TECHNICAL SUPPORT DOCUMENT
FOR PREVENTION OF SIGNIFICANT DETERIORATION
PSD 07-01, AMENDMENT 1

BOILER REPLACEMENT PROJECT
BP CHERRY POINT REFINERY
BLAINE, WASHINGTON

Prepared by

Washington State Department of Ecology
Air Quality Program

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EXECUTIVE SUMMARY

The BP Cherry Point Refinery (BP) is requesting an amendment to their existing PSD permit to increase the short-term sulfur dioxide (SO_2) emission limit imposed on two new boilers. The current short-term SO_2 limit is requested to be changed to an annual limit. No changes to any other air pollutant emission limits are requested. No increase in annual SO_2 emissions is requested. BP proposes no physical or operational changes to the boilers.

During 2009, the BP Cherry Point Refinery (BP) is in the process of commissioning the two new boilers (#6 and #7) at its Cherry Point Refinery. Each boiler is rated at 363 MMBtu/hour, and each may be fired with refinery fuel gas or natural gas. Construction and operation of these boilers were authorized in November 2007 by Prevention of Significant Deterioration permit PSD 07-01 issued by Ecology and Order of Approval to Construct #1001 issued by the Northwest Clean Air Agency (NWCAA). After commissioning of Boilers 6 and 7, BP will permanently shutdown Boilers 1 and 3.

The Washington State Department of Ecology (Ecology) finds that BP has satisfied all requirements for approval of the proposed PSD permit amendment for the Boiler Replacement Project and now sends the proposed amended permit for public comment.

1. INTRODUCTION

1.1 The PSD Process

The Prevention of Significant Deterioration (PSD) procedure is established in Title 40, Code of Federal Regulations (CFR), Part 52.21 and in Washington Administrative Code 173-400-700. Federal rules require PSD review of all new or modified air pollution sources that meet certain overall size, and pollution rate criteria. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a proposed new or modified source. PSD rules require that an applicant use the most effective air pollution control equipment and procedures after considering environmental, economic, and energy factors. The program sets up a mechanism for evaluating and controlling air emissions from a proposed source to minimize the impacts on air quality, visibility, soils, and vegetation.

The United States Environmental Protection Agency delegated the authority to implement the PSD program described in title 40 C.F.R. 52.21 and its supporting guidance and procedures documents to the Engineering Unit staff[1] of the Air Quality Program of the Washington State Department of Ecology.[2]

1.2 The Project

1.2.1 The Site

British Petroleum (BP) operates a refinery at Cherry Point in Whatcom County, Washington. The refinery is located in a rural setting near Blaine and Birch Bay, Washington. The surrounding land use is zoned heavy impact industrial and is mostly vacant. Historical uses were agricultural (dairy farming). Immediately to the west is the Puget Sound Energy's Whitehorn gas-turbine power generating station. About two miles west northwest of the refinery is Birch Bay State Park. UTM coordinates are 10 519600E and 5414800N.

1.2.2 The Proposal

The existing permit limits fuels fired in the boilers to refinery fuel gas or natural gas. Condition 3 limits emissions of SO_2 from each boiler to 13.6 pounds per hour (3-hour average). At maximum operation, this would allow 119 tons per year of SO_2 emissions.

The SO_2 emission limit in Condition 3 was calculated using an emission factor based on the average total sulfur content of the refinery fuel gas samples for the three preceding years (2003-2005). In retrospect, this was appropriate to estimate annual emissions for PSD applicability and

[1] An organizational unit in the Science and Engineering Section.
[2] Agreement for the Delegation of the Federal Prevention of Significant Deterioration (PSD) Regulations by the United States Environmental Protection Agency, Region 10 to the State of Washington Department of Ecology (February 23, 2005).

annual emission limits, but it underestimates emissions during short-term periods when the refinery fuel gas sulfur concentration is higher than average.

BP recognized the oversight of not requesting an additional, larger short-term SO_2 limit, and planned to request it at the same time as other planned adjustments to the boiler sulfur limits were made. The new 40 CFR 60 Subpart Ja NSPS was applicable to these new boilers, but it was still in draft form during the boilers' permitting. To deal with this, the permit required that within 30 days of finalization of the NSPS, BP request the permit's sulfur SO_2 limits be amended to meet whatever the final NSPS standards turned out to be.

The Ja NSPS SO_2 emission standards as proposed in the draft standard were very stringent. The final Ja NSPS standards ended up high enough that the boiler permit met them, so the permit did not need to be re-opened for NSPS reasons as anticipated. The permit only needed to be amended to add short-term SO_2 limits that properly reflected the variability of the refinery fuel gas sulfur content. The averaging period for the original SO_2 limit needed to be changed to what it really reflected, the annual potential SO_2 emissions.

The proposal is to add the appropriate short-term SO_2 emission limits as discussed in Section 1.3 on emissions. An increase of the testing frequency from quarterly to monthly for the refinery gas total sulfur analysis is also proposed.

