***9,994***	***1.2***	***0.8***
GE LMS100 (2 units)	SU	Gas	30	34.5	49	1.0	3.3	43,546	6.5	3.7
		Oil	30	59.9	39.6	3.7	14.3	58,849	0.6	0.5
	SD	Gas	8	3.4	1.8	0.03	1.0	4,621	0.7	0.4
		Oil	8	5.7	1.7	0.06	4.7	5,555	0.05	0.05
	Annual Emission (tpy)[a]			***10***	***12.8***	***0.3***	***1.3***	***12,462***	***1.7***	***1.7***

[a] Annual SUSD emission estimate includes emissions from two (2) GE LMS100 turbines.

2.2.1.3. Overall PTE of the New Combustion Turbines

Table 3 summarizes the annual PTE from all four turbine options for each pollutant, including SUSD emissions.

Table 3. Estimated Maximum Annual Emissions From Turbine(s), Including SUSD				
Pollutant (tpy)	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100
NO_X	31.3	30.1	37.2	36.3
CO	57.6	36.9	159.9[a]	30.6
VOC	6.0	4.9	20.1	8.4
$PM/PM_{10}/PM_{2.5}$	42.7	43.1	32.4	44.9
CO_2	309,364	272,725	299,810	325,312
GHGs (as CO_2e)	311,382	274,496	301,819	327,577
SO_2	6.8	6.0	6.3	7.8
H_2SO_4	15.8	14.1	16.7	17.3
Pb	0.0054	0.0048	0.0046	0.0042

[a] Under the 8 ppm BACT CO limit (Section 3.4), new annual CO emissions for the Siemens turbine option are equal to 157.4 tpy assuming there are no emission reductions during SUSD when firing distillate.

2.2.1.4. Maximum Fuel Uses

All emission calculations for any turbine option are based on hours of operation (standard peaking mode operations, start-ups, and shutdowns) for the purpose of analysis only. PSE and Ecology find it desirable to limit the fuel usage instead of the hours of operation because it offers flexibility a peaking facility needs. Annual fuel uses are estimated and summarized in Table 4.

Potential maximum annual fuel uses for the new unit(s) during standard peaking mode are based on full load equivalent turbine hours at an ambient temperature, pressure and relative humidity of 51°F, 14.68 psia and 75%, respectively; a maximum annual average natural gas sulfur content of 2.25 gr/100 scf;[2] and a maximum ULSD sulfur content of 15 ppmw. Potential maximum annual fuel uses for the new unit(s) during SUSD are based on fuel uses per SUSD event, and the number of SUSDs per year per fuel type allowed.

Table 4. Estimated Maximum Annual Fuel Uses From Turbine(s), Including SUSD

Options	Full load Hourly Fuel Use During Standard Peaking Mode (MMBtu/hr)		SUSD Fuel Use (MMBtu/SUSD)		Maximum Annual Fuel Use (MMBtu/yr)	
	Gas	Oil	Gas	Oil	Gas & Oil	Oil[b]
GE 7FA.05	2124	2252	864	938		
Annual (MMBtu/yr)		4,886,181[a]	124,348	13,136	**5,023,664**	**769,664**
GE 7FA.04	1858	2012	856	932		
Annual (MMBtu/yr)		4,288,120[a]	123,195	13,043	**4,424,358**	**688,973**
Siemens SGT6-5000F4	2102	1933	1057	987		
Annual (MMBtu/yr)		4,793,111[a]	152,277	13,820	**4,959,209**	**663,277**
GE LMS100 (per unit)	899	870	415	394		
Annual (MMBtu/yr)[c]		5,179,684[a]	199,258	11,038	**5,389,979**	**595,924**

[a] Annual Fuel Use During Standard Peaking Mode (AF_SPM):
i. If full load hourly fuel use firing with ULSD (FF_ULSD)>full load hourly fuel use with natural gas (FF_NG).
ii. If FF_ULSD ≤ FF_NG: AF_SPM = FF_NG x Annual Max Op. Hr

[b] Maximum Annual Fuel Use for oil: FF_ULSD x Max Op. Hr on ULSD + total SUSD fuel use on ULSD

[c] Two units combined. In addition, according to Chapter 80.80.010 RCW and WAC 173-407-130, natural gas and ULSD shall only be fired for a maximum of 4,726,461 MMBtu per unit per year, subject to the annual fuel use restriction. This estimation is based on one unit operated at full load condition for 60% of a full year.

[2] For the pipeline sulfur content, seven years of daily total sulfur measurements (June 1, 2002 through March 8, 2010) for the Northwest Pipeline compressor station at Sumas, WA, were analyzed. The maximum 365-day rolling average was 1.10 gr/100 dscf (June 2009). Because an upward trend was observed in data for 2009 and preceding years, PSE assumed a worst-case future concentration of 2.00 gr/100 dscf for the Williams Northwest Pipeline to achieve a margin of safety for the Project's emission compliance. On top of that, 0.25 gr/100 dscf was added to account for worst-case odorant addition by local natural gas utility, Cascade Natural Gas, for a total of 2.25 gr/100 dscf for annual emission calculations.

2.2.2. Emergency Generator

Potential emissions were estimated based on maximum hours of testing/maintenance and emergency use and emission factors either from EPA's "Compilation of Air Pollutant Emission Factors," commonly referred to as AP-42, or California Air Resources Board (CARB)'s Tier 2 Certified Diesel Generator Sheet.

Overall, testing and maintenance operations for the emergency generator are expected to occur one hour per week, or 52 hours per year. It is estimated that emergency use will not exceed 223 hours per year, for a total of up to 275 hours of emergency generator operation annually. Table 5 shows the maximum annual emissions for the emergency generator. Potential H_2SO_4 emissions from the emergency generator are not included in this table because they are very little (even if assuming 10% of SO_2 emissions are converted to SO_3, the annual H_2SO_4 emissions are far less than 0.001 tpy in this case).

Table 5. Estimated Annual Emissions from the Emergency Generator

Pollutant	Emission Factor		Annual Emission
	g/hp-hr	lb/hp-hr	tpy
NO_x[1]	4.32		1.05
CO[1]	0.6		0.15
VOC[1]	0.01		0.0024
$PM/PM_{10}/PM_{2.5}$[1]	0.06		0.015
CO_2[2]		1.16	128.28
CH_4[2]		6.35E-05	0.15 as CO_2e[3]
SO_2[2]		1.21E-05	0.0013

[1] NO_X, CO, VOC (HC), and PM emission factors from CARB Tier 2 Certified Diesel Generator sheet (Executive Order U-R-001-0380-1, New Off-Road Compression-Ignition Engines (August 30, 2010).
[2] CO_2, CH_4, and SO_2 emission factors from AP-42, Table 3.4.1.
[3] CH_4 GWP of 21 from 40 CFR 98, subpart A, Table A-1.

2.2.3. Substation Circuit Breakers Containing SF_6

A small amount of the GHG pollutant SF_6 is emitted from switchyard breakers as a result of unavoidable leakage. There are no other air pollutants emitted from the substation. The rate of leakage is conservatively assumed to be 0.5% per year based on a review of losses from PSE's existing SF_6 circuit breakers. The quantity of SF_6 in each circuit breaker is based on equipment specifications. Because specific breakers have not yet been chosen for this project, the equipment option with the highest volume of SF_6 has been assumed for the emission calculations.

The breaker emissions are used in the GHG analyses, applying the 100-year SF_6 GWP of 23,900 to convert SF_6 emissions to carbon dioxide equivalents (CO_2e). Table 6 shows annual CO_2e emissions from proposed substation breakers.

Table 6. Estimated Annual Emissions From Substation Breakers

# of Breakers	SF_6 Amount (lb/breaker)	Leak Rate	SF_6 Leakage Amount (lb/yr)	SF_6 GWP	Annual CO_2e Emissions (tpy)
10	201	0.5%	10.05	23900	120.10

2.2.4. Toxic Emissions

The PSE Fredonia Project will emit federally listed noncriteria pollutants and hazardous air pollutants (HAPs) primarily as a result of incomplete combustion. The non-criteria pollutants include both federal HAPs as defined by EPA in Title III of the 1990 Clean Air Act Amendments and PSD regulated non-criteria pollutants. Emission rates have not been estimated for several PSD regulated pollutants, including asbestos, fluorides, vinyl chloride, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, and radionuclides, because none of these PSD pollutants are expected to be emitted from the project.

PSE Fredonia estimated individual HAP annual maximum emission from the project (including the emergency generator) and found the total potential HAP emissions are 4.5 tpy for the GE 7FA.05 turbine; 3.9 tpy for the GE 7FA.04 turbine; 4.3 tpy for the Siemens SGT6 turbine; and 4.5 tpy for GE LMS100 turbines, which are all well below the major HAP threshold of 25 tpy of total HAPs (or individual major HAP threshold of 10 tpy). Therefore, the project will be a minor source of HAP emissions.

PSE Fredonia also estimated individual TAP (according to the WAC 173-460-150) maximum emission rate (for the respective averaging period) from the proposed project and compared each to Washington State's small quantity emission rates (SQERs) and acceptable source impact levels (ASILs). Their impacts are evaluated as part of the ambient air quality analysis of the application.

Toxic emissions are not regulated by the PSD program and will be regulated by NWCAA in the NOC permit they issue.

2.3. Overall Project Emissions Increase

The overall project emissions increase on a pollutant-to-pollutant basis is the sum of each pollutant PTE from each individual emission unit, as summarized in Table 7.

Table 7. Summary of PTE (TPY) and Comparison to PSD SER

Pollutant	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100	SER	PSD Review Required?
NO_X	32	31	38	37	40	NO
CO	58	37	**160**[a]	31	100	YES for SGT6
VOC	6	5	20	8	40	NO
PM	**43**	**43**	**32**	**45**	25	YES for all
PM_{10}	**43**	**43**	**32**	**45**	15	YES for all
$PM_{2.5}$	**43**	**43**	**32**	**45**	10	YES for all
CO_2e	**311,631**	**274,744**	**302,067**	**327,826**	75,000	YES for all
SO_2	7	6	6	8	40	NO
H_2SO_4	**16**	**14**	**17**	**17**	7	YES for all
Pb	0.020	0.019	0.019	0.019	0.6	NO

[a] Under the 8 ppm BACT CO limit (section 3.4), new annual CO emissions are rounded to 157 tpy assuming there are no emission reductions during SUSD when firing distillate.

As shown in the emission summary above, potential emissions from the expansion project will exceed the PSD SERs for all turbine options for PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG. Potential emissions are also expected to exceed the SER for CO for the Siemens SGT6-5000F4 option. These pollutants are subject to full PSD review, consisting of the following:

- Determination of BACT
- Air quality impact analysis
- Evaluation of source-related impacts on growth, soils, vegetation, and visibility
- Evaluation of Class I area impacts

2.4. New Source Performance Standard (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP)

2.4.1. NSPS

NSPS have been established by EPA to limit air pollutant emissions from certain categories of new and modified stationary sources. Stationary gas turbines are regulated under 40 CFR Part 60, Subpart KKKK. The enforcement of this NSPS has been delegated to Ecology, has been adopted by reference in WAC 173-400-115.

In general, local emission limitation rules or BACT requirements are far more restrictive than the NSPS requirements. For example, although this project is not subject to PSD review for NO_X, the anticipated controlled NO_X emission rate from any of the project's natural gas-fired turbine options is less than 0.13 lb of NO_X per MW-hr, which will be well below the Subpart KKKK requirement of 0.39 lb of NO_X per MW-hr.

Similarly, the projected maximum SO_2 emissions from any of the gas turbine options will be about 0.05 lb of SO_2 per MW-hr, which is substantially less than the Subpart KKKK requirement of 0.58 lb of SO_2 per MW-hr. NSPS fuel requirements for SO_2 will be satisfied by the use of natural gas as the primary fuel for the gas turbine generator(s), and emissions and fuel monitoring will be performed to demonstrate compliance with the requirements of BACT, NSPS, acid rain, and other regulatory requirements.

