Statement of Basis for the Air Operating Permit – AOP 015R2

- Final -

BP Products North America, Inc.
Cherry Point Refinery

Blaine, Washington

Final June 15, 2022

northwest Clean Air agency

Serving Island, Skagit & Whatcom Counties

PERMIT INFORMATION

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1 INTRODUCTION AND GENERAL FACILITY DESCRIPTION

The Cherry Point Refinery is currently owned by BP Products North America, Inc. following a December 31, 2019 merger with BP West Coast Products, LLC (former owner) and BP Products North America, Inc. The facility is required to obtain an Air Operating Permit (AOP or permit) because it has the potential to emit the following:

- 100 tons or more per year of nitrogen oxides (NO_x), sulfur oxides (SO_x), particulate matter (PM_{10}) and carbon monoxide (CO);
- 10 tons per year or more of any hazardous air pollutant; and
- 25 tons or more per year of a combination of hazardous air pollutants.
- Both 100,000 tons of carbon dioxide equivalent (CO_2e) per year and 100 tons of greenhouse gases (GHG) per year.

The purpose of this Statement of Basis (SOB) is to set forth the legal and factual basis for the terms of the Air Operating Permit (AOP) issued to the Cherry Point Refinery under the authority of the Washington Clean Air Act, Chapter 70A.15 Revised Code of Washington (RCW), Chapter 173-401 of the Washington Administrative Code (WAC), and Northwest Clean Air Agency Regulation Section 322. Unlike the permit, this document is not legally enforceable in accordance with WAC 173-401-700(8). It includes references to the applicable statutory or regulatory provisions that relate to the Cherry Point Refinery's air emissions and provides background information to facilitate review of the permit by interested parties.

1.1 Facility Description

The Cherry Point Refinery is located at 4519 Grandview Road in Blaine, WA, within Whatcom County. As shown in Figure 1.1-1 below, the refinery is on the coastline adjacent to the Strait of Georgia in a rural setting zoned for heavy industrial use. The surrounding land use is agricultural. Immediately to the west of the refinery is Puget Sound Energy's Whitehorn Generating Station comprised of a gas turbine peaking power generating station. Alcoa Aluminum Corporation and the Phillips 66 refinery are located south of the Cherry Point Refinery. Approximately two miles north of the refinery is the community of Birch Bay. The area surrounding the Cherry Point Refinery is designated in attainment for all National Ambient Air Quality Standards (NAAQS).

Figure 1.1-1 Cherry Point Refinery Footprint

The Cherry Point Refinery is a petroleum refinery that uses crude oil and some renewable feedstocks like animal tallow and soybean oil that are processed into a variety of petroleum products including gasoline, diesel, jet fuel, green coke, anode-grade calcined coke, liquefied petroleum gas (LPG), butanes, pentanes, elemental sulfur, and intermediates such as reformate. The refinery has a crude oil/renewable feedstock throughput capacity of approximately 250,000 barrels per day. These activities are classified under the Standard Industrial Classification code 2911.

The refining process at the Cherry Point Refinery is described as follows. Crude oil is received via marine tanker, rail car, and pipeline. Crude oil enters the refining process at the Crude Distillation Unit where hydrocarbon is separated into light and heavy fractions based on their boiling point. These fractions or "cuts" are routed to other process units where they undergo thermal cracking, catalytic cracking, catalytic reforming, isomerization, or treatment. Renewable diesel feedstocks (typically refined animal tallow and soybean oil) are received via truck and routed to a treating system for processing. Treating systems are used to remove or reduce fuel impurities such as sulfur and benzene. Sulfur is recovered in the Sulfur Recovery Unit (SRU) as elemental sulfur. Some of the lighter hydrocarbons are flashed off as gases during processing and used as fuel in the refinery's fuel gas systems. The refinery has an oily wastewater system that routes hydrocarbon contaminated wastewater to the refinery's wastewater treatment system prior to discharge into the Straits of Georgia. In final processing fuel components are blended into finished products and stored. Products are sent to market in several ways. Marine vessels and barges are used to ship gasoline, diesel jet fuel and intermediates. Pipelines are used to distribute gasoline, diesel, renewable diesel, and jet fuel. Rail cars are used to distribute LPG, butanes, sulfur, green coke, and calcined coke. Trucks are used to distribute LPG, gasoline, diesel, renewable diesel, 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 or by geographical areas within the refinery. Section 1 of the AOP presents a list of the process units/areas at the Cherry Point Refinery. Each major emission unit such as a heater or boiler has an associated equipment number. This identification number begins with a number identifying the process unit or area followed by the equipment number. The maximum firing rate capacity in million Btu per hour (MMBtu/hour) for each heater and boiler is included in Section 1 of the AOP. These firing capacities are derived from NWCAA construction permit documents, or when this information is not available, from the refinery's annual Emission Inventory or 40 CFR Part 98 CY 2019 greenhouse gas emission report.

The process flow diagram presented in Figure 1.1-2 below represents the interrelationship between process units within the refinery as of July 2018.

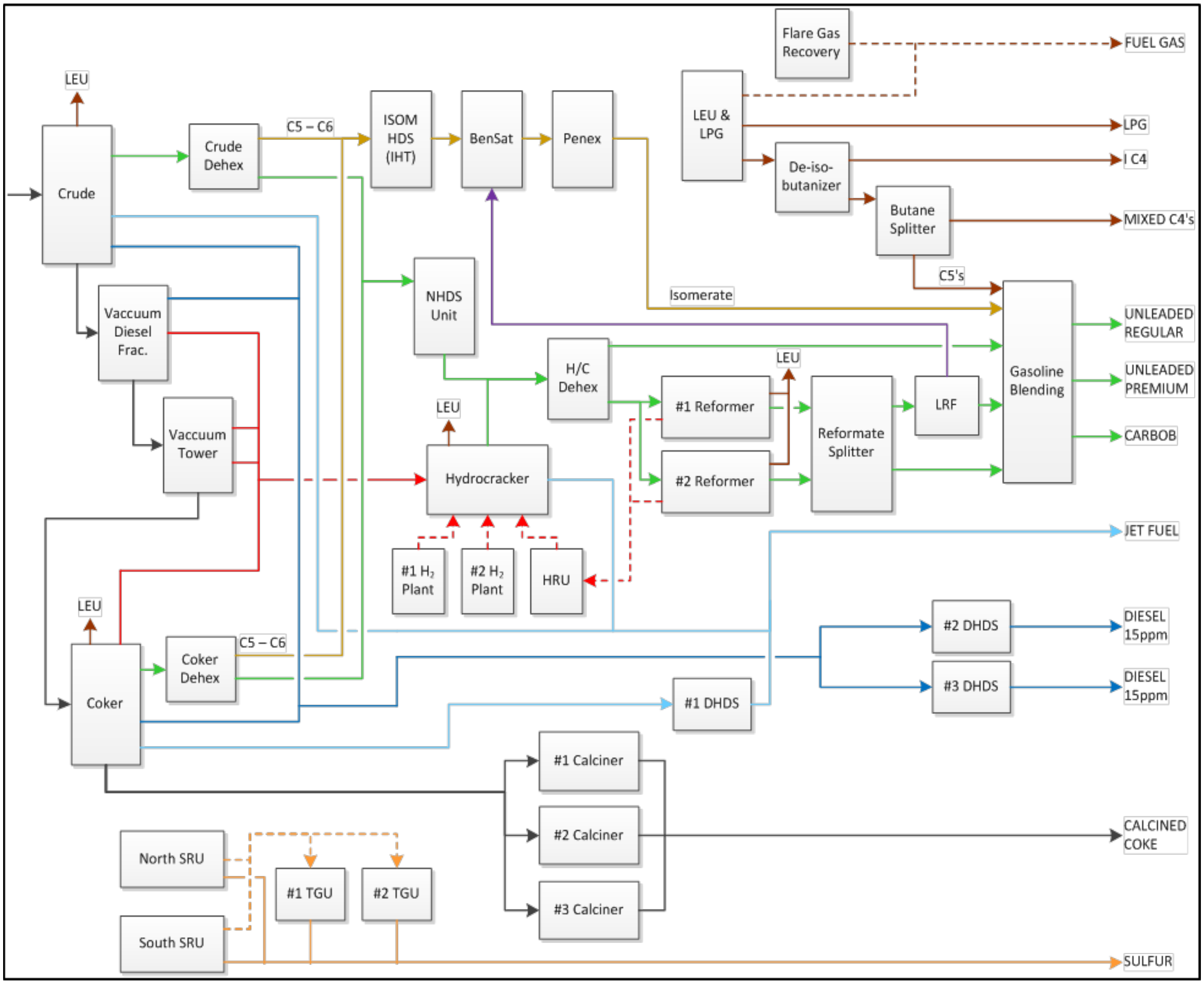

Figure 1.1-2 Cherry Point Refinery PFD

A more detailed description of common petroleum refinery processes and the resulting air emissions may be found in Chapter 5 of EPA's publication AP-42, Compilation of Air Pollutant Emission Factors. The principal sources of air emissions from the refinery include:

- Combustion units such as process heaters and boilers,
- Coking and calcining,
- Storage of hydrocarbon in tanks including crude oil, gasoline, intermediates, and byproducts,
- Fugitive emissions from leaking valves, pumps, and compressors, and other components,
- Hydrocracking,
- Sulfur Recovery Unit, and,
- Oily wastewater conveyance and treatment at the effluent plant.

All of the process heaters and utility boilers at the refinery are fueled by gases generated at the refinery. Refinery fuel gas is also used for supplemental firing at the Sulfur Recovery Complex Incinerator and for supplemental firing of the #1, #2 and #3 Calciners to generate steam when calcining operations are curtailed. Refinery fuel gas is typically generated as a by-product of the light gases separated at the top portions of distillation towers that are located throughout the refinery. These gases are collected and treated with amine to remove H_2S prior to distribution to the combustion devices.

There are three distinct refinery fuel gas streams at the Cherry Point Refinery. The main refinery fuel gas system collects gases from all the processing units except the Delayed Coking Unit (DCU). The gases are combined and mixed in the main mix drum before being routed to combustion devices throughout the refinery. When the refinery's fuel gas needs exceed on-site fuel gas generation, purchased natural gas is used to supplement the volume of gas in the main mix drum. The second refinery fuel gas stream is produced at the DCU and combusted in the East and West Coker Charge Heaters. The Delayed Coker fuel gas is rich in sulfur bearing mercaptans that are not removed during amine scrubbing. The third refinery fuel gas stream is vacuum tail gas that is produced in the vacuum section of the Crude and Vacuum Unit. The vacuum tail gas stream is relatively small in volume but rich in sulfur compounds. The vacuum tail gas is combusted in the Crude Heater along with fuel gas from the main mix drum.

The Delayed Coker fuel gas system and main refinery mix drum and are linked so that if one is short on fuel gas, the other fuel gas system may supplement. Under normal refinery operations the Delayed Coker generates excess fuel gas and supplements the supply of gas to the main refinery mix drum. Because the fuel gas generated at the Delayed Coker is characteristically high in non-H_2S sulfur compounds such as mercaptans, it may increase SO_2 emission rates from fuel gas combusted throughout the refinery when used.

1.2 <u>Permit Revisions during Second Renewal</u>

The NWCAA received the application for the second air operating permit renewal on January 15, 2017. The following revisions have been made to the AOP during this renewal.

- Revised the source contact information and general permit information on the permit information page.
- Revised Section 1 to reflect the current list of emission units, including the removal of the North and South Coker Heaters and their replacement with the East and West Coker Heaters. The order of the units listed in Section 1 has also been revised to better reflect the flow through the refinery.
- Revised Sections 2 and 3 to update applicable requirement effective dates and be consistent with current NWCAA format and content and clarify NWCAA's authority to enforce applicable requirements in the introductory text of each section. In addition to rule citation date changes in Section 2, these updates included revising references to RCW 70.94 with current RCW 70A.15. In Section 3, rule and delegation letter citation dates were updated, and the following subsections (as numbered in AOP 015R2) were substantially revised or added to align with currently applicable NSPS and NESHAP language:
    - 40 CFR Part 60 NSPS
        - 3.1.3 Startup, Shutdown, and Malfunction Records
        - 3.1.4.2 Excess Emissions Reports for 40 CFR 60 Subpart Ja Affected Sources
        - 3.1.6 Performance Tests
        - 3.1.19 Deadlines for Importing or Installing Stationary Compression Ignition Internal Combustion Engines Produced in Previous Model Years for 40 CFR 60 Subpart IIII

  - 40 CFR Part 61 NESHAP
    - 3.2.8 Emission Tests
  - 40 CFR Part 63 NESHAP
    - 3.3.3 Operation and Maintenance (affected sources include those subject to Subparts CC, UUU, ZZZZ, and DDDDD, which have specific O&M/general duty requirements, and are therefore included in either Section 4 or in Section 6.5)
    - 3.3.4 Startup, Shutdown, and Malfunction Plan (removed SSMP requirements for Subpart CC, UUU, and DDDDD)
    - 3.3.5 Compliance with Non-Opacity Emission Standards
    - 3.3.6 Compliance with Opacity and Visible Emission Standards
    - 3.3.8 Notification of Performance Tests (addition of language for Subpart CC and Subpart UUU affected sources)
    - 3.3.9 Conduct of Performance Tests
    - 3.3.10 Operation and Maintenance of Continuous Monitoring Systems (addition of language for Subpart CC and Subpart UUU affected sources)
    - 3.3.11 Continuous Monitoring Systems Out of Control Periods (addition of language for Subpart CC affected sources)
    - 3.3.12 Continuous Monitoring Systems Quality Control Program (addition of language for Subpart CC affected sources)
    - 3.3.13 Continuous Monitoring Systems Data Reduction (addition of language for Subpart CC, UUU, and ZZZZ affected sources)
    - 3.3.15 Notification (addition of language for Subpart UUU affected sources)
    - 3.3.16 Recordkeeping (addition of language for Subpart CC and UUU affected sources)
    - 3.3.17 Startup, Shutdown, and Malfunction Recordkeeping and Reports (addition of language for Subpart UUU and DDDDD affected sources)
    - 3.3.18 Reports (addition of language for Subpart CC, UUU, DDDDD affected sources)
    - 3.3.19 Deviation Reporting (addition of language for Subpart UUU affected sources)
    - 3.3.20 Recordkeeping Requirements for Sources with Continuous Monitoring Systems (addition of language for Subpart CC, UUU, DDDDD affected sources)
    - 3.3.21 Notification of Compliance Status
  - 40 CFR Part 65 Consolidated Federal Air Rule
    - 3.4.1-3.4.7 General Provisions of Part 65 (addition of language for sources referenced to Part 65 by a NSPS or NESHAP)
- Revised Sections 4 and 5 to update them with current federal, state and NWCAA regulatory citations and their applicable requirements to reflect any new or revised applicable regulation and clarify NWCAA's authority to enforce applicable requirements in the introductory text of each section as well as pair the enforcement authority citation with each specific condition. The order of emission units in Section 5 has also been revised in order to better reflect the flow through the refinery.

Substantial revisions in Section 4 (as numbered in AOP 015R2) include:

- 4.28 40 CFR 61 Subpart FF Benzene Waste Operations Refinery MACT Wastewater Provisions
- 4.29 & 4.30 Refinery MACT I
- 4.31-4.33 Refinery MACT II
- 4.34 & 4.35 RICE MACT
- 4.37-4.40 Fenceline Benzene Monitoring
- 4.41 MACT Maintenance Vents

Section 5 was revised with new and modified construction orders (i.e., OAC and PSD permits). This includes two new and 20 revised Orders of Approval to Construct issued by the NWCAA, and one new and six amended Prevention of Significant Deterioration permits issued by Ecology.

The following AOP subsections were revised with new or modified OACs and PSDs:

- 5.1 Crude and Vacuum Unit
  - OAC 273c
  - OAC 689c
  - OAC 814d
  - OAC 1200
  - PSD-5-A4
- 5.2 Isomerization Unit
  - OAC 814d
  - PSD-02-04-A2
- 5.3 Reformer and Naphtha Units
  - OAC 305b
  - OAC 977a
  - PSD-7-A1
- 5.5 Hydrocracker Unit
  - OAC 847d
  - OAC 850a
  - OAC 966d
- 5.6 Hydrogen Plants
  - OAC 1064b
  - PSD 10-01-A1
- 5.7 Delayed Coker
  - OAC 1200
  - OAC 1201b
  - OAC 1289
  - PSD-16-01
- 5.8 Sulfur Recovery Complex
  - OAC 1201b
- 5.9 #1 DHDS
  - OAC 949c
- 5.10 #2 DHDS
  - OAC 892d
- 5.11 #3 DHDS
  - OAC 1064b
  - PSD 10-01-A1
- 5.12 Calciners and Coke Handling
  - OAC 660b
  - OAC 689c
  - OAC 985c
  - PSD-95-01-A2

  - 5.13 Boilers and Cooling Towers
    - OAC 289b
    - OAC 351f
    - OAC 814d
    - OAC 1001e
    - PSD-07-01-A2
    - PSD-02-04-A2
  - 5.15 Shipping, Pumping, and Receiving
    - OAC 527f
  - 5.18 Petroleum Storage Tanks
    - OAC 527f
    - OAC 562e
- Removed any reference to the 2001 BP Exploration & Oil Co, et al. Consent Decree from the AOP. The Consent Decree provisions applicable to the Cherry Point Refinery were terminated May 13, 2020 by the Eleventh Amendment. References to the Consent Decree have been left in the SOB for historical purposes only.
- Added Section 6.6 for pressure relief devices subject to the Refinery MACT.
- Revised the list of inapplicable requirements in Section 7.
- Revised the list of definitions and acronyms in Section 8.

1.3 Enforcement History

A summary of Notices of Violation issued to the refinery by the NWCAA from October 2012 through August 2021 is presented in Table 1.3-1 below. All violations have been resolved through a combination of penalty assessments and by corrective action taken by the source.

Table 1.3-1 Notice of Violations Issued to the Cherry Point Refinery

Case No.	Violation Date	Issue Date	Description
4016a	10/20/12	04/17/13	#2 Tail Gas Unit depowered during maintenance due to inaccurate electrical diagrams, resulting in excess SO_2 emissions.
4057	12/13/12	11/12/13	Partial shutdown of Calciner Unit for planned maintenance, resulting in excess SO_2 emissions.
4039	01/12/13	09/05/13	Incompatible electrical equipment caused trip within SRU, resulting in excess SO_2 emissions.
4084	11/30/13	05/09/14	Automated Safety Instrumented System (SIS) tripped Hydrocracker Unit wet gas compressor, resulting in excess SO_2 emissions.
4093	09/18/13	05/30/14	Failed annual PM_{10} source test at Boiler #7.
4205	03/05/16	06/29/16	Shutdown of Flare Gas Recovery Unit (FGRU) compressor, resulting in excess SO_2 emissions.
4275	05/25/17	04/24/18	Startup of Hydrocracker Unit, resulting in excess SO_2 emissions.
4273	12/17/16 02/26/17 05/17/17 11/25/17	06/19/18	4 separate incidents within the SRU resulting in excess SO_2 emissions.
4274	04/12/18	06/20/18	Release of odorous compounds during turnaround activities resulting in verified nuisance odor impacts at neighboring properties.

1.4 Source Tests and Continuous Emissions Monitoring Systems (CEMS)

Each year, source tests at refinery process units are performed to determine compliance with emission limits and standards found in Orders of Approval to Construct (OAC) issued by NWCAA, Prevention of Significant Deterioration (PSD) permits issued by Ecology, and as part of New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutants (NESHAP) requirements. Appendix A to this document lists the source tests performed and results for the previous permit period.

Note that some emission units at the Cherry Point refinery are not source tested because the units are equipped with Continuous Emissions Monitoring Systems (CEMS). The Cherry Point Refinery is required by federal, state, and local standards, and AOP and OAC conditions to operate and maintain CEMS at 20 pieces of equipment or processes.

Table 1.4-1 below lists the CEMS at each process unit and the pollutant(s) being monitored. Note that while the CEMS for the main refinery fuel gas mix drum is listed as a separate table entry, the CEMS measures H_2S and TS for all of the heaters and boilers that use fuel from the drum. That includes the majority of fuel burning units at the facility.

Table 1.4-1: CEMS at the Cherry Point Refinery

CEM Location	Pollutant Monitored
South Vacuum Heater	NO_x, O_2
North Vacuum Heater	NO_x, O_2
#1 DHDS Charge Heater	NO_x, O_2
#1 DHDS Stabilizer Reboiler	NO_x, O_2
Hydrocracker 1st Stage Reactor Heater	NO_x, O_2
Hydrocracker 1st Stage Fractionator Reboiler	NO_x, O_2
#1 & #2 Calciners	SO_2, NO_x, CO_2, O_2
#3 Calciner	SO_2, NO_x, CO_2, O_2
#4 Boiler	NO_x, O_2
#5, 6 & 7 Boilers	NO_x, CO, O_2
#2 Hydrogen Plant SMR Furnace	SO_2, NO_x, CO, CO_2, O_2
Main Refinery Fuel Gas Mix Drum	H_2S, TS
Coker Fuel Gas	H_2S
East Coker Charge Heater	SO_2, NO_x, CO, CO_2, O_2
West Coker Charge Heater	SO_2, NO_x, CO, CO_2, O_2
Vacuum Tail Gas (Crude and Vacuum Unit)	H_2S
Sulfur Recovery Complex, Incinerator	SO_2, O_2
Sulfur Recovery Complex, #2 TGU	SO_2, O_2
Low-Pressure Flare	H_2S, TS
High-Pressure Flare	H_2S, TS

1.5 Periodic Reports

The Cherry Point Refinery has periodic reporting requirements contained in various orders and regulations. Reported elements provide a valuable tool indicating the refinery's compliance status with an applicable emission limit or operational limit. In addition to these periodic reports the refinery has specific action-based notifications and on-site recordkeeping requirements.

Monthly Reports:

Monthly emissions reports are submitted to the NWCAA within 30 days of the end of each calendar month. The supporting data must be maintained for least five years from date of generation. Monthly emission reports for the refinery include a wide range of data collected during the month, including maximum and average emissions for various pollutants for some process units, continuous emission monitoring system (CEMS) performance data (which provides information about the duration and nature of CEMS downtime, changes made to the CEMS, total operating time, and dates of CEMS audits or certifications), excess emissions, monitoring plan compliance, and AOP term deviations.

Quarterly and Semiannual Reports:

The refinery is required to submit quarterly reports under 40 CFR 61 Subpart FF certifying that the company met all applicable Subpart FF requirements. These include, but are not limited to, visual inspections of seals, hatches and openings, identification of API floating roof seal gap measurements, an indication that seal gaps were repaired within required timeframes, an indication that all flare pilots were lit at all times when process gas was sent to the flare, carbon canisters were replaced within required timeframes, and certification that all required inspections have been performed.

Quarterly CEMS quality assurance reports which document drift, out of control periods, and the results of relative accuracy test audits (RATA) and cylinder gas audits (CGA) are also required.

40 CFR 60 Subpart Db quarterly reporting includes NOx emission rates and CEMS performance data for the #4, #5, #6 & #7 Boilers.

The refinery is required to submit semiannual reports under 40 CFR 63 Subparts CC and UUU which address any deviations from the requirements of the rules including, but not limited to: delay of repair of storage tanks, failure of any pilot light on a flare, and leak detection and repair monitoring summaries. Subpart CC Fenceline benzene monitoring reports are submitted quarterly via EPA's CEDRI electronic reporting system.

Semiannual reports required under 40 CFR 60 Subparts J/Ja require disclosure of flare root cause analyses and corrective action analyses.

Semiannual reports required under 40 CFR 60 Subpart QQQ require reporting the date and type of defect found during inspection of individual drain systems along with the corrective action taken.

The leak detection and repair (LDAR) program (required under multiple regulations) also requires a semiannual report that summarizes the number of leaking components found and the number of components that were not repaired in a timely manner, an explanation as to the reason for the delay of repair, any process unit shutdowns, and any revisions to the program since the initial report.

Annual Reports:

40 CFR 61 Subpart FF requires an annual report that summarizes the total annual benzene (TAB) quantity from facility waste, identifies each waste stream, whether the waste stream will be controlled for benzene, and for uncontrolled streams, the uncontrolled annual benzene quantity.

The refinery is also required to submit an annual report under 40 CFR 61 Subpart FF that includes the results of annual monitoring per Method 21 and a summary of annual inspections of individual drain systems and vacuum trucks.

40 CFR 63 Subpart DDDDD requires an annual compliance report that summarizes tune-ups performed on subject boilers and heaters and post-tune-up combustion analysis.

Compliance Certifications:

All required monitoring reports must be certified by a responsible official who states that the information contained within are true, accurate, and complete after reasonable inquiry. Where an applicable requirement requires reporting more frequently than once every six months, the responsible official's certification need only to be submitted in a semiannual report that specifically identifies all documents subject to the certification.

Also, the refinery is required to submit an annual compliance certification that lists each term of the permit, the compliance status, whether the compliance was continuous or intermittent, and the methods used for determining the compliance status.

1.6 Annual Emission Inventories

Each year the refinery is required to submit an air pollution emissions inventory upon request of the NWCAA. This report includes criteria air pollutants, hazardous air pollutants (HAP), and from 2010 forward greenhouse gas (GHG) emissions. Emissions from the Cherry Point Refinery are included in the NWCAA emissions inventory that the agency publishes each year on its website that includes emissions summaries for all of the large industrial facilities located within Whatcom, Skagit and Island counties.

Table 1.6-1 summarizes the last five years of available emissions data for the Cherry Point Refinery. In general, emission rates at the refinery vary from year to year depending on the slate of crude oils used as a feedstock, the types and amounts products produced, modifications to process equipment and/or emission control devices, and to some extent improvements in the methods used to calculate emissions.

Table 1.6-1: Annual Emissions from the Cherry Point Refinery

Pollutant	Calendar Year Emissions (tons)				
	2016	2017	2018	2019	2020
PM_{10}	118	84	130	134	126
SO_2	781	828	726	608	649
NOx	1,905	1,930	1,820	1,916	1,706
VOC	362	361	417	484	401
CO	427	425	289	336	465
HAP	81.2	88.3	82.9	133.8	111.6
GHG (CO_2e)	2,540,369	2,131,918	2,140,426	2,418,086	2,121,888

1.7 Miscellaneous Refinery Non-Process Activities

There are several regulated activities that can emit air pollutants not generated by refining processes. These include refinery laboratory services, asbestos removal, fire training, abrasive blasting, painting, gasoline dispensing and cutback asphalt paving. Asbestos removal occurs during the demolition or modification of buildings and piping that are likely to contain asbestos-containing materials such as insulation and tiles. The refinery is subject to federal, state and NWCAA asbestos requirements. Fire training employs open burning during the instruction of the refinery's emergency response personnel. Open burning activities are subject to state and NWCAA requirements. Abrasive blasting and painting occurs during maintenance and repair activities of tanks and equipment at the refinery to remove old and chipped paint and surface contaminants. This activity is subject to state and NWCAA regulations. Gasoline is dispensed from one pump for fueling the refinery's fleet of vehicles used on site, regulated under NWCAA gasoline dispensing regulations. Finally, cutback asphalt paving occurs from time to time at the refinery to repair road and other impermeable surfaces. The use of cutback asphalt is subject to NWCAA regulations.

1.8 Insignificant Emission Units

The refinery has emission units and activities determined to be insignificant under WAC 173-401-530, -532, and -533. In general, they are considered insignificant because they have low emission rates or generate only fugitive emissions. The Generally Applicable Requirements in Section 4 of the air operating permit apply to these units, although the testing, monitoring, recordkeeping, and reporting requirements do not apply. As specified in WAC 173-401-530(2)(a), no emission unit or activity subject to a federally enforceable requirement, other than generally applicable requirements of the state implementation plan, may qualify as insignificant.

2 GENERAL REGULATORY REQUIREMENTS

This portion of the Statement of Basis identifies and discusses general regulatory applicability of a wide range of local, state and federal programs, orders, and requirements that apply broadly across the refinery to various refinery processes, process units, or equipment.

For a more detailed discussion of each process unit and its specifically applicable standards, including any approved Alternative Monitoring Plans in force, see Section 3 of this document.

2.1 Federal Standards – Refinery-Wide

2.1.1 40 CFR Part 60 - New Source Performance Standards (NSPS)

NSPS apply to the control of criteria pollutants emitted from specific types of sources that have been constructed or modified after the applicability date of each rule. Criteria air pollutants are those associated with national ambient air quality standards and include carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC) for secondary ozone formation. Generally, NSPS regulations are directly applicable based on the date an affected unit was constructed, reconstructed or modified.

The following is a summary of NSPS regulations that are either directly applicable or referenced by an applicable regulation at the Cherry Point Refinery.

2.1.1.1 40 CFR 60 Subpart A – General Provisions

When an NSPS applies to a facility, the General Provisions of 40 CFR 60 Subpart A also apply. Some of the requirements of Subpart A are included in the AOP, and some are not. Generally, if a Subpart A requirement is applicable when triggered by a particular action it is found in Section 3 of the AOP. Similarly, if a part of Subpart A does not have a specific requirement for the facility it is not included in the AOP. If the requirement was something in the past that was a one-time requirement that has been completed, it is not in the AOP.

2.1.1.2 40 CFR 60 Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Based on their heat input capacity size being greater than 100 MMBtu/hour and date of construction being after June 19, 1984, all boilers at the Cherry Point Refinery (#4, #5, #6 & #7) are affected units under Subpart Db and subject to the NOx and SO_2 requirements of the rule. To demonstrate compliance with the 0.20 lb/MMBtu limit each boiler is equipped with CEMS to continuously monitor NOx emissions. Subpart Db requires that the NOx CEMS be calibrated at 500 ppm, however, because of relatively low BACT limits for NOx applicable to each boiler established under OACs, each CEM is operated at a range below 500 ppm. Specifically, the CEM for the #4 Boiler has a NOx ppm range of 0-250 ppm, while #5, #6 & #7 Boilers have a range of 0-100 ppm. As a result, it is impractical to calibrate the CEMS at the Subpart Db specified 500 ppm value. Instead, they are calibrated within the CEMS's monitoring range. This is a minor change to the refineries compliance method, and it is a change that EPA has allowed in writing for similar facilities. For example, EPA allowed Air Products and Chemicals, Incorporated of Kentucky to use a calibration value below 500 ppm for a Subpart Db applicable unit in their February 17, 2000, letter to the Kentucky Division of Air Quality (EPA ADI 0000029) "provided that the span value is set high enough to ensure that all emissions from the unit can be quantified". With regard to the NOx CEMS for #4, #5, #6 & #7 Boilers, the CEM may be operated and calibrated below 500 ppm as long as each boiler is operated within the range of its CEM.

40 CFR 60 Subpart Db includes a provision (60.40b(c)) requiring that each boiler meet the 162 ppm H_2S, three-hour average requirement of 40 CFR 60 Subpart J or Ja for fuel gas combusted in the boiler. Compliance with this limit is demonstrated using a CEMS for H_2S at the main fuel gas mix drum.

Subpart Db applies to each of the boilers at the refinery. However, because these boilers are required to combust only gaseous fuel, they are not subject to the particulate standards of Subpart Db.

This subpart includes a 100 MMBtu/hour heat input applicability threshold. As a result, the supplemental fuel firing for steam generation at the #1 & #2 Calciners (60 MMBtu/hour each) and the #3 Calciner (86 MMBtu/hour) are exempt from Subpart Db applicability.

2.1.1.3 40 CFR 60 Subpart J and Subpart Ja - Standards of Performance for Petroleum Refineries

NSPS Subpart J establishes CO, SO_2, and PM emission limits and associated requirements applicable to fluid catalytic cracking units (FCCU) constructed or modified after June 11, 1973, and SO_2 emission limits and associated requirements for fuel gas combustion devices constructed or modified after June 11, 1973 as well as for all Claus sulfur recovery plants with a design capacity for sulfur feed of greater than 20 long tons per day constructed or modified after October 4, 1976.

The Cherry Point Refinery does not operate an FCCU. The Cherry Point Refinery does operate a sulfur recovery unit (SRU) and fuel gas combustion devices that are (or were) subject to NSPS Subpart J because they were either constructed, reconstructed or modified after the applicability date or were mandated affected sources under NWCAA Agreed Compliance Order (ACO) 05. ACO 05 requires that heaters and boilers at the refinery meet the fuel gas sulfur limits of Subpart J for heaters and boilers that were in place on June 18, 2001, the lodging date of the BP 2001 Consent Decree.

NSPS Subpart Ja establishes emissions limits and associated requirements applicable to FCCUs, fluid coking units (FCU), delayed coking units (DCU), fuel gas combustion devices, flares, and sulfur recovery plants constructed, modified, or reconstructed after May 14, 2007. Upon triggering direct applicability under Subpart Ja, the requirements of NWCAA ACO 05 no longer apply as of the date of initial notification pursuant to 40 CFR 60.108a (ACO 05 Term V.B.).

BP does not operate an FCCU or an FCU. BP does operate a DCU, but it is not subject to Subpart Ja. BP operates an SRU, fuel gas combustion devices, and flares that are subject to NSPS Subpart Ja because they were either constructed, reconstructed, or modified after the applicability date.

Regulatory applicability is discussed for each of these groups of sources below.

Fuel Gas Combustion Devices and Flares

All fuel gases combusted in the refinery are required to meet the New Source Performance Standards (NSPS) under 40 CFR 60 Subpart J or Subpart Ja. Specifically, Subpart J directly applies to eight of the refinery's fuel gas combustion devices, and 16 fuel gas combustion devices are considered affected sources under Subpart J per ACO 05. Subpart Ja has been triggered for 10 fuel gas combustion devices, including the High-Pressure and Low-Pressure flares.

Flares under NSPS Subpart Ja are considered independent affected sources rather than fuel gas combustion devices. NSPS Subpart Ja requires flared gas be limited to 162 ppmv H_2S on a 3-hr average basis. Process upset gases and fuel gas released to the flare as a result of relief valve leakage or from an emergency malfunction event are exempt from this limit. BP monitors flare gas H_2S to demonstrate compliance with NSPS Subpart Ja. The NSPS Subpart J and Subpart Ja 162 ppmv H_2S limits are essentially equivalent.

NSPS Subpart Ja also requires that the refinery develop and implement a flare management plan; conduct root cause analyses and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 standard cubic feet per day (scfd) above the baseline flow in a 24-hour period, or contains sulfur that, upon combustion, will emit more than 500 pounds of

SO_2 in a 24-hour period by continuously monitoring flare flow and the sulfur content in flare gas. As such, BP has installed and maintains a flare flow meter and total sulfur analyzer on the flare. If the SO_2 is emitted from flaring during a planned refinery startup or shutdown, the root cause analysis and corrective action is not required but the discharge must be recorded and reported.

Within the last AOP period, four fuel gas combustion devices triggered Subpart Ja applicability. The North Vacuum Heater triggered the requirements of Subpart Ja upon startup on May 12, 2019 after installation of ultra-low NOx burners, permitted under OAC 273c. The East and West Coker Heaters, as new combustion sources replacing the North and South Coker Heaters under OAC 1200 and PSD 16-01, triggered Subpart Ja applicability upon startup on April 29 and May 12, 2019, respectively. The SRU Incinerator, which burns refinery fuel gas as a supplemental fuel, triggered Ja applicability as a fuel gas combustion device upon startup on May 9, 2015 after a modification permitted by OAC 1201a.

Table 2.1-1 below summarizes Subparts J and Ja and ACO 05 applicability for each combustion device at the refinery.

Table 2.1-1 : Subpart J and Ja Regulatory Applicability for Combustion Devices

Combustion Device	Subpart J	Subpart Ja	ACO 05
Crude Heater			X
South Vacuum Heater			X
North Vacuum Heater		X	
#1 Reformer Heater			X
#2 Reformer Heater	X		
Naphtha HDS Charge Heater			X
Naphtha HDS Stripper Reboiler			X
Hydrocracker 1st Stage Reactor Heater			X
Hydrocracker 2nd Stage Reactor Heater			X
Hydrocracker 1st Stage Fractionator Reboiler			X
Hydrocracker 2nd Stage Fractionator Reboiler			X
North Coker Charge Heater	Notice of Permanent Shutdown 5/20/19 and 5/6/19, respectively		
South Coker Charge Heater			
East Coker Charge Heater		X	
West Coker Charge Heater		X	
#1 Diesel HDS Charge Heater			X
#1 Diesel HDS Stabilizer Reboiler			X
#2 Diesel HDS Charge Heater	X		
#3 Diesel HDS Charge Heater		X	
Isomerization IHT Heater	X		
#1 Hydrogen Plant, North Reforming Furnace			X
#1 Hydrogen Plant, South Reforming Furnace			X
#2 Hydrogen Plant SMR Furnace		X	
#1 & #2 Calciners (supplemental fuel)	X		X
#3 Calciner (supplemental fuel)	X		X
#4 Boiler	X		X
#5 Boiler	X		
#6 Boiler		X	
#7 Boiler		X	
Truck Loading Rack Vapor Combustor	X		
Sulfur Recovery Complex Incinerator (supplemental fuel)		X	
High and Low-Pressure Flares		X	

Sulfur Recovery Units (SRUs)

The refinery operates one SRU (comprised of two recovery trains, but considered one affected facility under Subpart Ja), constructed in 1970 within the original refinery footprint. The SRU triggered Ja applicability upon startup on May 9, 2015 after a modification permitted by OAC 1201a.

NSPS Ja establishes an SO_2 limit for sulfur complexes that use oxidation or reduction followed by combustion. For Claus units that use only ambient air in the Claus burner, or that elect not to monitor the O_2 concentration in the air/fuel mixture used in the Claus burner, or for non-Claus units, this limit is 250 ppm, 12-hour rolling average. NSPS Ja requires that the refinery conduct root cause analyses and take corrective action after releasing more than 500 pounds of SO_2 over the allowable limit in a 24-hour period. The refinery continuously monitors SO_2 emissions from the Incinerator, which primarily services the #1 TGU, and the #2 TGU stack.

Subpart Ja also permits emissions from sulfur pits above the 250 ppm, 12-hour rolling average during periods of sulfur pit maintenance, not to exceed 240 hours per year.

Delayed Coking Units (DCU)

BP operates a DCU that is not subject to Subpart Ja. Subpart Ja includes coke drum depressurization limits for new, modified, or reconstructed DCU, which include the coke drums, fractionator, bottoms receiver, overhead condenser, coke cutting water and quench system, and coke drum blowdown recovery compressor system. BP's only modification to the DCU after the May 14, 2007 cut-off date involved installation a new booster compressor to the coke drum blowdown recovery system as part of a project permitted by OAC 1289 in 2020, but the project did not constitute a modification of the DCU under Subpart Ja because the DCU capacity and hourly emissions did not increase.

2.1.1.4 40 CFR 60 Subparts K, Ka and Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels

The following NSPS apply to tanks (i.e., vessels) storing organic liquids at the refinery depending on the date the tank was constructed, reconstructed or modified.

- 40 CFR 60 Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978
- 40 CFR 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

There are no tanks at the refinery that were constructed, reconstructed or modified during the applicability dates of 40 CFR 60 Subpart Ka.

- 40 CFR 60 Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984.

Refer to Section 1.18 of the AOP and "Storage Tanks and Vessels" in Section 3.17 of this document for a description of the storage tanks at the refinery, their applicable requirements, and discussion of regulatory standard overlap between these NSPS standards, and the NESHAP, local, and state standards that apply.

2.1.1.5 40 CFR 60 Subparts GGG and GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries; 40 CFR 60 Subparts VV and VVa - Standards Of Performance For Equipment Leaks Of VOC In The SOCMI

The refinery has constructed, modified, or reconstructed various process units, triggering the applicability of either 40 CFR 60 Subpart GGG, or the more recent Subpart GGGa. Subpart GGG applies to process units with equipment components in VOC service that have been constructed, reconstructed, or modified between January 4, 1983, and November 7, 2006. Subpart GGGa applies to process units with equipment components in VOC service that have been constructed, reconstructed, or modified on or after November 7, 2006.

As of time of issuance of this document, NWCAA maintains that those process units subject to Subpart GGG and modified after November 7, 2006, remain subject only to Subpart GGG per the applicability exemption in 40 CFR 60.590a(d). In the AOP, this sometimes results in Leak Detection and Repair (LDAR) requirements that reference directly applicable Subpart GGG and

Best Available Control Technology (BACT) standards that align with Subpart GGGa, or "enhanced" Subpart GGG.

Subpart GGG and Subpart GGGa reference the leak detection and repair (LDAR) standards of 40 CFR 60 Subpart VV and Subpart VVa, respectively. 40 CFR 60 Subparts VV and VVa apply to equipment leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI). SOCMI units, for the purposes of Subparts VV/VVa, are those that produce, as intermediates or final products, one or more of the chemicals listed in 40 CFR 60.489. No process units at the Cherry Point Refinery produce any of the listed chemicals, and therefore neither Subparts VV nor VVa apply directly to any units at BP Cherry Point.

There are numerous compressors at the refinery, some employing reciprocating and other employing centrifugal compression technologies. It is noted that under Subpart GGG there is an exemption (60.593) for compressors in "hydrogen service". To be in hydrogen service, the percent hydrogen in the gas must reasonably expected to always exceed 50 percent by volume. Because of this exemption, only 5 refinery compressors are subject to the fugitive equipment leak standards of Subpart VV as referenced by Subpart GGG. These are Flare Gas Recovery compressors 28-1803 and 28-1804, LEU/LPG compressor 22-1801, and Hydrogen Plant compressors 14-1801 and 14-1802.

Some process units are also subject to the provisions of 40 CFR 63 Subpart CC because they have Group 1 components that are in hazardous air pollutant (HAP) service. The overlap provisions of 63.640(p)(1) state that, "[…] equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 standards promulgated before September 4, 2007, are required to comply only with the provisions specified in this subpart." The provisions specified in Part 63 Subpart CC reference the LDAR requirements of Part 60 Subpart VV. Whereas 63.640(p)(2) states that, "Equipment leaks that are also subject to the provisions of 40 CFR part 60, subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, subpart GGGa, except that pressure relief devices in organic HAP service must only comply with the requirements in 63.648(j)". See subsection 2.1.2.5 of this section for more discussion of Subpart CC applicability as it relates to equipment leaks.

NWCAA 580.8 also contains LDAR requirements for certain process units and loading sites which utilize butane or lighter hydrocarbons as a primary feedstock. NWCAA 580.8 references 40 CFR 60 Subpart GGG (which in turn references 40 CFR 60 Subpart VV), with the addition of a requirement to inspect relief vents that have opened to the atmosphere within 24 hours of venting. In recognition of the overlap between federal and local LDAR standards, process units that are subject to federal VOC or HAP leak standards were exempt from the requirements of NWCAA 580.8 per NWCAA 580.26 on February 8, 1996. However, NWCAA 580.26 is not SIP approved; therefore, NWCAA 580.8 <u>does</u> apply to those process units that would otherwise be exempt. Applicability of NWCAA 580.8 is also discussed in subsection 2.3.2.

In general, the LDAR standards discussed above are considered work practice standards that require that the refinery use an instrument to find leaking components such as valves and pumps, and to repair them in a timely manner. Table 2.1-2 lists directly applicable LDAR programs for each process unit at the Cherry Point refinery, including NESHAP and NWCAA regulations, and specific "enhanced" OAC requirements.

