BP Cherry Point Refinery
4519 Grandview Road
Blaine, Washington 98230
Telephone 360 371-1500

November 4, 2016

Mr. Gary Huitsing
Washington Department of Ecology
PO Box 47600
Olympia WA 98504-7600

Subject: Cherry Point Refinery Coker Heater Replacement Project

Dear Mr. Huitsing:

BP submitted a combined Notice of Construction/Prevention of Significant Deterioration permit application for the replacement of two coker heaters at the Cherry Point Refinery in Ferndale, Washington (the "Project"). The permit application was deemed complete by the Washington Department of Ecology in April 2016 and by the Northwest Clean Air Agency in May 2016. Nonetheless, WAC 173-400-730(2)(a) authorizes Ecology to request additional information even after an application is deemed complete.

The purpose of this letter and attachment is to respond to a request by Ecology to address an issue raised by the National Park Service in an October 14 letter to Ecology regarding the Project. Specifically, Ecology requested that BP re-evaluate the air quality impacts attributable to the Project using a different baseline period to determine the increases in emissions attributable to the Project. BP is also committing to reduce the combined hourly SO2 emission limit for the new coker heaters from 40 lb/hr to 37 lb/hr.

BP retained Ramboll Environ to supplement the technical analyses included in the permit application to respond to Ecology's request. Attached is Ramboll Environ's technical report summarizing short-term and annual emissions and local and regional dispersion modeling of those emissions. The supplemental analysis, following PSD regulations and FLAG guidance, indicates emission increases from the Project result in model-predicted ambient impacts below screening criteria for NAAQS, PSD increments, and AQRV.

Please feel free to call me at 360.599.4712 if you have any questions about this response.

Scott Inloes

Scott Inloes, P.E.
Senior Environmental Engineer

cc: Agata McIntyre, NWCAA
Steve Mrazek, BP

COKER HEATER REPLACEMENT PROJECT

SUPPLEMENTAL ANALYSES WITH REVISED BASELINE EMISSIONS

The purpose of this technical report is to respond to a request by Ecology to address an issue raised by the National Park Service (NPS) in an October 14 letter to Ecology regarding the Project. Specifically, Ecology requested a re-evaluation of the air quality impacts attributable to the Project using a different baseline period to determine the increases in emissions attributable to the Project. Ecology requested that BP use the average of the most recent two years of actual emissions as the baseline for the existing coker heaters and for other emissions units whose annual utilization may be affected by the Project.

The following narrative addresses that request and presents projected actual emissions from the Project in relation to the more recent baseline period. Ramboll Environ then summarizes the results of local and regional air quality modeling based on the increases in refinery emissions that result from a revised baseline and a revised projection of emissions. Although the NPS comments were focused on air quality related values (AQRV) in Class I areas, BP elected to also evaluate the effects of Project emissions on Prevention of Significant Deterioration (PSD) increments and National Ambient Air Quality Standards (NAAQS) in Class I and Class II areas. The modeling demonstrates the Project meets all criteria established to ensure protection of NAAQS, PSD increments, and AQRV.

CLASS I SCREENING PROCEDURE

The responsibilities and procedures to be followed by applicants and the federal land managers (FLMs) for Class I areas are provided in a guidance document generally referred to as FLAG2010.[1] That guidance includes a screening level procedure that allows applicants to determine when an AQRV modeling analyses is necessary:

> *Therefore, the Agencies will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO2, NOx, PM10, and H2SO4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions), divided by the distance (in km) from the Class I area (Q/D) is 10 or less. The Agencies would not request any further Class I AQRV impact analyses from such sources.*

The guidance mixes "source" and "project" throughout the document, but it is clear that the AQRV analysis focuses on a new source or a modification of an existing source (i.e., a project). See, for example, the flow diagram for the screening procedure on Page xiv of the FLAG2010.

The modeling protocol for the Project that was distributed and discussed in a pre-application meeting in March 2014 included a Q/D analysis with a maximum value of 7. Although there was a

[1] Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I report – revised (2010).

follow-up question confirming how Q was calculated, it was subsequently agreed that the analysis was conducted correctly and an acceptance that analysis of AQRV was not required. Nonetheless, the permit application included an AQRV analysis with the intent of making the application more transparent.

Baseline Emissions

The most readily available source of actual annual emissions from industrial sources is the Washington Emissions Inventory Reporting System (WEIRS). Based on its submittals to WEIRS, BP identified actual 2014 and 2015 emissions for each of the emission units affected by the Project and averaged those emissions to identify a baseline annual emission rate in tons. This baseline was used to assess sulfate and nitrate deposition and compliance with annual PSD increments and NAAQS.