The use of ULSD as backup fuel also meets these requirements. There are no NSPS requirements for other air pollutants in Subpart KKKK.

40 CFR Part 60, Subpart IIII applies to the proposed emergency generator. Engine manufacturers are required to certify engines to prescribed NO_X, PM, CO, and VOC emission standards, and operators are required to follow manufacturer's operation and maintenance instructions. Subpart IIII also limits emergency engines to 100 hr/yr of nonemergency operation (i.e., maintenance and testing). The proposed engine for the project will be a certified unit, and the PSD application has been prepared with the assumption of a maximum of 52 hr/yr of nonemergency use.

2.4.2. NESHAP

The EPA has issued a Maximum Achievable Control Technology (MACT) standard for gas-fired combustion turbines that are major HAP sources or are located at a major HAP source. However, on August 18, 2004, the EPA stayed the effective date of the MACT standard for lean pre-mix and diffusion flame gas-fired turbines until such time that these two subcategories could be deleted from the MACT standard. Since the proposed project on its own is a minor HAP source and any of the turbines allowed to be used are lean pre-mix turbines, there are currently no MACT standards applicable to the project.

3. BACT

3.1. Definitions and Policy Concerning BACT

All new major sources or major modifications are required to utilize BACT for those new and modified emission units that will experience an increase in emissions as a result of the project. BACT is defined as an emissions limitation based on the maximum degree of reduction for each pollutant subject to regulation, emitted from any proposed major stationary source or major modification, on a case-by-case basis, taking into account cost-effectiveness, economic, energy, environmental, and other impacts (40 CFR § 52.21(b)(12)).

Federal guidance requires each PSD permit applicant to implement a "top-down" BACT analysis process for each new or physically or operationally changed emissions unit. Ecology has

adopted the top-down BACT process for its BACT determinations. This top-down BACT analysis process consists of five basic steps described below:[3]

Step 1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

Step 2. Eliminate all technically infeasible control technologies;

Step 3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;

Step 4. Evaluate most effective controls and document results; and

Step 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

If the applicant proposes to implement the most effective or "top" available control strategy, step 4 is not necessary.

As shown above, the "top-down" BACT process starts by considering all available emission control technologies, and ranks them for further evaluation from most effective to least effective technically available control technology. The most effective emission reduction technology is then evaluated for economic feasibility. If the technology is proven infeasible based on economics, energy or other environmental considerations, then the next most stringent level of reduction is considered. The most stringent level of emissions control that is not determined to be technically and economically infeasible is selected as BACT. While the permitting agency makes the final BACT decision, the burden is on the applicant to prove why the most stringent level of control should not be used.

In the case of the PSE Fredonia Expansion Project, PSD BACT is triggered for:

- $PM/PM_{10}/PM_{2.5}$ for each of the four proposed gas turbine options.
- H_2SO_4 mist for each of the four proposed gas turbine options.
- CO for the Siemens turbine option only.
- GHG for each of the four proposed gas turbine options.

PSE Fredonia's BACT analysis focuses on recent relevant BACT determinations to identify the top current control levels achieved in practice. Three data sources were reviewed by PSE to identify relevant BACT determinations for simple cycle gas turbines in the past five years (2006–July 2011):

[3] See EPA's *Draft New Source Review Workshop Manual*, 1990; and PSD and Title V Permitting Guidance for Greenhouse Gases <http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf>.

- EPA's RACT/BACT/LAER Clearinghouse (RBLC)
- California Air Resources Board BACT Clearinghouse
- Information from California Energy Commission power plant sitting cases, including local air quality management district findings

Because BACT determinations generally become increasingly stringent as emission control technology and operating experience improve over time, only projects that were approved since January 2006 were included in this analysis.

In addition to reviewing the permit application and supporting documentation, Ecology performed independent review of the above data sources and other web resources, for the period January 1, 2006, through December 1, 2011. As necessary, Ecology contacted various permit agencies to obtain more information on issued and proposed permits.

3.2. BACT for PM, PM_{10}, and $PM_{2.5}$ Turbines

The objective of this analysis was to determine BACT for PM, PM_{10} and $PM_{2.5}$ emissions from any of four combustion turbine options. The simple cycle turbines will be dual fueled by natural gas and ULSD with total annual operation based on the maximum amount of fuel uses and types, summarized in Table 4.

PM emissions from combustion turbines are a combination of filterable and condensable particulate. Filterable PM is primarily formed from impurities contained in the fuels and incomplete combustion. Condensable particulate emissions are attributable primarily to the formation of secondary particulate from condensation of volatilized solid materials, unburned hydrocarbon, and the conversion of sulfates and nitrates in the exhaust stream after it has been vented from the stack into the atmosphere.

PM, PM_{10} and $PM_{2.5}$ are analyzed together because virtually all of the PM emitted from the turbines will be 2.5 micrometers (formerly called microns) or smaller, and referred to collectively as PM in this analysis.

3.2.1. Control Technology Review

The applicant submitted a full top-down BACT analysis for PM/PM_{10}/$PM_{2.5}$. In brief, available control technology options for PM emissions from the turbine are as follows:

Good combustion practices

Good combustion will ensure proper air/fuel mixing to achieve complete combustion, thus minimizing emissions of unburned hydrocarbons that can lead to formation of PM at the stack.

Clean-burning fuels

The use of clean-burning fuels that have low ash and sulfur content, such as natural gas, will result in minimal formation of PM during combustion.

Dry-low NO_X combustor

The use of a dry-low NO_X (DLN) combustor provides efficient combustion to ensure complete combustion thereby minimizing the emissions of unburned fuel that can form condensable PM. DLN combustors are in wide use on utility scale natural gas fired turbines.

Electrostatic precipitators

Electrostatic precipitators are used on solid fuel boilers and incinerators to remove PM from the exhaust. Electrostatic precipitators use a high-voltage direct-current corona to electrically charge particles in the gas stream. The suspended particles are attracted to collecting electrodes and deposited on collection plates. Particles are collected and disposed of by mechanically rapping the electrodes and plates and dislodging the particles into collection hoppers.

Baghouses

Baghouses are used to collect PM by drawing the exhaust gases through a fabric filter. Particulates collect on the outside of filter bags that are periodically shaken to release the particulates into hoppers.

Among all above control technologies, using natural gas exclusively as the fuel for the PSE Fredonia Project is not technically feasible because the nature of this project as a peaking facility. Dual-fuel simple cycle turbines represent the optimal method of generating power to meet peak demand. The use of ULSD as a backup fuel provides reliability during periods when there is high demand for natural gas, and usage of natural gas is curtailed at the Fredonia facility by the retail gas utility, or by the interstate pipeline owner. PSE Fredonia proposes to use natural gas whenever it is reasonably available, and ULSD will be used during what are expected to be very infrequent periods when natural gas is not reasonably available at the facility.

With respect to the add-on controls discussed above (i.e., electrostatic precipitators and baghouses), the EPA has indicated that PM control devices are not typically installed on combustion turbines and that the cost of installing such control devices is prohibitive.[4] When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the revised Subpart GG NSPS (2004) or Subpart KKKK (2006) did not impose a particulate emission standard. No example of add-on type particulate control for natural gas fueled

[4] "Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production," California Air Resources Board, <http://www.arb.ca.gov/energy/powerpl/appcfin.pdf>.

combustion turbines or similar natural gas combustion sources could be found in the EPA's RBLC, or from suppliers of control equipment.

The small particulate size and low particulate emission level, along with the lack of any example of add-on particulate controls, and lack of vendor performance guarantees led PSE Fredonia to propose that the primary use of natural gas with limited firing of ULSD and good combustion practices are BACT for all particulates emitted from the simple cycle combustion turbine.

3.2.2. Determination of Applicable PM BACT Emission Limitation

Using proposed above technologies, the emission rates are largely determined by the amount of fuel burned and the amount of sulfur in the fuel. In this portion of western Washington, our natural gas is from Canada. Long-term monitoring records of the total sulfur content of the gas imported from Canada shows this gas generally has higher sulfur content compared with the rest of country, and especially the gas sent to Washington and Oregon from Wyoming. PSE Fredonia analyzed seven years of daily total sulfur measurements (June 1, 2002 through March 8, 2010) for the Northwest Pipeline compressor station at Sumas, WA. The maximum 365-day rolling average was 1.10 grains of sulfur/100 standard cubic feet (gr/100 scf) of natural gas (June 2009) and the highest 99th percentile daily sulfur concentration measured at Sumas during the 7-year period is 3.23 gr/100 scf, plus an additional 0.25 gr/100 scf allowance for worst-case odorant addition by Cascade Natural Gas. In addition, an upward trend was observed in data for 2009 and proceeding years. While in California, the pipeline natural gas typically contains much less than one gr/100 dscf sulfur. For example, both the Marsh Landing and Panoche Energy Center permits limit natural gas sulfur to one gr/100 dscf in California.

As a result, unlike other pollutants' emission limits, it is impractical to compare the proposed PM emission limits with PM emission limits and performance data from simple cycle combustion turbines in other regions. Instead, the past BACT PM limits for other simple cycle turbines issued in Washington State are compared and listed in Table 8 to evaluate if the proposed PM emission limit satisfies the BACT requirement. Please note that the smaller size turbines will have lower mass emission rates in terms of pounds per hour. As a result, in order to provide a meaningful comparison with the proposed project, all emission limits are converted to lb/MMBtu input based on their approximate sizes. Another important factor to consider when comparing permit limits from different simple cycle combustion turbines is if the emission rates take into account the PM emissions associated with the add-on controls (SCR and oxidation catalysts). Please note that PM emission rates estimated in PSE Fredonia Expansion Project include contributions from sulfur and ammonia reactions in the catalysts.

Table 8. BACT PM Permitted Limits for Simple Cycle Gas Turbine in Washington State			
Facility, Turbines, and Add-On Controls	**PM (lb/hr)**	**Size (MMBtu/hr)**	**PM (lb/MMBtu)**
PSE Fredonia (PSD-X82-09), Units 1 & 2, Simple Cycle, Westinghouse W501D, 104 MW each	104 combined	Gas: 1119 Distillate: 1120	Gas: 0.046 Distillate: 0.046
PSE Fredonia (PSD-01-04), Units 3 & 4, Simple Cycle, Pratt & Whitney FT-8 Twin Pac, 54 MW each, SCR & Oxidation Catalyst	31	Gas: 516 Distillate: 507	Gas: 0.060 Distillate: 0.061

From Tables 8 and 9, it is clear that the proposed PSE Fredonia Project will have lower PM limits (lb/MMBtu) comparing with current operating PM BACT limits issued within Washington State. Ecology also found that when backup ULSD is used, the proposed PM BACT limits for any options also have lower PM limits (lb/MMBtu) comparing with York Plant Holding's proposed PM BACT limit of 0.041 lb/MMBtu (calculated by dividing the mass limit of 15 lb/hr by the turbine heat input of 365 MMBtu/hr ULSD as the fuel) for a simple cycle turbine with the same add-on controls as PSE proposed. Pennsylvania Department of Environmental Protection issued this draft permit in September 2011.

Ecology is aware that combined cycle facilities in Washington State are generally permitted with lower PM limits. However, Ecology believes that combined-cycle turbines permitted limits cannot be used to set up PM BACT limit for simple cycle turbines. An important difference is that simple cycle turbines have a higher exhaust temperature than combined-cycle turbines, which use a heat recovery boiler to recover some of the waste heat in the turbine exhaust in order to generate additional power. Higher temperature is likely to cause more PM to be formed in the oxidation catalyst and SCR system in simple cycle turbines compared with lower-temperature combined-cycle facility.