Table 2.1-2 LDAR Program Applicability

Process Unit	GGG	GGGa	CC	Enhanced (OAC)	NWCAA 580.8
Crude/Vacuum		X	X		
#1 Reformer	X		X		
Naphtha HDS		X	X		
#2 Reformer	X		X		
Hydrocracker		X	X		
Delayed Coker		X	X		
#1 Diesel HDS			X	949c	
#2 Diesel HDS	X		X	892d	
#3 Diesel HDS		X	X		
Isomerization	X		X	814d (VVa)	
Light Ends	X		X		X
LPG	X		X		X
#1 Hydrogen Plant			X		
#2 Hydrogen Plant		X	X		
#1, #2, #3 Calciners					
#4 & #5 Boilers					
#6 & #7 Boilers				1001e	
Flare Gas Recovery	X		X		X
SRU					
Sour Water		X	X	1043	
Chemical Treaters			X		
Truck Rack	X		X		X
Dock Piping					X
LPG Loading	X				X
Rail Loading			X	1142 (VVa)	X

2.1.1.6 <u>40 CFR 60 Subpart NNN - Standards of Performance for VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Distillation Operations</u>

Two units at the refinery contain vent streams that are complying with Subpart NNN in the absence of a facility-specific applicability determination from EPA: the Isomerization Unit and the Lean Oil Adsorption System within the Delayed Coker Unit. There is some question about whether Subpart NNN is directly applicable to equipment within these units. EPA has issued several letters on the applicability of Subpart NNN to various refinery units, some of which are included as Appendix B of this document and may also be found in the EPA's ADI database. EPA has stated in general terms that refinery units that produce as a saleable product, intermediate, or by-product any of the chemicals listed in Subpart NNN may be subject to the requirements of the rule. As such, NWCAA conservatively interprets NNN as applicable. At time of issuance of this permit, BP complies with the requirements of Subpart NNN using the alternative requirements found in 40 CFR Part 65 – Consolidated Federal Air Rule.

2.1.1.7 *40 CFR 60 Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems*

The refinery has added or modified individual drain systems at a number of process units after May 4, 1987, thereby triggering applicability of NSPS Subpart QQQ at those affected units. Table 2.1-3 below presents a list of process units/areas that have Subpart QQQ applicability and lists OACs associated with projects.

Table 2.1-3 Individual Drain Systems and NSPS Subpart QQQ Applicability

Process Unit	NSPS QQQ Constructed/ Modified after 5/4/87	Process Unit	NSPS QQQ Constructed/ Modified after 5/4/87
Crude/Vacuum	OAC 640a	Sour Water Unit	Yes
#1 Reformer	OAC 562d	Wastewater Treatment Plant	Yes
Hydrocracker	Yes	Tank Farm	OAC 620b, OAC 897
Delayed Coker	OAC 689c	Chemical Treater	Yes
#2 Diesel HDS	OAC 892b	Truck Rack	OAC 527f
#3 Diesel HDS	Yes	LPG Unit	Constructed 1987
#2 Hydrogen Plant	OAC 1064b	Isomerization Unit	OAC 814d
#1 & #2 Calciners	OAC 689c	NE Rail Facility	OAC 1142, Constructed 2013
#3 Calciner	Yes	Utility Boilers	OAC 1001e
Light Ends Unit	Yes	Sulfur Recovery Complex	OAC 1043

Under the overlap provisions of 40 CFR 63 Subpart CC 63.640(o), any Group 1 wastewater stream subject to 40 CFR 60 Subpart QQQ is required to comply only with the requirements of Subpart CC, which reference the NESHAP for Benzene Waste Operations under 40 CFR 61 Subpart FF standards. Under 40 CFR 63 Subpart CC, a "Group 1 wastewater stream" is defined 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".*

Under 40 CFR 63 Subpart CC, a "Group 2 wastewater stream" is defined as:

> *"a wastewater stream that does not meet the definition of Group 1 wastewater stream."*

In a letter from the Cherry Point Refinery to the NWCAA dated June 23, 2009, BP states that they are re-designating all wastewater streams subject to NSPS 40 CFR 60 Subpart QQQ and also defined as Group 2 wastewater streams under 40 CFR 63 Subpart CC to "Group 1 wastewater streams". In doing so BP is required only to control and treat those wastewater streams under the standards of 40 CFR 61 Subpart FF as required by §63.640(o). The requirements of 40 CFR 60 Subpart QQQ are not listed in Section 5 of the AOP, but because Subpart QQQ is technically applicable, it is listed as an applicable regulation in Section 1 of the AOP. The wastewater streams subject to Subpart QQQ are included under the refinery-wide 40 CFR 61 Subpart FF program. The AOP terms for Subpart FF are listed in Section 5 of the permit under "Oily Wastewater Collection, Storage and Treatment".

Because Subpart QQQ has more specific requirements (60.692-2) for individual drain systems than Subpart FF, AOP Term 5.17.2 has been gap-filled as follows to ensure that there has been no backsliding in stringency:

> *Directly Enforceable*
>
> Each active service drain shall be inspected monthly for indication of low water levels or other conditions that would reduce the effectiveness of the water seal control. Whenever low water levels are identified water shall be added or first efforts to repair shall be made as soon as practical but no later than 24 hours after detection.
>
> Each inactive service drain shall be inspected weekly for indication of low water levels or other conditions that would reduce the effectiveness of the water seal controls or problems that could result in emissions to the atmosphere.

2.1.1.8 *40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

All stationary internal combustion engines at the refinery are categorized as compression ignitions (CI) engines under 40 CFR 60 Subpart IIII. They are considered compression ignition because they burn diesel fuel and use the heat of compression for ignition. Each engine is subject to 40 CFR 60 Subpart IIII because construction commenced after July 11, 2005. The emergency generator engines were manufactured after April 1, 2006, and the fire pump engine was manufactured after July 12, 2006.

In summary, 40 CFR 60 Subpart IIII requires that the engines burn only ultra-low sulfur diesel with a sulfur content equal to or less than 15 ppmw, and that the engine has a permanent label documenting that it meets the emission limits applicable for its model year and power rating.

In addition, for engines in emergency service as defined by Subpart III, the following requirements or stipulations apply:

- There is no time limit on the use of emergency stationary ICE in emergency situations,
- The emergency stationary ICE may be operated for a maximum of 100 hours per calendar year for the purposes of maintenance checks, readiness testing, emergency demand response, and voltage or frequency deviation support. Any operation for non-emergency situations allowed as described in the next bullet counts as part of the 100 hours per calendar year, and,
- The emergency stationary ICE may be operated for 50 hours per year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response. Except under specific circumstances, the 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described above is prohibited. If the engine is not operated according to these requirements, the engine will not be considered an emergency engine and will need to meet all the requirements for non-emergency engines.

None of the refinery emergency generators are used, or are contractually obligated to be available for, more than 15 hours per calendar year for emergency demand response as described in 63.6640(f)(2)(ii) or voltage or frequency deviations of 5 percent or greater below standard voltage or frequency (63.6640(f)(2)(iii)).

Each stationary internal combustion engine at the refinery is also subject to 40 CFR 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants: Reciprocating Internal Combustion Engines. Section 2.1.2.10 discusses the requirements for engines subject to Subpart ZZZZ.

2.1.1.9 40 CFR 60 Subpart XX – Standards of Performance for Bulk Gasoline Terminals

NSPS Subpart XX applies to Bulk Gasoline Terminals constructed or modified after December 17, 1980. The gasoline loading rack at the refinery was constructed in 1994 and triggered NSPS Subpart XX. However, it is also an affected source under 40 CFR 63 Subpart CC; therefore, according to the overlap provisions in 40 CFR 63.640(r), those loading terminals that are subject to both NSPS Subpart XX and Subpart CC need only comply with the Subpart CC requirements, which reference portions of 40 CFR 63 Subpart R, which in turn references portions of Subpart XX. The AOP includes the directly applicable requirements of Subpart CC and the referenced requirements of Subparts R and XX. See Section 2.1.2.5 for a discussion of the overlap and referenced provisions.

2.1.2 40 CFR Parts 61 and 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP/MACT)

NESHAP apply to the emission of hazardous air pollutants (HAP) at existing sources, regardless of the construction or modification dates. NESHAP were developed to reduce emissions, by industrial source category, for the 187 HAP specified by Congress.

The following is a summary of NESHAP regulations that are either directly applicable or referenced by an applicable regulation at the Cherry Point Refinery.

2.1.2.1 40 CFR 61 Subpart A – General Provisions

When a Part 61 NESHAP applies to a facility, the general provisions of 40 CFR 61 Subpart A also apply. These general provisions are included in AOP Section 3. Conversely, if a part of Subpart A does not have specific requirement for the facility, it is not included in the AOP. If the requirement was something in the past that was a one-time requirement that has been completed, it is not in the AOP. Subpart A requirements tend to be applicable only when triggered by a particular action, such as an initial startup notice and an initial notification when a facility becomes subject to a standard under 40 CFR 61.

2.1.2.2 40 CFR 61 Subpart J - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene

The #1 Reformer includes a light reformate splitter tower (LRF) that has the capacity to concentrate benzene above the 10% by weight applicability threshold of 40 CFR 61 Subpart J. However, the overlap provisions of 40 CFR 63.640(p) stipulate that equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 standards promulgated before September 4, 2007, are required to comply only with the provisions specified in 40 CFR 63 Subpart CC.

Because 40 CFR 61 Subpart J was promulgated before September 4, 2007, and Subpart CC has applicability trigger of 4% by weight for benzene as a HAP that is more stringent than Subpart J, this overlap provision applies to all equipment in benzene service as defined in Subpart J. As a result the refinery is required to comply only with equipment leak provisions Subpart CC, and 40 CFR 61 Subpart J is not cited in Section 5 of the AOP.

2.1.2.3 40 CFR 61 Subpart FF - National Emission Standard for Benzene Waste Operations

In 1991, the refinery was required to come into compliance with 40 CFR 61 Subpart FF. The purpose of this regulation was to reduce the amount of benzene emissions to the atmosphere from wastewater operations. Benzene is a regulated HAP under the NESHAP regulations. The refinery's total annual benzene (TAB) quantity is calculated each year and is consistently above the 10 Mg/yr threshold for Subpart FF applicability. The TAB does not represent the level of benzene emissions to the atmosphere from waste operations, but rather the total amount of benzene that enters the wastewater collection system.

The refinery complies with 40 CFR 61 Subpart FF through the various control requirements of the rule. The standard allows the refinery to exempt waste streams by demonstrating that initially, and at least once a year thereafter that either:

- 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
- 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
- The streams selected for exemption, includes process turnaround waste, and that that exempt waste quality is determined for the calendar year in which the waste has generated.

There are several options for the control of emissions and treatment of the 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 the process wastewater.

2.1.2.4 40 CFR 61 Subpart BB – National Emission Standards for Hazardous Air Pollutants: Benzene Operations

40 CFR 63 Subpart BB applies to benzene distribution activities at the refinery. The refinery has the potential to trigger the control standards of Subpart BB, especially during an event where the Isomerization Unit is shutdown for an extended period and the refinery is in a position to ship out the benzene rich Isomerization unit feedstock in lieu of processing. The refinery does not anticipate a scenario where an extended Isomerization unit shutdown is likely. Therefore, the 40 CFR 63 Subpart BB provisions applicable to the refinery are recordkeeping only, and are found in Section 5 of the AOP under Organic Liquids Distribution.

2.1.2.5 40 CFR 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

The first seven sections of 40 CFR 63 Subpart CC (commonly referred to as Refinery MACT I) address equipment applicability. It applies to petroleum refining process units and to related emission points located at a major source, that emit, contact, or have equipment that contact one or more HAP listed in the NESHAP at or above 5 wt%. Refinery MACT I requires HAP emissions be controlled from various emission points within the refinery. The affected source at the Cherry Point Refinery is comprised of all the emission points listed below in combination:

- Miscellaneous process vents
- Storage vessels
- Wastewater streams and treatment operations
- Marine tank vessel loading
- Gasoline loading racks
- Heat exchanger systems

- Equipment leaks from petroleum refining process units
- Equipment releasing to atmosphere within delayed coking units
- Pressure relief devices routed to atmosphere or closed vent systems

There are some important equipment exemptions listed in the Refinery MACT I, 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, provided that any flares receiving gas from the fuel gas system are in compliance with the flare control requirements in 63.670. Other than the emission points routed to a fuel gas system, this equipment is regulated by Part 63 Subpart UUU, which is commonly referred to as Refinery MACT II.

40 CFR 63 Subpart CC requires that HAP emissions be controlled from the emission points listed above. Some of these emissions points may also be subject to other existing regulations including NSPS and other NESHAP. Subpart CC allows the source to comply with only the most stringent regulation which will demonstrate compliance with all applicable regulations. Table 2.1-4 below lists equipment regulated by Subpart CC that is also subject to another NSPS, NESHAP, or NWCAA regulation.

Table 2.1-4 Equipment Regulated by 40 CFR 63 Subpart CC and another NESHAP, NSPS, or NWCAA Regulation

Equipment	40 CFR 63	40 CFR 60	40 CFR 61	NWCAA Reg.
Storage Vessels/Tanks (including wastewater tanks)	Subpart CC	Subparts K, Ka, Kb	Subpart FF	560, 580.3, 580.9
Wastewater	Subpart CC	Subpart QQQ	Subpart FF	--
Equipment Leaks	Subpart CC	VV, VVa, GGG, GGGa	--	580.8

A discussion of applicability for various groups of emission points follows.

<u>Miscellaneous Process Vents</u>

For miscellaneous process vents there are no other existing regulations governing Group 1 and Group 2 categories. As a result, all Group 1 and Group 2 miscellaneous process vents must comply with the requirements of 40 CFR 63 Subpart CC. Atmospheric vents at the hydrogen plants are exempt from Subpart CC requirements under the definition of a miscellaneous process vent in 63.641(14).

Group 1 miscellaneous process vents are:

- Process vents for which the total organic HAP concentration is greater than or equal to 20 ppmv, and
- The total VOC emissions at the outlet of the final recovery device (if any) and prior to any control device and discharge to the atmosphere for existing sources are greater than or equal to 33 kg/day.

Group 2 miscellaneous process vents are any miscellaneous process vent that does not meet the definition of Group 1. Except for one miscellaneous process vent at the refinery, discussed below, Group 1 miscellaneous process vents at the Cherry Point Refinery are controlled by a flare.

Subpart CC provides an alternate pathway to compliance for certain emission points, including miscellaneous process vents, using emissions averaging provisions in 63.652. HAP emission "debits" from vents that would otherwise require controls under Subpart CC but remain uncontrolled are added to "credits" generated by an over-controlled emission point listed in 63.652(c). Subpart CC requires the submittal of quarterly reports to verify that enough credits are generated to satisfy the required debits. On December 20, 2017, BP proposed a plan for complying with the averaging provisions of 63.652 instead of 63.643 for one miscellaneous process vent at the #2 Hydrogen Plant, which is routed to the #2 Hydrogen Plant Flare. NWCAA approved the plan on January 29, 2018, and received the initial notice of compliance status on April 17, 2019. Controlled emissions from the gasoline loading rack and marine vapor combustion unit provide credits for this miscellaneous process vent.

Maintenance vents were designated as a special category of miscellaneous process vents as part of the RTR initiative with newly required operational standards. The Cherry Point Refinery has implemented procedures to identify all maintenance vents with emissions of > 72 lb/day VOC when in use during startup, shutdown, maintenance, or for inspection of equipment when emptied, depressurized, degassed or placed into service. Operational standards are in place to measure, record and ensure each maintenance vent has an LEL of less than 10% prior to release to atmosphere, or if the LEL of the vapor in the equipment cannot be measured, equipment pressure is reduced to 5 psig or less. BP has designated all maintenance vents Group 2 miscellaneous process vents. Requirements for maintenance vents are listed in the AOP in Section 4, under Generally Applicable Requirements.

Pressure Relief Devices

Refinery MACT I also requires controls and additional monitoring of the control device for all pressure relief devices (PRD) routed to a closed vent system, which at BP Cherry Point are routed to the refinery flare system.

For PRD that are released to atmosphere (atmospheric PRD), Refinery MACT I requires operating and pressure relief requirements and management of releases. These requirements are listed for these specific types of PRDs within the requirement tables in the AOP for the individual process units.

58 atmospheric PRD in the refinery have been identified as of the initial Notice of Compliance, received June 21, 2019. All atmospheric PRD are equipped with a pressure transmitter and an audible alarm at its respective unit's control board, are routinely inspected and maintained, and are part of a staged relief system.

Requirements for pressure relief devices are listed in the AOP in Section 6.6.

Flares

Flares used as control devices for emission points subject to this subpart are regulated under Refinery MACT I. Both the High and Low-Pressure Flares are used to control emissions from process vents and pressure relief devices within the refinery and are subject to the control and CPMS requirements contained in 63.670 and 63.671, in addition to the flare requirements in NSPS Ja. The #2 Hydrogen Plant Flare controls emissions from one miscellaneous process vent that would otherwise be subject to Subpart CC, but as described in the MPV section above, complies instead with the emissions averaging provisions in 63.652. Per the overlap provisions for flares in 63.640(s), flares subject to the provisions of either 60.18 or 63.11 in addition to Refinery MACT I are now only required to comply with the provisions specified in 40 CFR 63 Subpart CC.

As part of the new RTR initiative, flares used as control devices required upgrades to operational equipment, installation of monitoring equipment, tracking of operational parameters and alarms for operational limits.

Gasoline Loading Rack

The gasoline loading rack at The Cherry Point Refinery is a Group 1 affected source under Refinery MACT I and is also subject to 40 CFR 60 Subpart XX. Under the overlap provisions in 63.640(r), the gasoline loading rack is only required to comply with Refinery MACT I, which mandates that subject racks comply with referenced sections of 40 CFR 63 Subpart R; Subpart R then references sections of Subpart XX. The loading rack is not subject to Subpart R directly, as stated in 40 CFR 63.420(i). Table 2.1-5 below lists the federal rule applicability overlap and references.

Table 2.1-5 Applicable Federal Requirements for Gasoline Loading Rack

Requirement	References	Notes
63 Subpart CC – all requirements are directly applicable		
63.640(r) (2/4/2020)	N/A	Overlap provision with 60 Subpart XX requires compliance only with 63 Subpart CC
63.650 (12/1/2015)	63 Subpart R 63.421, 63.422(a)-(c) and (e), 63.425(a)-(c) and (e)-(i), 63.427(a) and (b) 63.428(b), (c), (g)(1), (h)(1)-(3), and (k)	Only these sections of Subpart R apply.
63.655(b) (2/4/2020)	63 Subpart R 63.428(b) and (c), (g)(1), (h)(1)-(3), and (k)	Note the referenced requirements here are repeated from 63.650, and are also found in Table 4 of 63 Subpart CC.
63 Subpart R – all requirements listed here are applicable by reference from 63 Subpart CC		
63.421 (2/4/2020)	N/A	Definitions
63.422(a) (12/19/2003)	Subpart XX 60.502(a), (d)-(i)	As modified further by applicable sections of Subpart R.
63.422(b) (12/19/2003)	N/A	
63.422(c) (12/19/2003)	Subpart XX 60.502(e)	Note the referenced requirement is repeated from 63.422(a), but is modified here.
63.422(e) (12/19/2003)	Subpart XX 60.502(h) and (i) 60.503(d)	Note the referenced requirements in 60.502(h) and (i) are repeated from 63.422(a), but are modified here.
63.425(a) (12/19/2003)	Subpart XX 60.503	60.503(b) is applicable as modified by 63.425(a)(1)(i). 60.503(c) performance test requirements do not apply to flares as defined by 63.421 and meeting requirements of 63.11(b), as stated in 63.425(a)(2).
63.425(b), (c), (e)-(h) (12/19/2003)	N/A	

63.425(i) (12/19/2003)	49 CFR 173.31(d), 179.7, 180.509, and 180.511	Alternative requirements referenced are available except as prohibited in 63.425(i)(3).
63.427(a) and (b) (12/19/2003)	N/A	
63.428(b), (c), (g)(1), (h)(1)-(3), (k) (4/6/2006)	N/A	
60 Subpart XX – Directly applicable, but CC overlap provision in 63.640(r) requires compliance <u>only</u> with 63 Subpart CC. 63 Subpart CC references 63 Subpart R, which references certain sections of 60 Subpart XX. These sections are listed here.		
60.502(a) and (d) (2/12/1999)	N/A	
60.502(e) (2/12/1999)	60.505(b)	As modified by 63.422(c).
60.502(f)-(g) (2/12/1999)	N/A	
60.502(h) (2/12/1999)	60.503(d)	As modified by 63.422(e).
60.502(i) (2/12/1999)	N/A	As modified by 63.422(e).
60.503(a) (12/19/2003)	N/A	
60.503(b) (12/19/2003)	N/A	As modified by 63.425(a)(1)(i). Note that although 60.503(b) is intended to show compliance with the requirements in 60.502(b), (c), and (h), only 60.502(h) is applicable.
60.503(c) (12/19/2003)	N/A	Does not apply to flares, as stated in 63.425(a)(2). Note that although 60.503(c) is intended to show compliance with the inapplicable requirements in 60.502(b) and (c), it still applies through 63.425(a).
60.503(d) (12/19/2003)	N/A	As modified by 63.422(e).
60.503(e) and (f) (12/19/2003)	N/A	See 63.425(a)(2) for applicable requirements for flares.
60.505(b) (12/19/2003)	N/A	As modified by 63.422(c).

<u>Marine Vessel Loading</u>

Marine Vessel loading operations, including the Marine Vapor Combustion Unit, are subject to Subpart CC, which references the control requirements of 40 CFR 63 Subpart Y - National Emission Standard for Marine Tank Vessel Loading Operations.

<u>Heat Exchangers</u>

Subpart CC includes monitoring requirements with leak definitions and repair scheduling obligations for both closed-loop and once-through systems. The Cherry Point Refinery only employs closed-loop systems so the once-through requirements were not addressed in the AOP.

The subject heat exchangers must be "in organic HAP service" which is defined as having at least 5 wt% of listed HAP. The refinery has 3 heat exchange systems subject to Subpart CC: two for the #1 Cooling Tower, and one for the #2 Cooling Tower. The cooling towers are monitored monthly with a leak action level of 6.2 ppmv. Requirements for heat exchanges are listed in the AOP in the specifically applicable requirements (Section 5) for Boilers and Cooling Towers.

Storage Vessels

Under Refinery MACT I, subject storage vessels are either Group 1 or Group 2 vessels. Existing Group 1 storage vessels are those with a design capacity greater than 151 m^3 (40,000 gal), a stored liquid maximum true vapor pressure of 5.2 kPa (0.75 psia), and an annual average HAP liquid concentration greater than 4 weight percent, or a design capacity greater than 76 m^3 (20,000 gal) but less than 151 m^3 (40,000 gal), a stored liquid maximum true vapor pressure of 13.1 kPa (1.9 psia), and an annual average liquid concentration greater than 2 weight percent. New Group 1 storage vessels are those with a design capacity greater than 151 m^3 (40,000 gal), a stored liquid maximum true vapor pressure of 3.4 kPa (0.5 psia), and an annual average HAP liquid concentration greater than 2 weight percent, or a design capacity greater than 76 m^3 (20,000 gal) but less than 151 m^3 (40,000 gal), a stored liquid maximum true vapor pressure of 13.1 kPa (1.9 psia), and an annual average liquid concentration greater than 2 weight percent.

Group 2 storage vessels are defined as any subject vessels that do not meet the Group 1 definition.

Storage vessels at an existing source may be subject to 40 CFR 60 Subparts K, Ka, or Kb, and NWCAA regulations, as well as 40 CFR 63.646 or 63.660. Where Subpart CC overlaps with NSPS Subpart Kb for Group 1 tanks, the overlap provisions in §63.640(n)(2) require compliance with either NSPS Subpart Kb with a few modifications listed under §63.640(n)(8) or Subpart CC. Subpart CC requires compliance with either 40 CFR 63.646 or 63.660. 63.660 requires compliance with 40 CFR 63 Subpart SS or Subpart WW. Subpart WW provides up to the next emptying and degassing event, or January 30, 2026, whichever is first, to upgrade seals and fittings to the Subpart WW requirements. As of issuance of this permit, all existing Group 1 tanks at The Cherry Point Refinery are complying with the requirements of 63.660, including those that have not yet triggered 63.660 after being emptied and degassed.

Group 1 storage vessels that are subject to NSPS Subpart K or Ka are only required to comply with Refinery MACT I. For Group 2 storage vessels, tanks that are subject to the control requirements under NSPS K or Ka must comply with the provisions of NSPS K or Ka as modified under 40 CFR 63.640(n)(9). If the control requirements of 40 CFR 60 Subpart K or Kb do not apply, the vessel is subject to 40 CFR 63 Subpart CC.

In addition to the federal requirements that apply to storage vessels, several NWCAA rules potentially apply to the refinery storage tanks. These programs include NWCAA 560 - Storage of Organic Liquid, NWCAA 580.3 - High Vapor Pressure Volatile Organic Compound Storage Tanks, and NWCAA 580.9 - High Vapor Pressure Volatile Organic Compound Storage in External Floating Roof Tanks. These applicable NWCAA regulations are discussed in section 2.3.1 of this document.

The applicability of these programs varies depending on tank capacity; construction, reconstruction, or modification date; vapor pressure (VP); and organic or HAP content of stored liquid. To demonstrate regulatory inapplicability for specific tanks, records demonstrating that the type of product stored and vapor pressures, periods of storage, and storage capacities of each tank must be kept.

Table 1.18 in the AOP lists the storage tanks at the refinery and the applicable regulations.

Wastewater

There are several wastewater stream regulations that overlap or are cross referenced in 40 CFR 63 Subpart CC. 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 are considered to be in compliance with the standards of 40 CFR 63 Subpart CC. Subpart CC standards apply only to Group 1 streams that are subject to 40 CFR 60 Subpart QQQ. Group 2 streams to which both Subpart CC and Subpart QQQ apply are required to comply with to Subpart QQQ. BP has redesignated all Group 2 streams that are subject to both NSPS QQQ and NESHAP CC as Group 1 streams, and so complies only with Subpart CC and Part 61 Subpart FF.

Equipment leaks

40 CFR 63 Subpart CC applies to fugitive emissions from leaking components and process equipment at a petroleum refinery that is a major source of HAP that contain or contact one or more of the listed HAP at or above 5 wt%. Refinery MACT I requires a LDAR program conducted in accordance with 40 CFR 60 Subpart VV. Note that compressors in hydrogen service are explicitly exempted from the monitoring requirements.

Pursuant to 40 CFR 63.640(p), equipment leaks subject to 40 CFR 63 Subpart CC along with provisions under 40 CFR 60 and 61 that were promulgated prior to September 4, 2007 (40 CFR 60 Subparts VV and GGG) must comply with Subpart CC. Equipment leaks that are subject to both Subpart CC and Subpart GGGa must comply with Subpart GGGa, except that pressure relief devices in organic HAP service must only comply with §63.648(j).

Subpart CC (63.640(q)) also provides an overlap provision that allows the refinery to apply a consistent LDAR program within a particular process unit:

> For overlap of subpart CC with local or State regulations, the permitting authority for the affected source may allow consolidation of the monitoring, recordkeeping, and reporting requirements under this subpart with the monitoring, recordkeeping, and reporting requirements under other applicable requirements in 40 CFR parts 60, 61, or 63, and in any 40 CFR part 52 approved State implementation plan provided the implementation plan allows for approval of alternative monitoring, reporting, or recordkeeping requirements and provided that the permit contains an equivalent degree of compliance and control.

See subsections 2.1.1.5 and 2.3.2 of this document for a discussion of GGG, GGGa, and NWCAA LDAR regulations.

Delayed Coking Units

For the DCU, there are no other applicable regulations governing decoking operations (see subsection 2.1.1.3 for a discussion of Subpart Ja inapplicability). Refinery MACT I requires DCUs at an existing affected source to depressure coke drums to a closed blowdown system until the average vessel pressure is less than 2 psig, or the average vessel temperature is 220 degrees Fahrenheit or less, both determined on a rolling 60-event basis. The Cherry Point Refinery operates four coke drums with a pressure monitoring system per 63.657(b).

Fenceline Benzene Monitoring

40 CFR 63 Subpart CC requires refineries to measure benzene emissions along the refinery perimeter. To meet this requirement, BP Cherry Point operates 19 sampling stations along the refinery's perimeter, a field blank and a duplicate sampler. Each sampler continuously pulls ambient air through a passive diffusive tube for two weeks, after which the tubes are changed. Benzene concentration for each two-week period from each sampler is reported to EPA on a quarterly basis. The lowest individual monitor reading is subtracted from the highest individual monitor reading for each two-week period to determine the benzene concentration difference (Δc). An annual rolling average Δc is calculated every two weeks from the most recent 26 two-week sampling periods. If the annual rolling average Δc exceeds the benzene action level (9 $\mu g/m^3$), the refinery must perform a root cause and corrective action analysis, but it does not constitute a violation of Refinery MACT I. Because the fenceline benzene monitoring program

applies facility-wide and is not associated with any individual processing unit, requirements are listed in the AOP in Section 4, under Generally Applicable Requirements.

2.1.2.6 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

40 CFR 63 Subpart UUU (commonly referred to as Refinery MACT II) contains continuing applicable requirements for process vents and bypass lines at the refinery's catalytic reforming units (during depressuring operations and catalyst regeneration) and sulfur recovery complex. The refinery does not operate any catalytic cracking units.

Catalytic Reforming Units

Organic HAP emissions during active purging or depressuring of the reformers are to be controlled by purging the unit to a flare or a combustion device that meets a total organic content (TOC) destruction efficiency of 98%, or limits emissions of TOC as hexane to 20 ppmvd corrected to 3% oxygen. Inorganic HAP emissions during coke burn off and catalyst regeneration must be reduced by 92 wt%, or to a concentration of 30 ppmvd, corrected to 3% oxygen.

Sulfur Recovery Units

Refinery MACT II limits emissions at the Cherry Point Refinery Sulfur Recovery Complex to the 40 CFR 60 Subpart Ja requirement of 250 ppm SO_2 at 0% oxygen, 12-hour rolling limit. During periods of startup and shutdown The Cherry Point Refinery complies with an alternate work practice standard and operates the Incinerator Unit above 1,200 degrees Fahrenheit and 2% oxygen while process gas is vented to it. Compliance is demonstrated by meeting emission limitations, installing and operating CPMS to meet operating limitations, and preparation of unit-specific operation, maintenance, and monitoring plans (OMMP) based on SO_2 emissions.

The refinery was required to provide updates to the OMMP for HAP emissions from the SRU during startup and shutdown. OMMP revisions were received April 2, 2018.

2.1.2.7 40 CFR 63 Subpart Y - National Emission Standards for Marine Tank Vessel Loading Operations

The Marine Terminal at the refinery is subject to 40 CFR 63 Subpart CC. Subpart CC references 40 CFR 63 Subpart Y for the applicable requirements. Under Subpart Y vapors displaced during marine loading operations must be controlled by a vapor collection system. Subpart Y specifies that the marine tank vessel must be compatible with the terminal's vapor collection system and must be vapor tight.

2.1.2.8 40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Boilers and Process Heaters

40 CFR 63 Subpart DDDDD applies to industrial, commercial, or institutional boilers and process heaters that are located at a major source of hazardous air pollutants (HAP) and is commonly referred to as the Boiler MACT.

All the subject process heaters and boilers at the refinery fall within the "units designed to burn gas 1 fuels" subcategory. Boiler MACT does not require any pollutant-specific emission limits for existing or new heaters and boilers in the gas 1 subcategory. Instead, the rule requires work practice standards that include periodic "tune-ups" and inspections, as described in 63.7540(a)(10).

The #1, #2 and #3 Calciners can burn refinery fuel gas as supplemental fuel to generate steam when calcining operations are curtailed. However, this does not trigger Subpart DDDDD applicability because the primary purpose of the calciners is not to generate steam.

Boiler MACT also identifies alternate work practices that apply instead of emission limitations, during periods of startup and shutdown. Because the boilers and process heaters at The Cherry Point Refinery are not subject to any Boiler MACT emission limitations, there are no alternate work practices that would apply during startup and shutdown. The work practice standards for units designed to burn gas 1 fuels are required at all times, therefore there are no AOP Terms for periods of startup or shutdown.

For units equipped with a continuous oxygen trim system, tune-ups are required once every five years; those without continuous oxygen trim systems must have tune-ups annually. Equipment subject to the Boiler MACT are listed in Table 2.1-6.

Table 2.1-6 Boiler MACT Units

Unit	Rating (MMBtu/hr)	EU ID	Oxygen Trim Control
Isomerization Heater	13	45-1402	No
#1 DHDS Charge Heater	48	13-1401	No
#1 DHDS Stabilizer Reboiler	56	13-1402	No
Crude Heater	720	10-1451	Yes
South Vacuum Heater	207	10-1451	Yes
North Vacuum Heater	117	10-1452	Yes
Naphtha HDS Charge Heater	60	11-1401	Yes
Naphtha HDS Stripper Reboiler	86	11-1402	Yes
#1 Reformer Heater	1075	11-1403-1406	Yes
East Coker Heater	303	12-1402	Yes
West Coker Heater	303	12-1401	Yes
#4, #5, #6, #7 Boilers	216, 363, 363, 363	30-1604-1607	Yes
#3 DHDS Charge Heater	28	27-1401	Yes
North #1 H2 Plant Furnace	325	14-1401	Yes
South #1 H2 Plant Furnace	325	14-1402	Yes
R1 Reaction Heater	121	15-1401	Yes
R4 Reaction Heater	60	15-1402	Yes
1st Stage Fractionation Reboiler	198	15-1451	Yes
2nd Stage Fractionation Reboiler	183	15-1452	Yes
#2 Reformer Heater	340	21-1421-1425	Yes
#2 HDS Charge Heater	35	26-1425	Yes
#2 H2 SMR Furnace	496	46-1401	Yes

Boiler MACT also required a one-time energy assessment performed by a qualified energy assessor as described in 40 CFR 63 Subpart DDDDD Table 3. BP certified that the assessment was performed on March 22, 2016. As this one-time requirement has been met, all references to required energy assessment have been removed from the permit.

2.1.2.9 *<u>40 CFR 63 Subpart EEEE – National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)</u>*

40 CFR 63 Subpart EEEE applies to non-gasoline organic liquid distribution activities at the refinery that handle HAP over thresholds specified in the rule. Under the 63.2338(c)(1) overlap provisions of Subpart EEEE, storage tanks, transfer racks, transport vehicles, containers, and equipment leak components that are part of an affected source under another 40 CFR part 63 NESHAP are excluded from applicability. Because 40 CFR 63 Subpart CC requires Refinery MACT controls at the truck rack and marine terminal, Subpart EEEE does not apply to these specific activities. However, railcar loading and/or other organic liquids distribution that is not addressed by Subpart CC has the potential to trigger the control standards of Subpart EEEE, especially, during an event where the Isomerization Unit is shutdown for an extended period and the refinery is in a position to ship out the benzene rich Isomerization unit feedstock in lieu of processing. The refinery does not anticipate a scenario where an extended Isomerization unit shutdown is likely. Therefore, the 40 CFR 63 Subpart EEEE provisions applicable to the refinery are recordkeeping only, and found in Section 5 of the AOP under Organic Liquids Distribution.

2.1.2.10 *<u>40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants: Reciprocating Internal Combustion Engines</u>*

All stationary internal combustion engines at the refinery are categorized as new compression ignitions (CI) engines under 40 CFR 63 Subpart ZZZZ. They are considered “new” and not ‘existing” under the rule because each engine after a power rating equal to, or less than 500 brake horse power (hp) was constructed on or before June 12, 2006, and each engine with a power rating greater than 500 hp was constructed on or after December 19, 2002. All stationary CI engines at the refinery are subject to Subpart ZZZZ, however, Subpart ZZZZ does not specify any requirements for these engines; except for initial notification for engines greater than 500 hp.

40 CFR 63 Subpart ZZZZ provides the following overlap provisions for engines that are also subject to 40 CFR 60 Subpart IIII.

For new CI engines equal to or less than 500 hp:

> *63.6590(c) Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.*

For new CI engines that are in emergency use and greater 500 hp:

> *63.6590(b) Stationary RICE subject to limited requirements. (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).*

2.1.2.11 *<u>40 CFR 63 Subpart GGGGG – National Emission Standards for Hazardous Air Pollutants: Site Remediation</u>*

40 CFR 63 Subpart GGGGG applies to site remediation activities at the refinery. Because the total HAP quantity in remediation materials for the year is less than 1 Mg, the refinery is not subject to the requirements of this standard. However, the refinery is obligated to maintain written documentation to support this determination. This recordkeeping requirement is found in Section 4 of the AOP because it is a generally applicable requirement that applies refinery-wide.

2.1.3 40 CFR Part 64 - Compliance Assurance Monitoring

40 CFR Part 64 - Compliance Assurance Monitoring (CAM) requires owners and operators to monitor the operation and maintenance of control equipment at large emission units to achieve a level of control that complies with applicable requirements. If owners and operators of these facilities find that their control equipment is not working properly, the CAM rule requires that action be taken to correct any malfunctions and to report such instances to the appropriate enforcement agency. Additionally, the CAM rule provides some enforcement tools that will help agencies require facilities to respond appropriately to the monitoring results and improve pollution control operations.

To determine the applicability of CAM, each pollutant-specific emission unit (PSEU) is evaluated on a pollutant-by-pollutant basis. To be subject to CAM, the PSEU must be:

1. Located at a major source required to obtain a Part 70 permit,
2. Subject to an emission limit or standard for the applicable pollutant,
3. Use a control device to achieve compliance,
4. Have potential pre-control emissions of the applicable pollutant that are at least 100% of major source threshold, and,
5. Not be otherwise exempt.

The Cherry Point Refinery is a major source required to obtain a Part 70 permit, so all emission units at the refinery are potentially subject to CAM. Table 2.1-7 below lists the five PSEU that are subject to CAM and their respective emission limitations.

Table 2.1-7 PSEU Subject to CAM

Pollutant-Specific Emission Unit	Description	Control Device	Pollutant
Calciner, Stack #1	#1 & #2 Calciner Hearth	WESP	PM_{10}
Calciner, Stack #1	#1 & #2 Calciner Hearth	WESP	H_2SO_4
Calciner, Stack #2	#3 Calciner Hearth	WESP	PM_{10}
Calciner, Stack #2	#3 Calciner Hearth	WESP	H_2SO_4
Calciner	Coke Silos and Loading	Bag House	PM_{10}

For these PSEU, the CAM rule requires that air operating permit include:

- An approved monitoring approach, including the indicators to be monitored, and performance requirements established to satisfy 40 CFR 64.3 (b) or (d), as applicable,
- The means by which the owner or operator will define exceedances or excursions,
- The duty to conduct monitoring,
- If appropriate, minimum data availability and averaging period requirements, and,
- Milestones for testing, installation, or final verification.

Section 5 of the air operating permit includes the appropriate monitoring parameters and methods to determine compliance as submitted by BP in their associated CAM plans for these PSEU.

Table 2.1-8 on the following page lists PSEU that are not subject to CAM and the basis for the non-applicability determination. A determination of non-applicability at a unit otherwise exempt due to being subject to a standard under 40 CFR Part 60 (NSPS), 40 CFR Part 61 (NESHAP), or

40 CFR Part 63 (MACT), is based on the date the final rule is promulgated instead of the proposal date, as all of the federal standards applicable at The Cherry Point Refinery that were proposed before November 15, 1990 were also finalized before November 15, 1990.

A PSEU is otherwise exempt when subject to:

- Post-11/15/90 proposed NSPS or NESHAP, as those standards were designed with monitoring that provides a reasonable assurance of compliance
- Stratospheric ozone protection requirements
- Acid rain program requirements
- Emission limitations, standards, or other requirements that apply solely under an approved emission trading program
- Emissions cap that meets the requirements of §70.4(b)(12)
- Emission limitations or standards for which a Part 70 permit specifies a continuous compliance determination method that does not use an assumed control factor, such as a CEMS used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard and provides data in units of the standard.

An emission unit is not exempted from the CAM rule if nonexempt emission limitations or standards (e.g., a state rule or an older NSPS emission limit) apply to the emission unit.

Fuel gas combustion devices are subject to fuel gas sulfur content requirements to limit SO_2 emissions. The amine system at the refinery removes sulfur from the fuel gas which is then burned in the fuel gas combustion devices, therefore CAM applicability is addressed as an individual line item for fuel gas sulfur content in the table.

Flares can be considered emission sources themselves with emission limits but also control devices for other refinery sources (e.g., miscellaneous process vents). The flare as an emission source does not have any active control equipment to meet the emission standards (e.g., opacity, SO_2); therefore, CAM does not apply directly. However, when the flare serves as the control device (e.g., MPVs, equipment leaks), CAM is addressed for the controlled unit.

Several emission units are required to monitor operations with a CEMS (e.g., fuel sulfur content under NSPS J and Ja or SO_2 under NESHAP UUU). These CEMS are also subject to NWCAA 367 and NWCAA Appendix A which requires quality assurance for the CEMS. As such, the CEMS is considered a continuous compliance determination method, which exempts it from CAM requirements.

Certain PSEU are subject to multiple overlapping NSPS and NESHAP which rely on each other for compliance demonstrations (e.g., NSPS J and MACT UUU at the SRU; NSPS QQQ, NESHAP FF, and MACT CC for process drains; NSPS XX and MACT CC at the Truck Rack Vapor Combustor; MACT A and CC for the flare). It is assumed in this analysis that when a newer post-November 5, 1990 rule utilizes an older rule for the compliance demonstration, the older rule's compliance demonstration is adequate for CAM and qualifies for the exemption.

Table 2.1-8 PSEU Not Subject to CAM

PSEU Designation	Unit Description & Control Device	Pollutant & Reasons for Non Applicability
Primary Crude/ Vacuum Process Area	• Crude Heater • North Vacuum Heater • South Vacuum Heater	These units have no control device

PSEU Designation	Unit Description & Control Device	Pollutant & Reasons for Non Applicability
Naphtha HDS and Reformer Units	• #1 Reformer Heater • #2 Reformer Heater • Naphtha HDS Charge Heater • Naphtha HDS Stripper Reboiler	These units have no control device
Hydrocracker	• 1st Stage Fractionator Reboiler • 2nd Stage Fractionator Reboiler • R-1 Hydrocracker Reactor Heater • R-4 Hydrocracker Reactor Heater	These units have no control device
Delayed Coker	• West Coker Heater • East Coker Heater	These units are subject to both NSPS and MACT standards and are equipped with CEMS.
Diesel HDS	• #1 Diesel HDS Charge Heater • #1 Diesel HDS Stabilizer Reboiler • #2 Diesel HDS Charge Heater	These units have no control device
Hydrogen Plant	• North Heater • South Heater	These units have no control device
	• #2 H2 SMR Furnace	This unit is subject to both NSPS and MACT standards and is equipped with CEMS.
Boilers and Cooling Towers	• Utility Boiler #1 • Utility Boiler #3 • Utility Boiler #4 • Utility Boiler #5 • Cooling Tower #1 • Cooling Tower #2	These units have no control device
Flares	• Flare Gas Recovery • Low-Pressure Flare • High-Pressure Flare	These units have no control device
Sulfur Complex	• #1 TGU Stack • #2 TGU Stack	These units are subject to both NSPS and MACT standards and are equipped with CEMS.
Wastewater Treatment Plant	• API Separators • Slop Oil • equalization and recovered oil tanks	These units are subject to MACT.
Storage and Handling	• Tank Farm • Butane/Pentane Spheres	These units have no control device
Shipping, Pumping and Receiving	• Marine Dock –Use Dock Thermal Oxidizer as control device • Truck Rack- Use Truck Rack Thermal Oxidizer as control device • Rail Car Loading • LPG Loading Racks	These units are subject to NSPS and MACT standards.

