

**STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL**

**TECHNICAL SUPPORT DOCUMENT FOR
PREVENTION OF SIGNIFICANT DETERIORATION AND
NOTICE OF CONSTRUCTION PERMIT
BP Cherry Point Cogeneration Project NO. EFSEC/2002-01 Amendment 1
Whatcom County, Washington
February 20, 2007**

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1. EXECUTIVE SUMMARY

BP West Coast Products received a permit to build a natural gas fired cogeneration facility at the BP refinery near Blaine Washington in June 2005. BP now proposes to change the design of the project from one using three combustion turbines, to one using two combustion turbines. An application to do this has been submitted. This application also extends the time that BP has to commence construction on the project for an additional eighteen months.

The Energy Facility Site Evaluation Council (EFSEC) has considered the application and found that the applicant has satisfied all requirements for modification to the PSD/Notice of Construction approval. This technical support document explains the project and the proposed changes to the permits.

2. INTRODUCTION

2.1. The Permitting Process

2.1.1. The Prevention of Significant Deterioration Process

The Prevention of Significant Deterioration (PSD) procedure is established in Title 40, Code of Federal Regulations (CFR), Part 52.21. Federal 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 serious adverse environmental impact from emissions into the atmosphere by a proposed new 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 environmentally related areas for such parameters as visibility, soils, and vegetation. PSD rules also require the utilization of the most effective air pollution control equipment and procedures, after considering environmental, economic, and energy factors.

The Washington State Energy Facility Site Evaluation Council (EFSEC) is the PSD permitting authority for new thermal energy facilities with a net electrical output greater 350 Megawatts (MW), sited in the state of Washington, per Chapter 80.50 of the Revised Code of Washington (RCW) and Chapter 463-60 of the Washington Administrative Code (WAC).

2.1.2. The Notice of Construction Process

The procedure for issuing a Notice of Construction (NOC) permit is established in Chapter 70.94 Revised Code of Washington. Chapter 173-400 WAC and Chapter 173-460 WAC, require all new or modified stationary sources of air pollution to file a NOC application and receive an order of approval, prior to establishing a new or modified stationary source.

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

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

EFSEC is the NOC permitting authority for energy facilities greater than 350 MW sited in the State of Washington as defined in Chapter 463-60 WAC, and Chapter 80.50 RCW.

2.1.3. 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)	40 CFR 60, Subpart KKKK
NSPS Quality Assurance Procedures	40 CFR 60 Appendix F
NSPS Performance Specifications	40 CFR 60, Appendix B
National Emission Standards for Hazardous Air Pollutants (NESHAP) (<i>currently stayed by EPA at the time of writing this document</i>)	40 CFR 63 Subpart YYYY
Acid Rain Permitting	40 CFR 72
Emissions Monitoring and Permitting	40 CFR 75
Sulfur Content of Natural Gas to be monitored	40 CFR 60.4360,, and 40 CFR 75, Appendix D

2.1.4. State Regulation 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.

Air emissions permits and authorizations	Chapter 463-60-536 WAC
General Regulations for Air Pollution Sources	Chapter 173-400 WAC
Operating Permit Regulations	Chapter 173-401 WAC
Acid Rain Regulations	Chapter 173-406 WAC
Controls For New Sources of Toxic Air Pollutants	Chapter 173-460 WAC

2.2. The Project

2.2.1. The Site

BP West Coast Products, LLC, a wholly-owned subsidiary of BP, PLC, was permitted effective June 21, 2005 to construct a 720-megawatt power cogeneration facility in northwestern Whatcom County, Washington. The BP Cherry Point Cogeneration Project (Project) would be located at the BP Cherry Point Refinery (Refinery), which is 6 miles northwest of Ferndale, 7 miles southeast of Blaine and about 15 miles north of Bellingham (T39N, R1E, S8, with UTM 10 520300E and 5415000N). The nearest community is Birch Bay, located about 2 miles northwest of the site. The Canadian border is about 8 miles directly north of the proposed site.

The Cogeneration Project would be sited adjacent to the northeast corner of the Refinery. The project, including the generation plant and support facilities, the new transmission line, natural gas and water supply lines, and construction laydown areas would be on BP Refinery owned property. This area is within the Cherry Point Major Industrial Urban Growth Area/Port Industrial Zone as defined in the Whatcom County Comprehensive Plan, issued May 20, 1997. The entire project area is zoned Heavy Impact Industrial. The Cogeneration Project site would occupy approximately 33 acres of unimproved land.

The land surrounding the proposed Cogeneration Project is relatively flat and owned by BP for at least 0.5 miles in all directions. The closest residence is about 0.75 miles north and east of the proposed Cogeneration Project. Industries in the area other than the Refinery include the Chemco plant located about 0.75 miles east of the project site and the Praxair plant located 0.75 miles south of the project site.

2.2.2. The BP Cogeneration Project

BP is applying to amend its original PSD permit for two reasons:

1. To allow for a revised project design as described in the following paragraphs.
2. To extend the original PSD permit for an additional 18 months. Approval Condition 29 of the existing permit states that “This approval shall become invalid if construction of the Project is not commenced within eighteen (18) months after receipt of final approval, or if construction of the facility is discontinued for a period of eighteen (18) months, unless EFSEC extends the 18 month period upon a satisfactory showing that an extension is justified, pursuant to 40 CFR 52.21(r)(2) and applicable EPA guidance.” The original permit became effective on June 21, 2005 when the EPA Environmental Appeals Board (EAB) denied review of a petition for review. Eighteen (18) months from that date is December 18, 2006. BP has initiated the extension process by submitting this application for permit amendment within that time frame.

BP proposes to amend the PSD permit to allow for the construction of an alternate configuration using two combustion turbines and one steam turbine (“2 x 1” design) for the cogeneration facility at the same location, referred to from here on as the “520 MW Project”, or the “Project.” Like the permitted 720 MW three combustion turbine/one steam turbine (“3 x 1” design) project, the cogeneration facility will be designed and permitted to provide base load electric service and to operate year-round except for maintenance. Distribution of the electric power will be to the nearby transmission system with a portion of its electric power dedicated to the BP Cherry Point Refinery. Commercial operation is expected to begin in the 2nd calendar quarter of 2009.

BP is considering the purchase of combustion turbines (CTs) from either of two turbine manufacturers, namely: General Electric (GE) and Siemens. Depending on the final selection of combustion turbines (CTs) and the final size of the steam turbine (ST), the nominal generating capacity of the cogeneration facility will be in the range of 520 to 570 megawatts (MW).

The Project will consist of two combustion turbines (CTs), two associated heat recovery steam generators (HRSG) and one unfired steam turbine (ST). The HRSGs will be equipped with supplemental firing capability (duct burners). The Project will be operated only in combined-cycle mode. The CTs will be fired with natural gas. The duct burners will be fired with gaseous fuels such as natural gas or refinery fuel gas (RFG) treated to reduce total sulfur in the RFG to a level equivalent to that of natural gas. Each of the CT/HRSG combinations will have an associated stack with Best Available Control Technology (BACT) applied to control potential air emissions.

If the Siemens turbines are used, the fuel consumption of the new 2x1 proposal will be very similar to the original 3x1 proposal. This is due to the slightly larger size of the Siemens turbines and the larger duct burners proposed in the 2x1 design. If the GE turbines are used, the total fuel consumption of the 2x1 design will be lower because the GE turbines are slightly smaller than the Siemens turbine. The maximum duct burner sizes are similar for both turbine choices. The 2x1 design will generate less total megawatts of power than the original 3x1 design, but it makes up for this by having the ability to send more steam to the refinery, especially on a short term basis.

One diesel driven emergency generator about 1,500 kW in size will be installed to provide support system power to critical plant instrument and lubrication systems in the event that electric power is not available from the grid. A diesel driven firewater pump will be used to maintain firewater pressure in the event that the electric power is not available or firewater pressure is inadequate. The diesel firewater pump is anticipated to be about 265 horsepower in size. The emergency generator and firewater pump are proposed to be operated a maximum of 250 hours per year for routine maintenance and training purposes.

The diesel fuel for the firewater pump and emergency generator will have a sulfur content determined by the Federal on road diesel specification at the time of fuel purchase. The sulfur content is modeled for this application at less than 0.05%. That Federal specification for sulfur in diesel fuel was reduced to less than 15 ppm (0.0015%) in mid 2006.

Water cooling needs will be supplied from an induced draft, counter flow, multi-cell cooling tower. Emissions from the cooling tower are expected to consist only of PM₁₀. These emissions originate from the dissolved solids in the droplets of cooling water, called “drift,” that escape in the air stream exiting the cooling tower. High efficiency drift eliminators with a drift rate of 0.0005% are proposed to be installed.

Table 1 Comparison of the currently permitted (720 MW) and proposed (520 MW) projects

Facility Design	3x1 720 MW Project	2x1 520 MW Project
Maximum Electrical Output	720 MW	520-570 MW
Type of service	Base load year round	Base load year round
Electricity to Refinery	85 MW	100 MW
Steam to Refinery	770,000 lbs per hour (max.) 510,000 lbs per hour (avg.)	1,200,000 lbs per hour (max.) 510,000 lbs per hour (avg.)
Gas Turbines	Three GE 7FA	Two GE 7FA, or Two Siemens SGT6-5000F
Number of HRSGs	Three	Two
Duct Burner maximum firing rate	315 MMBtu/Hr total (105 MMBtu/Hr each)	900-1200 MMBtu/Hr total (450-600 MMBtu/Hr each)
Duct Burner fuel	Natural Gas	Natural Gas or Refinery Fuel Gas Treated to Equivalent Sulfur Specification
Form of Ammonia	Anhydrous	Aqueous
Steam turbine and generator	243 MW	Steam turbine with about 200 MW electrical generator
Emergency Generator	1,500 kW diesel fueled	About 1,500 kW, diesel fueled
Firewater pump	265 hp diesel fueled	About 265 hp, diesel fueled
Cooling tower	Multi-cell cooling tower	Multi-cell cooling tower

2.3. Cogeneration Operation And Integration With The Refinery

The Cogeneration Project integrates its operation with the Refinery to increase efficiency and reduce the consumption of and impacts to natural resources. The Cogeneration Project would supply steam and electricity to the Refinery, which would in turn recycle condensate back to the Cogeneration Project. This cogeneration plant steam supply would allow the Refinery to reduce the use of boilers thus reducing their emissions to the atmosphere. Refinery use of steam from the cogeneration plant also makes more efficient use of steam energy than if the power plant was a stand alone power plant. A stand alone power plant sends the moderate pressure steam exiting the steam turbine to a cooling tower where it is condensed, wasting this energy. If that steam is sent instead to the refinery, its energy can be used in processes like heating crude oil to processing temperatures.

The emissions reduction benefits to the refinery because of the cogeneration operation are real and are estimated in the BP Cherry Point Cogeneration Project Application for Site Certification, but are not relied upon for any air permitting activities such as the PSD or NOC process. The PSD and NOC permits analyze and permit the Project as if it is a stand alone combined cycle power plant.

