Statement of Basis –
U.S. Oil & Refining Co.

Purpose

This document summarizes the legal and factual basis for the draft permit conditions in US Oil's operating permit (including references to the applicable statutory or regulatory provisions), as required under WAC 173-401-700(8).

To accomplish this purpose, this document includes a description of the facility, its permitting and compliance histories, and a summary of its emissions. This is followed by a description of the legal and factual basis for all decisions to:

- Add periodic monitoring and recordkeeping terms to the permit that were not applicable requirements prior to permit issuance;
- Define or clarify existing operational requirements and limitations in the permit; and to;
- List requirements in the permit as inapplicable.

Unlike the operating permit, this document is not legally enforceable.

Description

US Oil is located on 136 acres in the deep-water Port of Tacoma, Washington. This includes 11.5 waterfront acres with 1,350 feet of waterfront on the Blair Waterway which provides direct access by ocean-going barges and tankers. The refinery and marine terminal are connected by four pipelines varying in size from 8 to 24 inches. The refinery has direct rail access and is close to both a major interstate highway system and the Seattle-Tacoma International Airport.

US Oil receives all of its crude oil by ship or barge at its marine terminal. The refinery currently has storage capacity for approximately 1.6 million barrels of crude oil and 1.2 million barrels of refined petroleum products. The refinery is able to process a variety of crude oils in the Light Crude Unit (LCU) which employs both atmospheric and vacuum distillation. Process heater H-3 and related equipment from the former Heavy Crude Unit (HCU) have been incorporated into the LCU distillation train to improve throughput efficiencies. The HCU has effectively been eliminated.

The LCU, rated at 39,000 barrels per day, processes the company's principal crude feed stock, Alaskan North Slope crude oil. (ANS) The refinery processes other crude oils in addition to ANS as crude oil markets and product demands dictate. The atmospheric distillation process separates crude oil into hydrocarbon streams of specific boiling ranges (off-gas, liquid butane, naphtha, jet fuel, diesel, atmospheric gas oil and atmospheric residual oil) which then undergo further processing or are used as blending stocks. The vacuum distillation process separates residual oil from the atmospheric distillation process into off-gas, distillate, vacuum gas oil, flux and vacuum residual oil which are used as blend stocks to produce finished fuel oils and asphalts or are sold as unfinished intermediate products (FCC feed).

Light gases are separated from the light naphtha produced in the LCU via several downstream fractionators. The resultant butanes, which can be used as refinery fuel, are generally used in gasoline blending or sold. The propane and lighter gases are also consumed as refinery fuel. The remaining naphtha and the heavy naphtha portion produced in the light crude unit are kept segregated and are hydrotreated.

Hydrotreating removes sulfur compounds and other contaminants that are detrimental to reformers and isomerizer. In hydrotreating, hydrogen is mixed with the naphtha feed, vaporized and passed through a reactor. The reactor effluent is cooled and separated into off-gas (containing hydrogen sulfide), hydrogen, and the hydrotreated naphtha.

Heavy naphtha is sent to one of two reformers, which convert the low octane naphtha to high octane reformate. In reforming, the hydrotreated naphtha feed is pressurized and passed through a series of furnaces and reactors. The reactor effluent is cooled and separated into off-gas, hydrogen, and reformate.

Light naphtha is processed in an isomerization unit to improve the octane number before being directed to gasoline blending. The isomerization unit rearranges straight chain paraffins into branched paraffins. In isomerization, hydrogen is mixed with the hydrotreated naphtha feed, vaporized and passed through a reactor. The reactor effluent is cooled and routed to an isomerate stabilizer for further processing.

To accommodate the sulfur removed in hydrotreating, the refinery processes the various sulfur containing gas streams into elemental sulfur. The refinery has two sulfur recovery units, a LO-CAT® and a Claus unit. The LO-CAT® unit is primarily used to treat sour water stripper streams, but can be used when the Claus Unit is off-line.

In the Claus unit, refinery gas is passed through an amine scrubber to absorb hydrogen sulfide and other acid gases. The acid gases absorbed by the amine scrubber are removed from the amine solution by heating and stripping. The hydrogen sulfide is routed to the Claus unit where it is combusted and reacted to form liquid elemental sulfur. The remaining gases are reheated and passed through several catalytic beds to increase the conversion to sulfur and then sent to a tail gas treatment unit where sulfur compounds are absorbed into an amine solution. The scrubbed tail gas is sent to the tail gas incinerator, while hydrogen sulfide in the amine solution is stripped-out and returned to the Claus unit for reprocessing.

In the LO-CAT® unit, refinery gas is passed through an iron chelate scrubber to absorb hydrogen sulfide and other acid gases. The hydrogen sulfide rich solution is then routed to an oxidizer where it is regenerated and a sulfur slurry is produced by contacting the rich iron chelate solution with air. The sulfur slurry is recovered and typically distributed as an ingredient in soil amendment products. This unit also employs a sour water stripping tower, which removes hydrogen sulfide and ammonia from the sour refinery water streams. The off-gas from the stripping tower is directed back to the LO-CAT® or Claus unit for further processing.

Hydrocarbons in the refinery process gases are not removed by the amine scrubber in the Claus unit or the iron chelate scrubber in the LO-CAT® unit. These gases are blended with pipeline natural gas, hydrogen, and butane to fuel the refinery's two utility boilers, 14 process heaters, a vapor combustor, and the Claus unit incinerator. Each boiler and process heater is equipped to fire fuel gas, but only one boiler and two process heaters are equipped to burn fuel oil. Excess butane or fuel oil is burned when insufficient fuel gas is being produced to meet heating demands, there is a natural gas curtailment, or conditions warrant the combustion of a more economical fuel type. Fuel gas is flared in flare #1 when fuel gas in excess of demand is being produced, but only after being monitored for hydrogen sulfide content.

Final products include liquid butane (or LPG), gasoline, jet fuels, diesel, heating oils, fuel oils, asphalts and liquid sulfur. Gasoline is a blend of reformate, isomerate and butane. Jet fuel is a kerosene side stream from the atmospheric distillation process that is treated with caustic, clay and salt to remove water and other contaminants. Diesel is a slightly higher boiling point fraction from the distillation process that is hydrotreated to remove sulfur. Other gas oils with higher boiling point fractions are typically used as cutter stocks. Asphalt is the highest boiling point fraction and is blended to produce paving asphalts, cutback asphalts, and asphalt emulsions and fluxes.

Most products leave the facility in tank trucks, particularly gasoline and diesel. However, a significant fraction of the heavy fuel oil and most of the vacuum gas oil from the light crude unit vacuum distillation process are shipped out by barge. A significant portion of the jet fuel is sent directly to Joint Base Lewis-McChord via a pipeline. Some asphalt is loaded into railcars.

One refinery by-product is wastewater discharges. Stormwater and refinery wastewater are processed by an API oil-water separator, induced air floatation (IAF) and a biological treatment facility. The recovered oil is sent back to the refinery and the treated water is discharged to the Blair Waterway through an NPDES permitted outfall.

Another by-product is the air contaminant emissions. As shown below under the section entitled 'Emissions', most of the emissions come from fuel combustion and from fugitive emission sources. The refinery employs a vapor combustor to control the emission of gasoline vapors from storage tanks and employs two sulfur recovery units to control sulfur dioxide emissions from fuel gas combustion. The sulfur collected by the sulfur recovery units is marketed commercially.

Permits

The refinery was constructed in 1957, 11 years prior to the creation of PSCAA. Construction activity during the 1970's was limited to nine storage tank relocations (Order of Approval #1128, 1633), one asphalt storage tank (Order of Approval #1901), a second catalytic reforming unit (Order of Approval #1744), a diesel hydrotreater and a LO-CAT® sulfur recovery unit (Order of Approval 1879). Only the process heater for the diesel hydrotreater (H-901) was subject to a New Source Performance Standard (NSPS Subpart J).

In 1979, US Oil proposed modifications that would enable the processing of Alaskan North Slope crude oil and increase the refinery's capacity (Order of Approval #1911). This proposal required a Prevention of Significant Deterioration permit from EPA (PSD-X79-9) and was based on the installation of a Fluidized Bed Catalytic Cracking (FCC) unit. A new light crude unit atmospheric still heater (H-11) was installed in 1980, a boiler (B-4) in 1981 and a vacuum distillation unit (still and heater H-201) in 1983. These were all NSPS, Subpart J fuel gas combustion devices.

At that point, US Oil determined that the FCC-based expansion was no longer economical. Instead, US Oil requested to modify their PSD permit and filed a new Notice of Construction application with PSCAA (Order of Approval #2573) to pursue a hydrocracker-based approach. However, the economics again changed and US Oil ended up installing only a boiler (B-5) and two mercaptan oxidation treatment units. Since construction was discontinued for more than 18 months, the permits for the other proposed units expired. This was also the case for a proposed heavy crude unit visbreaker (Order of Approval #2459).

US Oil later requested PSCAA to amend the permit conditions associated with the aborted FCC and hydrocracker-based expansions. Although the new boilers and the light crude unit heaters installed under these permits had rated capacities greater than those that were shut down, the potential for debottlenecking was not reflected in terms of fuel oil combustion or heat input to the refinery.

PSCAA revised the permit conditions for these units, establishing new emission standards and netting each unit out of PSD by establishing limits on the amount of fuel oil each unit could burn and by requiring the shutdown of other emission units (Order of Approval #5429, 5430, 5431 and 5432).

Meanwhile, US Oil modified its crude unit flare to handle the increased load and ensure compliance with opacity standards (Order of Approval #2308). A larger flare was installed in 1982 (Order of Approval #2365). New state and local requirements for gasoline tank truck loading and petroleum refineries prompted the installation of a bottom loading system and lean oil vapor recovery system in 1982 (Order of Approval #2209), a cover on the API separator (Order of Approval #2617), and replacement of the heavy crude unit barometric condenser with a surface condenser in 1985 (Order of Approval #2633).