3.2.3. PM BACT Conclusion

Table 9. PM BACT Summary for the Combustion Turbines							
PM	**BACT Control Technology**	**Proposed BACT Limit**				**Averaging Time**	**Compliance Method**
		Natural Gas		**ULSD**			
		lb/hr	**lb/MMBtu**	**lb/hr**	**lb/MMBtu**		
GE 7FA.05	Good combustion practices, primary use of natural gas, and annual fuel use restrictions	47.7	0.027	38.5	0.027	Three 1-hr runs	Stack Test
GE 7FA.04		46.4	0.030	38.4	0.028		
Siemens 5000F4		40.0	0.020	34.6	0.025		
GE LMS100		17.8 (×2)	0.029	26.7 (×2)	0.040		

PSE Fredonia proposed the PM BACT limits based on mass emission rates (lb/hr). In addition to lb/hr mass emission limits, Ecology is also imposing PM BACT emissions limits on a heat input basis (lb/MMBtu). Ecology believes that a concentration-based BACT limit (i.e., ppm, lb/MMBtu) is necessary for determining compliance at the control technology's performance level, and for comparison between similar source types. This also conforms to EPA guidance stated in the draft NSR workshop manual (1990, pg. H.5): "In general, it is best to express the emission limits in two different ways, with one value serving as an emission cap (e.g., lbs/hr) and the other ensuring continuous compliance at any operating capacity (e.g., lb/MMBtu)." The PM emissions limits as shown in Table 9 are derived directly from the turbine vendors' (GE and Siemens) performance specifications, which were modeled to reflect site conditions, anticipated operating loads, fuel consumption, and fuel characteristics. As discussed in above sections, under good combustion practice, PM emissions can still vary with turbine design and natural gas quality. Turbine design is not a consideration under PSD review, and natural gas quality is determined by the natural gas source used for supply. There are no alternate sources of natural gas available at this site. The natural gas received from Canada has a low sulfur content compared to other fuels. For fuel oil combustion, the cleanest available fuel choice is ULSD fuel, which has a maximum sulfur content of 0.0015% by weight. Annual ULSD firing is limited to a maximum fuel use listed in Table 4, depending on turbine options. Consequently, Ecology believes the proposed PM emission limit has been specified using the best information available, and BACT is good combustion practices, primary use of natural gas, and fuel use restrictions.

3.3. BACT for H_2SO_4 Mist From Turbines

The objective of this analysis was to determine BACT for H_2SO_4 emissions from any of four combustion turbine options. The simple cycle turbines will be dual fueled by natural gas and ULSD with total annual operation based on the maximum amount of fuel uses and types, summarized in Table 4.

H_2SO_4 emissions are the result of oxidation of fuel sulfur during combustion. SO_2 is the dominant sulfur oxide formed in gas turbines, while a smaller amount of sulfur is oxidized to sulfur trioxide (SO_3). Additional oxidation also occurs at the oxidation catalyst. SO_3 combines with water vapor in the exhaust and in ambient air to form H_2SO_4. Because H_2SO_4 also readily reacts with NH_3, SCR systems tend to help inhibit H_2SO_4 emissions. In the PSE Fredonia Project, the estimated total oxidation SO_2 to SO_3 conversion rates (by % volume) across the turbine and oxidation and SCR catalysts are assumed to be 64% for the three GE options, and 67% for the Siemens option. The effect of the formation of ammonium sulfate and bisulfate to reduce direct H_2SO_4 emissions was not accounted for in this analysis.

3.3.1. Control Technology Review

Emissions of H_2SO_4 can be controlled by limiting sulfur content in the fuel. The primary fuel for this project is natural gas, which has a low sulfur content compared to other fuels. When the unit is firing fuel oil, the unit will fire ULSD fuel oil, which has a sulfur content of 0.0015% sulfur by

weight. The selection of natural gas as the primary fuel and ULSD as the backup fuel provides inherently low SO_2 emissions, thus controlling the formation of H_2SO_4.

A search of the RBLC for simple cycle turbines permitted did not show any control technology for minimization of H_2SO_4 mist emission other than use of low sulfur content fuels. Add-on controls that remove sulfur from the combustion exhaust, such as flue gas desulfurization system (FGD), have not been found to be financially feasible for natural gas fired turbine and have not been used in practice. These types of control devices are typically installed on coal-fired power plants that burn fuels with much higher sulfur contents. The SO_2 concentrations in flue gases from natural gas combustion are too low for the control technologies to work effectively, or be technologically feasible, or cost-effective. As a result, Ecology is not proposing to require any add-on controls as BACT for this project.

3.3.2. Determination of Applicable H_2SO_4 BACT Emission Limitation

Very similar to PM, H_2SO_4 emissions can vary with turbine design, natural gas quality, and add-on controls. Turbine design is not a consideration under PSD review, and natural gas quality is determined by the natural gas source used for supply. There are no alternate sources of natural gas available at this site. Add-on controls, such as oxidation catalysts, can change the H_2SO_4 emission a great deal as discussed earlier. Ecology did not find any similar size simple cycle turbines used in Washington State to provide a meaningful comparison. The only simple cycle turbine project in Washington State having a H_2SO_4 BACT limit is PSE Fredonia Units 3 and 4 PSD permit (PSD-01-04), which includes two Pratt & Whitney FT-8 Twin Pac simple cycle turbines, 54 MW each. The permit limits H_2SO_4 emissions to 88 lb/day while firing either natural gas or distillate oil with sulfur content less than 0.01 percent. Taking the turbine size into consideration (516 MMBtu/hr), the H_2SO_4 emission rate is approximately 0.0072 lb/MMBtu. However, this emission was based on a 20% SO_2-SO_3 conversion across the oxidation catalyst instead of 60% assumed in this project. As mentioned in the PM BACT section, simple cycle turbines have a higher exhaust temperature, which is likely to cause much more SO_3 (and therefore H_2SO_4) to be formed in the oxidation catalyst, because there is a nonlinear (exponential) relationship between exhaust temperature and SO_2 to SO_3 conversion. As a result, a SO_2 conversion assumption in the range of 60% is reasonable and consistent with literature.[5] In summary, it is not surprising that the proposed project will have higher H_2SO_4 emission rates due to the installation of the oxidation catalysts and the use of a high, more conservative SO_2 conversion assumption. Ecology believes that the proposed limits in Table 10 meet BACT requirements.

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5 <http://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2010/18404/Footnotes/PM%20White%20Paper%20for%20BAAQMD%20020310.ashx>

3.3.3. H_2SO_4 BACT Conclusion

Table 10. H_2SO_4 Mist BACT Summary for the Combustion Turbines

H_2SO_4 Mist	BACT Control Technology	Fuel Type				Averaging Time	Compliance Method
		Natural Gas		ULSD			
		lb/hr	lb/MMBtu	lb/hr	lb/MMBtu		
GE 7FA.05	Good combustion practices, primary use of natural gas, and annual fuel use restrictions	22.0	0.0097	3.4	0.0015	24-hour	Stack Test
GE 7FA.04		18.7	0.0097	3.0	0.0015		
Siemens 5000F4		23.0	0.0103	3.4	0.0016		
GE LMS100		8.7 (x2)	0.0098	1.3 (x2)	0.0015		

PSE Fredonia proposed the H_2SO_4 BACT limits in terms of lb/hr. In addition to that, based on the same reason stated in the PM BACT section, Ecology also imposes H_2SO_4 BACT emissions limits on a heat input basis (lb/MMBtu) as shown in Table 10. These emission rates are based on turbine vendors' performance specifications considering both the site-specific natural gas information relating to the total sulfur content, and installation of the SCR and oxidation catalyst controls. Ecology believes the proposed H_2SO_4 emission limit has been specified using the best information available, and BACT is the use of good combustion practices, primary use of natural gas, and annual fuel use restrictions. The maximum sulfur content of the natural gas is estimated to be 3.48 grains (gr) total sulfur per 100 standard cubic feet (scf) on an hourly basis and to 2.25 gr total sulfur per 100 scf on an annual average.

3.4. BACT for CO from the Siemens Turbine Only

The objective of this analysis was to determine BACT for CO emissions from the Siemens SGT6-5000F4 frame turbine option. A BACT analysis was not required for CO emissions from the other three turbine options since annual emissions will be below the PSD major modification thresholds. The Siemens SGT6-5000F4 will be dual fueled by natural gas and ULSD with total annual operation based on 4,959,209 MMBtu/yr, in which the ULSD is expected to be utilized up to 663,277 MMBtu/yr.

CO is a colorless gas that is a product of incomplete combustion. Ecology began its BACT analysis by evaluating the most effective control device and/or technique that has been achieved in practice at similar facilities. Ecology's BACT determination is explained below.

3.4.1. Control Technology Review

A search of the RBLC and other sources mentioned early in this section found that CO BACT technology for a simple cycle gas turbine is good combustion control and in some cases, an oxidation catalyst is used.

Good combustion controls

CO emissions are formed in combustion turbines as a result of incomplete combustion. Similar to generation of NO_X emissions, the primary factors influencing the generation of CO emissions are temperature and residence time within the combustion zone. Variations in fuel carbon content have relatively little effect on overall CO emissions. Generally, the effect of the combustion zone temperature and residence time on CO emissions generation is the exact opposite of their effect on NO_X emissions generation. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions, but higher NO_X emissions. Therefore, the key to the best design lies in the ability to use all the oxygen available with input air for combustion, while controlling the temperature such that NO_X formation can be minimized. Good combustion practices utilize "lean combustion;" large amount of excess air to produce a cooler flame temperature to minimize NO_X formation, while still ensuring good air/fuel mixing with excess air to achieve complete combustion, and thus minimizing CO emissions.

Ecology has identified good combustion practices as an available combustion control technology for minimizing CO formation during combustion. Gas turbine combustion technology has significantly improved over recent years with respect to lowering CO emissions. In some of the recent permits (Table 11), it can even reach 4 ppm @ 15% O_2 without post-combustion control when firing natural gas.

Oxidation catalyst

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst at elevated temperatures within the exhaust stream, CO will react with oxygen, converting it to carbon dioxide (CO_2). No supplementary reactant is used in conjunction with an oxidation catalyst.

Oxidation catalysts have been employed successfully for two decades, for both natural gas and oil-fired combustion turbines when uncontrolled CO emission levels are unacceptably high. Similar to SCR systems, for oxidation catalysts to be successful in oil-fired combustion turbine applications, it is generally best when both the amount and the sulfur content of the oil fired is low, in this case to minimize the contamination of the catalyst with sulfur compounds.

CO oxidation catalysts can be considered technically feasible for use in simple cycle peaking applications. Thus, installation of a CO oxidizing catalyst on the turbines is considered available BACT for this project.

Based on the foregoing analysis, Ecology has determined that the combination of good combustion practices to reduce the formation of CO during combustion and an oxidation catalyst to remove CO from the gas turbines exhaust is BACT.

3.4.2. Determination of Applicable CO BACT Emission Limitation

To establish what level of BACT emissions limits for CO has been permitted and achieved in practice for this type of facility, Ecology reviewed the CO emissions limits of other large simple cycle power plants at the EPA RBLC, CARB BACT clearinghouse and recent projects undergoing CEC licensing, and BACT guidance documents from other regional and local agencies.

CARB's BACT[6] guidance document for electric generating units rated at greater than 50 MW indicates that BACT for the control of CO emissions from a simple cycle gas turbine is 6 ppmvd @ 15% O_2.[7] The *Bay Area Air Quality Management District* (BAAQMD)'s BACT guidelines specify that, for natural gas-fired, simple cycle gas turbines larger than 40 MW, a CO limit of 6 ppmv @ 15% O_2 has been "achieved in practice."[8] The San Joaquin Valley Air Pollution Control District (SJVAPCD)' s BACT guidelines contained determinations for gas turbines larger than 50 MW with uniform load and without heat recovery to be 6 ppmv @ 15% O_2 achieved in practice.[9] A July 2011 BACT guideline from Massachusetts Department of Environmental Protection (MassDEP)[10] specify that a CO limit of 5 ppmv @ 15% O_2 is considered the top case for a simple cycle turbine >10MW/hr firing with natural gas or ULSD.

