northwest Clean Air agency

Serving Island, Skagit & Whatcom Counties

BP WEST COAST PRODUCTS, LLC

CHERRY POINT REFINERY

BLAINE, WASHINGTON

AIR OPERATING PERMIT

STATEMENT OF BASIS

FINAL MODIFICATION

September 06, 2006

Table of Contents

Section 1 - Introduction and General Facility Description

The British Petroleum (BP) Cherry Point Refinery owned by BP West Coast Products, LLC is required to obtain an operating permit because it has the potential to emit 100 tons or more of oxides of nitrogen and sulfur, particulate matter and carbon monoxide. These criteria pollutants are emitted in the operation of the oil refinery.

The purpose of this Statement of Basis (SOB) is to set forth the legal and factual basis for the conditions of the Air Operating Permit (AOP). This document also provides background information to facilitate review of the permit by interested parties. The Statement of Basis is not a legally enforceable document in accordance with WAC 173-401-700(8).

1.1 Facility Description

The facility produces petroleum-based fuels as classified under the Standard Industrial Classification code for this activity as 2911. The BP West Coast Products LLC operates the Cherry Point Refinery in Blaine, Washington, near Ferndale and Birch Bay. The refinery was originally built in 1970 by the Atlantic Richfield Company (ARCO). In April 2000, BP acquired the stock of ARCO. Effective January 1, 2002 ARCO transferred all of its retail and refining assets to a new affiliate, BP West Coast Products, LLC.

The surrounding area is designated in attainment of the National Ambient Air Quality Standards. The refinery is located in a rural setting zoned for heavy industrial use. The surrounding land use is agricultural. Immediately to the west of the refinery is the Puget Sound Energy's Whitehorn gas turbine peaking power generating station. Intalco Aluminum Corporation and the Conoco/Phillips Refinery are located south and west of the refinery. Approximately two miles north of the refinery is Birch Bay State Park.

The refinery receives crude oils via tanker or pipeline and produces a wide variety of products including gasoline, diesel, low-sulfur diesel, jet fuel, calcined coke, green coke, sulfur, liquefied petroleum gas (LPG), butane, pentane, as well as intermediates such as reformate. Products are sent to market in several ways. Ship and barges carry gasoline, jet fuel, diesels, and intermediates. Pipelines are used to carry gasoline, diesels, and jet fuels. Rail cars are used to ship LPG, butanes, sulfur, green coke, and calcined coke. Finally, trucks are used to carry LPG, gasoline, diesels, jet fuel, calcined coke, and sulfur.

For the purposes of this SOB and the AOP, refinery processes are grouped into logical areas either by process unit interrelationships or geographical areas. Table 1.1 presents a listing of the refinery units and the refinery's Process Unit Numbers.

Table 1.1 - BP Cherry Point Refinery Units

Area	Process Unit Number	Description of Major Emission Units
Flares	28	Flare Gas Recovery
	29	Low Pressure/ High Pressure Flare
Boilers and Cooling Towers	30	Utility Boiler #1, #3, # 4 and #5 Cooling Tower #1
	24	Cooling Tower #2
Crude/Vacuum	10	Crude Heater North Vacuum Heater South Vacuum Heater
	11	Naphtha HDS Charge Heater Naphtha HDS Stripper Boiler #1 Reformer Heater
	21	#2 Reformer Heater
Delayed Coker	12	North Coker Heater South Coker Heater
Diesel HDS	13	#1 Diesel HDS Charge Heater #1 Diesel HDS Stabilizer Reboiler
		#2 Diesel HDS Charge Heater
Hydrogen Plant	14	North Heater South Heater
Hydrocracker	15	R-1 Hydrocracker Reactor Heater R-4 Hydrocracker Reactor Heater 1st Stage Fractionator Reboiler 2nd Stage Fractionator Reboiler
Sulfur Complex	17, 19	#1 TGU Stack and #2 TGU Stack
LEU/LPG	22	Light End Unit (LEU) and Liquefied Petroleum Gas
Isomerization		IHT Heater
Calciner/Coke Handling	20	Calciner Stack #1 (Hearths #1 & #2) Calciner Stack #2 (Hearth #3) Coke Silos and Loading – Baghouses and Vents
Wastewater	32	API Separators Slop Oil, equalization and recovered oil tanks
Storage and Handling	33	Tank Farm Butane/Pentane Spheres
Shipping, Pumping and Receiving	34	Marine Dock Dock Thermal Oxidizer
	33	Truck Rack Truck Rack Thermal Oxidizer
	37	Rail Car Loading LPG Loading Racks

1.2 Enforcement History

Table1.2 presents a listing of recent Notices of Violation issued to the refinery. Each of the violations listed above has been resolved through a combination of penalty assessments and by corrective action taken by the source. In most cases corrective action taken by the source is submitted to the NWCAA as a written response to the violation. Additional information about each violation can be obtained upon request to the NWCAA

Table 1.2 - BP Cherry Point Refinery NOVs

NOV	Date Issued	Summary
3523a	2/22/2006	Failure to implement a startup, shutdown and maintenance plan (SSMP) for the IHT Heater and #5 Boiler in a timely manner. These new emissions units were required to have SSMPs by November 12, 2004, the effective date of 40 CFR 63 subpart DDDDD. The SSMPs were developed and implemented on September 29, 2005 (321 days late).
3527	2/17/2006	Calciner Stack #2 had emissions over applicable limits totaling 5,774 lbs of particulate and 651 lbs of H2SO4 during the period of October 1, 2005 through October 6, 2005. This occurred when #4 cell of the wet electrostatic precipitator (WESP) was disabled after a valve failed shut. The WESP was inadvertently left in this condition with no flow to #4 cell during the six-day period of non-compliance.
3515	11/29/2005	The August 30, 2005 source test conducted on the IHT Heater determined NOx emissions to be 0.487 pound per hour. In accordance with Condition 2 of PSD-02-04 (Amendment 1 issued April 20, 2005), NOx emissions from the IHT Heater are not to exceed 0.455 pounds per hour .
3451	5/15/2004	The Wet Electrostatic Precipitator shut down due to an inadvertent opening of an electrical breaker by maintenance worker. The shutdown lasted 25 minutes resulting in emissions of particulate matter (PM) and H_2SO_4.
3408	4/29/2004	Failure to conduct monitoring for two consecutive months under the refinery's LDAR program after installing new valves in service.

1.3 Emission Reports

The refinery has various reporting requirements in support of the air compliance program. These requirements can come from Federal, State and the NWCAA regulations as well as Prevention of Significant Deterioration permits (PSD's) and Orders of Approval to Construct (OACs). Many are listed under the applicable subpart of the Code of Federal Regulations and will not be duplicated here. There are periodic notifications and on-site record keeping requirements that are not discussed in the SOB. Additionally, the leak detection and repair (LDAR) program related reporting is discussed in Section 2.5.

Of particular interest is the refinery's monthly reporting requirements. This report is a valuable tool in monitoring the refinery's compliance with emission limits. Monthly emissions reports are submitted to the NWCAA within 30 days following the end of each calendar month. Supporting emission data must be kept at the refinery for at least five years and made available to NWCAA personnel upon request. Monthly emission reports for the refinery are divided into Continuous Emission Monitor (CEM) performance tests and monthly emissions reporting. Table 1.3 presents a list of CEMs at the refinery.

Monthly CEM reporting includes:

- The duration and nature of CEM downtime.
- Changes made to CEM
- Total source operating time
- Date of latest CEM audits and/or certifications

Table 1.3 - CEM Units at the BP Cherry Point Refinery

CEM Location	Pollutants Monitored
South Vacuum Heater	NOx, O_2
North Vacuum Heater	O_2
#1 DHDS Stabilizer Reboiler Heater	NOx, O_2
#1 Calciner Stack	SO_2, NOx, O_2
#2 Calciner Stack	SO_2, NOx, O_2
#2 Reformer	O_2
#4 Boiler	NOx, O_2
#5 Boiler Stack	NOx, CO, O_2
Refinery Fuel Gas Mix Drums	H_2S
Coker Heater Fuel Gas	H_2S
#1 TGU	SO_2, O_2
#2 TGU	SO_2, O_2

In addition to the CEMs, the refinery is also required to report the performance of the wet electrostatic precipitators (WESPs). Performance of the WESPs is done because no direct continuous emissions measurements can be taken. As a result, the refinery monitors the secondary voltage and secondary amperage accord to the *WESP Monitoring Plan* approved by NWCAA and the Department of Ecology.

The monthly pollutant emissions report includes:

- All measurements in excess of a standard with an explanation for their occurrence and the corrective actions taken or planned.
- Pollutant Emissions summary,
- Ambient SO_2 concentrations,
- Calibration and maintenance records for SO_2 analyzer, and
- Hourly metrological data.

Currently, the refinery provides ambient SO_2 data electronically in an Excel spreadsheet. Table 1.4 presents a summary of the monthly emissions reporting portion of the monthly report.

Table 1.4 - Monthly Emissions Reporting

Unit	Description	Authority
Refinery	Report H_2S concentration on refinery mix drum.	40 CFR 60 Subpart J NWCAA RO #028
	Report fuel usage.	6/8/70 permit to Construct
	Report total refinery monthly emissions of SO_2.	Calciner Bubble
	Report total monthly PM emissions from Calciners.	Calciner Bubble
Crude/ Vacuum	Report H_2S concentration on refinery mix drum.	PSD-5 OAC #689
	Report fuel usage on crude heater.	6/8/70 permit to Construct
	Report maximum heating load of North Vacuum Heater.	PSD-5
	Report the maximum heating load and number of excursions past 77 MMBtu/hr on the North Vacuum Heater.	PSD-5
	Report fuel usage of South Vacuum Heater.	6/8/70 permit to Construct
	Report 12-month rolling CO emissions in tons per year from North Vacuum Heater.	OAC #273b
	Report hourly average NOx concentration in stack at South Vacuum Heater and hourly emission of NOx in lbs/hr when NOx concentration exceeds 34 ppmv.	OAC #902
Naphtha HDS and Reformer Units	Report the maximum heating load on #2 Reformer Heater.	PSD-7
#1DHDS Stabilizer Reboiler Heater	Report NOx concentration corrected to 7% O_2 in the charge heater on a 24-hour rolling average. (Install CEM no later than 12/1/2008)	OAC #949
#2 DHDS Charge Heater	Report the rolling 24-hour average and 3-hour rolling average for H_2S in fuel gas to the heater.	OAC #892
Isomerization Unit	Report the rolling 24-hour average and 3-hour rolling average for H_2S in fuel gas to the heater.	OAC #814a
	Report monthly maximum of NOx and CO each month and include for each instance of an exceeded limit the following: time, magnitude, duration, probable cause, corrective action taken and name of agency contacted.	PSD-02-04
Hydrocracker	Report NOx emissions in tons per year as a 12-month rolling average from 2nd Stage Fractionator Reboiler Heater.	OAC #847
Delayed Coker	Report fuel usage in the North and South Coke Charge Heaters	6/8/70 permit to Construct
	Report the daily average of H_2S for fuel gas supplies to Coker charge heaters and excursions over 50 ppmdv	OAC #689
Calciners	Report performance for Hearths #1 & #2 including monthly average of coke production, total estimated tons per year of SO_2 emitted, and highest daily average SO_2 concentration in ppmv corrected to 7% O_2 and excursions.	OAC #689 OAC #660 PSD 89-2
	Report NOx emission performance for Hearths #1 & #2 (Stack #1) and Hearth #3 (Stack #2).	OAC #689 PSD 89-2
Boiler #4	Report maximum 30-day rolling NOx emissions average and estimated tons per month	OAC #351 40 CFR 60 Subpart Db

Unit	Description	Authority
Boiler #5	Report the rolling 24-hour average and 3-hour rolling average for H_2S in fuel gas to the boiler.	OAC #814a
	Report monthly maximum of NOx and CO each month and include for each instance of an exceeded limit the following: time, magnitude, duration, probable cause, corrective action taken and name of agency contacted.	PSD-02-04 40 CFR 60 Subpart Db
	Report 30-day rolling average for CO in semi-annual compliance report.	40 CFR Part 63 Subpart DDDDD
Sulfur Complex	Report performance of CEM SO_2 emissions (lb/hr) and performance (monthly average, highest value, and number of exceedances) compared to the 1,000 ppmv standard (@ 7% O_2) for the Tail Gas stack	NWCAA Letter 2/27/95 NWCAA RO #028 40 CFR 60 Subpart J
SRU & TGU's	Report the 12-hour rolling average and 1-hour average of H_2S concentration in #1 and #2 TGU stacks.	OAC #890a
	Report the total tons per year of SO_2 emitted from the SRU. in a rolling 12-month period.	OAC #890a

The refinery must also provide quarterly CEM quality assurance reports, a National New Source Performance Standards (NSPS) Subpart Db report for Boiler #4 and Boiler #5, and a Benzene Waste Operations National Emission Standards for Hazardous Air Pollutants (NESHAP) report. CEM quality assurance reports document drift, out of control periods, accuracy (RATA/RAA), and cylinder gas audits. This information along with source test data and RATA/RAA tests are used to assess whether the refinery is operating their CEMs properly and can clearly demonstrate compliance with emission standards. The quarterly Boiler #4 and Boiler #5 report is required by 40 CFR 60 Subpart Db. This report documents NOx emission rates and CEM performance data for Boiler #4 and Boiler #5. The Benzene Waste operations NESHAP report is required under 40 CFR 61 Subpart FF and allows the refinery to certify that it met all of the Subpart's applicable requirements.

The refinery also reports compliance performance with the Refinery Maximum Achievable Control Technology (MACT) and the Fugitive Emissions of volatile organic compounds (VOCs) from refinery operations on a semi-annual and/or quarterly basis. The Refinery MACT is required under 40 CFR 63 Subpart CC. This Refinery MACT report documents compliance with wastewater (through 40 CFR 61 Subpart FF), the gasoline loading racks, marine tank vessel loading dock, storage vessels, Group 1 miscellaneous process vents, and equipment leaks. The VOC report is required under 40 CFR 60 Subpart QQQ, Subpart GGG and 40 CFR 64 Subpart CC and is combined with the refinery's Leak Detection and Repair (LDAR) performance reporting. The facility is also subject to reporting under 40 CFR 63 Subpart DDDDD. Initial notification under this subpart for existing heaters and boilers was provided prior to November 20, 2004. New heaters and boilers must also provide a semi-annual compliance report.

1.4 Annual Emission Inventories

Each year the refinery is required to submit an emissions inventory for the refinery. This report includes both criteria air pollutants and hazardous air pollutants (HAPs). Reports from the refinery are categorized into different source groups as well as for individual emission units. In turn the NWCAA publishes a jurisdiction-wide emissions inventory report that includes a summary of annual emissions for large industrial facilities. This report lists criteria air pollutants emitted from the BP Cherry Point Refinery as follows:

Table 1.5 - Yearly Emissions Inventory

	Yearly Emissions (tons)				
Pollutant	**2000**	**2001**	**2002**	**2003**	**2004**
CO	399	1062	845	855	930
NOx	2497	3395	2367	2511	2215
PM_{10}	100	156	145	149	129
PM2.5	-	10	-	145	129
SO_2	1874	2526	1883	1837	1532
TSP	104	156	-	-	-
VOCs	1674	1050	505	492	434
Toxics	234	133	85	98	99

NOTE: - Emission rates vary from year to year depending on the amount of crude oil processed, the slate of products made, modifications made to process equipment and changes in the methods of calculating emissions.

Section 2 - Refinery-Wide Issues

The following discusses refinery-wide processes and regulatory issues. The fuel gas system at the refinery, used to supply fuel for the majority of combustion sources at the refinery is presented in Section 2.1. Section 2.2 presents a brief discussion of non-process specific activities performed at the refinery that can emit air pollutants. Sections 2.3 and 2.4 present summaries of the applicability of NSPS and NESHAP regulations to the refinery. An important refinery-wide program is the LDAR program that addresses fugitive emissions of VOCs and HAPs. Section 2.5 presents a discussion of the LDAR program.

There are three other unique issues that affect the refinery and require some explanation. The first, Calciner Bubble and SO_2 emissions, is presented in Section 2.6. The second is compliance plans. Section 2.7 presents an explanation of the BP Consent Decree and its applicability to the refinery's AOP.

2.1 Fuel Gas System

There is a distinct fuel gas system that collects light gases produced during refinery processing and distributes them to specific heaters and boilers. The main fuel gas drum (referred to as the refinery mix drum) collects gases from all processing units and serves all heaters and boilers as well as provides supplemental makeup fuel to combustion equipment. Some exceptions include the Crude Heater in the Crude/Vacuum unit that combusts refinery fuel gas and gases produced from the vacuum systems of the Vacuum Distillation Fractionator and Vacuum Tower. Also, the North and South Coker Heaters in the Delayed Coker unit combust fuel gas that is generated as a byproduct of its own processes.

If the refinery is low on fuel gas generation, fuel gas drums can also be supplemented with purchased natural gas. The fuel gas system subject is to New Source Performance Standards (NSPS) Subpart J, and NWCAA Regulatory Order #028 limits the hydrogen sulfide (H_2S) content of the gas to less than 162 ppmvd based on a 3-hour rolling average. In Subpart J the referenced fuel quality limit is 230 mg/dscm. Because H_2S CEM readout is in ppm the Subpart J standard has been converted to ppm and used in the AOP accordingly. Below is the conversion which uses standard conditions of 20 C and 760 mm Hg conservatively rounded to the nearest integer:

$$\frac{230\,mgH_2S}{dscm}\,x\,\frac{moleH_2S}{34g}\,x\,\frac{g}{10^6\,mg}\,\frac{24.04\,dscm}{mole} = 162\;ppmvdH_2S$$

In order to demonstrate continuous compliance with SO_2 emission requirements (not to exceed 1,000 ppm at 7% excess O_2 on a dry basis per WAC 173-400-040(6) and NWCAA 462.1) for combustion sources not using CEMs the refinery calculates the SO_2 concentrations in the flue gases using H_2S analyzers and fuel gas analysis for total sulfur and gravity. Assumptions include that the fuel gas is comprised of saturated hydrocarbons (olefins account for approximately 4.5 mole percent of the fuel gas), all carbon combusts to CO_2, hydrogen combusts to water, and all sulfur compounds combust to form SO_2.

The carbon to hydrogen ratio is first calculated for the fuel gas. The total number of moles of H_2S in the flue gas is then calculated based on fuel gas gravity, total sulfur concentration in the fuel gas, and the carbon to hydrogen ratio. The refinery assumes that all of the moles of H_2S calculated are converted to SO_2 during combustion.

2.2 Miscellaneous Non-Specific Activities

There are several non-specific activities that can emit pollutants to the atmosphere. These activities include asbestos removal, fire training, abrasive blasting, landfarming, and cutback asphalt paving. Section 2 of the AOP lists the applicable regulations for these activities except for landfarming which is discussed in Section 5 because it has a specific requirement as part of its construction permit. Asbestos removal occurs during the demolition or modification of buildings and units at the refinery which are likely to contain asbestos-containing materials such as insulation and tiles. The refinery is subject to federal and NWCAA requirements (40 CFR 61.145, 148, 150 and NWCAA 570). Fire training employs open burning during the instruction of the refinery's emergency response personnel. Open burning activities are subject to WAC and NWCAA requirements (WAC 173-425-036, -040, -045, -050, -060 & NWCAA 501, 502). Abrasive blasting occurs during maintenance and repair activities of various tanks and equipment at the refinery to remove old and chipped paint and surface contaminants. This activity is subject to state and NWCAA regulations (WAC 173-400-040(3) and NWCAA 550). Finally, cutback asphalt paving occurs from time to time at the refinery for the repair of roadways and unit areas as a means to reduce dust emissions and to provide storm water runoff control. This activity is subject to NWCAA 580.7.

2.3 New Source Performance Standards (NSPS)

The refinery owns and operates equipment regulated under five NSPS Subparts and Subpart A, General Provisions:

- Part 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units;
- Part 60 Subpart J – Standards of Performance for Petroleum Refineries;
- Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984;
- Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries;
- Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater System; and
- Subpart A – General Provisions.

The following is a summary of their applicability to the refinery.

2.3.1. Subpart Db (applies to new or modified units constructed after June 19, 1984.)

Two units at the refinery, Boiler #4, and Boiler #5 are subject to this NSPS. Boiler #4 was constructed in 1991 and Boiler #5 was put on stream in March 2004.

There are some aspects of Boiler #4 that should be explained in this Statement of Basis so that the reader can understand the applicability determinations made by the NWCAA. The refinery proposed best available control technology (BACT) to be a combination of burning only refinery fuel gas, low-NOx burners and induced flue gas recirculation. The refinery also employs a CEM to monitor NOx emissions. The Order of Approval to Construct (OAC) for Boiler #4 required NOx emissions not to exceed 0.07 lb/MMBTU on a monthly average. This is lower than Section 60.44b because the Boiler

#4 project required NOx emission offsets in order to avoid PSD analysis. Sections 60.48b and 60.49b, however do apply directly for monitoring and reporting using CEM system.

Boiler #5 was part of the "Clean Gasoline Project" which also included construction of an Isomerization Unit to produce higher quality gasoline at the plant. Boiler #5 is equipped with CEM's measuring NOx and CO as a condition of PSD-02-04.

2.3.2. Subpart J

Subpart J covers refinery fuel gas systems and sulfur recovery units at refineries. As discussed in Section 2.1, the refinery uses a refinery-wide fuel gas system as a primary source of fuel for heaters and boilers. The refinery also operates a Claus process sulfur recovery plant. As a result, 40 CFR 60 Subpart J applies to the refinery. Regulatory Order #28 (RO #28) requires that the refinery's fuel gas system comply with the requirements of 40 CFR 60 Subpart J for all heaters and boilers by September 30, 2005. Additionally, RO #28 requires that the SRU become compliant with 40 CFR 60 Subpart J by the end of the turnaround in 2006.

Of particular interest in Subpart J are the requirements associated with SO_2 emissions. Section 60.104(a)(1) limits the H_2S concentration in the refinery's fuel gas to 230 mg/dscm (0.01 gr/dscf). Section 60.104(a)(2) limits SO_2 emissions from the SRU to 250 ppmvd at 0% excess air SO_2 at the Tail Gas Unit. These requirements will also apply to the second Tail Gas Unit or equivalent technology that the refinery is required to install as part of RO #28

2.3.3. Subpart Kb

Subpart Kb applies to several storage vessels used at the refinery including Tank #40, a 365,000 barrel crude storage tank (constructed in 2005). Section 3.18 presents a detailed discussion of the requirements associated with 40 CFR 60 Subpart Kb.

2.3.4. Subpart GGG

The refinery has constructed, modified, or reconstructed many process units, which then became subject to this regulation. As of the date of permit issuance, these units include:

- Flare Gas Recovery
- Low and High Pressure Flares
- #4 Utility Boiler
- North Vacuum Heater
- Crude Unit *
- Reformer #1 and #2 *
- Isomerization Unit
- #1 DHDS Unit
- #2 DHDS Unit
- Delayed Coker *
- LPG Plant
- Calciner #2
- Truck Rack *
- Pentane Spheres
- LPG Loading
- Tanks 60, 62
- Tanks 24, 40, 50, 71, 72, 73, 73 *

Units listed with a "*" also have the potential to emit hazardous air pollutants (HAPs) above threshold levels. One provision of the Refinery MACT (63.640(p)) states that, "After the compliance dates specified in paragraph (h) of this section equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 are required to comply only with the provisions specified in this subpart". Therefore, up until August 18, 1998, the equipment in the aforementioned process units was only subject to Subpart GGG. However, many HAP service components in these units are now subject only to the Refinery MACT.

Subpart GGG requires compliance with the provisions of 60.482-1 through 60.482-10, 60.484, 60.485, 60.486, and 60.487, the standards, equivalence determination, test methods and procedures, recordkeeping, and reporting requirements of Subpart VV. A discussion of these requirements follows in the next section.

2.3.5. Subpart VV

The refinery is not a synthetic organic chemicals manufacturer, but the equipment leak provisions of the Refinery MACT require equipment subject to Subpart CC to comply with Subpart VV, with specific exemptions. Subpart VV specifies standards, monitoring, and recordkeeping associated with leaks from various process equipment including compressors, pumps in light liquid service, pressure relief devices in gas/vapor service, sampling connections, open-ended valves and lines, valves in gas/vapor and light liquid service, pumps and valves in heavy liquid service, pressure relief devices in heavy liquid and light liquid service, flanges, and other connections.

Under Subpart VV, the monitoring frequency for process equipment is specified and depending on the type of equipment being monitored and leak performance, the frequency can be decreased with the proviso that the frequency would be increased if leaks are detected. For pumps in light liquid service, a leak is defined at 10,000 ppm (§60.482-2) using EPA Method 21. For compressors, a seal system that employs a barrier fluid system is required (§60.482-3). For pressure relief devices in gas/vapor service a leak is defined at 500 ppm above background (§60.482-4). Sampling connections require a close-purged, close-loop, or closed-vent system. Open-ended valves and lines are required to be equipped with a cap, blind flange, or a second valve. For valves in gas/vapor and light liquid service a leak is defined as 10,000 ppm. For pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service and connectors a leak is defined at 10,000 ppm.

If a leak is measured (according to EPA Method 21), Subpart VV specifies the standards for repair as well as the delay of a repair (§60.482-9). Typically, repairs are required within 15 days of detection. Delays are allowed for technically infeasible repairs and/or when repairs would cause greater emissions than the leak. Under circumstances, delays can be allowed up to 6 months but not beyond a unit shutdown.

Closed vent systems are also regulated under Subpart VV. Closed vents system require a vapor recovery system that controls VOC emissions with a 95% efficiency or greater or to a concentration of 20 ppmv, which ever is less stringent (§60.482-10).

Subpart VV also allows for alternative standards for valves (§60.483-1 and §60.483-2). The first standard allows for 2% of all valves to meet the definition of leaking. This standard meets the same record keeping and repair criteria as specified in §60.482. The other alternative standard allows for skip-period of leak detection and repair for valves. The skip-period is performance based and regresses to the standards of §60.482 if greater than 2% of the valves meet the definition of leaking.

2.3.6. Subpart QQQ

The refinery has constructed, modified, or reconstructed many process units, and, as a result, the drain systems of which then became subject to this regulation. At the date of permit issuance, these units include:

- #4 Utility Boiler
- North Vacuum Heater
- Crude Unit *
- Reformer Unit *
- Isomerization Unit*
- Delayed Coker *
- #1 Diesel HDS
- #2 Diesel HDS
- Hydrocracker
- LEU/LPG Unit *
- Chemical Treater
- Calciner #2
- Tanks 24, 49, 50, 71, 72, 73, 74
- Truck Rack *
- Tanks 320, 321, 322, 323
- API Separators *

Under the regulatory overlap provisions of 40 CFR Part 63.640(o), any Group 1 wastewater stream subject to both Subpart QQQ and the Refinery MACT is required to comply only with the Refinery MACT. The units identified above with a "*" have overlap between QQQ and the Refinery MACT.

A Group 1 wastewater stream is defined in the Refinery MACT as

> "a wastewater stream at a petroleum refinery with a total annual benzene (TAB) loading of 10 megagrams per year or greater, as calculated according to the procedures in 40 CFR 61.342 of subpart FF of part 61, that has a flow rate of 0.02 liters per minute or greater, a benzene concentration of 10 parts per million by weight or greater, and is not exempt from control requirements under the provisions of 40 CFR part 61, subpart FF".

This is the same definition used for nonexempt wastewater streams under Part 61 Subpart FF. Therefore, any of the wastewater streams listed under the process areas mentioned above that are subject to Part 60 Subpart QQQ and Refinery MACT, are subject only to the Refinery MACT. But, the rules state that the owner or operator of a Group 1 wastewater stream shall comply with the requirements of §61.340 through 61.355 of Subpart FF. Group 2 wastewater streams defined under the Refinery MACT are still subject to Subpart QQQ as before.