Analyses of Project impacts to visibility in Class I areas are based on daily (24-hour) emissions. Increases in daily emissions attributable to the replacement of the coker heaters were calculated by subtracting the average daily emissions during the 2014 and 2015 baseline period from the potential emissions from the new heaters.[2]

Baseline short-term emissions for the new coker heaters are assumed to be zero, but the existing coker heaters will be removed from service. Baseline short-term emissions for the existing heaters were calculated using source test-based emission factors and actual firing rates during 2014 and 2015. Class II significance modeling evaluated the increases in short-term emissions (lb/hr) from the heaters, which were calculated by subtracting these baseline short-term emissions from the potential emissions from the new heaters.

Projected Actual Emissions

For the PSD permit application, the increase in emissions attributable to the Project must consider potential emissions from the new coker heaters, but the applicant may choose for existing emission units whether to use potential emissions or projected actual emissions resulting from changes in operation of those units due to the Project. 40 CFR 52.21(b)(41), incorporated by reference in WAC 173-400-720 (definition of "projected actual emissions"). The future emissions from existing emissions units identified in the permit application were intentionally higher than what BP expects to emit, and in several cases approached potential to emit. The rationale was that demonstrating compliance with all approval criteria using very conservative future emissions assumptions would simplify and expedite the permit review and approval process. In response to the incorporation of a 2014 and 2015 actual emissions baseline, BP took a closer look at projected actual emissions from units affected by the Project.

[2] Page 24 of FLAG2010 Guidance Document

The following documents the rationale behind the revised projections.

CRUDE HEATER

Because the new coker heaters will have on-line cleaning ability (spalling), there will be less down time for decoking. The higher on-line time for the coker unit will debottleneck the crude unit, allowing the crude unit to process an additional 1.25 thousand barrels per day (kbpd), a 0.5 percent increase from the 2014 and 2015 baseline period.

In addition, the proposed crude unit heat exchanger bypasses would allow processing of an additional 5.1 kbpd of crude on an annual average basis; this is a 2.3 percent increase from the 2014 and 2015 baseline period. The total crude throughput increase is 6.3 kbpd (2.8 percent) rather than the 8 kbpd (4 percent) conservatively assumed in the PSD application.

VACUUM HEATERS: Vacuum heater throughput will increase 3 percent (rounded up from the 2.8 percent increase in crude unit throughput).

COKER UNIT: Our PSD permit application assumed projected annual average coker throughput of 61.9 kbpd. The revised modeling analysis assumes annual average coker unit throughput of 60.0 kbpd, a 36 percent increase in annual coker unit utilization from the 2014 and 2015 baseline period.

COKER HEATERS: Projected emissions from the proposed coker heaters are equal to potential emissions presented in our PSD application, except that BP has committed to combined hourly SO2 emissions from the heaters equal to 37.2 lb/hr.

CALCINERS: Consistent with the coker throughput increase just discussed, BP projects that actual SO2 and PM10/PM2.5 emissions will be 36 percent higher than 2014 and 2015 baseline period. However, BP has found that an assumption in our application that NOx emissions increase with additional calciner utilization is not accurate. In fact, NOx emissions during calciner standby are almost equivalent to NOx emissions when calciners are processing coke. BP revised the projected NOx emissions from the calciners accordingly.

HYDROCRACKER: BP anticipates the hydrocracker would process an additional 5.3 kbpd over the 2014 and 2015 baseline period. This results in projected emissions that are 9 percent over the 2014 and 2015 baseline period.

HYDROGEN PRODUCTION: BP estimates the #1 Hydrogen Plant will need to produce an additional 8 million standard cubic feet per day of hydrogen to accommodate the additional coker unit throughput; this is a 15 percent increase over the 2014 and 2015 baseline production rate. The #2 Hydrogen Plant is included in the contemporaneous period and is modeled at its allowable emission rates, which over estimates emissions compared to 2014 and 2015 baseline actual emissions.

ISOMERIZATION UNIT: BP estimates the ISOM Unit would process an additional 1.1 kbpd, a 34 percent increase compared to the 2014 and 2015 baseline period.

NAPHTHA UNIT: BP estimates the Naphtha Unit would process an additional 1.8 kbpd, a 5 percent increase over the 2014 and 2015 baseline period.

Consistent with the increase in the crude unit throughput discussed above, BP assumes all other heaters, liquid product loadout, and sulfur plant throughput and emissions would increase 3 percent over the 2014 and 2015 baseline period.

EMISSION REDUCTION PROJECTS

The PSD permit process requires applicants to include emissions from contemporaneous projects that were not previously subject to PSD review. Consequently, the Project PSD application included emissions of NOx, SO2, CO, and PM2.5 from the Clean Fuels Project, emissions of PM10 from the Boilers 6 and 7 permit modification, and emissions from other contemporaneous projects.

Applicants may also take credit for contemporaneous emissions reductions. During the permitting of the Clean Fuels Project in 2010, BP committed to a burner retrofit on the Hydrocracker 1st Stage Fractionator Reboiler. The new burners began operation in May 2012.