PSEU Designation	Unit Description & Control Device	Pollutant & Reasons for Non Applicability
LEU/LPG	• Light End Unit (LEU) • Liquefied Petroleum Gas	This unit has no control device
Isomerization	• IHT Heater	This unit has no control device
Calciner	• Hearths #1, 2, & 3	VOC, NOx - No control device for these pollutants SO_2 – Units equipped with CEMS

2.1.4 40 CFR Part 65 – Consolidated Federal Air Rule

The requirements of Part 65 are referenced by several NSPS and NESHAP as an alternative to certain requirements in the directly applicable rules. Like Parts 60, 61, and 63, Part 65 contains general provisions that may apply when complying with these alternative provisions. BP complies with Part 65 as an alternative to some 40 CFR 60 Subpart NNN requirements. Relevant portions of the Part 65 general provisions appear in Section 3 of the AOP, as well as Section 5 for units for which BP has elected to comply with Part 65.

2.1.5 40 CFR Part 68 - Risk Management Plan (RMP)

The goal of 40 CFR Part 68 and the risk management program is to prevent accidental releases of substances that can cause serious harm to the public and the environment from short-term exposures and to mitigate the severity of releases that do occur. If a facility contains the hazardous or flammable substances listed in 40 CFR 68.130 in an amount above the "threshold quantity" specified for that substance, the facility operator is required to develop and implement a risk management program.

The Cherry Point Refinery maintains several substances in quantities greater than the listed thresholds. As such, BP submits RMP to the EPA as appropriate. This regulation is implemented in its entirety by the EPA. The refinery certifies ongoing compliance with all applicable requirements of 40 CFR 68 in their annual compliance certification.

2.1.6 40 CFR Part 98 – Federal Mandatory Greenhouse Gas Emission Inventory Regulation

This regulation applies to BP due to the quantity of greenhouse gases (GHG) emitted and type of facility. The rule requires annual GHG inventories and reporting beginning in calendar year 2010, with reports due to EPA by no later than March 31 of the following year. This regulation is implemented in its entirety by the EPA. While this regulation is applicable to BP, it is excluded from appearing in the AOP because it is not an "applicable requirement" as defined in WAC 173-401-200(4).

2.2 <u>State Standards – Refinery-Wide</u>

2.2.1 WAC Title 173 Chapter 441 – Reporting of Emissions of Greenhouse Gases

GHG are chemicals that contribute to climate change by trapping heat in the atmosphere. The greenhouse gases recognized by EPA and Ecology are: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6). "Hydrofluorocarbons" or "HFCs" are a class of greenhouse gases primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

The Cherry Point Refinery is required to meet Chapter 173-441 WAC, "Reporting of Emissions of Greenhouse Gases", which adopts a mandatory greenhouse gas reporting rule for:

- Suppliers that supply applicable fuels sold in Washington state of which the complete combustion or oxidation would result in at least 10,000 metric tons of carbon dioxide annually; or
- Any listed facility that emits at least 10,000 metric tons of carbon dioxide equivalents (CO_2e) of greenhouse gases annually in the state.

Chapter 173-441 WAC was adopted by Ecology on December 1, 2010, subsequently amended, and became effective on March 12, 2022. This regulation applies to the refinery because it emits at least 10,000 metric tons of CO_2e of greenhouse gases per year (see Table 1-3). The rule requires annual GHG inventories be provided to Ecology by no later than March 31 of the following year beginning for calendar year 2012. This regulation is implemented in its entirety by Ecology. Because the statutory authority for Chapter 173-441 WAC is the state Clean Air Act (Chapter 70A.15 RCW), it is considered an applicable requirement under the air operating permit program (WAC 173-401-200(4)); as such, it is included in the AOP.

2.2.2 WAC Title 173 Chapter 485 – Petroleum Refinery Greenhouse Gas (GHG) Emission Requirements

BP Cherry Point elected to comply with the one-time only requirement to meet an energy intensity index (EII) that is within the 50^{th} percentile or better for similar sized refineries using national 2006 EII data for comparison. This one-time only requirement was met on October 1, 2014 when the NWCAA received the refinery's initial and final GHG annual report required under WAC 173-485-090. The refinery selected 2010 as its baseline GHG year and reported that GHG emissions for calendar year 2010 were 2,796,273 metric tons. The report included a letter from Solomon Associates that certified that BP has a calculated EII that meets the Energy Efficiency Standard in WAC 173-485-040(1) and that using calendar year 2010 operational data, BP's EII value is equal to or more efficient that the EII value representing the 50^{th} percentile EII of similar sized refineries in the United States. In accordance with WAC 173-485-050 and 173-485-090(1), BP has no further reporting or compliance obligations under Chapter 173-485 WAC and it is therefore not listed in the AOP.

2.3 NWCAA Standards – Refinery-wide

2.3.1 NWCAA Section 560, 580.3, and 580.9

Historically, a number of regulations have driven emission control strategies for product storage at the refinery. Under the current version of NWCAA Sections 560, 580.3 and 580.9, vessels subject to both these NWCAA regulations and federal NSPS or NESHAP for VOC and HAP emissions from tanks are exempt per NWCAA 580.26 and 580.37. 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 560, 580.3 and 580.9 citations are found in the AOP.

Many of the requirements in NWCAA 560, 580.3, and 580.9 do not have associated monitoring, recordkeeping, and reporting requirements; as such, monitoring requirements have been gap-filled into the AOP. Most of the gap-filled requirements parallel those required in the other applicable rules for the tank(s).

2.3.2 NWCAA Section 580.8

NWCAA Section 580.8 requires a LDAR program conducted in accordance with 40 CFR 60 Subpart VV for components handling VOC at process units and loading sites which utilize butane or lighter hydrocarbons as a primary feedstock and excludes components in refinery fuel gas service.

There are four process units where NWCAA 580.8 is applicable because the units handle a butane or lighter feedstock. The non-SIP approved version of NWCAA 580.26 exempts process units from the requirements of Section 580 when they are already required to implement a VOC/HAP control program under federal regulation. Specifically, NWCAA 580.26 states;

580.26 Any petroleum refinery process unit, storage facility or other operation (including drains) subject to federal VOC or HAP standards (NSPS, Benzene Waste NESHAP, Petroleum Refinery NESHAP, etc.) is exempt from the requirements of NWCAA 580.3 through NWCAA 580.10. Such exemption shall take effect upon the date of required compliance with the federal standard.

NWCAA Section 580 was originally adopted by the agency on December 13, 1989. To reduce overlaps between Section 580 and similar requirements under federal regulations the NWCAA amended Section 580 adding the 580.26 exemption. However, for the 580.26 exemption to be federally enforceable it must be adopted into the Washington State Implementation Plan (SIP). To date, this has not been done. Consequently, the AOP includes Section 580.8 requirements for LDAR for applicable process units including one item that is called out because it is more stringent than similar LDAR requirements of 40 CFR 60 Subparts GGG and VV: the requirement in NWCAA 580.846 to inspect relief vents that have opened to the atmosphere within 24 hours of venting. The federal regulation allows up to five days for the relief valve to be checked to ensure that it has reseated.

2.3.3 NWCAA 460

An ambient SO_2 monitoring station is located north of the Cherry Point Refinery and just north of Grandview Road. This monitoring station is owned and operated by the refinery. NWCAA Section 460 requires that all refineries install, calibrate, maintain, and operate at least one sulfur dioxide ambient station. This requirement is found in Section 4 of the AOP.

2.4 Orders – Refinery-Wide

2.4.1 2001 Consent Decree

On August 29, 2001, the BP Consent Decree was entered in the following case.

United States, et. al. v. BP Exploration & Oil, et. al.
Northern District of Indiana, Hammond Division
Civil Action No. 2:96CV 095 RL

This consent decree was issued to BP Exploration & Oil based on alleged violations of federal Prevention of Significant Deterioration (PSD), major New Source Review (NSR), New Source Performance Standards (NSPS) 40 CFR 60 Subparts J and GGG, and National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 61 Subpart FF at various BP owned facilities across the country.

The Consent Decree provisions applicable to the Cherry Point Refinery were terminated May 13, 2020 by the Eleventh Amendment. References to the Consent Decree have been left in this document for historical purposes only.

2.4.2 Order of Approval to Construct 211c

On September 18, 2012, the NWCAA issued to Order of Approval to Construct (OAC) 211c as an administrative revision to OAC 211b issued on December 16, 1977, authorizing construction of the #1 and #2 Calciners. The original OAC 211 was issued October 26, 1977, and subsequently revised in November and December of that year.

OAC 211c establishes the following emission limits for combustion units that were in place in 1977 and the #1 & #2 Calciners, which were being permitted at that time.

- Particulate: 60 tons per calendar month
- Sulfur dioxide: 2,354 lb per hour, calendar month average

The refinery complies with these limits be keeping a monthly record of PM and SO_2 emissions from each subject combustion unit and a cumulative total from all for the month. Because OAC 211c is applicable to numerous emission units at the refinery, it is included in as AOP term 6.1 of the permit and each effected emissions unit listed in Section 5 of the permit refers to the requirements in Section 6.

2.4.3 Order of Approval to Construct 1054

On June 8, 1970, an OAC for "Cherry Point Refinery Sulfur Recovery Plant and Certain Heaters and Furnaces" was issued to approve original construction of the refinery. On April 12, 2012, this original order was superseded by OAC 1054, which approved the following emission units:

Process Heaters

- Crude Heater
- South Vacuum Heater
- North Coker Heater
- South Coker Heater
- Naphtha HDS Charge Heater
- Naphtha HDS Stripper Reboiler
- #1 Reformer Heater
- #1 DHDS Charge Heater
- #1 DHDS Stabilizer Reboiler
- #1 Hydrogen Plant South Reforming Furnace
- #1 Hydrogen Plant North Reforming Furnace
- Hydrocracker 1st Stage Reactor Heater (R-1)
- Hydrocracker 2st Stage Reactor Heater (R-4)
- Hydrocracker 1st Stage Fractionator Reboiler
- Hydrocracker 2st Stage Fractionator Reboiler
- Sulfur Recovery Complex Incinerator

The Order requires the emission units listed to combust gaseous fuel, or for specified units, a mixture of gaseous and liquid fuel. All combustion units at the refinery are now physically limited to burning only gaseous fuels. Note that the North and South Coker Heater have been permanently removed from service and are no longer referenced in the AOP.

2.4.4 Ecology Administrative Order 7836 Revision 2 (BART Order Rev. 2)

On July 7, 2010, the Washington State Department of Ecology issued Administrative Order 7836 (BART Order) to the BP Cherry Point Refinery in accordance with WAC 173-400-151 and 40 CFR Part 51 Subpart P, the state and federal visibility protection regulations. These regulations require the installation and use of best available retrofit technology (BART) to reduce emissions of visibility-impacting pollutants. The BART order was subsequently modified on August 16, 2013 and again on May 13, 2015. The May 13, 2015 version of the BART Order (Rev. 2) includes requirements for the following BART- eligible emissions units.

Process Heaters

- Crude Heater
- South Vacuum Heater
- #1 Reformer Heater
- Naphtha HDS Charge Heater
- Naphtha HDS Stripper Reboiler
- Hydrocracker 1st Stage Reactor Heater (R-1)
- Hydrocracker 1st Stage Fractionator Reboiler
- Hydrocracker 2st Stage Reactor Heater (R-4)
- Hydrocracker 2st Stage Fractionator Reboiler
- South Coker Charge Heater
- North Coker Charge Heater
- #1 DHDS Charge Heater
- #1 DHDS Stabilizer Reboiler
- #1 Hydrogen Plant South Reforming Furnace
- #1 Hydrogen Plant North Reforming Furnace

Sulfur Recovery Complex

- Incinerator
- #2 TGU

Flares

- Low-Pressure Flare
- High-Pressure Flare

As described in Section 2.4.3 above, the BART Order includes requirements for the now defunct North and South Coker Heaters. These requirements are not included in the AOP. The BART Order also includes green coke handling as a BART-eligible unit. However, because the BART Order does not include any requirements for green coke handling, the AOP does not include any BART Order conditions for green coke handling.

At the time the BART Order was written, the Order did not add any new substantive requirements for refinery because the BART review did not identify any best available retrofit technology to employ that was not already in place. For this reason, the conditions of the BART Order are tailored from existing requirements that were applicable at that time the BART Order was written.

Section 1 of the AOP lists the BART Order when an emissions unit has an applicable requirement under the BART Order. Sections 4 and 5 of the AOP include specific ongoing compliance obligations from the BART Order.

In cases where a condition of the BART Order differs from the original requirement, the BART Order will have its own term in the AOP. The difference may be a result of the original requirement being revised since the BART Order was issued (i.e., an OAC revision), or from the BART Order being written inconsistently from the original requirement.

In accordance with Condition 8 of the BART Order, BP may request that Ecology rescind the BART order after BART eligible units at the refinery have continuously complied with the emissions limitations set forth in the order for three years, the limits are incorporated into OAC, and the limits have been incorporated into the air operating permit.

3 PROCESS DESCRIPTIONS, CONSTRUCTION HISTORY, AND REGULATORY APPLICABILITY

The following section provides a description of each refinery area along with the 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 process. 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.

It is noted that many OACs list a ton per year (tpy) limit for pollutants. Unless the OAC is more specific, e.g., calendar year, the AOP term listing that limit has been described as a "12-month rolling" limit. This is because the basis for the tpy limit is usually PSD avoidance. In addition, unless otherwise specified in the OAC, the MR&R for the permit term has been gap-filled with "directly enforceable" language that requires keeping records of the consecutive 12-month rolling ton value.

A list of applicable NSR permit conditions that are not included in Section 5 of the AOP and the rationale is provided at the end of Section 3.

3.1 Original Refinery Footprint

General Approval Order – 1970 – Superseded

The original refinery was constructed in 1970. The project was approved by the NWCAA in an Order of Approval to Construct entitled "Cherry Point Refinery Sulfur Recovery Plant and Certain Heaters and Furnaces" dated June 8, 1970. The order included limits on the fuel type and in some cases the sulfur content for each boiler and process heater being constructed at the process units listed in Table 3.1-1 below.

Table 3.1-1 Original Refinery Units

Crude and Vacuum Unit	Light Ends Unit
#1 Reformer Unit	#1 Hydrogen Plant
Naphtha Unit	#1, #2 and #3 Boilers
Hydrocracker Unit	Sulfur Recovery with Incinerator
#1 Diesel HDS Unit	

The order did not include any concentration or mass-based emission limits for any of the approved equipment. In addition, the order did not specifically address petroleum storage tanks, wastewater treatment, the marine terminal, the low and High-Pressure flares, or the #1 Cooling Tower that were all constructed with the original refinery.

OAC 1054 – 2012 – Currently Applicable

On April 12, 2012, the NWCAA issued OAC 1054 superseding the original order dated June 8, 1970. OAC 1054 was written using the agency's current permitting format. The rewrite also clarified the applicable emission units and reworded the conditions for clarity for better incorporation into the AOP. See Section 2.3.6 for more discussion about OAC 1054.

3.2 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 to other process units for further processing. The bottoms from the vacuum unit are routed to the Delayed Coker for conversion into coke.

The Crude and Vacuum Unit has three process heaters: the Crude Heater, the South Vacuum Heater, and the North Vacuum Heater. All three heaters combust refinery fuel gas supplied by the main mix drum. In addition, the Crude Heater combusts a small volume of gas generated in the vacuum section of the unit called the Vacuum Tail Gas.

Construction History and Regulatory Applicability

The Crude and Vacuum Unit was built with the refinery in 1970. Eight major projects have been undertaken on this unit since 1970. The modifications or additions are: 1) Crude Heater combustion air preheater 2) New North Vacuum Heater; 3) Crude Pre-Flash Project; 4) Crude to Coker Condensate; 5) Crude Fractionation Project; 6) Delayed Coker and #1 & #2 Calciner modifications, 7) Vacuum Tail Gas amine scrubbing system; and in 2019, 8) North Vacuum Heater Ultra-Piping and Low NOx Burner Upgrade.

3.2.1 Combustion Air Preheater

<u>OAC 159 – 1975 – Currently Applicable</u>

In February 1975 the refinery proposed to install a combustion air preheater on the Crude Heater to improve energy efficiency by recovering heat from waste heat normally emitted to the atmosphere with the flue gas. The project lowered the stack gas temperature and potentially reduced 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 20, 1975, the NWCAA issued OAC 159 approving this project. OAC 159 does not include any specific requirements; therefore, this OAC has not been incorporated into the air operating permit.

3.2.2 North Vacuum Heater

<u>OAC 273 – 1983 - Superseded</u>

In 1983 the refinery installed the North Vacuum Heater with a heat input capacity of 55 MMBtu/hour when the air preheater is in service. The heater was designed with low-NOx burners. Emissions from this unit were determined to be below the PSD significance thresholds as long as the refinery operated the heater at 55 MMBtu/hour 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, under OAC 273.

To meet Best Available Control Technology (BACT) requirements, the heater was equipped with low-NOx burners. NSPS requirements for fuel gas were also triggered which limited the H_2S concentration in the fuel gas to 162 ppmvd for any three-hour period and required continuous monitoring of the H_2S concentration. 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.

PSD 5 – 1985 - Superseded

Subsequent heater efficiency studies performed by the refinery indicated that the North Vacuum Heater could be run at higher heat input rates than permitted under OAC 273, and in doing so would provide product splits favoring gas oil production over residual oil production. A PSD analysis was performed by Ecology and a final determination was made that NOx emissions from the project triggered the major PSD threshold. Subsequently, Ecology issued PSD-5 on December 17, 1985, thereby ensuring that the North Vacuum heater was properly permitted under PSD. PSD-5 limited emissions of CO to 9.5 tons/year on an average of any 60 consecutive minutes and NOx to 14.6 lb/hour on an average of any 60 consecutive minutes. PSD-5 also limited the North Vacuum Heater to a firing rate of 77 MMBtu/hour and the fuel gas feed to a H_2S concentration of 160 ppmv on a 3-hour rolling average. Other requirements of PSD-5 included the installation of continuous monitors for oxygen in the heater stack and H_2S for the refinery fuel gas combusted in the heater.

In addition, PSD-5 required the refinery to offset the increased NOx emissions either by installing a state-of-the-art staged fuel low-NOx burners in the heater during the next unit turnaround or within four years, whichever came first. The PSD permit also included an option of 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 the 28 ton per year NOx netting offset through installation of the Flare Gas Recovery Project. Subsequently, the emissions credits were applied toward that required the offset. Ecology 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.

PSD 5 Amendment 1 and OAC 273a – 1995 - Superseded

In 1995, the refinery requested a revision to PSD-5 to update CO emissions. At the time of the original PSD application, AP-42 did not have a CO emission factor for heaters with low-NOx burners and the application used an emission factor for an uncontrolled heater. By 1995, AP-42 had been revised to include a CO emission factor for low-NOx burners that was higher than that for uncontrolled heaters. As a result, the refinery requested that the CO emission limit in PSD-5 be increased from 9.5 to 16.6 tons per year. At that time the Ecology and NWCAA recognized that CO was not a PSD level pollutant and that the CO limit was more appropriately addressed in the minor NSR OAC permit. As a result on February 2, 1995, the NWCAA issued OAC 273 Revision 1 (or "a") with a 16.6 ton per year CO limit as its only substantive permit condition. On February 6, 1995, the Ecology issued PSD-5 Amendment 1 rescinding the CO limit from the PSD permit.

OAC 273b – 2004 - Superseded

On November 18, 2004, OAC 273 was 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 and more accurate emission factor of 0.0823lb/MMBtu as provided in AP-42 for this type of process heater. The revision also added a cumulative 12-month rolling period to the CO limit and an associated recordkeeping requirement.

PSD 5 Amendment 2 - Superseded

On January 22, 2009, Ecology issued PSD-5 Amendment 2. This amendment clarified that the firing rate limit for the North Vacuum Heater was based on a 30-day rolling average. This longer averaging time was needed to accommodate variability in the heater duty inherent in variable operating conditions such as weather or beginning verse end of run conditions in the Crude and Vacuum Unit. The second PSD amendment also removed the requirement to offset 28 tons per year of NOx emissions because this reduction had been documented in NWCAA's March 18, 1986 regulatory order to BP.

PSD 5 Amendment 3 – 2019 – Superseded, and,

OAC 273c – 2019 – Currently Applicable

On August 20, 2018, after a site-wide risk review for potential corrosion failure mechanisms identified issues with the metallurgy of the heater's tubing, BP requested a revision to both OAC 273b and PSD 5 Amendment 2. BP proposed to upgrade the heater's tubing, replace the low NOx burners with ultra-low NOx burners, increase the firing capacity of the heater from 77 MMBtu/hr to 117 MMBtu/hr, and modify the design of the heater to be primarily balanced draft with the option to operate in a natural draft mode.

NWCAA issued revised OAC 273c on February 19, 2019, which included BACT limits for emissions of NOx, SO2, PM, PM10, PM2.5, VOC, H2S, and TAP. The annual CO limit from OAC 273b was updated to be more stringent even after accounting for the increase in heater firing rate due to a lower emission factor proposed by BP during normal operation and the inclusion of an emission factor during startup and shutdown.

The revised OAC also provided BP the option to comply with SO_2 limits at the heater by installing a total sulfur (TS) analyzer on the heater's fuel gas system, subject to analyzer performance specification and data quality assurance program approval by NWCAA. The need for a TS monitor was identified through a review of existing monitoring required during revision c to OAC 273. As noted in the permit worksheet for OAC 273c, the total sulfur in the fuel gas varies from one hour to the next. This is not an anomaly. It is due to normal operations of the various pieces of equipment that provide gas to the fuel drum. Relying on monthly grab samples for sulfur content (previous monitoring method) does not provide a good representation of the sulfur content in the gas stream. NWCAA discussed these concerns with BP, and BP agreed that an appropriate long-term solution would be the installation of a total sulfur analyzer at the fuel drum. This analyzer could provide data about sulfur content for the North Vac Heater AND all of the other heaters and boilers that burn refinery fuel gas from the main fuel drum. However, due to budget constraints and timing, BP requested that NWCAA approve modification to OAC 273c with the TS monitor as one compliance option, but not the only option. NWCAA agreed to this approach to allow BP time to plan, design, purchase, and install the TS monitor. However, NWCAA noted that it would require the TS monitor as part of gap-filling under the 2021 AOP renewal.

On June 8, 2021, BP submitted a proposed monitoring plan for the TS analyzer, which NWCAA approved on July 6, 2021. The approval grants BP up to 180 days to certify the analyzer according to the monitoring plan and requires that it be operated as the SO_2 compliance instrument of record for the North Vacuum Heater unless an alternative is approved by the NWCAA in writing.

Ecology issued PSD 5 Amendment 3 on July 16, 2019. The amendment removed the H_2S limit from the permit after finding that H_2S was not originally subject to PSD review, increased the heater's firing rate limit to the proposed rate of 117 MMBtu/hr, and updated the NOx BACT limits.

PSD 5 Amendment 4 – 2021 – Currently Applicable

On November 8, 2021, PSD 5 Amendment 3 was modified by issuance of Amendment 4. PSD 5 Amendment 4 corrects typos in the NOx limits for the existing heater.

3.2.3 South Vacuum Heater

OAC 689 – 1999 - Superseded

The South Vacuum Heater was retrofitted with low-NOx burners in 1999 as required by OAC 689 to offset increased NOx emissions from the #1 & #2 Calciner production increase project approved under OAC 689.

OAC 902 – 2005 - Superseded

In early 2005, the South Vacuum Heater convection section was reconstructed, and the heater was equipped with ultra-low NOx burners (ULNB) due to operability issues with the low-NOx burners installed previously. The ULNB retrofit approved under OAC 902 allowed the refinery to reduce NOx emissions as part of their 2001 Consent Decree commitment to install NOx controls on 30% of the heater capacity at the refinery. The project resulted in the heater being de-rated from 222 MMBtu/hour to 207 MMBtu/hour. A CEM was installed to demonstrate compliance with the NOx emission limit of 10.5 lb/hour, calendar day average.

OAC 902a – 2005 - Superseded

The initial NOx CEM certification and source testing revealed that the heater could not comply with the original NOx emission limits in OAC 902. Revised OAC 902a was issued on November 1, 2005 to remove the ppm limit and increase the pound per hour limit, thereby reducing the NOx reduction credits for this project by 7 tons per year. The removal of the ppm limit eliminated the need to add a startup provision in the OAC. BP demonstrated compliance with the CO limit in OAC 902a with an initial, one-time only source test conducted on June 14, 2006. The test measured 0.15 lb/hour CO, significantly below the OAC 902a CO emission limit of 11.8 lb/hour. OAC 902a also specified that Conditions 1.3.1, 1.3.2, 2.3.1 and 2.3.2 of OAC 689 were void upon startup of the South Vacuum Heater following completion of the South Vacuum Heater Improvement Project. On May 24, 2005, the NWCAA received notice that the ULNB retrofit project was complete and that the South Vacuum Heater restarted on May 19, 2005, thereby, voiding the prior NOx and CO requirements of OAC 689. Because Conditions 1.3.1, 1.3.2, 2.3.1 and 2.3.2 of OAC 689 are void, they were removed from OAC 689 in revision "b". See sections 3.2.7 and 3.2.8 below for more discussion of OAC 689b and subsequent revisions.

3.2.4 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, it was determined that a Notice of Construction was not required for the project.

3.2.5 Crude to Coker Condensate

On April 4, 1990, the refinery submitted a proposal for the Crude to Coker Condensate project. The project was designed to route crude oil directly to the Delayed Coker in response to changing characteristics of the crude oil feed stocks. The project would increase the firing rates of various heaters in the refinery including those in the Reformers, Diesel and Naphtha units. The project did not include any physical changes to the heaters that would increase their pre-project design capacity. In their project submittal, the refinery proposed to install low-NOx burners in three heaters to mitigate NOx increases from the anticipated increase in heater firing rates. However, on August 8, 1990, the NWCAA issued a letter (OAC 281) stating that the project did not require approval because the affected heaters would not be firing above their design capacity. Subsequently, the refinery decided not to install the low-NOx burners. The August 8, 1990 NWCAA letter does not include any requirements and is not referenced in the air operating permit.

3.2.6 Crude Fractionation Project

OAC 640 – 1998 - Superseded

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.

On May 1, 1998, the NWCAA issued OAC 640 approving the Crude Fractionation Project. The OAC identified BACT as a LDAR program conducted in accordance with 40 CFR 60 Subparts GGG and VV for specific equipment at the Crude and Vacuum Units that were being modified as part of the Crude Fractionator Project. The units included the Crude Distillation Unit, Butane Distillation Unit, Stove Oil Stripper, Diesel Oil Stripper, Vacuum Diesel Fractionation Unit (VDF), and Vacuum Distillation Unit.

OAC 640a – 2012 – Currently Applicable

On May 9, 2012, the NWCAA issued revised OAC 640a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit. OAC 640a includes a single condition requiring a startup notice following completion of the project. The NWCAA received this startup notification on May 18, 1999, stating that the Crude Fractionation Project was completed, and that the Crude Unit would startup in June 1999. Because this single and one-time only requirement of OAC 640a has been completed, OAC 640a is not cited in the air operating permit.

3.2.7 Delayed Coker and #1 & #2 Calciner Modifications

OAC 689 – 1999 - Superseded

This project affected the South Vacuum Heater in the Crude and 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 approved under OAC 689 in 1999. 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. On October 27, 2008, revised OAC 689a was issued to restructure limits on the North and South Coker Charge Heaters but no changes were made to conditions that applied to the South Vacuum Heater and Vacuum/VDF Overhead Tail Gas DEA Scrubber.

Low-NOx burners were installed in the South Vacuum Heater in 1999. On June 29, 1999 the Vacuum Tail Gas amine scrubber began operating. Performance tests were performed on August 17, 1999, demonstrating that the scrubber achieved a greater than 80% H_2S reduction as required by OAC 689. Performance certification tests for NOx and CO emissions were performed on South Vacuum Heater on September 22, 1999.

OAC 689b – 2012 - Superseded

On September 18, 2012, the NWCAA issued OAC 689b. This revision made changes to clarify conditions and to clean up the order prior to incorporation into the air operating permit. Revision OAC 689b removed NOx and CO conditions for the South Vacuum Heater that were established following the low-NOx burner retrofit in 1999 because in 2005, the South Vacuum Heater was retrofit with ultra-low NOx burners (ULNB) approved under OAC 902. On May 24, 2005, the

NWCAA received notice that the ULNB retrofit project was complete and that the South Vacuum Heater was restarted on May 19, 2005.

OAC 689 – 1999 - Superseded

Prior to installing the DEA "amine" scrubber to treat Vacuum Tail Gas generated at the Vacuum Diesel Fractionator (VDF) and Vacuum Tower with the absorbed H_2S routed to the Sulfur Recovery Unit for conversion into elemental sulfur the untreated Vacuum Tail Gas was routed to the main refinery fuel gas system and/or routed directly into the Crude Heater as supplemental fuel. The purpose of the project was to improve VDF and Vacuum Tower performance by establishing pressure controls on the tower overheads and to reduce SO_2 emissions from the Crude Unit with the reductions used for PSD netting offsets.

The Vacuum Tail gas amine scrubbing project was approved April 13, 1999, under OAC 689. The scrubber was installed and began operating in June 29, 1999. The 80% SO_2 reduction required in the OAC was used for PSD netting of the Delayed Coker and #1 & #2 Calciner Modification project. The 80% reduction of SO_2 emissions from Vacuum Tail Gas scrubbing was estimated to result in a net decrease in SO_2 emissions of 515 tons per year.

In 2005, Vacuum Tail Gas that was being combusted in the Crude Heater was rerouted to the main refinery fuel gas mix drum. This was done so that the Crude Heater could be operated in compliance with the requirements of 40 CFR 60 Subpart J because the Vacuum Tail Gas was not being continuously monitored for H_2S in accordance with Subpart J. On April 10, 2008, US EPA Region 10 issued a temporary, 18 month, alternative monitoring plan (AMP) for Subpart J allowing combustion of Vacuum Tail Gas in the Crude Heater without a CEMS. The AMP required that the Vacuum Tail Gas be periodically monitored for H_2S using draeger tube sampling. Upon issuance of the AMP, the Vacuum Tail Gas was rerouted back to the Crude Heater as a supplemental fuel source in that heater. The AMP expired on October 10, 2009. Just prior to this expiration date, a CEMS was installed to continuously monitor H_2S in the Vacuum Tail Gas in accordance with the requirements of Subpart J.

OAC 689c – 2021 – Currently Applicable

OAC 689b was revised during issuance of OAC 689c on June 3, 2021. The revision replaced the requirement to reduce H_2S in the vacuum tail gas by 80% after amine scrubbing with the Subpart J requirement to limit H_2S in the vacuum tail gas to 162 ppmvd as a 3-hour rolling average, monitored by CEMS, after BP demonstrated that compliance with the Subpart J limit is at least as stringent. The PSD offset remains real, quantifiable, permanent, and enforceable.

OAC 814d – 2021 – Currently Applicable

OAC 814d was issued on June 3, 2021, which revised the existing 500 ppm H_2S limit on Vacuum Tail Gas to the more stringent Subpart J limit of 162 ppm H_2S. The original limit, established under OAC 814, provided the refinery with a federally enforceable SO_2 offset so that the #5 Boiler and Isomerization Unit project was below the PSD significance threshold of 40 tpy. This offset was approved as an SO_2 reduction by limiting the H_2S concentration in the Vacuum Tail Gas generated at the Crude and Vacuum Unit to 500 ppm, and was later revised under OAC 814d to a limit of 162 ppm. The PSD offset memorialized remains real, quantifiable, permanent, and enforceable.

See Section 3.7 and 3.11.2 for a discussion of previous versions of OAC 814d and the projects that triggered them.

3.3 Reformer Units and Naphtha HDS

The Reformers and Naphtha 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 hydro-desulfurization 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 EPA's effort to eliminate lead from gasoline, the refinery added an additional 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. In 1996 the refinery added a light reformate splitter (LRF) tower to the #1 Reformer Unit. The purpose of the LRF 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.

Reformer catalyst in the #1 and #2 Reformers is regenerated approximately once every six months. During catalyst regeneration, the process feed is stopped and the heater is put into hot stand-by operation. A hydrogen sweep is done to remove excess hydrocarbons and the gases are sent to flare. During catalyst regeneration, the catalyst goes through a burn-off process step and then an oxy-chlorination step. The burn-off process removes material attached to the catalyst and removes any impurities. The oxy-chlorination step reactivates the catalyst using a chlorinated solvent. As the catalyst is brought back up to temperature, a large amount of hydrogen chloride (HCl) is released. During catalyst regenerations, gases are scrubbed to remove the HCl at an approximate 98% efficiency rate before routing to the flare system. The catalyst regeneration process can be completed within about three days.

Major equipment at the Reformers and Naphtha unit 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 in heavy liquid, light liquid, and gaseous service that may emit VOCs and HAP.

Construction History and Regulatory Applicability

The #1 Reformer, 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 (OAC 1054). Four projects have been performed in this area since original construction: 1) Gasoline Reformer Unit; 2) New Light Reformate Splitter Tower; 3) Crude to Coker Condensate, and 4) #1 Reformer Recycle Gas Dryer project.

OAC 977 – 2007 - Superseded

On January 22, 2007, the NWCAA issued OAC 977 for the #1 Reformer Recycle Gas Dryer project. The project shortened the time period for regenerating the reformer catalyst. The OAC required an enhanced LDAR program at the unit, and required that the #1 Reformer Heater be source tested for NOx. The one-time only NOx test was completed on June 26, 2007. The other projects are described under the #2 Reformer Unit.

OAC 977a – 2018 – Currently Applicable

OAC 977 was modified on April 26, 2018. OAC 977a clarified the requirements of the enhanced LDAR program.

According to 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 #1 Reformer and #2 Reformer are each subject to 40 CFR 63 Subpart UUU.

3.3.1 #2 Reformer Unit

OAC 305 – 1985 - Superseded

In 1985, the refinery submitted a Notice of Construction (NOC) application to construct the #2 Reformer, including the #2 Reformer Heater with nominal heat input capacity of 340 MMBtu/hour. The project was also referred to as the "Gasoline Reformer" project. The project allowed the refinery to phase out the tetra-ethyl lead as an octane enhancer in gasoline as mandated by federal requirements by 1986. The #2 Reformer upgrades low octane components into high octane components. An additional Naphtha HDS Heater with a rated heat input capacity of 60 MMBtu/hour was proposed in the NOC application. However, the heater was never built.

The #2 Reformer project was approved under OAC 305 issued November 14, 1985.

PSD 7 – 1986 – Superseded

On March 13, 1986, Ecology issued PSD-7 approving the #2 Reformer. According to the Finding section of PSD-7, "Oxides of nitrogen are the only emissions which are subject to PSD review". However, PSD-7 contains specific limits on CO and NOx from the #2 Reformer Heater. It also limits the concentration of H_2S contained in fuel gas combusted in the #2 Reformer Heater.

The PSD addressed combustion emissions from the #2 Reformer Heater and fugitive emissions from process equipment leaks at the #2 Reformer Unit. BACT for the heater was determined to be the use of low-NOx burners with air preheat and computer-controlled oxygen trim. NSPS 40 CFR 60 Subpart J requirements were triggered for the project requiring continuous monitoring of the H_2S concentration in the refinery fuel gas combusted in the #2 Reformer Heater, with an associated 162 ppmvd H_2S, 3-hour rolling average. PSD-7 also includes a 90 ppm H_2S limit, monthly average, as BACT. PSD-7 established short-term (lb/hr) and long-term (tpy) NOx and CO limits for the #2 Reformer Heater. However, because the permit did not specify a method for determining ongoing compliance with these limits, the associated terms in the AOP have been gap-filled with directly enforceable requirements to conduct source testing for NOx and CO biennially.

OAC 305a – 2012 - Superseded

On May 3, 2012, the NWCAA issued revised OAC 305a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

OAC 305b – 2021 – Currently Applicable

OAC 305a was modified with issuance of OAC 305b on July 21, 2021. The revision streamlined the existing H_2S limits for the #2 Reformer Heater with more recent BACT limits on the heater's shared fuel gas system at the request of BP to simplify the compliance demonstration.

PSD-7-A1 – 2022 Currently Applicable

PSD 7 was superseded with issuance of PSD 7-A1. The current PSD remove the hourly average firing rate limit of 60 MMBtu/hr for the Naphtha Hydrodesulfurization (NHDS) Heater. This heater was never constructed as part of the Clean Gasoline Project that installed a new gasoline reformer (#2 Reformer) unit at the refinery. The revision also revised the fuel gas H_2S, 3-hour rolling average limit from 160 ppm to 162 ppm to align with both the NSPS limit and the applicable OAC BACT determination. The 90 ppm H_2S, monthly average limit was also revised to a more stringent 50 ppm, 24-hr average limit to align with previous NWCAA BACT determinations for that fuel gas system.

3.3.2 Light Reformate Splitter Tower (LRF Tower)

OAC 562 – 1996 - Superseded

In August 1995, the refinery proposed to construct a new Light Reformate Splitter Tower at the #1 Reformer Unit. The project included reconfiguring the existing reformate splitter so that the light reformate overhead would be drawn off and become the feed to the LRF Tower. The project was designed to produce C5/C6 paraffin overhead that would be used for gasoline blending and benzene concentrated (40% by weight) bottoms that would be stored in existing tanks prior to shipping off-site. The project would result in an increase in VOC and benzene emissions both from new equipment at the #1 Reformer Unit and from existing storage tanks handling products with relatively high in benzene concentrations.

The NWCAA determined that a WAC 173-460 Air Toxics, Second Tier (Tier II) analysis was required prior to approval of the project because modeling showed that benzene would exceed the acceptable source impact level (ASIL). A Tier II analysis was performed by Ecology and the project was approved based on a decision that proposed emissions controls represented Toxic Best Available Control Technology (T-BACT) and that the project would not result in an increased cancer risk of more than one in one hundred thousand.

On September 7, 1995 the NWCAA granted the refinery approval for the beginning of site preparation work, although the refinery was prohibited from actually installing and constructing the LRF tower until an approval order was issued. On January 3, 1996, the NWCAA issued OAC 562 approving the project.

OAC 562a – 1996 - Superseded

On February 14, 1996, the refinery requested a change to their Order of Approval that would allow the use of larger tanks for storage of the benzene concentrated LRF 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 because of this change. The requested change was incorporated into the Tier II analysis. On February 26, 1996, the NWCAA issued revision OAC 562a approving the change. The revised OAC included a new condition that specified those tanks that were allowed to store the benzene concentrate. On April 26, 1996, Ecology issued a Tier II Analysis Fact Sheet in support of the revised project.

The project was constructed and the new LRF Tower began operating on May 6, 1996. Once installed and operating, the refinery determined that through computer operation optimization the LRF Tower bottoms could be further concentrated to 70% by weight benzene, much better than the 40% by weight design. 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 cancer risk from the project was similar to the original calculations. On March 9, 2000, the NWCAA determined that new source review was not required as a result of this change.

OAC 562b – 2000 - Superseded

On December 8, 2000, the NWCAA issued OAC 562b which allowed transfers of the benzene concentrate between any two of the approved tanks to facilitate periodic inspection and maintenance of the tanks.

OAC 562c – 2003 – Superseded

On March 17, 2003, the NWCAA issued OAC 562c with a revised list of tanks that were allowed to transfer benzene concentrate.

OAC 562d – 2012 – Currently Applicable

On July 9, 2012, the NWCAA issued revised OAC 562d. This revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

3.3.3 Crude to Coker Condensate/COUP

Other construction projects affecting the Naphtha HDS were the Coker Olefin Upgrade Project (COUP) and the Crude to Coker Condensate Project both discussed under the Delayed Coker. The Crude to Coker Condensate project recovered waste heat from the Delayed Coke drum overhead gas and used it to pre-heat incoming crude oil at the Crude Unit. Additional heater firing takes place at several units including the Naphtha HDS and Reformer units. The COUP resulted in heat exchangers and pumps being replaced and a new hot flash drum installed. The COUP triggered regulatory requirements for the modified equipment. In a letter dated August 8, 1990, the NWCAA determined that the equipment components affected by the Crude to Coker Condensate Project were subject to 40 CFR 60 Subpart GGG as a result of the COUP.

3.4 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 Hydrocracker at the Cherry Point Refinery has two stages. The 1st stage of the Hydrocracker cracks a portion of the feed to product and the 2nd stage cracks the remaining feed to product. Products from the Hydrocracker are processed further in the Reformers and are used in blending fuels. Both stages make Heavy Hydrocrackate (HUX) which is reformer feed.

Major equipment at the Hydrocracker includes the 1st Stage Reactor Heater (R-1), 1st Stage Fractionator Reboiler, and 2nd Stage Reactor Heater (R-4) and the 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 HAP. Other components of the Hydrocracker 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

OACs 148 and 149 – 1975 – Currently Applicable

The original Hydrocracker unit was built with the refinery in 1970. On November 20, 1974, the NWCAA issued OAC 148 and OAC 149 approving the installation of air pre-heaters on the Hydrocracker 1st Stage Fractionator Reboiler and Hydrocracker 2nd Stage Fractionator Reboiler, respectively. These approval orders are considered narrative and do not include any specific requirements. Therefore, they have not been incorporated into the air operating permit.

CAA-10-2001-0096 – 2001 - Defunct

In early 2001 the refinery installed several skid mounted gas turbine generators to provide affordable and reliable electrical power during a period of high energy prices and potential power shortages. Even though the gas turbines were removed from the refinery in July 2002, their approval was contingent on the refinery offsetting NOx emissions from the turbines by installing low-NOx burners on the 2nd Stage Fractionator Reboiler as approved under Administrative Order on Consent (CAA-10-2001-0096) issued by EPA Region 10. Condition 9a of the order states, "ARCO will retrofit the second stage hydrocracker fractionation reboiler with low NOx burners during the first scheduled maintenance shutdown (turnaround) of that unit after June 1, 2001, but in no case later than May 31, 2004."

OAC 847 – 2003 - Superseded

On November 13, 2003, the NWCAA issued OAC 847 approving a low-NOx burner retrofit project for the Hydrocracker 2nd Stage Fractionator Reboiler. The OAC established a 0.07 lb/MMBtu NOx limit for the reboiler and 56.2 ton/year annual mass-based limit with compliance demonstrated through annual source testing.