The proposed BACT emission by the applicant for Siemens SGT6-5000F4 are 4.0 ppmvd and 12.0 ppmvd, corrected to 15% O_2 when burning with natural gas and ULSD, respectively, both on a 3-hour average. These levels are within the lower range of recent BACT determinations from the database searched and the guidance documents Ecology reviewed. However, they are not the most stringent levels being permitted.

A summary of recent CO BACT determination for the similar size simple cycle turbine is shown in Table 11. These limits are all lower than PSE's proposed limits. As listed in this table, the lowest CO BACT limits are 2 ppmvd @ 15% O_2 firing natural gas in two permits. However, for these two turbines, one permit was recently issued and the other permit is still under review. At the time of drafting this TSD, neither of them has been yet been constructed, so no performance data are available. This 2 ppm permit limit therefore is not considered achieved in practice. We are not aware of any available in-use data that shows whether compliance with the 2.0 ppm limits has been demonstrated in practice for a similar size simple cycle gas turbine. For fuel oil firing, the lowest CO BACT limits are 8 ppmvd @ 15% with good combustion practices.

[6] Note to reader: California's BACT process is more like what other states are required to do for nonattainment NSR than PSD permitting. However, once a control level and technology are utilized in California, the technology and the emission limitation become achievable (demonstrated in practice or existing in other agency permits) for purposes of a BACT analysis in Washington State.
[7] http://www.arb.ca.gov/energy/powerpl/guidocfi.pdf
[8] http://hank.baaqmd.gov/pmt/bactworkbook/
[9] http://www.valleyair.org/busind/pto/bact/chapter3.pdf
[10] http://www.mass.gov/dep/air/approvals/bactcmb.pdf

As a result, Ecology requested PSE Fredonia to investigate if they can meet the 8 ppm CO limit when firing ULSD. After research, PSE found that 8 ppm limit is achievable with a larger oxidation catalyst bed and, therefore, accepted Ecology's suggestion to limit CO to 8 ppm rather than 12 ppm while burning distillate fuel in the Siemens SGT6-5000F4 combustion turbine.

Based on all these facts, Ecology believes that the proposed limits meet BACT requirements.

Table 11. Selected CO BACT for the Similar Size Simple Cycle Turbine

Facility	Permit Approved Date	Model Type	CO Emissions	Fuel	Control
Mountain Creek Steam Electric Station	1/12/2011	(2) 198 MW SGT 5000 F Simple Cycle	2 ppmvd @ 15% O_2 (60-100% loads) 3-hr average	Natural Gas	Oxidation catalyst
Marsh Landing Generating Station	CEC review in progress	(4) 190MW SGT6-5000F Simple Cycle	2 ppmvd @15% O_2 3-hr average	Natural Gas	Oxidation catalyst
Progress Bartow Power Plant	6/12/2008	(1) 195 MW SGT6-5000F Simple Cycle	4.1 ppmvd @ 15% O_2	Natural Gas	Good combustion
			8 ppmvd @ 15% O_2	Fuel Oil	
Great River Energy-Elk River	7/1/2008	(1) 2169 MMBTU/hr GE 207FA Simple Cycle	4 ppmvd @ 15% O_2 >=70% load; 4-hr rolling average	Natural gas	Good combustion
			10 ppmd @ 15% O_2 >=70% load; 4-hr rolling average	Fuel Oil	

3.4.3. CO BACT Conclusion

Ecology has determined that the use of a CO catalyst and good combustion practices together with a limited fuel use meet BACT for minimizing CO for the Siemens SGT6-5000F4 turbine option. With these emission controls, Ecology is proposing setting the CO BACT emission limits as shown in Table 12.

In addition, the CO CEMS accuracy is about 0.5 ppm in a low operational range in general and CO emissions from the proposed turbine are within 4 ppm during normal operations firing with natural gas. The achievable relative accuracy is about 12.5 percent. As a result, Ecology allows the relative accuracy of the CO CEMS to go up to 15% instead of 5% listed in Section 13.2 of 40 CFR part 60 Appendix B, Performance Specification 4a.

Table 12. CO BACT Summary for the Combustion Turbine							
		Fuel Type					
		Natural Gas		ULSD			
CO	BACT Control Technology	ppm @ 15% O_2	lb/hr	ppm @ 15% O_2	lb/hr	Averaging Time	Compliance Method
Siemens SGT6-5000F4	Good combustion practices, an oxidation catalyst, and annual fuel use restrictions	4	14.4	8	33.1[a]	1-hr	CEMS
[a] Prorated value based on the 8 ppm BACT limit: 49.6 lb/hr x 8 ppm/12 ppm = 33.1 lb/hr							

Since the CO BACT limit on distillate drops from 12 ppm to 8 ppm, the corresponding mass rate (lb/hr) will drop too. Instead of requesting vendor specifications, PSE accepted Ecology's prorated mass rate of 33.1 lb/hr instead of 49.6 lb/hr (corresponding to 12 ppm at worst-case operating scenario (75% load, ambient temperature of 7ºF, and relative humidity of 40%) when firing with ULSD. Because of a low CO BACT limit on distillate, the annual CO emissions will change as well. Ecology estimated that new annual CO emissions will be 157.4 tpy (compared to 159.9 tpy) assuming no emission changes during SUSD on distillate due to the new CO BACT limit on distillate. The total CO emissions from SUSD on distillate are 15.2 tpy (5 tpy emission are from shutdown only). This is a small fraction of annual CO emissions. Therefore, Ecology feels it is safe not to include the potential emission reduction from SUSD on distillate in the annual limits.

3.5. BACT for GHG from Turbines

The objective of this analysis was to determine BACT for GHG emissions from any of four combustion turbine options. The simple cycle turbines will be dual fueled by natural gas and ULSD with total annual operation based on the maximum amount of fuel uses and types, summarized in Table 4.

As discussed in Section 2, CO_2 is by far the dominant GHG pollutant for the project. Even with GWPs of 21 for CH_4 and 310 for N_2O (the GWP of CO_2 is 1), these two pollutants will contribute less than 3% to the project's total CO_2e emissions. For these reasons, this BACT analysis focuses primarily on the CO_2 emissions from the gas turbine stack(s). However, GHG emissions from N_2O and CH_4 are also included in the final GHG BACT emission limits. In developing the GHG BACT limits, we have chosen to use the factors derived from the source testing performed at PSE's Sumas and Mint Farm Generating Stations in 2009.

A 5-step, top-down GHG BACT analysis for the simple cycle combustion turbine options is provided by PSE after Ecology's request and fully evaluated by Ecology.

3.5.1. Control Technology Review

According to EPA's recent guidance,[11] available control technologies should include lower emitting processes, practices and designs, the use of add-on controls and combinations of the two. Potentially available BACT technologies for this project are summarized below.

Fuel selection

The type of fuel burned determines the amount of GHG pollutants emitted. Viable existing local fuel options for the proposed project include natural gas and fuel oil. Burning natural gas produces less CO_2 than burning fuel oil due to the lower carbon/hydrogen count in methane. According to EPA AP-42 emission factors, burning distillate fuel oil produces less CH_4 and N_2O emissions than burning natural gas. These lower CO_4 and N_2O emissions are offset by the higher CO_2 emissions from burning distillate oil resulting in an overall higher CO_2e emission rate for distillate oil compared to natural gas.

Exclusive use of natural gas as fuel is not feasible as discussed in above BACT sections. As a result, this project will be fueled primarily by natural gas with limited firing with ULSD.

Carbon capture and sequestration (CCS)

CCS is a technology that involves capture and storage of CO_2 emissions to prevent their release to the atmosphere. For a gas turbine, this includes removal of CO_2 emissions from the exhaust stream, transportation of the CO_2 to an injection site, and injection of the CO_2 into available sequestration sites. Potential CO_2 sequestration sites include geological formations (including oil and gas fields for enhanced recovery) and ocean storage.

Voluntary BACT analyses of CCS have been performed for two projects permitted in late 2010: the Calpine Russell City Energy Center Project, which includes a combined cycle combustion turbine project, and Portland General Electric's Port Westward II Project, which includes a simple cycle GE LMS100 gas turbine. In both BACT analyses, CCS was found to be unavailable or infeasible in practice.

PSE also identified a PSD Permit (SE-09-01) issued to Palmdale Hybrid Power Project (PHPP) in southern California by EPA Region 9 on October 18, 2011, involving GHG BACT analyses. This proposed project includes solar technology and two combined cycle GE Frame 7FA CCCTs to generate electrical power. Region 9's BACT analysis for GHG emissions from the CCCTs considered two control technologies: (1) the use of new thermally efficient CCCTs and (2) the use of CCS. CCS was eliminated as technically infeasible for the PHPP and was not considered beyond BACT step 2.

[11] *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011.

In Ecology's independent BACT review, three additional combine cycle generating facilities, the Pacificorp Lake Side Power Plant (PLSPP), UT (DAQE-AN0130310010-11); the Lower Colorado River Authority (LCRA)-Thomas C Ferguson plant (PSD-TX-1244-GHG); and the Pioneer Valley Energy Center (PVEC)-Westfield, MA (EPA draft PSD 052-042-MA15) were identified and evaluated. The PLSPP permit was issued by Utah Department of Environmental Quality (DEQ) on May 4, 2011. The Utah DEQ concluded that high efficiency combustion turbine and HRSG design are the BACT for GHG. The LCRA permit is issued by EPA Region 6 on November 10, 2011. Region 6 concluded that there is no commercially available CCS system to proper scale to LCRA in the near term. In addition, even if technically feasible, the option has been eliminated based on cost-effectiveness basis. The PVEC draft permit prepared by EPA Region 1 was available for public comment from December 5, 2011to January 24, 2012. EPA Region 1 eliminated CCS technology for PVEC's proposed project as GHG BACT due to the energy, environmental, and economic impacts.

Ecology also identified four other combustion turbine permits involving GHG emissions, which are under review by state and local permitting authorities at the time of preparing this document and have received EPA written comments. These projects are the Effingham County Power Project (GA, DNR), Cricket Valley Energy Project (NY, DEC), York Plant Holding Project (PA, DEP), and Wolverine Power-Sumpter Project (MI, DEQ). The use of CCS has been all eliminated in these draft permits as BACT for GHG.

Within the PSE's permit application BACT analysis, the applicant proposed to eliminate CCS because CO_2 capture is not technically feasible for combustion turbine. In their application, PSE examined a list of 14 active and potential CCS projects (dominantly by the pre-combustion capture technology and only one by the post-combustion capture technology) published by the Global CCS Institute to see if any are similar to the proposed simple cycle gas turbine options. PSE also reviewed seven other post-combustion CO_2 capture and storage demonstration projects that were built and operated over the years, but are no longer in operation or on hold due to economic reasons, including a demonstration scale capture technology at a Florida Power and Light (FP&L) natural gas combine cycle turbine power plant in Bellingham, Massachusetts. The increased natural gas prices in 2004 to 2005 forced the FP&L power plant to operate in a peak load shaving mode, which rendered the CO_2 capture plant uneconomical after 14 years operation (1991–2005). During this time, only a fraction of CO_2 from gas-turbine exhaust was captured and provided for off-site sale. Sequestration was not attempted at the Bellingham plant.

PSE believes that carbon capture technologies are still demonstration projects for combined cycle facilities and remains undemonstrated for simple cycle peaking application to date. However, this CO_2 capture technology consideration appears to be more of a cost issue instead of a technical feasibility issue. Based on available information, Ecology considers carbon capture from gas turbines to be technically feasible for the project.

The applicant also identified four potential sequestration options: enhanced oil recovery (EOR), geologic sequestration, silicate mineral reactions, and industrial reuse. In the Pacific Northwest, EOR opportunities do not exist due to the lack of oil and gas production areas. Pipelines do not

exist for the transportation of CO_2 to distant oil and gas production areas to provide for EOR. Geologic sequestration, including deep saline formation, deep basalt formations, and the tectonic subduction zone, was also explored for this project and none of them is a viable option and/or within a reasonable distance of the project site (200 miles or more) in addition to the fact that two of the three approaches (deep basalt formations and injection in tectonic subduction zones) have not been demonstrated in practice. Silicate mineral reactions are also infeasible because the mineral deposit is undeveloped and there is no existing rail transport infrastructure to transport the minerals to and from the power plant site or developed disposal sites to receive the reacted minerals. These would become costs to be borne by this project as part of the cost to capture and sequester CO_2.