2.4. New Source Performance Standards (NSPS)

A new NSPS has become applicable to gas turbines since the original permit was issued. 40 CFR 60 Subpart GG is no longer the applicable NSPS. The federal "Standards of Performance for Stationary Combustion Turbines" 40 CFR 60 Subpart KKKK is now applicable to the nitrogen oxides (NO_x) and sulfur oxides (SO₂) emissions from the combustion turbines and duct burners. This NSPS limits NO_x emissions from the proposed project's turbines and duct burners to 15 parts per million dry volume (ppmdv) or 54 nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt hour (lb/MWh)). SO₂ emissions are not to be in excess of 110 ng/J (0.90 lb/MWh). As an alternative, sulfur in fuel may be monitored. Sulfur content is not to exceed 26 ng SO₂/J (0.060 lb SO₂/MMBtu) of heat input. This is the equivalent of a natural gas tariff of 20 grains sulfur per 100 cubic feet of natural gas. Test methods for NO_x and sulfur emissions are specified. It requires determination of daily sulfur emissions monitoring by keeping track of fuel sulfur content and usage. It allows development of a custom fuel monitoring schedule that must be approved by the United States Environmental Protection Agency's (EPA's) Region 10. Note that application of the "top down" Best Available Control Technology (BACT) process creates NO_x and sulfur emission limits that are lower than these NSPS maximum limits. There are no NSPS requirements for carbon monoxide (CO), particulates (PM), particulates less than 10 microns in diameter (PM₁₀), or volatile organic compounds (VOC) in Subpart KKKK.

As noted above, the duct burners are no longer subject to the NSPS for steam generating units in 40 CFR 60, Subpart Db. Their emissions are now included in the limitations of Subpart KKKK.

No NSPS standards apply to the emergency generator or the firewater pump engine. Both are subject to the requirements for new nonroad engines in 40 CFR 89 that are applicable to their engine size class at the time of engine manufacture.

2.5. British Columbian And Canadian Air Quality Objectives

The federal Canadian Environmental Protection Act provides for three levels of air quality objectives: Desirable, Acceptable and Tolerable. British Columbia (BC) has similar "Objectives and Guidelines" for air quality comprised of three levels: A, B, and C. The federal objectives are based on the following definitions (the BC definitions are similar, but not identical):

- **Maximum Desirable** defines the long term goal for air quality and provides a basis for an antidegradation policy for the country for the continuing development of control technology.
- **Maximum Acceptable** is intended to provide adequate protection against effects on soil, water, vegetation, material, animals, visibility and personal comfort and well-being.
- **Maximum Tolerable** denotes time-based concentrations of air contaminants beyond which, due to a diminishing margin of safety, appropriate action is required without delay to protect the health of the general population.

The Project is not subject to these Canadian standards, but because of the close proximity of the site to the border with British Columbia, the Project's Canadian impacts are analyzed and presented as a part of Section 4, the Ambient Air Quality Impacts Analysis, and Section 6 on Class I Areas Impacts Analysis.

2.6. Project Emissions And PSD Applicability

The BP Cherry Point Cogeneration Project (Project) is permitted as a major source.¹ Emission of a regulated pollutant² at levels considered significant³ by the federal PSD regulations require permitting under the federal PSD program. As Table 2 shows, NO_x, CO, VOC, PM₁₀, SO₂, and sulfuric acid mist (H₂SO₄) are all emitted in PSD significant quantities.

After the application of emission controls representing BACT or to protect ambient air quality, the Project is proposed to have annual emissions as shown in Table 2. The turbines will have short term emissions as shown in Table 3.

Table 2 Annual PSD Regulated Pollutant Emissions, Reflecting Proposed Emission Controls, and PSD Significant Emission Rate, all units are tons per year (tpy)

Equipment	Hours of operation per year	NO _x (tpy)	CO (tpy)	VOC (tpy)	PM ₁₀ ¹ (tpy)	SO ₂ (tpy)	H ₂ SO ₄ (tpy)
2 Turbines (520 MW 2x1 new proposal)	8,760	216.5	157.5	58.2	254.8	51.0	30.0
Emergency Generator	250	3.4	0.9	0.16	0.09	0.10	
Firewater Pump	250	0.42	0.021	0.018	0.006	0.013	
Cooling Tower	8,760	0	0	0	7.1	0	
Total		220.3	158.4	58.4	262.0	51.1	30.0
PSD Significant Emissions Rate	Annual	40	100	40	15	40	7
3 turbines (720 MW 3x1 original proposal) ²	8,760	229.4	156.8	42.2	254.4	50.9	35.5

1. All particulate matter is considered to be PM₁₀ for this project.
2. Originally proposed emissions from 3 turbines for comparison to new two turbine proposal.

¹ Combined cycle turbines are considered part of the category “Fossil fuel-fired steam electric plants.” They are a major source under PSD regulations if they, in total, have the potential to emit more than 100 tons per year of a pollutant regulated by the PSD permitting program. 40 CFR 52.21(b)(1)(i)(a).

² The PSD program directly regulates a list of specific pollutants. These are referred to as “regulated pollutants.” The compounds listed in Table 1 are the regulated pollutants applicable to the project. PSD regulates other pollutants indirectly through the broad categories of “regulated” pollutants such as VOC and particulates. In Washington State EFSEC issues a second permit (the Notice of Construction Approval, or NOC) that complements the PSD permit and includes all emissions regulated by state and local regulations. WAC 173-400-113.

³ The PSD regulations list a minimum annual emission rate for each regulated pollutant to be considered “significant” in 40 CFR 52.21(b)(23)(i). Some of these threshold levels are given in Table 2.

Table 3 Short Term PSD Regulated Pollutant Turbine Emissions

Design	Fuel (t+db) ¹ (MMBtu/hr)	NO _x (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM ₁₀ ¹ (lb/hr)	SO ₂ (lb/hr)	H ₂ SO ₄ (lb/hr)	NH ₃ (lb/hr)
2x1 per turbine	2,002 (t) 600 (db)	26.5	12.9	6.9	29.2	12.5	3.8	15.1
3x1 per turbine	1731.4 (t) 105.0 (db)	19.0	9.2	3.0	20.6	8.8	2.8	13.2
3x1 total	5,509	57.0	27.6	9.0	61.8	26.4	8.4	39.6
2x1 total	5,204	53.0	25.8	13.8	58.4	25.0	7.6	30.2

1. Maximum hourly fuel consumption for t=turbine, db=duct burner

Emissions are subject to both short term and long term limits. Short term limits, such as hourly, three hour, or 24 hour averaging periods are usually larger in order to allow for fluctuations in the emissions of the measured pollutant. Long term limits, such as monthly or annual, reflect the more stable average emission rate over that longer time period. The annual averages include emissions from events such as start up and shut down.

BP has carefully analyzed estimated emissions for this project, and determined that annual emissions of NO_x, CO, PM₁₀, and SO₂ are best estimated for modeling and impacts analysis purposes at rates different than would be represented by multiplying the shorter term emission factors (such as hourly, three hour, or daily) factors by 8,760 hours or other appropriate annualizing factor. The annual emission rates calculated by BP are based on careful estimates of operating hours under maximum and reduced load conditions, the effect of startup and shutdown emissions, and the number of non operating hours. The annual emissions limits in Table 4 are included in the permits.

Table 4: Annual Emission Limits on Individual Equipment

Unit	NO _x	CO	PM ₁₀	SO ₂	VOC
Each CTG/HRSG, tons/yr	108.3	78.8	127.4	25.5	29.1
Cooling Tower, tons/yr	NA ¹	NA ¹	7.2 ²	NA ¹	NA ¹
Emergency Generator, tons/yr	3.4	NA ¹	NA ¹	NA ¹	NA ¹

1. NA means “not applicable.” The cooling tower has no NO_x, CO, or SO₂ emissions.
2. The emergency generator’s NO_x emissions are the only emissions from the generator or the firewater pump estimated to be more than 1 ton per year.

2.7. Comparison of Emissions From the Original and Current Proposals

Table 2 summarizes long term maximum potential to emit (PTE) permit limits for regulated pollutants as proposed in the amended permit application. With the exception of CO, the quantities provided in this table assume operation of the gas turbines and duct burners at maximum emission rates for each hour of the year. Because of the combustion characteristics of gas turbines and the limited effectiveness of CO catalyst at low temperatures, the amount of CO produced during startups is much higher than the CO produced during maximum operation. For these reasons, the maximum PTE for CO is established by assuming partial operation during the year and including emissions associated with startups and shutdowns.

Table 2 also provides a summary of the long term PTE limits in the existing permit for the 3x1 project. A comparison of these emission limits shows the original and amended permit limits are similar, even though the amended permit application is for a project with two turbines versus three in the original

permit. Intuitively it seems the PTE emissions limits in the amended permit should be about 2/3 of those in the original permit. There are three reasons why this is not the case.

First, the amended permit application proposes using either GE 7FA or Siemens SGT6-5000F turbines. Table 2 uses the higher of the two emission rates for each of the pollutants above. NO_x, SO₂ and H₂SO₄ emissions in Table 2 represent emissions from the Siemens SGT6-5000F turbine, which are higher than the GE turbines because of the higher Siemens fuel consumption. CO, PM₁₀ and VOC emissions in Table 2 are for the GE 7FA turbine, which has higher emission factors for these pollutants than the Siemens turbine.

Second, the amended permit application allocates more CO emissions for startups and shutdowns. In the original permit, the CO potential to emit long term limit was 157 tons/year, which included 53 tons/year for startup and shutdown emissions and 104 tons/year for operating emissions. The amended permit application has the same 157 ton/year limit but allocates 95.5 tons/year for startup and shutdown emissions and 63.5 tons/year for operating emissions. The larger quantity of startup emissions are required to account for uncertainty in actual CO emissions during startup and to allow for more flexibility in operations.

Third, the project proposed in the amended permit application must have larger duct burners than did the original project. The project in the amended permit application will be capable of providing almost 50% more steam to the refinery than could the original project. Thermal efficiency of the Cogen project improves as steam export to the refinery increases, and avoided refinery boiler emissions also increase. Larger duct burners are also needed for steam reliability to the refinery in the event of a gas turbine failure. The original project had three gas turbines and if one gas turbine failed, duct burners in the other two trains could make up the steam lost as a result of the failure. The amended permit has only two gas turbines, so in the event of a gas turbine failure only one set of duct burners is available to make up for the steam lost.

Duct burners have an emission factor for VOCs that is over 6 times higher than the gas turbine VOC emission factor, so as a consequence VOCs in the amended permit application are 16 tons/year higher than those in the original permit.

On a Potential to Emit basis, maximum emissions from the project proposed in the amended permit application are close to those in the original permit. However BP expects that total criteria pollutant emissions from the project in the amended permit will be less than those in the original permit. This comparison is shown in Table 6 (page 8) of the Permit Amendment Description⁴.

2.8. Toxics Emissions

Most toxic air pollutants that would be emitted by the project are a subset of the of the criteria pollutant emissions listed in Table 3. This includes toxic air pollutants listed as federal Hazardous Air Pollutants (HAPS) and those listed as Washington State Toxic Air Pollutants (TAPs). For example, most organic based toxic compounds are included as a subset of VOC compounds. Metal toxic compounds emitted to air are a part of the PM₁₀. Nitrogen oxide (NO, a state TAP but not a federal HAP) is a portion of the NO_x potential emissions estimate.

Toxic air pollutant emissions are estimated and their impacts are evaluated as part of the ambient air quality analysis in Section 4 of this Technical Support Document. Toxic emissions are regulated in the NOC portion of this EFSEC permit according to the Washington State regulation 173-460 WAC.