More stringent state and local requirements for gasoline vapor recovery were adopted in 1991, prompting US Oil to replace the lean oil unit with a vapor combustor (Order of Approval #4841). More stringent federal limits for sulfur in diesel fuel prompted the installation of a non-NSPS Claus sulfur recovery unit in 1993 (Order of Approval #5433).

Asphalt fumes and odors from top loading of tank trucks prompted the installation of demisters on the speed rack in 1989 (Order of Approval #3184) and the flux/AC rack in 1998 (Order of Approval #6827). A new PG asphalt loading rack with demister was installed in 2000 (Order of Approval #8217).

The heater that was part of the HCU, (H-3), the original catalytic reforming unit (H-1101, 1102, 1103 and 1104), the diesel hydrotreater (H-901), and the light crude unit (H-11) were replaced with NSPS, Subpart J heaters (Order of Approval #2597, 3023, 4177) in 1985, 1989, 1993 and 1995, respectively.

A couple dozen storage tanks were installed, including six non-NSPS tanks (Order of Approval #2331, 3440, 6536, 8691), four NSPS, Subpart Ka tanks (Order of Approval #2046, 2501), nine NSPS Subpart Kb tanks (Order of Approval #3170, 7020, 7021, 7041, 8323, 8514, 8720), two NSPS subpart QQQ tank (Order of Approval #8514, 8692), and four NSPS Subpart UU tanks (Order of Approval #2960, 7761) heated by an NSPS, Subpart J tank heater (H-6).

Since the Title V Air Operating Permit was issued 12-31-2002, U.S. Oil has applied for and received approvals for the following Notices of Construction:

NOC 9007: Installation of NSPS Subpart Kb fixed roof tanks TK-1804 & TK-1807 (1804 later renamed 1805)

NOC 9021: Installation of MACT Group 1 tank TK-30006

NOC 9023: Installation of NSPS Subpart QQQ waterdraw system for tanks 80001, 80002, 80003, & 80004

NOC 9153: Retrofit of NSPS Subpart J Heater H-3 to incorporate into the LCU

NOC 9329: Installation of NSPS Subpart Kb fixed roof tank TK-10002

NOC 9343: Installation of NSPS Subpart J Light Crude Vacuum Unit Heater H-202

NOC 9580: Installation of NSPS Subpart Kb external floating roof tanks TK-80020, TK-80021, TK-80022, TK-300001, and TK-300002.

NOC 9679: Installation of NSPS Subpart Kb fixed roof tank TK-20002 (reconstruction).

NOC 9755: Installation of NSPS Subpart Kb internal floating roof tank TK-10010, and Subpart QQQ waterdraw system for TK-10010 and TK-5003.

NOC 9786 and 10053: Installation of an asphalt railcar loading rack and demister.

NOC 9932: Modification of the north heat exchanger cleaning pad under NSPS Subpart QQQ.

NOC 10029: Installation of an internal floating roof in NSPS Subpart Kb tank TK-5003.

NOC 10120: Installation of NSPS Subpart Ja process heater H-901 in the DHU.

Compliance

This discussion is limited to compliance since the permit was initially issued on 12/31/02.

Opacity and Particulate Matter (Ecology Method 9A, PSCAA Method 5)
No Notices of Violation were issued during the five-year permit cycle, although a written warning was issued for visible emissions from boiler B-5. U.S. Oil has been required to perform annual visual inspections of all the process heater and boilers stacks (daily for units firing oil). No opacity was observed during these inspections or during the initial performance tests for Heaters H-3 and H-202. No particulate matter tests were performed.

Sulfur Oxides (H_2S and SO_2 CEMS)
No Notices of Violation were issued during the permit cycle for excess hydrogen sulfide in the fuel gas, which is continuously monitored per NSPS Subpart J. The CEMS passed the quarterly Cylinder Gas Audits and annual Relative Accuracy Test Audits. Due to concern that noncondensable gases from the overhead systems of the vacuum distillation columns could qualify as ‘fuel gas’ under Subpart J, U.S. Oil installed a compressor to route these streams to the fuel gas treating system instead of firing it directly in a process heater.

A Notice of Violation was issued during the permit cycle for excess sulfur dioxide in the Tail Gas Treatment Unit (TGTU) incinerator, which is continuously monitored per NSPS Subpart J[1] and MACT Subpart UUU. The initial performance specification test was passed on 1/5/94. The Notice of Violation was issued for an upset that occurred because the acid gas feed line became plugged and gases by-passed the TGTU. The CEMS passed all quarterly Cylinder Gas Audits and annual Relative Accuracy Test Audits.

The Agency also issued a Notice of Violation during the five-year permit cycle for failing to report the startups of the Claus unit as deviations. Calculations performed prior to installation of the Claus unit indicate that emissions will exceed the limit of 1,000 ppm SO_2 (@7% O_2) during the startup process before the TGTU is on line. These potential excess emissions are deemed unavoidable provided that U.S. Oil reports the events as required and follows their SSMP which is designed to reduce emission to the extent possible. U.S. Oil initiated reporting of these events in their monthly CEM reports to resolve this issue. The Agency issued Notices of Violation and case closure letters for these events.

Nitrogen Oxides and Carbon Monoxide (EPA Methods 7E and 10)
No Notices of Violation were issued during the five-year permit cycle for excess NO_x or CO. Heaters H-3, H-11, H-201, and H-202, and boilers B-4 and B-5 were each tested once for NO_x while firing fuel gas. Boiler B-4 was also tested while co-firing fuel oil. Heaters H-3 and H-202 were also tested for CO per Order of Approval Nos. 9153 and 9343. Each demonstrated compliance with the emission limits, although the boilers passed only when rounding to the number of significant figures in the emission limit.

Inorganic Toxic Air Contaminants and Hazardous Air Pollutants (EPA Method 26A)

[1] The Claus unit and CEMS must meet the Subpart J requirements as Best Available Control Technology, but is not actually an ‘affected facility’ subject to this NSPS. Article 12 of PSCAA Reg. I requires all CEMS to meet Performance Specifications and Quality Assurance Procedures in 40 CFR Appendices B and F.

No Notices of Violation were issued during the five-year permit cycle for excess hydrochloric acid (HCl). Catalytic Reforming Units CRU-1 and CRU-2 were each tested twice. The first test followed EPA Method 26. Per revisions to Subpart UUU, the second test followed EPA Method 26A. Separate testing was performed during the primary and secondary regeneration on both catalytic reformer units. All of the HCl test results were below the detection limit with the exception of one HCl test result that was slightly above the detection limit. Based on these test results operating limits for colorimetric testing have been established as appropriate. Tank TK-102, which stores HCl, was also tested per Order of Approval No. 8691. Each demonstrated compliance with the emission limits.

VOC and Organic HAP (EPA Methods 21 and 25A, continuous temperature monitoring, visual)
Several Notices of Violation were issued during the five-year permit cycle for non compliance with the wastewater provisions of NSPS Subpart QQQ and PSCAA Regulation II. Most were associated with the API oil-water separator. U.S. Oil has since completed several major corrective actions including the replacement of the floating roof panels, replacement of the roof drains, and closure enhancements for the forebay covers.

The EPA issued several Notices of Violation during the five-year permit cycle for non compliance with the wastewater provisions of NESHAP Subpart FF (Benzene Waste). These violations were discovered by the National Enforcement Investigations Center (NEIC) during an inspection in November 2006 and are still pending enforcement actions.

The EPA (and PSCAA) also issued Notices of Violation during the five-year permit cycle for non compliance with Refinery MACT LDAR requirements. The EPA citations are still pending. PSCAA also issued Notices of Violation. The infractions included lack of secondary closure devices on open-ended lines, delay of repair of a pump seal, and failure to include a new compressor system in the LDAR program. U.S. Oil has completed the required corrective actions.

No reference method performance tests were conducted during the past five years on the Vapor Combustion Unit (VCU), which is equipped with a continuous monitoring system for temperature (and a thermostatic controller). However, several Notices of Violation were issued during the five-year permit cycle for failing to operate above 1200 °F (averaged over each operating cycle). In two of these cases, the VCU controller had malfunctioned, preventing the unit from using assist gas to achieve the required combustion temperature. In one case, the assist gas line had frozen during extremely cold weather. Notices of Violation were also issued for instances of a gauge hatch being left open, effectively shutting down the VCU which is activated by a pressure sensor. U.S. Oil has instituted several corrective actions including, but not limited to, the installation of locking gauge hatches and low pressure alarms to resolve this issue.

The following table lists the Notices of Violation (3-XXXXXX) and Written Warnings (2-YYYYYY) issued during the five-year permit cycle, the date issued, a brief description of the violation, the date of the violation, the Civil Penalty (CP) number and the amount of the penalties, if any paid for these violations.