Typical industrial uses of CO_2 such as welding operations, beverage carbonation, or use as a supercritical solvent do not qualify as permanent sequestration and would not reduce CO_2 emissions. No large-volume, permanently consumptive CO_2 industrial is known to exist near the project site and a pipeline system to transport the CO_2 to such a user does not exist and the cost to develop would have to be borne by this project. As a result, PSE does not consider carbon sequestration option to be technically feasible.

In spite of the technical infeasibility, PSE qualitatively performed a cost analysis for carbon capture and sequestration. Instead of a project-specific or site-specific cost estimate for implementing one of the CCS options discussed above, PSE considered cost per ton of CO_2 avoided prepared by others and then compared these projects specifications with the proposed PSE Fredonia Project specifications. PSE concluded that the fewer operating hours, additional steam requirement for the CO_2 capture system, heat rejection system with a bigger cooling duty, no available saline formation within a 50 mile radius of the facility, and a smaller size of a CCS system required for the PSE Fredonia Project will cause the cost per ton of CO_2 avoided much higher than currently acceptable economic thresholds. Give that carbon capture, alone, is demonstrated not to be economically viable for the PSE Fredonia Project, and any of the sequestration options would add significantly to the cost. Therefore, CCS systems are not cost-effective and were removed from further consideration in the BACT analysis for GHG. Ecology has reviewed PSE's CCS technical and cost analysis and concurs with the assessment.

Fuel efficient engine technology

CO_2e emissions are the direct result of the amount and type of fuel burned. Engines that are more efficient emit less CO_2e relative to the amount of electricity produced. Both Ecology and the applicant are aware that a combined cycle combustion turbine (CCCT) produces less GHG emissions per MW-hr of electricity generated due to the higher efficiency of the technology; however, combined cycle generation facility is a different type of generation project that would not meet the PSE Fredonia Project requirements to respond to rapidly changing and often short-term peak power demand on PSE's system. Simple cycle combustion turbines are best suited, and are more cost-effective for peaking applications. The applicant also investigated fast start versions of CCCT units, which have been recently announced by both Siemens and GE. PSE concluded that fast start CCCT are unproven technology and to their knowledge, neither

company has commercially constructed and operated a fast start CCCT. In addition, the minimum size of vendors' currently proposed new fast start combined cycle units is 270 MW, which is above the capacity that PSE is seeking to meet projected needs. This technology also currently offers continuous emission guarantees only at approximately 50% load or 135 MW. Using combined cycle technology would require the project to be fundamentally redefined. Therefore, CCCT is not an available technology option for consideration in this BACT evaluation. After elimination of CCCT as a potential alternative, the use of a modern and efficient simple cycle gas turbine is the control method remaining.

Ecology has requested that the BACT analysis include an efficiency evaluation of the different turbine options. Energy efficiency is a component of BACT that focuses on reduction of emissions through changes to the underlying process rather than using add-on control technology. GHG emissions are directly related to minimizing the quantity of fuel required to make electricity. This measure is reflected in the turbine's thermal efficiency meaning that a more efficient engine will reduce the GHG emissions under the same operational condition.

PSE Fredonia has requested the ability to select one of four specified combustion turbine options after the permit is issued to allow the company to choose the best engine of the four options at the time of the start of construction. Ecology does not intend to require a single make or model through the BACT decision. Ecology understands that high efficient engine does not necessary transfer directly to low GHG emissions because some operating parameters, such as fuel type, operating loads, and operating hours, will affect the total GHG emissions from the project. The applicant's ultimate decision about which turbine engines to install will depend upon a variety other considerations, including but not limited to equipment availability, cost, start-up time, operational performance, reliability, and maintenance issues. Ecology is willing to give the flexibility to the applicant but in the meantime, through this analysis, to make sure these four options proposed are all efficient engines suitable for the project.

Overall, besides the proposed four modern and efficient simple cycle turbine engine generators, the applicant also identified three other options (58 MW Pratt and Whitney FT8, 41 MW GE LM6000 simple cycle turbine engine generators, and 17 MW Wartsila model 18V50DF reciprocating engines) that could be used to satisfy the project's rapid-start peaking electricity generation. Of the available engine technologies, the Wartsila 18V50DF is not technically feasible because it could not satisfy other air permitting requirements. Ambient air quality modeling demonstrated that off-site impacts from the Wartsila 18V50DF engine emissions would significantly exceed the new federal 1-hour NO_X NAAQS at locations near the FGS.

Within the remaining six feasible turbine options, their estimated CO_2 and CO_2e emission rates in lb/MW-hr of electricity generated are listed in Table 13 together with other emission rates Ecology identified through other PSD permits.

Ecology found that a draft PSD permit issued in September 2011by Pennsylvania Department of Environmental Protection (DEP) approved the installation of any two simple cycle turbines among three turbine options (Rolls Royce Trent 60, 61.5MW each; Pratt & Whitney FT8, 49MW

each; and GE LM-6000, 47MW each). All of these turbine options are proposed to have SCR and oxidation catalyst to control emissions. PA DEP concluded that the GE LM-6000 option is the most efficient turbine option. The BACT limits are set as 1,330 lb CO_2e/MW-hr when firing with natural gas and 1,890 lb CO_2e/MW-hr when firing with ULSD. In addition, Ecology found in the Appendix D of the Port Westward II Project Voluntary GHG BACT analysis, the applicant estimated CO_2 emission rates from the proposed LMS100 simple cycle turbine to be 1,047 lb/MW-hr. However, this limit is not set as a BACT limit. Ecology also found that in Palmdale Hybrid Power Project (PSD SE 09-01) fact sheet, the permitting agency (EPA Region 9) estimated CO_2 emission rates from the proposed 7FA CT operating in simple cycle mode with a gross output of 154 MW each to be 1,319 lb/MW-hr.

Table 13. GHGs BACT Summary for the Combustion Turbines[1]

Turbine Options Without CCS	Emission Rate (lb CO_2/MW-hr)	Emission Rate (lb CO_2e/MW-hr)
LMS-100	1,044	1,052
LM-6000	1,145	1,153
7FA.05	1,176	1,185
5000F4	1,177	1,186
7FA.04	1,182	1,191
FT8-3	1,226	1,235
7FA turbine operating in simple cycle mode[2]	1,319	
GE LMS-100 simple cycle turbine[3]	1,047	
GE LM-6000 simple cycle turbine[4]		1,330 (gas) 1,890 (ULSD)

[1] Assumption except for the York Plant Holding Project:
a) Natural gas is the only fuel.
b) Turbines are operated under full load conditions.
c) Annual hours of operation are 8,760 hr.

[2] Palmdale Hybrid Power Project: "Fact sheet and ambient air quality impact report" Table 7-10, p. 30.

[3] Portland General Electric's Port Westward II Project, Appendix D, Table 4-1, p. 7.

[4] York Plant Holding, Inc. Project, p. 13. The emission rate is based on the proposed operating condition. Other two approved simple cycle turbines (Rolls Royce Trent 60 & Pratt & Whitney FT8) will have higher emission rates, but the permit and TSD do not include these limits.

The least efficient and highest emitting option proposed by PSE is the Pratt & Whitney FT8-3. Because this turbine option is also one of the most expensive to purchase and offered no significant advantages, the applicant dropped it from further consideration. The remaining five turbine options emit less CO_2e per MW-hr and are, therefore, considered to be feasible and the most effective controls for further evaluation relative to their emission performance and cost-effectiveness.

Table 14 summarizes the incremental cost analysis for CO_2 reduction via changes in unit thermal efficiency. For purposes of calculating the cost of incremental CO_2e reduction, the analysis

treats the fifth-ranked option, 7FA.04, as the base case, and calculates the additional cost per ton of using the other turbine models to further reduce CO_2e emissions. The analysis shows that further CO_2e reductions would cost between $710 and $4,660 per ton of CO_2e removed. This incremental cost range appears to be in excess of costs that have been considered "achievable" in other GHG BACT analyses, or in EPA's initial guidance on what might constitute BACT for GHGs. The calculated incremental costs are at least 10 times higher than the current market price of CO_2 offsets and credits (currently about $9.07 per ton) and greatly exceed the $20 per ton CO_2e approximate social cost of carbon recently cited by EPA.[12]

Table 14. Incremental Emission Reduction Cost Analysis for Five Turbine Options

	LMS100	LM-6000	7FA.05	5000F4	7FA.04
Emissions Calculations					
Plant Capacity, net (MW)	199.7	165.1	209.4	207.1	182.3
Generation (MW-hr), 200MW@7.5%CF[1]	131,400	131,400	131,400	131,400	131,400
Heat rate @ full load (Btu/kWh, HHV)	9,007	9,871	10,145	10,152	10,193
Fuel CO_2 Rate (lb/MMBtu, HHV)[2]	115.9	115.9	115.9	115.9	115.9
Fuel CO_2e Rate (lb/MMBtu, HHV)[3]	116.8	116.8	116.8	116.8	116.8
Plant CO_2e Emissions Rate (lb/MW-hr)	1,052	1,153	1,185	1,186	1,191
Annual CO_2e Emissions (tpy)	69,118	75,748	77,850	77,904	78,219
Emissions Rank (1 = lowest emitting)	1	2	3	4	5
CO_2e Reduction from Base Unit (tpy)	9,101	2,471	368	315	0
Cost Calculations					
Plant Book Life (yrs)	35	35	35	35	35
PSE Discount Rate	8.10%	8.10%	8.10%	8.10%	8.10%
Annual O&M					
Fixed O&M (FOM) ($/kW-yr)	15.71	19.06	11.48	11.76	12.32
First-Year FOM ($/yr)	3,136,522	3,146,952	2,403,015	2,436,339	2,246,140
FOM Escalation Rate[(1)](%/yr)	3.00%	3.00%	3.00%	3.00%	3.00%
FOM Levelized Cost ($/yr)	4,063,695	4,998,100	3,113,360	3,156,534	2,910,111
Variable O&M (VOM) ($/MW-hr)	3.58	4.34	11.88	10.28	10.68
First Year VOM ($/yr)	470,713	570,584	1,560,650	1,350,846	1,402,785
VOM Escalation Rate[(1)](%/yr)	3.00%	3.00%	3.00%	3.00%	3.00%
VOM Levelized Cost ($/yr)	609,858	906,221	2,021,987	1,750,164	1,817,457
Fuel ($/MMBtu, HHV)	8.08	8.08	8.08	8.08	8.08
First Year Fuel ($/yr)	9,562,840	10,480,159	10,771,068	10,778,500	10,822,030
Fuel Escalation Rate(%/yr)[4]	3.00%	3.00%	3.00%	3.00%	3.00%
Fuel Levelized Cost ($/yr)	12,389,669	16,644,959	13,955,056	13,964,685	14,021,083

[12] EPA Office of Air Quality Planning and Standards (OAQPS), June 17, 2011: Panel Outreach Meeting with SERs: *Rulemaking for Greenhouse Gas Emissions from Electric Utility Steam Generating Units*, p. 62.