The Coker Heater Replacement Project PSD application included the permanent shutdown of the existing coker heaters and the retrofit of the Hydrocracker 1st stage fractionator reboiler burners as creditable contemporaneous emission reductions when BP determined PSD applicability for the Project. However, BP (conservatively) did not include the emission reductions from the Hydrocracker retrofit in our impact analysis because this credit was not needed to demonstrate compliance with ambient impact criteria. BP elects to include the actual NOx emission reductions from this contemporaneous project (87.7 tons per year) in this current analysis.

As part of the Project, BP proposes to install a new compressor with a lean oil absorption system to recover propane and butane. The lean oil absorption system is designed to process approximately 44 percent of the coker off gas generated. A benefit of the lean oil absorption system is additional sulfur removal (39 percent annual average) from the coker off gas that will be used as fuel in the new coker heaters. This reduction in sulfur emissions from the coker heaters has not been included in the modeling, so actual emissions and impacts from the heaters will be lower than presented here.

Updated Increases in Emissions

Based on the rationale presented above, short and long-term increases in emissions attributable to the Project were calculated and are summarized in tables 1 and 2. The only change in short-term emissions is for the coker heaters. The calculated change in hourly emissions increased when the baseline was revised to reflect actual emissions from 2014 and 2015.

Table 2 presents the revised annual baselines and projected actual annual emissions (potential emissions for the new coker heaters). In general, the revised annual emission increases are less than the emission increases presented in the PSD application. Although the calculated emissions increase from the new coker heaters is higher than in the application, the more careful examination of Project effects on other process units resulted in a lower overall increase in emissions due to the Project.

A more detailed presentation of hourly and annual emissions is provided in the attachment. Tables A-1 and A-2 identify the emission rates used in AERMOD to demonstrate compliance with short term and annual ambient standards and PSD increments. Tables A-3 and A-4 provide speciated emissions used with the CALPUFF model to address Class I short-term AQRVs (visibility and SILs) and long-term AQRVs (deposition and SILs).

Again, Ramboll Environ notes that the emissions calculated for use in the impact analyses represent the Project, not the entire refinery. For example, page 9 of FLAG2010 discusses the elements of a permit review:

> *This analysis must show the contribution of the <u>proposed emissions</u> to increment consumption and to the existing ambient pollution levels in a Class I park or wilderness area. The applicant must perform a cumulative increment analysis for each pollutant and averaging time for which the <u>proposed source</u> will have a significant impact. (emphasis added)*

This is consistent with requirements for PSD increment and NAAQS compliance modeling, where facility-wide emissions are considered only if a project increase results in ambient concentrations greater than the SIL.

Updated Class I Screening Procedure

As noted above, the modeling protocol for the PSD permit application presented a "Q/D" screening analysis that indicated further evaluation of AQRV was not warranted. Table 3 presents an updated Q/D based on the maximum 24-hour emission rates from the coker heaters adjusted to annual emissions. Table 3 affirms again that the Project does not require an AQRV modeling analysis.

Updated Modeling Results

The detailed emission rates in Attachment A (Tables A-1 through A-4) were evaluated using the same models, meteorological data, receptors, and modeling assumptions that were used in the

permit application. Tables 4 and 5 indicate AERMOD- and CALPUFF-predicted concentrations are less than the applicable Class II and Class I Significant Impact Levels, indicating that Project emissions will not significantly affect PSD increment consumption or compliance with NAAQS.

Table 6 identifies CALPUFF-predicted sulfate and nitrate deposition attributable to the Project and compares the predictions to Deposition Analysis Thresholds established as impact criteria in Class I areas. FLAG 2010 defines DATs as follows:

> *A DAT is defined as the additional amount of nitrogen or sulfur deposition within an FLM area, below which estimated impacts from a proposed new or modified source are considered negligible. In other words, if the new or modified source has a predicted nitrogen or sulfur deposition impact below the respective DAT, the NPS and FWS will consider that impact to be negligible, and no further analysis would be required for that pollutant.*

Table 6 indicates predicted deposition rates are less than the DATs in all Class I areas, indicating the project will have a negligible effect.

Finally, Table 7 identifies the 98th percentile change in visibility attributable to Project emissions of NOx, SO2, and particulate matter. FLAG2010 establishes a visibility impact criterion as follows:

> *The visibility threshold for concern is not exceeded if the 98th percentile change in light extinction is less than 5% for each year modeled, when compared to the annual average natural condition value for that Class I area.*

Table 7 indicates that the 98th percentile change in visibility is less than 5% in all Class I areas for each of the three years of analysis. Consequently, emissions from the Project do not exceed the threshold of concern established by the federal land managers.