2.3.7. Subpart A

If a NSPS in 40 CFR Part 60 applies to a facility, Subpart A also applies. Some of the requirements from Subpart A are included in the AOP, and some are not. If a requirement is applicable when triggered by some action, it is not included in the AOP. Similarly, if a part of Subpart A did not have specific requirements for the facility (i.e., if it solely addressed applicability or definitions), it is not included. If the requirement was something in the past, or addressed something that a regulatory agency must do, it is not included. However, the fact that these parts are not included in the AOP does not exempt the facility from the requirements.

The following list contains the parts of Part 60 Subpart A that are included in either Section 3 or Section 5 of the AOP:

- 60.4(a) and (b)
- 60.7(a), (b), (c), and (f)
- 60.8
- 60.11(b), (c), (d), and (g)
- 60.12
- 60.13
- 60.18(c), (d), (e), and (f)

2.4 NESHAPs

The refinery owns and operates equipment regulated under five NESHAPs:

- Part 61 Subpart FF – National Emission Standard for Benzene Waste Operations, and

- Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

- Part 63 Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

- Part 63 Subpart Y – National Emission Standards for Marine Tank Vessel Loading Operations. Since the facility is subject to these NESHAPS, it is also subject to the General Provisions for Parts 63, Subpart A, and 61, also called Subpart A.

- Part 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Boilers and Process Heaters

The following is a discussion of each Subpart as it applies to the refinery.

2.4.1 Subpart CC (Refinery MACT)

The first seven sections of the Refinery MACT (Part 63 Subpart CC, (a) through (g)), address equipment applicability. The process units at the facility that are subject to Part 63 Subpart CC emit or have equipment containing or contacting one or more of the hazardous air pollutants listed in the NESHAP. The subject units include:

- Miscellaneous process vents
- Storage vessels
- Wastewater streams and treatment operations
- Marine tank vessel loading
- Equipment leaks from petroleum refining process units

There are some important equipment exemptions listed in Part the Refinery MACT, including catalytic cracking unit and catalytic reformer catalyst regeneration unit vents, as well as sulfur plant vents and emission points routed to a fuel gas system. Other than the emission points routed to a fuel gas system, this equipment was included in Part 63 Subpart UUU, which is sometimes referred to as Phase II MACT.

The Refinery MACT standard requires that HAP emissions be controlled from various emission points with the refinery. Some of these emissions points may also be subject to other existing regulations including NSPS and other NESHAPs. It was not the intent of the Refinery MACT to place an additional burden on the refinery, but rather to allow the source to comply with only the most stringent regulation which will demonstrate compliance with all applicable regulations.

For miscellaneous process vents there are no existing regulations governing Group 1 and Group 2 categories. As a result, all Group 1 and Group 2 process vents must comply with the Refinery MACT.

For storage vessels, there is overlap of the Refinery MACT with 40 CFR 60 Subpart K and Subpart Kb. The Refinery MACT standard is applicable for all Group 1 storage vessels not already governed by 40 CFR 60 Subpart Kb. For Group 2 storage vessels, if the control requirements of 40 CFR 60 Subpart K or Kb do not apply, the vessel is subject to the Refinery MACT. All units not subject to Subparts K and Kb are subject to the Refinery MACT

There are several wastewater stream regulations that are cross referenced in the Refinery MACT. These are 40 CFR 60 Subpart QQQ, 40 CFR 61 Subpart FF, and 40 CFR 63 Subpart G. New and existing sources in compliance with 40 CFR 61 Subpart FF (see Section 2.4.2) are considered in compliance with the Refinery MACT standards. The Refinery MACT standard is applicable only to Group 1 streams that are subject to 40 CFR 60 Subpart QQQ. Group 2 streams in which Subpart QQQ applies are still subject to Subpart QQQ.

Existing gasoline storage racks are governed by 40 CFR 63 Subpart R, which is referenced in the Refinery MACT. New sources are subject to 40 CFR 60 Subpart XX but are only required to comply with the requirements of the MACT standard.

Marine tank vessel loading operations are subject to 40 CFR 63 Subpart Y, which is referenced in the Refinery MACT.

Equipment leaks standards in the Refinery MACT cross-reference 40 CFR 60 Subpart VV and the modified 40 CFR 63 Subpart H. The refinery has selected to use the standards and monitoring, recordkeeping, and reporting requirements (MR&Rs) listed in 40 CFR 60 Subpart VV to demonstrate compliance for their existing sources. However, new sources at the refinery will have to comply with the standards of the modified 40 CFR 63 Subpart H.

2.4.2 Subpart FF

In 1991, the refinery was required to become into compliance with 40 CFR 61 Subpart FF National Emission Standards for Benzene Waste Operations. The purpose of this regulation was to reduce the amount of benzene emissions to the atmosphere from wastewater operations. Benzene's volatility increases when it is mixed with water. The refinery's total annual benzene (TAB) quantity is calculated to be 32 tons/yr, which is above the 10 Mg/yr threshold, listed in 40 CFR 61 Subpart FF. The TAB does not represent the level of benzene emissions from waste operations, but rather the total amount of benzene that enters the waste water collection system.

The refinery complies with 40 CFR 61 Subpart FF through the requirements of 61.342(c)(3)(ii). This standard allows the refinery to exempt waste streams by demonstrating that initially and at least once a year thereafter that either:

a) The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gpm) or an annual wastewater quantity of less than 11 tons/year; or

b) The total annual benzene quantity in all waste streams chosen for exemption does not exceed 2.0 Mg/yr (2.2 tons/year) as determined by 40 CFR 61.355(j); and
c) that stream selected for exemption, including process turnaround waste, is determined for the year in which the waste is generated.

There are several options for the control of emissions and treatment of wastewater. The refinery has selected to use a closed vent system (§61.349), covered oil/water separators (§61.347), carbon adsorption canisters (§61.349), and an enhanced biodegradation unit for the treatment of wastewater.

2.4.3 Subpart UUU

Subpart UUU (Refinery MACT II) which became effective on April 11, 2005 contains continuing applicable requirements for the catalytic reforming units (during depressuring operations and catalyst regeneration) and for the sulfur recovery unit at the refinery. The refinery was required to provide a operation, maintenance and monitoring (OM&M) plan for each reformer and the Sulfur Recovery Unit and abide by the plans at all times during operation of these units.

Organic HAP emissions during depressuring of the reformers are to be controlled by purging the unit to a combustion device that meets a destruction efficiency of 98%. In addition, inorganic HAP emissions during coke burn off and catalyst regeneration must be reduced by 98%.

Subpart UUU requires that emissions for a Claus sulfur recovery unit meet the Subpart J requirement of 250 ppm SO_2 at 0% excess air.

2.4.4 Subpart Y

The Marine terminal at the refinery is subject to 40 CFR 63 Subpart CC. However, the Refinery MACT references 40 CFR 63 Subpart Y for the applicable standards. Under Subpart Y the marine terminal must install and operate a vapor collection system designed to collect HAP vapors displaced from marine tank vessels during loading operations (§63.562(b)). The subpart also specifies that the marine tank vessel must be compatible with the terminal's vapor collection system and must be vapor tight (§63.562(b)(ii) and (iii)). The refinery has determined MACT to be a HAP vapor collection system and a thermal oxidizer. The thermal oxidizer is subject to §63.563 - 63.565 and §63.567.

2.4.5 Subpart CC

Subpart CC contains a table outlining the applicable parts of the general provisions, Subpart A. Some of the requirements from Subpart A have been included in the permit, and some have not. Logically, if a requirement is applicable when triggered by some action, it was not included in the permit. Similarly, if the part of Subpart A did not have specific requirements for the facility (i.e., if it solely addressed applicability or definitions), it was not included. If the requirement was something in the past, or addressed something that a regulatory agency must do, it was not included. The fact that these parts were not included in the permit does not exempt the facility from the requirement. The following list contains the parts of Subpart A that were included in either Section 3 or Section 5 of the permit:

63.4(a)(1)-63.4(a)(3)	63.5(b)(6)	63.9(d)	63.10(b)(2)(vi)
63.4(a)(5)	63.5(d)(1)(ii)	63.10(a)	63.10(d)(5)(i)
63.4(b)	63.5(d)(3)	63.10(b)(i)	63.10(d)(5)(i)
63.4(c)	63.5(d)(4)	63.10(b)(ii)	63.10(d)(5)(ii)

63.5(b)(1)	63.6(e)	63.10(b)(2)(i)	63.11
63.5(b)(3)	63.6(f)(1)	63.10(b)(2)(ii)	
63.5(b)(4)	63.6(h)(6)	63.10(b)(2)(iv)	
63.5(b)(5)	63.9(a)(4)	63.10(b)(2)(v)	

If a National Emission Standard for Hazardous Air Pollutant standard under 40 CFR Part 61 applies to a facility, Subpart A also applies. Some of the requirements from Subpart A have been included in the permit, and some have not. Logically, if a requirement is applicable when triggered by some action, it was not included in the permit. Similarly, if the part of Subpart A did not have specific requirements for the facility (i.e., if it solely addressed applicability or definitions), it was not included. If the requirement was something in the past, or addressed something that a regulatory agency must do, it was not included. The fact that these parts were not included in the permit does not exempt the facility from the requirement. The following list contains the parts of Subpart A that were included in either Section 3 or Section 5 of the permit:

61.05(a)	61.12
61.05(b), (c), and (d)	61.13
61.07	61.19
61.09	
61.10	

2.4.6 Subpart DDDDD

Subpart DDDDD governs process heaters and boilers with a heat input of greater than 10 MMBtu/hr. For existing sources burning only natural gas or refinery fuel gas an initial notification is the only requirement of the regulation. The notification must include a brief description of the nature, size, design, and method of operation along with an identification of the emission points within the affected source and the types of hazardous pollutants emitted.

New process heaters or boilers on which construction was commenced after January 13, 2003 and burn only natural gas or refinery fuel gas must provide initial notification and must develop and follow an approved Startup, Shutdown and Malfunction (SSM) Plan. In addition, sources less than 100 MMBtu/hr must conduct an annual performance test for CO while sources greater than 100 MMBtu/hr must install and operate a CEM for CO and O_2. CO is used as a surrogate to represent organic HAP emissions, and the CO concentration in the stack must be controlled to less than 400 ppmvd @ 3% O_2. The initial notifications were received by NWCAA on March 9, 2005.

2.5 Leak Detection and Repair (LDAR)

Although minor amounts of VOCs are released from combustion sources, the majority are emitted from fugitive VOC emission sources. There are three major areas for fugitive VOC emissions that include process equipment leaks, storage tanks and the wastewater treatment plant. Specifics concerning storage tanks and the wastewater treatment plant are provided in other sections of the SOB.

Fugitive VOC and HAPs are emitted from leaking process equipment. These components include pumps, valves and compressors and, to a lesser degree, other miscellaneous components such as flanges and open-ended lines. All process units in the refinery are periodically monitored for leaks and when leaks are identified, they must be repaired in a timely manner.

There may be a mix of components in VOC and/or HAP service within refinery units. Depending on the nature of the component's service, a process unit participates in the LDAR program under Subpart GGG, Refinery MACT, and/or Subpart QQQ. Because of the complexity of the underlying applicability drivers, some being VOC based and some being HAP based, combined with the ability of the refinery to consolidate programs under Refinery MACT, the refinery has elected to monitor in accordance with Subpart VV. Refinery MACT 63.640(p) allows for considerable consolidation of LDAR programs by stating that "equipment leaks that are also subject to the provisions of 40 CFR Parts 60 and 61 are required to comply only with the provisions of this subpart". This simplifies the manner in which the terms of the AOP are written and provides consistent program implementation throughout the refinery. The AOP separates those classes of components in respect to their current regulatory driver. Table 2-1 presents a listing of refinery units and their applicable regulatory driver.

Table 2.1 - LDAR Component Regulatory Drivers

Process Unit	NSPS GGG	NSPS QQQ	BACT (Enhanced LDAR)	Refinery MACT Components	Refinery MACT Drains
Flare Gas Recovery	X			X	
Low and High Pressure Flares	X				
#4 Utility Boiler	X	X			
Naphtha HDS and Reformer Units	X	X		X	X
Crude/Vacuum	X	X		X	X
Hydrocracker		X	X[a]	X	X
Delayed Coker	X	X		X	
#1 Diesel HDS	X	X	X[a]		
#2 Diesel HDS	X	X	X		
Calciners	X	X			
LEU/LPG Unit	X	X		X	X
Isomerization Unit	X	X	X	X	X
Sulfur Complex				X	
Wastewater Treatment Plant		X		X	X
Group 1 Tanks and Storage Vessels				X	
Non-Group 1 Tanks and Storage Vessels	X	X			
Chemical Treater	X	X		X	
Truck Rack	X	X		X	X
Marine Terminal				X	
LPG/LEU/Butane/Pentane Loading	X				

Note 'a': Project specific, not unit-wide

2.6 Calciner Bubble and SO_2 Emissions

The "Calciner Bubble" has a long history with the refinery. The need for a bubble, or emissions limit, was created after the installation of the original Coke Calciner in 1977. At the time of construction, BACT was used to control particulate matter emissions from the Calciners. Under OAC #211

NWCAA established a refinery-wide particulate emissions rate of 60 tons per 31-day month. However, after startup, the refinery experienced chronic difficulties in consistently meeting the 20% opacity and PM standards. The refinery undertook improvement programs that ultimately exceeded $1 million dollars. Although these efforts resulted in the Calciners meeting the opacity standard, particulate emissions continued to exceed standards.

The refinery met with NWCAA, State of Washington Department of Ecology (WDOE) and US EPA representatives to discuss granting a bubble for particulate emissions. A bubble application was filed by the refinery according to WAC 173-403-060 and reviewed by NWCAA, WDOE and US EPA staff. On June 13, 1984 the NWCAA issued a Regulatory Order granting a Calciner "bubble." In the Regulatory Order, the NWCAA determined that by issuing a bubble for particulate matter to the refinery that:

1. Particulate contaminants will be exchanged for particulate contaminants at the same Cherry Point Refinery facility;

2. The bubble will not interfere with attainment and maintenance of air quality standards;

3. The bubble will not result in the delay in compliance of any sources, nor a delay in any existing enforcement;

4. The bubble will not supersede any other applicable air pollution control laws or regulations;

5. The bubble will not increase the presently allowed particulate emissions of 60 tons per month from the plant as a whole from the specific units

6. The 20% opacity will remain in effect

The relevant conditions of the bubble are:

<u>Condition 1</u>: Total allowable particulate emissions from the Cherry Point Refinery shall not exceed the previously established limit of 60 tons per 31-day month

<u>Condition 2</u>: The allowable emissions from the Calciner Stack (Stack #1) shall not exceed 46.8 tons per 31-day month and a maximum Calciner production rate of 60 tons per hour, while at the same time the particulate emissions from the fuel gas burning in the Crude, Vacuum, Coker #1 and Coker #2 Heaters and one Utility Boiler shall not exceed 3.7 tons per a 31-day month provided a lower particulate emission rate from the Calciner stack will permit a commensurate increase in the particulate emissions from the said heaters and boiler.

<u>Condition 3</u>: There will be no added air pollution control restrictions as a result of this bubble authorization.

In 1984, the refinery proposed to install a third Calciner and supporting coke handling equipment. The project triggered the NOx Prevention of Significant Deterioration (PSD) threshold, and subsequently the refinery developed a PSD application. In the application the refinery determined that BACT for particulate matter (PM) was wet electrostatic precipitators (WESPs). The WDOE reviewed the refinery's PSD application and issued PSD-3. The NWCAA followed suit and issued OAC #299.

Condition 7 of PSD-3 stated that, in addition to a refinery-wide emission limit for SO_2 of 59,258 lbs/day, the refinery-wide PM emission rate was increased to 4,258 lbs/day (equivalent to 66 tons/month). The NWCAA OAC #299 required the refinery to be in compliance with the terms of PSD-3. The bubble requirements listed above still applied within the 66 tons/month.

Later in 1988 the refinery requested that the NOx emission limit listed in PSD-3 be increased because of errors in the original NOx emission factor. WDOE issued PSD 89-2, rescinding PSD-3. However, in writing PSD 89-2 WDOE inadvertently left out Condition 7; and, therefore, the PM and SO_2 refinery-wide emission limits specified in PSD 89-2 still apply

Since the inception of the bubble at the refinery, significant changes were made to the Calciner pollution control systems. Most notably was the voluntary installation of a Dynaware scrubber system on Stack #1. While installed to reduce SO_2 emission, the Dynaware scrubber system had the added effect of reducing PM emissions. Since then, all of the Calciners have been retrofitted with WESPs. The WESPs are more efficient than the Dynaware scrubber at controlling PM and have proven to be reliable means of maintaining PM emissions at or below current regulatory standards.

Finally, on March 9, 1995, the NWCAA issued a letter to the refinery clarifying the regulatory issues relating to the refinery-wide SO_2 and PM bubble as they apply to the air operating permit program (i.e., Title V). In the letter the NWCAA restates that the refinery-wide emission limit for SO_2 is 2,468 lbs/hr. Additionally, the NWCAA stated that the refinery-wide emission limit for PM is 4,258 lbs/day on a monthly average.

These changes along with improved regulatory standards applied to changes made after the bubble was approved have resulted in the refinery remaining under the Calciner bubble limit during normal operations. Hence, since the bubble cannot supersede any other applicable air pollution regulation or law, the bubble limitation has been essentially rendered moot. However, during turnaround activities the bubble is still a valid emission limitation that the refinery may refer to when discussing projects with the NWCAA.

2.7 Consent Decree

In the late 1990s, the USEPA conducted a nation-wide enforcement initiative of the petroleum refining industry, targeting alleged violations of the Clean Air Act (CCA), Resource Conservation and Recovery Act (RCRA) and the Toxic Substances Control Act (TSCA). Following this in-depth investigation, the refinery's parent company, British Petroleum Exploration & Oil Company, entered into consent decree agreements with EPA and intervening parties that will result in a reduction of air pollution emissions at their nine petroleum refineries. As one of the affected refineries, the BP Cherry Point Refinery will implement control strategies to reduce emissions of VOCs, NOx and SO_2 from refinery process units. In addition, they will adopt an enhanced fugitive emission control program. Implementation of these reduction efforts, however, cannot be applied as emission credits or offsets that could be applied to other refinery projects.

Because the requirements contained in the consent decree are not considered specific "requirements" under federal Title V definitions, the AOP incorporates only a compliance plan for items of the consent decree that will continue into perpetuity. This plan is listed in Section 8 of the AOP in accordance with 40 CFR 70.5(c)(8). It is recognized that the consent decree is, in and of itself, independently enforceable. Furthermore, many of the specific requirements contained in the consent decree overlap requirements found in the AOP, and knowledge of its contents are important in understanding how and why the refinery conducts specific compliance programs. For this purpose the consent decree settlement document is provided in their entirety at the following URL: http://nwcleanair.org/regulated/aop.html.

It should be noted that the NWCAA is a plaintiff-intervener in the consent decree. As such, it is a signing partner in the settlement agreements and shares a role with US EPA in matters of compliance enforcement and penalty assessment. The compliance plan under Section 8 of the AOP lists a subset of the consent decree. It is anticipated that consent decree requirements not listed in the compliance plan will "sunset" upon termination of the consent decree in 2008. Please refer to the actual text in the consent decree for more detailed information.

In response to a request by the refinery, the NWCAA issued Regulatory Order #28 on May 15, 2002 to address some of the issues listed in the BP Consent Decree. Terms of RO #28 are:

> Term I: The fuel gas combustion system for all of the heaters and boilers at the BP Cherry Point Refinery will meet the requirements of 40 CFR 60 Subpart J and shall comply with all requirements of 40 CFR 60, Subpart A and J, as those subparts apply to the fuel gas combustion in heaters and boilers by September 30, 2005.
>
> Term II: The Sulfur Recovery Plant (SRP) at the BP Cherry Point refinery is subject to the following monitoring provisions:
>
> 1. All SRP sulfur pit emissions shall be treated, monitored and included as part of the SRP's emissions subject to NSPS Subpart J limit for SO_2 by no later than the first turnaround of the Claus train that occurs six months after January 18, 2001 (i.e. the first turnaround of the Claus train after July 18, 2001). SO_2 from the SRP will be monitored according to requirements of 40 CFR 60 Subpart J.
>
> 2. By the end of the turnaround expected in 2006, the SRP shall comply with 40 CFR 60.104(a)(2). The SRP shall meet a SO_2 limit of 250 ppmvd at zero percent excess air, except for periods of startup, shutdown, or malfunction of the Tail Gas Units.

Other areas affected by the consent decree include the refinery's LDAR program and compliance program for the Benzene Waste Operations NESHAP. Below is a summary of the enhancements required under the BP Consent Decree.

Enhanced LDAR Program

Enhancements to the LDAR program according to the consent decree and to some degree BACT under specific OAC's include:

1. Develop and maintain an enhanced LDAR compliance program that includes the identification, monitoring and repair of components in HAP/VOC service. Use an electronic database and dataloggers to track leak rates and program performance on an individual component and on a process unit basis. The program shall provide adequate training for involved personnel. An initial external audit has been performed and thereafter shall, at minimum, conduct internal audits every four years or external audits every two years.

2. The work practice standards of the enhanced LDAR program shall be in place by no later than March 31, 2003. The program follows requirements of NSPS Subpart VV with modifications to defined leak rates and the allowable monitoring relaxation frequencies as summarized below.

    - Pumps - visually inspect weekly, monitor monthly at a leak definition of 2,000 ppm with no allowance for relaxing the frequency.

- Valves – monitor quarterly with no allowance for frequency relaxation or, monitor monthly with the following allowance for relaxation on a process unit basis; if < 2% leakers can skip to quarterly, if < 1% leakers can skip to semi-annually, if < 0.5% leakers can skip to annually. Regardless of the applied monitoring frequency the leak definition for valves is 500 ppm with an action level for first attempt at repair at 100 ppm. Valves leaking greater than 50,000 ppm and those leaking at greater than 10,000 ppm for more than three years shall undergo extraordinary repair efforts prior to putting on a "delay of repair list". Provisions are included for adjusting the monitoring frequencies during interruptions from process unit shutdowns and turnarounds.

Benzene Waste Operations NESHAP

The refinery employs the "2 Mg compliance" option for their Benzene Waste Operations NESHAP. Enhancements to the existing program include:

1. Shall conduct an audit on the refinery's waste stream inventory and TAB calculation.

2. Shall conduct audits of all laboratories used for the TAB calculation within the first year or subsequently an audit of laboratories every 2 years.

3. Carbon canisters
   a. Primary/Secondary Carbon Canisters: Install and operate in series, monitor breakthrough, replace secondary carbon canisters with fresh ones once a VOC concentration of 50 ppm is detected. Maintain fresh carbon canisters. Monitor until a second carbon canister is installed.

   b. Single Carbon Canister: Monitor breakthrough carbon canister when actual flow occurs. For canisters <55 gallon drum size, breakthrough is a reading of VOC above background. For canisters >55 gallon drum, breakthrough is either 50 ppm VOC or 1 ppm benzene. When a reading of 10 ppm VOCs is detected, monitoring of benzene must be conducted on the following schedule:

      i. Daily if historical replacement is less than 2 weeks; or
      ii. Monday, Wednesday, Friday if historical replacement greater than 2 weeks.

4. Shall account for all benzene spills in the TAB calculation and for benzene waste generated through spills with respect to the 2 Mg/yr

5. Develop and implement training for employees required to sample benzene wastes, establish SOPs for all control equipment used to comply with this program, and include annual training for operators assigned to these units

6. Maintain all records of waste/slop oil movements which are not controlled or identified in the refinery plan

7. Include a list of all uncontrolled waste streams in the facility according to the 2 Mg/yr option. List the content and annual flow of each of these streams in the annual report.

8. Sample quarterly all uncontrolled waste streams counting towards 2 Mg/yr option and streams containing greater than 0.05 Mg/yr of benzene.

9. Measure quarterly concentrations of all waste streams that qualify for the 10 ppm exemption on a quarterly basis.

10. Conduct monthly visual inspections of water traps within individual drain systems subject to Benzene NESHAPs, identify and mark segregated stormwater drain systems, monitor all conservation vents on process sewers for detectable leaks weekly and account for all leaks. Include in the TAB calculation all oil recovered from oil/water separators or sewer system until it is recycled or placed into a feed tank.

2.8 Administrative Order on Consent

In March of 2001, the USEPA issued an Administrative Order on Consent (Order) under the authority of Section 167 of the Clean Air Act with the Department of Ecology and Northwest Clean Air Agency as co-signers of the order. This order was written so the refinery could install 14 natural-gas fired turbines for affordable electric power during the energy crisis that had been declared by the Governor of Washington. Operation of these portable units continued during the period of May-June 2001.

The agreement included offsets of emissions from the turbines for NOx, carbon monoxide and particulate matter for up to a year prior to a final PSD being issued as well as a donation of $100,000 to a Whatcom County low income energy assistance fund. The refinery reduced the Reid Vapor Pressure at the truck rack for a period of time to mitigate the CO emissions and sold Low Sulfur Diesel in place of High Sulfur Diesel to offset the particulate matter emissions. They donated money to the Whatcom County Low Income Energy Assistance fund. In addition, NOx emissions will be mitigated when the second stage hydrocracker fractionation reboiler is retrofitted by 2004.

As power rates moderated in 2002, the incentive for operating these units diminished significantly. As a result, the portable natural gas fired turbines were shut down and removed from the facility in July, 2002. However, the refinery fulfilled its obligation to provide NOx offsets for the project and installed low-NOx burners in the second stage fractionator reboiler heater at the Hydrocracker in early 2005 under OAC #847.

Section 3 - Process Descriptions, Construction History, and Regulatory Applicability

The following section provides a description of each refinery area along with a construction history and regulatory applicability for each process unit or product handling system in that area. The refinery areas are presented in the same order found in the AOP for ease in cross-referencing. The construction history provides a valuable insight into how and why specific requirements were applied during the NSR permitting. In general, one-time only conditions that have been met are not discussed because they are not considered part of on-going compliance requirements for the facility. When a one-time requirement is used to determine on-going compliance, such as an initial source test, the results of that activity are provided. If a specific term in the AOP is clear and consistent with the underling requirement there is no need to discuss the term further in the SOB. However, where gap filling has occurred, a regulatory interpretation has been made or where the level of regulatory complexity warrants clarification, they are discussed herein.

3.1 Refinery-Wide

As discussed in Section 2.6, the refinery has two refinery-wide pollutant specific emission limits. These limits were developed as part of OAC #211, OAC #299, and PSD-3. Refinery-wide emissions for SO_2 are limited to 2,468 lbs/hr. The refinery-wide emission limit for PM is 4,258 lbs/day on a monthly average.

3.2 Compressors

Because of their unique applicability, compressors have been separated from the discussion of refinery units. There are numerous compressors at the refinery, some employing reciprocating and other employing centrifugal compression technologies. Compressors are subject to the 40 CFR 60 Subpart GGG, which references 40 CFR 609 VV. However, under Subpart GGG there is an exemption under 60.593 for compressors in hydrogen service. To be in hydrogen service, the percent hydrogen in the gas must reasonably expect to always exceed 50 percent by volume (60.593(b)). Because of this exemption, only 3 of the 19 refinery compressors are subject to the standards of VV. Flare gas compressors 28-1803 and 28-1804 and LEU/LPG compressor 22-1801 are subject to the requirements of Subpart VV.

Compressors subject to Subpart VV are required to be equipped with a seal system that includes a barrier fluid system that prevents the leakage of VOCs to the atmosphere. Of the options available, the refinery selected the option listed under 60.482-3(b)(1) in which the barrier fluid pressure is greater than the compressor stuffing box pressure.

It should be noted that many of the compressors in hydrogen service have components upstream and downstream of the compressor itself that are subject to Subpart GGG because VOCs are contained in the remaining portion of the hydrogen service gas. Compressors 12-1801, 11-1802, 11-1803, 21-1821, and 21-1822 have components that are subject to Subpart GGG.