Table 14. Incremental Emission Reduction Cost Analysis for Five Turbine Options					
	LMS100	**LM-6000**	**7FA.05**	**5000F4**	**7FA.04**
All-In CapEx ($)	279,000,000	274,000,000	198,000,000	191,000,000	185,000,000
Capital Recover Factor	8.67%	8.67%	8.67%	8.67%	8.67%
Annual CapEx ($/yr)	24,182,437	23,749,060	17,161,729	16,555,002	16,034,949
Total Levelized Annual Cost ($/yr)	41,245,660	46,298,340	36,252,133	35,426,384	34,783,600
Levelized Cost (Savings) Over Base ($/yr)	6,462,059	11,514,739	1,468,532	642,784	$0
Incremental Cost-Effectiveness ($/ton CO_2e)	$710	$4,660	$3,987	$2,043	$0

[1] Assuming the project would generate 131,400 MW-hrs of electricity per year for all options.
[2] Assuming natural gas would be used as the fuel.
[3] Based on source testing at PSE's Sumas and Mint Farm Generating Stations in 2009, CO_2 emissions account for approximately 99.27% of total CO_2e emissions.
[4] Assuming an escalation rate of 3% as an average inflationary number. This number falls within the range of historical inflation.

The applicant decided that the most expensive option, the LM6000, would not be pursued for the project, as it is offering no significant advantages. The applicant requests Ecology to recognize that the installation and operation of any one of four turbine options (F7A.04, GE F7A.05, Siemens SGT6-5000F4, and GE LMS100) satisfies the BACT requirements for GHGs.

Considering the fact that proposed annual operating scenarios and operating hours are different depending on the turbine option, the least efficient make or model is not necessarily the highest annual emitting option. For example, for a peaking facility in which a turbine does not operate all the time, a more efficient make or model would still have higher annual GHG emissions if more operating hours (i.e., use more fuel) were proposed, compared with a less efficient make or model with fewer operating hours (i.e., use less fuel). As a result, Ecology considered engine efficiency together with proposed operating scenarios associated all four options during the BACT analysis. In this project, the least efficient engine (7FA.04) generates the least annual GHG emissions while the most efficient engine (GE LMS100) generates the highest annual GHG emissions mainly because of more operation hours (i.e., more fuel use). As a result, Ecology agrees with the applicant that any of the four turbine options satisfies BACT requirements for GHG.

3.5.2. Determination of Applicable GHG BACT Emission Limitation

The numbers presented in Tables 13 and 14 are used to compare the efficiency among turbine models and do not translate directly into permit limitations. Permit limitations include the effects of other operational parameters and considerations such as fuel types, operating hours, loads, and the numbers and durations of start-ups and shutdowns.

Ecology used performance data from the turbine vendors and the operational scenarios, including SUSD, to estimate CO_2 emissions. Emissions for both CH_4 and N_2O utilized the results of

source testing at PSE's Sumas and Mint Farm Generating Stations in 2009 to estimate the GHG emissions in Tables 15. Any proposed BACT limits for this project are lower than the York Plant Holding Project proposed BACT limits as listed in Table 13 (this is the only available GHG BACT limit for a simple cycle turbine). In addition, New York[13] has proposed to restrict a simple cycle combustion turbine (>25MW) to emit less than 1,450 lb CO_2 per MW-hr. Any proposed BACT limits for this project are lower than this number as well. Therefore, Ecology believes these numbers meet the BACT requirement.

3.5.3. GHG BACT Conclusion

Ecology has determined the installation and operation of any of PSE's proposed simple cycle turbines as meeting BACT for GHG. With this BACT determination, permit conditions must be developed to ensure PSE installs the proposed energy efficient turbine(s) and will continue to operate the turbine(s) in an energy efficient manner. To ensure these two goals are met, Ecology is proposing in the permit two emission limits for GHGs as listed in Table 15, along with appropriate monitoring recordkeeping and reporting. These emission limits are based on a review of emissions data upon manufacturer guarantee considering a number of factors such as partial load, start-ups and shutdowns, which all affect the turbine's efficiency, and also incorporate emissions from CH_4 and N_2O using the emission factors from previous source testing at PSE's Sumas and Mint Farm Generating Stations in 2009.

Table 15. GHG BACT Summary for the Combustion Turbines

GHGs	BACT Control Technology	BACT Limits		Compliance Method
GE 7FA.05	High-efficiency simple cycle gas turbine technology, Primary Use of Natural Gas and annual fuel use restrictions	1,299	lb CO_2e/MW-hr net output, 365-day rolling average	Initial stack test for CO_2; CO_2 CEMS (only if elected) and recordkeeping
		311,382	tpy as CO_2e, 12-month rolling total	
GE 7FA.04		1,310	lb CO_2e/MW-hr net output, 365-day rolling average	
		274,496	tpy as CO_2e, 12-month rolling total	
SGT6-5000F4		1,278	lb CO_2e/MW-hr net output, 365-day rolling average	
		301,819	tpy as CO_2e, 12-month rolling total	
GE LMS100		1,138	lb CO_2e/MW-hr net output per unit, 365-day rolling average	
		327,577	tpy as CO_2e, 12-month rolling total	

In order to accurately measure efficiency, Ecology is requiring PSE Fredonia to measure the actual heat input in MMBtu/hr and measure the pounds of CO_2 on an hourly basis with a CO_2

[13] http://www.dec.ny.gov/regulations/79556.html

emission monitor. This analysis can be completed according to 40 CFR Part 75, Appendices F and G. As an alternative, PSE Fredonia may install, calibrate, and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1.

To demonstrate compliance with the GHG BACT limit of lb CO_2e per MW-hr (net), the measured hourly CO_2e emissions are divided by the net hourly energy output and averaged on a daily basis. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day rolling average.

An initial stack test is required to establish the actual quantities of CO_2 emissions from the turbine. An initial stack test is not required for CH_4 and N_2O because GHG emissions from N_2O and CH_4 are less than 3% of the total CO_2e emissions from any proposed turbine options and are considered a de minimis level in comparison to the CO_2 emissions.

3.6. BACT for GHG From Switchyard Breakers

The circuit breakers are subject to BACT for GHG emissions. The only GHG emitted from circuit breakers is sulfur hexafluoride (SF_6), a potent GHG with a global warming potential of 23,900. With the proposed control technologies, CO_2e emissions are estimated at 120.1 tpy.

The inherently lower-emitting control options for GHG emissions include:

- Use of oil-filled circuit breakers—these types of circuit breakers do not contain any GHG pollutant.
- Totally enclosed SF_6 circuit breakers—these types of circuit breakers have a maximum leak rate of 0.5% per year by weight.

Although oil-filled breakers contain/emit no GHG, oil presents other environmental and safety risks. An oil release and/or fire could result in the event of overheating and rupture of the breaker. The advantages of the use of SF_6 in circuit breakers include low operating energy requirements, no fire risk, no toxic hazards, corrosion protection, limited space requirements, extremely low failure rate, low maintenance costs, and long service life.

The applicant reviewed a recent combined cycle turbine project (PHPP PSD SE 09-01) issued by EPA Region IX and found the enclosed-pressure SF_6 circuit breakers with 0.5% annual leakage rate and leak detection systems was selected as BACT. Ecology's independent search found the

same BACT determination has been made for circuit breakers in other five projects: the Calpine Russell City Energy Center permit, CA (a combine cycle turbine project and a voluntary BACT), the Abengoa Bioenergy Biomass of Kansas draft permit, KS (a biomass to ethanol and biomass-to-energy production project), the Crawford Renewable Energy permit, PA (a waste tires-to-energy project), the Pioneer Valley Energy Center application supplement, MA (a combined cycle turbine project), and the Thomas C. Ferguson Power Plant permit, TX (a combined cycle turbine project).

As a result, the applicant proposed that SF_6 filled breakers are selected as BACT. Ecology agrees that the non-air quality impacts of oil-filled breakers are significant enough to select SF_6 filled circuit breakers as BACT.

Additionally, Ecology is requiring the SF_6 filled breakers be equipped with a leak detection system to identify SF_6 leaks immediately so that corrective actions can be taken in time to limit releases.

3.7. BACT for Emergency Generators

A diesel-fired compression ignition (CI) engine generator is proposed as the only technically feasible option to supply the new units' critical electrical loads in the event power could not be back-fed from either the site's 230 kilovolt (kV) or 115 kV transmission systems. A natural gas-fired generator is not a reasonable option because there is a risk for significant damage to the gas turbine(s) and other power plant system if both a power grid outage and a natural gas outage were to occur at the same time. This occurrence could happen in the event of a strong earthquake or a natural gas pipeline explosion.

BACT determinations on emergency generators are uncommon. Current BACT guidelines and determination published in the RBLC and by the following three California Districts were reviewed for BACT for the PSE's proposed emergency generator:

- BAAQMD BACT Guideline for emergency CI internal combustion (IC) engines >50 hp (http://hank.baaqmd.gov/pmt/bactworkbook/default.htm)
- SJVAQMD BACT Guideline 3.1.1 for emergency diesel IC engines (www.valleyair.org/busind/pto/bact/chapter3.pdf)
- SCAQMD LAER/BACT Determinations for emergency CI engines (http://aqmd.gov/bact/aqmdbactdeterminations.htm)

Current BAAQMD, SCAQMD, and SJVAPCD BACT guidelines require new stationary emergency CI engines to meet applicable EPA NSPS or CARB tier standards for NO_X, CO, $PM_{10,}$ and VOC. These same guidelines require the use of ULSD to control SO_2 emissions.

Federal Tier 2 standards for nonroad CI engines currently apply to new stationary emergency standby engines greater than 761 break-horsepower (bhp), or 560 brake-kilowatt (bkw) (40 CFR

Part 60, Subpart IIII). Emergency engines are exempt from the more stringent Tier 4 requirements in the NSPS. CARB is in the process of adopting rule revisions to retain a 0.15g/bhp-hr limit for PM and align the other pollutant emission standards with federal NSPS requirements for emergency standby CI engines. This change reflects CARB's recent finding that add-on controls (i.e., SCR and diesel particulate filter technology) are not justified for emergency engines due to significant economic and operational constraints.[14] This CARB finding is consistent with EPA's rationale for exempting emergency CI engines from Tier 4 requirements.

PSE proposes the purchase and install one 600 kW diesel-fired standby generator certified by the manufacturer to meet the Tier 2 standards.

The Caterpillar engine identified in this TSD has PM emissions that are lower than the CARB's 0.15 g/bhp-hr emission limit.[15] If a different make/model emergency standby generator is selected during detailed design for the project, a Tier 2 certified engine would be specified at time of purchase. Furthermore, PSE commits to use ULSD.

Ecology agrees with PSE that BACT for the proposed emergency standby generator is meeting the EPA NSPS for emergency compression ignition engine-generators and using ULSD (15 ppm) for the fuel. Annual operation for maintenance, testing, and training is limited to 275 hours. In addition, Ecology imposes an emission limits as shown in Table 16.

Table 16. BACT Summary for the Emergency Generator

Pollutant	BACT	Emission Limit	Compliance Method
CO (for SGT6-5000F4 turbine option only)	Use of ultra-low sulfur fuel, not to exceed 15 ppmvd fuel sulfur	3.5 g/kW-hr, five-load weighted average using the procedures in 40 C.F.R. Part 89, Subpart E	• A written manufacturer supplied certification. • Maintaining the engine according to manufacturer's recommendations. • Recordkeeping of the engine run times, duration, and purpose of each use.
$PM/PM_{10}/PM_{2.5}$		0.20 g/kW-hr, five-load weighted average using the procedures in 40 C.F.R. Part 89, Subpart E	
CO_2e		0.20 g/kW-hr, five-load weighted average using the procedures in 40 C.F.R. Part 89, Subpart E	Recordkeeping

[14] CARB, Staff Report: Initial Statement of Reasons for Proposed Rulemaking-Proposed Amendments for the Airborne Toxic Control Measure for Stationary Compression Ignition Engines, September 2010.
[15] CARB, executive Order U-R-001-0380-1 for the 2010 Caterpillar ACPXL 18.1 ESW engine family, August 30, 2010.