⁴ The Permit Amendment Description may be found at <http://www.efsec.wa.gov/bpcogen/SCA%20AMendment%202006-20-06/Amendment%20description%20006-19-06.pdf>

Ammonia would be used as part of the SCR NO_x control catalyst system. Ammonia is not a federal HAP, but is listed as a Washington State TAP. At the proposed maximum “slip” of 5.0 ppm_{dv},” total ammonia emissions to the atmosphere would be 129 tons per year. Ammonia and other toxic air pollutant emissions from the proposed Project that have modeled impacts are discussed in Section 4.2.

3. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

3.1. Definition And Policy Concerning BACT

All new sources are required to utilize Best Available Control Technology (BACT). 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)). A BACT review is required for this application both because of the change in project design, and to allow extension of the permit for an additional 18 months.

The "top down" BACT process starts by considering the most stringent form of emissions reduction technology possible, then determines if that technology is technically feasible and economically justifiable. If the technology is proven infeasible or unjustifiable, then the next less stringent level of reduction is considered. When an emission reduction technology meets the stringency, and technical and economical feasibility criteria, it is determined to be BACT.

3.2. BACT For Gas Turbine/Heat Recovery Steam Generator Systems

3.2.1. Nitrogen Oxides Control

NO_x can be formed in two ways in a combustion process:

- The combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x); and
- The oxidation of nitrogen chemically bound in the fuel (fuel-bound NO_x).

Natural gas does not contain a significant amount of fuel-bound nitrogen, so all NO_x emissions from the gas turbines and duct burners are considered to originate from thermally formed NO_x. The refinery gas fuel also has a very low fuel nitrogen content. NO_x emissions will be controlled to the same BACT level regardless which fuel is burned.

3.2.1.1. Review of Previous BACT Determinations for NO_x

The RBLC database was searched for natural gas-fired “large combustion turbines” that are combined cycle or cogeneration (process code 15.210). The period from 2001 to May 2006 was searched.

The lowest NO_x emission for CTs of similar size listed in USEPA’s RBLC (See Appendix D) is 2 ppm_{dv} for 16 facilities. According to the RBLC listing, three of these represent LAER and the rest represent BACT. Since 2003, nearly every facility has been permitted in the 2 to 3.5 ppm_{dv} range. Every combined cycle facility utilizes SCR as a control technology. None of the facilities listed is a cogeneration facility with the variable steam demands of an oil refinery.

Ten other plants listed in the RBLC were proposed in the Pacific Northwest. These include, in order of increasing NO_x limit, Sumas Generation in Washington and Wanapa Energy in Oregon which are listed at 2 ppm_{dv}; Cob Energy, Klamath Generation, the Port Westward Plant in Oregon, Wallula Generation,

Satsop Combustion Turbine project, Longview Energy in Washington and Garnet Energy in Idaho which are all listed at 2.5 ppmv; and Chehalis Generation in Washington at 3 ppmv. These facilities were all proposed to be located in attainment areas for NO_x and, therefore, represent BACT. All of the above named facilities proposed to use Selective Catalytic Reduction (SCR) catalyst systems for control of NO_x emissions.

In connection with the original PSD permitting decision for the 720MW Cogeneration Project, EFSEC and EPA considered whether it would be appropriate to limit NO_x emissions to 2.0 ppmv as in some of the facilities listed above. EFSEC and EPA concluded that a 2.5 ppmv limit was appropriate given the unique features of the project. As summarized in the PSD/NOC Permit No. EFSEC/2002-01, Responsiveness Summary (Sep. 24, 2004), on page 8, paragraph 4:

The Project's CTs and DBs will be fired under variable load conditions to adjust for continuous swings in steam demand across multiple process units at the BP Cherry Point Refinery. Variable DB and CT firing rates will generate greater NO_x emissions (exit gas NO_x concentrations) and therefore limit the Project's ability to reduce emissions below 2 ppmv NO_x. Stand-alone combined cycle power generation plants and cogeneration facilities with more predictable and steady-state steam loads simply enjoy more favorable operating conditions to control NO_x emissions below 2 ppmv.

The proposal to construct a 2x1 cogeneration project rather than the original 3x1 project does not affect this analysis. The Project will still be operated under variable load conditions with fluctuating and unanticipated changes in steam demand by the refinery.

Potentially Available Control Technologies

The formation of NO_x from the proposed CTs is minimized by the use of dry low NO_x combustors. These combustors control NO_x to about 9 ppmv for the GE 7FA turbine (Siemens turbines slightly higher) under full load operating conditions and for loads down to 50 percent during natural gas firing. The HRSG is proposed to be equipped with low NO_x duct burners with a NO_x emission rate of 0.08 lb/mmBtu. To achieve lower levels of NO_x, add-on controls are required.

A review of the information available at the US EPA's RBLC, vendor inquiries, and contacts with regulatory authorities indicated that three potential additional NO_x control technologies should be considered: Selective Catalytic Reduction (SCR), SCONOXTM, and XONON. All three claim to reduce NO_x to 2 ppmv, so they are considered equally stringent for this project. Other NO_x control technologies such as steam or water injection have been used in the past, but are not applicable to the current advanced dry low NO_x turbine combustors unless oil fuel is to be combusted in the turbines, which is not the case for this Project.

3.2.1.2. XONON

XONON is a catalytic process that reduces NO_x emissions within the turbine combustion zone by lowering the combustion temperature and hence the NO_x formation. Each XONON equipped turbine model requires a unique burner design. The first XONON burner has been commercially demonstrated on a Kawasaki 1.5 MW turbine. The owner of the process, Catalytica Energy Systems, has published news reports that XONON equipped combustors are currently being developed for use in several 5 to 10 MW sized turbines by other turbine manufacturers. Because XONON has not yet been developed for the larger GE or Siemens turbines, it is not considered technically feasible for this project and is eliminated from further consideration as BACT.

3.2.1.3. SCONOX™

SCONOX™ (SCONOX) is a developing control technology that has been given consideration by US EPA and state regulatory agencies as a potential emission control technology. SCONOX is a catalytic technique that simultaneously oxidizes CO to CO₂, NO to NO₂ and then absorbs NO₂ onto the surface of a catalyst through the use of a potassium carbonate absorber coating. VOCs are also removed by the catalyst system. This control technique does not use ammonia. According to EmeraChem (formerly Goal Line Environmental Technologies), the vendor of SCONOX, SCONOX can achieve NO_x emissions down to 2 ppmdv.

This control technology has been demonstrated on smaller combustion turbines (approximately 1 to 40 MW) in California and Massachusetts. However, to date, there have not been any SCONOX systems installed on large CT applications such as that being proposed here. Additional technical uncertainties regarding the applicability of SCONOX technology to “F” class turbines have been raised by other permitting agencies. The US EPA Environmental Appeals Board (EAB) and the California Energy Commission (CEC), on May 30, 2001 issued simultaneous rulings on another project refusing to overturn a BACT decision by the Shasta County Department of Resource Management Air Quality Management District that the SCONOX technology is not technically feasible for turbines of the size being considered for the proposed BP Project. The District’s BACT decision said that there are several operational requirements associated with the SCONOX technology that make it impractical as an emission control technology for ‘F’ Class turbines. It stated that all routine operating conditions were not covered in the SCONOX technology guarantee and that the guarantee would be voided if liquid water came into contact with the catalyst. Selective Catalytic Reduction (SCR) was the alternative BACT technology that was selected. For further information, see the “Three Mountain Power, LLC CEC Decision” and “EPA PSD Appeal No. 01-05 (May 30, 2001).” As of June 2006, no SCONOX (EMx) systems have actually been installed and operated on any large combustion turbine applications.

A cost quote was obtained directly from EmeraChem to install SCONOX on this project. EmeraChem offers two price options:

1. The complete system can be purchased, which includes the mechanical equipment and the catalyst. The economic analysis concluded that the annualized cost to remove 309 tons per year of NO_x from the GE turbines and 343 tons/yr of NO_x from the Siemens turbines (about 90 percent removal efficiency) is \$22,900 and \$22,600 dollars per ton removed, respectively.
2. The mechanical purchase/lease option allows the customer to buy the mechanical equipment and lease the catalyst. The annualized cost was estimated at \$15,500 and \$13,900 per ton of NO_x removed for GE and Siemens, respectively.

Since SCONOX can remove NO_x, CO, and VOC simultaneously, the cost per total pollutant removed using SCONOX was determined. The economic analysis concluded that the annualized cost was \$13,000 and \$13,400 per ton of pollutant (NO_x + CO + VOC) removed for GE and Siemens respectively (purchase option) and \$8,800 and \$9,100 for the lease option. As determined in the following sections, the annualized cost of the more normally used SCR and oxidation catalyst system is \$6,400 and \$6,600 per ton of total pollutant removed for GE and Siemens respectively.

Because SCONOX’s cost per ton of NO_x removal is greater than that of SCR (determined in the next section), and because of the technical uncertainties surrounding SCONOX, it is determined that SCONOX is not to be considered BACT for the control of turbine NO_x emissions for the BP Cogeneration project.

3.2.1.4. Selective Catalytic Reduction

SCR is a control technique that has been widely used for more than ten years in a large number of power generation applications, mainly for large gas turbine combined cycle power plants that include heat recovery steam generators. In an SCR system, ammonia is injected into the exhaust gas where it reacts with NO_x at a catalyst bed. The catalyst lowers the activation energy of the chemical reactions that take place in order to reduce ammonia and NO_x to nitrogen gas and water. SCR can provide 80 to 90 percent NO_x control.

The SCR catalyst reactor is typically of fixed bed design. In this reactor design, the catalyst bed is oriented perpendicular to the flue gas flow. In this Project, where there is an HRSG used for heat recovery, the SCR unit would likely be installed between the superheater and the high pressure evaporator coils of the HRSG. The catalyst would be a typical vanadium titanium catalyst system, which has an operating temperature range of about 600 to 800°F.

Installation of a catalyst bed also causes a pressure drop of approximately 4 inches of water, which contributes to a loss in power output from the facility.

Sulfur content of the fuel is an additional concern for systems that employ SCR. Catalyst systems promote oxidation of sulfur dioxide to sulfur trioxide (SO_3), which combines with water to form sulfuric acid or reacts with excess ammonia to form ammonium salts.

The SCR process is also subject to catalyst deactivation over time due to physical deactivation and chemical poisoning of the catalyst. Catalyst suppliers typically guarantee a three year catalyst life for combustion turbine applications. Experience with SCR catalyst life in Washington State indicates that the actual service life of these SCR catalysts is at least twice that three year guaranteed life, and probably more. Power plants combusting only natural gas have had minimal problems with their SCR catalyst systems due to deactivation or contamination from sulfur compounds in the natural gas fuel.

The use of SCR technology will result in ammonia emissions to the atmosphere due to unreacted ammonia leaving the SCR unit. During normal operation, low levels of the NH_3 emissions occur because ammonia is added slightly in excess of the required amount to control the nitrogen oxides present in the exhaust. These ammonia emissions are referred to as "ammonia slip". As the catalyst degrades over time, ammonia slip will increase, ultimately requiring catalyst replacement. The ammonia slip design rate for the proposed Project is a maximum of 5 ppm_{dv} and is expected to usually be lower in actual operation. Testing in Washington State confirms that the ammonia slip rate is typically much less than 5 ppm_{dv}.