Written Warning or NOV # Issued	Description of Violation	Date of Violation	CP # Issued	Amount Paid
Opacity and Particulate Matter				
3-003625 11/4/08	Opacity >20% from flare F-1.	9/9/08	09-191CP 8/20/09 CP cancelled 12/28/09	None
3-004291 9/4/08	Opacity >20% from flare F-1, an excusable excess emission per AOP term I.B.10.	7/7/08	closed 9/4/08	None
2-007879 5/2/08	Opacity >5% from boiler B-4 for 2.5 minutes.	4/29/08	closed 6/3/08	None
2-007285 8/7/06	Opacity potentially >5% from boiler B-5.	5/25/06	closed 8/24/06	None
Detriment to Person or Property, Fallout				
3-004292 9/4/08	Fallout from overpressurization of the atmospheric distillation column C-1, an excusable excess emission per AOP term I.B.10.	7/7/08	closed 9/4/08	None
Sulfur Oxides				
3-005202 5/25/10	SO2 emissions >1000 ppm during shutdown and startup, an excusable excess emission per AOP term I.B.10.	4/27/10, & 4/30/10	closed 5/25/10	None
2-007899 6/3/09	Failure to accurately analyze the SO_2 emissions.	5/14/09	closed 2/27/08	None
3-003627 11/20/08	SO_2 emissions >1000 ppm during startup, an excusable excess emission per AOP term I.B.10.	10/27/08	closed 11/20/08	None
3-003617 6/17/08	SO_2 emissions >1000 ppm during startup, an excusable excess emission per AOP term I.B.10.	5/8/08	closed 6/17/08	None
3-004282 4/10/08	SO_2 emissions >1000 ppm during startup, an excusable excess emission per AOP term I.B.10.	2/3/08	closed 4/22/08	None
3-004257 2/11/08	SO_2 emissions >1000 ppm during startup, an excusable excess emission per AOP term I.B.10	12/28/07	closed 2/27/08	None
3-002408 3/21/07	SO_2 emissions >1000 ppm during startup, an excusable excess emission per AOP term I.B.10	12/12/06	closed 3/21/07	None

Written Warning or NOV # Issued	Description of Violation	Date of Violation	CP # Issued	Amount Paid
3-002319 3/21/07	SO_2 emissions >1000 ppm during startup, an excusable excess emission per AOP term I.B.10	11/12/06	closed 3/21/07	None
3-002320 3/21/07	SO_2 emissions >250 ppm as a result of a malfunction caused by solids build-up.	11/6/06	closed 3/21/07	None
3-002312 9/5/06	SO_2 emissions >1000 ppm during startup, an excusable excess emission per AOP term I.B.10	5/31/06	closed 9/29/06	None
3-002401 10/27/06	SO_2 emissions >1000 ppm during startup, an excusable excess emission per AOP term I.B.10	6/12/03, 9/29/03, 10/24/03, 1/25/04, 5/09/04, 5/10/04, 1/20/05, 4/9/05, 4/10/05	closed 1/9/07	None
VOC and Organic HAP				
Wastewater NSPS Subpart QQQ, PSCAA Reg. II				
3-005304 12/7/09	Gasket damage on the API Separator forebay hatch.	10/6/09	10-137CP 7/7/10	
3-005305 12/7/09	Gasket damage on northern access hatch of east Baker Tank.	10/13/09	10-138CP 7/7/10	$1000 7/27/10
3-004872 10/16/09	Failure to equip the new individual drain system of TK-472 with water seal controls.	6/5/02	10-001CP 1/12/10	$1000 5/6/10
3-003615 1/30/08	Failure to equip the TK-30006 water draw junction with Subpart QQQ controls and perform semiannual inspections.	1/17/05	08-125CP 8/4/08	$1000 8/13/08
3-003613 1/30/08	Gaskets on the API oil water separator forebay hatches not providing a tight seal.	11/14/07	08-066CP 4/16/08	$2000 5/14/08
3-002321 3/27/07	Gasket damage on the API oil water separator floating roof hatch.	11/29/06	closed internally 9/12/07	None
3-002309 8/7/06	API separator forebay hatch not latched leaving visible gap	5/26/06	06-231CP 12/15/06	$1000 4/2/07
3-001191 8/23/06	API separator forebay hatch not latched leaving visible gap	5/26/06 – 5/31/06	06-185CP 10/19/06	$1000 1/5/07
3-002012 9/13/05	No latches on API oil water separator forebay hatches.	1/1/93-7/27/05	closed 9/13/05	none
3-001177 8/29/05	Gaskets on the Baker tank hatches not providing a tight seal.	4/20/05-4/22/05	closed 10/19/05	none
3-001176 8/29/05	Gaskets on the API oil water separator forebay hatches not providing a tight seal.	4/27/05	closed 11/9/05	none

Written Warning or NOV # Issued	Description of Violation	Date of Violation	CP # Issued	Amount Paid
3-001165 6/28/05	Gaskets on the API oil water separator forebay hatches not providing a tight seal.	11/3/04-11/9/04	closed 6/28/05	none
3-000573 10/13/03	Gaskets on the API oil water separator forebay hatches not providing a tight seal. Seal gap on API floating roof >0.5". Floating roof panels on API separator leaking.	6/24/03-7/8/03	closed 12/22/03	none
3-000563 8/20/03	Floating roof panels on API separator leaking.	7/29/03-7/30/03	closed 1/5/04	none
2-001588 8/1/03	Damaged emergency roof drain on API floating roof panel.	5/2/03-5/5/03	closed 10/15/03	none
Wastewater NESHAP Subpart FF				
EPA 10/5/07 violation 1	Failure to include the range of benzene concentrations for each uncontrolled waste stream.	reports for 2004 and 2005	Case Closed through Consent Decree[2]	See Consent Decree
EPA 10/5/07 violation 2	Failure to include all waste streams in the total annual benzene.	reports for 2001-2005	Case Closed through Consent Decree[2]	See Consent Decree
3-003108 3/27/07	Failure to include 3 waste streams in the total annual benzene. (Duplicate of violation above.)	reports for 2001-2005	closed internally 9/12/07	
EPA 10/5/07 violation 3	Failure to collect samples at the point of generation.	2001-2006	Case Closed through Consent Decree[2]	See Consent Decree
EPA 10/5/07 violation 4	Failure to collect samples using a collect samples at <10 C.	2001-2006	Case Closed through Consent Decree[2]	See Consent Decree

[2] Issues identified by EPA were resolved through a Consent Decree for Case No. 3:10-cv-05899-BHS, approved by the United States District Court for the Western District of Washington on February 1, 2011.

Leak Detection And Repair MACT Subpart CC, PSCAA Reg. II				
3-003626 11/4/08	Failure to monitor a pressure relief valve within 24 hours.	9/9/08	closed 12/4/08	none
3-004293 9/4/08	Failure to monitor a pressure relief valve within 24 hours and within 5 days of pressure release.	7/7/08	closed 9/11/08	none
3-004258 8/30/07	Failure to close 6 open-ended lines with a valve, plug, cap, or other device.	6/19/07	07-199CP 11/30/07	$2000 12/12/07
EPA 10/5/07 violation 5	Failure to monitor valves monthly for 2 successive months after detecting a leak that requires a process unit shutdown.	10/01-6/06	Case Closed through Consent Decree[2]	See Consent Decree
3-003104 3/27/07	Failure to monitor valves monthly for 2 successive months after detecting a leak that requires a process unit shutdown. (Duplicate of violation above.)	11/16/06	closed internally 9/12/07	none
EPA 10/5/07 violation 6	Designation of >3% of the total number of valves in 3 process units as difficult-to-inspect.	10/01-4/07	Case Closed through Consent Decree[2]	See Consent Decree
3-003102 3/27/07	Designation of >3% of the total number of valves in 3 process units as difficult-to-inspect. (Duplicate of violation above.)	11/16/06	closed internally 9/12/07	none
EPA 10/5/07 violation 7	Failure to perform 1st attempt to repair 59 valves within 5 days.	10/01- 10/06	Case Closed through Consent Decree[2]	See Consent Decree
3-003103 3/27/07	Failure to document 1st repair attempts on 14 components within 5 days. (Duplicate of violation above.	11/16/06	closed internally 9/12/07	none
EPA 10/5/07 violation 8	Failure to perform final repairs to 19 valves or place them on the delay-of-repair list within 15 days of detecting a leak.	10/01- 10/06	Case Closed through Consent Decree[2]	See Consent Decree
EPA 10/5/07 violation 9	Failure to include 4 leaking pumps identified by visual inspections in the semiannual reports.	1/04-6/06	Case Closed through Consent Decree[2]	See Consent Decree

EPA 10/5/07 violation 10	Failure to close 8 open-ended lines with a valve, plug, cap, or other device.	11/16/06	Case Closed through Consent Decree[2]	See Consent Decree
3-003107 3/27/07	Failure to close 7 open-ended lines with a valve, plug, cap, or other device. (Duplicate of violation above.)	11/16/06	closed internally 9/12/07	none
3-003106 3/27/07	Failure to include methanol and perc injection systems in the LDAR program.	11/16/06	closed internally 9/12/07	none
3-003105 3/27/07	Failure to monitor 3 dripping pump seals with EPA Method 21.	11/16/06	closed internally 9/12/07	none
3-001196 10/27/06	Failure to close 6 open-ended lines with a valve, plug, cap, or other device. Failure to include new non-condensable gas system (compressor and 29 valves) in the LDAR program	6/29/06 6/30/05-7/13/06	07-199CP 11/30/07	$2000 12/12/07 included NOV 3-004258
2-002210 8/8/06	Failure to retest leaking valve within 15 days of detecting a leak.	5/12/06	closed 9/29/06	none
3-001191 8/23/06	Failure to repair 2 pumps within 15 days of detecting a leak.	5/19/06	06-185CP 10/19/06	$1000 1/5/07
3-001155 9/23/04	Delay of pump repair.	5/9/04-6/24/04	CP #9830 12/8/04	$1000 1/5/05
3-001723 4/30/03	Failure to close 15 open-ended lines with a valve, plug, cap, or other device. Failure to have secondary closure devices for 3 open-ended lines.	12-31-02-3/15/03	closed 8/1/03	none
Floating Roof Tanks NSPS Subpart Kb, MACT Subpart CC, Chapter 173-491 WAC, PSCAA Reg. II				
3-004276 2/11/08	Torn secondary seal on tank TK-80011	12/3/07	closed 2/27/08	none
2-007868 9/24/07	Failure to perform semiannual visual inspection of floating roof tank	7/12/07	closed 11/7/07	none
2-007868 9/24/07	Failure to perform semiannual visual EFR tank inspection.	7/12/07	closed 11/7/07	none
3-001170 3/14/05	Secondary seal gap in excess of that allowed by NSPS Subpart Kb.	12/8/04	closed 3/14/05	none
2-000781 1/29/04	Hairline crack on pontoon of TK-14001.	11/25/03	closed 2/5/04	none