3.8. BACT for Start-Ups and Shutdowns

The BACT limits discussed in the previous sections apply to steady-state operation, when the turbines have reached stable operations and the emission control systems are operational. BACT must also be determined for periods of combustion turbine start-ups and shutdowns. Frequent start-ups and shutdowns are a normal part of the operation of a peaking power facility. Emission rates during start-ups and shutdowns are highly variable and turbine exhaust concentrations may be greater than those during steady-state operation, especially for combustion turbines with DLN combustors. This is especially true for CO, NO_X, and VOC since it is common for these concentrations to be higher during partial-load operation compared to normal operation. The reasons for increased concentrations are: (1) the turbines are less efficient when operating at low loads, (2) the exhaust temperatures are lower than during steady-state operations, which cause post-combustion emissions control systems such as the SCR catalyst and oxidation catalyst do not function optimally at these lower temperatures, and (3) combustion air and turbine exhaust gas flow rates are lower. Thus, mass emissions can be minimized for quick starts turbine design.

Modern simple cycle gas turbine generators are designed to achieve significantly improved rapid responses to load changes on the electrical grid. A more rapid response helps improve system reliability and efficiency. Modern simple cycle turbines have inherently low start-up emissions because they can quickly come up to full operating load.

A review of the EPA's RBLC database as well other sources did not identify any control technologies for simple cycle gas turbines specifically during the SUSD periods. Ecology is therefore establishing numerical emission limits on the quantity of emissions during each SUSD event while minimizing/limiting the SUSD duration (Table 17). These limits are calculated based on emissions estimates and start-up/shutdown operation profiles provided by the gas turbine vendors (General Electric and Siemens).

Table 17. Start-Ups and Shutdowns BACT

Options	SU/SD	Fuel	Max. Duration (Min.)	Max. # of SU/SD per Year	Emission (lb/event/unit)		
					CO	PM	H_2SO_4
GE 7FA.05	SU	Gas	30	144	---	9.2	5.8
		Oil	30	14	---	17	1.0
	SD	Gas	19	144	---	5.8	2.6
		Oil	17	14	---	9.6	0.4
GE 7FA.04	SU	Gas	30	144	---	6	8.0
		Oil	30	14	---	17	1.0
	SD	Gas	14	144	---	4	3.2
		Oil	14	14		9.6	0.4
Siemens 5000F4	SU	Gas	35	144	1,347	4.8	7.2
		Oil	38	14	1,462	15.6	1.0

Table 17. Start-Ups and Shutdowns BACT							
Options	SU/SD	Fuel	Max. Duration (Min.)	Max. # of SU/SD per Year	Emission (lb/event/unit)		
					CO	PM	H_2SO_4
	SD	Gas	17	144	443	2.4	3.6
		Oil	19	14	709	10	0.6
GE LMS100 (2 Units)	SU	Gas	30	240	---	3.3	3.7
		Oil	30	14	---	14.3	0.5
	SD	Gas	8	240	---	1.0	0.4
		Oil	8	14	---	4.7	0.05

In addition, in order to protect hourly air quality standards, the start-ups and shutdowns are limited to one per unit per hour, two per unit in a 3-hr period, five per unit in an 8-hr period, and five per unit in a 24-hr period. Furthermore, start-ups and shutdowns on distillate are limited to one per 24-hr period, with an addition of up to four each on natural gas.

GHG emissions are a function of fuel consumption, which is minimal during start-ups and shutdowns compared to full load operation. The four simple cycle gas turbines proposed for the project are all capable of achieving fast start-ups and shutdowns, which reduces the effect of start-ups and shutdowns on the GHG emissions. SUSD emissions for GHG are included in the annual emission limitation for GHG and as such do not need to be separately specified.

3.9. Toxic Air Pollutants

PSD rules require the applicant to consider emissions of TAPs during the course of a BACT analysis, but specifically exempt all pollutants subject to regulation under Section 112 of the federal Clean Air Act from regulation under the PSD program.

The emissions of TAPs will be covered in the NWCAA NOC approval for this project.

4. AMBIENT AIR QUALITY IMPACTS ANALYSIS

4.1. Regulatory Requirements

For PSD, an ambient Air Quality Impacts Analysis (AQIA) is required for all pollutants that are emitted in significant quantities to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that new emissions emitted from the proposed major stationary source or major modification will not cause or contribute to a violation of any applicable NAAQS or PSD increment.

The AQIA starts with preliminary modeling for each pollutant to determine whether an applicant can forego detailed analysis and preconstruction monitoring. If the projected ambient concentration increase for a given pollutant is below the PSD Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMCs) for each averaging period, no further analysis of the ambient impact is required for that pollutant.

For those pollutants with averaging periods that have impacts greater than the SIL, a full impact analysis is used to demonstrate compliance with NAAQS and PSD increments.

Typically, the AQIA includes an analysis of impacts to local areas that are within 50 kilometers (km) of the project, and a regional air quality impact assessment for impacts beyond 50 km. For projects in Washington State, this latter analysis usually includes impacts on Class I areas.

4.2. Modeling Methodology

Ecology is required to use dispersion models accepted in 40 C.F.R. §51, Appendix W, Air Quality Models. The AERMOD model (Version 09292) is the currently accepted model for assessing ambient air quality from industrial sources for distance out to 50 km. AERMOD is based on the Gaussian and planetary boundary layer concepts, designed for sources located in all types of terrain (flat, simple, intermediate, and complex) and for sources subject to aerodynamic building downwash. AERMOD has been used for this project to assess the AQIA in Class II areas within 50 km of the project site. A modeling protocol was submitted to Ecology and the Federal Land Managers (FLMs) on September 24, 2010. Additional amendments and correspondence with Ecology and the FLMs have been incorporated herein.

AERMOD was used to predict the increases in criteria pollutant concentrations due to the project emissions only. These impacts were then compared to the SILs to determine whether additional analyses would be required. The inputs to the model are discussed in detail in the permit application. Prior to submittal of the application, Ecology reviewed and accepted PSE's modeling protocol and has accepted the modeling results as presented in the application.

4.3. Estimated Max Emission Rates (Worst-Case Scenarios) for Modeling

Long-term emission rates used in the modeling were calculated as outlined in Section 2.2, and shown in Tables 3 and 5.

Short-term emission rates were developed based on the worst-case operating scenarios for each pollutant. These worst-case emission scenarios are dependent upon both the emission rate and the stack parameters under each scenario, which differs for each turbine option proposed. PSE Fredonia used a two-stage approach to develop worst-case scenarios for each turbine option. During the 1st stage (named "load check"), for each of the turbine options, only turbine operating emissions (excluding SUSD) are modeled for 1-hour impacts at each operating condition (by load, fuel, and ambient temperature for each turbine option) with corresponding source parameters. Based on these load check results, a refined worst-case scenario for full

modeling for each turbine option was then developed using a combination of worst-case load (that is operationally feasible for the time duration) and start-ups and shutdowns when they are operationally feasible for the time duration *and* have the potential to cause higher impacts due to increased emissions. The worst-case scenarios for each modeled pollutant are listed in Table 18.

The emergency generator is also included in the refined full modeling analyses. Only the location of the generator changes between the four turbine options because of site configuration requirements. The worst-case emissions for the emergency generator were modeled the same way for each of the options using the parameters shown in Table 19.

Table 18. Refined Modeling—Worst-Case Scenario Emissions for the Potential Turbine Options

Averaging Period	Turbine Stack Parameters				Emission Rate (lb/hr/unit)		Scenario Description
	Ht (ft)	Temp (°F)	Vel (fps)	Diam (ft)	PM	CO	
GE 7FA5							
Annual	145	800	120	23	9.76	---	Annual NG and Distillate—all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; average temperature (51°F).
24-hr	145	799	87	23	36.80	---	Distillate; 50% load; 7°F; no SU/SD.
GE 7FA4							
Annual	145	800	127	21	9.85	---	Annual NG and Distillate—all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; average temperature (51°F).
24-hr	145	799	102	21	37.60	---	NG at 3.48 gr/100 scf; 50% load; 7°F; no SU/SD.
Siemens SGT6-5000F4							
Annual	145	800	118	23	7.39	---	Annual NG and Distillate—all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; average temperature (51°F).
24-hr	145	799	95	23	32.80	---	Distillate; 70% load; 88°F; no SU/SD.
1-hr	145	799	103	23	---	2173[a]	Distillate; 75% load; 7°F; 1 Distillate SU/SD.
8-hr	145	799	103	23	---	1203[a]	Distillate; 75% load; 7°F; 1 Distillate SU/SD over 1 hr, and additional 4 NG SU/SD over 8-hr period.
GE LMS100							
Annual	110	777	127	12	5.12	---	Annual NG and Distillate—all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; average temperature (51°F).
24-hr	110	800	129	12	18.52	---	Distillate 80% (combined for 2 units) use factor over 24-hr period; 90% use at 100% load; 88°F.
	110	800	113	12	2.83	---	Distillate 80% (combined for 2 units) use factor over 24-hr period; 10% use down to 75% load; 88°F; 1 Distillate SU/SD.

[a] The actual worst-case CO emission rates are lower than numbers here, because of the new 8 ppm CO BACT limit on distillate. For the modeling impact analyses, emissions were based on the PSE proposed 12 ppm CO BACT limit on distillate.

Table 19. Refined Modeling—Worst-Case Scenario Emission for the Emergency Generator

Averaging Period	Generator Stack Parameters				Emission Rate (lb/hr)		Scenario Description
	Ht (ft)	Temp (°F)	Vel (fps)	Diam (ft)	PM	CO	
Caterpillar C18							
Annual	50	994	146	0.833	0.00607	---	Distillate; full load; 500 hr/yr,[1] inclusive of 52 hr testing and maintenance plus potential emergency operation
24-hr	50	994	146	0.833	0.1063	---	Distillate; full load; 24 hr (full-time)
1-hr	50	994	146	0.833	---	1.063	Distillate; full load; 1 hr (full-time)
8-hr	50	994	146	0.833	---	1.063	Distillate; full load; 8 hr (full-time)

[1] Total operation hours for the emergency generator will be limited to 275 hr/yr. The emissions provided in this application and TSD are based on this annual value. However, for the modeling impact analyses, emissions were based on the conservative 500 hr/yr, *except* for the Diesel Engine Exhaust Particulate (TAP) impact analysis, which used the revised 275 hr/yr operation.

4.4. Modeling Results for Air Quality Impact Assessment

The highest predicted short-term concentrations and highest predicted annual averages predicted by the modeling are compared to the appropriate SILs and SMCs as tabulated in Table 20. $PM_{2.5}$ and PM_{10} (and CO for Siemens Options only) air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants (under worst-case scenarios: by ambient condition, operation (i.e., start-up, shutdown, normal), loads, emergency generator, etc.) are less than the applicable PSD levels.

Table 20. Criteria Pollutant Impacts for the Potential Turbine Options at Class II Areas

Pollutant	Averaging Time	Maximum Predicted Impacts (µg/m³)				SIL (µg/m³)	Over SIL?	SMC (µg/m³)	Over SMC?
		GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)				
CO	1-hr	---	---	110	---	2,000	NO	---	---
	8-hr	---	---	23	---	500	NO	575	NO
PM_{10}	Annual	0.007	0.007	0.004	0.02	1.0	NO	---	---
	24-hr	1.04	1.04	0.48	1.71	5.0	NO	10	NO
$PM_{2.5}$	Annual	0.007	0.007	0.004	0.02	0.3	NO	---	---
	24-hr	1.04[1]	1.04	0.48	1.149[1]	1.2	NO	2.3	NO

[1] When using the correct coordinates, maximum predicted impacts for GE 7 FA.05 $PM_{2.5}$ (24-hr) is 0.99 µg/m³ and for GE LMS100 $PM_{2.5}$ (24-hr) is 1.13 µg/m³. Both corrected values are not over SIL. See February 14, 2012, memo submitted by the applicant.

In addition, these maximum impacts occur at locations well within the receptor grids, not on the borders, which would necessitate further grid analyses. As a result, no additional modeling was performed on the finer grid spacing.

Based on these results, a full NAAQS analysis and an increment analysis were not required for any pollutant.