The desired level of NO_x emission reduction is a function of the catalyst volume and NH_3/NO_x ratio. For a given catalyst volume, higher NH_3/NO_x ratios can be used to achieve higher NO_x emission reductions, but can result in undesired increased levels of ammonia slip. It is important to note that the reduction of NO_x emissions to levels below 2.5 ppm_{dv} may increase NH_3 emissions.

SCR has been demonstrated effective at numerous installations throughout the United States since the 1980's.

Capital costs for installation of an SCR system on each CT/HRSG were developed based on cost quotations obtained from Envirokinetics (Crites, July 2001). These costs have been inflation-adjusted to represent 2005 values, the most current available. The overall removal efficiency is approximately 72 to 80 percent to achieve a NO_x level of 2.5ppm. SCR capital equipment includes the catalyst, reactor, ammonia storage tanks, SCR control systems and instrumentation, and ammonia delivery system. Capital equipment cost is estimated at \$2,291,900 in 2001 dollars and \$2,475,300 in 2005 dollars. When the

direct and indirect installation costs are added, the total capital cost is estimated at approximately \$4,974,700 for each turbine. Annual costs include addition of operating labor, annual catalyst replacement cost, maintenance, ammonia use. When these annual costs and the annualized capital costs are combined, the cost per CT of adding an SCR system to the dry low NO_x combustor is \$5,900 per ton of NO_x removed (assuming a NO_x emission concentration of 2.5 ppmvd) for the GE turbine and \$5,400 for the Siemens turbine.

3.2.1.5. NO_x BACT Conclusion

NO_x BACT is control of NO_x emissions from each combustion turbine heat recovery steam generator stack to 2.5 ppmdv, 3 hour average. At maximum operating rate on a cold, 5°F day, this would result in emissions of 26.5 lbs/hr, 3 hour average. Lean premix dry low NO_x combustors, low NO_x burners for the duct burners, plus SCR are the control technology on which this NO_x BACT determination is based.

Annual NO_x emissions for each turbine are limited to 108.3 tons per year.

It is recognized that the use of cogeneration steam by the Refinery will reduce Refinery boiler steam production. The proposed Project's air emission impacts and all permit terms are determined for operation independent of the Refinery and do not depend on any emissions reductions that occur due to the Refinery's use of Project cogeneration steam.

3.2.2. Carbon Monoxide Control

Carbon monoxide (CO) is formed as a result of incomplete combustion of fuel. CO is controlled by providing adequate fuel residence time and high temperature in the combustion device to ensure complete combustion. These control factors, however, can also result in higher emission rates of NO_x. Conversely, a low NO_x emission rate can be achieved through flame temperature control (by low-NO_x combustors) and can result in higher levels of CO emissions. Thus, a compromise is established whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping the CO emission rates at acceptable levels.

3.2.2.1. Review of Previous BACT Determinations for CO

A review of USEPA's RBLC database from 2001 to May 2006 and contacts with combustion turbine manufacturers indicate that the most common add-on control for CO is catalytic oxidation. However, since low CO emissions can be achieved by combustion control alone, some entries in the RBLC quote good combustion control as the BACT control option.

The lowest CO level listed in the RBLC is the CVP Warren project in Virginia at 1.8 ppmdv. The permit for that plant indicates that CO compliance is to be determined by one time stack testing, not a continuous emission monitor (CEM). The plant site is located about 7 kilometers from the Shenandoah National Park (a Class I area), which places additional requirements on its emissions impacts analysis. Its emissions will also impact an ozone nonattainment area. It has not begun construction as of October, 2006.

There are many facilities listed in the RBLC with 2 ppmdv as BACT. Permitted limits range up to 10 ppmdv or higher for several facilities.

Pacific Northwest plants, in order of increasing short term CO limits, Goldendale Energy, Sumas Generation, and Wallula Generation in Washington, Wanapa Energy and Cob Energy in Oregon and Garnet Energy in Idaho at 2 ppmdv; Port Westward Plant in Oregon at 2.5 ppmdv; Chehalis Generation Facility and Satsop Combustion Turbine Project (WA) at 3.0 ppmdv; Klamath Generation (OR), at 5

ppmdv; Clark Public Utilities (River Road), Longview Energy, and Mint Farm at 6 ppmdv. Longview Energy and Mint Farm have 2.0 ppmdv annual limits in addition. These facilities were all proposed to be located in attainment areas for CO and, therefore, represent BACT decisions.

A review of the information available at the US EPA's RBLC, vendor inquiries, and contacts with regulatory authorities indicated that two potential CO control technologies should be considered:

1. Catalytic Oxidation, and
2. SCONOX

Each of these technologies claims to be able to reduce CO to 2.0 ppmdv, so they are considered equally stringent for this project.

3.2.2.2. Catalytic Oxidation

An oxidation catalyst removes CO and organic materials from the turbine and duct burner exhaust stream by reacting them with oxygen in the hot gas stream to form carbon dioxide (CO₂). Platinum, or a mix of similar metals, is typically the active catalytic ingredient. Technical factors relating to the CO catalyst system include reactor design, optimal operating temperature, pressure loss to the system, and catalyst life.

The oxidation catalyst is usually located in the HRSG, downstream of the duct burner where the temperature is within 700 to 1,100°F. As the exhaust gas flows through the catalyst, it causes a pressure drop of approximately 1.5 inches of water, which contributes to a slight loss in power output. Catalyst systems are subject to loss of activity over time due to physical deactivation and chemical poisoning. Catalyst suppliers typically guarantee a three year catalyst life for combustion turbine applications. Experience with oxidation catalysts in Washington State indicates that the expected lifetime of an oxidation catalyst combusting natural gas should be more than twice this guaranteed 3 year lifetime.

According to the manufacturer, the GE 7FA turbine can achieve 9 ppmvd CO at loads between 50 and 100 percent when firing natural gas without additional controls. According to the manufacturer, the Siemens SGT6-5000F turbine can achieve 4 ppmvd at 100 percent load and 10 ppmdv at lower loads. Both turbines will, with the implementation of a CO catalyst system, achieve an annual average CO emission rate of 2.0 ppmvd. Experience in Washington has shown that with addition of the oxidation catalyst, they can also meet a short term limit of 2.0 ppmvd.

An estimate for capital and annual costs associated with installation of an oxidation catalyst system on each GE 7FA CT/HRSG system was obtained from Envirokinetics (Crites, July 2001) for the 2003 Application. These costs have been inflation-adjusted to represent 2005 values, the most current available. Costs for installing the system on the Siemens SGT6-5000F CT/HRSG system are assumed to be comparable. The overall removal efficiency is approximately 72 to 87 percent to achieve a CO level of 2.0 ppmdv. The cost of basic equipment (including first catalyst load) was estimated at \$2,335,900. Addition of direct and indirect installation costs raised the total estimated capital cost to \$4,628,500.

Addition of annual operating costs such as operating labor, routine inspection and maintenance, spent catalyst replacement, and lost cycle efficiency due to the increased backpressure give an annualized cost of \$7,200 per ton of CO removed for the GE turbine and \$9,300 for the Siemens turbine. This cost is normally not considered reasonable for CO BACT in Washington. However, BP is proposing to voluntarily install more stringent CO emission controls such as a CO catalyst that reduces CO emissions to 2.0 ppmdv.

3.2.2.3. SCONO_x

A technical analysis of SCONO_x is presented in the previous Section 3.2.1.3 when discussing SCONO_x as a NO_x control. See that section for a discussion of the SCONO_x technical, environmental and economic impacts.

SCONO_x results in an estimated cost of \$31,100 and \$40,500 per ton CO removed for the complete system purchase option and \$21,000 and 27,400 for the mechanical purchase/catalyst lease option for the GE and Siemens turbines respectively. As stated in the NO_x BACT discussion, for removal of multiple pollutants (total tons of NO_x + CO + VOC removed) the estimated annualized cost is \$18,100 per ton of pollutant removed.

As determined in the NO_x BACT section, because of SCONO_x's high cost per ton of pollutant removal, and the technical uncertainties surrounding the process, it is determined SCONO_x is not considered BACT for the control of CO emissions for the BP Cogeneration project.

3.2.2.4. CO BACT Conclusion

Lean premix turbine combustors, plus an oxidation catalyst are considered to be CO BACT for this Project. The control system will control CO emissions from each combustion turbine heat recovery steam generator stack to 2.0 ppm_{dv} and 12.9 pounds per hour, both on a 3 hour average. An annual CO limit per of 78.8 tons per year per turbine is proposed by BP and accepted by EFSEC.

3.2.3. Volatile Organic Compounds (VOC) Control

Incomplete combustion of natural gas fuel results in emission of some unburned hydrocarbons. VOCs are by definition organic compounds that participate in atmospheric photochemical reactions. This excludes methane, ethane, and several other organic compounds that have negligible photochemical reactivity. Control of VOCs is first accomplished by providing good combustion practices such as adequate fuel residence time, good fuel/air mixing, and high temperature in the combustion device to ensure complete combustion. Add on control devices such as catalytic oxidation can control VOCs further.

The CO BACT conclusion determined that an oxidation catalyst was to be installed for CO emissions control. According to the CO oxidation catalyst vendor, an added benefit of the CO oxidation catalyst is that it can remove up to 30 percent of the unburned methane, ethane, and propane. The supplier also claimed that the CO catalyst could also remove up to 70 percent of smaller VOC compounds. Additional information from EPA supports the catalyst supplier's smaller VOC removal claim with data suggesting that the CO catalyst can remove smaller VOCs such as formaldehyde at approximately the same rate as it removes CO. This analysis conservatively assumes that the CO oxidation catalyst removes up to 30 percent of the VOC emissions from each CT/HRSG system, resulting in a maximum VOC emission rate of 6.9 pounds per hour from each unit.

The question then is whether additional controls are justified. The additional options are identical to those in the CO control technology analysis: addition of a second oxidation catalyst, or a SCONO_x installation after the already approved CO oxidation catalyst. As before, both technologies claim to perform similarly in CO or VOC reduction, so they are considered equally stringent.

A search of the EPA RBLC and other available sources failed to find any permitted installation of additional VOC controls in series with a CO oxidation catalyst.

3.2.3.1. SCONOX

A technical analysis of SCONOX was presented in the NO_x BACT analysis. See that section for a discussion of SCONOX technical, environmental and economic impacts.

The installation of the SCONOX system would cost similarly to the cost presented in the NO_x BACT analysis discussion. The major difference is that it would now be treating only a maximum of 29.1 tons per year of VOC assuming 100% removal. This leads to a cost of \$164,280 dollars/ton of VOC removed for the least expensive case, the mechanical system purchase/catalyst lease option. The technical uncertainties surrounding SCONOX are still valid. The high cost per ton of VOC reduced along with the technical uncertainties surrounding the SCONOX process combine to determine that SCONOX is not appropriate as an additional control for VOC.

3.2.3.2. Catalytic Oxidation

A technical analysis of catalytic oxidation was presented in the CO BACT analysis. See that section for a discussion of an oxidation catalyst's technical, environmental and economic impacts.

If an additional oxidation catalyst were to be installed, one that was designed specifically for VOC control, it would be at least as expensive as a CO oxidation catalyst. With the maximum of 29.1 tons per year of VOC emitted from each CT/HRSG system, the cost would be \$55,884 per ton assuming 100% removal. This high cost per ton puts consideration of an additional oxidation catalyst to reduce VOCs beyond that considered BACT by EFSEC.