Fixed Roof Tanks, Vapor Combustor, Closed Vent System NSPS Subpart Kb, MACT Subpart CC, Chapter 173-491 WAC, PSCAA Reg. II				
3-004873	Open emergency hatch on TK-10006	7/29/09	10-002CP 1/12/10	$1000 2/4/10
3-004874 10/16/09	Visual vapor leaks from TK-7501 gauge hatch and TK-10003 foam chamber.	4/2/09	closed 12/21/09	none
2-008103 1/30/08	Potential failure to collect and control at least 95% of VOC discharged from tanks, to operate the control device in such a manner as to reduce HAP and VOC emissions by 95% or more, and to comply with the no detectable emission limit for the closed-vent systems during gauging operations.	11/14/07	closed 6/11/09	none
3-004263 11/6/07	Open gauge hatch on fixed roof tank causes vapor combustor shutdown and uncontrolled emissions.	8/15/07 8/16/07	07-199CP 12/28/07	$2000 1/23/08
3-001184 3/30/06	Vapor combustor operating at <1200 °F.	12/16/05-12/19/05	06-236CP 3/16/07	$4000 4/3/07
3-001182 12/15/05	Open gauge hatch on fixed roof tank causes vapor combustor shutdown and uncontrolled emissions.	10/25/05-10/26/05	06-237CP 3/16/07	$1000 4/30/07
3-001175 6/28/05	Vapor combustor operating at <1200 °F.	11/13/04-11/15/04	closed 6/28/05	none
3-001157 8/27/04	Open gauge hatch on fixed roof tank causes vapor combustor shutdown and uncontrolled emissions.	6/18/04-6/21/04	CP #9811 1/19/05	$2000 2/17/05
3-001151 3/3/04	Vapor combustor operating at <1200 °F.	1/5/04-1/6/04	closed 3/3/04	none
3-000565 10/13/03	Vapor combustor operating at <1200 °F. Failure to submit deviation report for vapor combustor operating at <1200 °F.	7/30/03	closed 11/24/03	none
Asbestos				
4-042514 10/13/09	Failure to survey, notify, remove, and dispose of asbestos containing building material.	10/7/09	10-136CP 7/7/10	$1750 7/27/10
Good Working Order, Industrial Practice, and Air Pollution Control Practice PSCAA Reg. I, Section 9.20, NSPS, NESHAP and MACT Subpart A				
3-002309 8/7/06	Sticking poppet valve in vapor adaptor of employee gas tank. Water in spill bucket of employee gas tank.	5/26/06	06-231CP 12/15/06	$1000
3-002309 8/7/06	Failure to maintain the TK-5001/5002 demister pressure differential gauge in good working order.	5/26/06	06-231CP 12/15/06	$1000

O&M, OM&M, Startup, Shutdown and Malfunction Plans PSCAA Reg. I, Section 7.09, MACT Subpart A				
3-001181 11/14/05	Failure to revise SSMP for vapor combustor within 45 days after a malfunction event in 11/04 which it failed to address, and to submit the revision with the Periodic Report.	12/31/04- 8/31/05	closed 4/10/06	none
Reporting				
2-009364	Failure to submit an AOP compliance report in an electronic format.	10/1/09	closed 12/9/09	none
3-004277 2/20/08	Failure to submit deviation report within 30 days of the end of the month deviation was discovered.	12/31/07	closed 4/29/08	none
2-002214 3/21/07	Failed to submit all of the MACT Subpart DDDDD information required for Initial Notifications and Notification of Compliance Status for H-202.	10/31/05, 11/20/06	closed 3/21/07	none
2-002205 10/19/05	Failure to submit NO_x test report within 60 days of the test.	10/19/05	closed 5/15/06	none

Emissions

Volatile Organic Compound (VOC) emissions from the refinery are principally from leaking pipe fittings (e.g., pumps, valves, flanges, compressors, process drains, API separator). Emissions from equipment in gaseous and light liquid service were based on actual monitoring results (ppm correlation with lb/hr). Published (average) emission factors were used for other equipment leaks.

Other pollutants are emitted from fuel combustion. Only one boiler and two process heaters are capable of burning residual oil, and each have limits on the amount that can be burned in any given 12-month period. Additionally, Order of Approval No. 9143, Condition 8 requires that sulfur in the residual oil burned at the refinery shall not exceed 35,263 pounds during any consecutive 12 month period, the equivalent of 196,832 gallons of oil containing 2% by weight sulfur. The refinery is fired mostly on refinery fuel gas, which has an average H_2S content of <30ppmv. A small amount of diesel is burned in internal combustion engines for testing pumps in stormwater or firewater service, etc.

Most of the storage tanks in gasoline service and light liquid service are connected to the vapor control unit. Emissions from the other storage tanks come principally from external floating roof tanks storing crude oil and gasoline.

2009 Emissions (tons)

Pollutant	Res. Oil Burned[1]	Dist. Oil Burned[2]	Fuel Gas Burned[3]	Fugitive Emissions[4]	Fixed Roof Tanks[6]	FR Tanks – Combustor[5]	Floating Roof Tanks[6]	LO-CAT Sulfur Unit[7]	Marine Terminal[2]	Totals
NO_x	0	0.3	118.0	-	-	-	-	-	-	118
CO	0	0.1	87.0	-	-	-	-	-	-	87
VOC	0	<0.1	6.2	68.6	8.1	3.9	16.4	-	18.8	122
SO_2	0.5	<0.1	4.8	-	-	-	-	-	-	5
PM_{10}	0	<0.1	8.5	-	-	-	-	-	-	12
TAC	0.5	<0.1	4.8	11.4	0.7	0.4	1.5	38.9	4.1	57
HAP	0	<0.1	<0.1	7.5	0.9	0.3	1.4	-	4.9	15

[1] Based on AP-42, §1.1 for NO_x, CO, and VOC; material balance for SO_2, source test for PM_{10}.

[2] Based on AP-42.

[3] Based on AP-42, §1.4 for CO, PM_{10} and VOC; material balance for SO_2; AP-42 and source testing for NO_x.

[4] Based on EPA Protocol for Equipment Leak Estimates (11/95): correlation approach for pumps and valves; average emission factor approach for flanges and process drains; screening range approach for compressor seals. AP-42 emission factors for API separator.

[5] Based on EPA TANKS 4.09d modeling and source test result of 99% destruction.

[6] Based on EPA TANKS 4.09d modeling.

[7] Based on source testing.

Review of Permit Application

An air operating permit renewal application was received by the Agency on December 20, 2006. On 2/6/07, the Agency issued written notification to US Oil that the application was complete. The application included a compliance schedule which was fully completed in July 2007, approximately 6 months before the permit was to be renewed.

The renewal incorporates the specific provisions of MACT Subparts UUU (Catalytic Reforming Units and Sulfur Recovery Units), GGGGG (Site Remediation Activities), and ZZZZ (Stationary Reciprocating Internal Combustion Engines) now applicable to U.S. Oil. It also incorporates recent amendments to Subpart CC (Refineries) requiring a leak detection and repair program for heat exchange systems.

The renewal incorporates the specific provisions of NSPS Subparts Ja (Fuel Gas Combustion Devices and Flares) and IIII (Stationary Compression Ignition Internal Combustion Engines) now applicable to U.S. Oil. Subpart Ja regulates SO_2 emissions from fuel gas combustion devices and flares. However, several important provisions in Subpart Ja were stayed pending a final decision on three petitions for reconsideration (see 73 FR 78549-78552)[3]. Subpart IIII regulates emissions from compression ignition stationary internal combustion engines.

The renewal incorporates two separate findings and determinations by the Agency, which are attached to this Statement of Basis. In the first finding, the Agency determined that the process drains for tanks TK-30005 and TK-30006, along with their common junction box, the vacuum tank trucks used to transport waterdraws from these tanks to the API separator, and truck unloading facilities (drains, sewer lines) are affected facilities under NSPS Subpart QQQ. Sections 60.692-3(a)(2) and 60.692-3(e) apply to the vacuum tank trucks but the use of the vacuum pump to draw oily wastewater into the tank truck does not constitute purging of the vapor space in the tank.

In the second finding, the Agency determined that there are no exemptions from the 95% control requirement for the vapor combustor and the 500 ppm limit for the closed-vent system in NSPS Subpart Kb [§§60.112b(a)(3)(ii) and 60.112b(a)(3)(i)]. Subpart Kb [§60.113b(c)(1)] requires submittal (for approval by the Agency) of an operating plan for the closed vent system and control device as part of the notification required by §60.7(a)(1). It requires the closed vent system and control device to be monitored and operated in accordance with the plan approved by the Agency. The operating plan originally submitted by US Oil for the nine Subpart Kb tanks connected to their closed vent system and control device did not address the issues of tank gauging, sampling, p/v vent replacement. It didn't address the closed vent system. However, US Oil submitted such a plan on 5/27/09 which the Agency approved. This plan requires all pressure in the closed vent system to be relieved by operation of the thermal oxidizer prior to opening the hatches. It has been incorporated into the SSMP required by the Refinery MACT (Subpart CC) and is enforceable under Section II.I of the Title V permit.

The renewal incorporates all permit conditions from 13 Orders of Approval issued and from rules and regulations issued or revised during the five-year permit cycle.

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[3] The Court stayed the applicability provisions in §60.100a(c), flare definition in §60.101a, emission standards in §60.102a(g), and monitoring provisions in §60.107a(d) and (e).