1.3 PSD Applicability and Air Pollutant Emissions

BP is an existing major source[3] of a regulated pollutant.[4] The facility has several existing PSD permits for refinery processes and equipment. It has minor new source review permits and a Title V air permit issued by the Northwest Clean Air Agency (NWCAA).

Additions and modifications to the refinery that increase emissions above prescribed PSD Significant Emission Rates (SERs) are considered "major modifications" subject to the PSD permitting process.

A change in emission limits that does not cause a significant increase in annual emissions but does allow increased short-term emissions triggers PSD permitting requirements for minor modifications to an existing PSD permit. Modeling and evaluation of the short-term emission impact increases is the major permitting requirement. A new BACT review for SO_2 is not

[3] Petroleum Refineries 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. WAC 173-400-720(4)(a)(v) and 40 CFR 52.21(b)(1)(i)(a).

[4] The PSD program directly regulates a list of specific pollutants listed in 40 CFR 52.21(b)(23). These are referred to as "regulated pollutants." PSD regulates other pollutants indirectly through the broad categories of "regulated" pollutants such as VOC and particulates. In Washington State, the local air authority issues its own permit that complements the PSD permit and includes all emissions regulated by state and local regulations. WAC 173-400-113.

triggered because no physical change or change in the method of operation is proposed, and there is no increase in annual emissions of any pollutant, including SO_2.

Determination of PSD Applicable Pollutants

Pollutants to be regulated under PSD for the boilers were determined in the original permitting action to be carbon monoxide (CO), sulfur dioxide (SO_2), particulates less than 10 microns in diameter (PM_{10}), and particulates of any diameter (PM). $PM_{2.5}$ was analyzed as PM_{10} using the surrogate policy in place at that time. For Amendment 1, only SO_2 emissions are changed, so emissions of CO and particulates are not affected.

SO_2 emissions from the boilers are estimated by assuming all the sulfur in the natural gas or refinery fuel gas is oxidized to SO_2. Refinery fuel gas has a higher sulfur concentration than natural gas. This puts the focus of SO_2 emissions analysis on combusting refinery fuel gas. Key sulfurous compounds in refinery fuel gas are carbonyl sulfide (COS), mercaptans, and hydrogen sulfide (H_2S). Combustion of all of these compounds generates SO_2 emissions.

Federal NSPS regulations (Subpart Ja) regulate the H_2S content of refinery gas to 162 ppm on a 3-hour rolling average, and 60 ppm on a 365-day average basis. BP has several permits that limit H_2S concentrations in the refinery fuel gas to 50 ppmv on a 24-hour basis.

The refinery operates a fuel gas sulfur removal process which is monitored by a continuous H_2S analyzer at the refinery fuel gas drum to demonstrate continuous compliance with the NSPS and permit H_2S requirements. To determine the concentrations of all sulfurous compounds in the fuel gas, refinery personnel quarterly take canister samples of the refinery fuel gas that are analyzed by a gas chromatograph.

Review of the canister data demonstrates that H_2S is a relatively minor contributor to the total sulfur in the fuel gas because H_2S is more readily moved by the sulfur removal processes than the mercaptans.[5] BP proposes that short-term emissions reflect the highest allowable H_2S concentration (50 ppm) and the highest measured mercaptan concentrations. The highest mercaptan concentration was 412 ppm, measured on June 8, 2005. Table 1 compares fuel gas characteristics and SO_2 emissions considered in the 2007 application with those now being proposed based on these highest measured values.

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[5] For convenience, carbonyl sulfide is included when referring to mercaptans.

Table 1: SUMMARY OF FUEL GAS CHARACTERISTICS WITH CURRENT AND PROPOSED SO_2 EMISSION RATES (PER BOILER)

	2007 Application	Proposed Revision	
	3-hour average	24-hour average	1- & 3-hour averages
Fuel gas characteristics			
H_2S ppm	17	50	50
Mercaptan/COS ppm	283	412	800
Total S ppm	300	462	850
SO_2 lb/mscf	0.051	0.078	0.144
GBTU/scf	1352	1326	1326
Boiler emission rates			
SO_2 lb/mmbtu	0.038	0.059	0.108
SO_2 lb/hr/boiler	13.6	21.36	39.29
SO_2 ton/yr/boiler	59.6	59.6	

Table 1 shows that periodic operating conditions generate higher sulfur levels than those captured in the average of the canister tests. At Cherry Point Refinery, most of the mercaptans are generated by the Coker. The Coker currently provides about a third of the fuel gas in the main mix drum. When other units that generate fuel gas are shutdown, the proportion of fuel gas supplied by the Coker increases, which increases the mercaptan concentration in the main mix drum. This may happen during turnarounds or during an upset at a fuel gas-producing process unit. Table 1 identifies fuel gas characteristics and short-term SO_2 emissions (one to three hour average) under this operating scenario.