3.2.3.3. VOC BACT Conclusion

BACT for VOC for this project is determined to be use of the CO oxidation catalyst to also reduce VOCs approximately 30 percent. No additional control such as a second oxidation catalyst bed in series is justified. VOC emissions are limited to 6.9 pounds per hour (24 hour average) from each turbine/HRSG exhaust stack.

3.2.4. Sulfur Dioxide and Sulfuric Acid Mist Control

Sulfur dioxide (SO₂) is formed exclusively by the oxidation of the sulfur present in fuel. Some of the SO₂ may be converted (oxidized) to SO₃, which in turn can form sulfuric acid (H₂SO₄). The sulfuric acid can either be emitted as sulfuric acid mist, or it can combine with ammonia to form an ammonium sulfate or bisulfate salt.

It is important to note that sulfur compound emissions are due to the sulfur content of the fuel. They are not controllable by good combustion practices like emissions of NO_x, CO, or VOC are. Sulfur is considered a "pass through pollutant." The permitted emission limits are based on the best information available to estimate the daily maximum and annual average sulfur content of the natural gas fuel. If at some future time the sulfur content of the natural gas fuel rises above the design estimates, this is beyond the control of the Project. Discussions have suggested that a preferred way to deal with this is to report any emissions in excess of the permitted SO₂ and H₂SO₄ limits that are due to increased sulfur in the natural gas fuel as unavoidable excess emissions. The alternative would be to set more generous permit limits for SO₂ and H₂SO₄ emissions. The SO₂ and H₂SO₄ permit limits have been modeled and their impacts analyzed as very protective of all National Air Quality Standards, PSD increments, and Air Quality Related Values.

In this permit amendment; BP has requested to be allowed to burn refinery gas along with natural gas in the duct burners. The combustion turbines will burn only natural gas. The refinery gas will be processed

to remove sulfur compounds down to a level similar to the natural gas supply to assure that the modeled sulfur emissions impacts and sulfur (as SO₂) emissions limits are not exceeded. Continuous monitoring and recording of SO₂ emissions from the HRSG exhaust stack will be required.

3.2.4.1. Available Control Techniques:

The most stringent “front-end” SO₂ control method demonstrated for combustion sources is the use of low-sulfur fuel, such as natural gas. An available “back-end” control would be installation of a wet or dry scrubber.

Wet or dry scrubbers are generally not applied to combustion turbines that combust low sulfur fuels like natural gas due to the very low SO₂ emissions and the high cost of a scrubber. An economic analysis was performed to estimate the cost of installing a wet scrubber on the combustion turbine/HRSG system. It estimated a cost of \$268,700 per ton of total SO₂ and H₂SO₄ removed. The RBLC does not list any add-on controls as BACT for sulfur compounds from any combustion turbine combined-cycle plants.

The next most stringent control is the use of low sulfur fuel such as natural gas. Natural gas supply to the Project would be from the existing 16 inch diameter Ferndale Natural Gas pipeline. The Ferndale pipeline obtains natural gas at the Northwest Pipeline Sumas Station. The sulfur content of the Northwest Pipeline natural gas is tested hourly at the Sumas Station. The Ferndale pipeline adds a sulfur based odorant at a rate of about 0.3 grains per 100 standard cubic feet (scf). The Project’s natural gas fuel is expected to have a maximum daily average sulfur content of 1.6 grains per 100 scf of gas and an average annual sulfur content of no more than 0.8 grains per 100 scf.

3.2.4.2. Sulfur Dioxide and Sulfuric Acid BACT Conclusion

BP proposes and EFSEC agrees that the use of natural gas as fuel is BACT for controlling SO₂ and H₂SO₄ emissions from the combustion turbine/duct burners. SO₂ and H₂SO₄ emissions will be limited to 12.5 lb/hr and 3.5 lb/hr (24 hour average) respectively. Natural gas sulfur content will be determined on a daily basis based by fuel analysis information from the natural gas suppliers, then used with fuel consumption measurements to determine daily emissions of SO₂ and H₂SO₄ from each turbine/HRSG. Annual stack testing using EPA reference methods will provide a check on the sulfur in natural gas information provided by the supplier, and also determine how much sulfur is converted to sulfuric acid.

These limits on the emission of sulfur compounds also effectively limit the sulfur content of the natural gas that can be accepted by the Project. This makes additional sulfur content limits on the natural gas fuel duplicative and not necessary.

Refinery gas will be allowed to be combusted in the duct burners after a continuous emissions monitor (CEM) for SO₂ is installed and operational on the HRSG exhaust stack. All SO₂ emissions from that stack (from both natural gas and refinery gas) will then be monitored from that time on by CEM data rather than natural gas fuel data. Acid Rain program monitoring (40 CFR 75) requirements will be applicable to the CEM. The annual sulfuric acid testing requirement will be reduced to once every five years.

3.2.5. Particulate and Particulate Matter Less Than 10 Microns Control

There are no federal new source performance standards for particulate or for particulate matter less than 10 microns (PM₁₀) emitted from gas turbines in the applicable NSPS for combustion turbines, 40 CFR 60 Subpart KKKK.

Particulate matter (PM) is defined as fine solid or semisolid materials smaller than 100 microns in size. PM₁₀ is a subset of particulate and is defined as PM smaller than 10 microns in size. A third subset of PM is PM_{2.5}, which is PM smaller than 2.5 microns in size. PM_{2.5} is not currently regulated as a particulate class by PSD or NOC permitting processes, but per EPA guidance⁵, is regulated as part of PM₁₀ until new PSD regulations and guidance can be adopted. PM_{2.5} emissions are considered in more detail in Section 4 of this document, in the context of air quality impacts in Canada.

Particulates from natural gas consumption are generally all considered to fit within the PM₁₀ range, and this permit assumes that. The EPA's AP 42⁶, indicates that almost all PM emissions from gas turbines fired on natural gas are below one micrometer in size. In the following sections of this document and in the accompanying PSD and NOC permits, all particulates will be referred to as PM₁₀, for PSD permitting purposes unless specific reference is otherwise made to PM_{2.5}.

Particulates from combustion are classified by a second property: whether they are solid particles in the combustion stack, or whether they form particles (condense) immediately when they cool after leaving the hot stack. The first type is called filterable because it can be collected on the surface of a mechanical filter. The particulates collected represent what is typically thought of as particulates, such as soil, unburned particles of fuel, or other solid materials. The second type of particle is called condensable, because these particles form (condense) immediately upon cooling after leaving the combustion stack. They are measured by a different test method that cools and absorbs them into a liquid.

PM₁₀ emission levels from natural gas combustion are extremely low in mass as well as small in size. Testers are finding that flow samples must be taken for more than four hours just to get enough sample to measure in the EPA reference test methods. The particulate emission level achieved by combusting natural gas using good combustion practices in modern, well designed burners is comparable or even lower than control levels achievable by particulate control technologies such as bag filters, electrostatic filters, and venturi scrubbers. Particulate size and concentrations are below values for which vendors of such equipment are prepared to offer performance guarantees.

Some in the stack testing community are currently discussing and challenging the validity of these low particulate emission rate measurements, especially the condensable particulate test that typically represents more than 75% of the measured particulates. The issue is that the condensable particulate test method (EPA RM 202) creates a positive bias (indicates more condensable PM₁₀ than is actually emitted)⁷.

EPA has been addressing this condensable particulate measurement issue by developing Conditional Test Method CTM-039. CTM-039 was posted on the EPA Technology Transfer Network Emission Measurement Center web site (<http://www.epa.gov/ttn/emc/tmethods.html>) on June 5, 2003 and specified as available for use by Federal/State/Local agencies in permits and SIPs. CTM-039 is claimed

⁵ "Interim Implementation of New Source Review Requirements for PM_{2.5}", memo by John Seitz, available from the EPA Region 7 NSR & PSD Policy and Guidance Index at <http://www.epa.gov/region07/programs/artd/air/nsr/nsrpg.htm>

⁶ AP 42, Section 1.4, Natural Gas Combustion, available over the internet from the EPA's Technology Transfer Network's CHIEF section at <http://www.epa.gov/ttn/chief/efinformation.html>

⁷ "In-Stack Condensable Particulate Matter Measurements and Issues" Louis A. Corio and John Sherwell, Journal of Air & Waste Management Association, Volume 50, pages 207-218, February 2000.

to be appropriate for gas turbine particulate measurement, but it is a new method with little known history of use or proven applicability. It is recognized by this permit writer that in the future BP could submit materials justifying to EFSEC that CTM-039 or a similarly applicable method be allowed as an alternative method for particulate measurement as allowed in the PSD permit. This draft approval requires measurement of particulates using the currently approved filterable and condensable particulate EPA Reference Methods.

No example of add on type particulate control for natural gas fueled combustion turbines or similar natural gas combustion sources could be found in the EPA RBLC, or from suppliers of control equipment. The particulate control measures that were found included combustion of a low ash fuel such as natural gas and use of good combustion practices in well designed combustion devices.

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 for natural gas fired combustion units leads EFSEC to determine that add on controls for particulate are not technically feasible for this Project.

3.2.5.1. Particulate and PM₁₀ BACT Conclusion

BP proposes, and EFSEC agrees that BACT for PM and PM₁₀ is determined to be use of natural gas and/or refinery gas for fuel, and combustion of the fuel using good combustion practices in lean premix dry low NO_x turbine burners and low NO_x duct burners. The proposed BACT emission limits are 29.2 pounds per hour, averaged over 24 hours for each turbine/HRSG. An annual limit of 127.4 tons per year (filterable plus condensable) is also proposed. Initial performance tests and annual testing using EPA reference methods is proposed annually for the first three years of operation. If these tests all show compliance, the annual testing may be reduced to once every five years. Failure of a test will require a retest and reinstate annual testing until another three consecutive years of testing show compliance.

3.2.6. Toxic Air Pollutants Control

Almost all of the toxic emissions from the proposed Project fall into the category of PM₁₀ or VOC. Ammonia falls outside each of these because it is a gas, but not a VOC. This means that the same controls that were considered in the earlier BACT discussions for PM₁₀ and VOC emissions are considered for toxic emissions other than ammonia.

3.2.6.1. PM₁₀ Toxic Air pollutants

Baghouses and electrostatic precipitators (ESPs) are frequently used to control PM₁₀ emissions for electrical generation facilities not fueled by natural gas, such as coal fired power plants. These PM₁₀ controls were determined technically infeasible in the PM₁₀ BACT Section 3.2.5 because particulates from natural gas combustion are so small (below 1 micron in size) that these controls can not efficiently remove them. See Section 3.2.5 for a more complete discussion of these options. The arguments from that section apply equally well to the subset of these fine particulates that are toxic.

3.2.6.2. VOC Toxic Air Pollutants

VOC toxic emissions can be controlled by oxidation. As discussed in the VOC BACT Section 3.2.3, guidance indicates that an oxidation catalyst should control formaldehyde (the primary air toxic from natural gas combustion) to similar reduction levels as CO emissions. This means that the currently proposed CO oxidation catalyst should reduce formaldehyde emissions about 75% or more. The project emissions estimate conservatively assumes a 30% reduction in total VOC due to the CO oxidation catalyst.

The Federal Combustion Turbine NESHAP⁸ in 40 CFR 63 Subpart YYYYY is currently stayed due to a court action, and EPA is considering revising it. Because of this uncertainty, no NESHAP related provisions are included in this permitting action. Any future NESHAP requirements will be applicable whether included in a PSD permit or not. They will be included in the facility's Title V permit.