The renewal doesn’t incorporate case-by-case MACT determinations for process heaters and boilers, although US Oil submitted timely and complete Part 2 applications under 40 CFR Part 63, Subpart B for the process heaters (H-201 and H-901) subject to Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters), which was vacated and remanded the US Court of Appeals for the District of Columbia vacated and remanded on 6/19/07. (Their existing large gaseous fuel boilers and process heaters were subject only to an initial notification requirement.)

The Agency decided to await the outcome of recent proposed rulemakings under Subpart DDDDD (proposed on 6/4/10) and Subpart B (proposed on 3/30/10). Both rulemakings are expected to go final by the end of the year. The Subpart DDDDD proposal is substantially different from the vacated rule. The Subpart B proposal will finally address the Federal Clean Air Act Section 112(j) ‘MACT hammer’ provisions as they pertain to vacated rules.

Legal and Factual Basis for Permit Conditions

The permit content is prescribed by Part VI of the state operating permit rules under Chapter 173-401 of the Washington Administrative Code (WAC), which was adopted pursuant to Chapter 70.94 Revised Code of Washington (RCW), and is incorporated by reference under Puget Sound Clean Air Agency (PSCAA) Reg. I, Article 7.

WAC 173-401-600 requires the permit to lists all “applicable requirements” (as defined under WAC 173-401-200(4)), including all federally enforceable applicable requirements regardless of stringency. It also requires the permit to contain terms and conditions that assure compliance with these requirements at the time of permit issuance, and to specify and reference the origin of and authority for each term and condition.

The permit cites the applicable requirements and their adoption or effective dates. Although a paraphrase of the requirements is provided, it is not an enforceable provision of the permit. (A preface to the permit describes the permit format.)

The permit contains terms and conditions from Chapter 173-401 WAC. The authority for establishing these permit terms and conditions is cited but only the permit itself is enforceable, not the authority for establishing the terms and conditions.

The permit does not contain requirements applicable only to sources located in carbon monoxide and ozone nonattainment areas (e.g., PSCAA Reg. II, Section 2.09 and Chapter 173-490 WAC) because they were not applicable as of the date of permit renewal.

The permit does not contain applicable requirements that are not ongoing because they are not in effect during the term of the permit. These include, but are not limited to, initial performance testing requirements, initial notifications, and requirements to permanently remove equipment from service.

The permit does not contain Order of Approval conditions that are for information purposes only. For example:

- ‘Approval is granted...to install or establish the equipment, device or process described hereon at the installation address in accordance with the plans and specifications on file’;
- ‘Compliance with this order and its conditions does not relieve the owner or operator from the responsibility of compliance with Regulations I, II, or III, RCW 70.94 or any other emission control requirements, nor from the resulting liabilities and/or legal remedies for failure to comply’;
- ‘This approval does not relieve the applicant or owner of any requirement of any other governmental agency;’ and
- ‘This source is subject to 40 CFR Part 60, Subpart __.’

The following is a description of the legal and factual basis for all decisions to:

- Add periodic monitoring and recordkeeping terms to the permit that were not applicable requirements prior to permit issuance;
- Define or clarify existing operational requirements and limitations in the permit; and to
- List requirements in the permit as inapplicable.

Periodic Monitoring
Where an applicable requirement doesn’t include periodic monitoring or doesn’t specify a frequency or method, ‘monitoring sufficient to yield reliable data from the relevant time period that are representative of the source’s compliance’ has been added to the permit pursuant to WAC 173-401-615(1)(b). The criteria used to establish (or not to establish) periodic monitoring are consistent with EPA’s 4/30/99 Draft *Periodic Monitoring Technical Reference Document* and include:

- <u>Initial compliance</u>;
- <u>Margin of compliance</u>;
- <u>Variability of process and emissions</u>;
- <u>Air quality impact of deviations</u>; and
- <u>Technical considerations</u> (e.g., measures already employed to identify and prevent deviations; the available alternatives, their cost, and ability to detect deviations).

This rationale for periodic monitoring requirements added (or not added) to the permit is described below. Standard Term and Condition V.O establishes the minimum data recovery for these requirements. Any failure to comply with the periodic monitoring requirements and data recovery requirements is a permit deviation.

I.A. Opacity and Particulate Matter

None of the applicable requirements for opacity or mass concentration (grain loading) require periodic testing or monitoring. Section II.A.1 of the permit adds *daily* monitoring for visible emissions from equipment being fired on residual fuel oil, *quarterly* monitoring for the asphalt tank and loading rack demisters, and *annual* monitoring for process heaters and boilers fired on gas. (Daily monitoring may be reduced to weekly if no visible emissions are observed for 7 consecutive days. U.S. Oil must revert to daily observations of individual stacks if any visible emissions are observed.) If visible emissions are noted, the permit allows US Oil to use the reference test method to determine compliance. Otherwise, US Oil must take corrective action or shut the unit down within 24 hours. These added monitoring requirements are based upon:

- <u>Initial compliance</u>. The compliance history for opacity indicates that there have been no Notices of Violation issued during the five-year permit cycle, although a written warning (WW 2-007285) was issued on 8/7/06 for visible emissions from boiler B-5 observed on 5/25/06.
- <u>Margin of compliance</u>. Equipment fired on residual fuel oil inherently has greater particulate emissions than equipment fired on gas because of its higher ash and sulfur content and the need to atomize/vaporize it prior to combustion. Boiler B-4 tested at half the emission limit. The three units allowed to burn residual fuel oil (B-4, H-11, H-201,) have a more stringent emission limit of 0.01 grains per dry standard cubic foot (@7% oxygen) when they are fired on gas, but the other emission units have a very wide margin of compliance since they are subject only to the emission standard of 0.05 gr/dscf under Section 9.09 of PSCAA Regulation I.
- <u>Variability of process and emissions</u>. Process heaters and boilers are subject to variable load conditions, although changes in demand are usually not sudden. The flares are not flaring under normal conditions. Asphalt tank emissions increase when they are being filled. Asphalt demister truck loading rack demister emissions occur only during truck loading. Asphalt tank demister emissions occur primarily during the filling of the tanks.
- <u>Air quality impact of deviations</u>. The process heaters and boilers have fairly tall stacks with good dispersion. A failure of the asphalt tank and truck loading rack demisters would result in emissions (and odors) from the tank or truck being filled, similar to an uncontrolled tank or loading rack. The magnitude of any impact would depend upon the magnitude and duration of the deviation. It is highly unlikely that any single deviation could exceed an ambient air quality standard.
- <u>Technical considerations</u>. Visible emissions from process heaters and boilers represent not only wasted fuel but a potential catastrophic failure. Accordingly, US Oil adheres to a comprehensive preventative maintenance schedule and also continuously monitors them for many parameters including oxygen. Employees are ordered to report visible emissions from process heaters or boilers to the control room operators. Recording of visible emissions is not necessarily a violation of the grain loading standard, because the visible emissions

threshold often occurs at concentrations below the standard. Periodic source testing for compliance with the grain loading standard could be required for the process heaters and boilers. However, given the number of emission units to be tested, the cost of each test (~$5000), and the adequacy of visible emissions as a surrogate monitoring parameter, it is not being required.

Particulate matter (and SO_2)[4] emissions are also regulated by ash and sulfur limits for fuel oil. Ash and sulfur are standard specifications for fuel oils. Section II.A.12 of the permit adds monitoring (reference method testing for ash and sulfur) of each batch of residual fuel oil burned. This added monitoring requirement is based upon:

- Initial compliance. No Notices of Violation have been issued in the five-year permit cycle.
- Margin of compliance. The standards are 2.00% sulfur and 0.1% ash. Residual fuel oil (No. 6) burned at the refinery typically has 1.5-1.8% sulfur and 0.01-0.02% ash.
- Variability of process and emissions. The sulfur content of residual fuel oil is controlled by blending. Desalting of the crude removes inorganic salts and trace metals (ash).
- Air quality impact of deviations. Deviations would tend to be small, perhaps 5-10% above the limit. Such deviations are unlikely to exceed ambient air quality standards.
- Technical considerations. US Oil already uses the reference test method to analyze for ash and sulfur. Additionally, U.S. Oil must test for sulfur to track compliance with Order of Approval No. 9153, Condition 8.

None of the applicable requirements for fugitive dust require periodic monitoring. Section II.A.13 of the permit adds quarterly monitoring for visible dust emissions. This added monitoring requirement is based upon:

- Initial compliance. A review of the compliance history showed two Notices of Violation for abrasive blasting were issued prior to 1982. No complaints have been received by PSCAA regarding fugitive dust emissions at U.S. Oil.
- Margin of compliance. Although US Oil has equipment used in a manufacturing process, fuel burning equipment and control equipment, it does not handle any solid or dusty materials. The applicable requirements for other equipment and operations do not limit emissions. Instead, they require reasonable precautions, reasonably available control technology, or best available control technology to minimize the emissions. Most of the facility is paved and the remainder is undisturbed except during construction or maintenance activities. Vacuum blasting is now used for descaling storage tanks. This is considered BACT, provided that measures are employed during construction and maintenance activities to prevent the emission of fugitive dust. The absence of visible fugitive dust emissions indicates a significant margin of safety.
- Variability of process and emissions. Emissions could occur during major construction, demolition or maintenance activities, but typically do not occur at other times.
- Air quality impact of deviations. Failure to use reasonable precautions could cause a

[4] On average, 1-3% of the sulfur in the fuel is emitted directly as sulfate particles. Additional sulfate is formed downwind as a result of oxidation reactions. These reactions take hours, proceeding faster in the presence of fog, clouds, and photochemical oxidants.

nuisance, but is unlikely to exceed ambient air quality standards.

- Technical considerations. None. Semiannual stormwater inspections are required by Ecology and the inspection follows the same route.