As mentioned previously, the current PSD permit requires BP to demonstrate routine compliance with the SO_2 emission limit through continuous monitoring of H_2S in the fuel gas and quarterly measurements of the total sulfur in the fuel gas. BP proposes to monitor compliance with the revised short-term SO_2 emission limits proposed in Table 1 by adding real-time measurements of H_2S in the fuel gas to the average concentrations of other sulfur compounds derived from canister sampling measurements. BP also proposes to increase the frequency of canister sampling from quarterly to monthly. Compliance with the new annual SO_2 emission limit of 56.9 tons per boiler would be calculated on a 12-month rolling average basis using monthly fuel consumption and the average total sulfur concentration from the monthly canister samples.

1.4 New Source Performance Standards

New Source Performance Standards (NSPS) are nationally uniform standards applied to specific categories of stationary sources that are constructed, modified, or reconstructed after the standard was proposed. NSPS are found in Title 40, Part 60 of the Code of Federal Regulations (CFR). NSPS usually represent a minimum level of control that is required on a new source. NSPS that are applicable include Subpart A – General Provisions (40 CFR Part 60.1-60.19) and the following NSPS:

Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60.40b-49b)

NSPS Subpart Db addresses emissions from boilers that have a heat input greater than 100 MMBtu/hr and were constructed, modified, or reconstructed after June 19, 1984. Boilers 6 and 7 meet these criteria and are subject to Subpart Db. The new boilers also subject to Subpart Ja as well (see next subsection). As stated in 40 CFR 60.40b(c), units subject to both Subpart Db and Ja are subject to the particulate matter and NO_X emission limits of Subpart Db and the SO_2 limits in Subpart Ja.

The new boilers will combust gaseous fuel (i.e., natural gas and refinery fuel gas) and Subpart Db only includes particulate matter limits for boilers that burn coal, oil, wood, or solid waste. Therefore, the new boilers are only subject to the Subpart Db NO_X emission limitation of 0.10 lb/MMBtu. The proposed NO_X emission rate for the new boilers is 0.0108 lb/MMBtu, which is less than the NSPS Db limit. Therefore, the only substantive requirements stemming from applicability of Subpart Db relate to monitoring and reporting.

Subpart Ja – Standards of Performance for Petroleum Refineries (40 CFR Parts 60.100a – 60.109a)

In petroleum refineries, Subpart Ja applies to fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices, including flares and process heaters, and sulfur recovery plants.

Subpart Ja applies to fuel gas combustion devices constructed after May 14, 2007. This includes Boilers 6 and 7. The emissions limitations in 40 CFR 60.102a(g) allow two basic regulatory options to estimate sulfur emissions for boilers and heaters: either monitor SO_2 from the boiler stack, or monitor sulfur content of the unit's fuel. The stack gas monitoring option requires a short-term limit of 20 ppm SO_2 in the boiler exhaust with a 3-hour averaging period, and an 8 ppmv SO_2 limit with a 365-day rolling averaging period.

The fuel monitoring option requires a fuel content limit of 160 ppmv H_2S with a 3-hour averaging time, and a 60 ppmv H_2S fuel content limit with a 365-day rolling average SO_2 limit are required.

BP has chosen to use the fuel monitoring option.

Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries (40 CFR Parts 60.590 – 60.593).

Subpart GGG applies to all equipment (i.e., valves, pumps, pressure relief devices, open-ended valves or lines, flanges, and any other connectors in VOC service) within a process unit and compressors at a petroleum refinery installed after May 30, 1984. A process unit is one that produces intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. Because the boilers are not directly involved with the processing of petroleum, the associated fugitive components are not subject to Subpart GGG. Nevertheless, BP will include the proposed boilers in leak detection and repair (LDAR) program based on Subpart GGG and 40 CFR 63 Subpart CC mandated by the Consent Decree.

Consent Decree

On January 18, 2001, BP was issued a Consent Decree (entered August 29, 2001) which requires reductions of NO_X emissions for the refinery heaters and boilers at its Cherry Point Refinery in Whatcom County, Washington. The Boiler Replacement Project helps fulfill part of the NO_X reduction requirements. The Consent Order assures that all refinery heaters and fuel gas combustion units are Subpart J applicable, and it reduces sulfur and particulate emissions from refinery units that are not a part of this project.

1.5 State Regulations

BP is subject to Notice of Construction (NOC) permitting requirements under State of Washington regulations Chapters 173-400 and 173-460. NWCAA is the permitting authority for all air emission regulatory requirements not included in PSD permitting. This includes the NSR permitting of air toxics issues under federal MACT and state 173-460 WAC, and Title V permitting requirements.

NWCAA will be responsible for enforcement of all provisions of the PSD after they are included in the facility's Title V permit, and in the interim between permit issuance and that time.

2. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

All new and significantly modified sources are required to use Best Available Control Technology (BACT), which is defined in 40 CFR 52.21(b)(12) 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.

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.