The supplemental analysis, following PSD regulations and FLAG2010 guidance, indicates emission increases from the Project result in model-predicted ambient impacts below all screening criteria for NAAQS, PSD increments, and AQRV.

Table 1. Revised Hourly Emissions Summary (pounds)

Emission Unit	NOx				SO2				PM10			
	Baseline	New PTE	Increase[a]		Baseline	New PTE	Increase[a]		Baseline	New PTE	Increase[a]	
			current	Table 6-1			current	Table 6-1			current	Table 6-1
West Coker Heater	8.0	18.2	10.2	3.0	5.7	18.6	12.9	5.1	0.6	3.0	2.4	1.1
East Coker Heater	8.1	18.2	10.1	3.0	6.7	18.6	11.9	5.1	0.7	3.0	2.3	1.1
Boiler 6	--	--	0.0	0.0	--	--	0.0	0.0	--	--	1.6	1.6
Boiler 7	--	--	0.0	0.0	--	--	0.0	0.0	--	--	1.6	1.6
#3 Diesel Unit	--	--	1.0	1.0	--	--	3.0	3.0	--	--	0.3	0.3
#2 Hydrogen	--	--	3.5	3.5	--	--	2.8	2.8	--	--	5.0	5.0
Hydrogen Flare	--	--	13.0	13.0	--	--	0.0	0.0	--	--	1.9	1.9
Sulfur Unit	--	--	2.9	2.9	--	--	0.1	0.1	--	--	0.0	0.0
Total Increases	--	--	40.7	26.4	--	--	30.7	16.2	--	--	15.1	12.6

Notes:

a Increases over baseline emissions using the current methodology versus the increases presented in Table 6-1 of the permit application.

Table 2. Revised Annual Emissions (tons)

Emission Unit	NOx				SO2				PM10			
	New baseline	Revised	Increase[a]		New baseline	Revised	Increase[a]		New baseline	Revised	Increase[a]	
	2014 – 2015	PTE/PAE	current	Table 6-2	2014 – 2015	PTE/PAE	current	Table 6-2	2014 – 2015	PTE/PAE	current	Table 6-2
Coker Heater Emissions	34.5	79.7	45.2	35.4	26.5	66.0	39.5	23.2	3.0	13.3	10.3	10.0
Coker Heater Emissions	34.5	79.7	45.2	35.4	26.5	66.0	39.5	23.2	3.0	13.3	10.3	10.0
Calciners	508.0	650.0	142.0	142.8	214.2	291.3	77.1	119.3	20.7	28.1	7.4	3.9
Vacuum Heaters	77.6	79.9	2.3	15.4	27.6	28.3	0.7	0.0	2.2	2.3	0.1	0.4
Hydrocracker "R" heaters	29.1	31.7	2.6	12.8	12.5	13.6	1.1	2.0	9.0	9.5	0.5	1.6
Reformer Heaters	266.2	274.1	7.9	13.4	75.8	78.1	2.3	0.0	19.6	20.2	0.6	1.0
Other Heaters[b]	47.1	53.7	6.6	15.8	20.4	25.1	4.7	3.3	5.1	6.6	1.5	2.5
Hydrogen Plant Furnaces	126.7	161.2	34.5	25.0	39.4	51.6	12.2	6.3	11.0	34.3	23.3	22.5
Vapor Control Units	28.0	28.9	0.9	1.9	0.0	0.0	0.0	0.0	0.9	0.9	0.0	0.1
Flares	--	--	10.5	10.5	--	--	1.1	1.1	--	--	0.6	0.6
Coke Drum Venting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3	6.4	4.1	4.9
Crude Heater	426.0	437.9	11.9	17.7	143.5	147.6	4.1	7.0	19.6	20.2	0.6	0.8
1st & 2nd Stage HC Frac Reboilers	44.7	48.7	4.0	18.3	33.5	36.5	3.0	3.3	9.4	10.2	0.8	2.5
Sulfur plant	8.5	8.7	0.3	4.5	31.3	32.2	1.0	16.0	0.5	0.5	0.0	0.3
Tail gas unit 2	8.5	8.7	0.3	4.5	31.3	32.2	1.0	16.0	0.5	0.5	0.0	0.3
Crude Ship Pumping	32.1	33.1	1.0	1.4	134.7	135.1	0.4	1.0	8.8	9.1	0.3	0.4
Cooling Tower 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9	3.8	0.9	2.3
Cooling Tower 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9	3.7	0.8	1.1
Green Coke Handling 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.3	9.6	0.4	0.6
Green Coke Handling 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.3	9.6	0.4	0.6
Total Increases	1671	1976	315	355	817	1004	188	222	140	202	63	66

Notes:

a Increases over baseline emissions using the current methodology versus the increases presented in Table 6-2 of the permit application.