The Source Emission Reduction Plan (SERP) issued to US Oil pursuant to the air pollution episode avoidance plan provisions under RCW 70.94.715 and Chapter 173-435 WAC, does not require periodic monitoring. The permit does not require periodic monitoring because:

- Initial compliance. A review of the compliance history showed no Notices of Violation have been issued since the SERP was adopted in May 1973.
- Margin of compliance. The area has never reached the alert stage of an air pollution episode, which could actually trigger an action by US Oil. Air quality has improved markedly since the last forecast stage in December 1985.
- Variability of process and emissions. The alert and warning stages would restrict fuel oil combustion. US Oil seldom burns fuel oil, but the times when it does are often during winter air stagnations.
- Air quality impact of deviations. US Oil is not considered a major source of particulate matter. The impact of failing to switch fuels under the SERP is small.
- Technical considerations. Periodic monitoring would probably be in the form of recordkeeping. Periodic implies more than once. The SERP has not triggered an action even once in the 37 years since it was established.

I.B. Sulfur Oxides

Sulfur dioxide (and trioxide)[5] emissions from the refinery are controlled by limitations on the amount of sulfur in the fuel gas and fuel oil, and by limits on the amount of residual oil that can be burned. The fuel oil limit of 2% by weight sulfur and the fuel gas limit of 55 ppm H_2S (Order of Approval Nos. 9153, 9343, 10120) assure compliance with the SO_2 emission standards of 1000 ppm, corrected to 7% O_2, except for emissions from H-580 during startup of the Claus Unit. (Order of Approval No. 5433, Condition 5, deems such excess emissions to be unavoidable provided US Oil follows WAC 173-400-107.) Monitoring of the emissions from the tail gas incinerator (H-580) is required only when the Tail Gas Treatment Unit (TGTU) is in operation. Section II.B.8 of the permit adds a requirement to keep a record of the duration of all startups and shutdowns of the Claus Unit during which the TGTU is not in operation. This added monitoring requirement is based upon:

- Initial compliance. The Agency has issued written warnings or NOV's with case closure letters for the unavoidable excess emissions.
- Margin of compliance. Emissions when the TGTU is off-line are beyond the span of the CEMS (500 ppm). Initial engineering calculations submitted with the permit application for the Claus Unit indicated the emissions could reach over 1800 ppm @7% O_2. If emissions dropped to ≤200 ppm @7% O_2 (the Subpart UUU standard of 250 ppm @0% O_2) when the TGTU is brought on-line, emissions on an hourly average would be ≤1000 ppm @7% O_2 provided that the TGTU is off-line for under 30 minutes. This is considered credible evidence of a violation.

[5] On average, 1-5% of the sulfur in the fuel is emitted as sulfur trioxide.

- Variability of process and emissions. Startups and shutdowns occur infrequently, maybe once or twice per year.
- Air quality impact of deviations. There is a potential for violating the state ambient air quality standard of 0.4 ppm (1-hr average, not to be exceeded more than once per year) and 0.25 ppm (1-hr average, not to be exceeded more than twice in a consecutive 7-day period.
- Technical considerations. Startups and shutdowns are often unplanned, making it impractical to schedule a reference method test. Depending upon the nature of the event, the TGTU may or may not need to be taken off-line. Records of startup and shutdown of the Claus unit are already required under Subpart UUU. The added monitoring pertains to periods of Claus Unit operation when the TGTU is off-line.

The fuel oil standard in Section I.B.1 contains a sulfur limit but no monitoring requirement. Section II.B.1 of the permit adds monitoring (reference method testing for sulfur) for each batch of residual fuel oil burned. This added monitoring requirement is based upon:

- Initial compliance. No Notices of Violation have been issued in the five-year permit cycle.
- Margin of compliance. The standard is 2.00% sulfur. Residual fuel oil (No. 6) burned at the refinery typically has 1.5-1.8% sulfur.
- Variability of process and emissions. The sulfur content of residual fuel oil is controlled by blending.
- Air quality impact of deviations. Deviations would tend to be small, perhaps 5-10% above the limit. Such deviations are unlikely to exceed ambient air quality standards.
- Technical considerations. US Oil already uses the reference test method to analyze for sulfur. Additionally, U.S. Oil must test for sulfur to track compliance with Order of Approval No. 9153, Condition 8.

I.C. Nitrogen Oxides and Carbon Monoxide

None of the applicable requirements for nitrogen oxides require periodic monitoring or testing. Section II.C.1 of the permit initially required reference method tests *at least once every 5 years.* As part of the renewal application, U.S. Oil requested to eliminate this requirement for boiler B-5 and not to apply it to the new LCVU heaters H-3 and H-202. Because of the limited test data and small margins of compliance, this request was not approved. Testing of the three units capable of firing oil (H-11, H-201 and B-4) was initially required for oil firing only if they burned oil during the 5-year permit cycle. As part of the renewal application, U.S. Oil requested a 2000 bbl/yr threshold for testing on oil. Because of technical considerations, this request was approved. This added monitoring requirement is based upon:

- Initial compliance. Heater H-11 was tested on 8/18/05. The NO_x emissions were 0.08 lb/MMBtu, which complied with the emission limit of 0.10 lb/MMBtu for gas-firing. This heater didn't fire any oil during the five-year permit cycle. (A test conducted on 7/7/95 while co-firing refinery fuel gas and residual oil found an emission rate of 0.16 lb/MMBtu, potentially above the heat input weighted average emission limit of 0.15 lb/MMBtu.)

  Heater H-201 was tested on 8/19/05. The NO_x emissions were 0.08 lb/MMBtu, which complied with the emission limit of 0.1 lb/MMBtu. This heater didn't fire any oil during the five-year permit cycle and it hasn't been previously tested.

Heater H-3, retrofit with smaller burners for the LCU, was tested on 8/18/05. The NO_x emissions were 0.066 lb/MMBtu (52 ppm @3% O_2), which complied with the emission limit of 0.100 lb/MMBtu (85 ppm @3% O_2). The heater didn't fire any oil during the five-year permit cycle and it hasn't been previously tested.

Heater H-202 was tested on 10/16/06. The NO_x emissions were 20 ppm, which complied with the limit of 25 ppm @3% O_2.

Boiler B-5 was tested on 8/19/05. The NO_x emissions were 0.106 lb/MMBtu, which (when rounded to the significant figures of the standard, complied with the emission limit of 0.1 lb/MMBtu.

Boiler B-4 was tested on 10/19/06 while firing refinery fuel gas and then while co-firing fuel gas and residual oil. The NO_x emissions for gas firing were 0.124 lb/MMBtu (@ >7% oxygen and 52 MMBtu/hr), which when rounded to the significant figures of the standard, complied with the emission limit of 0.1 lb/MMBtu. The NOx emissions for co-firing were 0.18 lb/MMBtu, which complied with the heat-input weighted average emission limit of 0.18 lb/MMBtu. The boiler was running at approximately 8% oxygen and 60 MMBtu/hr, which is well below its rated capacity of 99 MMBtu/hr. While these tests are probably representative of its normal operation, higher NO_x emissions would be expected at maximum load.

- Margin of compliance. For gas firing, the test results found boiler B-5 had no margin of compliance and heaters H-11, H-201 and H-202 had a margin of compliance of ~20%. Boiler B-4 was ~30% below the standard and heater H-3 was ~33% below the standard. (The margin of compliance was considerably greater for B-5, H-201 and B-4 when rounded to the number of significant digits of the standard.) Test results for co-firing found H-11 and B-4 had no margin of compliance.
- Variability of process and emissions. NO_x emissions increase with increased load. (Fuel NO_x is fairly constant, but thermal NO_x increases.) NO_x emissions are higher for fuel oil than for fuel gas due to the higher fuel nitrogen content and combustion temperature. The performance of the emission units is not expected to deteriorate significantly as they age.
- Air quality impact of deviations. The NO_x limits are technology-based, not health-based. None of the affected emission units are major for NO_x. It is highly unlikely that any single deviation could exceed an ambient air quality standard.
- Technical considerations. The installation of NO_x CEMS on each unit is technologically feasible. However, since the emission standards are in terms of lb/MMBtu, it would also be necessary to simultaneously monitor the fuel input rate and the exhaust gas flow rate. This would be both difficult and expensive. The only practical alternative is reference method source testing. Given the cost of each test (~$5000) and the number of emission units to be tested, annual testing was not considered appropriate. Additional costs are incurred in testing the boilers because each requires the erection of over 50 feet of scaffolding at a cost of about $2500. Boiler B-5 is used primarily in a low-fire, standby mode.

U.S. Oil requested that testing while co-firing oil only be required if the quantity of oil burned exceeds 2,000 bbl/yr (84,000 gal/yr). U.S. Oil doesn't normally fire H-11 or H-201 on oil, even during a natural gas curtailment. And it would take B-4 about 3 weeks to consume this much oil if fired under the same conditions present during the 2006 test (60 MMBtu/hr total, 40% from oil). Like B-5, testing of the boiler requires the erection of over 50 feet of scaffolding at a cost of $2500. And scheduling the test to occur when oil is needed (rather than burning oil when it's not), must be done several weeks in advance.

None of the applicable requirements for carbon monoxide require periodic monitoring or testing. Section II.C.6 of the permit adds testing every 5 years after permit issuance. This added monitoring requirement for H-3, H-202 and H-901 is based upon:

- Initial compliance. Heater H-3 was tested on 8/18/05. CO emissions were 0.00005 lb/MMBtu (0.06 ppm @3% O_2), which complies with the emission limit of 0.050 lb/MMBtu (70 ppm @3% O_2). The heater was operating with 6% oxygen in the exhaust, which is considerable excess air for gas-firing. The heater was operating at 79% of capacity.