OAC 847a – 2008 - Superseded

On October 27, 2008 the NWCAA issued revised OAC 847a. The revision corrected the test method used for determining visual emissions from the 2nd Stage Fractionator Reboiler. In addition, the revision added a firing rate limit of 183.4 MMBtu/hour based on a 720-hour averaging period. This allows the reboiler to fire over the 183.4 MMBtu/hour limit for short-term periods to accommodate variability in duty. This operational flexibility was needed because the reboiler duty fluctuates substantially based on production rates, catalyst health, crude slate, feedstock temperature, fuel gas composition, end-of-run versus start-of-run conditions and weather.

OAC 847b – 2012 – Superseded

On July 17, 2012, the NWCAA issued revised OAC 847b. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit. Revised OAC 847c was issued on September 26, 2018, to reformat the OAC and align the source testing language with current NWCAA standards prior to incorporation into the AOP during this renewal.

OAC 847c – 2021 – Currently Applicable

The OAC was revised again on March 16, 2021, to further clarify source testing requirements.

OAC 966 – 2006 - Superseded

On August 9, 2006, the NWCAA issued OAC 966 approving a retrofit of the Hydrocracker 1st Stage Reactor Heater (R-1) with ultra-low NOx burners (ULNB). This project was done to achieve NOx reductions for the 2001 Consent Decree. OAC 966 established a NO_x limit for the heater and required that ongoing compliance be demonstrated with a CEM. As stated in a startup notification letter from BP dated October 30, 2006, the heater restarted with the ULNB on October 29, 2006. This startup notice fulfilled Condition 7 of OAC 966 and therefore, this one-time only condition is not included in the AOP.

OAC 966a – 2008 - Superseded

On January 29, 2008, the NWCAA issued revised OAC 966a. This revision corrected the EPA test method prescribed for annual CO source testing.

OAC 966b – 2011 - Superseded

On April 21, 2011, the NWCAA issued revised OAC 966b. This revision established a firing rate limit on the Hydrocracker 1st Stage Reactor Heater of 120.9 MMBtu/hour HHV, based on a 30-day rolling average. The revision increased the NOx short-term mass emission rate limit from 3.6 to 4.9 lb/hour, and added recordkeeping requirements to document ongoing compliance with NOx and CO limits of the OAC.

OAC 966c – 2018 – Superseded

OAC 966c was issued on April 26, 2018 to clarify LDAR program requirements. OAC 966d was issued on June 3, 2021 to clarify NOx emission limits, reduce CO source testing frequency, and clarify source test reporting requirements.

OAC 966d – 2021 – Currently Applicable

OAC 966d was issued on June 3, 2021 to clarify NOx emission limits, reduce CO source testing frequency, and clarify the source test reporting requirements at the request of BP.

OAC 850 – 2003 - Superseded

On December 1, 2003, the NWCAA issued OAC 850 approving the Hydrocracker Incremental Vacuum Gas Oil Production Project. The project increased feed rate at the Hydrocracker. The only requirement of OAC 850 was a condition to implement an enhanced LDAR on equipment components associate with the project. OAC 850 included a project summary that states that the incremental gas oil project will increase the gas oil processing rate by 2,600 barrels per day (bpd). This project summary statement is not considered an applicable requirement and as such is not included in the AOP.

OAC 850a – 2018 – Currently Applicable

OAC 850 was superseded by OAC 850a, issued April 26, 2018, which clarified the enhanced LDAR program requirements.

OAC 351 – 1992 - Superseded

On January 14, 1992, the NWCAA issued OAC 351 authorizing construction of the #4 Boiler at the refinery. As a PSD offset project, OAC 351 required a 27 ton per year NOx reduction at the Hydrocracker 1st Stage Fractionator Reboiler with a low-NOx burners retrofit project. On May 28, 1993, the refinery submitted a letter to the NWCAA stating that the NOx reductions associated with the 1st Stage Fractionator Reboiler low-NOx burner project had been validated through pre-project and post project source testing. The NWCAA sent a letter to the refinery dated March 7, 1994, stating that a review of the source test data confirmed that the required 27 ton NOx reduction had been met.

OAC 351e – 2010 - Superseded

On May 10, 2010, the NWCAA issued revised OAC 351e authorizing the refinery to modify the flue gas recirculation system on the #4 Boiler that was being done for Consent Decree creditable NOx reductions.

OAC 351f – 2021 – Currently Applicable

OAC 351e was modified with issuance of OAC 351f on June 3, 2021. The revision reformatted the OAC for incorporation into the AOP during this renewal.

OAC 1067 – 2010 – Superseded

On November 29, 2010, the NWCAA issued OAC 1067 authorizing replacement of the low-NOx burners on the Hydrocracker 1st Stage Fractionator Reboiler with state-of-the-art ULNB. This NOx reduction project was approved as a PSD netting offset project for the BP Clean Fuels Project approved under OAC 1064.

OAC 1067a – 2011 – Currently Applicable

OAC 1067 revision “a” was issued July 29, 2011 allowing the CO lb/hour limit to be the compliance demonstration method when the CO lb/MMBtu limit is exceeded. The effective date of OAC 1067a is the startup date of the 1st Stage Fractionator Reboiler following the ULNB retrofit project. On June 4, 2012, the NWCAA received a letter from BP notifying the agency that the reboiler began operating on May 16, 2012, following installation of the ULNB. This fulfills this one-time only notice of startup requirement of OAC 1067a Condition 11.

OAC 1122 – 2012 – Currently Applicable

On April 9, 2012, the NWCAA issued OAC 1122 approving the Hydrocracker Atmospheric Relief Valve (ARV) Project. The project involved routing a large emergency atmospheric relief vent to a new knockout vessel and then to the flare gas system. The project triggered NSPS Subpart GGGa applicability requiring the refinery to employ an enhanced LDAR program at the Hydrocracker Unit. OAC 1122 has only one condition that requires that the agency be notified of the startup date of the Hydrocracker Unit following completion of the ARV project. On May 17, 2012, the NWCAA received a letter from BP notifying the agency that the Hydrocracker Unit restarted on May 16, 2012, following completion of the ARV project. Because the one-time only requirement of OAC 1122 has been fulfilled, OAC 1122 is not cited in the air operating permit.

3.5 Delayed Coker

In many refineries, vacuum tower bottoms are sold as fuel oil. However, the Cherry Point Refinery converts vacuum tower bottoms to petroleum coke for off-site sale for electrode usage. Coking takes place at about 900°F in one of four coker drums. 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. The coker vents are opened for unloading once the drum pressure is less than 5 psig. 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.

Approximately once every six months, the tubes in the East and West Coker Charge Heaters need to be cleaned because solid carbonaceous deposits known as "coke" form over time. While coking in the drums is desired, the coking of other surfaces is deleterious. Coke in the charge heater tubes interferes with the heat transfer and velocity profile of the residuum being transferred from the heater to the coke drums. The heaters are taken out of service one at a time, steam cleaned and allowed to cool. A cleaning device called a pig is sent through each of the charge heater tubes to remove the coke deposits and collect wall thickness data on the tubes to ensure continued safe operations. Weak and worn tubes are replaced prior to restarting the heater.

Under normal operations, the coker blow down vapor recovery (CBVR) system collects the gases emitted from coking operations. These gases are routed through a series of drums, compressed, and directed through a MDEA absorber to remove H_2S. However, the Pressure Safety Valves (PSVs) on the CBVR system are set at relatively Low-Pressures to protect the coke drums. The steam cleaning phase of the heater shut down sequence occurs at pressures that exceed the PSV settings on the CBVR system. As a result, the CBVR system is not used during the steam cleaning phase. Instead, the gases emitted when the tubes are being de-coked are directed into the Low-Pressure Flare header where they are recovered by the flare gas recovery compressors and routed through its associated absorber to remove H_2S. During this operation, the High-Pressure compressor and Low-Pressure compressor are both lined up to collect gases from the Low-Pressure header to ensure that sufficient recovery capacity is available.

Major equipment at the Delayed Coker includes the East Coker Heater, the West 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 HAP. 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. Five major projects have been performed on the Delayed Coker since original construction: 1) Crude to Coker Condensate; 2) Coker Olefin Upgrade Project (COUP); 3) Modification of Coker Unit, and #1 & #2 Calciner Hearths; 4) construction of the East and West Coker Heaters and permanent shutdown of the North and South Coker Heaters; and 5) addition of a booster compressor to the CBVR. According to 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.

3.5.1 Crude to Coker Condensate

On April 4, 1990, the refinery submitted a proposal for the Crude to Coker Condensate project. The project was designed to route crude oil directly to the Delayed Coker in response to changing characteristics of the crude oil feed stocks. The project would increase the firing rates of various heaters in the refinery including those in the Reformers, Diesel and Naphtha units. The project did not include any physical changes to the heaters that would increase their pre-project design capacity. In their project submittal, the refinery proposed to install low-NOx burners in three heaters to mitigate NOx increases from the anticipated increase in heater firing rates. However, on August 8, 1990, the NWCAA issued a letter (NOC 281) stating that the project did not require approval because the affected heaters would not be firing above their design capacity. Subsequently, the refinery decided not to install the low-NOx burners. The August 8, 1990 NWCAA letter does not include any requirements and is not referenced in the air operating permit.

3.5.2 Coker Olefin Upgrade Project (COUP)

In 1990, the refinery proposed the Coker Olefin Upgrade Project (COUP) which was designed to improve recovery of light portions and naphtha at the Delayed Coker. At the time of the proposal, coker naphtha from the High-Pressure separator in the Delayed Coker was stabilized and routed to the Naphtha HDS Unit for treatment and removal of sulfur compounds. The COUP proposed to install equipment at the Delayed Coker to recover high octane, light coker naphtha streams for gasoline blending by installing a new dehexanizer tower downstream of the Delayed Coker's High-Pressure separator to recover hexane and lighter portions of the coker naphtha. The lighter portion was debutanized in the existing coker stabilizer and further processed in the Merox Unit (note, the Merox Unit was decommissioned in 2005 following startup of the Isomerization Unit). Minor changes to the Naphtha HDS unit were also required including new heat exchangers, pumps, and the installation of a hot flash drum upstream of the cold flash drum.

On May 15, 1990, the NWCAA issued a letter (NOC 283) stating that the Coker Olefin Upgrade Project (COUP) was reviewed under a "Notice of Intent", as opposed to the Notice of Construction (NOC) application review process required for an Order of Approval to Construct (OAC). The letter is not signed and is not considered an OAC. The letter includes a number of conditions that are reiterations of already applicable federal requirements. These include 40 CFR 60 Subpart GGG requirements at the Delayed Coker, and 40 CFR 60 Subpart QQQ requirements at the Wastewater Treatment Plant. Because the May 15, 1990 letter does not add any requirements not already required by direct federal applicability, and the fact that the letter is not considered an enforceable order issued under NWCAA Section 300, the letter and its conditions are not referenced in the air operating permit.

3.5.3 Delayed Coker and #1 & #2 Calciner Modifications

On December 9, 1998 the refinery notified the NWCAA of proposed modifications to the Delayed Coker and #1 & #2 Calciners. 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. To complete the project, there was an increase in the heat input capacity of the North and South Coker Charge Heaters and replacement of the four coke drums with larger drums. The coker heaters were retrofitted with staged air combustion and flue gas recirculation technology to control NOx emissions

Modifications to the Delayed Coker originally included rerouting fuel gas generated at the Merox Unit to supplement the refinery fuel gas stream being combusted in the North and South Coker Charge Heaters. In early 2005, the Merox Unit was decommissioned following startup of the Isomerization unit. As a result, the fuel gas stream combusted in the Coker Charge Heaters is now comprised of gas generated at the Delayed Coker supplemented by gas from the refinery's main fuel gas drum. Since 1999, the H_2S content of this "coker fuel gas" has been monitored with a CEM that was installed under approval Condition 2.5.1 of OAC 689.

Calciner modifications included increasing the heat capacity of #1 & #2 Calciner hearths as well as requiring BACT as a caustic scrubber followed by a wet electrostatic precipitator.

Emissions from the Delayed Coker and #1 & #2 Calciner Modification project included NO_X, 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 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 PSD significant thresholds for all criteria pollutants. Section 3.2 presents a detailed description of the Crude/Vacuum Unit modifications to the South Vacuum Heater and Tail-Gas Overhead System.

<u>OAC 689 – 1999 - Superseded</u>

On April 13, 1999, the NWCAA issued OAC 689 approving modifications to the Delayed Coker and #1 & #2 Calciners. The OAC set short-term (lb/hr) and long-term (tpy) limits for NOx, SO_2 and CO on the North and South Coker Charge Heaters. It also set a 5% opacity limit on the heater stacks and established a 50 ppmvd daily average limit for H_2S in the fuel gas combusted in the Coker Heaters.

The Delayed Coker and #1 & #2 Calciner Modification project was completed by the end of June 1999 and the units restarted.

<u>OAC 689a – 2008 - Superseded</u>

On October 27, 2008 the NWCAA issued revised OAC 689a. The revision converted the SO_2, CO, and NOx emission limits for the North and the South Coker Charge Heaters from lb/MMBtu to the equivalent lb/hr limit based on the full firing rate for each heater. This simplified reporting and clarified that emission limits are on a per heater basis, instead of on the combination of both heaters.

<u>OAC 689b – 2012 - Superseded</u>

On September 18, 2012, the NWCAA issued OAC 689b. This revision made changes to clarify conditions and clean up the order prior to incorporation into the air operating permit.

<u>OAC 689c – 2021 – Currently Applicable</u>

OAC 689b was revised during issuance of OAC 689c on June 3, 2021. The revision removed obsolete conditions for the now defunct North and South Coker heaters, corrected the units of an emission limit, and revised the PSD offset requirement to demonstrate an H_2S reduction in the Vacuum Tail Gas by 80% with the requirement to limit H_2S in the tail gas to 162 ppm, 3-hour rolling average.

3.5.4 Construction of the East and West Coker Heaters and Lean Oil Absorption System

PSD 16-01 and OAC 1200 – 2017 – Currently Applicable

On May 23 and 24, 2017, respectively, Ecology issued PSD 16-01 and NWCAA issued OAC 1200, which permitted the construction of two new, larger Coker heaters (East and West) to replace the North and South Coker Heaters, which were required to be decommissioned after startup of the new heaters. The project also included installation of a lean oil absorption system and compressor to recover additional light components from the Coker off gas. The Lean Oil Absorption System Fuel Gas Condition Unit Compressor was started up on February 15, 2019. The East Coker Heater was started up on April 29, 2019, in conjunction with permanent shutdown of the South Coker Heater. The West Coker Heater was started up on May 12, 2019, in conjunction with permanent shutdown of the North Coker Heater.

OAC 689c – 2021 – Currently Applicable

OAC 689b was revised with issuance of OAC 689c on June 3, 2021. Revision 'c' removed conditions for the now defunct North and South Coker Heaters.

3.5.5 Installation of the Coker Blowdown Vapor Recovery Booster Compressor

OAC 1289 – 2017 – Currently Applicable
On December 12, 2017 NWCAA issued OAC 1289 for installation of one new booster compressor within the Coker Blowdown Vapor Recovery system. The compressor enables BP to capture gases normally released directly to atmosphere or flared during coke drum venting and maintenance events, bringing BP into compliance with the requirements of 40 CFR 63.657(a), which state that existing affected sources must depressure coke drums to a closed blowdown system until the coke drum vessel pressure drops below an average of 2 psig determined on a rolling 60-event basis. The compressor was permanently started up on January 10, 2020, and is an affected facility under NSPS GGGa.

3.6 Diesel Hydrodesulfurization Units

Construction History and Regulatory Applicability

The #1 Diesel HDS Unit (#1 DHDS) was built with the refinery in 1970. Construction of the #2 Diesel HDS Unit (#2 DHDS) was completed in 2006, with startup occurring on May 22, 2006. The #3 Diesel HDS Unit (#3 DHDS) is currently under construction with a startup date scheduled for early 2013.

3.6.1 #1 Diesel HDS Unit

Diesel feed stock from the Crude and Vacuum Unit and Delayed Coker is processed using hydrodesulfurization (HDS) in the #1 Diesel HDS Unit. In the process diesel is combined with hydrogen, heated to 500°F and passed over a catalyst bed 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. The combustion sources at the #1 Diesel HDS include a charge heater and a stabilizer reboiler.

OAC 949 – 2006 - Superseded

On March 31, 2006, the NWCAA issued OAC 949 approving a heater reliability project at the #1 Diesel HDS. The project was comprised of installing ultra-low NOx burners on both the Charge Heater and Stabilizer Reboiler. The ULNB were installed in each and the unit restarted on May

20, 2006. As a condition of the OAC, a NOx CEM was required on the Stabilizer Reboiler to enable BP to demonstrate NOx reductions for the 2001 Consent Decree.

OAC 949a – 2009 - Superseded

On July 1, 2009 the NWCAA issued revised OAC 949a. This revision added a requirement for a NOx CEM on the #1 Diesel HDS Charge Heater to enable BP to demonstrate NOX reductions from retrofitting with ULNB for the 2001 Consent Decree. Other OAC revisions included a modification to the requirements for source testing to allow testing at representative firing rates rather than at 70% of the Charge Heater maximum firing rate and above 90% of the Stabilizer Reboiler maximum firing rate. The OAC includes a condition to conduct additional source testing within 90 days if the 720-rolling average firing rate exceeds the firing rate recorded during the most recent test by more than 20%.

OAC 949b – 2018 – Superseded

OAC 949a was revised with issuance of OAC 949b on April 26, 2018, to clarify LDAR program requirements.

OAC 949c – 2021 – Currently Applicable

OAC 949b was subsequently revised on June 3, 2021 with OAC 949c, which removed the previous 720-hour rolling firing rate CO source testing trigger, reduced CO source testing frequency, and clarified source test reporting requirements.

3.6.2 #2 Diesel HDS Unit

OAC 892 – 2005 - Superseded

Construction of the #2 Diesel HDS Unit (#2 DHDS) was completed in 2006, with startup occurring on May 22, 2006. The #2 DHDS allows the refinery to produce low-sulfur (less than 0.05 wt%) over-the-road diesel. The unit consists of a 25 MMBtu/hour Charge Heater, a catalyst bed reactor section and a fractionation section. In the hydrotreating process sulfur is converted in the presence of a catalyst and hydrogen to H_2S which is sent to the Sulfur Recovery Unit. The #2 DHDS reduces the sulfur content of the produced diesel stream by approximately 5000 tons per year. The NWCAA issued OAC 892 on March 3, 2005, approving construction and operating of the #2 DHDS Unit.

OAC 892a – 2007 - Superseded
On September 5, 2007, the NWCAA issued revised OAC 892a. This revision added a condition to limit the charge heater firing rate to 35 MMBtu/hour and reduced the firing rate under which the heater was to be source tested from 90% to 80%.

OAC 892b – 2009 - Superseded

On January 28, 2009, the NWCAA issued revised OAC 892b. This revision included a modification to the requirements for source testing to allow testing the Charge Heater at representative firing rates rather than at 80% of its maximum firing rate. The OAC includes a condition to conduct additional source testing within 90 days if the 720-rolling average firing rate exceeds, by more than 20%, the firing rate recorded during the most recent test.

OAC 892c – 2018 – Superseded

OAC 892b was revised with issuance of OAC 892c on April 12, 2018, to clarify LDAR program requirements.

OAC 892d – 2021 – Currently Applicable

OAC 892c was modified by OAC 892d on June 3, 2021, to remove the 720-hour rolling average firing rate testing trigger for CO, reduce CO source testing frequency, and clarify source test reporting requirements.

3.6.3 #3 Diesel HDS Unit

OAC 1064 and PSD 10-01 – 2010 – Superseded

The #3 Diesel Hydro-Desulfurization Unit (#3 DHDS) was approved by the NWCAA under OAC 1064 issued November 29, 2010 as part of the BP Clean Fuels Project. The Clean Fuels Project was also approved under PSD-10-01 issued by Ecology on December 13, 2010. The PSD permit addresses PM_{10} as the only PSD- applicable pollutant for the project. $PM_{2.5}$ was permitted as a minor pollutant because PSD applicability was based only on PM_{10} at the time the application was being reviewed. $PM_{2.5}$ became a PSD regulated pollutant only after EPA finalized the front and back half source test method for $PM_{2.5}$. This occurred in December 2010 after issuance of OAC 1064 for the Clean Fuels Project.

The Clean Fuels Project includes construction of the #2 Hydrogen Plant and #3 DHDS Unit. NOx emission increases that will result from the Clean Fuels Project are to be offset by retrofitting the Hydrocracker 1 Stage Fractionator Reboiler with ULNB. This offset project, approved by the NWCAA under OAC 1067 issued November 29, 2010, and revised as OAC 1067a on July 7, 2011, allowed the Clean Fuels Project to avoid PSD applicability for NOx.

The Clean Fuels Project will allow the refinery to produce ultra-low sulfur diesel fuel for the non-road market and to reduce the benzene content of gasoline. The #3 DHDS is scheduled for construction in 2011, with completion and startup anticipated in the fourth quarter of 2012. The primary emission unit at the unit is the #3 DHDS Charge Heater with a rated capacity of 28 MMBtu/hour HHV heat input. The heater will be equipped with ultra-low NOx burners (ULNB) to control emissions of NOx. The burner pilots will be fired with natural gas and the heater will combust refinery fuel gas from the existing main refinery mix drum. Although the heater will be designed with a maximum heat input capacity of 28 MMBtu/hour, this firing rate will only be required during startup because hydro-desulfurization is an exothermic process. The actual anticipated nominal firing rate for the heater during normal operations is estimated to be 12 MMBtu/hour. Other emissions at the #3 DHDS will be from equipment components (valves, flanges, pumps, compressors, connectors). Process equipment components in VOC or HAP service will be subject to the applicable requirements of NSPS 40 CFR 60 Subpart GGGa and NESHAP 40 CFR 63 Subpart CC. These federal programs require an enhanced LDAR program that is consistent with the existing program that the refinery implemented under past BACT determinations and under the 2001 BP Consent Decree. On May 1, 2013 the NWCAA received BP's compliance certification with the requirements of 40 CFR 60 Subpart GGGa for the clean fuels project.

OAC 1064a – 2014 – Superseded

OAC 1064a superseded OAC 1064 on March 13, 2014. After start-up of the units approved by OAC 1064, BP requested this revision to:

- address administrative changes
- remove inapplicable requirements dealing with construction and start-up
- remove stack velocity meter on #2 Hydrogen SMR stack and conduct Method 19 calculations instead (stack velocity meter was found to not track with process)
- remove velocity, Btu content, and Method 19Fd ongoing determination for #2 Hydrogen Flare

PSD 10-01 A1 – 2022 – Currently Applicable

PSD 10-01 was superseded by Amendment 1, issued January 24, 2022. Amendment 1 removed obsolete notification requirements and reduced PM_{10} source testing frequency for the #2 Reformer Steam Methane Reforming Furnace.

OAC 1064b – 2022 – Currently Applicable

OAC 1064a was revised in March 2022. The revised OAC provided BP the option to comply with SO_2 limits at the heater by installing a total sulfur (TS) analyzer on the heater's fuel gas system, subject to analyzer performance specification and data quality assurance program approval by NWCAA. On June 8, 2021, BP submitted a proposed monitoring plan for the TS analyzer, which NWCAA approved on July 6, 2021. The approval grants BP up to 180 days to certify the analyzer according to the monitoring plan and requires that it be operated as the SO_2 compliance instrument of record for the #3 DHDS Charge Heater unless an alternative is approved by the NWCAA in writing.

3.7 Isomerization Unit

The Isomerization Unit is comprised of four sub-units: 1) the Naphtha Dehexanizer; 2) the Isomerization Hydrotreater (IHT); 3) the BenSat™ Unit; and the Penex™ (isomerization) Unit. The Isomerization Unit is used to improve octane quality and reduce benzene compounds in gasoline blending stocks. This is accomplished by saturating the incoming streams using hydrogen.

Construction History and Regulatory Applicability

Construction of the Isomerization Unit was part of an overall refinery project for improving the quality of gasoline produced by the Cherry Point Refinery. This "Clean Gasoline Project" was designed to process light naphtha feedstocks to produce a gasoline blend component that has only trace amounts of benzene, olefins or sulfur and a high octane value. The Clean Gasoline Project was completed in July 2004, allowing the refinery produce gasoline with very low sulfur and benzene content that could meet the 2005 federal gasoline standard.

OAC 814 and PSD 02-04 – 2003 – Superseded

The NWCAA issued OAC 814 on June 2, 2003, and Ecology issued PSD-02-04 on May 16, 2003, approving construction of the new Isomerization Unit and a new #5 Boiler.

OAC 814a – 2004 – Superseded

On March 24, 2004, the NWCAA issued revised OAC 814a. The new Isomerization Unit started up on July 19, 2004. Shortly thereafter, the Merox Unit was decommissioned from service. The Merox Treater had previously been used for mercaptan extraction and sweetening (desulfurizing) of gasoline. The streams such as coker naphtha that were previously routed to this Merox Unit are now sent to the Isomerization Unit where they are converted to high quality gasoline blending components.

PSD 02-04 Amendment 1 – 2005 – Currently Applicable

On April 20, 2005, Ecology issued PSD-02-04 Amendment 1 with revised conditions for the #5 Boiler.

OAC 814b – 2012 - Superseded

On July 9, 2012, the NWCAA issued revised OAC 814b. This OAC superseded both of the previous versions because OAC 814a did not explicitly supersede OAC 814. OAC 814b was issued to improve formatting and to clean up the order for better incorporation into the air operating permit.

OAC 814c – 2017 - Superseded

OAC 814b was revised with issuance of OAC 814c on July 25, 2017 during permitting of the Flare Minimization Project. The revision permitted BP to install an additional splitter tower with overhead accumulator, steam reboiler, air cooled heat exchangers, cooling water trim cooler, circulation pumps, process feed exchangers, and tie-ins to the Naphtha HDS, #1 and #2 Reformers, and the Crude Unit. These modifications allow recovery of additional product and a reduction of flaring emissions during maintenance events at the Light Ends Unit (LEU). During periods of LEU downtime, gases that are normally processed by the LEU are routed instead to the new splitter tower within the Isomerization Unit rather than flared as they were historically.

<u>OAC 814d – 2021 – Currently Applicable</u>

OAC 814d was issued on June 3, 2021 and revised the visible emissions compliance method from EPA Method 9 to Washington Department of Ecology Method 9A prior to incorporation into the AOP during this renewal.

3.8 <u>Light Ends and LPG Units</u>

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 and 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 is 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 HAP.

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.

3.8.1 RVP Phasedown Project

<u>OAC 298 – 1990 - Superseded</u>

In 1990, the refinery proposed a project to lower the vapor pressure of gasoline as mandated by federal fuel requirements. The project was designed to reduce the maximum Reid vapor pressure (RVP) of gasoline from 10.5 psig to 9 psig during summer months. The objective of the project was to use less butane during gasoline and to ship the excess butane off site. The RVP Phasedown project consists converting three debutanizers, one in the Crude unit, one in the Hydrocracker Unit and, one in the #1 Reformer Unit, into depentanizers, construct new butane/pentane storage spheres, construct a new butane loading station, construct a new debutanizer tower at the Light Ends Unit (LEU). The project included an increase in the steam demand from the existing utility boilers. Emissions associated with the project included NOx, SO_2, PM, and CO from the increased boiler load and VOC from the LEU modifications. The refinery proposed to offset all incremental emission increases related to the RVP Phasedown through other completed projects and retired accrued emission reduction credits of 81 tons/year of NO_X, 5 tons/year of SO_2, 2 tons/year of PM_{10}, 20 tons/year of VOC, and 2 tons/year of CO.

The NWCAA approved the project under OAC 298 issued December 4, 1990.

OAC 298a – 2012 – Currently Applicable

On April 30, 2012, the NWCAA issued revised OAC 298a to improve formatting and to clean up the order for better incorporation into the air operating permit.

3.9 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 that produced by their reforming units. At the date of AOP issuance, the refinery has one hydrogen plant (#1 Hydrogen Plant) to produce hydrogen for the refinery. A second plant, the #2 Hydrogen Plant, was approved by the NWCAA in 2010 as part of the Clean Fuels Project. Both plants produce hydrogen gas based on the process of steam methane reforming of natural gas.

Construction History and Regulatory Applicability

3.9.1 #1 Hydrogen Plant

The #1 Hydrogen Plant was built during original refinery construction in 1970. To date, there have been no equipment modifications at the #1 Hydrogen Plant triggering NSR permitting, and therefore it is considered a "grandfathered' unit.

At the #1 Hydrogen Plant, hydrogen is produced in a four-step process involving reforming, shift conversion, purification, and methanation. Reforming is a catalytic reaction of methane with steam at high temperatures to form CO, CO_2 and H_2. High temperatures are achieved by heating in the reforming furnaces. After reforming, additional steam is added in a shift conversion that liberates additional H_2 from the reaction of CO and H_2O. In the third step, CO and CO_2 are absorbed in beds and the remaining H_2 rich gas is separated and purified. In the final step, any remaining CO and CO_2 left in the H_2 rich gas stream is converted back to CH_4 using catalyst and temperatures in the range of 700°F to 800°F.

The main emission units at the #1 Hydrogen Plant are the North and South Reforming Furnaces. The plant has a number of equipment components in gaseous service that can emit fugitive VOCs and HAP including valves, flanges, vents, sewer line connections and pressure relief devices. The #1 Hydrogen Plant produces a CO_2 rich gas stream that contains methanol, a federally listed HAP. A portion of 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 is allowed since this process stream is exempted from the "Miscellaneous Process Vent Category" regulated under 40 CFR 63 Subpart CC (NESHAP from Petroleum Refineries - §63.641) due to the low concentrations of methanol in the stream.

3.9.2 #2 Hydrogen Plant

OACs 1064, 1067, and PSD 10-01 – 2010 - Superseded

The #2 Hydrogen Plant was approved by the NWCAA under OAC 1064 issued November 29, 2010 as part of the BP Clean Fuels Project. The Clean Fuels Project was also approved under PSD-10-01 issued by Ecology on December 13, 2010. The PSD permit addressed only PM_{10} as the only PSD level pollutant for the project. The Clean Fuels Project included construction of the #2 Hydrogen Plant and #3 DHDS Unit. Projected NOx emission increases that resulted from the Clean Fuels Project were offset by retrofitting the Hydrocracker 1 Stage Fractionator Reboiler with ULNB. This offset project, approved by the NWCAA under OAC 1067 issued November 29, 2010, and revised to OAC 1067a on July 29, 2011, allowed the Clean Fuels Project to avoid PSD applicability for NOx.

The Clean Fuels Project allowed the refinery to produce ultra-low sulfur diesel fuel for the non-road market and to reduce the benzene content of gasoline. The #2 Hydrogen Plant was commissioned for commercial operation on April 13, 2013. The plant is designed to produce 40 million standard cubic feet per day (MMSCFD) of hydrogen and purify an additional 4 MMSCFD of hydrogen from refinery off gas streams. The main emission units at the new hydrogen plant include the #2 Hydrogen Plant Steam Methane Reformer (SMR) Furnace and new #2 Hydrogen Plant Flare. The flare is designed to combust off-specification hydrogen during operations such as plant startups, shutdowns and malfunctions. Process components such as pumps and valves at the #2 Hydrogen Plant will be a source of process fugitives including CO, VOC and HAP.

Similar to the #1 Hydrogen Plant, the #2 Hydrogen Plant produces hydrogen gas using a process of steam methane reforming of natural gas. Unlike the #1 Hydrogen Plant, the new plant includes a pressure swing adsorption (PSA) purification system. The PSA technology allows the #2 Hydrogen Plant to produce hydrogen that is higher purity than what is produced at the #1 Hydrogen Plant. Feedstocks to the #2 Hydrogen Plant include natural gas and certain high hydrogen content refinery off gas (ROG) streams. Process equipment at the #2 Hydrogen Plant consist of feed knock out pots, feed conditioning reactors, a product compressor, a furnace, a hot shift reactor, PSA vessels, purge gas vessel, steam production equipment, motor control center, pipe racks and ancillary equipment.

Hydrogen is produced by reacting superheated steam with a source of light hydrocarbons in the presence of a nickel catalyst where most of the hydrocarbon is converted to CO_2 and H_2. Carbon monoxide (CO) is produced as a byproduct of the reaction. In second step of the process, CO and H_2O are converted to CO_2 and H_2 in the hot shift reactor which contains a catalyst. The hydrogen is then purified by separating it from the other gases in a series of PSA vessels. These vessels contain an adsorbent that collects all gases except hydrogen, which passes through. The gases held in the PSA vessels are desorbed on a regularly scheduled basis. The desorbed gas is considered residue PSA off gas and is combusted as fuel in the SMR Furnace. The high purity hydrogen exiting the PSA vessels is compressed and distributed for use within the refinery.

The SMR Furnace has a nominal heat input capacity of 430 MMBtu/hour (HHV) during normal operation and a maximum designed heat input capacity of 496 MMBtu/hour. PSA residue gas is the primary source of fuel for the furnace with natural gas being supplemented when necessary. It was estimated that 90% of the heat input to the furnace is from PSA residue gas and 10% from natural gas. The furnace is equipped with ULNB and selective catalytic reduction (SCR) to control emissions of NOx. Aqueous ammonia injected into the SCR is supplied from the aqueous ammonia storage tanks that also serve the SCR system at the #6 & 7 Boilers. Because sulfur is harmful to the catalyst used to synthesize hydrogen, the #2 Hydrogen Plant is equipped with sulfur guard beds that purify the incoming natural gas feedstock. The sulfur guard beds contain a catalyst that converts sulfur to hydrogen sulfide (H_2S) and downstream zinc oxide (ZnO) beds adsorb the H_2S. The sulfur guard beds reduce the sulfur content of the natural gas feed to less than 0.1% ppm. The PSA residue gas used as fuel in the furnace has very low sulfur content.

The #2 Hydrogen Plant is equipped with an elevated flare that will continuously combust small volumes (about 4,600 scf/hour) comprised of nitrogen purges from compressor seals and compressor distance piece vents, and natural gas as sweep gas to maintain a collection header free of oxygen. The flare is also designed to handle higher volumes associated with startup, shutdown and malfunction events. The flare is attached to the SMR Furnace stack and is not configured to handle material generated from any other refinery units. Natural gas is used to maintain a flame in the flare pilot burners.

The flare is subject to the requirements of 40 CFR 60 Subpart Ja, including the requirement to have and implement a flare management plan. The flare management plan was last revised on September 27, 2019.

The #2 Hydrogen Plant produces steam to support the SMR reforming reaction. The hydrogen plant also has the capacity to produce 140,000 lb/hour of excess steam. This excess steam is routed to the refinery's common steam header as utility steam to support other refinery processes.

Fugitive emissions at the #2 Hydrogen Plant are from process equipment (valves, flanges, pumps, compressors, connectors). Process equipment components in VOC or HAP service are subject to the applicable requirements of NSPS 40 CFR 60 Subpart GGGa and NESHAP 40 CFR 63 Subpart CC. These federal programs require an enhanced LDAR program that is consistent with the existing program that the refinery implemented under past BACT determinations and under the 2001 BP Consent Decree. On May 1, 2013 the NWCAA received BP's compliance certification with the requirements of 40 CFR 60 Subpart GGGa for the clean fuels project.

<u>OAC 1064a – 2014 – Superseded</u>

OAC 1064a superseded OAC 1064 on 3/13/14. After start-up of the units approved by OAC 1064, BP requested this revision to:

- address administrative changes
- remove inapplicable requirements dealing with construction and start-up
- remove stack velocity meter on #2 Hydrogen SMR stack and conduct Method 19 calculations instead (stack velocity meter was found to not track with process)
- remove velocity, Btu content, and Method 19Fd ongoing determination for #2 Hydrogen Flare

<u>PSD 10-01 A1 – 2022 – Currently Applicable</u>

PSD 10-01 was superseded by Amendment 1, issued January 24, 2022. Amendment 1 removed obsolete notification requirements and reduced PM_{10} source testing frequency for the #2 Reformer Steam Methane Reforming Furnace.

<u>OAC 1064b – 2022 – Currently Applicable</u>

OAC 1064b was issued in March of 2022 to reduce the frequency of ammonia, particulate matter, and volatile organic compound source testing at the #2 H_2 SMR Furnace.

3.10 <u>Calciners and Coke Storage & Handling</u>

Petroleum coke calcining is a process used to convert "green coke" produced at the Delayed Coker into a more valuable "needle coke" or "calcined coke" product by exposing the material to sustained high temperatures in a rotating calciner hearth. The calcining process drives off sulfur and volatile organic compounds. The calcined coke produced at the Cherry Point Refinery is considered anode-grade quality due to its low metals content.

The #1, 2 & 3 Calciners are located adjacent to the Delayed Coker unit. Green coke produced at the coker is transferred by covered belt conveyor to raw (green) coke feeding bins where they are fed to one of the three calciner kilns. In the calciner, green coke is heated to temperatures between 2400° F and 2700° F in a rotary hearth type kiln. 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 conveyor to the calcined coke storage barns where it is stored until it is loaded into railcars or trucks. The refinery also has the equipment to unload green coke from railcars or to load green coke into railcars or trucks. Waste heat from the coke calcining process is recovered and used to generate steam for the refinery. When not calcining coke, supplemental firing of the heat recovery steam generators can be accomplished with refinery fuel gas. Also, the Calciner treats wastewater API-recovered slop oils as well as recovered coke and coke fines.

Flue gases from calcining operations are routed to one of two stacks. The flue gases from the #1 & #2 Calciners are routed through Stack #1 and flue gases from the #3 Calciner are routed through Stack #2. Air pollutants emitted from the calciners include products of combustion such as PM, NO_X, CO, VOC, and SO_2. Because of the high sulfur content of the green coke, the calciners emit relatively large amounts of SO_2 at the refinery as sulfur is thermally driven off in the hearths. The calciners are also a significant source of fine particulate emissions at the refinery.

Major equipment in the calciner area include green coke crushers and storage barn, conveyor systems, calcining hearths, calcined coke silos, green coke and calcined coke loadout. Major emissions control equipment on the #1 & #2 Calciners (Stack #1) include caustic scrubbers followed by wet electrostatic precipitators (WESP). There are also numerous baghouses to control fugitive emissions from calcined coke transfer and storage operations.

The caustic scrubbers are used to control SO_2 emissions from the calciner stacks and the WESPs are used to control PM-10 and H_2SO_4 emissions. In some cases the refinery will shut down one or more cells in a WESP for maintenance or safety reasons. With a reduced number of cells operating, the refinery can continue to meet emission limits, but may need to reduce calciner production rates accordingly. The refinery monitors the secondary voltage and secondary amperage of each WESP according to approved WESP monitoring plans. In general, the cells are operated at a minimum secondary voltage of 35 kV and minimum secondary amperage of 300 mA to maintain compliance with permitted PM and H_2SO_4 limits. In addition, the #3 Calciner (Stack #2) is required to meet a minimum Specific Collection Area (SCA) of 126 ft_2 per 1,000 acfm stack flow as required by OAC 985b.

Construction History and Regulatory Applicability

The history of construction approvals and associated regulatory orders for the calciners is long and complex, spanning from 1977 to the present. The #1 & #2 Calciners were constructed in 1977, and the #3 Calciner was constructed in 1985. Devices associated with controlling emissions from these calciner hearths have changed over the years in response to challenges in meeting PM and opacity limits.

3.10.1 #1 & #2 Calciners

The #1 & #2 Calciners were constructed in 1977 and have a long history of compliance and permitting related activities. The table below summeries these agency actions provides a basis for whether or not particular orders are incorporated into the air operating permit.

Table 3.10-1: #1 & #2 Calciner Permitting and Approval History

#1 & #2 Calciner (Stack #1)			
Order	**Date**	**In AOP?**	**Description/Comments**
OAC 211c	Issued 10/12/1977 Revised 11/17/1977 Revised 12/14/1977 Revised 9/18/12	Yes	Approval to construct the #1 & #2 Calciner with no specific emission limits on the Calciner stack. Instead the approval includes the following refinery-wide limits. • PM 60 ton/month • SO_2 2,354 lb/hour, monthly average
NWCAA Regulatory Order "PM Bubble"	Issued 06/13/1984	No, superseded by OAC 689b issued September 18, 2012	Issued in response to ongoing compliance problems at the Calciner. The order limits: • PM 60 ton/31-day month for the entire refinery • PM 50.5 ton/31-day month "bubble" for the #1 & #2 Calciner, Crude Heater, South Vacuum Heaters, North and South Coker Heaters and #1 Boiler. • Calcined coke production rate limited to 60 ton/hour.
NWCAA Regulatory Order "Opacity"	Issued 11/30/1984	No, superseded by Regulatory Order 11	RO issued in response to ongoing opacity exceedances. The order allowed up to 40% opacity until tube replacement in recuperators was complete and visual observations demonstrated that calciner was back into compliance with the 20% opacity SIP limit.
Emission Reduction Credit 14	Issued 10/13/1993	No, this ERC expired after 10 years	NWCAA granted an SO_2 ERC of 1548 tons from the voluntary installation of a Dynawave Scrubber on the #1 & #2 Calciners. The ERC set a 40 lb/hr SO_2 limit on the stack.
NWCAA Regulatory Order 011	Issued 05/23/1995	No, this RO was voided per OAC 660 following installation of the WESP and visual emissions data confirming compliance.	In lieu of continuous opacity monitoring, the RO required monitoring the oxygen concentration in the radiant section of the hearths and semi-monthly visual emission observations.
OAC 660b	Issued 12/07/98 Revised 9/18/12 Revised 7/6/21	Yes	Replacement of a portion of the Dynawave Scrubber with a wet electrostatic precipitator (WESP).

OAC 689c	Issued 04/13/1999 Revised 10/27/2008 Revised 9/18/12 Revised 6/3/21	Yes	As part of the Coker debottlenecking effort, increase the average coke processing rate in the Calciner from 28 ton/hr to 38 ton/hr. Establish opacity, PM_{10}, NOx, SO_2, and H_2SO_4 emission limits, and a SO_2 netting offset from H_2S scrubbing of the Vacuum Tail Gas.

<u>OAC 211 – 1977 – Currently Applicable</u>

The #1 & #2 Calciners, constructed in 1977, were approved under OAC 211, which established refinery-wide PM and SO_2 emission limits. These limits were based on the emission estimations that the refinery provided as part of their Notice of Construction application. There were no specific BACT limits placed on emissions from the #1 & #2 Calciners (Stack #1). However, the stack still had to meet general requirements for sources under applicable SIP rules, such as grain load standards for combustion devices and 20% opacity limits set forth in the WAC-173-400 and NWCAA Regulation.

<u>Particulate Regulatory Bubble – 1984 - Superseded</u>

After construction of the #1 & #2 Calciners, it became clear that controlling visual emissions from the stack to 20% opacity was going to be difficult due to a characteristic blue haze forming in the plume. The Calciner was also having challenges meeting grain loading limits. The refinery attempted to minimize opacity and particulate emissions by controlling various operating parameters including increasing excess oxygen levels in the hearths. These methods proved unsuccessful and on June 13, 1984, the NWCAA issued the Particulate Bubble Regulatory Order. The order allowed the #1 & 2 Calciners to increase particulate emissions above 46.8 tons per month with a commensurate reduction in emissions at four refinery heaters (Crude, South Vacuum, and North & South Delayed Coker Heaters) and one utility boiler (#1 Boiler that has since been decommissioned) by curtailing the amount of fuel oil burned in the heaters and boiler. The order set a 50.5 ton per month particulate "bubble "on the four heaters, one boiler and #1 & 2 Calciner stack. The Order also included a refinery-wide particulate limit of 60 tons per month and established a production rate limit on the #1 & 2 Calciner of 60 tons per hour.