As determined in Section 1.3, for this amendment only SO_2, emissions from Boilers 6 and 7 are subject to PSD permitting. Since there was no physical change or change in the method of operation, and no annual emissions increase for SO_2, a new BACT review for SO_2 is not required. Conditions are required to limit short-term emissions to within the emission rates evaluated to be acceptable through modeling of their impacts.

Based on the analysis presented in this action, BP proposes and Ecology agrees that there shall be additional emission limits for SO_2 emissions from each boiler of 39.3 lb/hr based on a 3-hour average, and 21.4 lb/hr based on a calendar day average. The existing emission limit of 13.6 lb/hr is applied as 59.6 tons per year limit based on a monthly rolling average. This is consistent with the existing SO_2 emission BACT determination from the original permit which was based on this emission rate for 8,760 hours per year.

BP will test the refinery gas fuel monthly for total sulfur content using ASTM Test Method D-5504 or another method approved by Ecology. A minimum of three canister samples, taken at least an hour apart, will be taken per monthly test, and then analyzed by chromatograph using the ASTM method.

BP will continuously monitor the H_2S content of the boiler fuel. H_2S content greater than 160 ppmv on a 3-hour average, or 50 ppmv on a daily average will be an indication of a possible violation of the SO_2 permit limits.

The total sulfur testing results plus the H_2S CEM monitoring results will be used to create the emission factor used to calculate boiler SO_2 emissions.

3. AIR QUALITY IMPACTS ANALYIS

The PSD permitting program requires that an Ambient Air Quality Impacts Analysis (AQIA) be made for pollutants emitted in significant quantities. The AQIA determines if emissions of any pollutant will cause or contribute to an exceedance of a National Ambient Air Quality Standard (NAAQS). It also determines if the change in air quality since the applicable baseline dates is greater than the Class I and Class II PSD Increment Levels.

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 significant impact levels (SILs). Then, for those pollutants and averaging periods that have impacts greater than their SIL, a cumulative full impacts analysis is used to determine if the proposed project will cause or contribute to an exceedance of a NAAQS. A PSD Increment analysis for those pollutants is also 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.

This section will discuss the AQIA of the nearby Class II area. The AQIA for the Class I areas will be discussed along with the Air Quality Related Values (AQRVs) in Section 4.

3.1 Model Selection and Procedures

The terrain in the immediate vicinity of the BP facility is rolling land historically used as farmland. For the purposes of regulatory dispersion modeling, intermediate terrain and complex terrain are defined as elevations above stack height and plume height, respectively. For the facility as proposed, intermediate terrain starts at an elevation of 165 feet (50.3m) above the highest stack base and complex terrain would range upwards from an elevation of about 380 feet (116 m) above the stack base for stable conditions. Such terrain features exist within the vicinity of the refinery. The dispersion model selected for the analysis needs to consider both complex terrain and building downwash effects.

BP applied AERMOD to evaluate local, or "Class II" concentrations of criteria pollutants impacts using the same methods discussed in the 2007 application except that the 5-year on-site meteorological data set (2001-2005) was re-processed according to updated EPA guidance.[6] Only short-term SO_2 standards and increments were evaluated because BP is not proposing any change in the annual SO_2 emission rate.

3.2 SILs Analysis

In the 2007 application, BP modeled the boilers and contemporaneous emission increases (from prior projects) for comparison with EPA Significant Impact Levels (SILs). BP updated the 2007 application modeling using the proposed higher short-term SO_2 emission rates for Boilers 6 and 7 with the SO_2 emission rates for the contemporaneous projects that were presented in the 2007 application.

When the maximum model-predicted concentration exceeds an applicable EPA SIL, additional evaluation is necessary to evaluate total increment consumption and evaluate compliance with the NAAQS. The results of the SO_2 modeling analysis presented in Table 2 indicate predicted SO_2 concentrations exceed each of the SILs. Consequently, NAAQS and PSD increment consumption must be evaluated for 3-hour and 24-hour SO_2 averaging periods, and WAAQS compliance must be evaluated for 1-hour SO_2.

[6] ENVIRON used the AERMET surface characteristic preprocessor, AERSURFACE (Version 08009) to determine seasonal surface parameters (albedo, Bowen ratio, and surface roughness length) for the area surrounding the BP meteorological site. This analysis was conducted consistent with EPA's AERMOD Implementation Guide (EPA, 2008) and the AERSURFACE User's Guide (EPA-454/B-08-001, January 2008).

Table 2: MAXIMUM MODEL-PREDICTED SHORT-TERM SO_2 CONCENTRATIONS ($\mu g/m^3$)

Pollutant	Averaging	Maximum Predicted Concentration	EPA SIL	Monitoring Threshold
SO_2	1-hour	127	None	None
	3-hour	47	25	None
	24-hour	9.3	5	13

3.3 NAAQS/WAAQS Analysis

BP operates an ambient SO_2 monitor adjacent to the refinery. A survey of monitor data from 2002 through 2006, inclusive, revealed a maximum 1-hour SO_2 concentration of 149 µg/m3, a maximum 3-hour SO_2 concentration of 92 $\mu g/m^3$, and a maximum 24-hour SO_2 concentration of 43 $\mu g/m^3$.