  Heater H-202 was tested on 10/16/06. The CO emissions were 0.7 ppm @ 3% O_2, which complied with the emission limit of 50 ppm @3% O_2. This heater has been retested annually for compliance with the vacated MACT standard under Subpart DDDDD. The subsequent tests in 2007-'09 found 16, 24 and 10 ppm @3% O_2.

- Margin of compliance. Heater H-3 had essentially no CO emissions and H-202 tests varied from only 1% to 48% of the limit.

- Variability of process and emissions. CO emissions increase with decreased load but these process heaters are not operated at high turndown. CO emissions will increase if insufficient excess air (oxygen) is supplied so proper trim control has a major affect. The performance of the emission units is not expected to deteriorate significantly as they age if the burners are properly maintained.

- Air quality impact of deviations. The CO limits are technology-based, not health-based. These are also small heaters. H-3 has a maximum heat input of 22 MMBtu/hr and H-202 only 13 MMBtu/hr. It's highly unlikely that any single deviation could exceed an ambient air quality standard.

- Technical considerations. The installation of CO CEMS on each unit is technologically feasible. However, this would be quite expensive. Proper trim control with oxygen sensors in the exhaust was considered BACT. The only practical alternative for verifying compliance is reference method source testing. The additional cost of performing CO tests when NO_x is being tested (every 5 years) is relatively small. Previous tests indicate annual testing is not warranted.

I.D. Nuisance

None of the applicable requirements for nuisance (odor or fallout) require periodic monitoring. Section II.D.1 of the permit requires reactive measures (complaint investigation) *within 3 days* of receipt of any complaint. These added monitoring requirements are based upon:

- Initial compliance. A review of the compliance history showed no Notices of Violation of the nuisance standards have been issued. In 2000 and 2008, upsets of US Oil's light crude unit atmospheric distillation column resulted in the release of oil through the second stage of the pressure relief system. Oil spray carried for several blocks and coated adjacent properties. US Oil paid to have the deposits removed from cars. No other nuisance complaints specific to US Oil have been received by PSCAA in recent years.

- Margin of compliance. US Oil emits some odor (no dust). It has taken measures to reduce odor emissions including, but not limited to, the installation of asphalt fume demisters, elimination of barometric condensers, and covering of the wastewater separator. Even on the property, odors are not strong.
- Variability of process and emissions. Unknown. Oil refining is a continuous process (not a batch process). The greatest potential for emissions is during startup and shutdown of a process unit. Some level of hydrocarbon odor is always present. A 'walk-around' the facility would be very unlikely to find higher than normal odor levels.
- Air quality impact of deviations. Violations would, by definition, be a 'detriment to person or property'. US Oil is located in the center of the most industrial area in the Puget Sound region.
- Technical considerations. US Oil is a large and complex facility subject to numerous inspection and monitoring requirements for VOC, HAP and SO_2 (see Sections II.F and II.B). Sources of VOC, HAP, and SO_2 are also the primary sources of odor. The facility is equipped with numerous continuous H_2S monitors/alarms for worker safety. The facility is also equipped with numerous process sensors that will alarm in the event of a malfunction (or release) and that are watched continuously by control room operators. US Oil is located in the middle of a large industrial area with many malodorous facilities including a rendering plant and a Kraft pulp mill.

I.E. Inorganic Toxic Air Contaminants and Hazardous Air Pollutants

Hydrochloric acid, lead, arsenic, cadmium, chromium, and dioxin emissions from oil combustion are regulated by limits on the content of chlorinated compounds (total halogens, PCB) and these metals in the fuel oil. The permit does not require monitoring (reference method testing) for these contaminants because:

- Initial compliance. A review of the compliance history showed no Notices of Violation have ever been issued.
- Margin of compliance. The limits in Section 9.08 of Regulation I restrict the blending and burning of used oil or solvents. US Oil uses only crude oil in the manufacture of its products. The metals concentrations measured by US Oil are typically 100 times below the limits. PCB and halogens are not detectable.
- Variability of process and emissions. There appears to be little variation in the residual fuel oil data provided by US Oil for 1/94-10/97. Metals concentrations remained consistently below the limits by a factor of 100.
- Air quality impact of deviations. There are no ambient air quality standards for TAC or HAP. The impact of a deviation would depend upon the magnitude and duration of the deviation. Most of the residual fuel oil, which has the higher metals content, is sold for use outside the four-county area (e.g., marine use).
- Technical considerations. There are international specifications for vanadium content, even one for aluminum+silicon, but none for halogens and PCB or the metals of interest.

Analyses are feasible, but US Oil has requested not to be required to perform them given the consistently low concentrations previously measured and the cost of performing the analyses.

Hydrochloric acid emissions from acid storage tank (TK-102) are controlled by a drum of activated carbon adsorbent. The permit does not require monitoring (reference method testing) for these contaminants because:

- Initial compliance. A review of the compliance history showed no Notices of Violation have been issued.
- Margin of compliance. The tank was installed and tested upon initial fill on 5/17/02 using EPA Method 26 combined with Standard Method 4500-Cl-C (mercuric nitrate method). The average of two test runs was 20 ppm, which is well below the standard of 100 ppm. But colorimetric tubes indicated no detectable emissions on a 1-20 ppm HCl scale.
- Variability of process and emissions. Emissions are primarily working losses that occur during filling of the storage tank. The 4500 gallon tank is refilled roughly twice per year (~6000 gal/yr). The emissions would increase rapidly if there was breakthrough on the adsorbent.
- Air quality impact of deviations. Section 9.10 of Regulation I limits the emission to 100 ppm. The IDLH is only 50 ppm and the PEL is only 5 ppm (ceiling value). The vent from the adsorber is ~10 feet above ground level. The odor detection threshold is <1 ppm and it is highly irritating. Uncontrolled, the concentration could theoretically exceed 50,000 ppm.
- Technical considerations. Because of the corrosive nature of HCl and the need to ensure worker safety at all times, US Oil replaces the drum of adsorbent once every 2 years as part of their preventative maintenance program. This amounts to the collection/neutralization of ~12 pounds of acid fumes prior to replacement, which should be well below the adsorbent capacity. It is possible to use colorimetric tubes, although they didn't appear to function reliably at the low concentrations encountered during the initial performance testing of the storage tank.

I.F. Volatile Organic Compounds and Organic Hazardous Air Pollutants

The applicable requirement for a pressure/vacuum vent on a junction box doesn’t require periodic monitoring. The permit does not require monitoring because:

- Initial compliance. The P/V vent is being installed in conjunction with the installation of five large storage tanks with NSPS Subpart QQQ water draw systems.
- Margin of compliance. Unknown.
- Variability of process and emissions. Emissions without the P/V vent would occur when the water level in the junction box rises. With the P/V vent small rises in the liquid level will not result in emissions to the atmosphere.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation. The primary concern would be worker safety.
- Technical considerations. The BACT requirement for a P/V vent was taken from NESHAP Subpart FF, which had no associated monitoring requirement. This component could be added to the LDAR program or it could be visually inspected. The MACT Subpart CC requirement for P/V vents on the closed-vent system for the storage tanks is an annual visual inspection while the system is under pressure. But it would be difficult to know when the junction box is under pressure as it has no pressure sensor.

None of the applicable requirements for vacuum-producing systems require periodic monitoring. The permit does not require monitoring because:

- Initial compliance. A review of the compliance history showed no Notices of Violation have been issued.
- Margin of compliance. The noncondensable gases are hard piped into a compressor that feeds the fuel gas system, which is monitored by a H_2S CEMS.
- Variability of process and emissions. Vapors are pulled from the distillation columns by means of steam-ejectors. The hard piping itself has virtually no emissions.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation. The primary concern would be worker safety.
- Technical considerations. The requirement is simply to combust all noncondensable VOC from the vacuum systems. Unless the piping leaks, the VOC will be combusted as part of the refinery fuel gas system. Some of the components are subject to the LDAR program. The noncondensable gases are some of the most malodorous at the refinery and will be readily detected by operating personnel if there is a leak.

None of the applicable requirements for open-ended valves and sampling connection systems require periodic monitoring. The permit does not require monitoring because:

- Initial compliance. A review of the compliance history showed five Notices of Violation have been issued for a relatively small number of open-ended lines that were promptly repaired.

- Margin of compliance. The applicable requirements are established operating procedures but operators inevitably forget to follow the procedures. All equipment reportedly meets these requirements.
- Variability of process and emissions. Emissions should be negligible if the valves and sampling connection systems are equipped with the required secondary seal.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation. The primary concern would be worker safety.
- Technical considerations. Monitoring is not required under the current MACT standard. However, proposed changes to 40 CFR 63 Subpart VV (Federal Register: 11/7/06 Volume 71, Number 215) include annual monitoring of open-ended lines. Open-ended lines are presently discovered during LDAR inspections of the associated valves.

None of the applicable requirements for floating roof storage tanks require periodic monitoring to verify compliance with the basic design requirement to have a floating roof with seals. The permit does not require monitoring because:

- Initial compliance. A review of the compliance history showed no Notices of Violation have been issued.
- Margin of compliance. All equipment meets these requirements. Standard operating procedures assure that the tank is emptied and refilled continuously and as rapidly as possible when the roof is resting on the leg supports.
- Variability of process and emissions. Emissions are greatest when the roof is resting on the leg supports during tank drawdowns and refilling.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation. The primary concern would be worker safety.
- Technical considerations. Monitoring is not required under the MACT standard. All NESHAP requirements proposed after 11/15/90 are deemed by EPA to satisfy the Title V monitoring requirements (see FR 54915 10/22/97, and 40 CFR 64.2(b)(1)(i)).

None of the applicable requirements for deck fittings under Conditions 5-7 of PSCAA Order of Approval Nos. 6536 and 9580 require periodic monitoring. The permit requires monitoring of the specific fittings *each time the tank is emptied and degassed* as part of the existing monitoring required under the MACT standard. These added monitoring requirements are based upon:

- Initial compliance. A review of the compliance history showed no Notices of Violation have been issued.