3.3 Crude/Vacuum Unit

Crude oil processing is the first step in the refinery process. Higher efficiencies and lower costs are achieved if the crude oil separation is accomplished in two steps: fractionating the fresh crude oil at essentially atmospheric pressure; then fractionating the higher-boiling bottoms at a high vacuum. Prior to fractionating crude oils are "washed" in the desalter to remove salts and other naturally occurring contaminants. The washed crude is then routed through a Pre-Flash Vacuum Tower. The pre-flash tower allows for the vaporization of light hydrocarbons that are subsequently re-introduced into the top of the crude tower to aid in fractionation. The remaining processed crude is heated to about 650° F in the Crude Heater. The heated crude is then routed to the crude tower in which crude is separated by distillation into hydrocarbon fractions according to boiling point. Crude distillation separates and recovers the relatively lighter fractions such as naphtha, stove oil, diesel, and gas oil cracking stock.

The heavier fractions (i.e. "bottoms" or crude residuum) are treated in a vacuum diesel fractionator then heated in two vacuum heaters, the North Vacuum Heater and South Vacuum Heater, to about 760 F. The heated residuum is processed in the Vacuum Tower. The vacuum separation processes the crude residuum in order to increase the yield of liquid distillates. Light vacuum gas oils and heavy vacuum gas oils are separated and routed in the refinery for further processing. The bottoms from the vacuum unit are routed to the Delayed Coker for conversion into a final product, calcined coke.

In support of other refinery upgrades and modifications, the Crude/Vacuum Unit has undergone other changes. These changes include the retrofitting of low-NOx burners on the South Vacuum Heater in 1999 and installation of a diethanolamine (DEA) scrubber on the Vacuum Overhead Tail-Gas system. The DEA scrubber removes H_2S from the Vacuum Tower and Vacuum Diesel Fractionator tail gases. DEA absorbs H_2S, extracting it from the tail-gas. The absorbed H_2S creates a rich DEA mixture that is regenerated using steam. At the DEA regenerator, concentrated H_2S is liberated, and the H_2S-laden stream is routed to the Sulfur Recovery Unit where elemental sulfur is made. The treated tail gas is burned in the Crude Heaters.

Major equipment at the Crude/Vacuum unit include desalters, a pre-fractionator tower, a crude heater, a crude tower, stove oil and diesel strippers, a debutanizer tower, a vacuum diesel fractionator, north and south vacuum heaters, and a vacuum tower. This unit has a number of components in heavy liquid, light liquid and gaseous service that can emit fugitive VOCs and HAPs. Other elements of this unit that may result in emissions to the air include pumps, valves, flanges, vents, sewer line connections and pressure relief devices.

Construction History and Regulatory Applicability

The original crude/vacuum unit was built with the refinery in 1970. Seven major projects have been undertaken on this unit since 1970 and these are: 1) Combustion Air Preheater 2) North Vacuum Heater; 3) Crude Pre-Flash Project; 4) Crude to Coker Condensate; 5) Crude Fractionation Project; 6) Coker Unit and #1 and # 2 Calciner Modifications; and 7) Vacuum Overhead Tail Gas Treating System. According the refinery's determination, the crude unit is subject to 40 CFR 63 Subpart CC Refinery MACT for Group 1 valves, pumps, and compressors.

The following is a discussion of each project.

Combustion Air Preheater

On February 1975 the refinery proposed to install a combustion air preheater to the crude heater. The preheater would improve energy efficiency at the crude heater by recovering heat from waste heat normally wasted to the atmosphere. The project would lower the stack gas temperature and potentially reduce SO_2 emissions. Dispersion modeling was performed to determine the effects on SO_2 emissions from this project. Model results indicated that ambient air SO_2 emissions would not change as a result of the project. On May 14, 1977 the NWCAA issued OAC #159. The equipment was installed and NWCAA issued a Certificate of Approval to Operate on April 25, 1977.

North Vacuum Heater

In 1983 the refinery installed a second vacuum heater, North Vacuum Heater (referred to in the application as Vacuum Heater #2) at a heating load of 55 MMBtu/hr with air preheater in service. The heater was designed with low-NOx burners. Emissions from this unit were determined to be below the PSD de-minimus thresholds as long as the refinery operated the heater at 55 MMBtu/hr with the air preheater in service or at 77 MMBtu without the air preheater in service. Construction related to the project was approved by the NWCAA on January 14, 1983 in OAC #273.

To meet Best Available Control Technology (BACT) requirements, the heater was installed with low-NOx burners. NSPS requirements for fuel gas were also triggered which required continuous monitoring the H_2S concentration in the fuel gas and that the H_2S concentration not exceed 160 ppmv for any three hour period. At the time of installation, no EPA-approved continuous H_2S monitor was available. As a result, the refinery took 8-hour samples of the fuel gas for H_2S analysis. The refinery stated that they would install an EPA-approved H_2S monitor when available.

Subsequent heater efficiency studies performed by the refinery indicated that the North Vacuum Heater could be run at a higher heating load of 77 MMBtu/hr and would provide product splits favoring gas oil production over residual oil production. The higher heating load caused the North Vacuum Heater to trigger PSD thresholds for NOx. Overall refinery NOx emissions would increase by 28 tons/year as a result of the project. A PSD analysis was performed by the WDOE, and a final determination created on December 17, 1985 in PSD-5.

The PSD-5 determination limited emissions of CO (Condition # 1a) to 9.5 tons/year on an average of any 60 consecutive minutes and NOx (Condition #1b) to 14.6 tons/hour on an average of any 60 consecutive minutes. The PSD-5 determination also limited the north vacuum heater to a firing load of 77 MMBtu/hr (Condition #2) and the fuel gas feed to a H_2S concentration of 160 ppmv on a 3 hour rolling average (Condition #5). Other requirements listed in PSD-5 included the installation of continuous monitors for oxygen on the heater (Condition #4) and H_2S on the fuel gas feed line heater (Condition #6) in accordance with 40 CFR 60 Appendix B.

Finally, PSD-5 required (Condition #3) the refinery to offset the increased NOx emissions either by:

- Installing a current state-of-the-art staged fuel burners during the next period of unit downtime or within four years, whichever came first; or
- Offsetting 28 tons per year of NOx emissions within 12 months elsewhere in the refinery.

The refinery selected the latter of the two options for meeting Condition #3 of PSD-5. On March 18, 1986, the NWCAA issued the refinery a Regulatory Order for emission credits for 29 tons/year of NOx for the installation of the Flare Gas Recovery Project. Subsequently, the emissions credits were applied toward PSD-5 Condition #3. The WDOE acknowledged the refinery's fulfillment of PSD-5 Condition #3 for NOx offsets on December 10, 1986. On January 20, 1987, the NWCAA followed suit by providing formal notification of canceling the emission credits as they were used to offset the 28 tons/year in NOx emissions.

In 1995, the refinery requested a revision to PSD-5 to update the level of CO emissions (Condition #1a). During the time of the PSD application and determination, USEPA via their publication of emission factors referred to as "AP-42" had not developed CO emission factors for low-NOx burners. The CO emission factor used was for uncontrolled heaters and boilers. However, by 1995, USEPA had developed emission factors for low-NOx burners. As a result, the refinery requested that CO emissions be increased to 16.6 tons/year for the North Vacuum Heater. The State Washington

Department of Ecology approved the request, rescinded Condition #1a and amended PSD-5. The NWCAA issued OAC# 273 Rev a reflecting the rescinded Condition #1a of PSD-5.

40 CFR 60 Subpart J limiting fuel gas to 162-ppm H_2S in the South and North Vacuum Heaters is required in accordance with Regulatory Order #28.

On November 18, 2004 OAC #273 was again revised (Revision b) to adjust the CO emission limit on the heater from 16.6 to 27.7 tons per year to reflect an updated (more accurate) emission factor (0.0823lbs/MMBtu) provided in AP-42 for these types of process heaters.

South Vacuum Heater

The South Vacuum Heater was retrofitted with low-NOx burners in 1999 to offset increased NOx emissions from the Coker Unit and No.1 Calciner Project OAC #689. In early 2005 the South Vacuum Heater was again equipped with new ultra low-NOx burners due to operability issues with the low-NOx burners installed previously. This project was also implemented to comply with a requirement of the 2001 Consent Decree which directed BP to install NOx controls on 30% of the heater capacity in the refinery. Emission limits for NOx and CO were included in OAC #902 for this project and are provided below:

Condition Number	Description of OAC #902 Conditions
1	Fuel combusted in the heater shall be limited to pipeline grade natural gas and treated refinery fuel gas.
3	NOx emissions from the stack shall not exceed 34 ppmvd at 7%O_2 based on a 1-hour average or, at times this limit is exceeded, 8.9 lbs/hour (equivalent to 0.043 lb/MMBtu).
4	CO emissions from the heater stack shall not exceed 11.8 lbs/hour as determined by a initial compliance test.

Crude Pre-Flash Project

On January 27, 1987, the refinery submitted a Notice of Construction for a new pre-flash vessel and a new vacuum diesel fractionator (VDF). It was calculated that the project would result in no net increase in emissions. Based on the NWCAA review of the application, no Notice of Construction was issued for the project.

Crude to Coker Condensate

In response to the changing characteristics of the feed crude, the refinery proposed to route crude oil directly to the delayed coker on April 4, 1990. Waste heat recovered from the coker drum overhead would be used to pre-heat the crude oil. Additional heater firing would take place at the Reformers and Diesel and Naphtha HDS units. The refinery estimated that emissions of SO_2 would increase by 0.20 tons/year and that NOx emissions would increase by 20.3 tons/year as a result of the implementation of this project. However, the refinery proposed to replace standard burners in three heaters with low-NOx burners to offset the increase NOx emissions. The subsequent increase of NOx emissions would be 7.87 tons/year. The NWCAA issued OAC #281 on August 8, 1990 in which NWCAA determined that no permit was necessary. According to refinery personnel, the low-NOx burners were not installed as the NWCAA did not issue an OAC requiring the installation of the burners.

This project also affected other refinery modifications. In a letter dated August 8, 1990, the NWCAA determined that the equipment and facilities affected by the Crude to Coker Condensate were subject to 40 CFR 60 Subpart GGG as a result of the COUP.

Crude Fractionator Project

On November 19, 1997 the refinery submitted a Notice of Construction to the NWCAA for improving crude fractionation and slightly increasing crude processing capacity. The project included modifications to the existing preheat exchange train and additional preheat exchangers, replacement of the existing pre-flash drum, replacement of the existing debutanizer tower with a larger tower, conversion of the existing pre-flash drum to a stove oil stripper, and the replacement of the existing vacuum tower. These modifications also required changes to pumps, heat exchangers, and process relief valves. The NWCAA issued OAC #640 on May 1, 1998.

In OAC #640, BACT was identified as a LDAR program for emission units such as valves, pumps, flanges, closed vent systems, and other connectors. Applicability of NSPS included the crude distillation unit, butane distillation unit, stove oil stripper, diesel oil stripper, VDF, and vacuum distillation unit. 40 CFR 60 Subpart GGG and QQQ apply to the affected units along with 40 CFR 60 Subpart VV for LDAR and 40 CFR 63 Subpart CC for the emissions of HAPs. The terms of OAC #640 are shown in the following table:

Condition Number	Description of OAC #640 Conditions
1	New and converted drains are subject to 40 CFR 60 Subpart QQQ for VOC emissions from Petroleum Wastewater Systems which requires that drains be equipped with water seals and inspected semiannually. Covered or enclosed sewer lines are visually inspected semiannually. New drains and junction boxes cannot be routed through a downstream catch basin.
2	Pumps in light liquid service including primary crude charge pumps, vacuum diesel fractionator diesel pumps, and prefractionation tower overhead product/reflux pumps are subject to 40 CFR 60 Subpart GGG and 40 CFR Subpart 60 VV for Equipment Leaks of VOCs in Petroleum Refineries and the Synthetic Organic Chemicals manufacturing Industry. Pump leaks are to be controlled and monitored per the refinery LDAR program.
3	Pressure relief devices in gas/vapor service within the affected facilities listed previously are subject to 40 CFR 60 Subpart GGG and 40 CFR 60 Subpart VV. These devices are to be operated without detectable emissions.
4	All sampling connection systems within the affected facilities listed previously are subject to 40 CFR 60 Subpart GGG and 40 CFR 60 Subpart VV. These systems shall be equipped with closed-purge, closed-loop or vent systems.
5	All open-ended valves or lines within the affected facilities listed previously are subject to 40 CFR 60 Subpart GGG and 40 CFR 60 Subpart VV. These components shall be equipped with caps, blinds, flanges, plugs, second valves, or equivalent.
6	All valves in gas/liquid service or light liquid service within the affected facilities listed previously are subject to 40 CFR 60 Subpart GGG and 40 CFR 60 Subpart VV. These components are subject to the LDAR program except for valves that have been determined to be non-detect, unsafe to monitor, or difficult to monitor.
7	All pumps and valves in heavy liquid service, pressure relief devices in light liquid service and flanges and other connectors within the affected facilities listed previously are subject to 40 CFR 60 Subpart GGG and 40 CFR 60 Subpart VV. These components are subject to the LDAR program except for valves that have been determined to be non-detect, unsafe to monitor, or difficult to monitor.

Condition Number	Description of OAC #640 Conditions
8	All added or changed components within the affected facilities listed previously are subject to 40 CFR 63 Subpart CC National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT). This includes process vents, pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, or instrumentation systems. These components are subject to the LDAR requirements under 40 CFR 60 Subpart VV. The refinery selected to control Group 1 process vents to the Low and High Pressure Flare System.

Modifications proposed in the Crude Fractionation Project were completed, and the unit started operation in June 1999. The NWCAA performed a field inspection to determine compliance with OAC #640 and subsequently determined the refinery in compliance.

Coker Unit and #1 and # 2 Calciner Modifications

A more detailed discussion of this project can be found in Section 3.9. This project affected the South Vacuum Heater in the Crude/Vacuum Unit and the Vacuum Tail Gas Overhead system. Increases in NOx emissions associated with the project were offset by the installation of low-NOx burners in the South Vacuum Heater (OAC #689 Conditions 1.3.1 and 1.3.2). Increases in SO_2 emissions associated with this project were off-set by the installation of a diethanolamine (DEA) scrubber in the Vacuum Tail-Gas Overhead system. A separate NOC was not issued for the DEA scrubber. OAC #689 applicable conditions are provided below:

Condition Number	Description of OAC #689 Conditions
1.3.1 2.3.1	NOx emissions shall be limited to 0.07 lb/MMBtu (68 tons/year) in the South Vacuum Heater. The refinery will demonstrate compliance using USEPA Method 7A or 7E.
1.3.2 2.3.2	CO emissions shall be limited to 0.02 lb/MMBtu (19 tons/year) in the South Vacuum Heater. The refinery will demonstrate compliance using USEPA Method 10.
1.4.1 2.4.1	DEA scrubber will operate at a minimum performance level of 80% reduction in H_2S. The refinery will demonstrate compliance using USEPA Method 11.

Low-NOx burners were installed and operating in the South Vacuum Heater prior to June 29, 1999. The DEA scrubber was installed and operating by June 29, 1999. Performance tests to document the 80% reduction in H_2S emissions were performed on August 17, 1999. Performance certification tests for NOx and CO emissions were performed on September 22, 1999.

Vacuum Overhead Tail-Gas System

On August 4, 1998 the refinery proposed installing a DEA scrubber to treat tail gas from the VDF (vacuum diesel fractionator) and vacuum tower. The H_2S rich DEA would be regenerated and the acid gas sent to the Sulfur Recovery Unit for further processing. The treated tail-gas would then be combined with refinery fuel gas and combusted in the crude heater. The purpose of the project was to improve VDF and vacuum tower performance by establishing pressure control on the tower overheads, reduce SO_2 emissions from the crude unit, and recover additional elemental sulfur for sale.

The refinery estimated that the project would result in a net decrease in SO_2 emissions of 515 tons/year. Other emissions associated with this project included PM_{10}, NOx, VOCs, CO, H_2S, and HAPs. However, all of the pollutants were calculated to be below *de minimus* levels as identified in

NWCAA 300.2 (r). On February 16, 1999 the NWCAA issued a letter stating that the refinery did not require a Notice of Construction Approval Order for this project.

In 2005 the sour gas being routed from the VDF and the Vacuum Tower to the Crude Heater was blocked and the gas was routed to the main refinery fuel gas mix drum. This was done so that the Crude Heater was no longer combusting gas with greater than the 162 ppmv H_2S Subpart J limit.

3.4 Naphtha HDS and Reformer Units

The Naphtha HDS and Reformer Units are used to increase the octane rating of hydrocarbons by converting straight chain hydrocarbons into aromatic and branched chain hydrocarbons. Prior to the reformers, naphtha feed stock from the Crude Unit and Delayed Coker is processed by hydrodesulfurization (HDS) in the Naphtha HDS unit. Naphtha is mixed with molecular hydrogen (H_2), heated to 500 F and passed over a catalyst to hydrogenate unsaturated chemical bonds and liberate sulfur and other impurities. Typically, organic sulfur compounds are converted to H_2S and organic nitrogen is converted to ammonia (NH_3). Removal of sulfur from the naphtha allows further processing in the Hydrocracker and Reformers because the catalysts involved in those processes can be poisoned by sulfur. The treated naphtha is then routed to Reformers for the production of higher octane products. This conversion takes place with H_2 again at about 700 F, under pressure, and in the presence of a catalyst. Also, waste heat from the reformers may be used to generate steam for refinery-wide use.

In response to USEPA's effort to eliminate lead from gasoline, the refinery added an addition reformer that would upgrade low octane components into high octane components for use in the gasoline blending system. As a result, the refinery discontinued the use of tetra-ethyl lead as a means to boost octane in gasoline products. Several years later the refinery added a light reformate splitter (LRS) to this unit. The purpose of the LRS is to reduce the benzene content of the light reformate overhead and produce a concentrated benzene bottom product that can be sold primarily to the chemical manufacturing industry as a reaction agent.

Major equipment at the Naphtha HDS and Reformer Units include: Naphtha HDS Charge Heater, Naphtha HDS Stripper Reboiler, #1 Reformer Heater, #2 Reformer Heater, and Light Reformate Fractionator (LRF). The unit has numerous components are in heavy liquid, light liquid, and gaseous service that may emit VOCs and HAPs. Other elements of this unit that may result in emissions to the air include pumps, valves, flanges, vents, sewer line connections and pressure relief devices.

<u>Construction History and Regulatory Applicability</u>

Reformer #1, Naphtha HDS Charge Heater, and Naphtha HDS Stripper Reboiler were built with the refinery in 1970. As a condition of construction the Naphtha HDS Charge Heater was required to burn fuel gas only. Three projects have been performed on this unit since original construction: 1) Gasoline Reformer Unit; 2) New Light Reformate Splitter Tower; and 3) Crude to Coker Condensate. Regulatory Order #28 which references 40 CFR 60 Subpart J limiting fuel gas to 162-ppm H_2S in the heaters is required for the Naphtha HDS Unit and Reformer #1 after 9/30/05. According the refinery's determination, the Naphtha HDS is subject to 40 CFR 63 Subpart CC Refinery MACT for Group 1 valves, pumps, and compressors. The refinery also determined in their Refinery MACT Initial Notification of Compliance Status Report submitted on July 25, 2002 that Reformer #1 and Reformer #2 are subject to 40 CFR 63 Subpart UUU.

The following is a discussion of the projects listed above.

Gasoline Reformer Unit (Reformer #2)

In 1985 the refinery submitted a Notice of Construction for the proposed construction of an additional gasoline reformer (#2 Reformer) that would comply with USEPA lead phasedown rules for motor fuels that became effective in January of 1986. The new reformer would upgrade low octane components into high octane components and eliminate the need for the use of tetra-ethyl lead. The NWCAA issued OAC #305 in November, 1985.

Air emissions from this project are primarily from the installation of the #2 Reformer Heater and a naphtha HDS heater. The heaters are non-contact gas fired heaters that produce combustion by-products such as CO, SO_2, PM, and NOx. Of these pollutants, the increase in the annual emissions of NOx (140 tons/year) exceeded the PSD threshold of 40 tons per year, thereby making the modifications subject to PSD review. On March 18, 1986 WDOE granted a final determination for the refinery's PSD application under PSD-7.

BACT for heaters were determined to be the use of low-NOx staged-fuel burners with air preheat and computer controlled excess oxygen levels. NSPS requirements for fuel gas were also triggered which required continuous monitoring of the H_2S concentration in the fuel gas and that the H_2S concentration not exceed 160 ppmv for any three hour period. After the PSD determination the refinery opted not to construct the naphtha HDS heater but did install #2 Reformer. It was found that the existing Naphtha HDS heater could service both units.

The NWCAA provided a Certificate of Approval to Operate to the refinery for this project on February 10, 1988. Operating conditions included in PSD-7 are shown in the table below:

Condition Number	Description of PSD-7 Conditions
1	Emissions limits of CO to 11 lbs/hr (48.3 tons/year) and NOx to 32 lbs/hr (140 tons/year) on any average 60 consecutive minutes.
2	Limits the firing of the Reformer #2 heaters to 340 MMBtu/hr.
3	Install a continuous O_2 monitor on the reformer heaters in accordance with 40 CFR 60 Appendix B.
4	Limits H_2S concentration to 160 ppm in the fuel to the vacuum heater, based on a three-hour rolling average, or 90 ppm on a monthly average.
5	Install a continuous H_2S monitor of the fuel feed line (refinery fuel gas mix tank) and operate it according to 40 CFR 60 Appendix B.

OAC #305 incorporates the PSD-7 conditions. Additional requirements from OAC #305 are:

Condition Number	Description of OAC #305 Conditions
1	Opacity shall not exceed 5% for more than three minutes in any one hour period.
2	Emission limits for particulate matter to 0.01 grain/dscf for exhaust gases, corrected to 7% O_2.
3	Establish a LDAR program for the new equipment according to 40 CFR 60 Subpart GGG.

40 CFR 60 Subpart J limiting fuel gas to 162-ppm H_2S is required at the Reformer #2 heater.

Light Reformate Splitter Tower (LRS)

On August 1995 the refinery notified the NWCAA that they proposed to build a new light reformate splitter tower. The existing reformate splitter would be reconfigured so that the light reformate overhead would be drawn off and become the feed to the LRS tower. The proposed LRS would produce C5/C6 paraffin overhead that would be used for on-site gasoline blending and benzene concentrated (40% by weight) bottoms for on-site storage and off-site sale. The LRS tower would have emissions of VOCs and benzene.

Based on the application, the NWCAA determined that a Second Tier (Tier II) analysis was required prior to approval of the project. The Tier II analysis was performed to evaluate the potential health risks associated with benzene emissions from the LRS tower and storage tankage. Based on the refinery's application, benzene emissions exceeded the acceptable source impact level (ASIL) as defined in WAC 173-460 thereby triggering the need for a Tier II analysis along with new source review.

Based on the Tier II analysis, WDOE may approve the emissions of benzene from this project where ambient benzene concentrations exceed the ASIL only if it is determined that the emissions controls represent at least Toxic Best Available Control Technology (T-BACT) and the source demonstrates that the emissions are not likely to result in an increased cancer risk of more than one in one hundred thousand. On the basis, WDOE determined that there was no significant health effects that were expected to occur in individuals exposed in either residences or businesses near the refinery. The ASIL for benzene is 0.12 $\mu g/m^3$. The annual average concentrations of benzene were estimated by the refinery to be 0.28 $\mu g/m^3$ and 0.51 $\mu g/m^3$ at the nearest residence and business, respectively. Emissions of benzene were calculated at 2.53 lb/day of benzene.

On September 7, 1995 the NWCAA granted the refinery approval for the beginning of site preparation work. The refinery was prohibited from actually installing and constructing the LRS tower until an OAC was issued. On January 3, 1996 the NWCAA issued a Conditional Notice of Construction (OAC #562) approving the refinery's application for the construction of a LRS tower and associated equipment.

On February 14, 1996 the refinery requested a change to their notice of construction that would allow the use of larger tanks (Tanks 1 through 16) for storage of the benzene-concentrated LRS tower bottoms. All of the tanks have similar construction and are equipped with emission controls. The refinery also proposed that they would use only one of these sixteen tanks at a time. Emissions were expected to increase slightly as a result of this change. The requested change was incorporated into the Tier II analysis. The NWCAA incorporated this request and revised OAC #562 on February 26, 1996 converting OAC #562 from conditional to final.

DOE issued a Tier II fact sheet on April 26, 1996. Table 3-1 presents a comparison of the estimated values associated with benzene air concentrations to health-based levels.

Table 3.1 - Comparison of LRS Tower Emissions with Health-based Levels

Receptor	Estimated Air Concentration ($\mu g/m^3$)	Health-based Limit for Blood Effects ($\mu g/m^3$)	Health-based Limit for Cancer ($\mu g/m^3$)	Increased Cancer Risk
Residence	0.28	40.0	2.8	3×10^{-6}
Business	0.51	40.0	2.8	4×10^{-6}

Operation of the LRS tower began on May 6, 1996. On August 9, 1996 NWCAA issued an Approval to Operate to the refinery for the light reformate tower and storage scenario.

OAC #562 conditions include:

Condition Number	Description of OAC #562 Conditions
2	Valves, pumps, pressure relief devices, sampling connection system, open-ended valves or lines, and flanges, and other connectors in VOC service are subject to 40 CFR 60 Subpart GGG (LDAR program).
3	Each individual drain system, oil-water separator, or aggregate facility within the process unit is subject to 40 CFR 60 Subpart QQQ.
4	Each source determined to be in benzene service are subject to 40 CFR 61 Subpart J for the National Emission Standards for Equipment Leaks of Benzene.
5	The LRS tower is subject to 40 CFR 61 Subpart FF National Emission Standards for Benzene Waste Operations.
6	Process vents, storage vessels, wastewater streams and treatment operations and equipment leaks are subject to 40 CFR 63 Subpart CC National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.
7	Benzene concentrated light reformate from the LRS tower may be stored in any one of the existing storage vessels identified as Tanks 1 through 16.

Once installed and operating, the refinery determined that through computer operation optimization that the LRS tower bottoms could be further concentrated to 70% wt/wt of benzene from the original 40% wt/wt (October 6, 1999). No changes to the equipment were proposed, and no increase in benzene emissions was anticipated. The refinery re-calculated benzene exposure levels for off-site receptors and determined the increased cancer risk similar to the original calculations. On March 9, 2000 the NWCAA determined that new source review was not triggered as a result of this change and subsequently approved the change in operation.

On March 17, 2003, the NWCAA issued OAC 562b modifying Condition #7. Condition #7 states:

> Condition 7: Benzene concentrated light reformate from the splitter tower may be stored in any one of the existing storage vessels identified as Tanks 1 through 10 and Tank 14. Transfers of the high benzene concentrate between any two of the tanks are allowed to facilitate maintenance and inspection requirements of the tanks.

Crude to Coker Condensate/COUP

Other construction projects affecting the Naphtha HDS were the COUP discussed in Section 3.6 and Crude to Coker Condensate project discussed in Section 3.3. For the Crude to Coker Condensate project, waste heat recovered from the coker drum overhead is used to pre-heat the incoming crude oil. Additional heater firing takes place at several units including the Naphtha HDS and Reformer units. Also, as part of the COUP, heat exchangers and pumps were replaced and a new hot flash drum installed. The COUP triggered regulatory requirements for equipment modified for the Crude to Coker Condensate project. In a letter dated August 8, 1990, the NWCAA determined that the equipment and facilities affected by the Crude to Coker Condensate were subject to 40 CFR 60 Subpart GGG as a result of the COUP.

3.5 Hydrocracker

Hydrocracking is a process that uses temperature, pressure, hydrogen, and catalyst to convert gas oil materials into product streams such as gasoline, blending components, Reformer feeds, and jet fuel. Typically, vacuum gas oil from the crude/vacuum and delayed coker units is reacted with hydrogen under pressure in the presence of a catalyst. Hydrocracking removes sulfur and nitrogen compounds and produces more valuable lower molecular weight hydrocarbons. Butane and refinery fuel gas are by-products of this process.

The refinery's hydrocracker has two stages. The first stage has a hydrogen-rich atmosphere at 700 F in which sulfur compounds are converted to H_2S and nitrogen compounds to NH_3. The effluent from the first stage is "cracked" in the second stage at about 550 F and high pressure. The products from the second stage are processed further in the Reformers and are used in blending fuels.