<u>OAC 689b – 2012 - Superseded</u>

September 18, 2012, as part of a comprehensive effort to clean up existing orders prior to incorporation into the AOP, the NWCAA issued OAC 689b. OAC 689b superseded the Particulate Bubble Regulatory Order because the reasons for order were no longer germane to the equipment and operating scenarios at the refinery, nor was it consistent with construction approvals issued for the #1 & 2 Calciners after 1984.

<u>Opacity Regulatory Order – 1984 - Defunct</u>

On November 30, 1984, the NWCAA issued an "Opacity" Regulatory Order allowing opacity from the #1 & #2 Calciners to exceed the 20% opacity limit of the NWCAA regulation, up to 40% until the tubes in the recuperators were replaced. This opacity improvement project was completed within one year and visual emissions observations demonstrated that the Calciners were back into compliance with the 20% limit. Demonstration of compliance by certified opacity readings conducted by the refinery effectively voided the "Opacity" Regulatory Order, as specified in the order.

<u>Emission Reduction Credit 14 – 1993 - Expired</u>

A state-of-the art flue gas desulfurization device called the Dynawave Scrubber was installed on the #1 & #2 Calciners and tested in phases from 1988 to 1993 with the aim of further controlling opacity and SO_2 emissions. Because the project was considered voluntary, no construction approval was required by the NWCAA. The Dynawave Scrubber made a significant reduction in SO_2 emissions and on October 13, 1993, the NWCAA issued Emission Reduction Credit 14 (ERC 14) crediting the refinery with a 1,548 ton per year SO_2 reduction from the project. To ensure that SO_2 emissions remained at expected levels, the ERC 14 established SO_2 emission limits of 40 lb per hour and 175 ton per year for the #1 & #2 Calciner stack.

The NWCAA issued Emission Reduction Credit 14 (ERC 14) expired October 13, 2003, ten years after issuance. There is no indication that this ERC was ever utilized to net out of Prevention of Significant Deterioration (PSD) major source permitting. If the SO_2 credits had been utilized, the SO_2 limits established in ERC 14 would have been reestablished in another federally enforceable order, presumably an OAC issued for the PSD netted project. In this particulate case, there is no record to substantiate that the emission reduction credits were ever utilized, sold or otherwise activated.

WAC 173-400-136 Use of Emission Reduction Credits (ERC).

(5) Redemption period. An unused ERC expires ten years after date of original issue

Emission Reduction Credit 14's expiration on October 13, 1993, was documented in a NWCAA memo to the file dated July 20, 2012. Because ERC 14 has expired, it is not cited in the air operating permit as an applicable requirement.

Regulatory Order 011 – 1995 - Superseded

On May 23, 1995, the NWCAA issued Regulatory Order 011 granting the refinery permission to monitor the average oxygen concentration in the radiant section of the #1 & #2 Calciner hearths in lieu of continuously monitoring opacity in the stack. The order established a 4.0% daily average oxygen limit.

OAC 660 – 1998 - Superseded

On December 7, 1998, the NWCAA issued OAC 660 approving replacement of a portion of the Dynawave Scrubber with a wet electrostatic precipitator (WESP). The WESP was designed to control particulate matter and sulfuric acid mist (H_2SO_4) from the #1 & #2 Calciner stack. In addition, the OAC included limits for SO_2 and opacity. The WESP control device is based on the principal of imparting an electrical charge to aerosols and solids (together referred to as particulates) suspended in the WESP inlet gas stream. Once polarized or charged, the particulates are drawn out of gas stream to an electrode through electrical attraction. A water flushing system periodically removes acid mist and particulates that adhere to collection plates.

The WESP was installed and commenced operation on June 13, 1999. On January 3, 2000, the refinery submitted data demonstrating compliance with Condition 4 of OAC 660 limiting opacity from the #1 & #2 Calciner stack to 20% as measured by Ecology Method 9B. As a result, Regulatory Order 011 was effectively voided and the refinery was no longer required to assure a minimum 4.0% oxygen level in the hearths.

OAC 689 – 1999 - Superseded

In 1999, as part of a Delayed Coker debottlenecking project, the refinery proposed increasing the calcined coke production rate from 28 tons to 38 tons per hour for each of the #1 & #2 Calciner hearths. The NWCAA approved this project on April 13, 1999 under OAC 689. The increased coke calcining rate required an increase in the heating load of the #1 & #2 Calciner hearths and project emissions included increases in NO_X, CO, SO_2, PM, and VOC. Of these pollutants, NOx and SO_2 were found to potentially exceed PSD thresholds, so the refinery modified the project to include a retrofit of the South Vacuum Heater with low-NOx burners. The refinery also proposed to offset potential increases in SO_2 emissions by installing a DEA scrubber on the Vacuum Tail-Gas overhead fuel gas stream. As a result, all net emission increases from the project were determined to be below significant PSD thresholds.

In developing the emission limits for OAC 689, the NWCAA took into consideration approval of the WESP under OAC 660, PSD thresholds for PM_{10} and H_2SO_4, and BACT requirements. OAC 689 also stated that the modified #1 & #2 Calciners are subject to applicable requirements of 40 CFR 60 Subparts GGG and QQQ, and 40 CFR 63 Subpart CC.

OAC 689a – 2008 - Superseded

On October 27, 2008, the NWCAA issued revised OAC 689a to restructure limits applicable to the North and South Coker Charge Heaters; however, no changes were made to conditions applicable to the #1 & #2 Calciners.

OACs 660a and 689b – 2012 - Superseded

On September 18, 2012, the NWCAA issued revisions OAC 660a and OAC 689b. These revisions were made to clarify the requirements and clean up the orders prior to incorporation into the air operating permit.

OACs 660b and 689c – 2021 – Currently Applicable

On June 3, 2021, OAC 689b was revised with issuance of OAC 689c, which corrected a typo in the units of the H_2SO_4 limit at the Calciner #1 Stack.

On July 6, 2021, NWCAA issued OAC 660b, which reduced Calciner Stack #1 H_2SO_4 source testing frequency, clarified source test reporting requirements, and revised the visual emissions compliance method from EPA Method 9 to Ecology Method 9A.

3.10.2 #3 Calciner

On September 27, 1984, an application was submitted for construction of the #3 Calciner. This new calciner was designed to double the calcining capacity at the refinery with the addition of a single new rotary hearth. The project also included additional conveyors and silos for calcined coke handling controlled by a set of baghouses. Emission controls from calciner hearths include two-stage combustion for NOx, a wet soda ash scrubber for SO_2, and a WESP for PM and H_2SO_4. Waste heat from flue gas is captured in a heat recovery steam generator, and steam can be generated with the calciner down through supplemental firing on refinery fuel gas.

The table below summarizes the permitting and approval history for the #3 Calciner and provides a basis for whether or not these orders are incorporated into the air operating permit.

Table 3.10-2: #3 Calciner Permitting and Approval History

#3 Calciner (Stack #2)			
Order	**Date**	**In AOP?**	**Description/Comments**
OAC 299	Issued 12/19/1984	No, the OAC is narrative only and contains no specific conditions.	Approve construction of the #3 Calciner controlled by a caustic scrubber and WESP.
PSD-3	Issued 12/20/1984	No, superseded by PSD-89-2	Approve construction of the #3 Calciner and caustic scrubber and WESP control equipment. Includes emission limits for opacity, PM, SO_2 and NOx. It also includes refinery-wide limits for PM and SO_2.
PSD-89-2	Issued 01/30/1989	Yes	Same conditions as PSD-3 except that the NOx limit increased from 373 to 509 tpy, and refinery-wide PM and SO_2 limits were removed.

#3 Calciner (Stack #2)			
Order	**Date**	**In AOP?**	**Description/Comments**
PSD-95-01	Issued 03/14/1995 Amended 01/23/09 Amended 4/12/2022	Yes	Established H_2SO_4 limit for the #3 Calciner that was inadvertently left out of PSD-89-2.
NWCAA RO 018	Issued 06/30/1998	No, superseded by OAC 985	Requires an alternative monitoring plan for H_2SO_4 control during times when the #3 Calciner is operated outside the conditions established in the," Third Hearth Monitoring Plan, Sulfuric Acid Removal" dated August 16, 1995. Ongoing parameter monitoring required.
OAC 985	Issued 3/6/2007 Revised 10/27/08 Revised 7/6/21	Yes	Sets PM_{10} and H_2SO_4 limits with ongoing compliance based on monitoring the Specific Collection Area of the WESP

PSD 3 – 1984 – Superseded, and

PSD 89-2 – 1989 – Currently Applicable

On December 20, 1984, Ecology issued PSD-3 approving construction of the #3 Calciner. This PSD permit addressed the following PSD level pollutants; NOx, SO_2, and TSP with estimated PTE at 373, 504, and 26 tons per year, respectively. The #3 Calciner was built and initial source testing conducted in April 1987.

Information gathered during the source test identified an error in the flue gas NOx concentration value used in the PSD application. As a result, the refinery requested to increase NOx limit in PSD-3 from 373 to 509 tons per year. No change in the design or operation of the calciner was proposed. Ecology agreed and stated that the refinery still met BACT with the increase in NOx emissions. On January 30, 1989, Ecology issued PSD-89-2 approving the higher NOx limit and superseding PSD-3. Aside from the higher NOx limit, PSD-89-2 was similar to the PSD-3, with one exception. It did not include the refinery-wide emission limits for PM and SO_2 that were included in PSD-3. On March 9, 1995, the NWCAA issued a letter to the refinery stating that the refinery-wide SO_2 and PM limits of PSD-3 were still valid even though PSD-3 was superseded by PSD-89-2, because Ecology had inadvertently omitted these limits when writing PSD-89-2. However in 2012 during the AOP renewal process, the NWCAA determined that the March 9, 1984 interpretation letter regarding the refinery-wide PM and SO_2 limits was not legally binding because PSD-89-2 explicitly supersedes all conditions set forth in PSD-3. For this reason, the refinery-wide PM and SO_2 limits of PSD-3 are no longer listed in the air operating permit.

The refinery initially proposed to demonstrate compliance with the 90% SO_2 removal, 24-hour rolling average condition of PSD 89-2 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. NWCAA subsequently used "gap-filling" authority under WAC 173-401-615 in the AOP term to require an annual source test at the scrubber inlet and outlet to demonstrate a 90% reduction in SO_2. Source testing over the previous 5 years has demonstrated scrubber efficiency of between 95%

and 98%, with an average of 96.5%, and an outlet SO_2 ppm of between 35 and 75 ppm at 7% O_2, with an average of 53 ppm at 7% O_2. The scrubber outlet concentration was initially estimated to be 1,600 ppm SO_2, with a 90% reduction resulting in an outlet concentration of 160 ppm SO_2. During this renewal, NWCAA will modify the gap-filled requirement to require compliance with the 160 ppm SO_2 at 7% O_2, calendar day average limit using the existing SO_2 CEMS in lieu of the annual scrubber inlet and outlet source testing.

PSD 95-01 – 1995 - Superseded

On May 20, 1994 the refinery stated that the performance test on the #3 Calciner indicated that the PSD threshold for acid mist (H_2SO_4) could be exceeded. The refinery requested the Ecology amend PSD-89-2 as a result. The PSD application for the amendment indicated that the current BACT employed at the #1 & #2 Calciner was considered current BACT for controlling sulfur compounds from the #3 Calciner including H_2SO_4. On March 14, 1995, Ecology issued PSD-95-01 that exclusively limited H_2SO_4 emissions. PSD-95-01 did not supersede PSD-89-2; therefore, both permits remain in effect.

PSD-95-01 includes a requirement for the refinery to develop a monitoring plan to be approved by Ecology to demonstrate ongoing compliance with the H_2SO4 limit. The *Third Hearth Monitoring Plan* was developed and approved by Ecology on October 17, 1995. Elements of this plan include;

- Measuring the secondary voltage and current on the WESPs. The hearth will be in compliance when at least 4 WESP cells are operating with a secondary voltage greater than 50 kV DC and a secondary current greater than 50 milliamps DC and the Calciner is not in startup, shutdown, or hot standby. Operation at secondary voltages less than 50 kV DC and/or secondary current less than 50 milliamps DC while the Calciner is in startup, shutdown, or hot standby mode are deemed to be 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.
- The WESP is on a scheduled cycle for flushing all six cells of approximately 72 hours.
- Monthly reports are 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 WESP 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 WESP cells were operating at compliance requirements.

Regulatory Order 018 – 1998 - Defunct

On June 30, 1998, the NWCAA issued Regulatory Order 018 (RO 018) establishing an alternative means of demonstrating compliance with PSD-95-01 Condition 1. 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 1, and update the *Third Hearth Monitoring Plan* to reflect the changes in conditions of operating the WESP 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 3 was met with 4 or more WESP cells operating. The NWCAA and Ecology approved the revised monitoring plan on August 26, 1998.

In 1999 during routine maintenance the refinery determined that the lead tubes in the WESP were stretching and cracking, allowing acid gases to attack the supporting structure of the lead tubes. One of the six WESP cells was so damaged that it required replacement. New special steel alloy was found to be available since the construction of the original WESP that allowed service in an acidic environmental thereby reducing long-term maintenance. This new WESP design was used to successfully replace the Dynaware scrubber on the #1 & #2 Calciner in 1999. The proposed new WESP for the #3 Calciner was designed with twice the collection surface area (CSA) of the original #3 Calciner WESP. The new designed was comprised of 238 hexagonal tubes, whereas, the original WESP consists of 98 lead tubes.

Because the new WESP required different operating conditions than the old WESP the *Third Hearth Monitoring Plan* was revised accordingly. The revised plan decreased the minimum secondary voltage to 35 kV and minimum secondary amperage to 300 milliamps to ensure ongoing compliance during normal #3 Calciner operations. In June 2000, the refinery again revised the *Third Hearth Monitoring Plan* to reflect changes to the ductwork designed to distribute more of the flue-gas through the WESP cell #4 and better utilize its large collection surface area. The collection surface area of cells 1, 2, 3, 5, & 6 is 4,362 ft^2, whereas, cell 4 has a surface area of 10,928 ft^2. Because of the increased surface area of cell #4 the refinery eliminated cell #1. A revised *Third Hearth Monitoring Plan* was finalized on January 4, 2001, and the NWCAA and Ecology approved the revised plan on January 19, 2001.

<u>OAC 985 – 2007 - Superseded</u>

On March 6, 2007, the NWCAA issued OAC 985 for a cell replacement project for the #3 Calciner WESP. The project involved replacing the four existing cells (2, 3, 5 and 6) with two larger cells. The cells were replaced due to erosion problems with the lead tube sheets. OAC 985 explicitly voided Regulatory Order 018.

<u>OAC 985a – 2008 - Superseded</u>

On October 27, 2008, the NWCAA issued revised OAC 985a to allow the use of an alternative test method for H_2SO_4 with advanced approval from the NWCAA. It was anticipated that the refinery would request the use of EPA Conditional Test Method 013 (CTM-013) in the future instead of Method 8 which is specified in the OAC. This OAC revision removed Condition 2 based confirmation from Dee Morse of the National Park Service that BP had satisfied this condition.

<u>PSD 95-01 Amendment 1 – 2009 – Superseded</u>

On January 23, 2009, Ecology issued PSD 95-01, Amendment 1 allowing the #3 Calciner to be tested for H_2SO_4 emissions using either EPA test Method 8 or CTM-013. PSD-95-01 A1 states the concentration based H_2SO_4 limit as 50 mg/m^3. However, the limit in OAC 985b and the air operating permit is stated as 50 mg/dscm (dry standard cubic meter – 0°C and 1 atmosphere) consistent with EPA Method 8.

<u>OAC 985b – 2021 – Currently Applicable</u>

OAC 985a was revised with issuance of OAC 985b on July 6, 2021. The revised OAC reduced H_2SO_4 source testing frequency and clarified source test reporting requirements.

<u>PSD 95-01 Amendment 2 – 2022 – Currently Applicable</u>

PSD 95-01-A2 was issued in April 2022 in order to correct a typo in the sulfuric acid mist limit for the #3 Calciner Hearth, reduce the frequency of sulfuric acid mist source testing, and to add an oxygen correction to the concentration-based limit.

3.10.3 Coke Handling and Storage

Table 3.10-3 Coke Storage & Handling Permitting and Approval History

Coke Storage & Handling			
Order	**Date**	**In AOP?**	**Description/Comments**
OAC 246	Issued 04/10/1980	No, the OAC is narrative only and contains no specific conditions.	Installation of a baghouse for calcined coke handling.
OAC 263	Approved 01/13/1982	No, there is no OAC. Instead the approval is narrative only as found in the minutes of the NWCAA Board meeting.	Installation of a baghouse to control PM during handling of calcined coke.
OAC 299	Issued 12/19/1984	No, the OAC is narrative only and contains no specific conditions.	Construct the #3 Calciner including calcined coke handling equipment controlled by baghouses.
OAC 293	Issued 9/13/1984	No, the OAC is narrative only and contains no specific conditions.	Installation of two additional calcined coke storage silos equipped with dust control.
OAC 306	Issued 11/14/1984	No, the OAC is narrative only and contains no specific conditions.	Installation of a coke dust loadout facility.
PSD-3	Issued 12/20/1984	No, superseded by PSD-89-2.	New silo, railcar loadout, and #3 Calciner transfer tower limited to 20% opacity, 0.01 gr/dscf and 21 tpy.
PSD-89-2	Issued 1/30/1989	Yes	Opacity and PM limits carried over from PSD-3.
Ecology Order of Discontinuance of Permit Violation, PSD-3/PSD-89-2	Issued 08/24/2001	No, April 28, 2002 letter from Ecology states that the conditions of the order have been satisfied.	Required control of SO_2 emissions from baghouses handling coke.

<u>OAC 246 – 1980 – Currently Applicable</u>

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 magnehelic gauges to measure the pressure drop across the bags. However, this OAC was considered narrative only, and therefore has not been included in the AOP.

<u>NOC 263 – 1981 – Never Issued</u>

On December 7, 1981 the refinery proposed constructing an additional baghouse (6,400 cfm) to improve the recovery of dust from transferring calcined coke. On April 23, 1982, the NWCAA Board of Directors approved the project as documented in the board minutes. The project was assigned NOC 263; however, there is no record of an approval letter being issued by the NWCAA in this matter. The NWCAA approval at the board meeting did not include any specific requirements for the project; therefore, there is no reference to this approval in the air operating permit.

OAC 306 – 1984 – Currently Applicable

The refinery continued its efforts to reduce particulate matter emissions from coke and calcined coke handling an in 1983 proposed to install a number of various baghouses at the calciner area to control dust. These included additional hearth area baghouses, silo baghouses, and calcined coke rail loading baghouses. The design included a pneumatic system to convey calcined coke dust to a new coke dust silo located north of green coke crusher and rail loading facility. The transfer system and silo 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 silo. On November 14, 1984, the NWCAA issued OAC 306 approving this calciner coke dust loadout facility project. OAC 306 is considered narrative and contains no requirements; therefore, this OAC is not referenced in the air operating permit.

OAC 293 – 1986 – Currently Applicable

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. On September 13, 1986, the NWCAA issued OAC 293 approving this project. However, because OAC 293 is considered narrative with no specific requirements; it is not referenced in the air operating permit.

PSD 89-2 – 1989 – Currently Applicable, and

As discussed above the refinery proposed to expand their coke calciner capacity with the construction of the #3 Calciner in 1984 (PSD-3, PSD-89-2, PSD-95-01). This allowed the refinery to convert nearly all of its green coke feedstock to a finished calcined coke product. The approval of the #3 calciner also included additional baghouses, expanded material handling capacity and storage silos. To control fugitive dust emission from the additional conveyance system and storage silos, the refinery proposed to install three new baghouses. According to the proposal these baghouses would be used in continuous operation to control fugitive dust emissions at coke transfer points. The conveyance systems and storage area would be covered. The baghouses are subject to the conditions of PSD 89-2.

Approval Letter – 1988 – Not enforceable

In 1988, the refinery proposed the construction of two new baghouses (5,800 cfm each) installed in conjunction with an existing baghouse (2,800 cfm) at the calcined coke loadout facility to control dust and particulate emissions. On December 19, 1988, the NWCAA issued a letter stating that the installation of these two additional baghouses does not require a Notice of Construction approval. The letter includes conditions; however, because it is not an Order of Approval to Construct (OAC), it is not considered a legally enforceable document and is therefore not referenced in the air operating permit.

Order of Discontinuance of Permit Violation for PSD 3 – 2001 - Defunct

Finally, on April 9, 2000, the refinery notified Ecology that a source of SO_2 emissions had been discovered at the refinery that was not anticipated when the Calciners were constructed and permitted. Emissions of SO_2 had been discovered at the stack of the baghouses for the #1, 2, & 3 Calciners. 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 Ecology 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 the #3 Calciner 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 #1 & #2 Calciners.

Construction of the collection system for the #3 Calciner was completed on December 21, 2001. The Ecology 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 #1 & #2 Calciners. For #1, 2 & 3 Calciners the gas streams from the baghouses are routed to waste heat recovery system induced draft 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.

The figure below shows particulate emission points and their associated control devices located within the calcined coke handling area. The conveyors and silo feed surge bin are controlled by routing fugitive emissions back to the calciner hearths. The silos are controlled using baghouses (B.H.) located on silo bin vents. The calcined coke loadout to railcars is controlled by the East and West baghouses. Relative to calcined coke, green coke is comprised of larger particles and contains enough moisture to minimize the release of fugitive emissions when handling. Therefore, green coke storage & handing does not require specific emission control equipment.

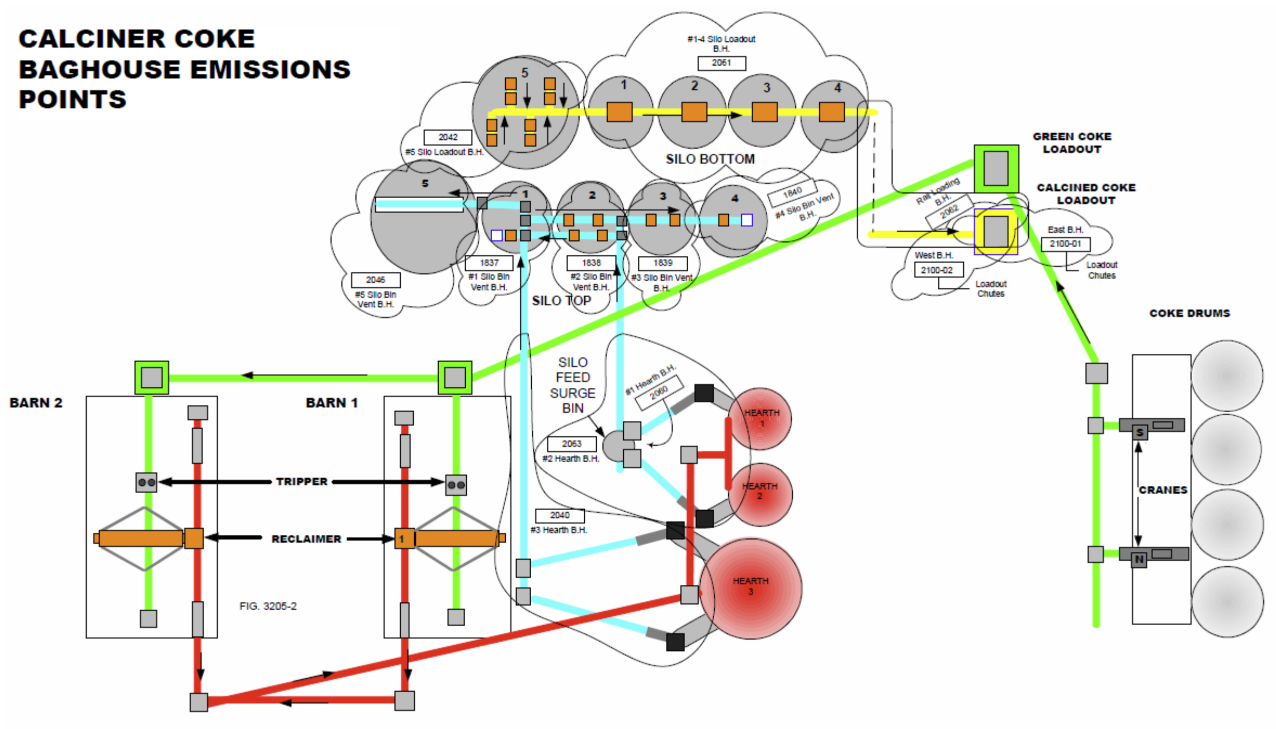

Figure 3.10-1 Calciner Coke Baghouse Emission Points

3.11 Boilers and Cooling Towers

Steam utility boilers and cooling towers are located within the Utility Area. There are two cooling towers at the refinery. These are non-contact cooling towers and as such hydrocarbon streams do not directly contact the cooling water. Instead non-contact heat exchangers are used to remove heat from hydrocarbon products. The cooling towers can be a source of VOC emissions to the atmosphere if leaks develop in cooling water heat exchangers or condensers.

Boilers produce steam that is used throughout the refinery for a wide variety of purposes including power for driving steam turbines, pumps, and compressors. Other examples of steam use at the refinery include heating of storage tanks with steam coils, increasing the temperature of hydrocarbon process streams with heat exchangers and for steam heat tracing of piping.

All boilers are located in the boilerhouse and burn refinery fuel gas and/or natural gas. Emissions from the boilers are from products of combustion including PM_{10}, SO_2, CO, NO_x, VOC and HAP.

Construction History and Regulatory Applicability

#1, 2 & 3 Boilers were constructed during original refinery construction in 1970. All three of these boilers have been replaced over time with the construction of the #4 Boiler in 1991, #5 Boiler in 2004, and #6 & 7 Boilers in 2008. The #2 Boiler was decommissioned in 2003, and the #1 & 3 Boilers were decommissioned in 2009.

The #1 Cooling Tower was constructed during original refinery construction in 1970. The #1 Cooling Tower is still in operation. Additional cooling capacity was added with construction of the #2 Cooling Tower in 1990, and will be again following permitting of an additional two cooling tower cells at the #2 Cooling Tower in 2021.

3.11.1 #4 Boiler

<u>OAC 351 – 1992 - Superseded</u>

On January 14, 1992 the NWCAA issued OAC 351 approving construction of the #4 Boiler at the refinery to supply steam in support of the RVP Phasedown project. The #4 Boiler has the capacity to produce 150,000 lb/hour of 600 psi steam, and a heat input capacity of 216 MMBtu HHV/hour. During permitting BACT was determined to be the use of gaseous fuel, low-NOx burners and induced flue gas recirculation. This approval order has been revised five times to its current version OAC 351e. Below is a summary of each revision.

<u>OAC 351a – 1993 - Superseded</u>

Revision a (June 4, 1993): Eliminated requirement on maximum steam production and testing requirements for PM10, VOC's, and SO2. During initial permitting of the #4 Boiler, the refinery netted out of PSD applicability for NOx through a NOx reduction of 27 tons per year at the Hydrocracker 1st Stage Fractionator Reboiler. This reduction was accomplished by retrofitting the 1st Stage Fractionator Reboiler with low-NOx burners as required by OAC 351a Condition 10. On May 28, 1993, the refinery submitted a letter stating that the NOx reductions associated with the 1st Stage Fractionator Reboiler low-NOx burner project had been validated with pre-project and post project source testing.

<u>OAC 351b – 1994 - Superseded</u>

Revision b (April 11, 1994): Due to results of source emission test results for NOx and CO the emission concentration requirement for NOx was deleted and the requirement for a CO continuous emission monitor was removed.

<u>OAC 351c – 1999 - Superseded</u>

Revision c (October 19, 1999): Removed CO emission limit and monitoring requirement based on decreased CO emissions resulting from burner change out.

OAC 351d – 2002 - Superseded

Revision d (June 28, 2002): Removed reference to CO in Condition 7 which was removed in previous revisions, and added monthly reporting of NOx in monthly emission reports.

OAC 351e – 2010 - Superseded

Revision e (May 10, 2010): Changed NOx emission limit from 0.07 lb/MMBtu and 66 NOx tons per year to 33 ppmvd and 8.36 lb/hour, which is equivalent to an emission factor of 0.04 lb/MMBtu. A CO limit was also added to the OAC. These permit revisions were done to facilitate a federally enforceable NOx reduction accomplished by a project to modify the flue gas recirculation (FGR) system in the #4 Boiler. The FGR modification project provided creditable NOx reductions to meet BP's 2001 Consent Decree obligations. OAC 351e became effective on November 11, 2010, with the startup of the #4 Boiler following completion of the #4 Boiler FGR modification project. OAC 351e superseded OAC 351d on its effective date.

OAC 351f – 2021 – Currently Applicable

Revision f (June 3, 2021): Reduced #4 Boiler CO source testing frequency. Clarified source test reporting requirements.

OAC 1067 – 2010 – Superseded, and

OAC 1067a – 2011 – Currently Applicable

On November 29, 2010, the NWCAA issued OAC 1067 authorizing replacement of the low-NOx burners on the Hydrocracker 1st Stage Fractionator Reboiler with state-of-the-art ULNB. This NOx reduction project was approved as a PSD netting offset project for the BP Clean Fuels Project approved under OAC 1064. OAC 1067 revision "a" was issued July 29, 2011. The effective date of OAC 1067a is the startup date of the 1st Stage Fractionator Reboiler following the ULNB retrofit project. On June 4, 2012, the NWCAA received a letter from BP notifying the agency that the reboiler began operating on May 16, 2012, following installation of the ULNB and activating OAC 1067a. OAC 1067a explicitly supersedes OAC 351e, Condition 11 requiring the 1st Stage Fractionator Reboiler to demonstration compliance with a 27 ton per year NOx reduction from the 1994 low-NOx burner retrofit project because the reboiler now has an ULNB.

3.11.2 #5 Boiler

PSD 02-04 – 2003 - Superseded

In 2002, the refinery proposed constructing a new 363 MMBtu/hour boiler to increase the supply of utility steam to support a new Isomerization Unit and to replace the aging #2 Boiler. The #5 Boiler, also referred to as the #2 Replacement Boiler, along with the new Isomerization Unit were approved by Ecology under PSD-02-04 issued May 16, 2003 for PSD major pollutants NO_x and CO.

OAC 814 – 2003 - Superseded

Similarly, the NWCAA approved the #5 Boiler and Isomerization Unit under OAC 814 issued June 2, 2003, for minor air pollutants PM_{10}, SO_2, VOC and HAP. OAC 814 provided the refinery with a federally enforceable SO_2 offset so that the #5 Boiler and Isomerization Unit project was below the PSD significance threshold of 40 tpy. This offset was approved as an SO_2 reduction required under by OAC 814 limiting the H_2S concentration in the Vacuum Tail Gas generated at the Crude and Vacuum Unit to 500 ppm. The #5 Boiler was constructed and began operating in 2004.

PSD 02-04 Amendment 1 – 2005 – Superseded

Since that time, the PSD permit was revised to its current version, PSD-02-04 Amendment 1, on April 20, 2005.

OACs 814a-814c – 2004-2017 – Superseded, and,

OAC 814d – 2021 – Currently Applicable

The NWCAA order was revised to OAC 814a on April 24, 2004, to OAC 814b on July 9, 2012, 814c on July 25, 2017, and 814d on June 3, 2021.

PSD 02-04 Amendment 2 – 2022 – Currently Applicable

PSD 02-04-A2 was issued in 2022 to streamline NOx and CO CEMS requirements for the #5 Boiler.

3.11.3 #6 and 7 Boilers

PSD 07-01 – 2007 – Superseded

To replace the aging #1 & 3 Boilers, each rated at 330 MMBtu HHV per hour, the refinery proposed constructing two new boilers. On November 19, 2007, Ecology issued PSD-07-01 authorizing construction of the #6 & 7 Boilers each rated at 363 MMBtu per hour. The PSD permit limits the emission of PM_{10}, SO_2 and CO, that are each considered major PSD pollutants.

One-time only initial source testing for CO, SO_2 and PM_{10} as required by PSD-07-01 was completed in August 2009, and testing for PM and Ammonia in September 2009. These source tests demonstrated that the #6 & 7 Boilers were in compliance with the applicable limits of the PSD permit. Ongoing compliance with NOx and CO limits are demonstrated with CEMs. Ongoing compliance with PM_{10} and ammonia limits is demonstrated through periodic source testing. In addition, an ammonia monitoring plan is used to prevent excessive ammonia slip. Ongoing compliance with SO_2 limits are demonstrated through periodic analysis of the refinery fuel gas for total sulfur.

OAC 1001 – 2007 - Superseded

Similarly, on November 29, 2007, the NWCAA issued OAC 1001 approving the #6 & 7 Boilers both equipped with low NOx burners and selective catalytic reduction (SCR) to control NO_x emissions.

OAC 1001a-1001c – 2009-2013 - Superseded

The OAC was revised three times to its current version, OAC 1001c issued May 20, 2013. The new boilers were constructed and began operating in March of 2009.

OAC 1001c Condition 10 required decommissioning the #1 & 3 Boilers within 12-months of the first startup of either the #6 or the #7 Boiler. #6 Boiler was the first to startup on March 27, 2009, triggering the requirement to decommission the #1 & 3 Boilers by no later than March 27, 2010. On January 14, 2010, the NWCAA received a written notice from the refinery that the #1 Boiler was decommissioned on October 28, 2009, and the #3 Boiler was decommissioned on October 3, 2009.

The #6 & 7 Boiler startup notifications were received by the NWCAA on April 8, 2009. The notice stated that #6 Boiler commenced operation on March 27, 2009 and that #7 Boiler commenced operation on March 28, 2009.

OAC 1001d – 2021 – Superseded

Revision ‘d’, issued on December 22, 2021, removed the requirement to test for emissions of ammonia at multiple loads after it was demonstrated that changes in boiler load did not correlate with changes in ammonia emissions. Ammonia source testing frequency was also reduced at the request of the refinery, contingent upon use of a conservative ammonia slip correction factor during continuous parametric monitoring, memorialized in the monitoring plan, and requiring approval by the NWCAA before revision.

Periodic stack testing is required for Boiler #6 and Boiler #7. Testing is normally required at 90% load. NWCAA may, on a case-by-case basis, approve testing at 90% steam load. However, this approval is case-by-case and subject to review prior to each test.

OAC 1001e – 2022 – Currently Applicable

OAC 1001e was issued in April 2022 to clarify existing source test reporting requirements and LDAR program requirements.

Administrative Compliance Order 01 – 2009 - Defunct

On March 31, 2009, the Cherry Point Refinery and the NWCAA signed NWCAA Administrative Compliance Order 01. The order was drafted after BP recognized a significant potential for the #6 & 7 Boilers to exceed the SO_2 13.6 lb/hr, 3-hr rolling limit of PSD-07-01. The order supported load shifting between refinery boilers to mitigate an exceedance. On December 11, 2009, as specified in the order, Administrative Compliance Order 01 was considered null and void upon issuance of PSD 07-01 Amendment 1.

PSD 07-01 Amendment 1 – 2009 – Superseded

The PSD amendment increased the SO_2 limit from 13.6 to 39.3 lb/hour, 3-hour average, thereby reducing the risk of non-compliance with the SO_2 limit.

PSD 07-01 Amendment 2 – 2016 – Currently Applicable

PSD 07-01 Amendment 1 was further revised on February 24, 2016 by Ecology at the request of BP. PSD 07-01 Amendment 2 increased the short-term PM_{10} limits for Boilers #6 & #7 after emissions test showed a high degree of variability in the measurement of the condensable portion of PM_{10}. A new annual PM_{10} limit was also established based on the old hourly emission rate, ensuring that annual emissions of PM_{10} did not increase with the new amendment.

3.11.4 #2 Cooling Tower

OAC 289 – 1990 - Superseded

In 1990, the refinery proposed construction of a second cooling tower to address a cooling capacity deficit. The NWCAA approved the #2 Cooling Tower with a heat release rate of 500 MMBtu/hour under OAC 289 issued August 23, 1990. The approval order required a hydrocarbon monitor installed and operated in accordance with manufacturer's specifications. The refinery installed a combustion analyzer to monitor the explosive limit of the vapors exiting the cooling tower.

OAC 289a – 2012 - Superseded

On April 12, 2012, the NWCAA issued revised OAC 289a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

OAC 289b – 2021 – Currently Applicable

OAC 289a was revised with issuance of OAC 289b on July 21, 2021, to approve an increase in the #2 Cooling tower nominal heat release rate from 500 MMBtu/hr to 750 MMBtu/hr through the addition of two additional cooling tower cells.

3.12 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.

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

There are three flares at the refinery. They are control devices necessary for the safe operation of the refinery and two of the flares, the High and Low-Pressure Flares, 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 third flare is the #2 H_2 Plant Flare and is specifically used only for gases from that 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 shut down for maintenance. The High and Low-Pressure 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 and reduce or avoid smoking (visible emissions). Steam rate is automatically controlled to respond to changes in flare vent gas volume to meet net heating value minimum of 270 btu/cf during flaring episodes and minimize visible emissions. A mass flow meter located on the flare header combined with a video camera directed at each flare tip assists operators in monitoring flare system operation and make adjustments to avoid visible emissions.

The High and Low-Pressure 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 in January 1999 as part of the refinery's Initial Notification of Compliance Status Report under 40 CFR 63 Subpart CC. 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 MACT Group 1 process vents and for control of leaks from pump seals, regulated equipment leaks in HAP service. The Hydrogen Plant Flare was constructed with the #2 Hydrogen Plant in 2013.

There are four primary compressors that are used to mitigate hydrocarbon flaring. These are the High and Low-Pressure Flare Gas Recovery compressors, delayed Coker Wet Gas Recovery compressor, and the delayed Coker Wet Gas booster compressor. The High and Low-Pressure Flare Gas Recovery compressors route recovered gases to amine treatment for H_2S removal and then to the refinery's main fuel gas system, whereas the Delayed Coker wet gas recovery compressor and booster compressor process recovered gases within the delayed Coker Unit.

Any time one of these compressors is down for maintenance, the refinery is considered in an alternative operating condition and must be careful about using remaining compressor capacity in order to continue to meet its compliance obligations at the flares.

The compressors can recover gases to a certain inlet pressure, and if the pressure or volume exceeds the compressor capacity, some of the gas will go to the flares. The reciprocating High and Low-Pressure Flare Gas Recovery compressors require regular maintenance shutdowns, so while one is shutdown the other compressor must be connected to the Low-Pressure flare. If the Coker Blowdown Vapor Recovery compressor system is down, Coker blowdown gas is sent to the Flare Gas Recovery system. There are various compressor line-up choices that are used to minimize flaring emissions. Maintenance shutdowns are scheduled to minimize emissions. Due to the sour (i.e., high sulfur content) characteristics of the Coker blowdown gas, a potential exceedance of the 1,000 ppm SO_2 limit of NWCAA 462 may occur at the flare when Coker blowdown vapors are not fully recovered.

Flares subject to the provisions of 40 CFR §60.18 or §63.11 and Refinery MACT 1 are only required to comply with Refinery MACT 1 per the overlap provisions in §63.640(s). Revisions to Refinery MACT 1 to reduce emissions of organic HAP include requirements and monitoring for flares used as control devices at sources subject to Refinery MACT 1 found in §63.670 and §63.671.

As part of the new RTR initiative, flares used as control devices required upgrades to operational equipment, installation of monitoring equipment, tracking of operational parameters and alarms for operational limits. BP was also required to develop a continuous parameter monitoring system (CPMS) plan, outlining how each of the monitoring devices are managed and maintained, as well as supplement their flare management plan (FMP), required under NSPS Subpart Ja. A copy of the most recent FMP incorporating requirements for minimizing emissions from flaring during startup, shutdown, or emergency releases, required in §63.670(o)(1), was submitted to NWCAA March 29, 2021.

BP requested approval for an alternative monitoring plan from EPA and NWCAA on August 2, 2019 due to safety concerns surrounding calibration of the total reduced sulfur (TRS) analyzers on the High and Low-Pressure Flares required by NSPS Ja. Subpart Ja requires a high point calibration using gases with concentrations ranging from 50-60% of the instrument span. Because the flares are designed to handle >95% TRS concentrations, BP requested that a lower concentration calibration gas be approved for use. EPA granted conditional approval of the alternative monitoring plan on September 9, 2019. NWCAA issued approval for parts of the alternative monitoring plan not addressed by EPA's conditional approval on November 14, 2019.

3.13 Sulfur Recovery Complex

The Sulfur Recovery Complex is comprised of several units: DEA Unit, Sour Water Stripper, sulfur recovery unit (SRU), two Tail Gas Units (TGUs), 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. Two TGUs serve the two sulfur recovery trains.

Crude oil may contain 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 an amine- based DEA unit. DEA units are located at the Coker, Hydrocracker, Naphtha HDS, Diesel HDS, LEU, Sour Water and Flare Gas recovery units. DEA absorbs H_2S from the refinery 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 this high concentration H_2S-laden stream is routed to the Sulfur Recovery Unit where it is converted into elemental sulfur.

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 formed in the SRU reaction are fed though waste heat boilers to generate steam. Following heat recovery 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 Units. The Tail Gas Units are designed to recover most of the remaining sulfur compounds before exhausting to the atmosphere. The TGUs are designed to control SO_2 to the NSPS Subpart Ja standard of 250 ppm, 12-hour rolling average. The #1 TGU accomplishes this using a three step process: 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 a methyl-diethanolamine (MDEA) based counter-current extractor. The rich MDEA is regenerated with steam, and the liberated H_2S is routed to the SRU for conversion into elemental sulfur. The remaining residual unabsorbed H_2S in the tail gas stream is routed to an incinerator where the remaining H_2S is oxidized to SO_2 and exhausted to the atmosphere.

The #2 TGU uses a proprietary CanSolve® process to remove sulfur from the tail gas stream. Prior to absorption H_2S and other reduced sulfur compounds are converted to SO_2 in the thermal oxidizer. The oxidized gas is cooled and the SO_2 absorbed in a lean diamine solution. The SO_2 rich diamine is regenerated using steam, and the concentrated SO_2 is routed to the SRU for conversion to elemental sulfur. Residual SO_2 that is not absorbed is exhausted to the #2 TGU stack.

Emissions from the sulfur complex are primarily SO_2 from the incinerator and #2 TGU stacks. Each stack is equipped with a CEM to continuously monitoring SO_2 emissions. NO_X, CO, PM_{10}, VOC and HAP emissions are generated as products of combustion in the SRU, incinerator and thermal oxidizer.

When the #2 Tail Gas Unit (TGU) is operated during periods that the #1 TGU down for maintenance, the refinery may need to reduce the sulfur production rate at the Sulfur Recovery Complex in order to meet its ongoing compliance requirements. In this operating mode only one Claus Unit is operated due to TGU capacity limitations.

Emissions from the elemental sulfur pits and tanks located at the Sulfur Recovery Complex are controlled with the Sulfur Pit Vapor Recovery (SPVR) system that uses a counter current wet scrubber using caustic solution as the absorption media. When the SPVR system is down for maintenance which is often due to the formation of sulfite and sulfate salts in the system, gases from the sulfur pits and tanks are routed directly to the #1 TGU incinerator. The incinerator stack is equipped with an SO_2 CEM and therefore, ongoing compliance is still continuously monitored. However, this situation is considered an alternative operating condition because it is not the normal mode of operation.