In Table 3, the maximum model-predicted 1-hour SO_2 concentration attributable to each boiler emitting 39.29 lb/hr is added to the highest 1-hour SO_2 observation recorded at BP's SO_2 monitoring site to demonstrate compliance with the 1-hour SO_2 WAAQS.

To demonstrate compliance with the 3-hour and 24-hour NAAQS and the 24-hour WAAQS, BP also modeled SO_2 emissions from all Cherry Point Refinery sources and from other regional industrial sources that have a significant impact on SO_2 concentrations near the refinery. Regional industrial sources, as determined in the 2007 application, include Alcoa Primary Metals Intalco Works (formerly Intalco Aluminum), Conoco Phillips, and Puget Sound Refining Company.

Table 3 compares the sum of predicted concentrations due to industrial sources and the maximum background concentrations with ambient air quality standards. All predicted 3-hour and 24-hour cumulative concentrations are less than the lowest applicable standards.

Table 3: MAXIMUM MODEL-PREDICTED SHORT-TERM SO_2 CONCENTRATIONS AND COMPARISON WITH APPLICABLE AMBIENT AIR QUALITY STANDARDS

Criteria Pollutant	Averaging Period	Maximum Concentrations (μg/m³)		Total[b]	Standard (μg/m³)	
		BP and Other Regional Industrial Sources	Background[a]			
SO_2	1	127	149	276	1,050	WAAQS
	3	697	92	789	1,300	NAAQS
	24	111	43	154	365	NAAQS
	24	111	43	154	262	WAAQS

[a] Background concentrations reflect the highest observations from 2002-2006 collected at a BP SO_2 monitoring station located adjacent to BP's meteorological monitoring tower.

[b] Pollutants for which the project did not trigger PSD (1-hour SO_2) were modeled only with Boilers 6 and 7 and were combined with a background concentration for comparison with the ambient standard. (The inclusion of contemporaneous emission increases pertains to the PSD review process, and the 1-hour standard is a state standard that is not governed by the PSD process.)

In addition to the state and federal ambient standards, NWCAA also established two short-term SO_2 ambient standards:

- 655 μg/m³, average for any one hour not to be exceeded more than two times in any consecutive seven days
- 2,096 μg/m³ for any 5-minute average, not to be exceeded more than once per year

The maximum predicted 1-hour average concentration presented in Table 3 is less than the NWCAA 1-hour SO_2 standard, so it is clear that the second highest concentration in any 7-day period would also be less than the NWCAA 1-hour standard.

Demonstrating compliance with a 5-minute standard is somewhat less direct because the shortest time averaging period offered by AERMOD is one hour. In order to evaluate shorter time averaging periods, ENVIRON employed a scaling procedure recommended by Turner (1970).[7] Turner recommends that 1-hour concentrations be multiplied 1.64 to estimate 5-minute average concentrations. Conservatively, applying this scaling factor to the cumulative 1-hour concentration presented in Table 3 results in a maximum 5-minute concentration of 453 μg/m³. This is 22 percent of the NWCAA ambient standard.

3.4 Increment Analysis

Because the predicted short-term SO_2 concentrations attributable to the new boilers and the contemporaneous emission increases exceed the SILs, a PSD increment analysis must be performed. BP's increment analysis evaluated virtually all the sources included in the NAAQS

[7] D. Bruce Turner, Workbook of Atmospheric Dispersion Estimates, CRC Press. First published in 1970.

analysis (all Cherry Point Refinery SO_2 sources as well as sources located within 50 km of the project's significant impact area). Although PSD Increment analyses need not include any emission sources that are part of the PSD SO_2 major source or SO_2 minor source baseline dates (January 6, 1975 and August 23, 1979, respectively), BP found it time consuming to confirm that a given emission unit is in the baseline. BP's Class II Increment analysis conservatively includes all BP and other industrial SO_2 sources except the tanker pumping crude oil to the refinery; the tanker is a large source of SO_2 emissions and is clearly part of the baseline (operational since 1970).

The results of the PSD Increment analysis are compared with PSD increments in Table 4. Maximum model-predicted 3-hour and 24-hour average SO_2 concentrations in the impact area are less than the associated SO_2 PSD increments.

Table 4: MAXIMUM PREDICTED SHORT-TERM SO_2 CONCENTRATIONS AND COMPARISON WITH APPLICABLE PSD INCREMENTS

Averaging Period	BP Refinery and Other Regional Industrial Sources (µg/m^3)	PSD Increment (µg/m^3)
3	389	512
24	75	91
Note: There is no PSD increment for 1-hour or 5-minute averaging periods.		