Major equipment at the Hydrocracker includes R-1 Hydrocracker Reactor Heater, 1st Stage Fractionator Reboiler, and 2nd Stage Fractionator Reboiler. This unit has a number of components in heavy liquid, light liquid and gaseous service that can emit fugitive VOCs and HAPs. Other elements of this unit that may result in emissions to the air include pumps, valves, flanges, vents, sewer line connections and pressure relief devices.

Construction History and Regulatory Applicability

The original hydrocracker unit was built with the refinery in 1970. In 1974/1975 preheaters were installed in the 1st and 2nd Stage Fractionator Reboilers. In support of the construction of the Boiler #4 project, the Hydrocracker 1st Stage Fractionator was modified. Regulatory Order #28 which reference 40 CFR 60 Subpart J limiting fuel gas to 162-ppm H_2S in the heaters is required by 9/30/05. According the refinery's determination, the Hydrocracker is subject to 40 CFR 63 Subpart CC Refinery MACT for Group 1 valves, pumps, and compressors. In addition, the 2nd Stage Fractionator reboilers will be retrofitted with low-NOx burners as part of the Administrative Order on Consent (CAA-10-2001-0096) by May 31, 2004.

Below is a discussion of the modifications.

1st and 2nd Stage Fractionator Reboilers

On October 10, 1974 the refinery submitted an application to install air preheaters on the 1st Stage and 2nd Stage Fractionator Reboilers. The preheaters would improve energy efficiency. The NWCAA issued OAC #148 and #149 on November 13, 1974 for the 1st Stage and 2nd Stage Fractionator Boiler, respectively. Final approval was contingent on emissions form the new equipment "meeting the applicable air pollution control regulations." Emissions would result from the combustion of refinery fuel gas.

In early 2001 the refinery installed 12 skid mounted gas turbine generators to provide affordable and reliable electrical power during a period of predicted high energy prices and power shortages. In order to offset NOx emissions from the gas turbines, BP agreed to install low-NOx burners on the 2nd Stage Fractionator Reboiler Heater at the Hydrocracking Unit. Even though the gas turbines were removed from the plant by July 2002, the project to install the low-NOx burners was completed in early 2005. The operating conditions for this heater were prescribed by OAC #847 and are shown in the table below:

Condition Number	Description of OAC #847 Conditions
1	The heater shall combust only refinery fuel gas and pipeline grade natural gas.
3	The maximum firing rate of the reboiler heater shall not exceed 183.4 MMBtu/hr.
4	Emissions of NOx from the heater shall not exceed 0.07 lb NOx/MMBtu based on a 24-hour average. Emission of NOx shall not exceed 56.2 tons per year on a calendar year rolling average.
5	Perform initial source test for NOx and then periodically every five years

Boiler #4

As part of the installation of #4 Boiler, the refinery proposed to offset increased NOx emissions (27 tons/year) by installing low-NOx burners in the 1st Stage Fractionator Reboiler in the Hydrocracking unit (OAC #351 Condition #12 January 14, 1992). Low-NOx burners were installed during the unit's October 1991 turnaround. On March 7 1994, the NWCAA confirmed that the refinery had met Condition #12 of OAC #351 by installing low-NOx burners in the 1st Stage Fractionator Reboiler.

3.6 Delayed Coker

In many refineries, vacuum tower bottoms are sold as fuel oil. However, the BP Cherry Point Refinery converts vacuum tower bottoms to petroleum coke for off-site sale for electrodes usage. Coking takes place at about 900 F in one of four coker vessels. Vacuum residuum from the crude unit is decomposed (cracked) into lighter fractions by thermal cracking and coking followed by steam stripping and fractionation. The heavy feed is first heated and then charged to large drums that provide the long residence time needed for thermal cracking and coking to proceed to completion. Feedstocks to the coker include slop oil recovered from the API separator and other hydrocarbon sludges and wastes in addition to vacuum tower bottoms. Naphtha and gas oils are produced along with the coke and are routed to other refinery units for processing and finishing.

After coking, the coke is removed from the drums by high pressure steam and water. Coke and water are separated by screens. The water is routed to an API separator where the fine coke particles are recovered and recycled back into the coker. The extracted coke, referred to as "green" coke, is then either calcined in the refinery's Calciner or sold as a final product.

Major equipment at the Delayed Coker includes the North Coker Heater, the South Coker Heater, and Coker Fractionator. This unit has a number of components in heavy liquid, light liquid and gaseous service that can emit fugitive VOCs and HAPs. Other elements of this unit that may result in emissions to the air include pumps, valves, flanges, vents, sewer line connections and pressure relief devices.

Construction History and Regulatory Applicability

The original Delayed Coker was built with the refinery in 1970. Three major projects have been performed on the Delayed Coker since original construction: 1) Crude to Coker Condensate; 2) Coker Olefin Upgrade Project (COUP); and 3) Modification of Coker Unit and #1 and #2 Calciner Hearths. 40 CFR 60 Subpart J limiting fuel gas to 162-ppm H_2S in the heaters is required. According the refinery's determination, the Coker unit is subject to 40 CFR 63 Subpart CC Refinery MACT for Group 1 valves, pumps, and compressors.

The following is a discussion of each project.

Crude to Coker Condensate

In response to the changing characteristics of the feed crude, the refinery proposed to route crude oil directly to the delayed coker on April 4, 1990. Waste heat recovered from the coker drum overhead would be used to pre-heat the crude oil. This description is provided for the sake of completeness. Please refer to the Section 3.3 for a complete description of the Crude to Coker Condensate Project. The NWCAA issued OAC #281 on August 8, 1990 in which NWCAA determined that no permit was necessary.

This project was affected by other refinery modifications. Section 3.6 provides a detailed description of the Coker Olefin Upgrade Project (COUP). In a letter dated August 8, 1990, the NWCAA determined that the equipment and facilities affected by the Crude to Coker Condensate were subject to 40 CFR 60 Subpart GGG as a result of the COUP.

Coker Olefin Upgrade Project (COUP)

In April 1990, the refinery proposed to improve recovery of light portions and naphtha from the delayed coker. At the time of this proposal, coker naphtha from the high pressure separator in the coker was stabilized and routed to the Naphtha HDS unit for the treatment and removal of sulfur compounds. In the new design, the refinery proposed installing equipment at the coker to recover high octane, light coker naphtha streams for gasoline blending.

In support of the changes to the coker, the refinery installed a new dehexanizer downstream of the high pressure separator to recover hexane and lighter portions of the coker naphtha. The lighter portion is then debutanized in the existing coker stabilizer and subsequently processed further in the refinery's new Merox unit (Section 3.11). Minor changes to the Naphtha HDS unit were also required. New heat exchangers, pumps, and the installation of a hot flash drum upstream of the Cold Flash Drum were made.

On May 15, 1990 the NWCAA issued OAC #283 for the COUP. The OAC #283 condition that relates to the Delayed Coker is:

> Condition #2: A VOC monitoring program (LDAR) subject to 40 CFR 60 Subpart GGG will be installed at the Delayed Coker.

The COUP was completed and equipment started up on December 6, 1990.

Coker Unit and #1 and # 2 Calciner Modifications

On December 9, 1998 the refinery notified the NWCAA of proposed modifications to the Delayed Coker and #1 and #2 Calciner Hearths. This project was part of an effort to debottleneck the coker process. When completed, calcined coke production could increase. Additionally, the project would allow for other refinery units to increase production without having to make equipment modifications.

The project would increase the heat capacity of the coker heaters and replace the four coke drums with larger drums. The gas-fired coker heaters would be retrofitted with staged air combustion and flue gas recirculation technology. The refinery's fuel-gas routed to the coker heaters would also be combined with Merox off-gas prior to being combusted in the coker heaters. A new CEM would be installed to separately monitor H_2S concentrations in the fuel-gas and Merox off-gas. The total H_2S concentration in the fuel-gas burned at the coker would be calculated based on the flow weighted average of the H_2S concentrations from the refinery fuel-gas and Merox off-gas.

However, the refinery found the monitoring of the Merox off-gas impractical. As a result, the total H_2S concentration in the fuel gas to the Coker Heaters is determined by calculating the sum of the H_2S in the Coker fuel gas and the H_2S in the Merox fuel-gas. The streams are not flow-weighted because there is no direct measurement method available for the Merox off-gas.

Calciner modifications include increasing the heat capacity of Hearths 1 and of Calciner #1 as well as the requiring BACT of a quencher followed by a wet electrostatic precipitator. Section 3.9 presents a more detailed description of the Calciner modifications.

Emissions from this project included NOx, CO, SO_2, PM, and VOCs. Of these pollutants, only NOx was determined to be above PSD thresholds. The refinery modified the project to include retrofitting the South Vacuum Heater with low-NOx burners to off-set the NOx increase and avoid PSD review. The refinery also proposed to off-set increased SO_2 emissions by installing a DEA scrubber in the Vacuum Tail-Gas Overhead system. As a result, net emission increases were determined by the NWCAA to be below significant thresholds for all criteria pollutants. Section 3.3 presents a detailed description of the Crude/vacuum Unit modifications to the South Vacuum Heater and Tail-Gas Overhead System.

The NWCAA issued OAC #689 on April 13, 1999 for this project. Applicable conditions of OAC #689 for the No 1 and No 2 Coker Charge Heaters are:

Condition Number	Description of OAC #689 Conditions
1.1.1 1.2.1	NOx emissions shall be limited to 0.08 lb/MMBtu (66 tons/year). The refinery to conduct a biennial performance test using USEPA Method 7A or 7E.
1.1.2 2.1.2	SO_2 emissions shall be limited to 101 lb/MMscf (72 tons/year). The refinery to conduct a biennial performance test using USEPA Method 6 or 6C or fuel gas analysis via USEPA Method 11.
1.1.3 2.1.3	CO emissions shall be limited to 29 lb/MMscf (19 tons/year). The refinery to conduct a biennial performance test using USEPA Method 10, 10B, or approve alternative.
1.1.4 2.1.4	Opacity not to exceed 5% over any 6-minute averaging period. The refinery to determine opacity using USEPA Method 9.
1.5.1 2.5.1	Refinery fuel-gas supplied to the coker charge heaters shall be limited to 50 ppmdv of H_2S on a daily average. The refinery to monitor H_2S concentration in the fuel-gas feed to the heaters using USEPA Method 11. Compliance with the 50 ppmdv requirement can be demonstrated by calculating the sum of H_2S concentration in the Merox off-gas routed to the Coker heaters and the H_2S in the Coker fuel gas.

Additionally, OAC #689 specified that the No 1 and No 2 Coker Charge Heaters were subject to 40 CFR 60 Subpart GGG and QQQ along with 40 CFR 60 Subpart VV for LDAR and 40 CFR 63 Subpart CC for the emissions of HAPs.

The entire project was completed by the end of June 1999. The modifications to the Coker charge heaters were completed on June 27, 1999.

3.7 Diesel Hydrodesulfurization (DHDS) Units

3.7.1 #1 DHDS

Similar to the Naphtha HDS process, diesel feed stock from the Crude Unit and Delayed Coker is processed by hydro-desulfurization in the #1 DHDS. Diesel is combined with hydrogen, heated to 500 F and passed over a catalyst to hydrogenate unsaturated chemical bonds and liberate sulfur and other impurities. Typically, organic sulfur compounds are converted to H_2S and organic nitrogen into NH_3. Removal of sulfur from the diesel allows further processing.

Major equipment at the #1 DHDS unit includes the Diesel HDS Charge Heater and the Diesel HDS Stabilizer Reboiler. This unit has a number of components in heavy liquid, light liquid and gaseous service that can emit fugitive VOCs and HAPs. Other elements of this unit that may result in emissions to the air include pumps, valves, flanges, vents, sewer line connections and pressure relief devices.

On March 31, 2006, the NWCAA issued OAC #949 approving BP's #1 DHDS Heater Reliability Project. The project involved installing new ultra-low NOx burners (0.04 lb/MMBtu) on the Charge Heater and Stabilizer Reboiler. The project was completed and the heaters were returned to service on May 20, 2006. A NOx CEM was installed on the Stabilizer Reboiler in order to provide NOx reductions creditable to the required NOx reductions of the 2001 Consent Order. In addition, the Charge Heater and Stabilizer Reboiler each source tested in July 2006 to assure compliance with the NOx and CO limits of OAC #949.

3.7.2 #2 DHDS

Construction of the #2 Diesel Hydrodesulfurization Unit (#2 DHDS) began in early 2005. Construction was completed and the new process unit started up on May 21, 2006.
The addition of the #2 DHDS unit allowed the refinery to produce ultra low-sulfur (15 ppm sulfur) "over the road" diesel. The unit consists of a 25 MMBtu/hour process heater, a reaction section and a fractionation section. In the hydrotreating process sulfur is removed from the diesel, converted to H_2S and sent to the Sulfur Recovery Plant. The #2 DHDS Unit will reduce the sulfur content of the finished diesel product by approximately 5000 tons per year. In March 2005 the NWCAA issued OAC # 892 approving construction of the #2 DHDS unit. The approval order required a number of operating conditions as shown in the table below:

Condition Number	Description of OAC #892 Conditions
1	Fuel combusted in the #2 DHDS Unit Heater shall be limited to pipeline natural gas or treated refinery fuel gas.
3	The H_2S content of the fuel gas combusted in the heater shall not exceed 162 ppmvd based on a 3-hour rolling average or 50 ppmvd based on a 24-hour average.
4	Emissions from the #2 DHDS Unit Heater shall not exceed 0.035 lb NOx/MMBtu or 70 ppmvd CO at 7% O_2. Compliance shall be determined by a initial source testing and annual performance testing thereafter.
6	The unit shall be subject to an enhanced LDAR monitoring program with the leak definitions set at 500 ppm for block valves and control valves and 200o ppm for pumps. LDAR monitoring shall be performed on a quarterly basis.

Construction History and Regulatory Applicability

The #1 DHDS unit was built with the original refinery construction in 1970. Regulatory Order #28 which reference 40 CFR 60 Subpart J and limits refinery fuel gas burned in the #1 DHDS heaters (Charge Heater and Stabilizer Reboiler) to 162-ppm H_2S. According the refinery's determination, the #1 DHDS unit is subject to 40 CFR 63 Subpart CC Refinery MACT for Group 1 valves, pumps, and compressors.

Crude to Coker Condensate/COUP

As discussed in Section 3.3 the refinery proposed to route crude oil directly to the Delayed Coker on April 4, 1990. Waste heat recovered from the coker drum overhead would be used to pre-heat the crude oil. Additional heater firing would take place at the Reformers and Diesel and Naphtha HDS units. The NWCAA issued OAC #281 on August 8, 1990 in which NWCAA determined that no permit was necessary.

This project also affected other refinery modifications. Section 3.6 provides a detailed description of the COUP. In a letter dated August 8, 1990, the NWCAA determined that the equipment and facilities affected by the Crude to Coker Condensate were subject to 40 CFR 60 Subpart GGG as a result of the COUP.

3.8 Hydrogen Plant

There are a number of processes that are not directly involved in the production of hydrocarbon fuels but serve a supporting role. The Hydrogen Plant is one such unit. Refineries with extensive hydrotreating and hydrocracking operations require more hydrogen than is produced by their reforming units.

The refinery used steam reforming of methane to produce hydrogen. This process is accomplished in four steps: reforming, shift conversion, purification, and methanation. Reforming involves the catalytic reaction of methane with steam at high temperature to form CO and H_2. After reforming more steam is adding in a shift conversion liberates additional H_2 from the reaction of CO and H_2O. The third step is gas purification in which CO_2 is absorbed from the H_2 rich gas stream. Finally, the remaining CO and CO_2 in the gas stream are converted back into CH_4 using catalyst and temperatures in the range of 700 F to 800 F.

The major units of the Hydrogen Plant include the catalytic reactors. This unit has a number of components in gaseous service that can emit fugitive VOCs and HAPs. Other elements of this unit that may result in emissions to the air include valves, flanges, vents, sewer line connections and pressure relief devices.

The Hydrogen Plant produces a CO_2 laden vent gas stream that contains methanol (a hazardous air pollutant). A portion this stream is routed to the adjacent Praxair facility for further processing, and the remainder is normally vented to the atmosphere due to processing limitations at Praxair. This off-gas vent is exempt from regulation under Refinery MACT 40 CFR 63 subpart CC through the definition of a “miscellaneous process vent”. Under the MACT definitions found in §63.641, miscellaneous process vents do not include:

> *(14) Hydrogen production plant vents through which carbon dioxide is removed from process streams or through which steam condensate produced or treated within the hydrogen plant is degassed or deaerated.*

Construction History and Regulatory Applicability

The original Hydrogen Plant was built with the refinery in 1970. Regulatory Order #28 which references 40 CFR 60 Subpart J limiting fuel gas to 162-ppm H_2S in the heaters is required by 9/30/05.

3.9 Calciners

Coke calcining is a process used to improve the quality and value of “green coke” produced at the Delayed Coker. Coke is calcined to convert “green” coke to a more valuable “needle” coke and to reduce sulfur and VOC content. The Calciners physically located next to the Delayed Coker to aide transfer of green coke to the Calciner. Green coke from a coking unit arrives by covered belt conveyor to raw coke feeding bins. The bins feed one of three calciner kilns, long tubular rotating hearths, and heat the coke to 2400 F to 2700 F. The calcined coke leaves the kiln and goes through a transfer chute to a water spray cooler. The cooled coke is then conveyed by covered belt to the calcined coke storage barns where it is stored until loadout to rail cars or trucks. Green coke loadout facilities are co-located with the Calciner unit. Waste heat from the Calciner is recovered and used to generate steam. When not in use, the Calciners can be used to generate steam directly. Also, the Calciner also treats wastewater API recovered slop oils as well as recovered coke and coke fines.

Flue gases from the Calciners are routed to one of two stacks. Stack #1 is fed from Calciner Hearths #1 and #2 while Stack #2 is fed from Calciner Hearth #3. Emissions from the Calciner include combustion pollutants such as NOx, CO, VOCs, and SO_2. Because of the nature of calcining, the Calciners are a major source of SO_2 at the refinery. Finally, the fine particulate nature of the green coke and calcined coke also make the Calciners a major source of PM for the refinery.

Major equipment at the Calciners include green coke crusher and storage barn, conveyor system, calcining hearths, calcined coke silos, green coke and calcined coke loadout facilities, green coke unloading system, dust loadout system, wet electrostatic precipitators (WESPs) and baghouses. This unit has a number of components in gaseous service that can emit fugitive VOCs and HAPs. Other elements of this unit that may result in emissions to the air include pumps, valves, flanges, vents, and conveyor system.

Construction History and Regulatory Applicability

The construction and regulatory history of the Calciners is complex and spans the life of the refinery since 1977. Table 3.2 summarizes the construction and permitting activities for the Calciners.

Table 3.2 - Summary of Calciner Construction and Permitting Activities

Date of Approval	Approval	Description
December 16, 1977	OAC #211	Installation of a Calciner facility. Refinery-wide PM emissions limit set at 60 tons per a 31-day month
April 10, 1980	OAC #246	Installation of particulate collection via a baghouse for calcined coke
March 23, 1982	OAC #263	Installation of a baghouse to improve control of particulate emissions from the transferring of calcined coke in the Calciner unit
June 30, 1984	Resolution 129	Establishment of the Calciner "bubble" for particulate matter at 60 tons per a 31-day month for the entire refinery. Calciner stack PM emissions cannot exceed 46.8 tons per year.
September 13, 1984	OAC #293	Installation of two additional calcined coke storage silos equipped with baghouses
November 14 , 1984	OAC #306	Installation of a coke dust loadout facility and a coke dust transport system
December 20, 1984	PSD-3 OAC #299	Construction of a third Calciner and associated equipment including baghouses, material handling equipment, combustion system, flue-gas cleaning and heat recovery systems, and wet electrostatic precipitator (WESP) for BACT.
December 19, 1988	Letter from NWCAA	Installation of two additional baghouses to control fugitive emissions at the coke loadout facility
January 30, 1989	PSD-89-2	PSD-3 rescinded and reissued as PSD-89-2 to include an increase in NOx emission limit from 373 tons per year to 509 tons per year.
October 13, 1993	ERC #14	NWCAA granted and emissions reduction credit of 1548 tons of SO_2 because of the voluntary installation of a Dynaware scrubber on Stack #1. Emission limits for SO_2 set for Stack #1
March 14, 1995	PSD-95-01	In conjunction with PSD-89-2, issue PSD-95-01 to include H_2SO_4 acid mist emissions for the #3 Calciner.
May 23, 1995	RO #011	In lieu of continuous opacity monitoring, operate #1 and #2 Calciner Hearths by monitoring the average O_2 concentration in the radiant section of the hearths and make twice-monthly visual emission observations.
June 30, 1998	RO #018	Source test of Calciner #3 WESP to determine compliance with H_2SO_4 acid mist emissions revised to reflect alternative operating scenarios

Date of Approval	Approval	Description
December 7, 1998	OAC #660	Replace a portion of the existing Dynawave scrubbing system on #1 and #2 Calciner Hearths which share a common Stack, #1, with a wet electrostatic precipitator (WESP)
April 13, 1999	OAC #689	As part of the Coker debottlenecking effort, increase the average coke run in Calciner #1 and #2 Hearths
August 24, 2001	Order of Discontinuance for PSD-3	Control SO_2 emissions from the baghouse for Calciner Hearths #1, #2, and #3.

As shown in Table 3-2, the Calciner was constructed in 1977. In support of the construction effort, the NWCAA and the refinery established a refinery-wide limit on PM emissions at 60 tons per 31-day month. In an effort to consolidate the discussion of the construction and permitting activities, the Calciner unit has been grouped into several categories: Calciner #1 & #2, Calciner #3, and Coke Handling and Storage. The PM emission "bubble" is discussed in Section 2.6. The following is a discussion of each category.

Calciner #1 & #2

Calciner #1 and #2 comprise the original Calciner constructed in 1977 (OAC #211). As part of the conditions of OAC #211, the NWCAA established a refinery-wide emission limit of PM to 60 tons per 31-day month. This limit was based on the emission estimations the refinery provided to the NWCAA as part of the Notice of Construction Application.

During the course of operation of Calciner #1 and #2, it became clear that control of opacity was difficult. Opacity took the form of a blue haze from Stack #1 which served Calciner Hearths #1 and #2. From the mid-1980s to 1998 the refinery attempted to control opacity through controlling various operating parameters including increasing excess oxygen in the hearths. In 1995, the NWCAA issued Regulatory Order #011 granting the refinery permission to monitor the average oxygen concentration in the radiant section of the hearths in lieu of continuous opacity monitoring. Additionally, RO #011 required that the daily average concentration of oxygen shall not exceed 4.0 percent. An exceedance of this limitation would be considered a violation.

In addition to opacity, the refinery acknowledged that SO_2 emissions from the Calciner comprised a significant proportion of the total SO_2 emissions from the refinery. In a voluntary effort, the refinery embarked on a project to install a state-of-the art flue gas desulfurization system referred to as a Dynaware scrubber. The Dynaware scrubber was tested and installed in phases from 1988 to 1993. It was hoped that in addition to achieving reductions in SO_2, that the Dynaware scrubber would alleviate opacity issues. The refinery applied for SO_2 emission credits and was granted credits by the NWCAA of 1,548 tons of SO_2 (Emission Record of Credit (ERC) #14). The ERC #14 also limited SO_2 emissions at Stack #1 at 40 lbs/hr and 175 tons per year.

In 1998, the refinery proposed to install a WESP on Stack #1 to control H_2SO_4 acid mist emissions. The project would install a WESP downstream of the existing quencher and polisher and demolish the existing froth column of the Dynaware system to make room for the WESP. A WESP is based on the principal of imparting an electrical charge on aerosols and solids (together referred to as particulates) suspended in the inlet gas stream. Once polarized or charged, the particulates are drawn out of gas stream to an electrode through electrical attraction. A flushing system periodically removes collected acid mist and particulates. The NWCAA issued OAC #660 on December 7, 1998 for this project. Applicable terms of OAC #660 are:

Condition Number	Description of OAC #660 Conditions
1	Emissions of H_2SO_4 acid mist shall not exceed 15 lbs/hr on a daily average basis.
3	Emissions of SO_2 from Stack #1 are limited to 35 ppmv corrected to 7% O_2 on daily average basis. Compliance will be demonstrated using a CEMS. Total emissions of SO_2 from the stack shall not exceed 175 tons per year.
4	Opacity shall not exceed 20% as measured by Washington State Department of Ecology Method 9B. Compliance shall be determined by monthly tests until a total of six consecutive tests demonstrate compliance with the standard. Upon submission of acceptable test data, opacity testing will be required on an annual basis. Also, NWCAA RO #011 will become void upon submittal of satisfactory test data.
5	PM emissions shall be limited to 0.01 gr/dscf corrected to 7% oxygen. A performance certification test at Stack #1 required to demonstrate compliance.
6	Submit monthly reports that include the Calciner #1 and #2 production data, monthly average, total estimated tone per year of SO_2 emitted from Stack #1, and highest daily average SO_2 concentration in ppmv corrected to 7% oxygen.
7	Report exceedances of the SO_2 limit including the time of occurrence, magnitude of the emissions, duration, probable cause, and corrective actions taken.

The WESP was installed and operating on June 13, 1999. On January 3, 2000, the refinery submitted satisfactory data demonstrating compliance with Condition #4 of OAC #660. As a result, RO #011 was voided by the NWCAA.

Finally, as part of the Coker debottlenecking effort (OAC #689), the refinery proposed to increase the average calcined coke run 28 tons per hour to 38 tons per hour. This increase in processing would require an increase in the heating load of both Calciner Hearths #1 and #2. Emissions from this project included NOx, CO, SO_2, PM, and VOCs. Of these pollutants, only NOx was determined to be above PSD thresholds. The refinery modified the project to include retrofitting the South Vacuum Heater with low-NOx burners to offset the NOx increase and avoid PSD review. The refinery also proposed to offset increased SO_2 emissions by installing a DEA scrubber in the Vacuum Tail-Gas Overhead system. As a result, net emission increases were determined by the NWCAA to be below significant thresholds for all criteria pollutants. Section 3.4 presents a detailed description of the Crude/vacuum Unit modifications to the South Vacuum Heater and Tail-Gas Overhead System.

The NWCAA issued OAC #689 on April 13, 1999 for this project. In developing the emission limits and standards for the Calciner Hearths, the NWCAA also took into consideration the installation of a WESP at Stack #1 (OAC #660), PSD thresholds for PM_{10} and H_2SO_4, and BACT requirements. Applicable conditions of OAC #689 for Calciner Hearths #1 and #2:

Condition Number	Description of OAC #689 Conditions
1.2.1 2.2.1 3.2.1	NOx emissions limited to a daily average of 325 ppmdv, corrected to 7% oxygen. NOx limited to 509 tons on a 12 month rolling average. The refinery shall monitor NOx using a CEM and USEPA Method 7A or 7E. Include NOx emissions on the refinery's monthly report.
1.2.2 2.2.2 3.2.2	SO_2 emissions limited to a daily average of 35 ppmdv, corrected to 7% oxygen. SO_2 emissions limited to 175 tons on a 12-month rolling average. The refinery shall monitor SO_2 using a CEM and USEPA Method 8. Include SO_2 emissions on the refinery's monthly report.
1.2.3 2.2.3	PM_{10} emissions limited to 34 tons per year. The refinery shall monitor PM_{10} using USEPA Method 5 and provide a compliance plan within 6 months after startup.
1.2.4 2.2.4	H_2SO_4 emissions limited to 14 ppmdv, corrected to 7% oxygen. H_2SO_4 emissions limited to 39 tons per year. The refinery shall monitor PM10 using USEPA Method 8 and provide a compliance plan within 6 months after startup.
1.2.5 2.2.5 3.2.5	Opacity limited to 20% in any 6-minute average period. The refinery shall monitor opacity using USEPA Method 9B on a monthly basis. Maintain records of monthly opacity monitoring.