b DHDS1 reboiler, Naptha charge heater, Naptha stripper reboiler, isom heater, and DHDS3 charge heater

Table 3: Updated Q/D Summary

Class I Area ID	Class I Area Name	Approximate distance to closest part of Class I area (km)	Q/D Value New Heaters Only (TPY/km)	Q/D Value New Heaters minus Old Heaters (TPY/km)
NCAS	North Cascades NP	78	5	3
OLYM	Olympic NP	102	4	2
GLAC	Glacier Peak WA	108	3	2
PASA	Pasayten WA	123	3	2
ALPL	Alpine Lakes WA	157	2	1
RAIN	Mt. Rainier NP	213	2	1
GOAT	Goat Rocks WA	255	1	1
ADAM	Mt. Adams NP	291	1	1

Table 4: Maximum AERMOD-Predicted Criteria Pollutant Concentrations

Criteria Pollutant	Averaging Period	Max. AERMOD Concentration ($\mu g/m^3$)	Modeling Significance Level ($\mu g/m^3$)	Monitoring De Minimus Concentration ($\mu g/m^3$)
NO_2 [a]	1-hr [c]	2.8	7.5 [b]	None
	Annual	0.5	1	14
SO_2	1-hr [c]	7.6	7.8 [b]	None
	3-hr	5.4	25	None
	24-hr	1.6	5	13
	Annual	0.6	1	None
CO	1-hr	42.8	2,000	None
	8-hr	8.8	500	575
PM_{10}	24-hr	1.0	5	10
$PM_{2.5}$	24-hr [c]	0.9	1.2 [d]	4 [d]
	Annual [c]	0.24	0.3 [d]	None

Notes:

a NO_2 1-hour and annual concentrations are assumed to be 80 percent and 75 percent of NO_X based on ARM.

b The 1-hour NO_2 standard has been set (188 µg/m3, or 100 ppb) EPA provided an interim SIL of 7.5 ug/m3.

For the 1-hour SO2 standard (196 µg/m3, or 75 ppb), EPA provided an interim SIL of 7.8 $\mu g/m^3$ (1-hr)

c 1-hour NO_2, 1-hour SO_2, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$ model predictions based on the maximum five year average of the 100th percentile values at each receptor.

d The $PM_{2.5}$ significance and monitoring de minimus levels were vacated on January 22, 2013 from the Federal PSD regulations, but are presented here for comparison purposes.

Table 5: CALPUFF-Predicted Class I Area Criteria Pollutant Concentrations

Class I Area of Interest	Maximum Predicted Concentration ($\mu g/m^3$)					
	NO_2 [a]	$PM_{2.5}$		SO_2		
	Annual Average	24-Hour Average [c]	Annual Average	3-Hour Average	24-Hour Average	Annual Average
Alpine Lakes Wilderness	0.0003	0.016	0.0009	0.02	0.0075	0.0005
Glacier Peak Wilderness	0.0025	0.028	0.0026	0.09	0.0250	0.0025
Goat Rocks Wilderness	0.00003	0.005	0.0003	0.004	0.0011	0.0001
Mount Adams Wilderness	0.00002	0.003	0.0002	0.004	0.0008	0.0001
Mount Rainier National Park	0.0001	0.008	0.0004	0.01	0.0019	0.0002
N Cascades National Park	0.0063	0.044	0.0051	0.15	0.0417	0.0061
Olympic National Park	0.0059	0.055	0.0075	0.09	0.0292	0.0056
Pasayten Wilderness	0.0029	0.026	0.0036	0.07	0.0213	0.0033
Class I Maximum Concentration	0.0063	0.055	0.0075	0.15	0.0417	0.0061
EPA Proposed Class I SIL [b]	0.1	0.07	0.06	1	0.2	0.1
Mount Baker Wilderness [e]	0.0102	0.055	0.0066	0.22	0.0733	0.0094
San Juan Islands [e]	0.0144	0.070	0.0109	0.19	0.0790	0.0129
Class I Area PSD Increment [d]	2.5	2	1	25	5	2

Notes:

a NO_x was conservatively assumed to be 75 percent converted to NO_2, per Section 6.2.3 of EPA's Guideline on Air Quality Models (Appendix W to 40 CFR Part 51).

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

c 24-hour PM2.5 concentrations based on the highest 3-year average PM2.5 concentration in each area.

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

e Mount Baker Wilderness Area and San Juan Islands are not Class I Areas, results are included in the analysis because FLMs have requested its inclusion in previous permit application.