Low Operating Rates and Start-up Considerations

In the original permit, the possibility of operating these boilers at lower operating rates and at idle was discussed. This will affect CO and NO_X emissions from the boilers, but Amendment 1 only changes short-term SO_2 emission rates. Since SO_2 emissions are proportional to fuel usage, at low operating rates SO_2 emissions will always be lower than emissions analyzed at full operating rates.

3.5 Toxic Air Pollutants

PSD rules require the applicant to consider emissions of toxic air pollutants. Washington State regulations (Chapter 173-460 WAC) require an ambient air quality analysis of Toxic Air Pollutant (TAP) emissions, which usually serves the purpose of PSD toxics review in Washington State. The Notice of Construction issued by the Northwest Clean Air Agency in conjunction with this PSD permit fulfills all requirements of WAC 173-460.

4. CLASS I AREA IMPACT ANALYSIS

Federal[8] and Washington State[9] PSD regulations require the impact of a proposed facility on federal Class I areas be analyzed. Class I areas are areas of special national or regional value

[8] 40 CFR 52.21 (p)

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. The AQRVs of concern include visibility and deposition.

Air pollutant impacts to Class I areas were evaluated extensively in the 2007 application. Because SO_2 is one of the pollutants examined in Class I assessments, BP's proposal to increase short-term SO_2 emissions requires reconsideration of potential impacts. Rather than repeat the entire analysis, however, BP completed two abbreviated evaluations that confirmed the increase in short-term SO_2 emissions would not have a significant adverse effect on Class I areas.

4.1 Screening Method

On June 27, 2008, the Federal Land Managers (FLMs) circulated a proposal that establishes a threshold triggering their formal review of Air Quality Related Values (AQRVs) in Class I areas. The method divides the total annual emissions (in tons) of SO_2, NO_X, PM_{10}, and sulfuric acid mist (H_2SO_4) from a project by the distance (in kilometers) to the nearest Class I area. If this quotient is less than 10, the FLMs will probably not be concerned and an extensive review by the Park Service or the U.S. Forest Service is not necessary. The National Park Service, National Forest Service, and EPA checked this screening tool out over all recent PSD permit applications, and it worked very well to their satisfaction. It is now an approved screening tool for NPS and USFS PSD application review. Many other PSD related Class I requirements still apply though.

Table 5 presents the distance to each of the seven Class I areas within 300 kilometers of BP Cherry Point. The distance to the nearest Class I area, North Cascades National Park, is approximately 78 kilometers.

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[9] WAC 173-400-117

Table 5: CLASS I AREA DISTANCES FROM BP CHERRY POINT

Class I Area	Distance (km)
Alpine Lakes Wilderness Area	156
Glacier Peak Wilderness Area	106
Goat Rocks Wilderness Area	253
Mount Adams Wilderness Area	291
Mount Rainier National Park	211
North Cascades National Park	78
Olympic National Park	98
Pasayten Wilderness Area	123
Mount Baker[1]	56
[1] Mount Baker Wilderness Area is not a Class I area, it is included in the analysis because FLMs have requested its inclusion in previous permit applications.	

Table 6 presents the total annual potential emissions of visibility-affecting pollutants for two scenarios:

- The proposed incremental change in boiler emissions: the proposed 24-hour SO_2 emission rate minus the current SO_2 emission limit for Boilers 6 and 7, and
- The total proposed emissions from Boilers 6 and 7: the proposed 24-hour SO_2 emission rate with the existing PM_{10} and NO_X emission limits for Boilers 6 and 7.

Considering only the incremental increase in the 24-hour SO_2 emissions (69 tons), the emissions-over-distance quotient is 0.9.[10] The maximum total annual potential emissions of visibility-affecting pollutants are 255.5 tons, and the emissions-over-distance quotient is 3.3. Both quotients are less than half the threshold that triggers FLM review.

BP also evaluated the emissions-over-distance quotient for the Mount Baker Wilderness Area (56 kilometers from the facility) even though Mount Baker is not a Class I area. The quotient for 255.5 tons of visibility-affecting pollutant emissions at Mount Baker is 4.6, less than half the threshold that triggers FLM review. The quotient for Mount Baker considering only the increase in 24-hour average SO_2 emissions is 1.2.

[10] Visibility impacts and this screening method are based on 24-hour average emission rates. Applying this screening approach suggests that there would be a 69 ton increase in annual SO_2 emissions from the boiler. As stated earlier, however, BP is not proposing an increase in annual emissions.

Table 6: COMPARISON OF BOILERS 6 AND 7 EMISSIONS RELEVANT TO AQRVs

Project	NO_X		SO_2		PM_{10}		H_2SO_4		Total
	24-hr	Annual	24-hr	Annual	24-hr	Annual	24-hr	Annual	Annual
Incremental Boilers 6 and 7, 24-hr SO_2 Increase[1]	0.0	0.0	15.52	68.0	0	0.0	0.3	1.5	69.4
Proposed 24-hr SO_2 Limit on Boilers 6 and 7[2]	7.9	34.6	42.72	187.1	6.8	29.8	0.9	4.0	255.5

Note: 24-hour emissions in lb/hr. Annual emission in tons.
Boilers 6 and 7 H_2SO_4 emissions based on 1.4% conversion of SO_2 and molecular weight correction.