OAC #689 also determined that modified units in the Calciner Hearths #1 and #2 are subject to applicable requirements of 40 CFR 60 Subparts GGG and QQQ as well as 40 CFR 63 Subpart CC and NWCAA 580.

Calciner #3

On September 27, 1984 the refinery proposed to expand their coke calciner capacity with the construction of a new rotary hearth. This would allow the refinery to convert nearly all of its green coke feedstock to a Calciner coke product. The project also included additional baghouses, expanded material handling capacity, silos, a two-stage combustion system, a flue gas cleaning system and stack (Stack #2), and a flue-gas waste heat recovery system.

Emissions from this project include NOx, SO_2, TSP, and CO. Of these pollutants, only CO was below the PSD threshold. Calculated emissions from Stack #2 for NO_x, SO_2, and TSP were 373 tons per year, 504 tons per year, and 26 tons per year, respectively. The refinery determined BACT for this project to be two-staged combustion for NOx, a wet soda ash scrubber for SO_2, and 6-unit WESP and baghouses for TSP. Baghouses would be used on the coke conveyance system while the WESPs would be installed on Stack #2.

The WDOE performed a PSD analysis and created a final determination, PSD-3, on December 20, 1984. Conditions of PSD-3 applicable to the Calciner Hearth #3 and Stack #2 are:

Condition Number	Description of PSD-3 Conditions
1a	Emissions of SO_2 shall be limited to 160 piped, corrected to 7% oxygen, based on a calendar day.
1b	Emissions of PM shall be limited 0.01 gr/sdcf, corrected to 7% oxygen, based on an average if any 60 consecutive minutes.
1c	Emissions of SO_2 shall be limited to 504 tons per year.
1d	Emissions of PM shall be limited to 26 tons per year.
1f	SO_2 removal efficiency shall be a minimum of 90%.
1g	Opacity shall be limited to 20% per Washington State Department of Ecology Method 9B.

After construction was completed and the initial compliance tests conducted on April 7 through 10 of 1987, it became apparent that an error was made in the refinery's application. As a result, the refinery requested changing PSD-3 Condition 1e from a NOx emission limit of 373 tons per year to 509 tons per year. No change in the design or operation of the Calciner was proposed by the refinery. The original BACT analysis for two-staged combustion estimated a NOx concentration of 2.7×10^{-5} lbs/dscf. The actual NOx concentration at the time of the compliance test was lower at 1.9×10^{-5} lbs/dcsf. The refinery contended that since there were no BACT determinations for coke Calciners and the actual emissions may be lower, it was reasonable to assume that BACT had not changed. The WDOE agreed and stated that the refinery still met BACT with the proposed increase in NOx emissions.

As a result, the WDOE rescinded PSD-3 and reissued the PSD determination as PSD-89-2 on January 30, 1989. PSD-89-2 is similar to PSD-3 except for Condition 2e reflecting the NOx emission increase to 509 tons per year. Condition 1 of PSD 89-2 stipulated that the conditions of PSD-89-2 supersede the conditions in PSD-3.

As part of the Calciner #3 compliance plan, the refinery proposed to demonstrate compliance with the 90% SO_2 removal condition by analyzing green coke sulfur and calculating a four week rolling average. The scrubber inlet SO_2 concentration was then calculated from the four week average and the scrubber efficiency calculated from the inlet and outlet concentrations.

On May 20, 1994 the refinery stated that performance test on Calciner Hearth #3 (Stack #2) indicated that the PSD threshold for H_2SO_4 acid mist could be exceeded. The refinery requested the WDOE amend PSD-89-2 as a result. The PSD application indicated that the current BACT employed at Calciner Hearth #2 was the current BACT for controlling the combined emissions of sulfur compounds including SO_2 and H_2SO_4 acid mist. The WDOE created a final determination under PSD-95-01 on March 14, 1995. PSD-95-01 complements PSD 89-2 as stated by the Department of Ecology that the terms and conditions of PSD-89-2 remain in effect.

Applicable conditions for PSD-95-01 are:

Condition Number	Description of PSD-95-01 Conditions
I	Emissions of H_2SO_4 shall not exceed 18.3 lb/hr or 50 mg/m3 in a 24-hour average.
III	Compliance with Condition I will be measured by monitoring the performance of the WESPs plus an annual performance test.
V	Perform annual source test for H_2SO_4 using 40 CFR Appendix A Method 8.

The refinery developed the *Third Hearth Monitoring Plan* which received approval from the NWCAA and WDOE on October 17, 1995. Compliance with Condition I of PSD-95-01 was demonstrated by:

- Measuring the secondary voltage and current on the WESPs. The hearth will be in compliance when at least 4 WESPs are operating with a secondary voltage greater than 50 kV DC and a secondary current greater than 50 milliamps DC and the hearth is not in startup, shutdown, or hot standby. Operation at secondary voltages less than 50 kV DC and/pr 50 milliamps DC during startup, shutdown, or hot standby will also be deemed in compliance.

- The averaging period is 24-hours

- After a turnaround (approximately every two years) the integrity of the WESP units will be determined by running an Air Load Test on each of the units.

- WESPs will be on a scheduled cycle for flushing approximately every 72 hours.

Monthly reports will be provided to NWCAA on WESP operation including operating times; dates and time when the secondary voltage or secondary current was not collected when the unit was operating normally; an explanation of periods when the WESPs secondary voltage and/or secondary current were below compliance requirements when not in startup, shutdown or hot standby; and any time periods and explanation as to why when fewer than 4 WESPs were operating at compliance requirements.

On June 30, 1998 the NWCAA issued Regulatory Order #018 establishing an alternative means of demonstrating compliance with PSD-95-01 Condition I. The Order required the refinery to modify their monitoring plan to include alternative operating conditions, conduct an emissions test according to the revised plan, determine operating conditions that correlate with compliance with PSD-95-01 Condition I, and update the *Third Hearth Monitoring Plan* to reflect the changes in conditions of operating the WESPs at a lower secondary voltage of 40 kV. The refinery performed a compliance test at the 40 kV secondary voltage condition and determined that PSD-95-01 Condition III was met with 4 or more WESPs operating. The NWCAA and WDOE approved the revised monitoring plan on August 26, 1998.

In 1999 during routine maintenance the refinery determined that the lead tubes in the WESPs were stretching and cracking, allowing acid gases to attack the supporting structure of the lead tubes. One of the six WESPs was so damaged that it required replacement. New technology in metals since the construction of the six WESPs on Calciner #3 now allow the WESPs used in acidic service to be constructed of special steel alloys instead, improving maintenance performance. The replaced WESP consists of 238 hexagonal tubes (versus the 98 lead tubes in the old design) and has twice the collection surface area. (Note: this updated WESP design was employed in the WESPs for Calciner Hearths #1 and #2 described previously).

This new design also required different operating conditions. As a result, the *Third Hearth Monitoring Plan* was revised to reflect the difference in operating conditions between the "old" WESPs and the new WESP. Those conditions are:

> Old WESPs (cells 1, 2, 3, 5 & 6): Operate at or above 40 kV secondary voltage and 50 milliamps DC secondary current
>
> New WESP (cell 4): Operate at or above 35 kV secondary voltage and 300 milliamp DC secondary current.

In June of 2000 the refinery again revised the *Third Hearth Monitoring Plan* to reflect proposed changes to the ductwork that would distribute more of the flue-gas from Stack #2 through the new WESP cell 4, thereby taking advantage of the increased surface area. The change would balance the flow to the cells based on their respective surface area. For cells 1, 2, 3, 5, & 6 the tube surface area is 4,362 ft^2. Cell 4, on the other hand, has a surface area of 10,928 ft^2. Hence, cell 4 would treat more than twice as much flue gas as each of the old cells. Because of the increased surface area of cell 4 the refinery proposed to eliminate cell 1. Finally, the flushing frequency was increased to 12 from 48 hours per cell. The *Third Hearth Monitoring Plan* was finalized on January 4, 2001. The NWCAA and the WDOE approved the revised test plan on January 19 2001.

Coke Handling and Storage

After the construction of the original Calciner and Coker, the refinery discovered that during the "debugging" phase of the project there was a dust collection problem and the original system, without revision, would not be able to fully recover dust that was emitted as part of the conveyance and handling of green and calcined coke. On March 1980, the refinery proposed to install 4 additional baghouses (approximately 2,500 cfm at 6-inches water gauge), one on top of each silo. The NWCAA issued OAC #246 in April 1980. OAC #246 required that the refinery install magnahelic gauges to measure the pressure drop across the bags.

On December 7, 1981 the refinery proposed to install an additional baghouse (6,400 cfm) to improve the recovery of dust from transferring calcined coke. The NWCAA issued OAC #263 on April 23, 1992 approving the installation of the baghouse.

The refinery continued its efforts to reduce particulate matter emissions from coke and calcined coke handling in 1983. The refinery proposed to install a calcined coke dust loadout facility that consists of collection equipment and transport equipment located at the Hearth #1 and #2 baghouses, silo baghouse, and calcined coke rail loading baghouse. Recovered calcined coke dust would be pneumatically conveyed to the new coke dust silo located north of green coke crusher and rail loading facility. The transfer system is equipped with a bin vent (with filter bag) to control particulate emissions. The loadout system is designed to minimize dust being emitted to the atmosphere by the application of a slight vacuum on the loading hood and loading from the silo through a 10-inch nozzle in a 60-degree discharge cone of the silo. When this project was proposed, the NWCAA determined that a permit was not required. However, during a NWCAA inspection in June 1985 NWCAA determined that a permit was required. On November 14, 1984 the NWCAA issued OAC #306 for this project.

On August 8, 1984 the refinery proposed to install two additional storage silos to increase the storage of calcined coke and minimize rail service disruptions. Emissions from the silos would be total suspended particulates. One baghouse would be installed to control PM emissions from the two new silos. The baghouse would have a nominal 10,000 cfm capacity with a 6 to 8:1 cloth ratio. The NWCAA issued OAC #293 on September 13, 1986.

As discussed previously the refinery proposed to expand their coke calciner capacity with the construction of a new rotary hearth in 1984 (PSD-3, PSD-89-2, PSD-95-01). This would allow the refinery to convert nearly all of its green coke feedstock to a Calciner coke product. The project also included additional baghouses, expanded material handling capacity, silos, a two-stage combustion system, a flue gas cleaning system and stack (Stack #2), and a flue-gas waste heat recovery system. To control fugitive dust emission from the additional conveyance system and storage silos, the refinery proposed to install 3 new baghouses. According to the proposal these baghouses would be in continuous operation at coke transfer points. The conveyance systems and storage area would be covered. The baghouses are subject to the conditions of PSD 98-2 and PSD-95-01.

In December 1988 the refinery proposed the installation of two new baghouses (5,800 cfm each) installed in conjunction with the existing baghouse (2,800 cfm) at the coke loadout facility. The NWCAA issued a letter dated December 19, 1988 stating that a notice of construction was not required. However, the letter also had the following requirements:

> Condition 2: particulate emissions from the two baghouses shall not exceed 0.02 gr/dscf
>
> Condition 3: Opacity from the baghouse exhaust stacks shall not exceed 10%.
>
> Condition 4: All other points shall not exceed zero (0%) opacity

Finally, on April 9, 2000 the refinery notified the WDOE that a source of SO_2 emissions had been discovered at the refinery that was not anticipated when the Calciner was constructed and permitted. Emissions of SO_2 had been discovered at the stack of the baghouses for Calciners #1, #2, and #3. Baghouses are designed to control particulates and not gaseous pollutants such as SO_2. As a result, the refinery proposed to install BACT to control these emissions. On August 24, 2001 the WDOE issued an Order of Discontinuance of Permit Violation for PSD-3. Conditions of this Order are:

> Condition 1: The refinery shall complete the necessary construction modification to collect all SO_2 emissions from Calciner #3 and route them to the flue gas duct upstream of the wet scrubber by not later than December 31, 2001.
>
> Condition 2: Ecology or designated representative will inspect the modification within 60 days after completion.

The refinery proposed to follow the same approach to controlling SO_2 emission from Calciner #1 and #2.

Construction of the collection system for Calciner #3 was completed on December 21, 2001. The WDOE requested that a representative of the NWCAA perform the visual inspection in accordance with the Order of Discontinuance. On June 23, 2002 the refinery completed installation of BACT on Calciner #1 and #2. For Calciners #1, #2, and #3 the gas streams from the baghouses are routed to waste heat recovery system I.D. fans where SO_2 is removed in the existing caustic scrubber. On October 24, 2002 a representative of NWCAA performed a visual inspection and confirmed the changes.

3.10 Light Ends (LEU)/LPG Unit

The Light Ends Unit (LEU) and Liquefied Petroleum Gas (LPG) Unit produce light hydrocarbon products for commercial or industrial sale. Commercial liquefied gas consists of propane, butane, and mixtures thereof. Other products can include methane for feed stocks to petrochemical plants, butanes for gasoline blending.

In general the LEU processes feed streams by distillation to produce products that are used in gasoline blending or for direct sale. Similarly, the LPG Unit processes feed streams to produce products that are used for refinery fuel gas or for direct sales.

Feed streams to the LPG Unit consist of fuel gas from various refinery processes including crude distillation, catalytic reforming, steam cracking, and coking. The feed streams are compressed and routed through a deethanizer. Methane and ethane overheads are recovered and recycled as refinery fuel gas for use in heaters and boilers throughout the refinery. Bottoms from the deethanizer are routed through a depropanizer from which LPG and butanes are separated. The LPG is then processed to remove residual sulfur containing compounds, dried, and stored in pressure vessels for commercial sale. The butanes are further processed to separate isobutanes from normal butane in debutanizers and depentanizers. A fraction of the recovered butanes are used for blending with gasoline. The remaining butane is sold.

Major equipment at the LEU/LPG Unit pumps, valves, flanges, drains, and compressors along with the deethanizer, depropanizer, debutanizer, and depentanizers. This unit has a number of components in light liquid and gaseous service that can emit fugitive VOCs and HAPs.

Construction History and Regulatory Applicability

The LEU was built with the refinery in 1970. The LPG Unit was built later in 1987. One major project occurred at this unit that affected air emissions: the RVP Phasedown Project. The following is a discussion of the project.

RVP Phasedown Project

In 1990, the refinery proposed to lower the vapor pressure of gasoline as required by federal rules. The project would reduce the maximum Reid Vapor Pressure (RVP) of gasoline from 10.5 psig to 9 psig during the summer months (May through September, inclusive). With the reduction in RVP, less butane can be blended into gasoline and subsequently must be shipped from the refinery for sale.

The project required the refinery to modify three debutanizers into depentanizers at the crude unit, the Hydrocracker, and reformers; add butane/pentane storage spheres; add four butane loading stations; add a new debutanizer tower and associated equipment at the LEU; and increase boiler steam load. Emissions associated with this project included NOx, SOx, PM, and CO from increased boiler steam load and VOCs from the LEU modifications. The refinery proposed to off-set all incremental emission increases related to the RVP Phasedown through other completed projects. The NWCAA reviewed the application and issues OAC #298 on December 4, 1990. Applicable conditions of OAC #298 are:

> Condition 2: New processes and equipment in the LEU shall be subject to 40 CFR 60 Subpart GGG.

The NWCAA also retired accrued emission credits of 81 tons/year of NOx, 5 tons/year of SO_2, 2 tons/year of PM_{10}, 20 tons/year of VOCs, and 2 tons/year of CO. The NWCAA issues a Certificate of Approval to operate to the refinery for the RVP Phasedown project on February 3, 1993.

3.11 Isomerization Unit

The Isomerization Unit is part of an overall refinery project for improving the quality of gasoline produced by the BP Cherry Point Refinery. The Clean Gasoline Project was designed to process light naphtha feedstocks to produce a gasoline blend component that has essentially no benzene, olefins or sulfur and that has a higher octane number than the streams it uses for its feed. The project allows BP Cherry Point Refinery to meet the 2005 federal standard for sulfur in gasoline and decreases the benzene level of all gasoline produced at the refinery.

The Isomerization Unit is comprised of four sub-units: 1) the Naphtha Dehexanizer; 2) IHT Heater; 3) the BenSat™ Unit; and the Penex™ (isomerization) Unit. Additional facilities that are part of the project include connections to existing processes within the refinery and changes in tank services.

An additional boiler (Boiler #5) that replaces Boiler #2 is also part of the project. Boiler #5 was constructed at the previous location of Boiler #2 and is used to supply heat to the dehexanizer tower. In addition to supplying heat to the dehexanizer reboiler, Boiler #5 will provide steam to the BenSat™ , Penex™, and the refinery 600 psig steam system. Boiler #2 was removed from service; however, its stack was used for the new Boiler #5

Construction History and Regulatory Applicability

The Clean Gasoline Project will allow the BP Refinery to reduce the sulfur content and the benzene content of their gasoline products. This will result in lower emissions of SO_2 and hazardous air pollutants (HAPs) from vehicles using their gasolines. This projected was completed in July 2004.

OAC #814a put forth a number of operational requirements for the Isomerization Unit as identified in the following table:

Condition Number	Description of OAC #814a Conditions
1	The IHT Heater shall combust only pipeline grade natural gas, treated refinery fuel gas or a combination of these fuels.
2	Visible emissions from the IHT Heater shall not exceed 5% opacity for more than six minutes in any hour.
3	Fuel combusted in the IHT Heater shall not exceed 162 ppmvd H_2S for a 3-hour rolling average or 50 ppmvd H_2S over a 24-hour rolling average. H_2S shall be monitored continuously per 40 CFR 60 Subpart J.
5	Project components shall be subject to applicable portion of 40 CFR 60 Subpart GGG and 40 CFR 63 Subpart CC (Leak Detection and Repair – LDAR).
6	LDAR shall occur no less frequently than quarterly and use the following leak definitions: 1) 500 ppm for block valves and control valves and 2) 2000 ppm for pumps,

PSD Permit No. PSD-02-04 imposed some additional operating conditions as noted below:

Condition Number	Description of PSD- 02-04 Conditions
1	The Isomerization Heater shall combust only pipeline grade natural gas, treated refinery fuel gas or a combination of these fuels.
2	Emissions of NOx from the IHT Heater shall not exceed 0.10 lb/MMBtu or 0.455 lbs/hr on a calendar day average basis.
4	Emissions of CO from the IHT Heater shall not exceed 70 ppmvd at 7% O_2 or 1.1 lbs/hr on a calendar day average basis.

3.12 Merox Treater

The Merox Treater previously used for mercaptan extraction and sweetening (desulfurizing) of gasoline or lower boiling products has been shut down. The streams such as coker naphtha that were previously were routed to this unit are now sent to the Isomerization Unit where they are converted to high quality gasoline blending components.

3.13 Cooling Towers and Utility Boilers

Cooling towers and utility boilers are located within the Utility process unit along with the flare system. There are two cooling towers at the refinery. The cooling towers are used to cool process water at the refinery. The process hydrocarbon stream does not directly contact the cooling water, instead it is circulated through heat exchangers where heat can either be added or removed from hydrocarbon products through the use of non-contact heat exchangers. The cooling towers can be a source of VOC emissions to the atmosphere if leaks develop in cooling water heat exchangers or condensers.

The utility boilers are housed within the boilerhouse at the refinery. These boilers produce steam that is used throughout the refinery for purposes such as driving steam turbines, pumps, and compressors; heat tanks, heat exchangers, reboilers, and line tracing; separate hydrocarbon mixtures; cooling of process streams and equipment; fight fires by cooling and cutting off the supply of oxygen to the flame.

Refinery boilers typically operate at high pressures (1,500 psig) and high temperatures (1000 F). They are fired by refinery fuel gas or natural gas at the BP Cherry Point Refinery. When fired, heat is liberated and transferred to water in the furnace tubes to produce steam. The steam can also be superheated. Emissions from utility boilers include PM, SO_2, CO, NOx, and VOCs.

Construction History and Regulatory Applicability

Utility Boilers #1, #2, and #3 along with Cooling Tower #1 were constructed with the refinery in 1970. A condition of construction was that the fuel for these boilers be limited to 25% fuel gas and 75% fuel oil containing less than or equal 2.0 %w sulfur. Utility Boilers #1, #2, and #3 covered under Regulatory Order #28 which references 40 CFR 60 Subpart J limiting fuel gas to 162 ppm H_2S in the heaters by 9/30/05. Since 1970, the refinery added Cooling Tower #2 in 1990 and utility Boiler #4 in 1991. The following discusses each project.

Cooling Tower #2

In 1990, the refinery proposed to install an additional cooling tower to address the cooling capacity deficit. The cooling tower has a heat release rate of 500 MMBtu/hr. An increase (7.4 tons/year) in VOCs was estimated for this project. The refinery proposed to offset this increase in VOCs by taking VOC emission credits associated with installation of covering refinery's wastewater API separator. As a result, this project would result in no net increase in VOCs.

The NWCAA reviewed the application and issued a letter date August 23, 1990 granting the refinery authorization to construct Cooling Tower #2. (Note: No OAC number was assigned to this project). In this letter, the NWCAA required that the refinery install and operate a hydrocarbon (LEL) monitor in accordance with manufacturer's specifications and follow NWCAA regulations 365 and 366 for quality assurance. The NWCAA issued a Certificate of Approval to Operate on February 3, 1993.

Utility Boiler #4

On November 14, 1991 the refinery proposed to install an additional utility boiler, Boiler #4, to supply steam in support for the RVP Phasedown project. Boiler #4 would be capable of producing 150,000 lbs/hr of 600 psi steam (216 MMBtu/hr). Emissions from the boiler include 11 tons/year of SO_2, 66 tons/year of NOx, 69 tons/year of CO, 2 tons/year of PM, and 4 tons/year of VOCs. The refinery proposed BACT to be a combination of burning only refinery fuel gas, low-NOx burners and induced flue gas recirculation. Emission of SO_2, NOx, PM, and VOCs would be off-set with emission credits thereby avoiding a PSD determination.

On January 14, 1992 the NWCAA issued OAC #351. The NWCAA noted that only the estimated NOx level exceeded PSD thresholds. As a result, NWCAA required the refinery to only off-set NOx emissions. Conditions of OAC #351 were:

Condition Number	Description of OAC #351 Conditions
2	Opacity from boiler stack shall not exceed 5% opacity for more than 6-minutes in any one-hour period as measured by EPA Method 9.
3	NOx emissions from the boiler stack shall not exceed 35 ppmdv at 7% O_2 and 15.2 lbs/hr (0.07 lb/MMBtu) on an hourly average. and 66 tons per year. Compliance shall be determined by EPA Method 7A or 7E or equivalent method approved by NWCAA.
4	SO_2 emissions from the boiler stack shall not exceed 10 ppmdv at 7% O_2 and 2.6 lbs/hr on an hourly average. Compliance shall be determined by EPA Method 6 or an equivalent method approved by NWCAA.
5	CO emissions from the boiler stack shall not exceed 100 ppmdv at 7% O_2 and 15.8 lbs/hr on an hourly average. Compliance shall be determined by EPA Method 10 or an equivalent method approved by NWCAA.
6	VOC emissions shall not exceed 1 lb/hr.
7	PM_{10} emissions from the boiler stack shall not exceed 0.012 grains/dscf at 7% O_2 and 0.5 lbs/hr. Compliance shall be determined by EPA Method 5 as of July 1 1990, EPA Method 201 or 201A of 40 CFR Part 51 Appendix A as of July 1 1990, or an equivalent method approved by NWCAA.
8	Boiler shall burn only pipeline grade natural gas or refinery fuel gas subject to 40 CFR 60.104(1).
9	A CEMS or equivalent method shall be used to measure NOx emissions. A quality control plan shall be submitted to NWCAA that is consistent with 40 CFR 60 Subpart Db.
10	Develop and follow operation and maintenance manuals for equipment that can affect pollutant emissions to the atmosphere.
11	Conduct a performance test 180-days after startup for NOx, CO, SO_2, VOC, PM10 and opacity.
12	Emission reduction credits in the amount of at least 27 tons shall be used to offset NOx emissions from this project. The credits shall be retired within 180-days of start-up.

Boiler testing started on April 11, 1992. Based on the results of the performance test (OAC #351 Condition #11) the refinery proposed to continuously calculate NOx emissions by correlating stack O_2 concentrations and steam flow rate to NOx emission levels. Results of the testing also revealed that the boiler was not able to meet OAC #351 Condition #5. During testing, the average CO concentration was 126 ppmdv when producing 150,000 lbs/hr of steam, which is above the 100 ppmdv requirement. The 100 ppmdv level for CO was recommended by the manufacturer of the boiler. As a result, the refinery requested that OAC #351 be revised to reflect the actual CO emission level of 126 ppmdv (99.7 tons/year) at a steam production rate of 150,000 lbs/yr. The refinery also agreed to limit boiler operation to 150,000 lb/yr to keep the potential to emit below the 100 tons/yr trigger for PSD review.

On May 28, 1993 the refinery submitted a letter stating that the NOx reductions associated with the 1st Stage Hydrocracker Refractionator reboiler turnaround performed in October 1991 shall be applied towards OAC #351 Condition 12. During the turnaround, low-NOx burners were installed in the 1st Stage Refractionator Reboiler. The estimated NOx reduction was 103 tons/yr. The refinery had not applied to NWCAA for emission credits associated with the NOx reduction. However, the refinery argued that since the turnaround was within the specified 180 days of the April 11, 1992 startup of Boiler #4 the NOx reductions could be credited towards the NOx reduction requirement for Boiler #4.

On June 1 1993 the refinery submitted their continuous emission quality control plan for CO emissions. The refinery proposed emission of CO from Boiler #4 could be calculated based on the steam product rate provided that excess O_2 in the stack be adjusted according to the source test results. As a result, the refinery proposed continuously monitoring the excess O_2 in the stack gas along with steam production rates. A linear correlation was developed that estimated CO emissions.

Also submitted to NWCAA on June 1, 1993 was a refinery study of the ambient CO impacts from Boiler #4. The EPA-approved SCREEN model was used to assess the ambient impacts from Boiler #4's CO emissions. The model calculated that the maximum 1-hour concentration of CO was 20.51 $\mu g/m^3$ and the maximum 8-hour concentration was 14.36 $\mu g/m^3$. Both of these estimated values were below ambient air quality standards and EPA's significant air quality impact levels.

On June 4, 1993 the NWCAA revised OAC #351 to reflect the results of source testing and to incorporate the refinery's revision requests. Because of the extensive changes to OAC #351a, the conditions are restated:

Condition Number	Description of OAC #351a Conditions
2	Opacity from boiler stack shall not exceed 5% opacity for more than 6-minutes in any one-hour period as measured by EPA Method 9.
3	NOx emissions from the boiler stack shall not exceed 35 ppmdv at 7% O_2 and 15.2 lbs/hr (0.07 lb/MMBtu) on an hourly average. Compliance shall be determined by EPA Method 7A or 7E or equivalent method approved by NWCAA.
4	CO emissions from the boiler stack shall not exceed 95 tons/year. Compliance shall be determined by an alternative monitoring method proposed by the refinery and approved by NWCAA. CO emissions shall be tracked continuously and reported to NWCAA in the monthly report.
5	The boiler shall burn only pipeline grade natural gas or refinery fuel gas subject to 40 CFR 60 Subpart J.
6	A CEM or equivalent method approved by NWCAA shall be used to measure NOx emissions. A continuous emission quality control plan shall be submitted to NWCAA for approval prior to start-up consistent with 40 CFR 60 Subpart Db.
7	Develop and follow operation and maintenance manuals for equipment that can affect pollutant emissions to the atmosphere.
8	Conduct a performance test for NOx (EPA Method 7A or 7E) and CO (EPA Method 10) on the boiler stack within 180-days of start-up.
9	The boiler shall not exceed a maximum steam production rate of 160,000 lbs/hr.
10	A contemporaneous decrease in NOx emission shall be realized by the installation of low-NOx burners on the 1st Stage Fractionator Reboiler. The refinery shall document the decrease by a source emission test for NOx in conformance with EPA Method 7A or 7E.
11	Perform a source emission test for NOx and CO in conformance with EPA Method 7A or &e and EPA Method 10 respectively within 180-days of receipt the modified permit.