In November of 2014, BP submitted a request for approval of an alternative monitoring plan to EPA for use during periods of Incinerator maintenance, when sulfur pit vapors could not be routed to the CEM equipped stack. OAC 1201a, issued April 16, 2015, included requirements from this proposed monitoring plan during periods of Incinerator maintenance until NSPS Ja was triggered. On April 1, 2019, EPA responded to BP requesting more information regarding the proposed monitoring plan. BP responded with clarifications on July 1, 2020. The request for AMP approval during Incinerator outages is ongoing as of the date of issuance of this document.

NSPS Ja limits emissions of SO_2 to 250 ppmvd @ 0% O_2 for Claus units that use only ambient air in the burner or elect not to monitor oxygen concentration of the air mixture used in the burner, but also provides the option of a calculated adjustment to the SO_2 emission limit for SRUs that operate oxygen-enrichment to the Claus burners. As of time of issuance of this document, the Cherry Point Refinery is complying with the 250 ppmvd SO_2 limit.

Construction History and Regulatory Applicability

#1 TGU Approval – 1977 - Superseded

The sulfur complex comprised of the north and south sulfur recovery trains (CLAUS trains) was built along with the original refinery in 1970. Following construction, it was determined that the sulfur recovery complex could not meet the NWCAA 462 regulation limiting stack SO_2 emission to 1,000 ppm at 7% oxygen. On March 13, 1974, the NWCAA issued a variance that required the refinery to comply by July 1, 1977. In 1975, the #1 Tail Gas Unit (#1 TGU) was added to the Sulfur Recovery Complex bringing the refinery into compliance with NWCAA 462. NWCAA issued an unnumbered OAC dated June 30, 1977 approving the #1 TGU. The approval letter included a condition that limited elemental sulfur production to 127 long tons per day and required a source test to demonstrate compliance with the 1,000 ppm @ 7% oxygen SO_2 limit.

Approval Letter – 1990 - Defunct

In a July 9, 1990 letter, the NWCAA granted the refinery permission to increase their elemental production sulfur rate with the condition that a CEM for SO_2 be installed on the incinerator stack. The CEM was installed and certified on February 27, 1995, thereby lifting the requirement to operate within a long ton per day elemental sulfur production limit at the sulfur recovery complex.

OAC 290 – 1984 – Currently Applicable

On June 14, 1984, the NWCAA approved construction of a second elemental sulfur storage tank at the sulfur recovery complex under OAC 290. The refinery did not plan to increase sulfur production rates as a result of adding the tank and identified fugitive H_2S as the only emission associated with the new tank. OAC 290 does not include any specific conditions or requirements; therefore, this OAC is not referenced in the air operating permit.

Regulatory Order 28 – 2002 - Superseded

The 2001 Consent Decree required applicability of 40 CFR 60 Subpart J requirements at the Sulfur Recover Complex. Subpart J requires that emissions of SO_2 do not exceed 250 ppmvd @ 0% oxygen, 12-hour rolling average limit on the sulfur recover complex incinerator stack. On May 15, 2002, the NWCAA formalized this requirement under Regulatory Order 28.

OAC 890 – 2005 - Superseded

The 2001 Consent Decree (paragraph 21) also required the refinery to construct a second tail gas unit to provide process redundancy and eliminate acid gas flaring during #1 TGU maintenance activities. Construction of the second tail gas unit was required by the end of 2006 to assure consistent ongoing compliance with 40 CFR 60 Subpart J. Following submittal of an NOC application, on February 22, 2005, the NWCAA issued OAC 890 authorizing construction of the #2 TGU. Startup of the #2 TGU occurred on June 30, 2006.

Because the project increased the sulfur handling capacity of the sulfur recovery complex by about 12%, the resultant potential increase in SO_2 emissions was offset with the Coker Blowdown Vapor Recovery Project to prevent SO_2 emission from triggering PSD thresholds. The Coker Blowdown Vapor Recovery Project reduced SO_2 emissions by capturing sour coker drum blowdown vapors using the previously underutilized capacity at the Delayed Coker Wet Gas Compressor. As required under OAC 890, the Coker Blowdown Vapor Recovery Project completed prior to startup of the #2 TGU. Because the addition of the #2 TGU impacted overall operation at the sulfur recovery complex, OAC 890 was written to supersede previously applicable orders issued by the NWCAA.

OAC 890a – 2005 - Superseded

On October 26, 2005 revision OAC 890a was issued providing an alternative monitoring plan for monitoring emissions from the sulfur pit and sulfur tank during periods when the caustic scrubber and/or #1 TGU incinerator is off-line for maintenance. On February 25, 2009, revision OAC 890b was issued adding clarification to applicability of the SO_2 limit during startup, shutdown and malfunction events. The revision also removed NOx, CO, H_2SO_4 and H_2S emissions limits for the #2 TGU stack because the emissions limits were based on a one-time only demonstration of compliance through source testing. This testing was completed in August 2006 and October 2008 showing compliance with the NOx, CO, H_2SO_4 and H_2S limits of OAC 890a.

OAC 890b – 2009 - Superseded

OAC 890b included a new requirement for annual source testing of the #2 TGU for SO_2 because of the complexities inherent using calculating stack flow rates and converting ppm values from the CEM to lb/hour and tpy mass emission rates. Lastly, OAC 890b included a new provision to allow bypassing of the caustic scrubber controlling sulfur pit and elemental sulfur tank emissions for up to 240 hours per year to accommodate expected maintenance activities on the scrubber. 40 CFR 60 Subpart Ja includes this 240 hour bypass clause.

The 240 hour bypass provision from controlling emissions from the sulfur pit and elemental sulfur tanks is not included in 40 C FR 60 Subpart J which was the applicable NSPS standard at the Sulfur Recovery Complex. Because bypassing events do not alleviate the refinery's requirement to comply with the 40 CFR 60 Subpart J, the 250 ppm SO2 emission limit was applicable at all times. The OAC included an alternative monitoring plan using colorimetric detector tube sampling for SO_2 and H_2S that was used to demonstrate compliance with Subpart J during periods when the scrubber is being bypassed.

<u>OAC 890c – 2011 - Superseded</u>

On July 21, 2011, the NWCAA issued revised OAC 890c authorizing an alternative operating configuration at the Sulfur Recovery Complex that allows facility to produce up to 270 long tons per day (LTPD) of elemental sulfur. Prior to construction of the #2 TGU, each of the two Claus trains were nominally rated at 100 LTPD of elemental sulfur production with the #1 TGU serving to control post-Claus SO_2 emissions. When the #2 TGU was constructed in 2005, the project included tie-ins to existing equipment allowing concentrated SO_2 generated at the #2 TGU to be routed to the front end of each Claus train. This had the effect of improving sulfur recovery in the Claus units. The NOC application for OAC 890 estimated that the improved Claus efficiency would result in an overall elemental sulfur production capacity increase at the facility of 12.5%, or from 200 to 225 LTPD.

The #2 TGU was constructed as a first-time application of a proprietary CanSolv® diamine SO_2 absorption system with regard to serving as a refinery sulfur recovery tail gas control system. After a five year shake out period at the refinery including various system adjustments to the #2 TGU, it became apparent that the Sulfur Recovery Complex could operate in a configuration optimized for sulfur removal efficiency with operational stability producing to 270 LTPD of elemental sulfur and remain in compliance with all applicable emission limits. This could be done with no physical changes because the Sulfur Recovery Complex was capable of accommodating the configuration following completion of the #2 TGU project in 2005.

<u>OAC 1043 – 2009 – Currently Applicable</u>

On May 29, 2009, the NWCAA issued OAC 1043 approving the Sour Water Handling Project at the Sour Water Unit. The project was completed and place into service on April 24, 2010. The project included the addition of a second flash drum and replacement of components in the non-phenolic stripper tower to provide a designed increase in the sour water processing capacity from 760 to 1,005 barrels per hour. The project added one new MACT Group 1 vent that is routed to the flare gas recovery system. The project also triggered applicability of 40 CFR 60 Subpart GGGa, which references Subpart VVa as the federal enhance LDAR standard.

<u>OAC 1201 – 2015 - Superseded</u>

On March 11, 2015, NWCAA issued OAC 1201, which permitted modifications that allow the SRU to process up to 270 long tons per day. OAC 1201 superseded OACs 890a-890c.

The project involved modifications to unit heat exchangers to improve sulfur cooling, re-rating of the sulfur recovery unit's overall operating pressure, and modifying the pure oxygen system to enable higher oxygen flow rates to the north and south sulfur plants, all of which could result in a higher hourly production of sulfur. All of the additional flow is routed through the #1 TGU followed by the Incinerator.

The increase in hourly production resulted in an increase in hourly emissions of SO_2, and therefore, NSPS Subpart Ja was triggered for the entire SRU. Subpart Ja requirements for the sulfur plant are discussed in more detail in Section 2.1.1.3.

OAC 1201a – 2015 – Superseded

OAC 1201 was revised with issuance of OAC 1201a on April 16, 2015, which added the upgrade of the north and south regenerator towers' trays to the project summary.

OAC 1201b – 2022 – Currently Applicable

OAC 1201b was issued in March 2022 to remove references to obsolete startup, shutdown, and malfunction plans, incorporate the alternative work practice standard BP has selected to demonstrate compliance with NESHAP UUU, and clarify source test reporting requirements.

3.14 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 listed in Section 1.18 of the AOP. The following is a discussion of each unit.

3.14.1 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.

3.14.2 Truck Loading Rack

The Truck Loading Rack is used to load gasoline, jet fuel and diesel products into truck cargo transport tanks. The facility 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 dedicated loading arms for gasoline, diesel and jet fuel. LPG can also be loaded at the truck rack. Automatic interlock devices are in place to prevent loading unless appropriate thermal oxidation temperatures in the vapor combustor are met and to assure that the tanks loaded have a valid annual leak tightness test certification on record. Under OAC 527f, the Truck Loading Rack is limited to 26,000 barrels of gasoline per day, and the total loadout of diesel and jet fuel is limited to 76,000 barrels per day.

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 natural gas as a supplemental fuel to assure that the temperature in the oxidizing zone is at or above 1,200°F at all times when displaced vapors are routed to it during loading. This baseline temperature was determined during initial performance testing required pursuant to applicable federal regulations. The NWCAA was notified of the result of the initial testing in a December 27, 1995 letter from the refinery. Operation at an average temperature of 1200°F ensures that the emission standard of 10 milligrams VOC per liter loaded will be met.

VOCs and HAP are also emitted from loading losses and equipment components (pumps, flanges, valves, pressure relief devices) and from emissions from storage tank emissions.

Construction History and Regulatory Applicability

OAC 527 – 1994 - Superseded

Construction of the Truck Loading Rack was proposed on October 6, 1994. The project included the construction of three new finished product storage tanks (Tanks #72, 73 & 74). The NWCAA issued OAC 527 on December 24, 1995, approving construction of the Truck Loading Rack and tanks.

OACs 527a and 527b – 1996 - Superseded

On August 27, 1996 the refinery proposed to modify the Truck Loading Rack by adding a new bay for the delivery of jet and diesel fuel. 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) approving the project.

OAC 527c – 2001 - Superseded

On November 6, 2001, the refinery proposed to increase the throughput of the Truck Loading Rack without any physical modifications. On December 13, 2001, the NWCAA approved the increase under OAC 527c.

OAC 527d – 2012 - Superseded

On July 9, 2012, the NWCAA issued revised OAC 527d which explicitly superseded all previous versions of this order. The revision eliminated confusing overlap between requirements in federal, state and NWCAA regulations and those contained in the order. The revision also improved formatting and cleaned up the order for better incorporation into the air operating permit.

OAC 527e – 2018 - Superseded

OAC 527d was revised with issuance of OAC 527e on August 29, 2018. Revision 'e' clarified conditions for source testing during gasoline loading.

OAC 527f – 2021 – Currently Applicable

A subsequent revision, OAC 527f, on March 16, 2021, further clarified source testing and reporting requirements

There are a number of overlapping regulations that apply to the Truck Loading Rack. These include; NWCAA 580.4, WAC 173-491-040 (2), 40 CFR 60 Subpart XX, and 40 CFR 63 Subpart CC (Refinery MACT). Equipment components in VOC/HAP service are under a leak detection and repair (LDAR) program pursuant to NWCAA 580 (RACT), 40 CFR 60 Subpart GG (NSPS) and 40 CFR 63 Subpart CC (MACT). In addition, fugitive VOC emissions from the oily wastewater system at the Truck Loading Rack are regulated under 40 CFR 60 Subpart QQQ. 40 CFR 63 Subpart CC (Refinery MACT) applies a modified version of 40 CFR 63 Subpart R, and by reference, 60 Subpart XX at the Truck Loading Rack. As such, only those portions of Subpart R listed in 40 CFR 63.650 of Subpart CC, and the referenced portions of 60 Subpart XX, are cited in the air operating permit. See Section 2.1.2.5 for a discussion of this overlap.

3.14.3 Marine Terminal

The marine terminal is used to unload crude oil from ships and barges, and to load products onto ships and barges such as gasoline, gasoline blending components, diesel, jet fuel, and intermediates such as HUX, and reformate. The south berthing dock has crude oil unloading capability. The north berthing dock is equipped to load liquids onto ships and barges; however, it does not have equipment that would enable unloading operations.

Figure 3.14-1 Cherry Point Refinery Marine Terminal

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 on the north berthing dock. A vapor collection knockout pot, vapor blower, and liquid seal skid, and a vapor combustor are located at the trestle head platform. The vapor combustor is considered a thermal oxidizer because vapors collected during loading are combusted within an enclosed device.

Vapors are collected through an arm connected to the vessel being loaded. 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 vapor combustor 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 vapor combustor (thermal oxidizer) and destroyed through combustion with a designed minimum destruction removal efficiency of 98 percent.

Construction History and Regulatory Applicability

OAC 437 – 1993 - Superseded, and

OAC 716 – 2000 - Superseded

The trestle way and south berthing dock were constructed as part of the original refinery construction in 1971. On June 7, 1993, the NWCAA issued OAC 437 approving a project to modify the dock piping system. On January 26, 2000, the NWCAA issued OAC 716 approving construction of the north berthing dock. This second berthing area was needed to alleviate scheduling problems, reduce demurrage costs, and increase product shipping flexibility. The north berthing dock was designed specifically to handle product loading onto ships and barges and does not have equipment to facilitate unloading of crude oil.

OAC 716a – 2001 - Superseded

On May 3, 2001, the NWCAA issued OAC 716a approving a project to connect the vapor collection and vapor combustor control system to the south dock. As approved, all vapors that are displaced during ship and barge loading of light liquids (i.e., vapor pressure ≥ 1.5 psia) at both the north and south docks are collected and routed to the vapor combustor for control.

OAC 716b – 2012 – Currently Applicable

On July 9, 2012, the NWCAA issued OAC 716b. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit. OAC 716b explicitly superseded OAC 437 and therefore, OAC 437 is no longer valid and not cited in the air operating permit.

40 CFR 63 Subpart Y – National Emission Standards for Marine Tank Vessel Loading Operations

After construction of the north dock, the Marine Terminal became an affected facility under 40 CFR 63 Subpart Y – National Emission Standards for Marine Tank Vessel Loading Operations. In accordance with §63.650(a)(1), the facility was considered a new MACT source under Subpart Y with emissions from the Marine Terminal below the 10 tons of any single HAP, or 25 tons of a combination of HAP. In accordance with §63.650(b)(1), the Marine Terminal is also considered a RACT source under Subpart Y, because gasoline loading exceeded the 10 million barrel annual average applicability threshold of the rule. Subpart Y requires that emissions of VOC be controlled by at least 98% by weight during loading of all light liquids, and to no more than 1,000 VOC ppmv during the loading of gasoline. Compliance is demonstrated through a one-time initial source test using EPA Method 25 and the establishment of a baseline temperature at which the vapor combustor is to the operated. In April 2002, the refinery conducted initial source testing of the vapor control system as required under Subpart Y. During the test, the exhaust temperature of the vapor combustor's thermal oxidizer was monitored and a baseline temperature established of 1350°F for demonstrating ongoing compliance with each block hour cycle. In accordance with Subpart Y, the average 3-hour block average temperature must remain at or above 1350°F for the vapor combustor to demonstrate ongoing compliance with the rule.

40 CFR 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

40 CFR 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries includes an overlap provision for marine terminals.

> *40 CFR 63.651 - Marine tank vessel loading operation provisions*
>
> *(a) Except as provided in paragraphs (b) through (d) of this section, each owner or operator of a marine tank vessel loading operation located at a petroleum refinery shall comply with the requirements of §§63.560 through 63.568.*

The Subpart CC overlap provision does not change any of the emission limits, monitoring or recordkeeping requirements of Subpart Y.

40 CFR 60 Subpart J - New Source Performance Standards for Petroleum Refineries

40 CFR 60 Subpart J - New Source Performance Standards for Petroleum Refineries is not an applicable regulation at the marine terminal for two reasons. First, the definition of fuel gas under Subpart J specifically exempts gas generated from marine tank vessel loading operations. Secondly, the thermal oxidizer at the marine terminal uses only natural gas (a supplemental fuel) as a pilot and to maintain combustion temperatures. Because the refinery-generated gas is not combusted at the marine terminal either as recovered vapors during loading, or as supplemental fuel in the thermal oxidizer, 40 CFR 60 Subpart J is not an applicable regulation at this unit.

3.14.4 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

HAP 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.

3.14.5 Crude Rail Car Unloading

OAC 1142 – 2013 – Currently Applicable

A new crude rail car unloading facility was approved under OAC 1142 on January 22, 2013. The facility includes a 1.9 mile rail loop and an unloading area capable of accomodating the concurrent unloading of up to 52 railcars. OAC 1142 did not approve an increase in crude processing capacity. The approval mearly provided BP with the ability to ship more crude feedstock via rail as opposed to shipping via ship or pipeline. The facility was constructed in 2013.

40 CFR 60 Subpart QQQ, 40 CFR 61 Subpart FF, and 40 CFR 63 Subpart CC
On December 12, 2013 NWCAA received BP's notification of compliance with the applicable provisions for NSPS Subpart QQQ, 40 CFR 63 Subpart CC, and 40 CFR 61 Subpart FF.

40 CFR 60 Subpart GGGa
40 CFR 60 Subpart GGGa does not currently apply to the Rail Logistics Project because the railcar unloading facility is not considered a "process unit" as defined in Subpart GGGa. The expanded definition of "process unit" has been stayed and at this time the narrower version of the definition is being applied that limits applicability to traditional refinery process units, and not shipping, receiving or storage operations.

While 40 CFR 60 Subpart GGGa doesn't technically apply, the requirements of the subpart are being relied on as BACT in OAC 1142 Condition 7 (AOP term 5.15.54). BP's December 12, 2013 notification of compliance included a statement that the facility is complying with the requirements of 40 CFR 60 Subpart GGGa.

3.15 Landfarm

On May 8 1992, the refinery proposed construction of a new non-hazardous waste landfarm to replace the existing non-hazardous waste landfarms that began operating in 1971. The new landfarm is used to treat and dispose of non-hazardous waste, including oily wastes and waste biomass from the oil wastewater treatment plant. Dangerous wastes, as defined by WAC 173-303 are not allowed. The landfarm conforms to the Washington State standards for solid waste handling under WAC 173-304. The landfarm is located on top of existing clean construction fill. Potential emissions include air toxics such as benzene and ammonia.

OAC 382 – 1992 – Superseded

On June 30, 1992 the NWCAA issued OAC 382 approving the new non-hazardous waste landfarm.

OAC 382a – 2012 – Currently Applicable

On May 15, 2012, the NWCAA issued revised OAC 382a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

3.16 Oily Wastewater Collection, Storage and Treatment

The Wastewater Treatment Plant (WWTP) 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 Strait.

The WWTP 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 Strait. Biosolids from the biodegradation unit are produced and dewatered as necessary.

Major equipment at the WWTP 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 WWTP are primarily VOCs and HAP including benzene. Other components that are sources of emissions include valves, flanges, seals, and drains.

Construction History and Regulatory Applicability

<u>40 CFR 61 Subpart FF, 40 CFR 60 Subpart QQQ, and 40 CFR 63 Subpart CC</u>

The majority of the WWTP 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:

- 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
- 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. Most changes to the WWTP have been driven by compliance with 40 CFR 61 Subpart FF. The following is a discussion of those changes.

3.16.1 API Separator Covers.

On September 15, 1989, the refinery proposed to install floating covers on the forebays and main bays of the API oil/water separator to reduce VOC and benzene emissions at the wastewater treatment plant. The refinery estimated that VOC emission would be reduced by 2,543 tons per year at the forebays and 636 tons per year at the main bays as a result of the project. On December 13, 1989, the NWCAA adopted a requirement to cover API oil/water separator forebays under Subsection 580.23 of the NWCAA Regulation. On March 7, 1990, EPA promulgated 40 CFR 61 Subpart FF—National Emission Standard for Benzene Waste Operations requiring covers or alternate controls on both the API oil/water separator forebays and main bays.

<u>OAC 272 – 1990 – Currently Applicable</u>

On April 17, 1990, the NWCAA issued OAC 272 approving the project cover the forebays and main bays consistent with NWCAA and federal requirements. OAC 272 does not include any specific requirements; therefore, this approval order is not referenced in the air operating permit.

3.16.2 Wastewater System Benzene NESHAP Modifications

On October 23, 1991 the refinery submitted their application to make modifications to the oily wastewater system 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.

<u>OAC 348 – 1992 - Superseded</u>

Modifications to the oily wastewater system were approved by the NWCAA under OAC 348 issued January 8, 1992.

Changes to the oily wastewater system 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: Construct internal floating roof 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.

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 airtight 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 the forebays and main bays, and floating roofs are installed on the effluent sumps. All fixed covers on the are vented to carbon absorber control systems through a closed vent system. The system includes a nitrogen purge to mitigate the risk of combustion under the roofs.

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.

OAC 348a – 2012 – Currently Applicable

On May 3, 2012, the NWCAA issued revised OAC 348a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

3.17 Storage Tanks and Vessels

There are a variety of storage tanks located at the refinery. Tanks configured to store light liquids such as gasoline and crude oil are equipped with internal floating roofs. Tanks configured to store heavy products such as distillates and residual intermediates are equipped with fixed roofs. Most of the tanks are located at the Tank Farm where they store crude oil, feed for process units, intermediate products, blending components, and finished products. Section 1 of the permit includes a table describing each store vessel, its year of construction or modification and comments regarding regulatory applicability.

Storage vessels at an existing source may trigger applicability for 40 CFR 60 Subparts K, Ka, and Kb, and NWCAA Regulations, as well as 40 CFR 63 Subpart CC.

The table below presents the regulatory triggers applicable when storing volatile organic liquids (VOL). Tanks storing VOL that has a vapor pressure less than the regulatory 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 3.17-1 Regulatory Triggers for Storage Tanks and Vessels

Regulatory Trigger	kPa	Psia
NWCAA control for tanks ≥ 151 m^3	10.4	1.5
NSPS K and Ka control for tanks ≥ 151 m^3	10.4	1.5
NSPS Kb control for tanks ≥ 151 m^3	3.5	0.5
NSPS control for tanks ≥ 75 m^3 and ≤ 151 m^3	15.0	2.18

Regulatory Trigger	kPa	Psia
MACT control for new Group 1 tanks ≥ 151 m^3	3.4	0.5
MACT control for existing Group 1 tanks ≥ 151 m^3	5.2	0.75
MACT control for Group 1 tanks ≥ 76 m^3 and ≤ 151 m^3	13.1	1.9
Maximum True VP of stored VOL for EFR or IFR tanks	76.6	11.1

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

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 VOL 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. However, this reference is intended to clarify that the substantive requirements of Subpart Kb apply and does not imply that Kb was necessary triggered. This becomes important when the 40 CFR 63 Subpart CC overlap provisions are analyzed.

Under the current version of NWCAA Section 580 (580.26 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 the refinery 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.

3.17.1 Crude Oil Tanks #47 and 48

OAC 116 – 1973 – Currently Applicable

On August 16, 1973 the refinery proposed construction of two internal floating roof crude oil storage tanks, each with a capacity of 268,000 barrels. On September 17, 1973, the NWCAA issued OAC 116 approving the tanks. On June 21, 1974, the NWCAA issued a letter identifying the tanks as #1947 and #1948 and that the agency had conducted an inspection of the newly constructed tanks. The tanks are currently referred to as Tanks #47 and 48. OAC 116 is considered narrative with no enforceable conditions; therefore, this OAC is not referenced in the air operating permit.

OAC 120 – 1973 – Defunct

On August 16, 1973, the refinery proposed the construction of three internal floating roof crude oil storage tanks, each with a capacity of 312,000 barrels. On October 12, 1973, the NWCAA issued OAC 120 approving construction the three tanks. It is not clear in the NWCAA record if these tanks were actually constructed.

3.17.2 Crude Oil Tank #50

OAC 253 – 1989 - Superseded

On March 17, 1989, the refinery proposed construction of a 500,000 barrel internal floating roof crude oil storage tank (Tank #50). On May 15, 1989, the NWCAA issued OAC 253 approving the project.

OAC 253a – 2002 – Currently Applicable

On August 8, 2002, the NWCAA issued revised OAC 253a by clarifying that the tank is subject to 40 CFR 60 Subpart Kb. Because OAC 253a is considered narrative with no enforceable conditions, it is not referenced in the air operating permit.

3.17.3 Intermediate Storage Tank #71

OAC 371 – 1992 - Superseded

On March 12, 1992, the refinery proposed construction of a 31,500 barrel internal floating roof storage tank (Tank #71). The tank was designed to be used as 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. On May 1, 1992, the NWCAA issued OAC 371 approving the project.

OAC 371a – 2002 – Currently Applicable

On August 8, 2002, the NWCAA revised OAC 371a clarifying that the tank is subject to 40 CFR 60 Subpart Kb and is in organic hazardous air pollutant service subject to 40 CFR 63 Subpart CC. Because OAC 371a is considered narrative with no enforceable conditions, it is not cited in the air operating permit.

3.17.4 Finished Product Tank #24

OAC 453 – 1993 - Superseded

On August 26, 1993, the refinery proposed construction of a 200,000 barrel petroleum internal floating roof storage tank (Tank #24). The tank was designed to be used to store finished diesel product as well as 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). On November 23, 1993, the NWCAA issued OAC 453 approving the project with a condition that limited the vapor pressure of the stored liquid to 8.3 psia.

OAC 453a – 1993 - Superseded

On November 18, 1993, the refinery proposed to install a geodesic dome on the internal floating roof rather than the originally proposed internal floating roof design. On November 23, 1993, the NWCAA issued OAC 453a with a revised condition allowing the vapor pressure of the stored liquid to go as high as 11.1 psia.

OAC 453b – 2002 – Currently Applicable

On August 8, 2002, the NWCAA issued revised OAC 453b to eliminate overlapping requirements and the revision removed all of the conditions of approval. Because OAC 453b is considered narrative with no enforceable requirements, it is not referenced in the air operating permit.

3.17.5 Truck Loading Rack Finished Product Tanks #72, 73 and 74

On October 6, 1994, the refinery proposed the construction of a new Truck Loading Rack for loading gasoline, diesel and jet fuel into truck cargo tanks for transport off-site. The project included the construction of three new internal floating roof storage tanks: two 10,000 barrel tanks, and one 20,000 barrel tank, each tank equipped with a liquid mounted primary seal meeting the requirements of 40 CFR 60 Subpart Kb. Secondary seals were added to all three tanks after they were constructed.

OACs 527-527e – 1995 - Superseded

On December 24, 1995, the NWCAA issued OAC 527 approving the project.

OAC 527f – 2021 – Currently Applicable

There have been numerous revisions to this order, the last being OAC 527f issued March 16, 2021, which is cited in the air operating permit. OAC 527f limits the type of products that can be stored in Tanks #72, 73 and 74 and has associated recordkeeping requirements to demonstrate compliance. These requirements are included in the AOP.

3.17.6 Light Reformate Splitter Tower Tanks #1-10, and 14)

OAC 526 – 1996 - Superseded

As previously discussed, on August 1995 the refinery notified the NWCAA that they proposed to build a new Light Reformate Splitter Tower (LRF Tower) at the #1 Reformer Unit. The project was approved under OAC 526 issued January 3, 1996.

OAC 526a – 1996 – Superseded

On February 14, 1996, the refinery requested a change to the project to allow the use of existing tanks to storage benzene-concentrated LRF Tower bottoms. All of the tanks are configured with internal floating roofs to control emissions. The use of these tanks for handling benzene concentrate was determined to result in an increase in emissions from the project, and this increase was incorporated into the project's WAC 173-460 Tier II Analysis completed by Ecology. On February 26, 1996, the NWCAA issued revised OAC 562a approving the project including the use of existing storage tanks to store benzene concentrate from the LRF Tower.

On May 6, 1996, the refinery began operating the LRF Tower. Once operating, they determined through computer optimization that the LRF Tower bottoms could be further concentrated to 70% by weight benzene from the original 40% by weight estimate of the original design without any changes to the equipment. On March 9, 2000, the NWCAA determined that new source review was not required as a result of this operational change.

<u>OAC 562b – 2000 - Superseded</u>

On, December 8, 2000, the NWCAA issued revised OAC 526b allowing transfer of benzene concentrate between tanks to accommodate the need for conducting inspection and maintenance work on the tanks.

<u>OAC 562c – 2003 - Superseded</u>

On March 17, 2003, the NWCAA issued OAC 526c revising the list of tanks that were allowed to be used to storage benzene concentrate to the current list of Tanks #1 through 10, and 14.

<u>OAC 562d – 2012 – Currently Applicable</u>

On July 9, 2012, the NWCAA issued revised OAC 526d to improve formatting and to clean up the order for better incorporation into the air operating permit.

3.17.7 Crude Oil Tank #49

<u>OAC 620 – 1997 - Superseded</u>

On June 2, 1997 the refinery proposed the construction of a 400,000 barrel, internal floating roof, crude oil storage Tank #49. Additional crude oil storage capacity was needed to reduce the number of marine tanker deliveries. Emissions from the tank would include VOC and TAP/HAP emissions and required controls specified under 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC. On August 13, 1997, the NWCAA issued OAC 620 approving the project.

<u>OAC 620a – 2002 - Superseded</u>

On August 8, 2002, the NWCAA issued revised OAC 620a removing requirements that overlapped with other directly applicable requirements, i.e., 40 CFR 60 Subpart Kb, 40 CFR 63 Subpart CC, 40 CFR 60 Subpart GGG, 40 CFR 60 Subpart QQQ, and NWCAA 560 and 580.

<u>OAC 620b – 2012 – Currently Applicable</u>

On July 9, 2012, the NWCAA issued revised OAC 620b. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

<u>OAC 897 – 2004 - Superseded</u>

In 2005 the tank was equipped with an internal steam heating coil to allow the flexibility to store heavier crude oils. The steam coil installation proposal was submitted with the Tank #40 project and approved by the NWCAA under OAC 897 issued November 15, 2004.

<u>OAC 897a – 2012 – Currently Applicable</u>

On July 9, 2012, the NWCAA issued revised OAC 897a. Neither OAC contain any specifically applicable requirements for Tank #49.

Secondary seals were added to the tank after it was constructed.

3.17.8 Crude Oil Tank #40

<u>OAC 897 – 2004 - Superseded</u>

On November 15, 2004, the NWCAA issued OAC 897 approving construction of a new, 365,000 barrel, internal floating roof crude oil storage Tank #40. The tank was needed in order to segregate, store and process a wider variety of crude oils because the production and supply of Alaskan North Slope Crudes, which historically had been the primary source of crude oil for the refinery, was declining. The tank was constructed and was put into operation October 2005. Typical of other storage tanks at the refinery, Tank #40 is equipped an internal floating roof with a mechanical shoe primary seal and rim mounted secondary seal. The tank is equipped with an internal steam coil to allow storage of heavy crudes. Tank #40 is subject to a number of federal and NWCAA requirements including 40 CFR 60 Subpart Kb, 40 CFR 63 Subpart CC, and NWCAA 560 and 580.

OAC 897a – 2012 – Currently Applicable

On July 9, 2012, the NWCAA issued revised OAC 897a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

3.17.9 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 extension 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).

3.17.10 Internal Floating Roof Tanks

Internal floating roof (IFR) tanks are also used to store high vapor pressure VOL 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 most of 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, determined on a monthly average. 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 advanced 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.

3.17.11 Pressurized Vessels

Gaseous products, such as 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 are vented to the atmosphere, however, in some cases they are routed through a closed vent system to the flares.

3.18 Internal Combustion Engines

The Cherry Point Refinery operates 19 emergency diesel generators regulated by 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.

17 of the emergency generators are less than 500 hp and were installed after June 11, 2005. Per 60.4202(a)(2), these engines must meet the Tier 3 standards for new non-road compression-ignition engines in 40 CFR 1039, Appendix I, and 1039.105. Two generators, rated at more than 500 hp, were installed after December 19, 2002, and must meet the Tier 2 standards for new non-road compression-ignition engines in in 40 CFR 1039, Appendix I, and 1039.105. Diesel fuel used to fire the engines must also meet the requirements in 1090.305, including a sulfur content of less than 15 ppmw.

The fire water pump is used to pressurize the refinery firewater system which services the entire refinery. The refinery firewater system provides pressurized water to fight fires. The fire water pump is in emergency service, was installed after June 12, 2006, and is rated at less than 500 hp.

Note that this regulatory analysis assumes that the engines are in emergency service as defined in 40 CFR 63 Subpart ZZZZ. This definition allows for limited operation in non-emergency service. Should BP choose to operate them otherwise, these engines would be subject to other requirements.

3.19 Applicable NSR Requirements not Included in AOP Section 5

Table 3.19-1 below lists NSR permits that are currently applicable but have conditions that were not included in AOP Section 5, and the reason for exclusion.

Table 3.19-1 Applicable NSR Requirements not Included in AOP Section 5

Permit	Condition	Description	Rationale for Exclusion from AOP Section 5
OAC 159	All	General approval	No specific requirements.
OAC 273c	10	Recordkeeping	Fulfilled by AOP Term 2.4.3 Required Recordkeeping
	11	Initial notification	Satisfied on 5/28/2019
PSD 5 A4	4	Recordkeeping	Fulfilled by AOP Term 2.4.3 Required Recordkeeping
	5	Duty to comply	Fulfilled by AOP Term 2.1.1 Duty to comply
	6	Inspection and entry	Fulfilled by AOP Term 2.1.6 Inspection and Entry
OAC 640a	1	Initial notification	Satisfied on 5/18/1999
PSD 7-A1	5	Duty to comply	Fulfilled by AOP Term 2.1.1 Duty to comply

	6	Inspection and entry	Fulfilled by AOP Term 2.1.6 Inspection and Entry
OAC 148	All	General approval	No specific requirements.
OAC 149	All	General approval	No specific requirements.
OAC 1067a	11	Initial notification	Satisfied 6/4/2012
OAC 1122	1	Initial notification	Satisfied 5/17/2012
PSD 16-01	I	Effective date	Permit issued
	II	Commence construction	Construction commenced
	III	Construction notification	Satisfied 1/16/2020
	IV	Equipment list	No requirements
	VI	BACT descriptions	Redundant requirements to V
	VII	Statement of fact	Not enforceable requirement
	IX.A-B	Recordkeeping	Fulfilled by AOP Term 2.4.3 Required Recordkeeping
	IX.C	Annual Emission Inventory	Fulfilled by AOP Term 2.4.4 Pollutant Disclosure
	IX.D	Source test reporting	Fulfilled by AOP Term 2.1.9 Testing and Sampling
	X.A	Minimize emissions	Fulfilled by AOP Term 2.5.1 Excess Emissions
	X.B.	Credible evidence	Fulfilled by AOP Term 2.1.11 Credible Evidence
	XI	Excess emissions reporting	Fulfilled by AOP Term 2.5.1 Excess Emissions
	XII	Inspection and entry	Fulfilled by AOP Term 2.1.6 Inspection and Entry
	XIII	Transfer of ownership	Fulfilled by AOP Term 2.2.10 Permit Revisions
	XIV	Duty to comply	Fulfilled by AOP Term 2.1.1 Duty to comply
	XV	Appeal procedures	Not enforceable

OAC 1200	3	Operate only 2 heaters	North and South heater defunct
	4 and 5	Shutdown North and South Coker Heaters	North and South heater defunct
	6	Startup notifications for LOA, East and West Coker Heaters	Satisfied on 2/22/2019, 5/6/2019, and 5/20/2019
	7	Shutdown notifications for North and South Coker Heaters	Satisfied on 5/6/2019 and 5/20/2019
OAC 1289	1	Initial notification	1/10/2020
PSD 10-01 A1	15	Provide sample ports	Fulfilled by AOP Term 2.1.9 Testing and Sampling
	17	Inspection and entry	Fulfilled by AOP Term 2.1.6 Inspection and Entry
	18	Notification after incorporation into AOP	Not enforceable
	19	Recordkeeping	Fulfilled by AOP Term 2.4.3 Required Recordkeeping
PSD 02-04 A2	9	Provide sample ports	Fulfilled by AOP Term 2.1.9 Testing and Sampling
	11	Inspection and entry	Fulfilled by AOP Term 2.1.6 Inspection and Entry
PSD 95-01 A2	4	Duty to comply	Fulfilled by AOP Term 2.1.1 Duty to comply
	5	Inspection and entry	Fulfilled by AOP Term 2.1.6 Inspection and Entry
PSD 89-2	4	Commence construction	Construction commenced
	5	Duty to comply	Fulfilled by AOP Term 2.1.1 Duty to comply
	6	Inspection and entry	Fulfilled by AOP Term 2.1.6 Inspection and Entry
OAC 246	All	Measure pressure drop across coke silo baghouses	No specific requirements
OAC 306	All	General approval	No specific requirements

OAC 293	All	General approval	No specific requirements
PSD 07-01 A2	5	Initial notification	Satisfied
	6, 7, 8	Initial testing	Satisfied on 9/11/2009
	15	Provide sample ports	Fulfilled by AOP Term 2.1.9 Testing and Sampling
	17	Inspection and entry	Fulfilled by AOP Term 2.1.6 Inspection and Entry
	18	Commence construction	Construction commenced
	19	Appeal procedures	Not enforceable
OAC 290	All	General approval	No specific requirements
OAC 1043	2	Initial notification	Satisfied on 9/23/2010
OAC 1142	8	Initial notification	Satisfied
OAC 272	All	General approval	No specific requirements
OAC 116	All	General approval	No specific requirements
OAC 253a	All	General approval	No specific requirements
OAC 371a	All	General approval	No specific requirements
OAC 453b	All	General approval	No specific requirements

4 AIR OPERATING PERMIT ADMINISTRATION

In developing the AOP for the 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 "Narrative" Orders of Approval to Construct (OAC)

The following Order of Approval to Construct (OAC) permits issued by the NWCAA under their minor new source review program have not been incorporated into the AOP because they are considered to be "narrative only". These permits are all relatively old, all originally being issued prior to 1995. Because they are narrative in content, they do not contain any specific conditions that are considered specifically applicable requirements under Title V. These orders are also included in Table 3.19-1.

- OAC 116 issued September 17, 1973 – Storage Tanks #47 and #48
- OAC 120 issued October 12, 1973 – Three crude storage tanks (not built)
- OAC 148 issued November 20, 1974 - HC 1st Stage Frac Reboiler Preheater
- OAC 149 issued November 20, 1974 - HC 2nd Stage Frac Reboiler Preheater
- OAC 159 issued May 20, 1975 – Crude Heater Preheater
- OAC 246 issued April 10, 1980 - New baghouse at #1 & 2 Calciner
- OAC 253a issued May 15, 1989 – New crude storage Tank #50
- OAC 272 issued April 17, 1990– Wastewater Treatment Plant covers
- OAC 281 issued August 8, 1990 – Crude to Condensate Project
- OAC 283 issued May 15, 1990 - Coker Olefin Upgrade Project (COUP)
- OAC 290 issued June 14, 1984 - New elemental sulfur storage tank
- OAC 293 issued September 13, 1984 - Two new calcined coke silos
- OAC 299 issued December 19, 1984 - #3 Calciner (permitted under PSD)
- OAC 306 issued November 14, 1984 – New calcined coke loadout facility
- NWCAA Letter dated December 19, 1988 - Two new baghouses to control dust at the coke loadout facility
- OAC 371a issued May 1, 1992 – New 31,500 barrel storage Tank #71.
- OAC 453b issued November 23, 1993 – New 200,000 barrel storage Tank #24

4.1.3 "Superseded Requirements"

Requirements in permits (OAC or PSD permits) that have been superseded are not considered applicable requirements and are not included in the AOP.

4.1.4 Federal Enforceability

Federally enforceable requirements are terms and conditions required under the Federal Clean Air Act (FCAA) or under any of its applicable requirements. Local and state regulations may become federally enforceable by formal approval and incorporation into the State Implementation Plan (SIP) or through other delegation mechanisms. Federally enforceable requirements are enforceable by the EPA and citizens. All applicable requirements in the 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.

Most rules and requirements are followed by a date in parentheses. Two different versions (identified by the date) of the same regulatory citation may apply to the source if federal approval/delegation lags changes made to the Washington Administrative Code (WAC) or the NWCAA Regulation. For Washington Administrative Code (WAC) regulations, the date listed in parenthesis in the air operating permit represents the State Effective date. For NWCAA regulations, the date represents the most recent Board of Directors adoption date, which is identified as the "Passed" or "Amended" date in the NWCAA Regulation. The date associated with an OAC or PSD permit represents the issuance date of that new source review construction permit. For a federal rule, the date is the rule's most recent promulgation date.

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 terms based on Chapter 173-401 WAC will become federally enforceable for the source.

In the case of an OAC or PSD permit, the date in parenthesis represents the issuance date of that order or NSR permit.

4.1.5 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.

4.1.6 Compliance Options

The 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.

There are certain emission units that are permitted to operate in different modes; for those units, both scenarios are written into the permit with a recordkeeping requirement to document under which scenario the emission unit is operating.

4.1.7 Gap Filling & Sufficiency Monitoring

Title V of the Federal Clean Air Act is the basis for 40 CFR Part 70, which is the basis for the State of Washington air operating permit regulation, Chapter 173-401 WAC. Title V requires that all air pollution regulations applicable to the source be called out in the air operating permit for that source. Title V also requires that each applicable regulation be accompanied by a federally enforceable means of "reasonably assuring continuous compliance". 40 CFR Part 70 and WAC 173-401-615 all contain a "gap-filling" provision to address situations where no monitoring is present. 40 CFR Part 70.6(c)(1) and WAC 173-401-630(1) contain authority to address situations where monitoring exists but is deemed to be insufficient. NWCAA relied upon these authorities to add monitoring where needed to the air operating permit (AOP).

Most cases where monitoring needed to be added were older regulations, permits and NWCAA tank requirements that contained no monitoring. For example, NWCAA used its gap-filling authority to add monitoring for the 20% visible emission standard, NWCAA 451.1. The term "Directly Enforceable" is included in each AOP term where NWCAA added gap-filling.