[1] Source: New proposed SO_2 emission limits (21.36 lb SO_2/hr, per boiler) minus existing SO_2 emission limit (13.6 lb SO_2/hr, per boiler). Existing SO_2 emission limit from Boiler Replacement Project PSD Permit (PSD 07-01).

[2] Source: New proposed SO_2 emission limit (21.4 lb SO_2/hr, per boiler) and existing NO_X and PM_{10} emission limits. Existing NO_X and PM_{10} emission limit from Boiler Replacement Project OAC Permit (#1001) and PSD Permit (PSD 07-01).

4.2 Scaling 2007 Application Results for Higher SO_2 Emissions

Even though the Screening Method indicated that the Boiler Replacement Project would not have unacceptable impacts on the Class I areas, BP chose to do additional analysis to refine the original 2007 permit Class I impacts analysis to include estimates of the impacts of increased short-term emission levels as well as the original annual average impacts analysis. To estimate the effect higher boiler emissions would have in Class I areas without re-doing the entire Class I modeling analysis, BP conservatively scaled up the Class I SO_2 modeling results using the ratio of the now-proposed SO_2 emissions to those evaluated in the 2007 application.[11] A factor of 2.89 (ratio of 78.59 SO_2/hr to 27.23 lb SO_2/hr) was applied to the 3-hour SO_2 results and a factor of 1.57 (ratio of 42.72 lb SO_2/hr and 27.23 lb SO_2/hr) was applied to the 24-hour SO_2 results.

Table 7 compares scaled SO_2 concentrations in each Class I area to the Class I SILs. The maximum 3-hour and 24-hour SO_2 concentrations are less than the applicable Class I SILs at all locations.

To evaluate whether higher boiler SO_2 emission rate would change the findings of the 2007 application's Class I area visibility assessment, ENVIRON scaled up the fraction of extinction attributable to sulfurous emissions from the refinery. As shown in Table 6, the maximum predicted change in extinction on any one day was 3.69 percent, less than the five percent threshold established by the FLMs.

[11] This is conservative because the boiler emissions were less than half the total SO_2 emissions modeled in the application. The contemporaneous project emissions need not be scaled up – BP is seeking an increase in only the boiler emissions. By scaling up the previously-predicted concentrations, we are in effect assuming the same percentage increases from the contemporaneous projects.

Sulfur deposition in Class I areas is typically evaluated in PSD permits. However, annual sulfur deposition was not evaluated because BP is not proposing to increase the annual SO_2 emission rate for Boilers 6 and 7.

In reality, there will be virtually no increase in SO_2 concentrations in Class II or Class I areas because the refinery fuel gas will be combusted in other refinery combustion units if not in Boilers 6 and 7.

Table 7: MAXIMUM SCALED CLASS I AREA SHORT-TERM SO_2 CONCENTRATIONS

Concentrations in micrograms per cubic meter ($\mu g/m^3$)

Class I Area of Interest	Scaled SO_2 Concentration	
	3-hour Average	24-hour Average
Alpine Lakes Wilderness	0.183	0.00110
Glacier Peak Wilderness	0.237	0.00141
Goat Rocks Wilderness	0.048	0.00031
Mount Adams Wilderness	0.041	0.00016
Mount Baker Wilderness[1]	0.877	0.00486
Mount Rainier National Park	0.066	0.00078
North Cascades National Park	0.276	0.00235
Olympic National Park	0.460	0.00377
Pasayten Wilderness	0.145	0.00126
Class I Area & Mt. Baker Maximum Concentration	0.877	0.00486
EPA Proposed SIL[2]	1	0.2
FLM Recommended SIL[2]	0.48	0.07
Class I PSD Increment[3]	25	5

[1] Mount Baker Wilderness Area is not a Class I area, it is included in the analysis because FLMs have requested its inclusion in previous permit applications.

[2] SIL = Significant Impact Level; EPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.

[3] PSD = Prevention of Significant Deterioration; from 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v).

Table 8: TEN DAYS WITH MAXIMUM PREDICTED CLASS I AREA EXTINCTION CHANGE SCALED TO REFLECT HIGHER 24-HOUR SO_2 EMISSION RATE FOR BOILERS 6 AND 7

Extinction coefficient in inverse megameters (1/Mm)