On August 5, 1993 the refinery proposed to modify Boiler #4. Louvers and burner assembly modifications would aid the refinery in the operations of the boiler, increase steam production rates and balance combustion air in the different burner zones. The modifications would also allow better control of air flow at lower firing rates. Modifications were completed by September 9, 1993.

Source testing was performed in December 1993 in accordance with OAC #351a Condition 11. Results of the stack testing revealed that changes made to Boiler #4 resulted in lower emission rates for CO (measured at 29.1 tons per year) and that NOx emission rates were below the NOx requirement listed in OAC #351a Condition 3. The refinery requested the NWCAA to again revise OAC #351 to:

- Eliminate the inconsistency of the 35 ppmv NOx versus 0.07 lb/MMBtu requirement;
- Eliminate the need for continuous monitoring of CO since the CO emission rates were no longer near the 100 ton/year PSD threshold;
- Eliminate Condition 9 since the NOx emission level can now be met at all firing levels above 160,000 lbs/hr for steam production.

In conjunction with the source test, the NWCAA reviewed the source tests performed on the Hydrocracker 1st Stage Refractionator Reboiler to determine compliance with OAC #351a Condition 10. On March 7, 1994 the NWCAA agreed with the refinery that the NOx emission reductions at the 1st Stage Refractionator Reboiler (determined to be 91 tons/year) was proof that the refinery had complied with OAC #351 Condition 12. (Note: this condition was revised to OAC #351a Condition 10).

On April 11, 1994 the NWCAA revised OAC #351a to reflect the emissions related to the Boiler #4 modifications and NOx emission credits. Revised conditions of OAC #351b are:

Condition Number	Description of OAC #351b Conditions
3	NOx emissions from the boiler stack shall not exceed 0.07 lb/MMBtu on a monthly average. NOx emissions from the boiler stack shall not exceed 66 tons per year.
4	CO emissions from the boiler stack shall not exceed 95 tons/year. A continuous emission monitor or an equivalent method approved by the Control Officer shall be used to measure CO emissions.
10	The refinery shall submit a monthly emission report that lists monthly mass emissions of NOx and CO from the #4 Boiler.

Condition #10 of OAC #351a was deleted.

The refinery selected to meet Condition #4 of OAC #351b through the use of a predictive method previously discussed. Additionally, the refinery selected to meet Condition #6 of OAC #351b through the continued use of a predictive method for NOx emissions monitoring.

On October 19, 1999 the NWCAA revised OAC #351b to eliminate the need for continuous emission monitoring for CO and the yearly CO emission rate. The NWCAA believed that the modifications made to Boiler #4 in 1993 justified the deletion of the CO emission requirements. On June 28, 2002 the NWCAA revised OAC #351c to delete the superfluous requirement for a performance test to determine CO emissions within 180-days of startup. This change was considered cosmetic and reflects the current status of Boiler #4. For the purposes of completeness the terms of OAC #351d for Boiler #4 are as follows:

Condition Number	Description of OAC #351d Conditions
2	Opacity from boiler stack shall not exceed 5% opacity for more than 6-minutes in any one-hour period as measured by EPA Method 9.
3	NOx emissions from the boiler stack shall not exceed 0.07 lb/MMBtu on a monthly average. NOx emissions from the boiler stack shall not exceed 66 tons per year.
4	The boiler shall burn only pipeline grade natural gas or refinery fuel gas (<162 ppm H_2S) subject to 40 CFR 60 Subpart J.
5	A CEM or equivalent method approved by NWCAA shall be used to measure NOx emissions. A continuous emission quality control plan shall be submitted to NWCAA for approval prior to start-up consistent with 40 CFR 60 Subpart Db.
6	Develop and follow operation and maintenance manuals for equipment that can affect pollutant emissions to the atmosphere.
7	Conduct a performance test for NOx (EPA Method 7E) on the boiler stack to determine compliance with Condition #3 within 180-days of start-up.
8	A contemporaneous decrease in NOx emissions of at least 27 tons/yr shall be realized by the installation of low-NOx burners on the 1st Stage Fractionator Reboiler. The refinery shall document the decrease by a source emission test for NOx in conformance with EPA Method 7A or 7E.
9	The refinery shall submit a monthly emission report that lists monthly mass emission of NOx from #4 Boiler.

Utility Boiler #5

The Isomerization Project and to a lesser extent the #2 Diesel HDU required additional steam heating requirements above what the existing boilers at the refinery could provide. Therefore, Boiler #5 was proposed as part of the Isomerization Unit (Clean Gasoline) Project. The boiler was designed for a heat input of 363 MMBtu/hr and was constructed so that it could use the existing #2 Boiler stack. The #2 Boiler which was located at the same site was shut down and has been demolished. The entire project, but primarily because of #5 Boiler, was determined to have “significant” emissions greater than 40 tons per year of NOx and 100 tons per year of CO, and, therefore, subject to PSD permitting.

After review of emissions for the project and developing a BACT determination, the WDOE issued PSD-02-04 in May 2003. After a review of the boiler design criteria, it was determined that the boiler could not meet the operating limits in the PSD permit throughout the entire operating range. WDOE modified the PSD permit and issued Amendment 1 to the permit in May 2005. The amendment modified NOx and CO emission limits and added boiler startup conditions along with other minor changes to the original PSD permit. The new operating conditions for Boiler #5 are provided in the following table.

Condition Number	Description of PSD-02-04 Amendment 1 Conditions
1	The boiler shall be fueled by either natural gas or refinery fuel gas and monitored by a maintaining a written log of the fuel used.
3	Emissions of NOx from the boiler shall not exceed 10.1 lbs/hr on a calendar day average. Continuous compliance shall be monitored by a CEM for NOx and O_2.
5	CO emissions shall not exceed 18.1 lbs/hr on a calendar day average. Continuous compliance shall be monitored by a CEM for CO and O_2.
6	Emission limits are relieved during startup periods, and CO shall be limited to 50 lbs/hr averaged over the startup period.

Additional operating conditions for the #5 Boiler were imposed by OAC #814a issued by NWCAA on March 24, 2005. These are outlined in the table below:

Condition Number	Description of PSD-02-04 Amendment 1 Conditions
2	Fuel combusted in the boiler shall not exceed 162 ppm H_2S on a 3-hour rolling average or 50 ppm on a 24-hour rolling average.

3.14 Flares

Another part of the Utility process unit is the flare system. The flare system thermally destroys gases of various flow rates and compositions. It also destroys gases released during upsets, malfunctions, and routine operations.

There are two flares at the refinery. They are control devices necessary for the safe operation of the refinery and can alternate service. The High Pressure flare is connected to higher pressure, higher volume units such as the Hydrocracker unit. The Low Pressure flare is connected to the lower pressure, lower volume units such as the LPG unit. The flares are designed to handle a wide range of flow rates including emergency releases of refinery gases in the event that a unit shuts down or controlled releases of gases when a single piece of equipment is shutdown for maintenance. The flares are equipped with recovery compressors to capture the maximum amount of gases possible which are then recovered and treated to remove H_2S and recycled to the refinery fuel gas system. Steam is injected (steam-assisted) at each flare tip to create turbulence needed to enhance mixing of flared hydrocarbon gases with ambient air for better combustion. When done properly, visible emissions from flaring are kept below 20%.

Major equipment for this unit are the High Pressure Flare, Low Pressure Flare, recovery compressors, pumps, valves, flanges and drains. Emissions associated with the flares include VOCs, PM, HAPs and SO_2.

<u>Construction History and Regulatory Applicability</u>

Both flares were installed during the original construction of the refinery in 1970. A design analysis was completed on the flares and submitted to the NWCAA as part of the source's Refinery MACT Initial Notification of Compliance Status Report submitted in January 1999. The report satisfied the initial performance test requirements for each flare in accordance with 40 CFR 60 Subpart A, 60.18

and 40 CFR 63 Subpart A, 63.11. The analysis was required because the refinery uses the flares as control devices for Refinery MACT Group 1 process vents and for control of leaks from pump seals regulated under Refinery MACT equipment leaks in HAP service. NSPS provisions are required because the flares were built or rebuilt after the NSPS Subpart J applicability trigger date of June 11, 1973.

3.15 Sulfur Complex

The sulfur complex is comprised of several units: DEA Unit, Sour Water Stripper, sulfur recovery unit (SRU), Tail Gas Unit, and sulfur storage tanks and pits. The sulfur complex is designed to destroy NH_3 and process H_2S as well as other sulfur containing compounds by converting them into elemental sulfur that can be sold. The SRU is composed of two trains, North and South. A single Tail Gas Unit serves both trains.

Alaskan crude oil contains significant amounts of sulfur compounds. Hydrodesulfurization and hydrocracking convert much of the sulfur into H_2S. Some of the H_2S is dissolved in water and is treated in the sour water stripper. However, much of the H_2S goes to the refinery fuel gas system. H_2S is removed from the refinery fuel gas system by passing the fuel gas through a DEA unit (DEA units are located at the Coker, Hydrocacker, Naphtha HDS, Diesel HDS, LEU, Sour Water and Flare Gas recovery units). DEA absorbs H_2S, extracting it from the untreated fuel-gas. The absorbed H_2S creates a rich DEA mixture that is regenerated using steam. At the DEA Unit concentrated H_2S is liberated and the H_2S-laden stream is routed to the Sulfur Recovery unit where elemental sulfur is made.

As mentioned previously, another source of H_2S at the refinery is sour water. The Sour Water Unit collects water throughout the refinery known to contain H_2S as well as NH_3. H_2S and NH_3 are stripped from the water in the Sour Water Unit. The removed H_2S and NH_3 are routed to the SRU for further treatment.

The SRU converts the recovered and stripped H_2S into elemental sulfur using a catalytic reaction generically referred to as the Claus process. Typically, one third of the H_2S is oxidized to SO_2 with air while the remaining H_2S reacts with SO_2 to form elemental sulfur. NH_3 is destroyed as part of this process (taking the form of N_2). The hot gases are fed though waste heat boilers in which steam is generated and gases cooled. The cooled gases are routed through sulfur condensers in which the elemental sulfur is removed and sent to sulfur tanks and/or sulfur pits for storage.

However, the Claus process is not 100% complete. As a result the remaining gas, referred to as tail-gas, is treated in the Tail Gas Unit. The Tail Gas Unit is designed to recover and recycle H_2S from the SRU and then to combust residual gases. The Tail Gas Unit recovers sulfur using three processes: hydrogenation, hydrolysis, and H_2S absorption. Untreated tail gas undergoes hydrogenation and hydrolysis in which SO_2 and other sulfur compounds are converted into H_2S. The newly formed H_2S is then absorbed in using counter-current extractor of methyl-diethanolamine (MDEA). The rich MDEA is regenerated, and the absorbed H_2S is routed to the SRU. The H_2S not recovered by the Tail Gas Unit is oxidized to SO_2 during combustion.

Major equipment at the Sulfur Complex includes: DEA Unit, sour water stripper and associated tankage; SRU; Tail Gas Unit; sulfur storage tanks; sulfur pits. Emissions from the sulfur complex are primarily SO_2. However, emission of NOx, CO, PM_{10}, VOCs and HAPs also occur. This unit has a number of components in gaseous service that can emit fugitive VOCs and HAPs. Other elements of this unit that may result in emissions to the air include pumps, valves, flanges, vents, compressors, sewer line connections and pressure relief devices.

Construction History and Regulatory Applicability

The sulfur complex was built along with the original refinery in 1970. The Tail Gas Unit was added to the Sulfur Complex in 1975. Because of the dates on construction for the Sulfur Complex and Tail Gas Unit, the regulatory requirements associated with this unit are driven by the 1974 variance issued by the NWCAA and Regulatory Order #28. Also, according the refinery's determination, the Sulfur Complex is subject to 40 CFR 63 Subpart CC Refinery MACT for Group 1 valves, pumps, and compressors. The Sulfur Complex is subject to 40 CFR 63 Subpart UUU National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units by the April 11, 2005 compliance date. The following is a discussion of the Tail Gas Unit variance, sulfur tank installation, and the requirements of Regulatory Order #28 as they relate to the construction and regulatory applicability of the Sulfur Complex.

#1 and #2 Tail Gas Units

On March 13, 1974 the NWCAA granted the refinery a variance from NWCAA 462 that allowed the refinery to operate the Sulfur Complex incinerator until a new tail gas modification could be installed. The expiration date for this variance was July 1, 1977. By June 28, 1977 the refinery submitted to the NWCAA atmospheric emission compliance test results to NWCAA. The results demonstrated that SO_2 emissions from the tail gas modification were less than the 1000 ppm standard – NWCAA 462. As a result, the NWCAA issued an unnumbered OAC dated June 30, 1977 listing the following terms for operating the tail gas unit and Sulfur Complex:

Condition Number	Description of OAC Dated June 30, 1977 Conditions
1	The sulfur plant is not to be operated at greater than 127 long tons per day of elemental sulfur production. If at future time the sulfur plant can be operated at a higher capacity, it will be necessary for the refinery to demonstrate that the tail gas SO_2 emissions will be less than the 1000 ppm emission standard.
2	Determine the ambient SO_2 emission concentration from the tail gas stack.
3	Conduct a SO_2 source emission test on the sulfur plant stack in approximately six months after startup of the tail gas facility and at least annually thereafter provided these test indicate compliance with the SO_2 emission standard.
4	Submit as part of the monthly sulfur compound emission report, a summary of sulfur plant SO_2 emissions to the atmosphere in ppmv corrected to 7% oxygen. This report is to include the monthly average, highest value, and all concentrations that exceed the 1000 ppmv standard. If the standard was exceeded during a startup, shutdown or upset condition, this fact is to be noted on the report and correlated with the emission that exceeded the standard.

The refinery demonstrated compliance with Condition #2 by correlating SO_2 concentrations in the tail gas stack with H_2S concentrations continuously measured at AR-2. The NWCAA preferred for the refinery to install a continuous SO_2 monitor on the tail gas stack but accepted the alternative compliance method.

On July 9, 1990 the NWCAA granted the refinery permission to increase their operating capacity of long tons of elemental sulfur. Permission was granted until a SO_2 analyzer could be installed at the tail gas stack. On February 27, 1995, the NWCAA confirmed that the refinery has installed a certified SO_2 analyzer on the tail gas stack. As a result, the NWCAA removed the elemental sulfur production limit. The NWCAA did determine that the tail gas stack was subject to the NWCAA 462 standard of 1000 ppm SO_2 corrected to 7% oxygen. The limit became into effect for the Sulfur Complex on March 1, 1995.

In late 2004 the facility requested and was granted approval to install a second tail gas treating unit (#2 TGU). The primary driver for this action was Condition 21 of the Consent Decree between BP West Coast Products and it predecessor companies (ARCO) and EPA and NWCAA. The provisions of the Consent Decree required the refinery to install a second (backup) tail gas treating unit at the Sulfur Recovery Unit by the end of 2006 to consistently meet the requirements of 40 CFR 60 Subpart J. The new #2 TGU will employ proprietary Cansolv® gas/liquid absorption technology and will provide process redundancy and eliminate acid gas flaring during tail gas unit maintenance activities. Subpart J imposes a limit of 250 ppmvd SO_2 at 0% excess air for discharge of gases from a Claus sulfur recovery plant. The operating requirements were provided in OAC #890a issued by NWCAA on February 22, 2005. The table below shows the major operating conditions.

Condition Number	Description of OAC #890a Conditions
1	Supplemental fuel to the #2 TGU shall be pipeline natural gas.
3	Sulfur emissions from #1 TGU and #2 TGU shall not exceed 250 ppmvd corrected to 0% oxygen based on a 12-hour rolling average or 1500 ppmvd corrected to 0% oxygen based on a 1-hour rolling average. Compliance shall be determined by a CEM installed, calibrated, maintained and operated on each tail gas unit stack.
4	Total tons of SO_2 emitted from the SRU shall not exceed 135 tons on a 12-month rolling average.
5	Emissions from the #2 TGU stack shall not exceed any of the following emissions rates: 24 lbs/hr SO_2; 2.5 lbs/hr NOx; 3.9lbs/hr CO; 1.23 lbs/hr H_2SO_4 and 0.43 lbs/hr of H_2S. Compliance shall be demonstrated by conducting an initial performance test under maximum operating rates that are at or above 80% of full capacity.
7	Emissions form the elemental sulfur storage pits at the SRU shall be controlled through a closed vent system that is routed to a device capable of meeting the emission limits and monitoring requirements of condition 3, above.

Additional Sulfur Tank

In May of 1984 the refinery proposed to install an additional sulfur storage tank, similar to the existing tank, at the Sulfur Complex. The additional tank was needed to support the increased demand for elemental sulfur in the market. The refinery did not plan to increase sulfur production rates as a result of this new tank. The refinery identified that emissions associated with the new tank was H_2S. The NWCAA approved the project and issued OAC #290 on June 14, 1984.

Regulatory Order #28

The refinery is required to make several physical modifications to the Sulfur Complex as per the NWCAA issued Regulatory Order #28 on May 15, 2002. The modifications are:

- Reroute the vent from the sour water stripper tank from the sulfur recovery plant incinerator to some other point upstream of the sulfur recovery plant no later than 18-months after 1/17/01.
- Install either a second tail gas unit or equivalent control technology to ensure compliance with 40 CFR 60 Subpart J. This requirement becomes effective by the end of the turnaround in 2006.
- All sulfur pit emissions shall be treated, monitored, and included as part of the Sulfur Complex emissions which are subject to 40 CFR 60 Subpart J limit of SO_2 no later than the first turnaround after 1/18/01 of the Claus train.

- Emissions of SO_2 shall not exceed 250 ppmv on a dry basis and 0% O_2 except for periods of startup, shutdown, or malfunction of the SRU or malfunction of the tail gas unit no later than end of the turnaround in 2006.

Additionally, the refinery is required to be in compliance with 40 CFR 60 Subpart J except during periods of startup, shutdown or malfunction of Sulfur Complex or malfunction of the Tail Gas Unit.

The refinery rerouted the vent from the sour water stripper tank on July 18, 2002.

Upon startup of the #2 TGU in July 2006, OAC #890a condition 12 voided part II of Regulatory Order #28 for all conditions in the Regulatory Order related to the sulfur plant. Instead, these, or similar requirements to control sulfur pit emissions and control TGU emissions to 40 CFR 60 subpart J limitations are prescribed in the OAC.

#1 TGU uses refinery fuel gas from the refinery's main mix drum as supplemental fuel for the incinerator stack. Therefore, 40 CFR 60 subpart J that limits the sulfur content of refinery fuel gas applies to this combustion device. It is noted however, that the thermal oxidizer on #2 TGU that converts the feed stream to SO_2 prior to diamine adsorption is fired by natural gas. Therefore, the fuel quality provisions of 40 CFR 60 subpart J do not apply to this combustion device because it does not burn refinery fuel gas.

3.16 Wastewater Treatment

The Wastewater Treatment plant (WWT) treats oil-contaminated wastewater from the refinery that is routed through the process water sewer system. Sources of oily water include catch basins located under processing units, storage tank drains, and ballast water from ships and barges. Oily water and storm water are drained to the wastewater from the process units through separate sewers. Sanitary sewage is pumped to Birch Bay for treatment. Oil that is recovered at the Effluent Plant is sent back to the Refinery for processing. Treated wastewater is discharged into the Georgia Straight.

The WWT is designed to handle abrupt changes in flow while still separating water, oil, and solids. It employs flow equalization, settling, floatation, skimming, clarification and enhanced biological treatment. The API Separators collect wastewaters from a variety of areas including process units, laboratory samples, tank farm, and certain remediation wastes. Ship ballast is routed through Tank 320 for flow equalization and then routed to the API Separators. Additionally, vacuum trucks throughout the refinery can discharge through dewatering operations wastewater to the API Separators.

At the API Separators, oils, solids, and water are separated through setting and skimming. Recovered oils are stored in Tanks 321, 322 and 26 prior to being sent back into the refinery. Settled solids are routed to the sludge holding area then dewatered. The water portion from the API Separators is stored in Tanks 323 and/or 320 for flow equalization prior to being treated in the enhanced biodegradation unit then discharged to the Georgia Straight. Biosolids from the biodegradation unit are produced and dewatered as necessary.

Major equipment at the WWT include: Sewers, forebay, API Separators; Tanks 320, 321, 322, 323; carbon canisters; enhanced biodegradation unit; and biosolids handling. Waste streams in each process unit are managed in individual drain systems that contain water seals. Tank water draws and remediation wastes are managed in controlled individual drain system. All individual drain systems are connected to common API Separators (4) where vapors are controlled with carbon canisters. There are 12 adsorbers, six of which are on-line and six which serve as spares when breakthrough is detected on the primary units. All tanks that managed benzene waste streams are controlled with floating roofs. Waste streams that are managed in vacuum trucks are discharged into controlled tanks. All benzene waste streams are controlled except for one remediation waste stream and a small quantity that is transferred off-site or to the land farm. The remediation waste stream flows into a controlled system. Pollutants associated with the WWT are primarily VOCs and HAPs including benzene. Other components that are sources of emissions include valves, flanges, seals, and drains.

Construction History and Regulatory Applicability

The majority of the WWT was constructed with the original refinery in 1970. In 1991, the refinery was required to become into compliance with 40 CFR 61 Subpart FF National Emission Standards for Benzene Waste Operations. The refinery's TAB of 32 tons/yr was above the 10 Mg/yr threshold listed in 40 CFR 61 Subpart FF.

The refinery complies with 40 CFR 61 Subpart FF through the requirements of 40 CFR 61.342(c)(3)(ii). This standard requires that the refinery can exempt waste streams by demonstrating that initially and at least once a year thereafter that the either:

A) The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gpm) or an annual wastewater quantity of less than 11 tons/year; or

B) The total annual benzene quantity in all waste streams chosen for exemption does not exceed 2.0 Mg/yr (2.2 tons/year) as determined by 40 CFR 61.355(j); and
that stream selected for exemption, including process turnaround waste, is determined for the year in which the waste is generated.

In addition to 40 CFR 61 Subpart FF, there are wastewater drains that were built after the NSPS applicability date of May 4, 1987, thereby triggering 40 CFR 60 Subpart QQQ requirements for VOC control. These include process drains at the Crude/Vacuum Unit (OAC #640). Downstream of these NSPS drains, the wastewater enters a sewer system controlled under 40 CFR 61 Subpart FF. Through an overlap provision, Refinery MACT 63.640(o) allows for consolidation of wastewater programs by stating that "a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR part 60, subpart QQQ is required to comply only with this subpart." In Refinery MACT, a Group 1 wastewater stream is equivalent to the definition of a benzene waste stream found in 40 CFR 61 Subpart FF. Therefore Subpart FF becomes the single applicable standard. The majority of changes to the WWT have been driven by compliance with 40 CFR 61 Subpart FF. The following is a discussion of those changes.

API Separator Covers.

On September 15, 1989 the refinery proposed to voluntarily install floating covers on the forebays of the API separators and main channels in order to reduce the level of VOC emissions. The refinery estimated that VOC emission could be reduce by 2,543 tons per year at the API Separators and 636 tons per year by the main channel floating covers. On April 17, 1990 the NWCAA issued OAC #272 approving the floating roof modifications for the API Separators. On March 6, 1991 the NWCAA issued a Certificate of Approval to Operate to the refinery for this project.

Wastewater System Benzene NESHAP Modifications

On October 23, 1991 the refinery submitted their application to make modifications to the WWT in order comply with 40 CFR 61 Subpart FF. The refinery had selected the option to comply with this regulation by sealing the collection and treatment system from each drain system up to the activated sludge treatment unit. The activated sludge treatment unit met the definition of enhanced biological degradation and was therefore exempt from the regulation. Proposed changes to the WWT included:

- All process water systems: Seal manhole cover; install seals on tank drains with rubber boots or seal enclosures with hatches; install sealed pop-up vents on junction boxes.
- API Separators: Install fixed covers with sealed openings; install carbon filters to collect vapors.
- API Pump Sump: Install a combination of fixed and floating covers; install and operate carbon filters to collect vapors.
- Secondary API Separators: Install fixed covers with sealed openings; install carbon filters to collect vapors.
- Skim Oil Pump: Install floating covers.
- Recovered Oil Tanks: Install internal floating roof tanks – Tanks 320, 321 & 322.
- Oily Water Surge Tank: Install an internal floating roof.
- Ballast Water Tank: Install an internal floating roof – Tank 323
- Trickle Filter: remove the trickle filter form service.

On January 8, 1992 the NWCAA issued OAC #348 authorizing the refinery to construct the proposed project. The terms of OAC #348 are:

Condition Number	Description of OAC #348 Conditions
2	All internal floating roof tanks including the recovered oil tanks, the oily water surge tank, and the ballast water tank shall be installed with primary seals as required by 40 CFR 60.112b(2).
3	The primary and secondary API separators shall be subject to the requirements of 40 CFR 61.347.
4	The process water sewer system shall be subject to 40 CFR 61.346.
5	The skim oil sump and the API pump sump shall be subject to 40 CFR 61.343.
6	All closed vent systems shall be subject to the emission control requirements of 40 CFR 61.349(a)(1).
7	Operation of the additions and modifications to the process sewer system and the wastewater treatment plant shall be subject to the appropriate sections of 40 CFR 61.350, 61.354, 61.355, 61.356, and 61.357.

Tanks 320, 321, 322, and 323 are equipped with a fixed roof and internal floating roof in accordance with the requirements of 40 CFR 61.351. Individual drains were originally constructed with water seal controls (p-traps). Tank water draws on affected tanks in the storage and handling area are fitted with an air tight boot connecting the drain hub and tank nozzle. All tank drains are equipped with P-traps. All process sewer clean out manhole and junction box covers are plugged and sealed.

The oil water separators have been fitted with a combination of fixed and floating roof covers. Fixed covers are installed on all parts except for the API effluent sumps. All fixed covers on the API separators are vented to carbon absorber control systems through a closed vent system.

The wastewater from the API separators enters the aeration basins of an activated sludge process. The aeration basin is an exempt unit according to 40 CFR 61.348(b). The activated sludge system meets the definition of an enhanced biodegradation unit.

All required controls are presently in place and operating. In accordance with 40 CFR 61 Subpart FF, seals on the API covers are visually inspected on a quarterly basis and instrument monitored annually for leaks greater than 500 ppm. Activated carbon beds are monitored for breakthrough (500 ppm) at a frequency that is based on 20% of the carbon bed's estimated life expectancy. Monitoring is encouraged to be done on a more frequent basis, especially when abnormal conditions occur at the refinery that would warrant additional attention potential breakthrough.

3.17 Tanks and Storage Vessels

There are a variety of tanks located at the refinery. Tankage with internal floating roofs include Tanks #'s 1 through 27, 29, 31, 33, 41 through 50, and 71 through 74. Tankage with fixed roofs includes Tanks #'s 28, 30, 32, 34, 37, 38, and 70. The majority of the tanks are located at the Tank Farm which houses tanks that store crude oil, feed for process units, intermediate products, blending components, and finished products.

Construction History and Regulatory Applicability

Table 3-3 presents the construction history of the tanks and storage vessels at the refinery.