One specific case worth expanding is the new requirement to operate a total sulfur (TS) monitor at the main fuel drum. This is a new requirement in this 2021 AOP renewal. In previous versions of the AOP, NWCAA listed a gap-filled requirement for monthly grab sampling of the fuel drum for sulfur content. However, after reviewing several years of data, NWCAA found that the sulfur content of the gas varies widely with time. This variation is a normal outcome of the process units that feed the fuel drum. However, this process variability makes monthly grab sampling problematic. NWCAA discussed this variability with BP and BP agreed that a better method for tracking fuel gas sulfur content would be the use of a TS monitor. BP agreed to install a TS monitor on the main fuel drum as part of the AOP renewal. The sulfur data review took place as part of a 2019 project at the North Vac Heater, which required a revision to OAC 273c. (See Section 3.2.2 for further detail.) NWCAA cites its gap-filling authority to use the TS monitor for all units that use gas from the fuel drum other than the OAC 273c conditions of the North Vac Heater. The use of the TS monitor is one of the compliance options in OAC 273c for the North Vac Heater, so it isn't gap-filled. NWCAA has also updated gap-filled monitoring for emission units that now operate monitors (e.g., H2S and TS monitors at the low-pressure and high-pressure flares). These monitors may have been installed for a variety of reasons, including compliance with new federal rule provisions. Where appropriate, NWCAA updated its gap-filled monitoring to include these new monitors.

There were also some limited cases where monitoring did exist but was found to be insufficient. NWCAA used its sufficiency monitoring authority (WAC 173-401-630(1)) to add monitoring in those cases. "Directly Enforceable" is included in the AOP term when NWCAA used its authority to supplement insufficient monitoring.

The type and frequency of monitoring added under the authorities in WAC 173-401-615 and WAC 173-401-630(1) were set based on the following factors:

1. Historical Compliance – NWCAA reviewed the facility's past compliance with the underlying requirement. This information helped inform the decision about monitoring frequency and stringency.
2. Margin of Compliance – The margin of compliance is a measure of whether the facility can easily achieve compliance with a requirement, or whether they operate close to an exceedance. NWCAA considered the facility's margin of compliance for each underlying requirements in setting monitoring for that requirement.
3. Variability of Process and Emissions – Processes that vary their production rates and/or emissions over time (e.g., batch loading of grain silos, VOC emissions from lumber drying kilns) require different monitoring from steady-state processes. NWCAA considered process and emission variability in setting monitoring.
4. Environmental Impact of a Problem – Exceedances of some permit requirements have greater environmental consequences than others. For example, a problem that causes an exceedance of a refinery sulfur plant limit could have a greater environmental impact

than failing to use ultra-low sulfur diesel at an emergency generator. NWCAA considered the environmental impact of a problem in setting monitoring.

5. Clarity and Complexity – The requirements that apply to AOP facilities are numerous, varied, and can be complex. The greater number, variety, and complexity of requirements, the harder it is for a facility to understand and comply. NWCAA's goal is to write clear, concise permits the facilities can understand. To help achieve this goal, when possible, NWCAA aligned additional monitoring with monitoring that the facility is already performing. This approach required careful thought. NWCAA reviewed the monitoring the facility is already performing to see if it was adequate to stand-in as monitoring for the permit term, and only used it if deemed adequate. For example, an older storage tank may have a NWCAA construction permit that didn't list monitoring. The same tank may also be subject to 40 CFR 60 Subpart Kb. Subpart Kb monitoring would only be used as the gap-filled (or sufficiency monitoring) if we found it was adequate to show compliance with the construction permit.

Table 4-1 lists where in the AOP NWCAA used its gap-filling monitoring authority.

Table 4-1: Gap-filling under WAC 173-401-615

AOP Terms	Description	Monitoring
4.2	Operation & maintenance	Monitor, keep records & report
4.3-4.13, 4.15	Nuisance (contaminants, odors, PM, fugitives)	Written air contaminant response plan
4.16, 5.2.3, 5.3.33, 5.5.4, 5.5.19, 5.5.30, 5.6.12, 5.6.30, 5.6.31, 5.8.11, 5.9.3, 5.9.12, 5.10.3, 5.11.3, 5.12.8, 5.12.15, 5.13.1, 5.13.10, 5.13.19	Visible emissions	Visible emission observation monitoring
4.18	Weight/heat rate standard – sulfur compounds	Maintain records of refinery calendar monthly average SO_2, lb/MMBtu
4.19-4.22	Emissions of sulfur compounds	Monitor & record concentration of sulfur content of fuel gas, or alternatively, stack SO_2
4.23	Sulfur in fuel	Retain fuel specifications & purchase records
4.26	Equipment reduction, collection & disposal of VOC; noncondensable VOC reduction, collection & disposal - closed vent systems routed to flare; tightly covered hot wells - contact condensers	Written documentation of operation & maintenance activities

AOP Terms	Description	Monitoring
5.1.1, 5.1.6, 5.1.7, 5.1.17, 5.2.1, 5.3.1, 5.3.15, 5.3.20, 5.3.30, 5.5.1, 5.5.2, 5.5.12, 5.5.16, 5.5.17, 5.5.27, 5.5.28, 5.6.1, 5.6.10, 5.8.10, 5.9.1, 5.9.2, 5.9.10, 5.9.11, 5.10.1, 5.11.1, 5.13.8, 5.13.17	Combust gaseous fuel	Certify annually that only approved fuels were combusted
5.1.13	Emissions not to exceed mass hourly limit	Determine continuous compliance using emission factor generated during most recent source test.
5.1.15, 5.3.16, 5.3.31, 5.5.29	Firing rate limit	Recordkeeping
5.7.5	PSD operating mode definitions	Recordkeeping
5.1.28, 5.1.29	VOC controls for hot wells	Recordkeeping
5.3.36, 5.3.37	Emissions not to exceed mass hourly and 12-month rolling limits	Conduct source testing, maintain records
5.12.16	Emissions not to exceed mass limit	Recordkeeping
5.13.31	Hydrocarbon monitor	Recordkeeping
5.15.8	Emissions not to exceed mass limit	Conduct source testing. Alternative test method may be used
5.15.11-5.15.13, 5.15.15, 5.15.17, 5.15.18, 5.15.21, 5.15.26	Truck Loading Rack vapor control system	Operate and inspect system according to requirements in OMMP or FR, recordkeeping
5.15.20	Gasoline transport tank tightness	Recordkeeping
5.15.22	Truck Loading Rack emissions	Report annually in emission inventory
5.15.27	Truck Loading Rack spills	Comply with general duty to minimize emissions
5.15.33-5.15.36, 5.15.46	Marine Loading Vapor Control	Monitoring, recordkeeping, reporting
5.17.14-5.17.16, 5.17.18	WWTP IFR Tanks	Comply with Subpart Kb
5.18.1-5.18.3, 5.18.6	IFR Tanks	Comply with Subpart CC
5.18.8	IFR Tanks	Recordkeeping

AOP Terms	Description	Monitoring
5.18.13-5.18.15	IFR Tanks	Comply with Subpart Kb
5.6.25, 5.6.26	SEPA MDNS	Certify compliance annually
6.1	Opacity monitoring	As described in AOP Term 6.1

Table 4-2 lists where in the AOP NWCAA used its sufficiency monitoring authority.

Table 4-2: Sufficiency Monitoring under WAC 173-401-630(1)

AOP Terms	Description	Monitoring
4.1	Required monitoring reports	Reporting periods identified
4.14	Visible emissions	VE observation monitoring
4.17	Ambient SO_2	Reporting
5.1.3	H_2S in fuel gas	Reporting
5.6.13, 5.6.21, 5.7.2, 5.7.9, 5.7.10, 5.11.4	Emissions not to exceed performance based limit	Report certain parameters in source test report
5.7.6, 5.7.7	Emissions not to exceed limits based on operating mode	Maintain records of operating mode
5.2.6, 5.2.7, 5.5.10,5.9.8, 5.13.5, 5.15.5	Emissions not to exceed mass limit	Alternative test method may be used
5.6.3, 5.12.9	H_2S limit in fuel gas	Reporting
	Emissions not to exceed 12-month rolling limit	Conduct source testing, maintain records
5.12.6, 5.12.7, 5.12.11, 5.12.13	Emission limit based on WESP operation	Recordkeeping
5.1.16, 5.12.5, 5.12.10, 5.12.12	Emission limit monitored by CEMS	Recordkeeping
5.15.14	Gauge pressure limit	Recordkeeping
5.17.2	Oily wastewater drain system requirements	Monthly inspections
6.3.1, 6.3.2, 6.3.7, 6.3.9	LDAR for pumps and valves	Calibration requirements
6.3.4	LDAR for pressure relief devices	Calibration requirements

4.2 <u>Permit Elements</u>

The permit is organized in the following sequence:

Permit Information

Attest

Table of Contents

Section 1 - Emission Unit Identification

Section 2 - Standard Terms and Conditions

Section 3 - Standard Terms and Conditions for NSPS and NESHAP

Section 4 - Generally Applicable Requirements

Section 5 - Specific Applicable Requirements

Section 6 - Specific Applicable Common Requirements

Section 7 - Inapplicable Requirements

Section 8 – Definitions and Acronyms

AOP Sections 2 through 6 include citations to applicable requirements (e.g., regulations and OACs) and a summary of that requirement. In addition, Sections 4 through 6 include the monitoring, recordkeeping and reports (MR&R) obligations for each requirement.

4.2.1 Permit Information and Attest Pages.

The Information Page identifies the facility, the responsible corporate official, and the agency personnel responsible for permit preparation, review, and issuance. The Attest section provides NWCAA's authorization for the source to operate under the terms and conditions contained in the permit.

4.2.2 Emission Unit Identification

AOP Section 1 entitled "Emission Unit Identification" is a non-enforceable section of the permit that is meant to list and provide relevant information on significant emission units at the refinery. It includes emission unit identification numbers, size of the unit, control equipment where applicable, fuel type, and other related comments. The emission unit identification number commonly used at the refiner is the process unit/area number followed by the equipment number.

4.2.3 Standard Terms and Conditions

AOP Sections 2 and 3 entitled "Standard Terms and Conditions" contain 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 clarity 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. An example of these would be the requirement to file a "Notice of Construction and Application for Approval" prior to construction a new emissions unit.

The Standard Terms and Conditions for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutant (NESHAP), AOP Section 3, specifies administrative requirements or prohibitions with no ongoing compliance monitoring requirements. The conditions in this section are taken from the "General Provisions" of 40 CFR Parts 60, 61, and 63. They apply specifically to the affected sources, affected facilities, or stationary sources subject to the standards of 40 CFR Parts 60, 61, and 63.

4.2.4 Generally Applicable Requirements

AOP Section 4 entitled "Generally Applicable Requirements" 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 AOP 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 last column lists the monitoring, recordkeeping and reporting (MR&R) requirements. The MR&R is a summary of the underlying requirement cited in the "citation" column and is not directly enforceable. However, when there is text in the MR&R column that states, "Directly Enforceable", all text below that statement has been added by the NWCAA as part of the agency's gap-filling or sufficiency monitoring authority (discussed above), found in WAC 173-401-615(b) and WAC 173-401-630, and these gap-filled requirements are enforceable.

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. Note that the facility must certify annual compliance with each term even if there are no explicit MR&R requirements.

4.2.5 Specifically Applicable Requirements

AOP Section 5 entitled "Specifically Applicable Requirements" lists requirements that are specific to the individual emission units within the refinery. Each table in Section 5 represents a refinery process unit or area. Within each table emission units (EU) are presented in order of their size. As a general practice heaters are presented first, followed by vents, drains and lastly fugitive emissions components. For each emission unit, permit terms are generally presented in the following manner: general, visual emissions (VE), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NOX), carbon monoxide (CO), volatile organic compounds (VOC) and hazardous air pollutants (HAP).

The emission limitations and monitoring, recordkeeping and reporting requirements are derived from the underlying requirements that are cited in the second column. 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 in many of the heater and boiler stacks to continuously monitor the concentration of gaseous pollutants including NOx and CO, as well as H_2S and total reduced sulfur (TRS) as surrogates to SO_2. Pollutant concentration values are also used to determine compliance with mass emission limits such as lb/hour or tons per year limits given flue gas flow rates which are often calculated based on the amount of refinery flue gas that is combusted. Pollutants not continuously monitored, such as visible emissions, PM, NH_3 and VOC, are monitored periodically through visible emission observations and source testing and may be supplemented with continuous parameter monitoring to ensure on-going compliance.

4.2.6 Specifically Applicable Common Requirements

Section 6 entitled "Specifically Applicable Common Requirements" includes:

Ongoing compliance with visual emissions standards (i.e., 20% opacity under NWCAA 451 and/or more stringent NSR conditions) are qualitatively assessed by conducting periodic visual observations of the refinery stacks. Unless otherwise specified in the term, the MR&R for visual emissions is found in Section 6 of the permit which is called "Specifically Applicable Common Requirements". Under Section 6.1 the permittee must periodically conduct visual observations of the refinery stacks. If visible emissions are observed, the permittee must reduce to zero, or take certified opacity readings using Method Ecology 9A within 24 hours of observing the visual emissions. Visual emissions are considered to be in excess of the applicable opacity limit if a certified reading is not taken. Some emission units have specifically applicable requirements that require more frequent visual observations than those of Section 6.1.

Visual observation monitoring under Section 6.1 is also used to determine ongoing compliance with various particulate emission standards (e.g., 0.05 grain/dscf under NWCAA 455). Although particulate emission rates are not directly linked to opacity, a zero percent opacity action level is likely to ensure that emissions are less than the applicable grain loading standard. This surrogate monitoring approach ensures proper operation of equipment, thereby reducing the potential for particulate emissions of the emissions unit.

Section 6 includes requirements that apply to a number of emission units located throughout the refinery under OAC 211c. Section 6 also includes the leak detection and repair (LDAR) requirements of 40 CFR 60 Subpart VV and Subpart VVa that apply to equipment components located at a variety of process units, Boiler MACT requirements, and pressure relief device Refinery MACT requirements.

4.2.7 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.

4.2.8 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 and not included in the air operating permit.

4.3 Public Docket

Copies of the Cherry Point Refinery's Air Operating Permit, permit application, and technical support documents are available online at www.nwcleanairwa.gov or at the following location:

Northwest Clean Air Agency
1600 South Second Street
Mount Vernon, WA 98273-5202

4.3.1 Public Comment Period

A 30-day comment period was conducted from April 25, 2022, to May 25, 2022. Notice was posted in the Washington Department of Ecology's Permit Register as well as on the NWCAA website. Copies of the draft permit and statement of basis were available on the NWCAA website and mailed or emailed to the public upon request throughout the public comment period.

During this comment period the agency received no comments.

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:

ACO	Agreed Compliance Order
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
Btu	British thermal unit
BQ6	Benzene waste Quantity under 6 Mg/yr (wastewater)
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEM	continuous emission monitor
CEMS	continuous emission monitoring system
CI-ICE	Compression Ignition – Internal Combustion Engine
CFM	cubic feet per minute
COM	continuous opacity monitor
CFR	Code of Federal Regulations
CPMS	continuous parameter monitoring system
CRU	Catalytic Reforming Unit
DAF	Dissolved Air Floatation (wastewater)
DHDS	Diesel Hydrodesulfurization Unit
DCU	Delayed Coking Unit
EFR	External Floating Roof (tank)
EPA	United States Environmental Protection Agency
ERC	Emission Reduction Credit
ESP	Electrostatic Precipitator
FCAA	Federal Clean Air Act
FCCU	Fluid Catalytic Cracking Unit
FGR	Flue Gas Recirculation
HAP	Hazardous Air Pollutants
HC	hydrocarbon
HHV	Higher Heating Value (heat content of fuel)
HON	Hazardous Organic NESHAP
HTU	Hydrotreater Unit
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
hp	horsepower, brake
HRSG	heat recovery steam generator

HSR	Heavy Straight Run
IFR	Internal Floating Roof (tank)
IHT	Isomerization Process Heater
ISO	International Standards Organization
kPa	kilopascals (10^3 pascals pressure)
LDAR	leak detection and repair
LNB	Low-NOx Burner
LEL	lower explosive limit
LTPD	Long tons per day (imperial ton, 2,240 pounds)
MACT	Maximum Achievable Control Technology
MDEA	methyl-diethanolamine
Mg	megagrams (10^6 grams mass)
MMBtu	million British thermal units
MMSCFD	million standard cubic feet per day
MPS	meters per second
MR&R	monitoring, recordkeeping and reporting requirements
MTVP	maximum true vapor pressure
NIST	National Institute of Standards and Technology
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	part per million by volume, dry
ppmw	part per million by weight
psia	pounds per square inch absolute
PTE	Potential to Emit (annual, unless otherwise noted)
PRD	pressure relief device
QA/QC	quality assurance/quality control
RCW	Revised Code of Washington
RICE	Reciprocation Internal Combustion Engine
RO	Regulatory Order (issued by the NWCAA)
SCF	Standard cubic feet
SCFM	Standard cubic feet per minute
SCR	selective catalytic reduction
SEPA	State Environmental Policy Act
SMR	steam methane reformer
SOB	Statement of Basis (AOP)
SOP	Standard Operating Procedure
SRU	Sulfur Recovery Unit
SIP	State Implementation Plan
SO_2	sulfur dioxide
TAB	Total Annual Benzene
TGTU	Tail Gas Treating Unit
TPY (tpy)	Tons per Year
TVP	True Vapor Pressure
ULNB	Ultra-Low NOx Burner (designed for ≤ 0.04 lb/MMBtu)
VE	Visual Emissions
VPS	Vacuum Pipe Still (Crude Unit)

VOC	volatile organic compounds
VOL	volatile organic liquid
WAC	Washington Administration Code
WDOE	Washington State Department of Ecology (Ecology)
WESP	wet electrostatic precipitator
WWSG	Waste Water Stripper Gas

5 PREVIOUS CHANGES TO AOP 015R1

This section provides a summary of changes to AOP 015R1 but does not include a discussion of changes made during the current renewal (changes made to AOP 015R1M1). Changes incorporated into the current renewal are addressed in Sections 1-4 of this document.

Additional detail regarding construction permit history or issued OACs, can be found in the specific permitting documentation.

In accordance with WAC 173-401-730, the NWCAA has a legal requirement to incorporate new and revised OACs, regulatory orders, and regulations into the AOP. The April 2014 modification meets this requirement. The following changes were made to the AOP:

5.1.1 Best Available Retrofit Technology (BART) Order 7836, Revision 1

The Washington Department of Ecology issued revision 1 to BART Order 7836 on August 16, 2013. This revision removed references to Boiler 6 and Boiler 7 from the BART Order as these units were not BART eligible. BART Order 7836 was replaced by BART Order 7836 Revision 1 in the AOP.

5.1.2 Boiler MACT – 40 CFR 63 Subpart DDDDD

The Boiler MACT wasn't final as of the date AOP 015R1 was issued. The regulation has since been finalized. The Cherry Point Refinery operates refinery gas fueled units which are affected sources under the rule. The applicable Boiler MACT requirements for affected units were added to the AOP.

5.1.3 OAC 1001 Revision C (OAC 1001c)

BP requested a modification to OAC 1001, which approved the operation of the #6 and #7 utility boilers. The changes requested by BP were approved under OAC 1001c. OAC 1001c superseded OAC 1001b, which was previously listed in AOP 015R1. OAC 1001b was removed from the AOP, and OAC 1001c was added in its place.

5.1.4 OAC 1064 Revision A (OAC 1064a)

BP requested a modification to OAC 1064, which approved a new hydrogen plant and new diesel hydro-desulfurization unit as part of BP's Clean Fuels project. The changes requested by BP were approved under OAC 1064a. OAC 1064a superseded OAC 1064, which was previously listed in AOP 015R1. OAC 1064 was removed from the AOP, and OAC 1064a was added in its place.

5.1.5 OAC 1142

OAC 1142 approved the construction of the new crude oil railcar unloading terminal. OAC 1142 was issued on January 22, 2013, which was after the issuance date of AOP 015R1. The OAC has been added to Emission Unit 15, Shipping, Pumping, and Receiving.

5.1.6 Other Changes

Corrected typo to the description of the regulatory requirements in several sections.

Changed regulatory citation in AOP term 5.17.8 dealing with 40 CFR 61 Subpart FF. There are compliance options in Subpart FF. The Cherry Point Refinery has chosen to comply with the 10 ppm flow-weighted annual average limit, measured at the biodegradation unit. A change was made to the AOP to list this option instead of the option to comply with the benzene limit in the NPDES permit.

Clarified applicability of opacity monitoring to calciners, incinerators, and tail gas units. Clarified actions the Cherry Point Refinery must take if Ecology Method 9A monitoring shows visible emissions are below the applicable limit.

Approved the use of test method CTM-13B for OAC required testing at the calciners.

Added information to the statement of basis about when the NWCAA may approve testing under 90% steam load conditions, vs. testing under 90% of max heat input.

APPENDIX A – SOURCE TEST RESULTS FOR THE PREVIOUS PERMIT PERIOD

Date Performed	Equipment	Pollutant	Pass/Fail
8/26/2014	North Vacuum Heater 10-1452	NOx	Pass
8/27/2014	No. 2 DHDS 26-1401	CO	Pass
8/27/2014	No. 2 DHDS 26-1401	NOx	Pass
9/11/2014	Marine Terminal Vapor Combustor		Pass
9/24/2014	No. 4 Boiler 30-1604	CO	Pass
10/7/2014	No. 6 Boiler	NH3	Pass
10/9/2014	No. 7 Boiler	NH3	Pass
10/13/2014	No. 2 Tail Gas Unit	SO2	Pass
10/15/2014	IHT Heater	CO	Pass
10/15/2014	IHT Heater	NOx	Pass
10/16/2014	No. 5 Boiler	CO	Pass
10/21/2014	HC 1st Stage Fractionator Reboiler	CO	Pass
10/23/2014	HC 2nd Stage Fractionator Reboiler	NOx	Pass
12/17/2014	Boiler No. 7 PM	PM10	Pass
3/1/2015	Hydrocracker 1st Stage Reactor Heater	CO	Pass
3/1/2015	Hydrocracker 1st Stage Reactor Heater	NOx	Pass
7/1/2015	#2 Hydrogen Plant SMR Furnace	NH3	Pass
7/1/2015	#2 Hydrogen Plant SMR Furnace	PM10	Pass
7/1/2015	#2 Hydrogen Plant SMR Furnace	VOC	Pass
7/7/2015	North Coker Charge Heater	CO	Pass
7/7/2015	North Coker Charge Heater	NOx	Pass
7/7/2015	North Coker Charge Heater	SO2	Pass
7/9/2015	No. 1 Diesel HDS Charge Heater	CO	Pass
7/15/2015	Truck Rack Vapor Combustor	VOC	Pass
7/24/2015	Calciner Nos. 1 & 2 (Stack No. 1)	H2S04+SO3	Pass
7/24/2015	Calciner No. 3 (Stack No. 2)	H2S04+SO3	Pass
7/30/2015	High Pressure Flare	VE	Pass
7/30/2015	Low Pressure Flare	VE	Pass
8/15/2015	Calciner No. 3 (Stack No. 2)	PM10	Pass
8/15/2015	Calciner No. 3 (Stack No. 2)	SO2	Pass
8/20/2015	No. 1 DHDS Stabilizer Reboiler	CO	Pass
8/20/2015	No. 2 DHDS Charge Heater	CO	Pass
8/20/2015	No. 2 DHDS Charge Heater	NOx	Pass
8/25/2015	North Vacuum Heater	NOx	Pass
8/27/2015	No. 4 Boiler	CO	Pass
9/15/2015	No. 1 TGU Incinerator	CO	Pass
9/15/2015	No. 1 TGU Incinerator	NOx	Pass
9/15/2015	No. 1 TGU Incinerator	SO2	Pass
9/17/2015	No. 2 Tail Gas Unit	SO2	Pass
9/18/2015	Marine Terminal Vapor Combustor		Pass
10/6/2015	Boiler No. 6	NH3	Pass
10/10/2015	Boiler No. 7	NH3	Pass
10/10/2015	Boiler No. 7	PM	Pass
10/13/2015	No. 5 Boiler	CO	Pass
10/20/2015	HC 1st Stage Fractionator Reboiler	CO	Pass
10/20/2015	HC 2nd Stage Fractionator Reboiler	NOx	Pass
11/2/2015	No. 2 Reformer Heater	CO	Pass

11/2/2015	No. 2 Reformer Heater	NOx	Pass
11/17/2015	Isomerization Heater (45-1402)	CO	Pass
11/17/2015	Isomerization Heater (45-1402)	NOx	Pass
12/3/2015	RETEST Isomerization Heater (45-1402)	NOx	Pass
2/22/2016	North Vacuum Heater	NOx	Pass
2/25/2016	Hydrocracker 1st Stage Reactor Heater	CO	Pass
4/11/2016	High Pressure Flare	H2S	Pass
4/11/2016	High Pressure Flare	VE	Pass
4/12/2016	Low Pressure Flare	H2S	Pass
4/12/2016	Low Pressure Flare	VE	Pass
5/11/2016	Boiler No. 6	NH3	Pass
5/12/2016	Boiler No. 7	NH3	Pass
5/17/2016	IHT Heater	CO	Pass
5/17/2016	IHT Heater	NOx	Pass
7/12/2016	Calciner Nos. 1 & 2 (Stack No. 1)	H2S04+SO3	Pass
7/26/2016	No. 3 DHDS Charge Heater	CO	Pass
7/26/2016	No. 3 DHDS Charge Heater	NOx	Pass
7/26/2016	No. 3 DHDS Charge Heater	PM2.5	Pass
7/26/2016	No. 3 DHDS Charge Heater	SO2	Pass
7/28/2016	No. 4 Boiler	CO	Pass
7/28/2016	No. 2 Hydrogen SMR Furnace	NH3	Pass
7/28/2016	No. 2 Hydrogen SMR Furnace	PM10	Pass
7/28/2016	No. 2 Hydrogen SMR Furnace	VOC	Pass
8/2/2016	Calciner No. 3 (Stack No. 2)	H2S04+SO3	Pass
8/2/2016	Calciner No. 3 (Stack No. 2)	PM10	Pass
8/2/2016	Calciner No. 3 (Stack No. 2)	SO2	Pass
8/16/2016	#2 DHDS Charge Heater (EU ID 26-1401)	CO	Pass
8/16/2016	#2 DHDS Charge Heater (EU ID 26-1401)	NOx	Pass
8/23/2016	No. 1 TGU Incinerator (EU ID 17-1481)	CO	Pass
8/23/2016	No. 1 TGU Incinerator (EU ID 17-1481)	NOx	Pass
8/23/2016	No. 1 TGU Incinerator (EU ID 17-1481)	SO2	Pass
8/26/2016	No. 2 Tail Gas Unit (EU ID 25)	SO2	Pass
8/29/2016	Hydrocracker 1st Stage Fractionator Reboiler	CO	Pass
8/31/2016	Hydrocracker 2nd Stage Fractionator Reboiler	NOx	Pass
9/19/2016	No. 5 Boiler (EU ID 30-1606)	CO	Pass
9/22/2016	Marine Terminal Vapor Combustor		Pass
2/14/2017	North Vacuum Heater (EU 10-1452)	NOx	Pass
2/17/2017	Hydrocracker 1st Stage Reactor Heater R1	CO	Pass
2/17/2017	Hydrocracker 1st Stage Reactor Heater R1	NOx	Pass
2/20/2017	No. 2 Hydrogen SMR Furnace	NH3	Pass
2/20/2017	No. 2 Hydrogen SMR Furnace	PM10	Pass
2/20/2017	No. 2 Hydrogen SMR Furnace	VOC	Pass
3/21/2017	Truck Rack Vapor Combustor (33-151)	VOC	Pass
4/11/2017	#2 Hydrogen Plant, Flare (46-2803)		Pass
4/11/2017	#2 Hydrogen Plant, Flare (46-2803)	PM	Pass
6/8/2017	#6 Boiler (30-1607)	NH3	Pass
6/22/2017	#7 Boiler (30-1608)	NH3	Pass
6/26/2017	South Coker Charge Heater (12-1401-02)	CO	Pass
6/26/2017	South Coker Charge Heater (12-1401-02)	NOx	Pass

6/26/2017	South Coker Charge Heater (12-1401-02)	SO2	Pass
6/28/2017	#4 Boiler (30-1604)	CO	Pass
7/14/2017	#1 and #2 Calciners, Stack #1 (20-70)	H2S04+SO3	Pass
7/19/2017	#3 Calciner, Stack #2 (20-71)	H2S04+SO3	Pass
7/19/2017	#3 Calciner, Stack #2 (20-71)	PM10	Pass
7/19/2017	#3 Calciner, Stack #2 (20-71)	SO2	Pass
8/15/2017	#2 Diesel HDS Charge Heater (26-1401)	CO	Pass
8/15/2017	#2 Diesel HDS Charge Heater (26-1401)	NOx	Pass
8/16/2017	Incinerator (17-1481)	CO	Pass
8/16/2017	Incinerator (17-1481)	NOx	Pass
8/16/2017	Incinerator (17-1481)	SO2	Pass
8/17/2017	#2 Tail Gas Unit (25)	SO2	Pass
8/22/2017	#2 Reformer Heater (21-1421:1424)	CO	Pass
8/22/2017	#2 Reformer Heater (21-1421:1424)	NOx	Pass
8/23/2017	Hydrocracker 2nd Stage Fractionator Reboiler (15-1452)	NOx	Pass
8/24/2017	Hydrocracker 1st Stage Fractionator Reboiler (15-1451)	CO	Pass
9/11/2017	#5 Boiler (30-1606)	CO	Pass
9/14/2017	Isomerization Heater (45-1402)	CO	Pass
9/14/2017	Isomerization Heater (45-1402)	NOx	Pass
9/15/2017	Marine Terminal, Vapor Combustor (35-161)		Pass
2/6/2018	#2 Hydrogen Plant, SMR Furnace (46-1401)	NH3	Pass
2/6/2018	#2 Hydrogen Plant, SMR Furnace (46-1401)	PM2.5	Pass
2/6/2018	#2 Hydrogen Plant, SMR Furnace (46-1401)	VOC	Pass
2/13/2018	North Vacuum Heater (10-1452)	NOx	Pass
2/15/2018	Hydrocracker 1st stage reactor heater, R-1 (15-1401)	CO	Pass
5/16/2018	#6 Boiler (30-1607)	NH3	Pass
5/16/2018	#6 Boiler (30-1607)	PM10	Pass
5/18/2018	#7 Boiler (30-1608)	NH3	Pass
6/5/2018	#4 Boiler (30-1604)	CO	Pass
7/12/2018	#1 and #2 Calciners, Stack #1 (20-70)	H2S04+SO3	Pass
7/19/2018	#3 Calciner, Stack #2 (20-71)	H2S04+SO3	Pass
7/19/2018	#3 Calciner, Stack #2 (20-71)	PM10	Pass
7/19/2018	#3 Calciner, Stack #2 (20-71)	SO2	Pass
7/31/2018	#1 Diesel HDS Charge Heater (13-1401)	CO	Pass
8/1/2018	#1 Diesel HDS Stabilizer Reboiler (13-1402)	CO	Pass
8/14/2018	#2 Diesel HDS Charge Heater (26-1401)	CO	Pass
8/14/2018	#2 Diesel HDS Charge Heater (26-1401)	NOx	Pass
8/15/2018	Incinerator (17-1481)	CO	Pass
8/15/2018	Incinerator (17-1481)	NOx	Pass
8/15/2018	Incinerator (17-1481)	SO2	Pass
8/20/2018	#2 Tail Gas Unit (25)	SO2	Pass
8/22/2018	Hydrocracker 1st Stage Fractionator Reboiler (15-1451)	CO	Pass

8/23/2018	Hydrocracker 2nd Stage Fractionator Reboiler (15-1452)	NOx	Pass
9/11/2018	Marine Terminal, Vapor Combustor (35-161)		Pass
9/11/2018	Isomerization Heater (45-1402)	CO	Pass
9/11/2018	Isomerization Heater (45-1402)	NOx	Pass
12/4/2018	#5 Boiler (30-1606)	CO	Pass
12/5/2018	No. 2 Hydrogen Pressure Swing Adsorption (PSA) bed		N/A
12/5/2018	No. 2 Hydrogen Pressure Swing Adsorption (PSA) bed	BZ	N/A
12/5/2018	No. 2 Hydrogen Pressure Swing Adsorption (PSA) bed	C9H12	N/A
2/5/2019	North Vacuum Heater (10-1452)	NOx	Pass
2/8/2019	Hydrocracker 1st stage reactor heater, R-1 (15-1401)	CO	Pass
2/8/2019	Hydrocracker 1st stage reactor heater, R-1 (15-1401)	NOx	Pass
3/21/2019	#2 Hydrogen Plant, SMR Furnace (46-1401)	NH3	Pass
3/21/2019	#2 Hydrogen Plant, SMR Furnace (46-1401)	PM2.5	Pass
3/21/2019	#2 Hydrogen Plant, SMR Furnace (46-1401)	VOC	Pass
6/6/2019	#6 Boiler (30-1607)	NH3	Pass
6/7/2019	#7 Boiler (30-1608)	NH3	Pass
6/18/2019	#4 Boiler (30-1604)	CO	Pass
7/23/2019	#1 and #2 Calciners, Stack #1 (20-70)	H2S04+SO3	Pass
7/31/2019	#3 Calciner, Stack #2 (20-71)	H2S04+SO3	Pass
7/31/2019	#3 Calciner, Stack #2 (20-71)	PM10	Pass
7/31/2019	#3 Calciner, Stack #2 (20-71)	SO2	Pass
8/6/2019	No. 3 DHDS Charge Heater	CO	Pass
8/6/2019	No. 3 DHDS Charge Heater	NOx	Pass
8/6/2019	No. 3 DHDS Charge Heater	PM2.5	Pass
8/6/2019	No. 3 DHDS Charge Heater	SO2	Pass
8/13/2019	Hydrocracker 1st Stage Fractionator Reboiler (15-1451)	CO	Pass
8/14/2019	Hydrocracker 2nd Stage Fractionator Reboiler (15-1452)	NOx	Pass
8/15/2019	#2 Reformer Heater (21-1421:1424)	CO	Pass
8/15/2019	#2 Reformer Heater (21-1421:1424)	NOx	Pass
9/9/2019	North Vacuum Heater (10-1452)	NOx	Pass
9/9/2019	North Vacuum Heater (10-1452)	PM10	Pass
9/11/2019	Isomerization Heater (45-1402)	CO	Pass
9/11/2019	Isomerization Heater (45-1402)	NOx	Pass
9/12/2019	Marine Terminal, Vapor Combustor (35-161)		Pass
9/13/2019	#5 Boiler (30-1606)	CO	Pass
9/17/2019	#2 Tail Gas Unit (25)	SO2	Pass
9/18/2019	Incinerator (17-1481)	CO	Pass
9/18/2019	Incinerator (17-1481)	NOx	Pass

9/18/2019	Incinerator (17-1481)	SO2	Pass
9/19/2019	#2 Diesel HDS Charge Heater (26-1401)	CO	Pass
9/19/2019	#2 Diesel HDS Charge Heater (26-1401)	NOx	Pass
10/11/2019	East Coker Charge Heater	H2SO4	Pass
10/11/2019	East Coker Charge Heater	NOx	Pass
10/11/2019	East Coker Charge Heater	PM	Pass
10/11/2019	East Coker Charge Heater	VOC	Pass
10/16/2019	West Coker Charge Heater	H2SO4	Pass
10/16/2019	West Coker Charge Heater	NOx	Pass
10/16/2019	West Coker Charge Heater	PM	Pass
10/16/2019	West Coker Charge Heater	VOC	Pass
2/12/2020	Hydrocracker 1st stage reactor heater, R-1 (15-1401)	CO	Pass
3/18/2020	#2 Hydrogen Plant, SMR Furnace (46-1401)	NH3	Pass
3/18/2020	#2 Hydrogen Plant, SMR Furnace (46-1401)	PM2.5	Pass
3/18/2020	#2 Hydrogen Plant, SMR Furnace (46-1401)	VOC	Pass
4/29/2020	#6 Boiler (30-1607)	NH3	Pass
5/1/2020	#7 Boiler (30-1608)	NH3	Pass
5/1/2020	#7 Boiler (30-1608)	PM	Pass
6/22/2020	#4 Boiler (30-1604)	CO	Pass
7/24/2020	#3 Calciner, Stack #2 (20-71)	H2S04+SO3	Pass
7/24/2020	#3 Calciner, Stack #2 (20-71)	PM10	Pass
7/24/2020	#3 Calciner, Stack #2 (20-71)	SO2	Pass
8/4/2020	#5 Boiler (30-1606)	CO	Pass
8/7/2020	Marine Terminal, Vapor Combustor (35-161)		Pass
8/19/2020	#1 and #2 Calciners, Stack #1 (20-70)	H2S04+SO3	Pass
8/25/2020	Hydrocracker 2nd Stage Fractionator Reboiler (15-1452)	NOx	Pass
8/27/2020	Hydrocracker 1st Stage Fractionator Reboiler (15-1451)	CO	Pass
9/15/2020	Isomerization Heater (45-1402)	CO	Pass
9/15/2020	Isomerization Heater (45-1402)	NOx	Pass
9/16/2020	#2 Diesel HDS Charge Heater (26-1401)	CO	Pass
9/16/2020	#2 Diesel HDS Charge Heater (26-1401)	NOx	Pass
9/29/2020	#2 Tail Gas Unit (25)	SO2	Pass
9/30/2020	Incinerator (17-1481)	CO	Pass
9/30/2020	Incinerator (17-1481)	NOx	Pass
9/30/2020	Incinerator (17-1481)	SO2	Pass
10/7/2020	East Coker Charge Heater	PM	Pass
10/10/2020	West Coker Charge Heater	PM	Pass
2/15/2021	Hydrocracker 1st stage reactor heater, R-1 (15-1401)	CO	Pass
2/15/2021	Hydrocracker 1st stage reactor heater, R-1 (15-1401)	NOx	Pass
2/18/2021	#6 Boiler (30-1607)	NH3	Pass
2/19/2021	#7 Boiler (30-1608)	NH3	Pass
2/19/2021	#7 Boiler (30-1608)	PM	Pass

3/18/2021	#2 Hydrogen Plant, SMR Furnace (46-1401)	NH3	Pass
3/18/2021	#2 Hydrogen Plant, SMR Furnace (46-1401)	PM2.5	Pass
3/18/2021	#2 Hydrogen Plant, SMR Furnace (46-1401)	VOC	Pass
6/15/2021	#4 Boiler (30-1604)	CO	Pass
7/14/2021	#1 and #2 Calciners, Stack #1 (20-70)	H2S04+SO3	Pass
7/22/2021	#3 Calciner, Stack #2 (20-71)	H2S04+SO3	Pass
7/22/2021	#3 Calciner, Stack #2 (20-71)	PM10	Pass
7/22/2021	#3 Calciner, Stack #2 (20-71)	SO2	Pass
7/28/2021	No. 1 DHDS Stabilizer Reboiler	CO	Pass
7/27/2021	No. 1 DHDS Charge Heater	CO	Pass
7/29/2021	Marine Terminal, Vapor Combustor (35-161)		Pass
8/12/2021	#5 Boiler (30-1606)	CO	Pass
8/10/2021	#2 Reformer Heater (21-1421:1424)	CO	Pass
8/10/2021	#2 Reformer Heater (21-1421:1424)	NOx	Pass
10/21/2021	East Coker Charge Heater	PM	Pass
10/21/2021	West Coker Charge Heater	PM	Pass
9/15/2021	Hydrocracker 2nd Stage Fractionator Reboiler (15-1452)	NOx	Pass
9/15/2021	Hydrocracker 1st Stage Fractionator Reboiler (15-1451)	CO	Pass
11/19/2021	#2 Tail Gas Unit (25)	SO2	Pass
11/19/2021	Incinerator (17-1481)	CO	Pass
11/19/2021	Incinerator (17-1481)	NOx	Pass
11/19/2021	Incinerator (17-1481)	SO2	Pass
11/22/2021	Isomerization Heater (45-1402)	CO	Pass
11/22/2021	Isomerization Heater (45-1402)	NOx	Pass

APPENDIX B – REFERENCED APPLICABILITY DETERMINATION INDEX DOCUMENTS FOR 40 CFR 60 SUBPART NNN

U.S. Environmental Protection Agency
Applicability Determination Index

Control Number: M020014

Category: MACT
EPA Office: Region 4
Date: 09/27/2002
Title: Gas Streams Combusted in Fuel Gas System
Recipient: Jerry Cain
Author: R. Douglas Neeley

Subparts: Part 63, F, HON
Part 63, G, HON

References: 60.661
60.701
63.101
63.107
63.110(d)(10)

Abstract:

Q: A refinery has process area reactors and distillation columns whose only gas streams are combusted in the refinery's fuel gas system. These gas streams are exempt from any compliance monitoring requirements under 40 CFR Part 63 Subpart G. Does 40 CFR 63.110(d)(10) also exempt those gas streams from the requirements of NSPS Subparts NNN and RRR?

A: No. Section 63.110(d)(10) does not exempt the gas streams from meeting the requirements of NSPS Subparts NNN and RRR.

Letter:

September 27, 2002

4APT-ATMB

Jerry W. Cain, P.E., DEE
Chief
Environmental Permits Division
Mississippi Department of Environmental Quality
P.O. Box 10385
Jackson, Mississippi 39289-0385

Dear Mr. Cain:

We have received your July 29, 2002, letter requesting a determination concerning the applicability of New Source Performance Standards (NSPS) 40 CFR Part 60 Subpart NNN - "Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Manufacturing Industry (SOCMI) Distillation Operations" and Subpart RRR - "Standards of Performance for Volatile Organic Compound Emissions From SOCMI Reactor Processes." The request relates to the Chevron Products Company, Pascagoula Refinery in Pascagoula, Mississippi and also involves the applicability of 40 CFR Part 63 Subpart G - "National Emission Standards for Organic Hazardous Air Pollutants from the SOCMI for Process Vents, Storage Vessels, Transfer Operations, and Wastewater."

As described in your letter, there are approximately ten process, reactor, and distillation vents in the Chevron refinery's Aromax and Ethylbenzene process areas that are subject to NSPS Subparts NNN and RRR, and portions of the equipment are also subject to 40 CFR Part 63 Subpart G. As indicated in your letter, for process vents subject to Part 63 Subpart G and NSPS Subparts NNN or RRR, Subpart G at Sec. 63.110(d)(10) allows the refinery to demonstrate compliance with both the Part 63 and NSPS regulations by using the procedures outlined in 40 CFR Part 63 Subpart G. You have asked whether the refinery may use the compliance procedures outlined in Subpart G to demonstrate compliance for the emission sources in the same chemical manufacturing process unit that are subject to NSPS Subparts NNN and RRR but are not subject to 40 CFR Part 63 Subpart G. Based on our review, the Aromax and Ethylbenzene process area reactors and distillation columns whose only gas streams are combusted in the refinery's fuel gas system are regulated by NSPS Subparts NNN and RRR, but are not allowed to use the compliance methods specified in Part 63 Subpart G to verify compliance with NSPS Subparts NNN and RRR. Since Part 63 Subpart G does not consider gas streams going to a fuel gas system to be vent streams and does not include compliance monitoring requirements for such gas streams, the compliance monitoring requirements of Part 63 Subpart G are not appropriate for verifying compliance with NSPS Subparts NNN and RRR for those gas streams.