3.2.6.3. Ammonia

Ammonia is not a Federal Hazardous Air Pollutant (HAP), but it is a State of Washington Toxic Air Pollutant listed in Chapter 173-460 WAC. Ammonia is used as a reactant in the SCR catalyst system to reduce NO_x emissions. See Section 3.2.1.4 which discusses both SCR and ammonia's part in the process. Ammonia that slips through the SCR catalyst bed is referred to as "slip." A search of the EPA RBLC database and the other permit information sources use for the NO_x BACT determination (Section 3.2.1.1) determined that the ammonia slip rate traditionally allowed has been 10 ppm_{dv} or lower. Recent permits have reduced that to 5 ppm_{dv}. The 5 ppm_{dv} slip limit is proposed for this Project.

A further discussion of turbine toxics emissions is found in Section 4.2 of this document.

3.2.6.4. Toxic Air Pollutants BACT Conclusion

Toxic BACT for Toxic Air Pollutants for this project is determined to be use of the CO oxidation catalyst to also reduce toxic VOCs. Ammonia emissions are limited to a maximum of 5 ppm_{dv} and 19.6 pounds per hour (both at a 24 hour average) from the Turbine/HRSG exhaust stack.

3.2.7. Turbine Startup And Shutdown Control

3.2.7.1. Description of startup and shutdown

Turbine startup is defined as any operating period that is ramping up from less than partial load. Partial load is when the turbine is operating at less than 50% of turbine power generation capacity. Startup ends when normal temperatures have been reached in both the catalytic oxidation and selective catalytic reduction modules. Normal operating temperatures for these two catalyst systems are recommended by the catalyst system manufacturer. The draft approval limits the time allowed for startups in case that these proper operating temperatures are not obtained within a reasonable time.

Shutdown starts when ramping down from normal operation (between 50 and 100% turbine power generation capacity), and ends when fuel flow ends.

Startups are classified into three types; hot starts, warm starts, and cold starts. Hot starts are those starts that occur less than 8 hours after the turbine has been shut down. Warm starts occur when the turbine is restarted after being shut down for 8 to 72 hours. Cold starts occur when the turbine is restarted after being shut down for more than 72 hours.

An integrated microprocessor based control system will be provided for the turbine equipment, for data acquisition, and for data analysis. The control system will be used for startup, shutdown, monitoring and control of emissions, and for protection of personnel and equipment. This assures that the turbine startups and shutdowns are carefully done to be safe, protect the equipment from damage, and minimize emissions. The startup procedure for a two turbine power block is staged, where the first turbine started heats the second turbine's equipment, effectively shortening the total startup time.

⁸ Combustion Turbine NESHAP information is available from the US EPA at the web site <http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html>

3.2.7.2. Emissions during startup and shutdown

The turbine manufacturers (General Electric and Siemens) provided estimates of emissions during startup and shutdown. NO_x, CO, and VOC emissions increase during startup because the low NO_x turbine burners take time to stage into low NO_x operating mode, and because the SCR and oxidation catalysts are not up to operating temperature yet. PM₁₀ and SO₂ emissions are proportional to fuel flow, not combustion conditions, so their emission rate does not increase above permitted levels.

The impact of NO_x, CO, and VOC startup emissions were modeled for the initial permit's 3x1 design.⁹ Impacts were well below any air quality standard. The permit's time limits on startup and shutdown are very protective of these air quality standards. NO_x and CO continuous emission monitors will be operational during startups and shutdowns to measure emissions.

Emissions impact of startup periods from the new 2 x 1 design is expected to be very similar to the original 3x1 impacts, or possibly lower. Startup times for the new 2x1 proposal are shorter, and the quantity of fuel burned by two turbines during startup periods is less than that burned by three. Also, when the impacts from normal operation were remodeled for the new 2x1 turbine configuration and compared to the initial 3x1 design, only minor differences were found. This is discussed in the next chapter.

Table 5 and Table 6 show the maximum modeled startup emissions impacts in the U.S. and Canada respectively, as modeled for the original 3x1 proposal. These are expected to be either representative or slightly over estimate the 2x1 project's startup emissions impacts.

Table 5: Maximum Modeled Impacts in the U.S. From Startup

Pollutant	Averaging Time	Maximum Concentration (µg/m ³)			Lower of WAAQS or NAAQS (µg/m ³)
		Modeled	Background	Total	
SO ₂	24-hour	0.6	13	14	260
	3-hour	3.2	27	30	1,300
	1-hour	4.1	35	39	1,065
PM ₁₀	24-hour	1.6	35	37	150
PM _{2.5}	24-hour	1.6	29	31	65
CO	8-hour	47	2,668	2,715	10,000
	1-hour	584	2,900	3,484	40,000

Background concentration is the maximum value for each pollutant and averaging time of the two nearest representative ambient measuring stations (see Application for Site Certification Tables 3.2-8 and 3.2-9).
 In the United States, there is no short-term (24-hour or 1 hour) NAAQS for NO₂.
 Excludes the effect of Refinery emissions reductions.

⁹ Startup emissions were modeled for the initial permit. Startup and shutdown as well other modeling issues are discussed in the prefiled direct testimony of Brian R. Phillips, Exhibit 22 in the files of the initial permit.

Table 6: Maximum Modeled Impacts in Canada From Startup

Pollutant	Averaging Time	Maximum Concentration in Canada ($\mu\text{g}/\text{m}^3$)			Most Stringent Canadian Objective or Standard ($\mu\text{g}/\text{m}^3$)
		Modeled	Background	Total	
SO ₂	24-hour	0.6	16	17	150
	3-hour	2.5	27	30	374
	1-hour	3.3	59	62	450
PM ₁₀	24-hour	1.5	35	37	50
PM _{2.5}	24-hour	1.5	18	20	30
CO	8-hour	27	2,668	2,695	5,500
	1-hour	340	2,900	3,240	14,300
NO ₂	24-hour	2.0	69	71	200
	1-hour	87.4	107	194	400

Notes:
 PM_{2.5} emissions are conservatively assumed to be equal to PM₁₀ emissions.
 The PM_{2.5} Canada-wide standard is based on the 98th percentile averaged over 3 years, therefore the modeled and background values indicated above are also based on these assumptions.
 NO_x is considered to be fully converted to NO₂.
 Excludes the effect of Refinery emissions reductions.

The permit application was prepared and emissions estimated by assuming 100 hot starts and 100 shut downs per year. Emissions from these startup and shutdowns were used to develop the annual per turbine pollutant emissions estimates and limits. The short term (hourly and 24 hour average) and long term (12 month rolling average) emissions during startup and shutdown were modeled. Table 5 and Table 6 show the short term impacts. Measuring and counting the startup and shutdown emissions towards the annual emissions is appropriate also. The NO_x and CO annual limits effectively limit the number of startups and shutdowns to the emissions modeled in the application.

3.2.7.3. Startup and Shutdown BACT Conclusion

BACT for startups and shutdowns is to follow the startup and shutdown procedures that are developed by the equipment manufacturers and documented by BP in the equipment Start-up, Shutdown, and Malfunction Procedures Manual required by PSD permit Approval Condition 13. Startups will end when one of two events occurs: either the turbine(s) are operating above 50% load and normal operating temperatures have been reached in both the catalytic oxidation and selective catalytic reduction modules as indicated by the above referenced manual, or else two (2), three (3), or five (5) hours have elapsed since fuel was first introduced to the turbines on a hot, warm, or cold start respectively. Normal operating limits for NO_x, CO, and VOC are relieved while in startup or shutdown mode, but these and all emissions are measured and counted toward annual emissions. Annual emission limits on emissions of NO_x and CO limit the quantity of startup and shutdown generated emissions.

3.3. Cooling Tower

3.3.1. Description of Cooling Tower System

Cooling needs will be supplied by an induced draft, counter flow, multi-cell cooling tower. In this type of cooling tower, fans at the top of each cooling tower cell maintain a flow of air through the cooling tower. Circulating water pumps move the water from the steam condenser, where it picks up heat, to the top of the cooling tower. At the top of the cooling tower, the warm water is distributed onto a perforated deck. The water then falls through the perforations and is cooled by evaporation as it fall through baffles (called

“fill”) to a basin at the bottom of the tower. Cool water from the cooling tower basin is returned to the condenser via the circulating water pumps.

3.3.2. Emissions

Emissions from the cooling tower are expected to consist only of PM₁₀. These emissions originate from the dissolved solids contained in droplets of cooling water, called “drift,” that escape in the air stream exiting the cooling tower. The magnitude of drift loss is influenced by the number and size of droplets produced within the cooling tower, which in turn are determined by the fill design, the air and water patterns, and the efficiency of the drift eliminator.

Drift eliminators are incorporated into the tower design to remove as many droplets as practical from the air stream before the air exits the tower. PM₁₀ emissions from cooling towers are usually estimated by using the tower’s design drift rate and the Total Dissolved Solids (TDS) concentration of the tower’s incoming cooling water. A high efficiency drift eliminator with a drift rate of 0.0005 percent is proposed for the Project. That is a very low drift rate, equivalent to Lowest Achievable emission Rate (LAER) permitting decisions for projects sited in particulate non attainment areas.

3.3.3. Cooling Tower BACT Conclusion

BP proposes, and EFSEC agrees, that installation and operation of drift eliminators with a drift loss rate of 0.0005% of the recirculating flow rate constitutes BACT for the cooling tower. Initial compliance will be based on submission of a copy of the drift eliminator manufacturer’s certification that the drift eliminators are installed in accordance with its installation criteria.

BP is required to submit to EFSEC a methodology they will use to estimate PM/PM₁₀ emissions from the cooling tower. The methodology shall be reviewed and approved by EFSEC prior to the first operation of the cooling tower. PM₁₀ emissions shall be limited to 7.1 tons per year on a rolling annual average, estimated monthly.

Routine compliance will be achieved by using the calculation methodology once each quarter to estimate the PM/PM₁₀ emissions from each cooling tower. Emissions shall be reported in each quarterly emissions report.

3.4. Emergency Generator And Firewater Pump

3.4.1. Description of Emergency Generator and Firewater Pump

One diesel driven emergency generator about 1,500 kW in size will be installed to provide support system power to critical plant instrument and lubrication systems in the event that electric power is not available from the grid. A diesel driven firewater pump will be used to maintain firewater pressure in the event that electric power is not available or firewater pressure is inadequate. The diesel firewater pump is currently anticipated to be similar to a John Deere Model 6081A engine (or equivalent) rated at 265 brake horsepower (bhp).

3.4.2. Emissions

The diesel engines will be of latest design, and meet the new engine specifications for either 2006 or the year of purchase, which ever is later. This minimizes the NO_x, CO, VOC, and PM emissions by using a well designed engine with good combustion design. The SO₂ emissions from the diesel engines will be minimized by using on road specification diesel fuel. The sulfur content of on road specification diesel oil is limited to less than 15 ppm (0.0015%) as of October 15, 2006 per 40 CFR 80.500.

The emergency generator and firewater pump are proposed to be operated only for their intended emergency uses, and for limited testing and training periods. The hours of operation necessary for these purposes is estimated to be less than 250 hours per year, so the emissions from these units were estimated and evaluated for both a full 24 hour period, and for 250 hours per year total. Emission factors for new engines that meet current federal engine standards were used. Expected annual emissions for pollutants were listed earlier in Table 9.