On December 19, 2011, Ecology was informed that the location coordinates provided for the combustion turbine stacks (for each turbine option) in the permit application were off by a few hundred feet to the east and south. Additional analysis was performed by PSE Fredonia and approved by Ecology on February 10, 2012. PSE Fredonia demonstrated that the error did not significantly affect air quality modeling results presented in original permit application. Therefore, the original analysis in PSE Fredonia's PSD permit application is sufficiently accurate to demonstrate compliance with air quality standards.

5. ADDITIONAL IMPACTS ANALYSIS

PSD regulations and guidance require additional impact analyses to evaluate the effects of the project's emissions on visibility, local soils, and vegetation in Class I and II areas, and the effect of increased air pollutant concentrations on flora and fauna in the Class I areas. The additional impact analyses are also used to evaluate the effect of the project on growth in the area surrounding the project.

5.1. Growth Analysis

PSE Fredonia facility is located at 13085 Ball Road near Mount Vernon, Skagit County, Washington. According to 2009 census data, Skagit County experienced a total population growth rate of 16.1% between 2000 and 2009. Expansion of the FGS does not cause growth, but provides some of its power to the community it serves in Skagit County.

The construction of the project is expected to begin in 2013 and should take approximately 18 months to complete. The completion of the project will require approximately 200 temporary construction-related jobs, though there will not be 200 construction workers on-site for the whole construction period. The expanded facility will create two to four additional permanent jobs. The municipal and residential services currently provided in the surrounding communities will be adequate to support the proposed project. Therefore, potential negative impacts on local air quality and Class I area air quality associated with municipal and residential growth are not anticipated.

5.2. Soils and Vegetation Analysis

Project emissions that have the most potential to affect soils and vegetation are those that contain either sulfur or nitrogen. SO_2 and NO_X are not subjected to PSD review for this project because their emissions are less than their respective SERs. As a result, no deposition analysis was required, but this analysis was conducted and is included in the application.

5.3. Visibility Impairment Analysis

The local visibility impacts of the project should be negligible. Natural gas combustion does not typically produce any visible particulate emissions. The turbine exhaust stack emissions will typically be clear, and the opacity will be limited through the NWCAA NOC permitting process. This amount of opacity is normally just barely perceptible. Visibility impacts on more distant Class I areas (and, in a conservative manner, on the Mount Baker Wilderness Area (MTB), a Class II area) are discussed in the Air Quality Related Value (AQRV) analysis below.

5.4. Class I Areas Impacts Analysis

Federal (40 C.F.R. §52.21) and Washington State (WAC 173-400-117) PSD regulations require that the impact of a proposed facility on federal Class I areas is analyzed. Mandatory Class I

areas are defined in the federal Clean Air Act and are afforded the highest level of air quality protection under the PSD rules. They include most national parks, national wilderness areas, and national memorial parks. WAC 173-400-030(16) lists the Class I areas in Washington State. North Cascades National Park (NCNP), Olympic National Park (ONP), Glacier Peak Wilderness (GPW), and Alpine Lakes Wilderness (ALW) are the only Class I areas near this project site. In addition to these Class I analyses, per request of the United States Forest Service (USFS), visibility and deposition was evaluated for MTB, a Class II protected area located approximately 41 km from the project site.

In general, the impacts analysis includes an assessment of increment consumption and impacts to AQRVs in Class I areas. The objective of the AQRV analysis is to demonstrate that air emissions from the proposed project would not cause or contribute to a significant impact on visibility, regional haze, or total nitrogen (N) or total sulfur (S) deposition in any of the specifically modeled Class I areas. The National Park Service (NPS) and USFS are the FLMs who have the responsibility of ensuring that AQRVs in the Washington Class I areas are not adversely affected.

5.4.1. Criteria Pollutant Maximum Predicted Concentrations in Class I Areas

Per request of USFS and Ecology, the Class I area impact analysis was performed for MTB, a Class II area located less than 50 km from the proposed project. Impacts were evaluated using the results of the AERMOD modeling discussed in Section 4.

Table 21. Criteria Pollutant Impacts for the Potential Turbine Options at MTB

Pollutant	Averaging Period	Maximum Predicted Impacts (µg/m^3)				Class I SIL (µg/m^3)
		GE 7FA.05	GE 7FA.04	Siemens SGT6- 5000F4	GE LMS100 (2 Units)	
PM_{10}	Annual	0.001	0.001	0.001	0.001	0.08
	24-hr	0.041	0.041	0.037	0.055	0.27
$PM_{2.5}$	Annual	0.001	0.001	0.001	0.001	0.06
	24-hr	0.041	0.041	0.037	0.055	0.07

This modeling indicates (as shown in Table 21) that the $PM_{2.5}$ and PM_{10} concentrations are well under their respective SILs. Given that all the Class I areas are a further distance to the facility compared with MTB and these impacts at MTB are all well below their respective SILs, it is safe to conclude that all Class I areas within 100 km of the project have impacts below the SILs, and no further analysis is required. Additional dispersion modeling using the accepted guideline model was not performed.

5.4.2. AQRV Screening Analysis

The NPS, USFWS, and the USFS released revised guidance *Federal Land Managers' Air Quality Relative Values Work Group (FLAG) Phase 1 Report –Revised (2010)* (Natural Resources Report NPS/NRPC/NRR – 2010/232, October, 2010; 75 FR 207, October 27, 2010). This final version of updates, initially issued in 2008, includes a threshold ratio of emissions to distance (Q/d), below which the services have determined a detailed AQRV review is not required. The FLAG document contains the following decision process:

If Q (tpy)/d (km) is less than 10, no AQRV analysis is required, where:

- Q is the emission increase of SO_2, NO_X, PM_{10}, and H_2SO_4 mist combined in tpy.
- d is the nearest distance to a Class I area in km.

If Q/d is less than 10 for a Class I Area, then presumptively, there is no adverse impact and a project "screens out" of a Class I AQRV analysis. If Q/d results in a value above 10, a Class I analysis is required.

Q for use in the above formula was based on the project's maximum 24-hour emission rates converted to an annual emission rate assuming full-time (8760 hours) operation. A calculation of Q was developed for each turbine option. Table 22 provides the estimates of both the specific pollutant emission rates, and the total emissions, Q, for each turbine technology option (including 24 hours of emergency engine use). These values are then divided by the distance to the nearest Class I area (NCNP at 69 km from the PSE project site). Using these conservative estimates for emissions, all of the project's options have a Q/d value below 10 (for each Class I area). Therefore, the FLMs do not require any additional AQRV analyses. However, a full AQRV analysis was still conducted for the Class II MTB. Details about this analysis are available in the permit application.

Table 22. AQRV Q/d Screening Analysis

	Turbine Option			
	GE 7FA.05	**GE7FA.04**	**Siemens SGT6-5000F4**	**GE LMS100 (2 Units)**
Maximum Emissions (lb/hr) on a 24-hr Basis[1]				
NO_X	52	30	52	39
PM_{10}	48	46	40	54
SO_2	10	9	9	9
H_2SO_4	22	19	23	17
Sum of Emissions Prorated to Full-Time Annual Basis (tpy)[2]				
Q	578	458	543	517
AQRV Screening[3]				
Q/d	**8.38**	**6.64**	**7.87**	**7.49**

[1] Emission rates include emergency generator operation.
[2] Annual emissions (Q) assume 8760 hr at maximum 24-hr lb/hr emission rate.
[3] Distance to nearest Class I area is 69 km (NCNP).

6. ENDANGERED SPECIES ACT

Pursuant to Section V.A. of the Agreement For The Delegation Of The Federal Prevention of Significant Deterioration Program from the United States Environmental Protection Agency to the Washington State Department of Ecology, dated November 17, 2011, Ecology shall not issue a PSD permit until EPA has notified Ecology in writing that EPA has satisfied its obligations, if any, under Section 7 of the Endangered Species Act (ESA), 16 U.S.C. § 1531 et seq., and 50 C.F.R. Part 402, Subpart B (Consultation Procedures), and with Section 305(b)(2) of the Magnuson-Stevens Fishery and Conservation Act (Magnuson-Stevens Act, MSA), 16 U.S.C. § 1801 et seq., 50 C.F.R. Part 600, Subpart K (EFH Coordination, Consultation, and Recommendations), for federal PSD permits, regarding essential fish habitat. Therefore, the final PSD permit will not be issued for this project until EPA has notified Ecology that this consultation has been completed.

On December 13, 2012, the EPA notified Ecology that they have satisfied their obligations under the Endangered Species Act and the Magnuson-Stevens Act relative to this permitting action. No further ESA or MSA consultation was undertaken relative to this action.

7. STATE ENVIRONMENTAL POLICY ACT (SEPA)

Under Washington State rules, a final PSD permit shall not be issued for a project until the applicant has demonstrated that SEPA review has been completed for the project. The Skagit County is the lead agency for SEPA.

On February 3, 2012, PSE submitted a "Determination of SEPA Compliance" to Skagit County. The county explained that the proposed expansion and changes in air quality emissions at PSE Fredonia have been addressed through land use and environmental reviews. The county concluded that "total site emissions of VOCs with the proposed project will be well below the maximum level established in the 1991 [Environmental Impact Statement, EIS]. No further study of air quality emissions will be required by Skagit County . . . ."

Ecology concludes that the applicant has adequately demonstrated compliance with SEPA requirements.

8. AGENCY CONTACT

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ACRONYMS AND ABBREVIATIONS

°F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter
ALW	Alpine Wilderness
AQIA	air quality impacts analysis
AQRV	air quality related values
ASIL	acceptable source impact level
BACT	best available control technology
BART	best available retrofit technology
bhp	brake-horsepower
bkw	brake-kilowatt
CAA	Clean Air Act
CARB	California Air Resources Board
CCCT	combine cycle combustion turbine
CCS	carbon capture and sequestration
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
DAT	deposition analysis threshold
DC	direct current
DCS	distributed control system
DLN	dry-low NO_X
Ecology	Washington State Department of Ecology
EOR	enhanced oil recovery
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act
FGS	Fredonia Generating Station
FLAG	Federal Land Managers' Air Quality Relative Values Workgroup
FLM	Federal Land Manager
FR	Federal Register
GE	General Electric

GHG	greenhouse gas
GPW	Glacier Peak Wilderness
gr	grains
GWP	global warming potential
H_2SO_4	sulfuric acid mist
HAPs	hazardous air pollutants
hr/yr	hours per year
kV	kilovolt
kW	kilowatt
LAC	level of acceptable change
LCRA	Lower Colorado River Authority
MACT	maximum achievable control technology
MSA	Magnuson-Stevens Act
MSL	mean sea level
MTB	Mt. Baker Wilderness Area
MW	megawatts
N	total nitrogen
NAAQS	National Ambient Air Quality Standards
NCNP	North Cascades National Park
NESHAP	National Emission Standards for Hazardous Air Pollutants
NG	natural gas
NOC	Notice of Construction
NO_X	nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	new source review
NWCAA	Northwest Clean Air Agency
ONP	Olympic National Park
Pb	lead
PM	particulate matter
PM_{10}	particulate matter less than 10 micrometers in diameter
$PM_{2.5}$	particulate matter less than 2.5 micrometers in diameter

ppb	parts per billion
ppm	parts per million
ppmv	parts per million by volume
ppmvd	parts per million by volume on a dry basis
PSD	Prevention of Significant Deterioration
PSE	Puget Sound Energy
PTE	potential to emit
PVEC	Pioneer Valley Energy Center
Q/d	emissions to distance
RBLC	RACT/BACT/LAER Clearinghouse
S	total sulfur
SCR	selective catalytic reduction
SEPA	State Environmental Policy Act
SER	significant emission rate
SF_6	sulfur hexafluoride
SIL	significant impact level
SQER	small quantity emission rate
SUSD	start-up and shutdown
SWCAA	Southwest Clean Air Agency
TAP	toxic air pollutant
tpy	tons per year
ULSD	ultra-low sulfur diesel
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
VAC	voltage alternating current
VDC	voltage direct current
WAC	Washington Administrative Code