Table 6: Predicted Class I Area Deposition Fluxes

Class I Area of Interest	Nitrogen Deposition (kg/ha/yr)	Sulfur Deposition (kg/ha/yr)
Alpine Lakes Wilderness Area	0.0003	0.0005
Glacier Peak Wilderness Area	0.0011	0.0015
Goat Rocks Wilderness Area	0.0001	0.0001
Mount Adams Wilderness Area	0.0001	0.0001
Mount Rainier National Park	0.0001	0.0002
N. Cascades National Park	0.0026	0.0037
Olympic National Park	0.0016	0.0025
Pasayten Wilderness Area	0.002	0.0029
NPS DAT	0.005	0.005
Mount Baker Wilderness Area [a]	0.0037	0.0051
San Juan Island [a]	0.0018	0.0039

Notes:

[a] Mount Baker Wilderness Area and San Juan Island are not Class I Areas, they are included in the analysis because FLMs have requested inclusion in previous permit applications.

Table 7: Predicted Class I Area Visibility Results

Class I Area of Interest	98th Percentile Change in Visibility			
	2003	2004	2005	3 year
Alpine Lakes Wilderness	0.38	0.42	0.38	0.4
Glacier Peak Wilderness	0.87	0.89	0.96	0.89
Goat Rocks Wilderness	0.11	0.1	0.14	0.12
Mount Adams Wilderness	0.08	0.08	0.09	0.08
Mount Rainier National Park	0.18	0.18	0.2	0.19
N Cascades National Park	1.34	1.35	1.25	1.34
Olympic National Park	2.74	2.24	2.77	2.64
Pasayten Wilderness	0.78	0.95	0.77	0.87
Mount Baker Wilderness [a]	1.65	1.85	1.99	1.91
San Juan Islands [a]	3.61	2.95	3.17	3.2

Notes:

a Mount Baker Wilderness Area and San Juan Islands are not Class I Areas, results are included in the analysis because FLMs have requested its inclusion in previous permit applications.

Attachment A.
Detailed Emission Tables for Class I and Class II Modeling Analyses

Table A-1: Class II Short-Term Emission Rates for Analysis (in lb/hr)

AERMOD Source ID	Description	NO_X	SO_2	CO	PM10	PM2.5
WCOKE	New Coker Heater (West)	18.2	18.6	6.1	3.0	3.0
ECOKE	New Coker Heater (East)	18.2	18.6	6.1	3.0	3.0
O_NCOKE [a]	Old Coker Heater - North	-12.9	-13.0	-0.9	-1.8	-1.8
O_SCOKE [a]	Old Coker Heater - South	-12.9	-13.0	-0.9	-1.8	-1.8
BOIL6 [b]	Boiler 6 (Contemporaneous)	--	--	--	1.6	1.6
BOIL7 [b]	Boiler 7 (Contemporaneous)	--	--	--	1.6	1.6
DHDS3 [c]	#3 DHDS Heater (Contemporaneous)	1.0	3.0	1.0	0.3	0.3
H2SMR [c]	#2 Hydrogen Plant (Contemporaneous)	3.5	2.8	4.3	5.0	5.0
H2FLR_ST [c]	#2 Hydrogen Plant Flare (Contemporaneous)	13.0	0.0	75.9	1.9	1.9
SRU1_M [d]	Sulfur Plant Incinerator (Contemporaneous)	2.9	0.15	31.0	--	--
O_HCR1BL [e]	1st Stage Frac. Reboiler Burner Retrofit (Contemporaneous)	-33.3	--	--	--	--

Notes:

a Emission decreases from existing coker heaters based on emission factors from July 2015 source test and maximum hourly firing rates in calendar year 2015 (176.3 MMBtu/hr).

b Contemporaneous project to increase short-term PM10/PM2.5 emission limits for Boilers 6 & 7.

c Contemporaneous project to construct #2 Hydrogen Plant (steam methane reformer and flare) and #3 DHDS.

d Contemporaneous project to increase short-term SRU incinerator emissions.

e Contemporaneous project to replace burners in the 1st Stage Fractionator Reboiler. NOx emission decrease from the heater based on post-project potential to emit (9.9 lb/hr) and pre-project actual emissions (43.2 lb/hr).