3.4.3. Emergency Generator and Firewater Pump BACT Conclusion

BP proposes, and EFSEC agrees that the limitation to 250 hours of operation, purchase of the latest designed engines, and use of on road specification diesel fuel is BACT for the emergency generator and firewater pump. NO_x emissions from the emergency generator are limited to 3.4 tons per year on a 12 month rolling average. SO₂ emissions will be determined by calculations based on hours of operation and diesel fuel sulfur content. All other emissions from these units are estimated to be less than one ton per year, and are not required to be reported.

4. AMBIENT AIR QUALITY IMPACTS ANALYSIS

4.1. Regulated Pollutants

The PSD permitting program requires that an ambient Air Quality Impacts Analysis (AQIA) be made for pollutants emitted in significant quantities. As shown in Section 2.6 of this Technical Support Document, nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), particulates less than 10 microns (PM₁₀), sulfur dioxide (SO₂), and sulfuric acid mist (H₂SO₄) are all emitted in PSD significant quantities from this project.

An air quality analysis can include up to three parts: Significant Impact analysis, National Ambient Air Quality Standards (NAAQS) analysis, and PSD Increment analysis. The first step in the air quality analysis is to determine if emissions from the proposed project result in impacts greater than the modeling significance levels (MSLs). Then, for those pollutants and averaging periods that have impacts greater than the MSL, a NAAQS analysis is used to determine if the proposed project will cause or contribute to an exceedance of a NAAQS. The PSD Increment analysis is used to determine if the change in the Air Quality since the applicable baseline dates is greater than the Class I and Class II PSD Increment Levels.

4.1.1. Modeling Methodology

The methodologies and protocols used in the air quality impact analysis follow USEPA Guidelines and the requirements of Ecology and the Federal Land Manager (FLM). Dispersion modeling is used to simulate the projected impact of the facility's emissions on local and regional air quality levels. Protocols for the modeling performed in connection with the 2003 Application were submitted to EFSEC on October 29, 2001. The same protocols were followed in conducting the modeling performed for this PSD permit amendment application.

Two different models were used to determine the project's effect on air quality. The Industrial Source Complex model (ISC-Prime) was used to determine pollutant concentrations within a 50 kilometer by 50 kilometer area surrounding the project site. The CalPuff model was used to model for the visibility analysis in the Class I areas and in Canada. The modeling was done according to a Modeling Protocol agreed to by the Project's modeling consultant (Air Permits.com), the Department of Ecology's modeler (Clint Bowman), and the National Park Service and National Forest Service modeling technical staff.

The ISC-Prime dispersion model incorporates updated building-wake (downwash) calculations. The suite of models, provided by Bowman Environmental Engineering (BEE), is called BEEST (Version 9.50) and includes the executable versions of the both the current ISCST3 model and its variant, the ISC-Prime

model (BEE Version 03002). The model execution options, averaging periods, sources and emissions information, receptors and terrain, buildings and structures, and meteorology inputs of the ISC-Prime dispersion model are identical to those of the ISCST3 dispersion model. Ecology has indicated that the ISC-Prime model is an approved model for use in the BP modeling analyses (Bowman, 2006).

The Cal Puff model is preferred for evaluating impacts beyond 50 kilometers because it is more accurate beyond that distance than the ISC model. As all of the Class I areas are more than 50 kilometers from the proposed project, CalPuff was used for the Class I SIL analysis and AQRV analysis. CalPuff is a multi-layer, multi-species, non-steady-state puff dispersion model that simulates the effects of time and space varying meteorological conditions on pollutant transport, transformation, and removal. CalPuff version 5.4, provided by Earth Tech Inc., was used. One year of MM5 data (supplied by the University of Washington) from April of 1998 through February of 1999 was used in conjunction with data from 25 National Weather Service (NWS) surface meteorological stations to develop the meteorological field using CalMet, which is part of the CalPuff modeling system. Terrain data and land use data was obtained from the USGS website at <http://edc.usgs.gov/geodata/>.

The CalPuff modeling was performed on emissions from the proposed 720 MW cogeneration facility in connection with the 2003 Application. The results of that modeling were presented in the 2003 Application, and are discussed later in this section and in Section 6 “Class I Area Impacts Analysis.” The emissions in the new two turbine configuration are 85 to 95 percent of the three turbine configuration of the 2003 Application while the stack parameters are similar. All CalPuff modeling results are expected to be lower for the 520MW Project with two turbines than the 720 MW three turbine configuration, regardless of whether the GE or Siemens turbines are used. Therefore, further CalPuff modeling was not performed.

On January 30, 2006, EPA added NO_x to the list of chemicals considered ozone precursors for PSD permitting purposes.¹⁰ From then on, if a proposed project has emissions of either VOC or NO_x of more than 100 tons per year, an ozone impacts analysis must be performed. Since the estimated NO_x emissions are greater than 100 tpy, BP contracted with Washington State University (WSU) to do an ozone impacts analysis.

WSU had recently modeled the Puget Sound area for ozone impacts for three very hot days during July 22-28, 1998 using the MM5/MCIP/CMAQ modeling system. For the BP project, WSU updated the modeling protocol and regional emissions inventories slightly, then re-ran the model with the baseline emissions inventory to generate a base case ozone concentration map. The NO_x and VOC emissions for the proposed turbines were then added to the existing regional emission inventory, and the models were run again. The difference in predicted ozone concentrations between the base case and the run with the added turbine emissions gave an estimate of how much ozone the additional NO_x and VOC emissions might create. The three days had different wind patterns on each day. July 26 had northerly winds (out of the north), July 27 had southwesterly winds (out of the southwest), and July 28 had fairly calm winds.

4.1.2. Modeling Results

The results of the dispersion modeling analysis for Class I and Class II pollutant concentrations show that no Class I or Class II SIL is expected to be exceeded under the “worst case” emission scenarios. EPA and Washington State use these SILs as a screening threshold. Because all modeled impacts are below their respective SILs, no further dispersion modeling is required to demonstrate compliance with air quality standards and PSD increments. Table 7 shows the modeling results and the corresponding SILs.

¹⁰ Federal Register /Vol.70, No. 228/Tuesday, November 29, 2005, pages 71612-71705

Table 7: Significant Impact and Pre-Construction Monitoring Modeling Results

Pollutant	Averaging Period	Class II Areas			Class I Areas	
		Modeled Maximum Concentration ($\mu\text{g}/\text{m}^3$)	Modeling Significance Level ($\mu\text{g}/\text{m}^3$)	Monitoring De Minimus Concentrations ($\mu\text{g}/\text{m}^3$)	Modeled Maximum Concentration ($\mu\text{g}/\text{m}^3$)	Modeling Significance Level ($\mu\text{g}/\text{m}^3$)
NO _x	Annual	0.8	1	14	0.0053	0.1
CO	8-hour	10.9	500	575	--	--
	1-hour	83.0	2,000	--	--	--
PM ₁₀	Annual	0.55	1	--	0.0054	0.2
	24-hour	4.0	5	10	0.087	0.3
SO ₂	Annual	0.06	1	--	0.001	0.1
	24-hour	0.8	5	13	0.021	0.2
	3-hour	5.0	25	--	0.048	1.0

Notes:
 Excludes the effect of Refinery emissions reductions.

The impact of the Project's emissions on Canada were modeled and are presented in Table 8.

Table 8: Project Maximum Impact on Canada

Pollutant	Averaging Time	Maximum Concentration in Canada ($\mu\text{g}/\text{m}^3$)			Most Stringent Canadian Objective or Standard
		Modeled	Background	Total	
NO ₂	Annual	0.2	27	27	60
	24-hour	1.6	69	71	200
	1-hour	16.7	107	124	400
CO	8-hour	4.8	2,668	2,673	5,500
	1-hour	13.6	2,900	2,914	14,300
PM _{2.5}	24-hour	0.9	18	19	30
PM ₁₀	Annual	0.2	13	13	30
	24-hour	2.5	35	38	50
SO ₂	Annual	0.03	3	3	25
	24-hour	0.7	16	17	150
	3-hour	3.3	27	30	374
	1-hour	5.3	59	64	450

Notes:
 PM_{2.5} emissions are conservatively assumed to be equal to PM₁₀ emissions.
 The PM_{2.5} Canada-wide standard is based on the 98th percentile averaged over 3 years, therefore the modeled and background values indicated above are also based on these assumptions.
 NO_x is considered to be fully converted to NO₂.
 Excludes the effect of Refinery emissions reductions.

These modeling results indicate that the maximum impact of the project in Canada is lower than the impact in Washington State. Impacts are well below current background concentrations, and a small percentage of each pollutant's most stringent Canadian Objective or Standard.

Maps with isopleths of constant concentration were created for each air pollutant and averaging time for the original 720 MW 3x1 configuration¹¹ and for the proposed 520 MW 2x1 configuration¹². These

¹¹Partially available in Exhibit 22 and 3 attachments in the prefiled testimony section at <http://www.efsec.wa.gov/bpcogen/Adjudications/bpadj.shtml> . Full set available upon request to EFSEC.

¹² Available on EFSEC website at <http://www.efsec.wa.gov/bpcogen.shtml> or by request to EFSEC.

isopleth maps cover impacts for about 50 kilometers around the plant, which includes most of western Whatcom County, the San Juan Islands, and the lower Fraser River Valley in British Columbia, Canada. Pollutant emission rates are generally lower for the 2x1 configuration, so are expected to produce isopleths with lower concentrations. The modeling showed that this was true for the impacts of most pollutants and averaging times. Due to slight modeling differences, this was not always the case. For example, the change in configuration may have affected building downwash in a way that lower emissions produced slightly higher annual impacts for the annual SO₂ emissions. All impacts were a small fraction of the existing background pollutant concentrations and by definition did not contribute to any exceedance of a NAAQS.¹³

The modeled ozone impact of adding the proposed gas turbines was determined to small. The ozone concentrations increased from 0.1 to 0.6 ppb on the three high ozone days. On July 26, the areas where these increases (up to 0.2 ppb) occurred were mainly towards the south and southwest with a slight impact around the Seattle area. On July 27, the impact (up to 0.2 ppb) mainly occurred on the Canadian side of the domain due to southwesterly flows. With lighter winds, maximum ozone increases (up to 0.6 ppb) were predicted on July 28 fairly close to the source. The area of maximum increase did not occur at the Enumclaw and Pack Forest monitoring sites where the highest ozone concentrations were observed, and therefore, maximum ozone level remained unchanged from the base case. There were ozone decreases up to 1.3 ppb very close to the source, which was related to the titration of ozone from fresh NO emissions.

EFSEC, Ecology, and EPA reviewed the ozone impacts analysis and determined that the impacts were acceptable.

4.2. Toxic Air Pollutants

EFSEC requires an ambient air quality analysis of toxic air pollutants (TAPs) emissions in accordance with WAC 173-460 "Controls for New Sources of Toxic Air Pollutants". The TAPs are evaluated for both acute (24 hour) and chronic (annual) effects as required by the regulation. The quantities of all TAPs known to be emitted from the turbines and duct burners, and diesel engines were estimated and screened against the small quantity emission rates in WAC 173-460.