Class I Area	Date	b_{ext}[1]			Change (%)	f(RH)	b_{ext} by Component[4]					
		Project[2]	Bckgrnd[3]	Total			SO_4[6]	NO_3	OC	EC	PMC	PMF
Mt. Baker WA[5]	02/10/03	0.71	18.47	19.18	3.69	6.62	0.549	0.155	0.001	0.000	0.000	0.002
Mt. Baker WA[5]	02/09/04	0.68	19.56	20.24	3.35	8.44	0.493	0.179	0.003	0.000	0.000	0.004
Olympic NP	11/22/04	0.60	19.01	19.61	3.06	7.52	0.428	0.166	0.002	0.000	0.000	0.003
Olympia NP	02/11/03	0.56	17.37	17.93	3.13	4.78	0.438	0.120	0.002	0.000	0.000	0.002
Mt. Baker WA[5]	10/28/03	0.54	17.90	18.44	2.95	5.66	0.397	0.143	0.002	0.000	0.000	0.003
Olympic NP	02/08/03	0.47	16.08	16.55	2.87	2.63	0.340	0.127	0.003	0.000	0.000	0.004
Mt. Baker WA[5]	12/13/05	0.54	18.29	18.83	2.88	6.31	0.408	0.132	0.001	0.000	0.000	0.002
Mt. Baker WA[5]	02/04/03	0.51	18.47	18.98	2.69	6.62	0.337	0.168	0.002	0.000	0.000	0.003
Olympic NP	11/18/05	0.42	16.10	16.53	2.56	2.67	0.270	0.141	0.005	0.000	0.000	0.007
Mt. Baker WA[5]	09/15/03	0.48	18.01	18.49	2.60	5.85	0.340	0.136	0.002	0.000	0.000	0.003

[1] Project and background extinction values for daily period that resulted in the maximum percent change in extinction.
[2] Emission rates based on continuous year-round operation for three years.
[3] Background extinction derived from default annual average Western U.S. extinction components provided in FLAG guidance document.
[4] Extinction coefficient components are: SO_4 = fine sulfate, NO_3 = fine nitrate, OC = fine organic carbon, EC = fine elemental carbon, PMC = coarse mass, PMF = fine crustal mass.
[5] Mount Baker Wilderness Area is not a Class I area, it is included in the analysis because FLMs have requested its inclusion in previous applications.
[6] SO_4 extinction coefficient conservatively scaled up by 1.57 to reflect the ratio of proposed 24-hour SO_2 emission rates for Boilers 6 and 7 combined (42.72 lb SO_2/hr) compared to the short-term SO_2 emission rate identified in the 2007 application (27.23 lb SO_2/hr for Boilers 6 and 7 combined).

4.3 Conclusion Concerning AQRVs

Ecology determines that increased emissions from the project are not expected to significantly impact AQRVs in the North Cascades National Park, the Olympic National Park, or any other Class I area.

5. ADDITIONAL IMPACTS ANALYSIS

Under 40 CFR 52.21(o), PSD applications must provide: “an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification.” In accordance with these requirements, the following analysis of additional impacts from the proposed project has been prepared.

Growth Analysis: BP produces fuels that are shipped by truck and pipeline to meet regional energy requirements. As such, the Boiler Replacement Project would not represent a large influx of a commodity that would spur secondary growth in the Cherry Point area.

During construction, the demand for skilled crafts people in the area would increase. This demand would be temporary (18 months or less). Once operational, the facility is expected to result in no additional permanent jobs. This would not cause significant growth in the Cherry Point area. Since Amendment 1 does not authorize any further construction or change operations, it will not affect growth either.

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. The new boilers (and the other refinery sources) will combust only low-sulfur natural gas or refinery fuel gas, thus minimizing the emission of sulfur compounds. For emissions of NO_X (assuming full conversion to NO_2), potential plant damage could begin to occur with 24-hour NO_2 concentrations of 15 to 50 parts per billion (ppb).[12] From the modeling results, the maximum annual concentration of NO_2 is below 0.3 $\mu g/m^3$ (about 0.2 ppb). The potential impact on local agriculture is expected to be negligible. In reality, there will be no increase in SO_2 concentrations and impacts from the refinery due to this project because the volume of refinery fuel gas produced and combusted by the refinery will not change. Additional fuel usage (natural gas) will actually be less because Boilers 6 and 7 produce steam more efficiently than the two older boilers they are replacing.

Visibility Impairment Analysis: On a local scale, "visibility" is usually evaluated by considering perceptibility of a plume from a stack or cooling tower. State and local regulations restrict visible emissions to 20 percent opacity; however, emissions from the fuel gas-fired boilers are typically less than five percent and are rarely visible. No cooling towers are impacted by this project. As such, the potential impact of the Boiler Replacement Project on Class II visibility is expected to be negligible. Amendment 1 will not affect the boilers' operation, so it will not change this analysis. The long-range visibility impacts from the proposed source are evaluated for the Class I areas and are discussed in Section 4.

6. CONCLUSION

The proposed permit amendment will have no significant adverse impact on air quality or air quality-related values. The Washington State Department of Ecology finds the applicant, the BP Cherry Point Refinery, has satisfied all requirements for approval of their application for a PSD permit amendment for the proposed Boiler Replacement Project.

[12] USDA Forest Service. May 1992. Guidelines for Evaluating Air Pollution Impacts on Class I Wilderness Areas in the Pacific Northwest. PNW-GTR-299.

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