Table 3-3: Construction History of Tanks and Storage Vessels

Tank #	Tank Service (Typical Contents)	Constructed /Modified	Comments
1	Hydrocarbon, Petroleum Products- Light Reformate Benzene Storage	1970	Group 1, OAC #562b
2	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 1, OAC #562b
3	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 1, OAC #562b
4	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 1, OAC #562b
5	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 1, OAC #562b
6	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 1, OAC #562b
7	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 1, OAC #562b
8	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 1, OAC #562b
9	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 1, OAC #562b
10	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 1, OAC #562b
11	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 2

Tank #	Tank Service (Typical Contents)	Constructed /Modified	Comments
12	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 2
13	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 2
14	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 1, OAC #562b
15	Hydrocarbon, Petroleum Products	1970	Group 2
16	Hydrocarbon, Petroleum Products - Light Reformate Benzene Storage	1970	Group 2
17	Hydrocarbon, Petroleum Products	1970	Group 1
18	Hydrocarbon, Petroleum Products	1970	Group 1
19	Hydrocarbon, Petroleum Products	1970	Group 2
20	Hydrocarbon, Petroleum Products	1970	Group 2
21	Hydrocarbon, Petroleum Products	1970	Group 1
22	Hydrocarbon, Petroleum Products	1975	Group 2, Subpart K (Service change to Group 1 – 6/06)
23	Hydrocarbon, Petroleum Products	1970	Group 2
24	Finished Diesel or Gasoline. True Vapor Pressure ≤11.1 psia.	1994	Subpart Kb, OAC #453b
25	Hydrocarbon, Petroleum Products	1970	Group 1
26	Hydrocarbon, Petroleum Products	1970	Group 1
27	Hydrocarbon, Petroleum Products	1970	Group 1
28	True Vapor Pressure of Stored Material must be <1.5 psia.– Coker Feed	1970	Group 2, fixed roof tank with no internal floating roof
29	Hydrocarbon, Petroleum Products	1970	Group 2
30	True Vapor Pressure of Stored Material must be <1.5 psia.– Coker Heavy Gas Oil	1970	Group 2, fixed roof tank with no internal floating roof
31	Hydrocarbon, Petroleum Products	1970	Group 1
32	True Vapor Pressure of Stored Material must be <1.5 psia.– Coker Feed	1970	Group 2, fixed roof tank with no internal floating roof
33	Hydrocarbon, Petroleum Products	1970	Group 2
34	True Vapor Pressure of Stored Material must be <1.5 psia.- Diesel	1970	Group 2, fixed roof tank with no internal floating roof
35	Hydrocarbon, Petroleum Products	1990	Volume threshold below Kb
36	Hydrocarbon, Petroleum Products	1990	Volume threshold below Kb
37	True Vapor Pressure of Stored Material must be <1.5 psia. - Diesel	1975	Group 2, Subpart K, Fixed roof tank with no internal floating roof
38	True Vapor Pressure of Stored Material must be <1.5 psia - Diesel	1970	Group 2, Fixed roof tank with no internal floating roof
40	Crude Oil	2005	Group 1, Subpart Kb, OAC #897a, QQQ

Tank #	Tank Service (Typical Contents)	Constructed /Modified	Comments
41	Hydrocarbon, Petroleum Products – Crude	1970	Group 1
42	Hydrocarbon, Petroleum Products – Crude	1970	Group 1
43	Hydrocarbon, Petroleum Products – Crude/Jet/Misc.	1970	Group 1
44	Hydrocarbon, Petroleum Products - Crude	1970	Group 1
45	Hydrocarbon, Petroleum Products – Crude/Diesel	1970	Group 1
46	Hydrocarbon, Petroleum Products – Crude	1970	Group 1
47	Hydrocarbon, Petroleum Products – Crude	1973	Group 1, Subpart K, OAC #116, OAC #123
48	Hydrocarbon, Petroleum Products – Crude	1973	Group 1, Subpart K, OAC #116, OAC #123
49	Crude Oil	1998/ 2005	Group 1, Subpart Kb, OAC #620a, OAC #897, QQQ
50	Hydrocarbon, Petroleum Products – Crude	1989	Subpart Kb, OAC #283
60	Butane/Pentane Sphere	1990	Pressure vessel
61	Butane/Pentane Sphere	1970	Pressure vessel
62	Butane/Pentane Sphere	1990	Pressure vessel
63	Butane/Pentane Sphere	1970	Pressure vessel
64	Butane/Pentane Sphere	1970	Pressure vessel
65	Butane/Pentane Sphere	1970	Pressure Vessel
70	True Vapor Pressure of Stored Material must be <1.5 psia – Hydrocracker Recycle	1970	Group 2, fixed roof tank with no internal floating roof
71	True Vapor Pressure of Stored Material must be ≤11.1 psia.	1991	Subpart Kb, OAC #371a
72	Limited to Gasoline or Diesel Storage. Only 2 of 3 in Gasoline Service at Given Time.	1995	Subpart Kb, OAC #527c
73	Limited to Gasoline or Diesel Storage. Only 2 of 3 in Gasoline Service at Given Time.	1995	Subpart Kb, OAC #527c
74	Limited to Gasoline or Diesel Storage. Only 2 of 3 in Gasoline Service at Given Time.	1995	Subpart Kb, OAC #527c
81	LPG	1986	Pressure Vessel
82	LPG	1986	Pressure Vessel
83	LPG	1986	Pressure Vessel
84	LPG	1986	Pressure Vessel
85	LPG	1986	Pressure Vessel
86	LPG	1986	Pressure Vessel
87	LPG	1986	Pressure Vessel
88	LPG	1986	Pressure Vessel
89	LPG	1986	Pressure Vessel

The level of VOC and HAP control employed is dependent on the size of the tank or vessel and characteristics of products being stored. These characteristics include vapor pressure, HAP content and odor potential. Generally, products having a vapor pressure greater than 1.5 psia at actual storage temperatures are required to use VOC/HAP control equipment and maintain equipment in accordance with underlying inspection and repair requirements. The type of storage vessels with emission controls include internal and external floating roof tanks and fixed roof tanks equipped with activated carbon. Uncontrolled tanks are those with fixed roofs that do not have internal floating roofs. Uncontrolled tanks are allowed if they store heavy products such as distillates, or aqueous based materials such as sulfuric acid. Pressurized vessels, although not specifically controlled through regulation, are considered closed systems that do not have the potential for on-going emissions to the atmosphere.

Tanks storing volatile organic liquids (VOL) are located in the tank farm area. Common VOLs that are required to be stored in controlled tanks include crude oils, refinery intermediates and finished products such as gasoline. Under NSPS regulations, control equipment is required when storing VOLs with maximum true vapor pressure of 0.75 psia. Otherwise control requirements generally trigger at 1.5 psia. Table 3-4 presents the regulatory triggers when storing VOLs. Tanks storing VOLs below the vapor pressure thresholds are required to keep records of type of products stored and their vapor pressures, periods of storage and information about the design specifications for each tank.

Table 3.4 - Regulatory Triggers for Tanks and Storage Vessels

Regulatory Trigger	kPa	Psia
NSPS control for tanks ≥ 151 m^3	5.2	0.75
R-MACT and NWCAA control for tanks ≥ 151 m^3	10.4	1.50
NSPS and R-MACT control for tanks ≥ 75 m^3	27.6	4.00
Maximum True VP of stored VOL for EFR or IFR tanks	76.6	11.1
	cubic meters	**Gallons**
NSPS control for MTVP ≥ 5.2 kPa	75	20,000
NWCAA control for MTVP ≥ 10.4 kPa	151	39,900
R-MACT control for MTVP ≥ 10.4 kPa	177	46,800

Note - Federal regulations use IS units, whereas the NWCAA regulation uses English units.

Because high vapor pressure VOLs must be stored in “controlled” tanks, the underlying requirements define how these tanks are constructed and monitored. VOL tanks constructed after July 23, 1984 are required to operate in accordance with NSPS 40 CFR 60 Subpart Kb and are exempt from Refinery MACT requirements as allowed under the overlap provisions of 63.640(n). Tanks constructed before that date and holding VOLs containing HAPs are required to meet the applicable Refinery MACT requirements of NESHAP 40 CFR 63 Subpart CC, which refers to the control standards of 40 CFR 63 Subpart G. It should be noted that, Refinery MACT Subpart CC defines applicability and reporting requirements whereas Subpart G defines equipment and monitoring requirements for storage tanks. Furthermore, specific sections found within Subpart G are specific for each tank design (i.e., different portions apply to external floating roof (EFR) versus internal floating roof (IFR) tanks).

Although the Refinery MACT is applicable to vessels storing HAPs, for all practical purposes, all VOLs having vapor pressures over 1.5 psia are likely to contain HAPs greater than the 4% by weight Subpart CC trigger and therefore need controls. Hence, whether the underlying regulation is HAP or VOC driven becomes relatively moot. One overlap provision that helps simplify the compliance program for storage tanks can be found under 40 CFR 63.640(n)(8)(v). This allows NSPS Subpart Kb applicable tanks to share the same reporting requirements for those tanks regulated under Refinery MACT. In essence, it aligns the requirements for report submittal to the semiannually Refinery MACT periodic reports (40 CFR 63.654(g)).

Historically, a number of regulations have driven emission control strategies for product storage at the refinery. In 1989, the NWCAA adopted Section 580 requiring the installation of secondary seals on all EFR tanks storing VOLs with MTVP equal to or greater 1.5 psia. The deadline for completing all secondary seal retrofits under NWCAA 580 was December 31, 1999. The refinery met the compliance deadline having completed all secondary seal work by the end of 1999. On August 18, 1998, Refinery MACT became applicable. Similar to NWCAA 580, the Refinery MACT required secondary seals on EFR tanks however, it allowed for a phase-in period that extends into 2008. As a result, the AOP has been written ignoring the Refinery MACT's phase in schedule and instead assumes current applicability of the standard. Another issue considered during the writing of the AOP was the fact that NWCAA 580.32 allows three options when defining a control strategy for controlled tanks.

> 580.32 It shall be unlawful for any person to cause or allow storage of volatile organic compounds as specified in Section 580.31 unless each storage tank or container:
>
> 580.321 Meets the equipment specifications and maintenance requirements of the Federal Standards of Performance for New Stationary Sources -Storage Vessels for Petroleum Liquids (40 CFR 60, subpart Kb); or
>
> 580.322 Is retrofitted with a floating roof or internal floating cover using a metallic seal or a nonmetallic resilient seal at least meeting the equipment specifications of the Federal standards referred to in 580.321 of this subsection, or its equivalent; or
>
> 580.323 Is fitted with a floating roof or internal floating cover meeting the manufacturer's equipment specifications in effect when it was installed.

Because of the regulatory uncertainty associated with 580.322 and 580.323, the AOP is written on the basis that the refinery is using NSPS Subpart Kb as the control method. Therefore, citations to NWCAA 580 include references to the equipment specifications and maintenance sections of 40 CFR 60 Subpart Kb.

Under the current version of NWCAA Section 580 (50.26 and 580.37) there are exemptions allowing the source to only follow a federal rule (NSPS or NESHAP) for controlling emissions from tanks. However, these exemptions are not found in the current State Implementation Plan (SIP) and therefore cannot be used by the source because they are not federally enforceable. Because of this discrepancy, only the SIP adopted version of NWCAA 580 citations are found in the AOP.

In addition to the underlying NWCAA and federal regulations, there are some tanks at that were constructed under a NWCAA OAC. In some cases these OACs do not add any additional requirements not already present in the underlying regulation. However, the OACs are cited as specifically applicable requirements because their conditions are unique and federally enforceable. The following is a discussion of the OACs.

<u>Additional Crude Oil Storage Capacity (Tanks #47 and #48)</u>

On August 16, 1973 the refinery proposed to install additional tankage for the storage of crude oil. Each tank would have a capacity of 268,000 barrels of crude (Tanks 33-1947 and 33-1948) equipped with external fixed roofs and internal floating roofs. The NWCAA issued OAC #116/123 on

September 17, 1973. Within this OAC, the NWCAA determined that construction of the two crude tanks was in compliance with NWCAA regulation 560 for the control of hydrocarbon vapors.

Construction of 500,000 Barrel Crude Oil Tank (Tank #50)

On March 17, 1989, the refinery proposed to construct and operate a 500,000 barrel crude oil tank (Tank #50). The NWCAA issued OAC #253 on May 15, 1989. On August 8, 2002 NWCAA revised this approval by clarifying that the tank is subject to 40 CFR 60 Subpart Kb (OAC #253a).

Construction of 31,500 Barrel Storage Tank (Tank #71)

On March 12, 1992 the refinery proposed to construct and operate a 31,500 barrel storage tank (Tank #71). The tank would be used an intermediate storage tank for material which is drained from product shipping lines used to load ships and barges at the docks as well as a correction tank to assist in product blending. The NWCAA issued OAC #371 on May 1, 1992. On August 8, 2002, the NWCAA revised OAC #371 clarifying that the tank is subject to 40 CFR 60 Subpart Kb and is in organic hazardous air pollutant service and is subject to 40 CFR 63 Subpart CC (OAC #371a).

Construction of 200,000 Barrel Product Storage Tank (Tank #24)

On August 26, 1993, the refinery proposed to construct and operate a 200,000 barrel petroleum storage tank. The proposed tank would be used to store finished diesel ready for sale as well a potentially storing other higher vapor pressure liquids such as gasoline. The refinery estimated the maximum true vapor pressure for the tank to be 8.3 psia (gasoline). The tank's construction would consist of an internal floating roof with the appropriate seals that met the requirements of 40 CFR 60 Subpart Kb and NWCAA 580.3. The NWCAA issued OAC #453 on November 23, 1993 approving the construction of the tank with the following conditions:

Condition Number	Description of OAC #453 Conditions
2	The tank may only be used for the storage of diesel or gasoline products with a true vapor pressure not to exceed 8.5 psia.
3	All requirements of CGR 60 Subpart Kb including testing, reporting, recordkeeping, and monitoring must be adhered to.
4	Emissions from the tank will be reported to the NWCAA on an annual basis no later than 105 days following the end of the calendar year.

In response to OAC #453, the refinery requested a change to the tank's design be approved. On November 18, 1993 the refinery proposed to install a geodesic dome with an internal floating roof rather than the originally proposed fixed external roof with internal floating roof. The geodesic dome meets the requirements of NWCAA 580.3and 40 CFR 60 Subpart Kb and could result in lower VOC emissions. Additionally, the refinery performed a screening model to determine if any ASILs would be triggered by emissions from the new tank. Results of the screening modeling indicated calculated that at a true vapor pressure of 11.1 psia for stored liquids ASILs were not exceeded. The NWCAA concurred and issued OAC #453a on November 23, 1993 with a revised Condition #2 stating that:

> Condition 2: The tank may only be used for the storage of finished diesel or gasoline product with a true vapor pressure not to exceed 11.1 psia.

The tank was installed with the geodesic dome cover and a Certificate of Approval to Operate was issued by the NWCAA on August 11, 1994.

In order to resolve overlapping regulations, the NWCAA issued OAC #453b on August 8, 2002. Conditions 1 through 4 were deleted. Condition 1 was removed because it for compliance with the NOC. Condition 2 and 3 were removed to eliminate overlap of control and monitoring requirements. Finally, Condition 4 was deleted since reporting of emissions from the tank is already required under emissions inventory regulations for all sources by the State of Washington and NWCAA.

Truck Terminal Facility (Tanks #72, #73 and #74)

On October 6, 1994 (later amended on November 21, 1994) the refinery proposed to construct and operate a truck loading terminal facility in which gasoline and diesel products would be loaded into trucks for transportation off-site. Three tanks were proposed: 10,000 barrel gasoline tank, 10,000 barrel diesel only tank, and 20,000 barrel diesel tank. The three tanks would be constructed with external fixed roofs and internal floating roofs with liquid mounted seals meeting the requirements of 40 CFR 60 Subpart Kb and NWCAA 580. The NWAP issued OAC #527 on December 24, 1995. Conditions applicable to the three tanks were:

Condition Number	Description of OAC #527 Conditions
2	All three tanks shall be constructed to the standards identified in 40 CFR 60 Subpart Kb with internal floating roofs and liquid mounted foam filled resilient seals. Only two of the three tanks may be in gasoline service at any given time.
3	Tanks are subject to all applicable NSPS 40 CFR 60 Subpart Kb requirements including testing and MR&Rs.
4	Maintain records of tank dimensions, capacity, number of turnovers per year, and materials stored for a period of at least two years.
17	Emissions from the truck terminal will be reported to the NWCAA on an annual basis no later than 105 days following the end of the calendar year.
18	Equipment located at the truck terminal including but not limited to valves, pumps, pressure relief devices and flanges are subject to all applicable requirements of NSPS 40 CFR 60 Subpart GGG.
19	Drain systems, junction boxes, and sewer lines are subject to all applicable requirements of NSPS 40 CFR 60 Subpart QQQ.

On August 27, 1996 the refinery proposed to modify the truck terminal, adding a new bay for the delivery of jet fuel, diesel, and low-sulfur diesel through the addition of new loading arms. The refinery also proposed to limit the maximum throughput of the terminal to 10,000 barrels/day of gasoline and 100,000 barrels/day combined of jet fuel, diesel and low-sulfur diesel. The NWCAA issued OAC #527R2 on October 24, 1996 (OAC #527R1 was issued on September 27, 1996 with an incorrect capacity for one of the diesel tanks).

On November 6, 2001 the refinery proposed to increase the maximum throughput of the terminal to 26,000 barrels/day of gasoline and 76,000 barrels/day combined of jet fuel and diesel fuel. The NWCAA issued OAC #527c on December 13, 2001. No changes were made to the applicable conditions for the storage tanks other than the terminal was now subject to 40 CFR 63 Subpart CC (Condition #5).

The vapor combustor servicing the truck rack uses natural gas as a supplemental fuel. Therefore, 40 CFR 60 subpart J that limits the sulfur content of fuel gas does not apply to this combustion device because it does not burn refinery fuel gas.

<u>New Light Reformate Splitter Tower (Tanks #1 through #10 and Tank 14)</u>

As previously discussed, on August 1995 the refinery notified the NWCAA that they proposed to build a new light reformate splitter tower. The existing reformate splitter would be reconfigured so that the light reformate overhead would be drawn off and become the feed to the LRS tower. The proposed LRS would produce C5/C6 paraffin overhead that would be used for on-site gasoline blending and benzene concentrated (40% by weight) bottoms for on-site storage and off-site sale. The LRS tower would have emissions of VOCs and benzene.

On September 7, 1995 the NWCAA granted the refinery approval for the beginning of site preparation work. The refinery was prohibited from actually installing and constructing the LRS tower until an OAC was issued. On January 3, 1996 the NWCAA issued a Conditional Notice of Construction (OAC #562) approving the refinery's application for the construction of a LRS tower and associated equipment.

On February 14, 1996 the refinery requested a change to their notice of construction that would allow the use of larger storage tanks (Tanks 1 through 10 and Tank 14) for storage of the benzene-concentrated LRS tower bottoms. All of the tanks have similar construction and are equipped with emission controls. The refinery also proposed that they would use only one of these sixteen tanks at a time. Emissions were expected to increase slightly as a result of this change. The requested change was incorporated into the Tier II analysis. The NWCAA incorporated this request and revised OAC #562 on February 26, 1996 converting OAC #562 from conditional to final.

Operation of the LRS tower began on May 6, 1996. On August 9, 1996 NWCAA issued an Approval to Operate to the refinery for the light reformate tower and storage scenario.

OAC #562 applicable conditions include:

Condition Number	Description of OAC #562 Conditions
2	Valves, pumps, pressure relief devices, sampling connection system, open-ended valves or lines, and flanges, and other connectors in VOC service are subject to 40 CFR 60 Subpart GGG (LDAR program).
3	Each individual drain system, oil-water separator, or aggregate facility within the process unit is subject to 40 CFR 60 Subpart QQQ.
4	Each source determined to be in benzene service are subject to 40 CFR 61 Subpart J for the National Emission Standards for Equipment Leaks of Benzene.
6	Process vents, storage vessels, wastewater streams and treatment operations and equipment leaks are subject to 40 CFR 63 Subpart CC National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.
7	Benzene concentrated light reformate from the LRS tower may be stored in any one of the existing storage vessels identified as Tanks 1 through 10 and Tank 14.

Once installed and operating, the refinery determined that through computer operation optimization that the LRS tower bottoms could be further concentrated to 70% wt/wt of benzene from the original 40% wt/wt (October 6, 1999). No changes to the equipment were proposed and no increase in benzene emissions was anticipated. The refinery re-calculated benzene exposure levels for off-site receptors and determined the increased cancer risk similar to the original calculations. On March 9, 2000 the NWCAA determined that new source review was not triggered as a result of this change and subsequently approved the change in operation.

On March 17, 2003, the NWCAA issued OAC 562b modifying Condition #7. Condition #7 states:

Condition 7: Benzene concentrated light reformate from the splitter tower may be stored in any one of the existing storage vessels identified as Tanks 1 through 10 and Tank 14. Transfers of the high benzene concentrate between any two of the tanks are allowed to facilitate maintenance and inspection requirements of the tanks.

Construction of 400,000 Barrel Crude Oil Tank (Tank #49)

On June 2, 1997 the refinery proposed to install a 400,000 barrel crude oil tank. The tank would be located in the existing tank farm and would employ BACT. The purpose of the tank was not to increase the throughput of crude processing but to reduce the number of tanker deliveries. Emissions from this tank would include VOCs (4.7 tons/year) and HAPs. The tank would be constructed with a fixed external roof and an internal floating roof with double seals. This construction also satisfied MACT for crude oil tanks. On August 13, 1997, the NWCAA issued OAC #620. On August 8, 2002 the NWCAA revised OAC #620 to remove overlapping regulatory requirements. OAC #620a determined that Tank #49 is subject to 40 CFR 60 Subpart Kb (and by association 40 CFR 63 Subpart CC), 40 CFR 60 Subpart GGG, 40 CFR 60 Subpart QQQ, and NWCAA 560 and 580. In 2005 the tank was equipped with an internal steam heating coil.

Construction of 365,000 Barrel Crude Oil tank (Tank #40)

In November 2004 NWCAA issued OAC #897 for construction of a 365,000 barrel crude storage tank. This tank was needed in order to segregate, store and process a wider variety of crude oils since the supply of Alaskan North Slope Crude, which has been the primary source of crude oil at the refinery, is declining. This tank will be equipped an internal floating roof and double seals (mechanical shoe primary seal with a secondary vapor seal). It will also be provided with a steam coil to allow storage of heavy crude oil. Emissions from this tank were estimated to be approximately 3.8 tons per year. As with Tank 49 above, Tank 40 is subject to 40 CFR 60 Subpart Kb (and by association 40 CFR 63 Subpart CC), 40 CFR 60 Subpart GGG, 40 CFR 60 Subpart QQQ, and NWCAA 560 and 580.

3.17.1 Inspection and Maintenance

Seals are inspected in accordance with the frequencies specified in the underlying regulation. For IFR tanks, the annual inspection is visual through the fixed roof hatch with a comprehensive internal inspection being required once every five years for tanks with a single seal and once every ten years for tanks with double seals. The NWCAA is notified of all annual inspections and gap tests on a schedule developed by the refinery at the beginning of each calendar year. Adjustments to the schedule are be made at other times during the year as long as notices meet the 30/7 day advance notice requirements of the underlying rule. Advanced notices allow regulatory staff an opportunity to attend seal gap testing and internal inspections of tanks when they are degassed. Inspection and gap testing requirements are common to both 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC. Any seal gap measurements or other defects found during inspections which exceed the compliance thresholds are required to be corrected within 45 days (unless an extensions is used) and reported to the NWCAA on semiannual reports.

Internal and external floating roof tanks may not store volatile organic products that exceed a MTVP of 11.1 psia. Because the vapor pressure characteristics of crude oils and other non-finished products can vary considerably, their vapor pressures are sampled and tested to assure that they are maintained below 11.1 psia on an on-going basis. In addition some tanks have internal heaters that can increase storage temperatures above ambient. Temperature and vapor pressure records are kept by the facility and are available for inspection. Maximum true vapor pressures are calculated in using the methods in API Chapter 19.2 Evaporative Loss From Floating Roof Tanks (previously API Bulletin 2517).

Internal Floating Roof Tanks

Internal floating roof (IFR) tanks are also used to store high vapor pressure VOLs products at the refinery. They are also used for store of a wider array of materials (e.g., slop oils, wastewater emulsions) when compared to the EFR tanks. IFR tanks use a fixed cone roof covering over the top of the tank along with an internal floating roof having at least a single seal system between the tank wall and floating roof cover. A second seal is not required by the underlying regulations because the fixed roof cover serves to reduce exposure of the floating roof thereby limiting fugitive VOC and HAP emissions. In some cases, two internal seals are used for added emission control. IFR Tanks equipped with a double seal system are allowed a more flexible inspection schedule under NSPS and Refinery MACT requirements.

IFR tanks regulated under NSPS Subpart Kb are exempt from the requirements of Refinery MACT in accordance with the overlap provisions of 63.640(n). Although there are subtle differences in the underlying rules, compliance for IFR tanks can be summarized into the following conditions.

Internal Floating Roof Tank Monitoring Recordkeeping and Reporting Summary

Report as an upset, any time that stored VOL exceeds a true vapor pressure of 11.1 psia. The report shall be made to the NWCAA within 12 hours of discovering the condition in accordance with NWCAA 340.

Quarterly, conduct a visual inspection of the tank to assure that openings are closed.

Annually, conduct a visual inspection of the floating roof through roof hatches to assure that:

There are no tears in the seal, the seal is not detached, there is no petroleum liquid accumulated on the floating roof and that the floating roof is resting on the VOL surface.

Once every ten years, empty and degas the tank and conduct an internal inspection to assure that:

- The primary seal is either a mechanical shoe seal or a liquid-mounted seal that completely covers the annular space between the edge of the floating roof and the tank wall.
- There are no defects in the floating roof, primary seal or secondary seal (if one is in place) and that are no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.
- If a mechanical shoe primary seal is in use, that it extends into the liquid and also extends at least 24 inches above the liquid surface.
- That, except for openings that are automatic bleeder vents (vacuum breakers) and rim space vents, each opening in a non-contact floating roof has a projection below the liquid surface.
- Sample wells are covered by a slotted fabric that covers at least 90% of the opening.
- Each roof opening has a cover, lid or is otherwise sealed (except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells and stub drains).
- Automatic bleeder vents are gasketed and closed except when the roof is being floated off, landed on, or resting on the roof leg supports.
- Column wells have a flexible fabric sleeve seal or gasketed sliding cover.
- Each ladder well has a gasketed sliding cover.

Notice of refill

- Notify the NWCAA at least 30 days in advance that a tank will be refilled. If refilling is unplanned, 7 day verbal notice followed immediately by a written notice is allowed.

Operational Records

- Shall include tank #, type of VOL stored, its maximum true vapor pressure and dates of storage.

Repair of Defects/Failures

- Any defect found during inspection and/or gap testing shall be repaired within 45 days or the tank emptied. If neither occurs, a 60 day extension past the initial 45 day period can be used if the refinery documents that no alternate storage capacity is available and that the repairs are completed as soon as possible.

Inspection Reports

- On semiannual Refinery MACT Periodic Reports, submit information including the date of inspection, a list of defects/failures discovered and the nature and date of their repair. If a delay of repair (extension) is utilized, include documentation that alternate storage capacity is unavailable and information showing that repairs were completed as soon as possible.

Pressurized Vessels

Gaseous products, such butane, propane and LPG are stored in pressurized vessels. There are no requirements for pressurized vessels as they are considered closed systems that do not vent to the atmosphere. However, each is equipped with a pressure relief device (PRD) that limits stress on the vessel before its pressure limits are exceeded. In many cases PRD's are vented to the atmosphere, however, in some cases they are routed through a closed vent system to the flares.

3.18 Shipping, Pumping and Receiving

Shipping, pumping, and receiving involve numerous processes and areas. For the purposes of the AOP, NWCAA divided this area into four units: Chemical Treater, Truck Rack, Marine Terminal, and LPG/LEU/Butane/Pentane Loading. Tankage associated with these units is discussed in Section 1.14. The following is a discussion of each unit.

3.18.1 Chemical Treater

The chemical treater consists of two separate processes, a stove oil treater and a diesel treater. The stove oil treater is designed to remove water and other impurities from the stove oil. The diesel treater is designed to remove water from diesel fuel.

On November 19, 1997 the refinery submitted a Notice of Construction to the NWCAA for improving crude fractionation and slightly increasing crude processing capacity. The project included modifications to the existing preheat exchange train and additional preheat exchangers, replacement of the existing pre-flash drum, replacement of the existing debutanizer tower with a larger tower, conversion of the existing pre-flash drum to a stove oil stripper, and the replacement of the existing vacuum tower. These modifications also required changes to pumps, heat exchangers, and process relief valves. The NWCAA issued OAC #640 on May 1, 1998.