TAP emissions exceeding the small quantity emission rate exclusion were modeled to determine their maximum ambient concentrations. These maximum ambient concentrations were compared to the respective acceptable source impact levels (ASIL) listed in WAC 173-400-150 and 160. These ASILs are not health effect levels, but conservative thresholds that, if exceeded, indicate the need for further investigation of the effects of the TAP on ambient air quality and human health. Table 9 compares the TAPS modeled, the modeled concentration impacts, and their respective ASIL.

¹³ Under PSD permitting rules, if the impact of a pollutant is less than its "Significant Impact Level," the impact of the emission is small enough to be considered insignificant. No further impacts analysis is required.

Table 9: Toxic Air Pollutants Significant Impact Level Modeling Results

Pollutant	Maximum Predicted Concentration ($\mu\text{g}/\text{m}^3$) ⁴		ASIL ($\mu\text{g}/\text{m}^3$) ³	ASIL Exceeded (Yes/No)
	Annual ¹	24-hr ²		
Acetaldehyde	0.00018	NA	0.45	No
Acrolein	NA	0.0021	0.02	No
Ammonia	NA	2.84	100	No
Arsenic	0.0001	NA	0.00023	No
1,3-Butadiene	0.00001	NA	0.0036	No
Benzene	0.00036	NA	0.12	No
Beryllium	< 0.00001	NA	0.00042	No
Cadmium	0.00001	NA	0.00056	No
Chromium	NA	0.0026	1.7	No
Formaldehyde	0.00499	NA	0.077	No
Nickel	0.00008	NA	0.0021	No
PAH	0.00009	NA	0.00048	No
Sulfuric Acid	NA	0.57	3.3	No

1. Highest of annual cases 1AB, 1BB, 1CB, 7B (all at 50°F).
 2. Highest of all cases for 1995, 1996, 1998, 1999, 2000.
 3. Acceptable source impact levels (ASIL).
 4. Since no toxics were modeled for the Siemens CTs, this table refers to GE toxic impacts only.

The proposed Combustion Turbine NESHAP (40 CFR 63 Subpart YYYYY) recognizes that the HAP emitted in the largest quantity from a combustion turbine burning natural gas is formaldehyde. The formaldehyde limit in the NESHAP is a concentration of 91 parts per billion in the turbine's exhaust, adjusted to 15% oxygen. The CO oxidation catalyst proposed for this project is also the preferred control under the NESHAP. The best evidence available indicates that the oxidation catalyst will reduce formaldehyde emissions similarly to CO.

The final status of the Combustion Turbine NESHAP is uncertain at this time. Subpart YYYYY has been stayed by the courts until late 2007 (at the earliest) while EPA continues consideration of the toxicity factor for formaldehyde and also whether to continue the category delisting process.¹⁴ Because of this uncertainty, all NESHAP requirements that were originally in the Notice of Construction portion of this permit have been eliminated. If future NESHAP requirements become applicable, they will become part of the Title V permit for the project.

Since there were no TAPS that exceeded their ASIL screening values, no additional toxics review is required. Because of this, EFSEC concludes that no adverse health impacts are expected to occur due to the increase in toxic pollutants emitted from the Project.

4.3. Ammonia Emissions

Ammonia emissions from the BP Project deserve special discussion. Ammonia is a TAP defined in WAC 173-460. Unreacted ammonia is released from the SCR process because a slight excess is required to reduce NO_x emissions down to the desired levels. The excess ammonia is called "ammonia slip". Ammonia slip can be used as an indicator of SCR catalyst activity. High slip indicates poor operational control or degraded catalyst activity, resulting in higher NO_x emissions. SCR manufacturers have traditionally guaranteed that this slip of unused ammonia will be less than 10.0 ppm and occasionally as low as 5 ppm. Recent operating experience indicates that ammonia slip may be maintained at rates

¹⁴ August 9, 2006 email from Madonna Narvaez of EPA Region 10

consistently below 5 ppm¹⁵ for a number of years after the initial start of the plant's operation. BP has agreed to this new, lower ammonia slip limit. The air toxics modeling in Table 9 show that modeled maximum ammonia impacts will be well below the ammonia ASIL found in 473-460 WAC.

EFSEC concludes that 5.0 ppm_v ammonia emission limits for the BP Cherry Point Cogeneration Project does not threaten human health and is appropriate for the Project.

5. ADDITIONAL IMPACTS ANALYSIS

PSD regulations and guidance require an additional impact analysis for the effects of emissions on local soils, vegetation, and visibility from the source or modification under review, and from associated growth in the area surrounding the project.

Growth Analysis: The project site is within an area already zoned for Heavy Impact Industrial Use. During the anticipated 2-year construction period, the peak construction work force could be about 670 people. For daily operation and maintenance of the facility, about 30 full time staff may be required. Air quality and visibility impacts due to growth-related activities associated with the proposed facility are expected to be negligible.

Soils and Vegetation Analysis: Based on the results of the dispersion modeling analyses, facility emissions are expected to have a negligible effect on soils and vegetation. Project emissions that have the most potential to affect soils and vegetation are those that contain either sulfur or nitrogen. As shown in Table 7 of Section 4.1.2, the maximum modeled impacts of these emissions are well below all federal permitting modeling and monitoring significance levels. These levels are intended to be protective of soil and vegetation as well as human health. Other ambient monitoring data (tests to measure the concentration of NO_x and SO₂ in normal background air) show that the annual modeled concentrations of SO₂ and NO₂ are only 1 and 2 percent respectively of their current annual average background levels at their impact area.

For emissions of NO_x (assuming full conversion to NO₂), potential plant damage could begin to occur with 24-hour NO₂ concentrations of 15 to 50 parts per billion (ppb) (USFS 1992). From the modeling results, the maximum annual concentration of NO₂ is below 1.0 microgram per cubic meter (μg/m³) (about 1.1 ppb). The potential impact on local agriculture is expected to be negligible.

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 are limited to an opacity of 5%. This amount of opacity is just barely perceptible. Under some conditions water might condense to form a steam plume. Visibility impacts on more distant Class I areas are discussed in the next section and determined to be acceptable.

6. CLASS I AREAS IMPACTS ANALYSIS

Federal¹⁶ and Washington State¹⁷ PSD regulations require that the impact of a proposed facility on federal Class I areas be analyzed. Class I Areas are areas of special national or regional value from a natural, scenic, recreational, or historic perspective and are afforded the highest level of protection under the PSD rules. They include certain national parks, national wilderness areas, and national memorial parks.

¹⁵ For example: PGE Coyote Springs in Morrow County, Oregon and Hermiston Generating Project, Umatilla County, Oregon operate at less than 4.4 ppm ammonia slip with NO_x below 4 ppm. Also see Selective Catalytic Reduction Control of NO_x Emissions, prepared by the Institute of Clean Air Companies, 1660 L St., Suite 1100, Washington, D.C., page 12 (1997).

¹⁶ 40 CFR 52.21 (p)

¹⁷ WAC 173-400-117

As discussed in Section 4, CalPuff modeling of Class I concentration, visibility, and deposition has not been performed for the new two turbine scenario. Modeling was performed for the 720 MW project and those results were presented in the original Technical Support Document. Modeling parameters such as stack flow, velocity, and temperature are very similar for the new 520 MW proposal. Total pollutant emissions are either lower or just slightly higher for the new, 520 MW two combustion turbine project. The Department of Ecology, acting as permit writer for EFSEC, agreed that the original modeling was representative of the impacts of the new proposal, and might actually over estimate impacts for some pollutants. The following Air Quality Related Values (AQRV) discussion is essentially repeated from the original project's Technical support document.

6.1. Visibility Impacts

Two different visibility analyses were done for visibility, one for the U.S. and one for Canada. Both analyses were performed using the CalPuff modeling procedure described in Section 4.1.1. The U.S. evaluation focused on the visibility at Class I areas, while the Canadian analyses focused on specific lines of site identified by the air quality staff of the Greater Vancouver Regional District (GVRD).

Visibility in the Class I areas in the U.S. was performed with the CalPuff model. PM₁₀, NO_x, and SO₂ were modeled, with chemical transformations of secondary pollutants such as ammonia nitrate and ammonia sulfate, and the results were combined to calculate a visibility coefficient. The results were then compared with background data to find a visibility change, in percent. The federal land managers consider over 5% to be a perceptible change in visibility and over 10% to be unacceptable.

Table 10 shows that the project emissions predict one day at one Class I area (Olympic National Park) has a visibility change over 5%. The National Park land managers were consulted about this perceptible change, and considered it acceptable.

BP also modeled visibility impacts considering reduction in emissions from the Refinery boilers and the net visibility impact considering those reductions. This was not relied upon for any PSD or NOC permitting, but is presented in Table 10 for informational purposes only.

Table 10: Visibility Impacts on U.S. Class I Areas

Class I area	Maximum Visibility Change (%)	Number of days over 5%	Maximum Visibility Change including Boiler Emissions Reductions	Number of days over 5%
Olympic National Park	6.0	1	1.9	0
North Cascades National Park	2.6	0	1.5	0
Alpine Lakes Wilderness Area	4.1	0	2.3	0
Glacier Peak Wilderness Area	4.4	0	2.1	0
Pasayten Wilderness Area	1.8	0	1.2	0
Mt. Baker Wilderness Area	4.1	0	2.3	0

Visibility modeling in Canada was performed differently. The calculated visibility coefficient was averaged over a line of sight, generally from a valley floor to a mountain peak. The modeled lines of sight were established by GVRD. The modeled visibility was compared with background data to determine if any additional days will have impaired visibility as compared to current conditions. Table 11 shows that the project will have no detrimental impact on visibility along these lines of sight.

Table 11: Visibility Impacts on Canadian Lines of Sight

Line of Sight	Number of days with impaired visibility, background conditions	Additional days with impaired visibility due to Cogeneration Project	Maximum visibility change
1	171	0	1.2%
2	166	0	2.4%
3	166	0	2.1%
4	166	0	2.2%
5	166	0	2.7%
6	166	0	1.5%
7	166	0	1.4%

6.2. Deposition Impacts

The National Park Service and the US fish and Wildlife Service have developed guidance on what levels of nitrate and sulfate deposition increases due to a single source would cause them to perform more detailed reviews of the impacts of the deposition within their Class 1 areas. The threshold established by these agencies is 5 grams/hectare/year. The maximum predicted nitrogen deposition level is 0.67 g nitrate/hectare/year in the Mt. Baker Wilderness Area. The maximum predicted sulfate deposition level is 0.73 g sulfate/hectare/year in the Alpine Lakes Wilderness Area.

Table 12: Deposition Impacts on Class I Areas

Class I area	Nitrogen Deposition g/ha/yr	Sulfur Deposition g/ha/yr
Olympic National Park	0.09	0.12
North Cascades National Park	0.47	0.32
Alpine Lakes Wilderness Area	0.60	0.73
Glacier Peak Wilderness Area	0.44	0.34
Pasayten Wilderness Area	0.24	0.14
Mt. Baker Wilderness Area	0.67	0.60
Threshold	5	5

7. CONCLUSION

The project will have no significant adverse impact on air quality. The Washington State Energy Facility Site Evaluation Council finds that the Applicant, BP West Coast Products LLC, has satisfied all requirements for an amendment to the existing Notice of Construction/Prevention of Significant Deterioration approval for the BP Cherry Point Cogeneration Project.

For additional information please contact:

Stephen C. Posner
 Siting Specialist
 Washington State Energy Facility Site Evaluation Council
 PO Box 43172
 Olympia, Washington 98504-3172
 (360) 956-2063
 stephenp@cted.wa.gov