Table A-2: Class II Long-Term Emission Rates for Analysis (in tons per year)					
AERMOD Source ID	Description	NO_X	SO_2	PM10	PM2.5
WCOKE	New Coker Heater (West)	79.6	66.0	13.3	13.3
ECOKE	New Coker Heater (East)	79.6	66.0	13.3	13.3
CVENT	Coke Drum Venting	0.0	0.0	4.2	4.2
CALC1N2	Calciner #1 & #2	73.5	7.3	3.5	3.5
CALC3	Calciner #3	68.5	69.8	3.9	3.9
CRUDEHTR	Crude Heater	11.9	4.0	0.55	0.55
NVACHTR	North Vacuum Heater	1.3	0.2	0.07	0.07
SVACHTR	South Vacuum Heater	1.0	0.6	0.16	0.16
HCREBLU	Hydrocracker 1st and 2nd Stage Frac. Heaters	4.0	3.0	0.84	0.84
HCR1HTRU	Hydrocracker R1 Heater	0.7	0.7	0.19	0.19
HCR4HTRU	Hydrocracker R4 Heater	2.0	0.4	0.12	0.12
REF1HTR1	#1 Reformer - Heater 1	3.5	0.9	0.24	0.24
REF1HTR2	#1 Reformer - Heater 2	3.5	0.9	0.24	0.24
REF2HTR	#2 Reformer Heater	1.0	0.4	0.11	0.11
DHDS1RBL	#1 DHDS Reboiler	0.1	0.2	0.04	0.04
NAPHTR	Naphtha Heater	1.1	0.3	0.09	0.09
NAPRBOIL	Naphtha Reboiler	1.1	0.3	0.09	0.09
IHTHTR	Isom Heater	0.1	0.6	0.04	0.04
REF1FUR1	#1 Hydrogen Furnace 1	4.8	1.5	0.41	0.41
REF1FUR2		4.8	1.5	0.41	0.41
REF2FUR1		4.8	1.5	0.41	0.41
REF2FUR2		4.8	1.5	0.41	0.41
SRU1	Sulfur Plant Incinerator	0.3	0.9	0.01	0.01
TGU2	#2 Tail Gas Unit	0.3	0.9	0.01	0.01
DOCKVCU	Dock Vapor Combustor	0.6	0.0	0.00	0.00
TRUCKVCU	Truck Vapor Combustor	0.2	0.0	0.02	0.02
COOL1C1	#1 Cooling Tower Cells 1 - 9	--	--	0.11	0.001
COOL1C2		--	--	0.11	0.001
COOL1C3		--	--	0.11	0.001
COOL1C4		--	--	0.11	0.001
COOL1C5		--	--	0.11	0.001
COOL1C6		--	--	0.11	0.001
COOL1C7		--	--	0.11	0.001
COOL1C8		--	--	0.11	0.001
COOL1C9		--	--	0.11	0.001
COOL2C1	#2 Cooling Tower Cells 1 - 4	--	--	0.14	0.03
COOL2C2		--	--	0.14	0.03
COOL2C3		--	--	0.14	0.03
COOL2C4		--	--	0.14	0.03
HPFLR	HP Flare (Project)	0.2	0.2	0.02	0.02
GCOKE1	Green Coke Handling	--	--	0.3	0.1
GCOKE2	Green Coke Handling	--	--	0.3	0.1
SHIPPMPN	Crude Ship Pumping	1.0	0.4	0.26	0.26
O_NCOKE [a]	Old Coker Heater - North	-34.3	-26.5	-2.8	-2.8
O_SCOKE [a]	Old Coker Heater - South	-34.3	-26.5	-2.8	-2.8
CALC3_R [b]	#3 Calciner (Contemporaneous)	0.1	0.0	0.00	0.00

Table A-2: Class II Long-Term Emission Rates for Analysis (in tons per year)

AERMOD Source ID	Description	NO_X	SO_2	PM10	PM2.5
HPFLR_CA [b]	HP Flare (Contemporaneous)	7.7	0.4	0.17	0.17
DHDS3 [c]	#3 DHDS Heater (Contemporaneous)	4.3	3.2	1.2	1.2
H2SMR [c]	#2 Hydrogen Plant (Contemporaneous)	15.5	6.3	21.7	21.7
H2FLR_LT [c]	#2 Hydrogen Plant Flare - lt (Contemporaneous)	2.5	0.08	0.37	0.37
HPFLR_CF [c]	HP Flare (Contemporaneous)	0.0	0.45	0.00	0.00
O_HCR1BL [d]	1st Stage Frac. Reboiler Burner Retrofit (Contemporaneous)	-87.7	--	--	--

Notes:

a Emission decreases from existing coker heaters based on baseline average (2014 and 2015)

b Contemporaneous project to repair #3 Calciner Heater.

c Contemporaneous project to construct #2 Hydrogen Plant (steam methane reformer and flare) and #3 DHDS.

d Contemporaneous project to replace burners in the 1st Stage Fractionator Reboiler. NOx emission decrease from the heater based on post-project potential to emit (43.4 tons per year) and pre-project actual emissions (131.1 tons per year).