As indicated in your letter, the Aromax and Ethylbenzene process areas include certain reactors and distillation columns whose only gas streams are combusted in the refinery's fuel gas system. Chevron has questioned the applicability of NSPS regulations to gas streams combusted as fuel gas. In NSPS Subparts NNN and RRR, a "vent stream" is defined as any gas stream discharged directly to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. While the definition of a "vent stream" in both NSPS subparts goes on to exclude relief valve discharges and equipment leaks, the definition does not exclude gaseous streams routed to a fuel gas system. However, this is not the case with Part 63 Subpart G. 40 CFR Part 63 Subpart F - "National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry" provides applicability provisions, definitions, and other provisions for 40 CFR Part 63 Subparts G and H. The definition of "process vent" in Subpart F is the point of discharge to the atmosphere (or the point of entry into a control device, if any) of a gas stream if the gas stream has any characteristics specified in Sec. 63.107(b) through (h), or meets the criteria specified in Sec. 63.107(i). Subpart F at Sec. 63.107(h) indicates that a gas stream going to a fuel gas system, as defined in Sec. 63.101, is not considered a gas stream under the standard, which means that such gas streams are not regulated as process vents under Part 63 Subparts G and H. Due to these differences in the definitions provided under NSPS Subparts NNN and RRR and Part 63 Subpart F and the exemption of gaseous streams routed to a fuel gas system provided under Part 63, the use of Subpart G to verify compliance with NSPS provisions for these gas streams is not appropriate.

The difference in the definitions under Part 63 and the NSPS has been previously discussed by the United States Environmental Protection Agency (EPA) in response to comments received during the comment period for the January 20, 2000, (65 FR 3169) proposed revisions to Part 63. Enclosed is a copy of the September 18, 2000, memorandum which relates to this issue. In Section 4 of that memorandum, one commenter (IX-D-1) requested clarification concerning the difference in the definitions since the HON definition of a process vent excludes gas streams going to fuel gas systems, while the NSPS rules do not include this exception. The commenter (IX-D-1) believed that the EPA's intent was to simplify and streamline requirements that apply to the same equipment and thus believed that it would be appropriate to extend this exception to the gas streams subject to the NSPS. The EPA's response to this comment was that the change requested by the commenter would change the applicability of three NSPS rules (i.e., NSPS Subparts III, NNN, and RRR) and thus, would require proposal of amendments to the three NSPS subparts. Accordingly, EPA indicated that it did not think that it was appropriate to make this change through the Part 63 rulemaking. The EPA pointed out that the change in NSPS definitions would also not be consistent with the intent of the overlap provisions in Sec. 63.110(d). The provisions in Sec. 63.110(d) were included in Part 63 Subpart G to avoid duplication of monitoring, recordkeeping, and reporting requirements where the same equipment would be subject to substantively the same requirements in multiple rules. The docket indicates that EPA did not, and never intended to, change the applicability of control requirements through these overlap provisions in Subpart G. The EPA responded that whether it would be appropriate to revise the applicability of the requirements in NSPS for air oxidation reactors, distillation operations, or reactor processes would have to be considered in the context of the intent and objectives of those NSPS rules.

To ensure that this determination follows the intent of NSPS Subparts NNN and RRR and 40 CFR Part 63 Subpart G, the determination has been prepared with assistance from the EPA's Office of Enforcement and Compliance Assurance (OECA) and the Office of Air Quality Planning and Standards (OAQPS). If there are any questions regarding this letter, please contact Keith Goff of the Region 4 staff at (404)562-9137.

Sincerely,

R. Douglas Neeley
Chief Air Toxics and Monitoring Branch
Air, Pesticides, and Toxics Management Division

Enclosure

cc: Marcia Mia, OECA
Mark Morris, OAQPS
Rick Colyer, OAQPS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

DEC - 8 2010

Received 12/11/10

OFFICE OF
ENFORCEMENT AND
COMPLIANCE ASSURANCE

Mike R. Hopperton
Senior Environmental Advisor – Air
Refining and Logistics Technology
BP Products North America, Inc.
4050 Charleston Lane
Roswell, Georgia 30075

Re: BP's Regulatory Interpretation Request for Miscellaneous Process Vents Subject to Refinery Maximum Achievable Control Technology (MACT) CC (40 CFR Part 63, Subpart CC)

Dear Mr. Hopperton:

This is in response to your letter dated June 8, 2010, to Mr. Kent C. Hustvedt of the United States Environmental Protection Agency (EPA or Agency), Office of Air Quality Planning and Standards (OAQPS). In the first paragraph of your letter, you state that you are requesting a:

> . . . Regulatory Interpretation Request to confirm that Miscellaneous Process Vents [MPVs] subject to 40 CFR Part 63 Subpart CC ["Refinery MACT"] are not potentially subject to [New Source Performance Standards] NSPS Subpart[s] NNN, RRR or III.

However, in the "Request" section of your letter, you state that you are:

> . . . requesting clarification from EPA that the promulgation of NSPS Subparts NNN, RRR and III ["SOCMI NSPS"] regulations are intended to apply to process vents from distillation operations, reactors and air oxidation processes, respectively at [synthetic organic chemical manufacturing industry] SOCMI process units that operate under [standard industrial classification] SIC Code 2869, and not petroleum refining process units that operate under SIC Code 2911.

These are two slightly different questions, and, therefore, we are addressing each separately.

EPA provides regulatory interpretations of rules as they pertain to the whole source category. For example, EPA might provide a regulatory interpretation regarding the type of testing, monitoring, recordkeeping, or reporting that applies to a specific source category, such as how often sources are required to sample fuel, or the deadline for performance testing. In addition, EPA might issue a regulatory interpretation when there is an obvious gap or disconnect in the regulation which applies equally across the entire source category. See EPA 305-B-99-004, ***How to Review and Issue Clean Air Act Applicability Determinations and Alternative Monitoring,*** page 5, on the website: http://www.epa.gov/reg3artd/airregulations/delegate/appdet.pdf. EPA does not issue regulatory interpretations regarding the applicability of particular provisions of specific rules at specific facilities. Instead, BP can request a site-specific applicability determination from the Agency for any of its specific facilities. 40 CFR Section 60.5.

While we cannot provide the kind of regulatory interpretation of the Refinery MACT that you request, we are providing general guidance concerning the potential applicability of both the Refinery MACT and the Synthetic Organic Chemical Manufacturing Industry (SOCMI) New Source Performance Standards (NSPS) for affected facilities at a petroleum refinery.

The next sections address the two questions you raised in your letter.

1. Confirm that MPVs subject to the Refinery MACT are not Potentially Subject to NSPS Subparts III, NNN, or RRR

The determination of whether an NSPS or a MACT standard is applicable to a particular source at a particular plant site is based on the applicability provisions of that NSPS or MACT. For the Refinery MACT, applicability is based, in part, on the petroleum refining process units and its related emissions points. 40 CFR Section 63.640(a). The "related emissions point" at issue in this determination is the MPV. (See 40 CFR Section 63.640(c)(1) and as described in your letter). In NSPS Subparts III, NNN and RRR, the applicability is based, in part, on the specific unit operation (i.e., air oxidation reactor, distillation unit, or reactor) with a vent stream, operating as part of a process unit. 40 CFR Sections 60.610, 60.660, and 60.700. Furthermore, the product being made by the particular process unit is an important factor in determining applicability of the Refinery MACT, or one of the SOCMI NSPS, to that process unit.

A petroleum refinery process unit subject to the Refinery MACT is primarily engaged in petroleum refining and producing products as described in the definition of "petroleum refining process unit" at 40 CFR Section 63.641:

> *Petroleum refining process unit* means a process unit used in an establishment primarily engaged in petroleum refining as defined in the Standard Industrial Classification code for petroleum refining (2911), and used primarily for the following:
> (1) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;
> (2) Separating petroleum; or

(3) Separating, cracking, reacting, or reforming intermediate petroleum streams.
(4) Examples of such units include, but are not limited to, petroleum-based solvent units, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal processes, and blending, sweetening, and treating processes. Petroleum refining process units also include sulfur plants.

For NSPS Subparts III, NNN, or RRR, a process unit (40 CFR Sections 60.611, 60.661, and 60.701) produces one of the SOCMI chemicals listed in those rules. 40 CFR Sections 60.617, 60.667, and 60.707. While the refinery product is usually a mixed product, such as kerosene, fuel oils, and liquid petroleum gases (LPG), as described by paragraphs (1)-(3) in the definition of "petroleum refining process unit", the product for the NSPS is one of the discreet chemicals listed in the table of chemicals in NSPS Subparts III, NNN, and RRR. Since the products are different, a petroleum refinery process unit under the Refinery MACT and a process unit under the SOCMI NSPS should not be the same. It follows that the resultant MPV (Refinery MACT) and vent stream (NSPS Subparts III, NNN and RRR) would not be the same gas stream.

However, as a caveat, LPG is a mixture of chemicals, primarily propane and butane. These chemicals also appear as discreet chemicals in the tables contained in NSPS Subparts III NNN, and RRR. The Agency has previously provided general guidance in determining the applicability of NSPS Subparts III, NNN, and RRR to products which are a mixture of listed chemicals. [See Applicability Determination (AD) Control Number N13 and 0700002 at http://cfpub.epa.gov/adi).

For this reason, we only can state, in general terms, that we believe that most gas streams generated from distillation, oxidation, or air oxidation unit operations that are part of the petroleum refinery process unit at a petroleum refinery, which meet the definition of "miscellaneous process vent" under the Refinery MACT, will not be "vent streams" under NSPS Subparts III, NNN, and RRR.

2. Clarification that NSPS Subparts III, NNN, and RRR are intended to apply to process vents from distillation operations, reactors, and air oxidation processes at SOCMI process units operating under SIC Code 2869 and not to petroleum refinery process units operating under SIC Code 2911

SOCMI chemicals often use petroleum feedstocks as raw materials, and a particular plant may be vertically integrated from the refining step to the final production of a chemical listed in 40 CFR Sections 60.617, 60.667, or 60.707. This could result in both the Refinery MACT and NSPS Subparts III, NNN, or RRR being applicable at the same facility, regardless of the SIC code under which the facility may claim they operate. In the preamble for the proposed rule for

NSPS Subpart NNN, EPA indicated that Subpart NNN can be applicable at both petroleum refineries and SOCMI plants:

> Most organic chemicals are manufactured in a chain of chemical processes which is based upon about 15 feedstock chemicals. The feedstock chemicals, for the most part, are derived from crude oil. The 219 chemicals can be produced either at petroleum refineries or at chemical plants, and the demarcation between an organic chemical plant and a petroleum refinery is not well defined. The distillation technology and applicable control systems are the same regardless of whether the chemical is produced at a refinery or a chemical plant. For these reasons, the proposed standards apply to distillation units involved in the production of the 219 chemicals, regardless of location. 48 FR 57538, 57541, December 30, 1983.

We note that while there are certain exemptions contained in each NSPS, the exemptions are not dependent upon the location of the distillation, reactor, and/or air oxidation reactor (i.e., no NSPS exemptions for process units located at petroleum refineries). Each of NSPS Subparts III, NNN, and RRR contain certain exemption provisions that may preclude applicability of these subparts at a particular facility. In assessing whether these NSPS would apply at any of its petroleum refineries, BP should also consider the applicability of these exemptions at those refineries. 40 CFR Sections 60.610, 60.660, and 60.700. In addition, there are no SIC code criteria in NSPS Subparts III, NNN, and RRR; and as discussed in the Subpart NNN proposed preamble, EPA intended that the standards would apply regardless of location. Thus, depending on the specific circumstances at a particular refinery, it is possible that both the Refinery MACT and NSPS Subparts III, NNN, and/or RRR may be applicable to gas streams from distillation operations, reactors, and air oxidation processes at a petroleum refinery.

If you would like a formal applicability determination for a particular process unit at a specific petroleum refinery, such as the debutanizer and depropanizer process units you mention in your letter, you may direct such a request to the appropriate delegated authority, who is usually the state government environment office in which the source is located.

This response was coordinated with the Office of Air Quality Planning and Standards and the Office of General Counsel. If you have any questions, you may contact Marcia Mia at (202) 564-7042.

Sincerely,

for Ken Gigliello

Richard F. Duffy, Acting Division Director
Compliance Assessment and Media Programs Division
Office of Compliance

U.S. Environmental Protection Agency
Applicability Determination Index

Control Number: 9900053

Category:	NSPS
EPA Office:	Region 6
Date:	08/11/1999
Title:	Alternative Monitoring and Waiver of Testing for Subpart NNN
Recipient:	Kirk A. Saffell
Author:	Hepola, John R.

Subparts: Part 60, A, General Provisions
Part 60, NNN, SOCMI Distillation Operations
Part 60, RRR, VOC Emissions from SOCMI Reactor Processes

References: 60.13(i)
60.18
60.663
60.664
60.703
60.705
60.8(b)

Abstract:

Q: Will EPA approve alternative monitoring for a boiler or flare which is used to combust a vent stream from a facility subject to Subpart NNN?

A: Yes, EPA will approve the provisions of Subpart RRR as alternative monitoring to the provisions of Subpart NNN.

Q: Will EPA waive the performance testing of a boiler if a vent stream from a facility subject to Subpart NNN is routed to a fuel gas system?

A: Yes, EPA will waive the performance testing of a boiler if a vent stream from a facility subject to Subpart NNN is routed to a fuel gas system.

Letter:

August 11, 1999

Mr. Kirk A. Saffell
Manager, Environmental Engineering
Valero Refining Company - Texas
P.O. Box 9370
Corpus Christi, TX 78469-9370

Re: Approval of Alternative Monitoring and Waiver of Testing for NSPS Subpart NNN Valero Refining Company - Texas Corpus Christi Refinery TNRCC Account No. NE-0112-G

Dear Mr. Saffell:

By letter dated January 20, 1999, Valero Refining Company - Texas (Valero) requested approval of alternative monitoring and testing for vent streams that are routed to a fuel gas system at its petroleum refinery in Corpus Christi, Texas, from distillation units that are subject to the New Source Performance Standards (NSPS) under Subpart NNN - Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations of Title 40, Code of Federal Regulations (CFR) Part 60. Valero requested that monitoring and testing provisions under NSPS Subpart RRR - Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes be approved as alternative monitoring and testing provisions. By letter dated May 21, 1999, we notified the Texas Natural Resource Conservation Commission (TNRCC) of our proposed approval of alternative monitoring and waiver of performance testing for Valero. We sent a copy of our May 21, 1999, letter to Valero. By letter dated June 10, 1999, Valero requested revisions to our proposed alternative monitoring.

Under NSPS Subpart NNN, an initial performance test is required if the vent stream is combusted in a boiler or process heater with a design capacity of less than 150 million Btu per hour. Under NSPS Subpart RRR, the requirement for an initial performance test is waived when a vent stream is introduced into a boiler or process heater with the primary fuel. An initial performance test to demonstrate compliance with the requirements of 40 CFR 60.18 is required under both NSPS Subpart NNN and NSPS Subpart RRR if the vent stream is combusted in a flare.

Under NSPS Subpart NNN, a flow indicator that provides a record of the vent stream flow to the flare or to the boiler or process heater at least once every hour for each affected facility or distillation unit is required. A temperature monitoring device in the firebox with a continuous recorder is required if the vent stream is combusted in a boiler or process heater with a design capacity of less than 150 million Btu per hour. Under NSPS Subpart RRR, a flow indicator must be installed at the entrance to any bypass line that could divert the vent stream from being routed to the flare or to the boiler or process heater or the bypass line valve must be secured in the closed position with a car-seal or a lock-and-key type configuration. If the vent stream is combusted in a flare, a heat sensing device, such as a ultra-violet beam sensor or thermocouple, at the pilot light to indicate the continuous presence of a flame is required under both NSPS Subpart NNN and NSPS Subpart RRR.

Reasons why EPA has determined that performance testing and temperature monitoring for boilers and process heaters combusting vent streams as primary fuel are not warranted are presented in the Federal Register preamble to NSPS Subpart RRR (58 FR 45962, August 31, 1993). In this preamble, EPA also stated that it decided to promulgate vent stream flow monitoring requirements under NSPS Subpart RRR that are different from those under NSPS Subpart NNN because it realized that the installation of flow indicators as specified under NSPS Subpart NNN may be insufficient to meet the intent of the flow monitoring requirements.

We will not waive the requirement for Valero to conduct performance testing to demonstrate compliance with the standards under section 60.662(b) of NSPS Subpart NNN and under section 60.702(b) of NSPS Subpart RRR when the vent gas is combusted in a flare. We will not approve the provisions of NSPS Subpart RRR as alternative monitoring to the provisions of NSPS Subpart NNN where the monitoring provisions of NSPS Subparts NNN and RRR are identical.

Pursuant to 40 CFR 60.8(b), we are issuing a waiver of the requirement for Valero to conduct performance testing to demonstrate compliance with the standards under section 60.662(a) of NSPS Subpart NNN for the boilers and process heaters which are fired with fuel gas which contains vent streams from the Butamer Stabilizer Vent (Equipment No. 36-T-02), the Butamer Deisobutanizer Overhead Accumulator (Equipment No. 36-V-06), the MTBE Butene Column Overhead Drum (Equipment No. 37-V-03), the MTBE Depropanizer Overhead Drum (Equipment No. 37-V-05), the HOC MTBE DME Stripper Overhead Drum (Equipment No. 54-V-42), and the LPG Recovery Unit Stabilizer Overhead (Equipment No. 20-V-03). This waiver is contingent upon all of these vent streams being vented to a fuel gas system and is applicable for boilers and process heaters which meet the definitions of a boiler or process heater under 40 CFR 60.701.

Pursuant to 40 CFR 60.13(i), we are approving the provisions of paragraphs (c)(1), (c)(1)(i), (c)(1)(ii) and (c)(2) of section 60.703 of NSPS Subpart RRR as alternative monitoring to the provisions of paragraphs (c)(1), (c)(2), and (c)(3) of section 60.663 of NSPS Subpart NNN for the vent streams from the Butamer Stabilizer Vent (Equipment No. 36-T-02), the Butamer Deisobutanizer Overhead Accumulator (Equipment No. 36-V-06), the MTBE Butene Column Overhead Drum (Equipment No. 37-V-03), the MTBE Depropanizer Overhead Drum (Equipment No. 37-V-05), the HOC MTBE DME Stripper Overhead Drum (Equipment No. 54-V-42), and the LPG Recovery Unit Stabilizer Overhead (Equipment No. 20-V-03). Valero must comply with the reporting and recordkeeping requirements under paragraphs (d)(1), (d)(2), (l)(2), and (l)(7) of section 60.705 of NSPS Subpart RRR. This alternative monitoring is contingent upon all of these vent streams being vented to a fuel gas system and is applicable while the fuel gas is combusted in boilers and process heaters which meet the definitions of a boiler or process heater under 40 CFR 60.701.

Pursuant to 40 CFR 60.13(i), we are approving the provisions of paragraphs (b)(2), (b)(2)(i), and (b)(2)(ii) of section 60.703 of NSPS Subpart RRR as alternative monitoring to the provisions of paragraph (b)(2) of section 60.663 of NSPS Subpart NNN for the vent streams from the Butamer Stabilizer Vent (Equipment No. 36-T-02), the Butamer Deisobutanizer Overhead Accumulator (Equipment No. 36-V-06), the MTBE Butene Column Overhead Drum (Equipment No. 37-V-03), the MTBE Depropanizer Overhead Drum (Equipment No. 37-V-05), the HOC MTBE DME Stripper Overhead Drum (Equipment No. 54-V-42), and the LPG Recovery Unit Stabilizer Overhead (Equipment No. 20-V-03). Valero must comply with the reporting and recordkeeping requirements under paragraphs (d)(1), (d)(2), (l)(2), and (l)(7) of section 60.705 of NSPS Subpart RRR. This alternative monitoring is applicable while the vent stream is combusted in a flare that meets the requirements of 40 CFR 60.18.

Pursuant to 40 CFR 60.13(i), we are approving the provisions of paragraphs (b)(2), (b)(2)(i), and (b)(2)(ii) of section 60.703 of NSPS Subpart RRR as alternative monitoring to the provisions of paragraph (b)(2) of section 60.663 of NSPS Subpart NNN for the vent stream from the Naphtha Reformer Product Separator (Equipment No. 49-V-01). Valero must comply with the reporting and recordkeeping requirements under paragraphs (d)(1), (d)(2), (l)(2), and (l)(7) of section 60.705 of NSPS Subpart RRR. This alternative monitoring is contingent upon this vent stream being combusted in a flare that meets the requirements of 40 CFR 60.18.

By letter dated July 2, 1999, we notified the TNRCC of our intention to approve this waiver and alternative monitoring. The TNRCC did not have any objections to our approving this waiver and alternative monitoring, nor any proposed conditions to this waiver and alternative monitoring.

If you have any questions concerning this matter, please contact Mr. George V. Marusak, of my staff, at (214) 665-8366.

Sincerely yours,

John R. Hepola
Chief
Air/Toxics and Inspection
Coordination Branch

cc: Jeffrey P. Greif, TNRCC
David Bower, TNRCC
Jim Bowman, TNRCC Region 14 - Corpus Christi

Mr. Ronald W. Gore
Chief, Air Division
Alabama Department of
Environmental Management
P.O. Box 301463
Montgomery, Alabama 36130-1463

Dear Mr. Gore:

This letter is in response to a March 26, 2010, letter in which Larry Brown of your staff requested that the U.S. Environmental Protection Agency (EPA) provide a determination regarding an alternative monitoring proposal and an initial performance test waiver request that the BP Amoco Chemical Company (BP Amoco) submitted for its Decatur, Alabama facility. These proposals are for three distillation columns located in the plant's No. 1 Para-xylene Process Unit. The vent streams from these distillation columns are subject to 40 Code of Federal Regulations (CFR) Part 60, Subpart NNN - Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Manufacturing Industry (SOCMI) Distillation Operations. Based upon our review, the alternative monitoring proposal and the performance test waiver request from BP Amoco are acceptable. Details regarding the basis for our determination are provided in the remainder of this letter.

In a November 13, 2009, letter to your agency, BP Amoco requested permission to use the compliance procedures provided in 40 CFR Part 60, Subpart RRR (Standards of Performance for Volatile Organic Compound Emissions From SOCMI Reactor Processes) to demonstrate compliance for the three distillation units that are subject to Subpart NNN. The vent streams from the distillation units in question are routed to the fuel gas system at the plant with the primary fuel (natural gas) and are burned in either process heaters or utility boilers. The process heaters used for controlling volatile organic compound emissions in the vent stream have a heat input capacity of less than 150 million British thermal units per hour (Btu/hr).

Subpart NNN at 40 CFR Section 60.662(a) allows an owner/operator of an affected facility to comply with the standard by reducing the total emissions of total organic compounds (TOC) in the gas stream by 98 weight-percent, or to a TOC (less methane and ethane) concentration of 20 parts per million, on a dry basis corrected to three percent oxygen. If a boiler or process heater is used to comply with these limits, the vent gas stream must be introduced into the flame zone of the boiler or process heater. The terms "boiler" and "process heater" are defined under 40 CFR Section 60.661 of Subpart NNN. Subpart RRR at 40 CFR Section 60.702(a) includes the same emission standards. However, Subpart RRR allows more flexibility regarding performance testing and monitoring. The waiver of an initial performance test and the particular sections of Subpart NNN for which BP Amoco is requesting an alternative monitoring procedure are described below, along with the corresponding Subpart RRR requirements which BP Amoco proposes to use.

For affected facilities that comply with 40 CFR Section 60.662(a) by using a boiler or process heater, Subpart NNN at 40 CFR Section 60.663(c)(1) requires the installation of a flow indicator that provides a record of vent stream flow to the boiler or process heater at least once every hour. The corresponding section under Subpart RRR, 40 CFR Section 60.703(c)(1), requires a flow indicator only on any bypass line that may divert the vent stream from the boiler or process heater. This section of Subpart RRR also indicates that no flow indicator is required if the bypass line is secured in the closed position with a car-seal or lock-and-key type configuration. BP Amoco has proposed to use the requirement of 40 CFR Section 60.703(c)(1) in Subpart RRR as alternative monitoring for 40 CFR Section 60.663(c)(1) of Subpart NNN.

Subpart NNN at 40 CFR Section 60.663(c)(2) requires a temperature monitoring device in the firebox equipped with a continuous recorder if the vent stream is combusted in a boiler or process heater with a design heat input capacity of less than 150 million Btu/hr. The corresponding section under Subpart RRR in 40 CFR Section 60.703(c)(2), does not require a temperature monitoring device if the vent stream is introduced with the primary fuel into a boiler or process heater. BP Amoco has requested that no temperature monitoring device be required for their Subpart NNN affected facilities whose vent streams are introduced with the primary fuel, since none is required under Subpart RRR.

Subpart NNN at 40 CFR Section 60.664(c) waives the initial performance test requirement when a boiler or process heater with a design heat input capacity of 150 million Btu/hr or greater is used to comply with 40 CFR Section 60.662(a). The corresponding section under Subpart RRR, 40 CFR Section 60.704(b)(5), waives the requirement for an initial performance test under the same conditions provided under Subpart NNN and also waives the requirement for an initial performance test when a vent stream is introduced into a boiler or process heater with the primary fuel. BP Amoco has requested that the waiver of the initial performance test provided in Subpart RRR be allowed for Subpart NNN affected facilities whose vent streams are introduced with the primary fuel in process heaters or boilers that have a heat input capacity of less than 150 million Btu/hr.

The rationale for determining that temperature monitoring and performance testing for boilers and process heaters combusting vent streams as primary fuel were not warranted under New Source Performance Standard (NSPS) Subpart RRR is presented in the Federal Register preamble for the standard (58 FR 45957; August 31, 1993). Based on the performance of boilers and process heaters, the preamble indicates that it is believed that they would already be achieving the performance levels required by the standard, and no performance testing and temperature monitoring are necessary to ensure compliance. The preamble to Subpart RRR also discusses the flow monitoring requirements for vent streams used as primary fuel in boilers and process heaters and indicates that the use of flow indicators was being altered (from that required under Subpart NNN) to indicate those times when the vent stream is being diverted to the atmosphere. The flow monitoring requirements under Subpart RRR were considered to be more appropriate than those under Subpart NNN for meeting the intent of flow monitoring requirements.

Pursuant to 40 CFR Section 60.13(i), we are approving the provisions of NSPS Subpart RRR at 40 CFR Section 60.703(c)(1) and (c)(2) as alternative monitoring for the provisions of NSPS Subpart NNN at 40 CCR Section 60.663(c)(1) and (c)(2). BP Amoco must comply with the Subpart RRR record keeping and reporting requirements at 40 CFR Section 60.705(d)(1), (d)(2), (l)(2), and (l)(7). Pursuant to 40 CFR Section 60.8(b)(4), we are also approving a waiver of the requirement for an initial performance test for vent streams introduced into a boiler or process heater with the primary fuel. This approval of the alternate monitoring requirements and the waiver of initial performance testing are consistent with previous determinations made by EPA for Subpart NNN affected facilities.

If you have any questions about the determination provided in this letter, please contact David McNeal of my staff at (404) 562-9102.

Sincerely,

Kenneth R. Lapierre
Acting Director
Air, Pesticides and Toxics
Management Division

cc: Larry Brown, Chief
Chemical Branch
Air Division
Alabama Department of
Environmental Management

U.S. Environmental Protection Agency
Applicability Determination Index

Control Number: 0700002

Category:	NSPS
EPA Office:	Region 4
Date:	10/30/2006
Title:	By-Product Chemical Mixture
Recipient:	Lyons, John
Author:	Banister, Beverly H.
Comments:	

Part 60, VV SOCMI Equipment Leaks

References: 60.480(d)(1)
60.480(d)(3)
60.481

Abstract:

Q1: The Cymetech facility in Calvert City, Kentucky, produces a by-product which contains a mixture of chemicals, some of which are listed in 40 CFR 60.489. Does 40 CFR part 60, subpart VV, apply to the operation?

A1: Yes. EPA finds that the operations are subject to NSPS subpart VV because the by-product includes listed chemicals and is sold because of the chemical characteristics of the listed chemicals.

Q2: If the Cymetech facilitiy in Calverty City, Kentucky, is subject to 40 CFR part 60, subpart VV, does the exemption in 40 CFR 60.480(d)(3) apply?

A2: Yes. EPA finds that because the affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, the exemption in 40 CFR 60.480(d)(3) is applicable, and the facility is not subject to the standards in 40 CFR 60.482.

Letter:

4APT-ATMB

Mr. John Lyons
Director
Division of Air Quality
Department of Environmental Protection
Kentucky Natural Resources & Environmental Protection Cabinet 803 Schenkel Lane
Frankfort, KY 40601

Dear Mr. Lyons:

We have received a request from Mr. Ralph Gosney for an applicability determination concerning New Source Performance Standards (NSPS) Subpart VV "Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemicals Manufacturing Industry

(SOCMI)." The request relates to the applicability of Subpart VV at the Cymetech facility in Calvert City, Kentucky. The facility produces a by- product which contains a mixture of chemicals which are listed in Subpart VV at Section 60.489. If the Environmental Protection Agency (EPA) determines that Cymetech is subject to Subpart VV, the company requests a determination as to whether the exemption in Section 60.480(d)(3) applies to the facility. Based on our review, we have determined that the Cymetech facility produces chemicals listed in Section 60.489 and meets the Subpart VV applicability criteria in Section 60.480(a). However, since the affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, the exemption in Section 60.480(d)(3) is applicable, and the facility is not subject to the standards in Section 60.482.

The Cymetech facility is designed to extract high purity (greater than 97 percent) dicyclopentadiene (DCPD) from a crude stream containing 40 to 60 percent DCPD. The process involves reducing all of the contained DCPD to cyclopentadiene (CPD), distilling the CPD from the higher and lower molecular weight materials, and then recombining the CPD under controlled conditions to yield a high purity DCPD product. The crude DCPD raw material contains mixed chemicals, as contaminants, which are listed in Section 60.489. These chemicals, after removal of the DCPD product, are carried through to the Resin Former and Resin Oil Heavies by-products. The Resin Former by-product is sold by Cymetech as a raw material for the manufacture of resins. The specification for the Resin Former by-product requires that the total concentration of "reactives" must be greater than 50 percent. The Resin Former by-product includes seven listed chemicals (from Section 60.489) which are considered "reactives" for purposes of the product specification, and together make up a portion (25.5 percent) of the product specification.

As indicated in Section 60.480, Subpart VV is applicable to affected facilities (i.e., group of all equipment in a process unit) in the synthetic organic chemicals manufacturing industry. The "synthetic organic chemicals manufacturing industry" (SOCMI) is defined in Section 60.481 as the industry that produces, as intermediates or final products, one or more of the chemicals listed in Section 60.489. Cymetech has indicated their facility is not subject to Subpart VV and has referenced the enclosed April 6, 1994, EPA determination, Control No. 9700142 on the Applicability Determination Index (ADI), to support their position. The determination relates to NSPS SOCMI regulations for equipment leaks, air oxidation, and distillation operations (NSPS Subparts VV, III, and NNN, respectively). As indicated in the determination, the applicability of Subparts VV, III, and NNN depends on whether a listed chemical is produced as a product, which also includes the production of a listed chemical as a by-product, co-product, or intermediate. The determination indicates that EPA considers either of the following downstream uses as indicative of the production of a listed chemical as a product: (1) production for sale as that listed chemical, or (2) use in another process where that listed chemical is needed. The determination also indicates that if a listed chemical is only part of a mixed stream exiting a process unit and cannot be sold or used in another process as the listed chemical, that chemical is not considered to be produced as a product.

Another previous determination regarding NSPS regulations for SOCMI operations is also relevant to the applicability of Subpart VV to the Cymetech facility. Enclosed is an April 22, 1991, EPA determination, Control No. NS13 on the ADI, regarding products composed of mixtures of listed chemicals and the applicability of NSPS to SOCMI operations. Although the determination relates to Subpart NNN, the same logic would apply to NSPS Subparts VV and III, since all three standards apply to the production of listed chemicals. As stated in the determination:

If a mixture is produced as a "product" and contains a listed chemical which is intentionally included in the mixture for use of its chemical characteristics, the process would be subject to Subpart NNN. A mixture would not be subject if the listed chemical is included only as a contaminant, that is, the chemical is not produced for its specific chemical characteristics.

Based on the April 22, 1991, and April 6, 1994, determinations, the Resin Former by- product produced by Cymetech is a product. The Resin Former by-product mixture contains listed chemicals, and the mixture is sold because of the chemical characteristics of the listed chemicals and the intentional use of those chemicals. Since the Resin Former by-product is sold because of the useful properties of the listed chemicals, the listed chemicals are not considered contaminants. Cymetech indicates that the Resin Former by-product is sold as a raw material for the manufacture of resins. The April 6, 1994, EPA determination referenced by Cymetech only exempts a listed chemical which is part of a mixed stream if it cannot be sold or used in another process as the listed chemical. That is not the case with the listed chemicals in the Resin Former by-product produced at the Cymetech facility. Also, production of listed chemicals under Subpart VV includes a variety of operations, including physical operations. As stated in the preamble for the final Subpart VV standard (48 FR 48328; October 18, 1983) - "Process units used to produce the chemicals covered by the standards may involve chemical synthesis, biological synthesis, other processing, or physical operations, such as separation." Therefore, Subpart VV regulates process units which separate chemical contaminants from raw materials and produce a saleable product which relies on the properties of those chemicals.

Although the applicability criteria in Section 60.480(a) are met, Cymetech has requested a determination as to whether they would meet the exemption from the Subpart VV standards at Section 60.482 due to the provision in Section 60.480(d)(3). As indicated in Section 60.480(d)(3), an exemption is allowed if an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw material. Information provided by Cymetech concerning the process unit feed material and products indicates that none of these streams are light liquids (as defined by Sections 60.481 and 60.485(e)) and that they meet the definition of heavy liquids. Therefore, the exemption in Section 60.480(d)(3) is applicable, and the Cymetech facility is not subject to the standards in Section 60.482. However, Subpart VV at Section 60.480(d)(1) requires that an exempt facility maintain records as specified in Section 60.486(i).

This determination was coordinated with the EPA's Office of Compliance. If there are any questions regarding this determination, please contact Mr. Keith Goff of the Region 4 staff at (404) 562-9137.

Sincerely,

Beverly H. Banister
Director
Air, Pesticides, and Toxics
Management Division

Enclosures (2)

cc: Ralph Gosney, Kentucky Division of Air Quality Marcia Mia, Office of Compliance

U.S. Environmental Protection Agency
Applicability Determination Index

Control Number: 0700001

Category:	NSPS
EPA Office:	Region 6
Date:	10/12/2006
Title:	Testing, Monitoring and Recordkeeping for VOC Emissions
Recipient:	Gorman, Claudine
Author:	David Garcia
Comments:	

Part 60, NNN	SOCMI Distillation Operations	
	RRR	VOC Emissions from SOCMI Reactor Processes

References:

60.8(b)
60.704(b)(5)
60.705(c)(4)
60.705(s)

Abstract:

Q: May the Chalmette Refinery, located in Chalmette, Louisiana, comply with 40 CFR part 60, subpart RRR, in lieu of 40 CFR part 60, subpart NNN, for testing, monitoring, and recordkeeping related specifically to use of boilers and process heaters for compliance with the standards of both subparts?

A: Yes. The facility's refinery fuel gas system comprises boilers and process heaters, some with heat input capacities equal to or greater than 150 MMBTU/hr and some with heat input capacities less than 150 MMBTU/hr. Vent gases are mixed with other gaseous streams collected in the fuel gas system and distributed as a mixed gas stream that constitutes the primary fuel introduced into the flame zone of each boiler or process heater. None of the distillation vents are equipped with a bypass directly to the atmosphere. Thus, compliance with NSPS subpart RRR testing, monitoring, and recordkeeping requirements in lieu of NSPS subpart NNN similar requirements is acceptable. However, the facility must provide a copy of the schematic required by 40 CFR 60.705(s) and maintain the schematic in its onsite file for the life of the system to ensure that the affected vent streams are being routed to appropriate control devices under this approval.

Letter:

October 12, 2006

Ms. Claudine Gorman
Environmental Group Leader
Chalmette Refining, L.L.C.
P.O. Box 1007
Chalmette, Louisiana 70044

RE: Performance Test Waiver and Alternative Monitoring Request

40 CFR Part 60 Subparts NNN and RRR - Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations (Subpart NNN) and Reactor Processes (Subpart RRR) Toluene Disproportionation Unit (TDU), Distillation Vents at the Chalmette Refinery located in Chalmette, Louisiana.

Dear Ms. Gorman:

This letter is in response to your request dated August 31, 2006, on the above referenced waiver and alternative monitoring under New Source Performance Standards (NSPS). As delineated below, we are approving your request for meeting Subpart RRR in lieu of Subpart NNN requirements for testing, monitoring, and record-keeping related specifically to use of boilers and process heaters for compliance with the standards of both Subparts.

In your letter, you requested a waiver of the NSPS initial performance test requirement for the following TDU distillation vents:

C-4210 - Benzene Tower
C-4212 - Xylene Tower
C-4208 - Del-Tol Tower
C-4206 - Stabilizer

Your letter indicates that these vents are normally routed to the refinery fuel gas system, but can be routed to the No. 2 Flare. Our understanding is that the refinery fuel gas system is comprised of boilers and process heaters, some with heat input capacities equal to or greater than 150 MMBTU/hr and some with heat input capacities less than 150 MMBTU/hr. Vent gases are mixed with other gaseous streams collected in the fuel gas system and, after further processing and/or treatment, are distributed as a mixed gas stream from the refinery fuel gas system. However, in all cases, the mixed gas stream from the fuel gas system constitutes the primary fuel and is introduced into the flame zone of each boiler or process heater. In addition, none of the distillation vents are equipped with a bypass directly to the atmosphere.

The United States Environmental Protection Agency (EPA) hereby approves your request to waive the initial performance test for those vents specified in your letter as being introduced with the primary fuel into a boiler or process heater in accordance with 40 CFR Sec. 60.8(b) and as provided for in Sec. 60.704(b)(5). Furthermore, EPA approves your request to implement the Subpart RRR monitoring provisions in lieu of complying with the monitoring provisions of 40 CFR Sec. 60.663(c) under Subpart NNN. Finally, EPA approves your request to comply with the recordkeeping requirements of 40 CFR Sec. 60.705(c)(4) in lieu of the recordkeeping requirements of Subpart NNN since these recordkeeping requirements correspond directly to those monitoring requirements to be implemented for the TDU distillation vents under Subpart RRR. Please be advised that you must provide a copy of the schematic required by Subpart RRR Sec. 60.705(s) in your initial report to the state agency and maintain a copy onsite for the life of the system to ensure that the affected vent streams are being routed to appropriate control devices under this approval.

This approval is based upon the information submitted in your request for those units specified and identified within this letter. This approval is consistent with previous determinations made by EPA for Subpart NNN affected facilities. Enclosed, please find our detailed comparison of Subpart NNN and Subpart RRR requirements in relation to your request. If any new information becomes available or process unit operations are changed, this determination may become void and a new determination may be necessary. If you have any questions or concerns about this determination, please feel free to contact Ms. Cynthia J. Kaleri of my staff at (214)665-6772.

Sincerely,

David F. Garcia
Chief
Air/Toxics Inspection and Coordination Branch

Enclosure

cc: Jeff Greif (TCEQ, Austin)
Marcia Mia (EPA OECA)

Brenda Shine (EPA OAQPS)

6EN-AA 6EN-AA

KALERI DONALDSON

Enclosure

Comparison of 40 CFR Subparts NNN and RRR For Flares and Boilers/Process Heaters

The performance standards of Sec. 60.662 (Subpart NNN) and Sec. 60.702 (Subpart RRR) are established to minimize the emissions of volatile organic compounds (VOC) through the application of best demonstrated technology (BDT). Therefore, different technology controls have different testing, monitoring, and reporting requirements.

When a flare is used to seek compliance with either Sec. 60.662(b) or Sec. 60.702(b), both Subparts NNN and RRR require that the flare meet the requirements of Sec. 60.18 {see same requirement under testing at Sec. 60.664(d) and Sec. 60.704(c)}. Monitoring requirements are similar, except Subpart RRR includes monitoring flow diverted from the flare to the atmosphere via a bypass line {see Sec. 60.703 (b)(2)} while Subpart NNN requirements include monitoring vent streams routed to each flare prior to being combined with other gases {see Sec. 60.662 (b)(2)}. Therefore, Subpart RRR requires recording the flow rate more frequently (every 15 minutes) than Subpart NNN (every hour).

When a boiler or process heater is used to seek compliance with Sec. 60.662(a) and Sec. 60.702(a), the testing, monitoring, and recordkeeping requirements differ between Subparts NNN and RRR. EPA's rationale for waiving performance testing, temperature monitoring, and for refining the location and monitoring of flow indicators can be found on pages 45957 through 45959 in the Federal Register preamble to NSPS Subpart RRR (58 FR 45948 August 31, 1993. In general, Subpart RRR provides consideration of vent gases that are mixed with other gaseous streams and used as a primary fuel for the boiler(s) or process heater(s) whereas Subpart NNN does not address such primary fuel systems. Also, Subpart RRR addresses vent gas flows diverted away from a boiler(s) or process heater(s) via a bypass line(s) to the atmosphere whereas Subpart NNN merely addresses vent gases as routed to boilers or process heaters. For this reason, Subpart RRR requires recording the flow rate more frequently (every 15 minutes) in comparison to Subpart NNN (every hour). Specific citation comparisons are relevant as follows:

Specific to testing, both Subpart NNN Sec. 60.664(b)(5) and Subpart RRR Sec. 60.704(b)(5) waive the initial performance test requirement when a boiler or process heater with a design heat input capacity of 150 MBtu/hour or greater is used to comply with Sec. 60.662(a) and 60.702(a), respectively. Subpart RRR Sec. 60.704(b)(5) also waives the requirement for an initial performance test when a vent stream is introduced with the primary fuel into a boiler or process heater, regardless of heat input capacity.

Specific to monitoring, both Subpart NNN Sec. 60.663(c) and Subpart RRR Sec. 60.703(c) outline requirements for locating and monitoring vent gas flow indicators as well as monitoring firebox temperature. However, Subpart RRR Sec. 60.703(c)(1)(ii) waives the need for a flow indicator where bypass line valves to the atmosphere are secured in a closed position with a lock-and-key type configuration. Also, Subpart RRR Sec. 60.703(c)(2) exempts the temperature monitoring requirement for any vent stream introduced with the primary fuel into a boiler or process heater.

Since Subpart RRR provides some relief in testing and monitoring requirements in comparison to Subpart NNN, as discussed above, an additional reporting requirement was deemed necessary. In order to ensure that the affected vent streams are being routed to appropriate control devices, Subpart RRR Sec. 60.705(s) requires that the facility maintain on file a schematic diagram of the affected vent streams, collection system(s), fuel systems, control devices, and bypass systems as part of the initial report submitted in accordance with Sec. 60.705(b). This additional reporting requirement (not required in Subpart NNN) is further discussed in the Federal Register preamble referenced above.

Enclosure, Chalmette Refining (Louisiana) page 2 of 2 Performance Test Waiver and Alternative Monitoring Request for TDU Vents