In OAC #640, BACT was identified as a leak detection and repair program (LDAR) for emission units such as valves, pumps, flanges, closed vent systems, and other connectors. Applicability of NSPS included the crude distillation unit, butane distillation unit, stove oil stripper, diesel oil stripper VDF, and vacuum distillation unit. 40 CFR 60 Subpart GGG and QQQ apply to the affected units along with 40 CFR 60 Subpart VV for LDAR and 40 CFR 63 Subpart CC for the emissions of HAPs.

The term of OAC #640 applicable to the Chemical Treater is:

> Condition #1: New and converted drains are subject to 40 CFR 60 Subpart QQQ for VOC emissions from Petroleum Wastewater Systems which requires that drains be equipped with water seals and inspected semiannually. Covered or enclosed sewer lines are visually inspected semiannually. New drains and junction boxes cannot be routed through a downstream catch basin.

3.18.2 Truck Rack

The original truck rack terminal was proposed on October 6, 1994 in which gasoline, jet fuel and diesel products would be loaded into trucks for transportation off-site. Three tanks are used to store products for loading: 10,000 barrel gasoline tank, 10,000 barrel diesel only tank, and 20,000 barrel diesel tank. The three tanks are constructed with external fixed roofs and internal floating roofs with liquid mounted seals meeting the requirements of 40 CFR 60 Subpart Kb and NWCAA 580. The mode of operation for the terminal is submerged loading with vapor recovery and control (vapor recovery combustion).

The terminal contains loading lanes, each equipped with two bottom loading stops: one for the front tank and one for the rear tank. Each loading arm contains loading arms for gasoline, USEPA diesel, high-sulfur diesel and jet fuel. LPG can also be loaded into trucks at the truck rack. At any time, only one arm can be in operation. Automatic interlock devices are in place to prevent loading unless appropriate thermal oxidation temperatures are met and to assure that the tanks loaded all have a valid leak tighten test certification on record. Current regulated maximum loadout of gasoline through the terminal is limited to 26,000 barrels per day. Total loadout of diesels and jet fuel is limited to 76,000 barrels per day, combined.

Although sometimes called a flare, for regulatory purposes the vapor combustor is considered a thermal oxidation unit, because the oxidation process is enclosed and combustion temperatures monitored. The vapor combustion device uses propane as a supplemental fuel to assure that the temperature in the oxidizing zone is at or above 1,200 F at all times when vapors are being routed from the rack. This temperature set point is determined during source testing in accordance with NSPS and NESHAP specified procedures for determining continuous monitoring requirements.

The vapor combustor was designed and built by John Zink Company, a company that has installed numerous vapor combustors at loading terminals. The manufacturer guarantees vapor combustors on a mass emissions in lieu of destruction efficiency. This follows the Federal guidelines for mass emission limits to the atmosphere from the vapor collection and processing systems not exceed 10 milligrams of total organic compounds per liter of gasoline loaded. Also, the vapor control system shall prevent the emission of at least 90 percent by weight of the VOC and shall limit the emission to no more than 35 milligrams VOC per liter of gasoline transferred.

Emissions include VOCs and HAPs as well as combustion products from the vapor combustor. Emission comes from loading losses, components (pumps, flanges, valves, pressure relief devices), and storage tank emissions.

The NWCAA issued OAC #527 on December 24, 1995 for the original construction of the truck loading terminal. On August 27, 1996 the refinery proposed to modify the truck terminal, adding a new bay for the delivery of jet fuel, diesel, and low-sulfur diesel through the addition of new loading arms. The refinery also proposed to limit the maximum throughput of the terminal to 10,000 barrels/day of gasoline and 100,000 barrels/day combined of jet fuel, diesel and low-sulfur diesel. The NWCAA issued OAC #527R2 on October 24, 1996 (OAC #527R1 was issued on September 27, 1996 with an incorrect capacity for one of the diesel tanks). On November 6, 2001 the refinery proposed to increase the maximum throughput of the terminal to 26,000 barrels/day of gasoline and 76,000 barrels/day combined of jet fuel and diesel fuel. The NWCAA issued OAC #527c on December 13, 2001.

There are a number of overlapping regulations that apply to the truck loading terminal. These include; NWCAA 580.4, WAC 173-491-040 (2) and NSPS Subpart XX. As with most process units, components in VOC/HAP service are under a LDAR program pursuant to NWCAA 580 and the Refinery MACT regulations. VOC emissions from refinery wastewater system (40 CFR 60 Subpart

QQQ) apply to the components of the unit. In addition, Refinery MACT regulations apply a modified version of NESHAP Subpart R for gasoline terminals. As such, specifically applicable regulations cited in the AOP only include those in Subpart R that are specifically called out as applicable in 40 CFR 63.650 (Subpart CC).

There are no applicable regulations controlling NOx or SO_2 emissions at the gasoline/diesel truck terminal. Recent EPA applicability investigations indicate that NSPS Subpart J for SO_2 is applicable to the thermal oxidizer because it is combusting hydrocarbon gas generated at the refinery. Regarding fuel gas, the thermal oxidizer servicing the truck rack uses only natural gas for supplemental fuel. Therefore, 40 CFR 60 subpart J that limits the sulfur content of the refinery fuel gas does not apply to this combustion device as it relates to supplemental firing with natural gas.

Applicable conditions of OAC #527c (excluding tanks – see Section 1.14) are:

Condition Number	Description of OAC #527c Conditions
5	Bulk gasoline loading terminal is subject to all applicable requirements of NSPS Subpart XX, Bulk Gasoline Terminal WAC 173-491-040, gasoline vapor control requirements, NWCAA 580.4 and 40 CFR 63 Subpart CC (Refinery MACT).
6	The loading terminal shall employ submerged loading or bottom loading.
7	All loading lines and vapor lines shall be equipped with vapor-tight fittings which close automatically upon disconnect. The point of closure shall be on the tank side of any hose or immediate connecting line.
8	All vapor return line shall be connected between the transport tank and the vapor control system such that all displaced VOCs are vented to the vapor recovery system.
9	The emissions to the atmosphere from the vapor collection system are not to exceed 10 milligrams of total organic compounds per liter of gasoline loaded. The vapor control system shall prevent the emissions of at 90 percent by weight of the VOCs. Compliance shall be demonstrated biennially by conducting emission testing according to EPA Method 25 or another method approved by the Director.
10	The vapor control system shall be equipped with an appropriate alarm system to alert personnel when the system is not in compliance with NWCAA 580.424.
11	All loading arms shall be designed, maintained and operated to prevent overfill, prevent fugitive liquid or vapor leak, and prevent excess gasoline drainage during disconnect in accordance with the requirements of NWCAA 580.10.
12	The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the delivery tank from exceeding 4,500 Pascals (450 mm of water) during product loading.
13	Each calendar month, the vapor collection system, the vapor processing system, and each loading rack handling gasoline shall be inspected during the loading of gasoline tank trucks for total organic compounds liquid or vapor leaks. Each detected leak shall be recorded and the source of the leak repaired within 15 calendar days after it is detected. A record of each monthly leak inspection shall be kept on file at the terminal for at least 2 years.
14	The tank truck vapor tightness documentation required under 60.502(e)(1) shall be kept on file at the terminal in a permanent form available for inspection and update annually.
15	The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the delivery tank from exceeding 4,500 Pascals (450 mm of water) during product loading. This level is not to be exceeded when measured by the procedures specified in 60.503(d). A pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure within 2.5 mm of water precision, shall be calibrated and installed on the terminal's vapor collection system at a pressure tap located as close as possible to the connection with the gasoline tank truck.
16	The refinery shall keep records of all replacements or additions of components performed on an existing vapor processing system for at least 3 years.
17	Emissions from the truck terminal will be report to NWCAA on an annual basis no later than 105 days following the end of the calendar year.
18	Equipment located at the truck terminal including but not limited to valves, pumps, pressure relief devices, and flanges are subject to all applicable requirements of NSPS Subpart GGG.
19	Drain systems, junction boxes, and sewer lines are subject to all applicable requirements of NSPS Subpart QQQ.
20	Maximum loadout of gasoline through the terminal shall be limited to 26,000 barrels per day. Total loadout of diesels and jet fuel shall be limited to 76,000 barrels per day combined.

3.18.3 Marine Terminal

Originally, the refinery has one marine dock for the unloading crude oil and loading a variety of hydrocarbon products including gasoline, reformulated gasoline blend components, diesel, jet fuel, light and heavy hydrocrackate, and light and heavy reformate. The original dock was constructed during the original refinery construction in 1971. The original plan and permit were for two berthing docks attached to one trestleway, but the north dock was never built. To alleviate scheduling problems, reduce demurrage costs, and increase product shipping flexibility, the refinery installed a new berthing dock, north dock on October 31, 2001. The south berthing dock has crude oil unloading capability, while the north dock does not.

The docks consist of a loading platform, trestle end platform, connecting trestle platform, trestle head platform, wye connecting bridges, and wye pipe bridge. Hydrocarbon product loading arms and a vapor collection system are located on the loading platform. A vapor collection knockout pot, vapor blower, and liquid seal skid, and a thermal oxidizer are located at the trestle head platform.

Vapors are collected through an arm connected to the vessel being loaded or unloaded. The vapors first pass through a detonation arrestor, then natural gas is added to enrich the gas stream above the upper explosive limit (UEL). Enriched vapors are transported through a 12-inch pipe to the trestle head platform where the blower skid and thermal oxidizer are located. The vapors pass through a knockout pot to remove any entrained liquid, then the blower, the liquid seal, and another detonation arrestor. The liquid seal and detonation arrestors ensure that flames cannot flash back through the vapor collection pipe. Finally, the vapors are injected into the thermal oxidizer and destroyed through combustion with a designed minimum 98% destruction removal efficiency.

In 1993, the refinery proposed to modify the dock piping system. The NWCAA reviewed the project and issued OAC #437 on June 7, 1993. The OAC had only one currently applicable condition:

> Condition 2: A LDAR program shall be conducted on the piping system in accordance with NWCAA regulations, Section 580.

The north dock was proposed by the refinery on October 8, 1999. Emissions from this project include VOCs, NOx, and CO. BACT was determined to be a vapor collection system and thermal oxidation with a 98% VOC destruction efficiency. The NWCAA issued OAC #716 on January 26, 2000. The marine terminal is subject to applicable requirements of 40 CFR 60 Subpart J, 40 CFR 63 Subpart CC, and 40 CFR 61 Subpart BB. The original south dock triggered RACT under 40 CFR 63 Subpart CC. As a result, the refinery proposed to connect the south dock to the vapor collection and thermal oxidizer. The NWCAA issued OAC #716a on May 3, 2001 approving the request to tie-in a south dock vapor collection system into the existing north dock thermal oxidizer.

The thermal oxidizer servicing the north dock uses natural gas as a supplemental fuel. Therefore, 40 CFR 60 subpart J that limits the sulfur content of fuel gas does not apply to this combustion device because it does not burn refinery fuel gas.

The conditions of OAC #716a are:

Condition Number	Description of OAC #527c Conditions
1	The berthing docks shall be equipped with a vapor collection system that is designed to collect VOC vapors displaced from marine vessels during loading of all light refinery products.
2	Marine task vessel loading of li8ght refinery products shall be limited to those vessels that are equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.
3	Marine tank vessel loading of light refinery products shall be limited to those vessels that are vapor-tight and to those vessels that are connected to the vapor collection system.
4	Thermal oxidation of the captured vapors from the marine tank vessel loading operations shall reduce VOCs by 98 weight percent.
5	Loading of light refinery product may be performed without emission control for a period not to exceed 14 days on a rolling 12-month average to allow maintenance on the vapor control equipment. Records for all maintenance performed on the air pollution control equipment shall be maintained.
6	Ductwork, piping, and connectors shall be monitored for leaks and repaired using the procedures described in 40 CFR 63.563(c).
7	Compliance with Conditions 1, 2, 3, and 4 shall be determined using the procedures described in 40 CFR 63.563(a) and (b).
8	Compliance with monitoring of the marine terminal vapor collection and combustion system shall be conducted in accordance with 40 CFR 63.564(a), (b), (c), (d), and (e).
9	Performance testing of the mariner terminal vapor collection and combustion system shall be conducted in accordance with the procedures of 40 CFR 63.565 (a), (b), (c), (d), (f), and (g).
10	Records shall be maintained according to the procedures in 40 CFR 63.567 (f), (g), (h), (i), and (k). Records shall be maintained on site for a period of five years. In addition, records of total refinery product loaded at each berthing dock shall be maintained on site for a period of five years.
11	All refinery fuel gas streams combusted in a fuel gas combustion device shall be subject to the applicable requirements of 40 CFR 60 Subpart J
12	At all times including periods of startup, shutdown, and malfunction, owners, or operators shall operate the terminal in a manner consistent with safety and good air pollution control practices for minimizing emissions.

3.18.4 LPG/LEU/Butane/Pentane Loading

Gaseous products, such butane, propane and LPG are stored in pressurized vessels. There are no requirements for pressurized vessels as they are considered closed systems that do not vent to the atmosphere. Propane, butane, and pentane are typically loaded into rail cars. Propane can also be loaded into trucks at the truck rack. Equipment that emits pollutants such as VOCs and HAPs include pumps, valves, flanges, and seals. As a result, these pieces of equipment are subject to the refinery's LDAR program as well as NWCAA 580.

3.19 Landfarm

On May 8 1992, the refinery proposed to construct and operate a non-hazardous waste landfarm replacing the old non-hazardous waste landfarms operated since 1971. The landfarm is used to treat and dispose of non-hazardous waste, including oily wastes and waste biomass from the WWT unit. Dangerous wastes, as defined by WAC 173-303 are not allowed. It conforms to the Washington State standards (WAC 173-304) for solid waste handling. The landfarm is located on top of existing clean construction fill. Potential emissions include air toxics including benzene and ammonia. Pollutant emission rates, 9.5 lbs/yr and 2.0 lbs/yr respectively, were below the small quantity emission rate.

On June 30, 1992 the NWCAA issued OAC #382. The applicable condition from OAC #382 is:

> Condition 2: Emissions from the landfarm shall be reported on an annual basis as part of the NWCAA emission inventory.

Section 4 - Air Operating Permit Administration

In developing the AOP for the BP Cherry Point Refinery, the NWCAA developed assumptions for the AOP and established permit elements. Assumptions are discussed in Section 4.1. Permit elements are presented in Section 4.2. Section 4.3 lists the AOP Public docket information. Finally, Section 4.4 lists the definitions and acronyms used throughout the SOB and AOP.

4.1 Permit Assumptions

The following describes the assumptions the NWCAA used in developing this Statement of Basis and AOP.

4.1.1. One-Time Only Requirements

Applicable requirements that were satisfied by a single past action on the part of the source are not included in the AOP, but are discussed in the Statement of Basis. Regulations that require action by a regulatory agency, but not of the regulated source are not included as applicable permit conditions.

4.1.2. Federal Enforceability

Federally enforceable requirements are terms and conditions required under the Federal Clean Air Act or under any of its applicable requirements. Local and state regulations may become federally enforceable by formal approval into the State Implementation Plan or through other delegation mechanisms. Federally enforceable requirements are enforceable by the EPA and citizens. All applicable requirements in this permit, including standard terms and conditions, generally applicable requirements, and specifically applicable requirements are federally enforceable unless identified in the permit as enforceable only by the state. If two different versions of the same regulatory citation apply, one version is federally enforceable and the other version is only enforceable by the state. Both are listed as separate applicable requirements. If a regulation has both federally enforceable and state-only enforceable versions and the text is the same, the cited date is the most current available. The citation for each applicable requirement in the permit includes a date; this date may be the filing date (in the case of WACs) or it may be the approval date or the publication date for NWCAA Regulation sections and federal regulations, respectively.

Chapter 173-401 WAC is not federally enforceable although the requirements of this regulation are based on federal requirements for the air operating permit program. Upon issuance of the permit, the permit terms based on Chapter 173-401 WAC will become federally enforceable.

4.1.3. Future Requirements

Applicable requirements that have been promulgated with future effective compliance dates may be included as applicable requirements in the permit. Some requirements that are not applicable until triggered by an action, such as the requirement to file a Notice of Construction application prior to building a new emission unit, are addressed within the standard terms and conditions section of the permit.

4.1.4. Compliance Options

The BP Cherry Point refinery did not request emissions trading provisions or specify more than one operating scenario in the air operating permit application; therefore the permit does not address these options as allowed under WAC 173-401-650. This permit does not condense overlapping applicable requirements (streamlining) nor does it provide any alternative emission limitations.

4.2 Permit Elements

The permit is organized in the following sequence:

Permit Information
Attest
Table of Contents
Emission Unit Identification
Standard Terms and Conditions
Generally Applicable Requirements
Specific Requirements for Emissions Units
Inapplicable Requirements
Consent Decree Applicable Requirements

Within the Standard Terms and Conditions, Generally Applicable Requirements, and Specific Applicable Requirements sections, applicable regulations and OACs issued to the facility are listed. After each is a date in parenthesis. When the date is associated with a regulation, it represents the current version date for that regulation. Specifically, for a federal Subchapter regulation (e.g. 40 CFR 60 Subpart GGG) this date represents the date of publication in the Federal Register. For Washington Administrative Code (WAC) regulation this date represents the date filed with the State Code Reviser. For NWCAA regulation, it represents the Board of Directors adoption date. In the case of an OAC, it represents the issuance date of the order.

4.2.1. Permit Information, Attest, and Emissions Unit Descriptions

The General Information section identifies the source, the responsible corporate official, and the agency personnel responsible for permit preparation, review, and issuance. The Attest section provides authorization by the NWCAA for the source to operate under the terms and conditions contained in the permit. The Emissions Unit Identification section lists the significant emissions units, associated control equipment, fuel type, and installation dates. This section is a general overview of the facility. Detailed information about the plant can be found in the permit application and supporting files.

4.2.2. Standard Terms and Conditions

The Standard Terms and Conditions section contains administrative requirements and prohibitions that do not have ongoing compliance monitoring requirements. The citations giving legal authority to the Standard Terms and Conditions are provided in the section. At times, requirements are paraphrased. In this case the language of the cited regulation takes precedence over the paraphrased summary. For understanding and readability, the terms and conditions have been grouped by function. Similar requirements from the State and the NWCAA are grouped together where possible. There are several requirements included that are not applicable until triggered. Examples of these would be the requirement to file a “Notice of Construction” and “Application for Approval".

4.2.3. Generally Applicable Requirements

The Generally Applicable Requirements section identifies requirements that apply broadly to the refinery. These requirements are generally not called out in OACs and instead are found as general air pollution rules in the NWCAA Regulation or the Washington Administrative Codes.

When referring to the tables in sections 4 and 5, the first column lists the permit term number and pollutant or type of requirement. The permit terms are numbered consecutively so that the reader may locate a listed requirement. Next, the citation column includes the legal citation which is a federally enforceable requirement unless listed as "state only". The "description" column is a paraphrase of the requirement and is not intended to be a legal requirement as it is for descriptive purposes only. The "test method" column is the legal test method that the enforcement agency would use to confirm compliance with the requirement. However, it is not a requirement of the source unless stated in the last column, which lists the monitoring, recordkeeping and reporting (MR&R) requirements.

The MR&R column is a summary of the underlying requirement cited in the "citation" column and is not directly enforceable. If there is a statement in the MR&R column that states "directly enforceable" than that MR&R requirement is enforceable and represents gap filling done by the NWCAA during writing of the AOP. In some cases there are no MR&R or test methods listed in the AOP for a permit term. This is often due to the nature of the emission source, the lack of specifics in the underlying requirement and/or the slim likelihood that the legal requirement will be violated.

4.2.4. Gap-Filling

There are some air pollution rules and regulations and OAC conditions that do not specifically call out a monitoring, reporting, or recordkeeping method(s) to demonstrate compliance with the applicable requirement. In this case the permitting agency would develop a site-specific requirement that the source must follow. The inclusion of these customized requirements is called "gap filling". The refinery has many specific monitoring, reporting, and recordkeeping requirements in the form of continuous emission monitors and periodic reporting. In some instances however, gap filling has been used. For instance, nuisance rules and opacity requirements have site specific gap filled obligations for the source. Any areas where gap-filling has taken place, the monitoring, recordkeeping and reporting for that term will state "directly enforceable".

4.2.5. Specific Requirements for Emission Units

This section lists applicable requirements that specifically apply to the emission units. The emission units are grouped by process unit and or area. The emission limitations and monitoring, recordkeeping and reporting requirements are derived from BACT determinations and/or from applicable regulations. The format and organization of this section is the same as the table for generally applicable requirements. As with generally applicable requirements some specifically applicable requirements do not have source monitoring requirements due to the inherent nature of the source and the likelihood that the legal requirement will not be violated.

The refinery uses CEMs and COMs to continuously monitor various emission units for SO_2, NOx, CO, O_2 and opacity. In these cases continuous compliance for concentration and mass emission limits is a straightforward determination. Pollutants not continuously monitored are VOCs and fine particulates. Periodic opacity observations and source test data assure that the permit conditions for fine particulate are not exceeded. Low carbon monoxide emissions measured by a CEM are an indicator of good combustion and consequently can serve as a surrogate monitoring parameter for VOC compliance.

4.2.6. Inapplicable Requirements

WAC 173-401-640 requires that the permitting authority to issue a determination regarding the applicability of requirements with which the source must comply. The Air Operating Permit lists requirements that are deemed inapplicable to the facility. The basis for each determination of inapplicability is included.

4.2.7. Insignificant Emissions Units

Categorically exempt emissions units listed in WAC 173-401-532 are present at the refinery. These emission units have very low, if any, emissions associated with their use and are therefore considered insignificant by regulation.

4.3 Public Docket

Copies of BP Cherry Point Refinery's Air Operating Permit, permit application and technical support documents are available at the following location:

Northwest Clean Air Agency
1600 South Second Street
Mount Vernon, WA 98273-5202
www.nwcleanair.org

4.4 Definitions and Acronyms

Definitions are assumed to be those found in the underlying regulation. A short list of definitions has been included to cover those not previously defined.

An "applicable requirement" is a provision, standard, condition or requirement in any of the listed regulations or statutes as it applies to an emission unit or facility at a stationary source.

An "emission unit" is any part or activity of a stationary source that emits or has the potential to emit any regulated air pollutant.

A "permit" means for the purposes of the air operating permit program an air operating permit issued pursuant to Title 5 of the 1990 Federal Clean Air Act.

"Technology-Based Emission Standard" means a standard, the stringency of which is based on determinations of what is technologically feasible considering relevant factors.

"State" means for the purposes of the air operating permit program the NWCAA or the Washington State Department of Ecology.

The following is a list of Acronyms used in the Air Operating Permit and/or Statement of Basis:

AIRS	Aerometric Information Retrieval System
AMP	Alternative Monitoring Plan
AOP	Air Operating Permit
ASIL	Acceptable Source Impact Level
ASTM	American Society for Testing and Materials
Avjet	aviation jet fuel
BACT	best available control technology
BHU	Butadiene Hydrogenation Unit
BQ6	Benzene waste Quantity under 6 Mg/yr (wastewater)
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CD	Consent Decree
CEM	continuous emission monitor
COM	continuous opacity monitor

CFR	Code of Federal Regulations
CRU	Catalytic Reforming Unit
DAF	Dissolved Air Floatation (wastewater)
DHDS	Diesel Hydrodesulfurization Unit
DCU	Delayed Coking Unit
EFR	External Floating Roof (tank)
ESP	Electrostatic Precipitator
FCAA	Federal Clean Air Act
FCCU	Fluid Catalytic Cracking Unit
HAP	Hazardous Air Pollutants
HC	hydrocarbon
HDS	Hydrodesulfurization
HON	Hazardous Organic NESHAP
HTU	Hydrotreater Unit
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HRSG	heat recovery steam generator
HSR	Heavy Straight Run
IFR	Internal Floating Roof (tank)
ISO	International Standards Organization
kPa	kilopascals (10^3 pascals pressure)
LDAR	leak detection and repair
LEL	lower explosive limit
MACT	Maximum Achievable Control Technology
MDEA	methyl-diethanolamine
Mg	megagrams (10^6 grams mass)
MMBtu	million British thermal units
MR&R	monitoring, recordkeeping and reporting requirements
MTVP	maximum true vapor pressure
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOC	Notice of Construction
NOx	oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
NWCAA	Northwest Clean Air Agency
O_2	oxygen
OAC	Order of Approval to Construct
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in diameter
ppmvd	parts per million by volume, dry
psia	pounds per square inch atmospheric
PTE	Potential to Emit (annual, unless otherwise noted)
PRD	pressure relief device
QA/QC	quality assurance/quality control
RCW	Revised Code of Washington
RMACT	Refinery MACT per 40 CFR 63 Subpart CC
RO	Regulatory Order (under WAC 173-400-091)
SCR	selective catalytic reduction
SOP	Standard Operating Procedure
SRU	Sulfur Recovery Unit
SIP	State Implementation Plan
SO_2	sulfur dioxide
TAB	Total Annual Benzene

TGU	Tail Gas Unit
VPS	Vacuum Pipe Still (Crude Unit)
VOC	volatile organic compounds
VOL	volatile organic liquid
WAC	Washington Administration Code
WDOE	Washington State Department of Ecology
WESP	wet electrostatic precipitator
WWSG	Waste Water Stripper Gas

Appendix A - LIST OF 2006 AOP MODIFICATIONS

Permit Information Page

- ♦ Changed permit applicability dates

Section 1 - Emission Unit Group Identification

- ♦ Included new processing equipment in the listing of sources as identified in recently issued OAC's (see Section 5 below).
- ♦ Added firing or rate capacities for heaters, boilers and calciners

Section 2 – Standard Terms and Conditions

- ♦ Included the latest version of this section with new dates and language from revisions to WAC 173-040 and NWCAA Regulations

Section 3 - Standard Terms and Conditions for NSPS and NESHAPS

- ♦ Added a new language that includes April 20, 2006 revisions to requirements for Startup, Shutdown and Malfunction (SSM) Plans

Section 4 – Generally Applicable Requirements

- ♦ Changed WAC 173-040 and NWCAA Regulations applicability dates

Section 5 – Specifically Applicable Terms and Conditions

- ♦ Added new permit terms for new processing units, processing unit modifications and OAC revisions indicated in the following list:
  - OAC #273b – New CO limits on North Vacuum Heater
  - OAC # 814a – Installation of a new Isomerization Unit consisting of a Straight Run Naphtha Dehexanizer, Benzene Saturation Unit, Isomerization Process Heater (Clean Gasoline Project) and a new gas fired boiler (Boiler #5)
  - PSD 02-04 Amendment - 1 Clean Gasoline Project
  - OAC # 847 – Installation of new low NOx burners on the Hydrocracker 2nd Stage Fractionator Reboiler
  - OAC #850 – Modifications at the Hydrocracker to allow processing of incremental Vacuum Gas Oil production
  - OAC #890a – Construction and operation of a second Tail Gas Unit (#2 TGU) at the Sulfur Recovery Plant
  - OAC #892 – Construction and operation of a new #2 DHDS

- OAC #897 – Installation of a new 365,000 internal floating roof crude oil storage tank – Tank 40
- OAC # 902a – Installation of ultra-low NOx burners in the existing South Vacuum Heater
- OAC #949 - Installing of ultra-low NOx burners in existing #1 DHDS Charge Heater and #1 DHDS Stabilizer Reboiler Heater

♦ Added 40 CFR Part 60 Subpart Db regulations for boilers

♦ Added 40 CFR Part 63 Subpart UUU requirements for Reformer regeneration and Sulfur Recovery Unit

♦ Added 40 CFR Part 63 Subpart DDDDD Requirements for applicable process heaters and boilers

Section 6 – Specifically Applicable Common Requirements

♦ Added new Subsection 6.3 with Enhanced Monitoring provisions required for the Isomerization Unit, the #2 DHDS Unit and portions of the Hydrocracker Unit and the #1 DHDS Unit.

Section 7 – Inapplicable Requirements

♦ Removed 40 CFR 63 Subpart Y provisions (NESHAPS for Marine Tank Vessel Loading Operations)