Table A-3: Speciated Short-Term Emission Rates for AQRV Visibility Analysis

CALPUFF Sources	SO_2	NO_X	Speciated PM_{10} (lb/hr) [a]					
			Coarse Mass	Fine Sulfate (as SO_4)	Fine Nitrate (as NO_3)	Fine Elemental Carbon	Fine Organic Carbon	Fine Crustal Material
WCOKE [b, c]	12.9	10.2	0	0.8	0.010	0	0.20	1.1
ECOKE [b, c]	11.9	10.1	0	0.8	0.010	0	0.20	1.0
BOIL6 [b]	0	0	0	0.5	0.007	0	0.13	0.7
BOIL7 [b]	0	0	0	0.5	0.007	0	0.13	0.7
DHDS3 [b]	3.0	1.0	0	0.10	0.001	0	0.02	0.1
H2SMR [b]	2.8	3.5	0	1.7	0.021	0	0.4	2.2
H2FLR_ST [d]	0.0	13.0	0	0	0	0	1.9	0
SRU1_M [e]	0.1	2.9	0	0	0	0	0	0

Notes:

a PM_{10} speciated using a speciation database provided by Ecology based on speciation profiles recommended by EPA aerosol modeling. PM_{10} is the sum of coarse mass and the fine PM ($PM_{2.5}$) components: ammonium sulfate, ammonium nitrate, fine crustal material, elemental carbon and organic carbon.

b PM_{10} speciation calculated using SCC speciation profile: 30600106 (Process heaters, process gas-fired).

c Existing coker heater emissions were subtracted from new coker heater potential emissions. Hourly emission reductions from existing heaters based on 2014 & 2015 annual emissions divided by annual operating hours.

d PM_{10} speciation calculated using SCC speciation profile: 30600904 (Flares, process gas).

e PM_{10} speciation calculated using SCC speciation profile: 30603301 (Sulfur recovery units).

Table A-4: Speciated Long-Term Emission Rates for AQRV Deposition Analysis

CALPUFF Sources	SO_2	NO_X	Speciated PM_{10} (lb/hr) [a]					
			Coarse Mass	Fine Sulfate (as SO_4)	Fine Nitrate (as NO_3)	Fine Elemental Carbon	Fine Organic Carbon	Fine Crustal Material
WCOKE [b, j]	9.0	10.4	0	0.8	0.010	0	0.20	1.1
ECOKE [b, j]	9.0	10.4	0	0.8	0.010	0	0.20	1.1
CALCNS [c]	17.6	32.4	0	0.3	0.004	0	0.07	1.2
VHTRS [b]	0	0.5	0	0.018	0.0002	0	0.0044	0.02
HC_RHTRS [b]	0.3	0.6	0	0.0	0.000	0	0.01	0.0
REF_HTRS [b]	0.5	1.8	0	0.046	0.0006	0	0.01	0.06
OTHTRS [b]	1.1	1.5	0	0.1	0.001	0	0.03	0.1
H2_FURNS [b]	2.8	7.9	0	1.8	0.023	0	0.45	2.4
VCUS [d]	0.0004	0.2	0	0.0009	0.0000	0	0.0036	0.001
FLARES [d]	0.3	2.4	0	0	0	0	0.13	0
CVENT [e]	0	0	0	0.2	0.002	0	0.04	0.7
CRUDEHTR [b]	1	2.7	0	0.043	0.0005	0	0.0105	0.06
HCREBLU [b]	0.7	0.9	0	0.1	0.001	0	0.02	0.1
SRU1 [f]	0.2	0.1	0	0.001	0.0000	0	0.0001	0.00
TGU2 [f]	0.2	0.1	0	0.001	0.0000	0	0.0001	0.00
SHIPPMPN [g]	0.1	0.2	0	0.024	0.00002	0.005	0.0065	0.02
COOL1 [h]	0	0	0	0.039	0.00049	0	0.0095	0.16
COOL2 [h]	0	0	0	0.021	0.0003	0	0.0052	0.09
GCOKE1 [i]	0	0	0	0.013	0.0002	0	0.0032	0.06
GCOKE2 [i]	0	0	0	0.013	0.0002	0	0.0032	0.06

Notes:

a PM_{10} speciated using a speciation database provided by Ecology based on speciation profiles recommended by EPA aerosol modeling. PM_{10} is the sum of coarse mass and the fine PM ($PM_{2.5}$) components: ammonium sulfate, ammonium nitrate, fine crustal material, elemental carbon and organic carbon.

b PM_{10} speciation calculated using SCC speciation profile: 30600106 (Process heaters, process gas-fired).

c PM_{10} speciation calculated using SCC speciation profile: 30601401 (Coke Calciner).

d PM_{10} speciation calculated using SCC speciation profile: 30609904 (Flares, process gas).

e PM_{10} speciation calculated using SCC speciation profile: 30600402 (petroleum blowdown system).

f PM_{10} speciation calculated using SCC speciation profile: 30603301 (Sulfur recovery units).

g PM_{10} speciation calculated using SCC speciation profile: 30600103 (Oil-Fired Process).

h PM_{10} speciation calculated using SCC speciation profile: 30600701 (Cooling towers).

i PM_{10} speciation calculated using SCC speciation profile: 30601402 (Delayed Coker).

j Existing coker heater emissions were subtracted from new coker heater potential emissions. Emission reductions from existing heaters based on 2014 & 2015 annual emissions.