- Margin of compliance. All equipment meets these requirements.
- Variability of process and emissions. Emissions are a function of the vapor pressure of the product stored, which is a function of its temperature.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation. The primary concern would be worker safety.
- Technical considerations. Monitoring of deck fittings is required under the MACT standard and under Subpart Kb each time the tank is emptied and degassed. Tanks TK-80020, TK-80021, TK-80022, TK-300001, and TK-300002 are subject to NSPS Subpart Kb. Tanks TK-14001 and TK-14002 are not technically Subpart Kb tanks, but the Subpart Kb design requirements and these additional requirements were determined to be the Best Available Control Technology at the time of installation. This level of monitoring was considered appropriate for all deck fitting requirements. No monitoring is deemed necessary for exterior paint color.

None of the applicable requirements limiting the back pressure in the vapor hoses at the gasoline tank truck loading rack require periodic monitoring. The permit does not require monitoring because:

- Initial compliance. A review of the compliance history showed no Notices of Violation have been issued.
- Margin of compliance. The vapor combustor is activated when pressure in the closed-vent system reaches 2.5 inches of water, which is well below the limit of 18 inches.
- Variability of process and emissions. Excessive back pressure would cause the pressure relief vents on the tank truck to open.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation. The primary concern would be worker safety.
- Technical considerations. A failure could potentially occur if a foreign object were to enter the hose, which is rare. Monitoring of backpressure is not required under the MACT standard. All NESHAP requirements proposed after 11/15/90 are deemed by EPA to satisfy the Title V monitoring requirements (see FR 54915 10/22/97, and 40 CFR 64.2(b)(1)(i)). This rare event would be detected pursuant to the monitoring required under 40 CFR 63.148(b)(2)(ii). This provision requires US Oil to perform annual monitoring of the flexible vapor hoses for leaks, which are most likely to be found if the system is overpressurized. Truck drivers should also notice their relief valves venting and report it to the dispatch manager.

None of the applicable requirements for the gasoline tank truck loading rack require periodic monitoring to verify compliance with the basic requirement to have bottom loading with vapor recovery. The permit does not require monitoring because:

- Initial compliance. A review of the compliance history showed no Notices of Violation have been issued.
- Margin of compliance. The equipment clearly meets this requirement. Trucks cannot physically be loaded by any other means.
- Variability of process and emissions. Emissions can only occur during truck loading.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation. The primary concern would be worker safety.
- Technical considerations. Monitoring is not required under the MACT standard. All NESHAP requirements proposed after 11/15/90 are deemed by EPA to satisfy the Title V monitoring requirements (see FR 54915 10/22/97, and 40 CFR 64.2(b)(1)(i)).

None of the applicable requirements for the gasoline tank truck loading rack require periodic monitoring to verify compliance with the limit on liquid leaks. The permit requires *quarterly* monitoring. These added monitoring requirements are based upon:

- Initial compliance. A review of the compliance history (see above) showed one Notice of Violation was issued in 1985.
- Margin of compliance. Normally, the leak rate is much lower than the limit.
- Variability of process and emissions. Dry break connectors are virtually leak-free, but will eventually wear out and start to drip. Drips can also occur as a result of wear of the couplers on the tank truck side. This is why the standards average over three disconnects.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation. The primary concern would be worker safety.
- Technical considerations. No similar requirements are found under the MACT standard, Subpart XX of Part 60, or the Hazardous Organic NESHAP. US Oil has a preventative maintenance work order, performed quarterly, that requires checks of the vapor and product hoses and fittings, etc. Also, once per shift the dispatcher visually inspects the loading rack for leaks following a checklist. US Oil is required by the Oil Handlers Training and Certification Program to have a program for instructing truck drivers on hookup procedures and spill response.

The applicable requirement for truck drivers to connect the vapor recovery system does not require periodic monitoring. The permit does not require monitoring because:

- Initial compliance. A review of the compliance history showed no Notices of Violation have been issued.

- Margin of compliance. Loading is not possible unless the vapor recovery system is connected.
- Variability of process and emissions. Emissions can only occur during truck loading.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation. The primary concern would be worker safety.
- Technical considerations. The applicable requirement specifies that posting signs is an acceptable means of compliance. US Oil posts such instructions. Monitoring is not required under the MACT standard. All NESHAP requirements proposed after 11/15/90 are deemed by EPA to satisfy the Title V monitoring requirements (see FR 54915 10/22/97, and 40 CFR 64.2(b)(1)(i)).

Of the applicable requirements for the gasoline tank truck loading rack, only the MACT standard requires periodic monitoring to assure that only trucks with current certifications on file are loaded. The permit does not require additional monitoring because:

- Initial compliance. A review of the compliance history showed no Notices of Violation have been issued.
- Margin of compliance. With the computerized system employed by US Oil, it is not possible for trucks without current certifications on file to load unless the driver intentionally inputs the ID number of a different (certified) transport tank. There is no evidence that this practice is occurring.
- Variability of process and emissions. Without the computerized tracking system, there would be a greater potential for loading product onto an uncertified transport tank and that could result in increased emissions.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation. The primary concern would be worker safety.
- Technical considerations. When the emission standards were originally adopted in the early 1980's, computerized systems probably didn't exist. Today, all of the gasoline loading terminals in the Puget Sound area use such systems. The MACT standard still references the (outdated) Subpart XX requirement to manually cross check the transport tank ID numbers with the certificates on file within 2 weeks of the loading activity. Continuous monitoring makes these requirements irrelevant.

The applicable requirement for cutback asphalt use does not require any periodic monitoring. The permit requires US Oil to notify (in writing) each of its cutback asphalt customers of the requirement. This added monitoring requirement is based upon:

- Initial compliance. A review of the compliance history showed no Notices of Violation have been issued.
- Margin of compliance. Section 3.01 of PSCAA Regulation II makes it unlawful to 'cause or allow' the use of cutback asphalt during summer months except under certain conditions. US Oil does not use asphalt, but supplies it to end users. And since it needs to be heated, it is generally used shortly after being loaded. Only in that sense could US Oil 'cause or

allow' its use in violation of the prohibition.

- Variability of process and emissions. The use of cutback asphalt results in substantial VOC emissions. This is why its use is largely prohibited during the summer months.
- Air quality impact of deviations. There are no ambient air quality standards for VOC or HAP. The magnitude of any impact would depend upon the magnitude and duration of the deviation.
- Technical considerations. A one-time notification to each cutback asphalt customer was deemed appropriate by US Oil and has been instituted.

Operational Requirements and Limitations

WAC 173-401-605(1) requires the permit to contain 'emission limitations and standards, including those operational requirements and limitations that assure compliance'. WAC 173-401-600(2) requires the permit to 'identify any difference in form as compared to the applicable requirement upon which the term or condition is based'.

Emission limitations and performance standards containing language that is further defined in the permit include:

- PSCAA Reg. I, §7.09(b), which requires 'prompt repair of defective equipment and control equipment';
- PSCAA Reg. I, §7.09(b), which requires 'recording of equipment and control equipment performance' and 'a record of all actions required by the [O&M] plan';
- PSCAA Reg. I, §9.20, which requires equipment to be 'maintained in good working order';
- PSCAA Reg. I, §3.07(a), which requires that 'testing of sources for compliance with emission standards shall be performed in accordance with current US EPA approved methods unless specific methods have been adopted by the Board';
- WAC 173-400-105(4), which requires 'approved EPA methods from 40 CFR parts 51, 60, 61 and 63, or approved procedures contained in "*Source Test Manual - Procedures for Compliance Testing*," state of Washington, Department of Ecology, as of July 12, 1990'.
- PSCAA Order of Approval No. 4841, Condition 3, 40 CFR 60.113b(c)(2) and 40 CFR 63.120(d)(5), which relate to monitoring of the combustion chamber temperature of the vapor combustor (H-1501).

Prompt Repair - PSCAA Reg. I, §7.09(b)

PSCAA Reg. I, §7.09(b) (listed in Section II.H of the permit) requires 'prompt repair of defective equipment and control equipment.' This is defined by the permit to mean 'as soon as practicable but no later than 24 hours after identification, except where the applicable requirement specifies a different timeframe. Shutdown of the defective (noncompliant) equipment within 24-hours is an alternative to repair.' The permit also requires complaints to be investigated within 24 hours.

The storage tanks regulated by the state and local rules are also regulated under Subpart Kb of 40 CFR Part 60 or Subpart CC of 40 CFR Part 63. Defective storage tank equipment must be repaired in accordance with the timeframes specified in the federal rules.

The gasoline tank truck loading rack is also regulated by federal, state and local rules. Defective loading rack equipment must be repaired in accordance with the timeframes specified in Subpart CC of 40 CFR Part 63 for valves in gas/vapor or light liquid service and for the closed-vent system (manifold connecting storage tanks, loading rack, and vapor combustor).

Records - PSCAA Reg. I, §7.09(b)

PSCAA Reg. I, §7.09(b) also requires 'recording of equipment and control equipment performance' and 'a record of all actions required by the [O&M] plan.' This is defined as the date and the results of the inspection, tests or other actions including corrective actions and who conducted the inspection, tests or other actions. For complaint investigations, records must also include the date and time of the complaint, the name of the person complaining (if known) and the nature of the complaint. These recordkeeping requirements have been combined with those required under WAC 173-401-615(1)(b) and (2)(a) and listed in Section II of the permit, as appropriate.

'Good Working Order' - PSCAA Reg. I, §9.20 and RCW 70.94.152(7)

PSCAA Reg. I, §9.20 requires equipment to be 'maintained in good working order'. Similarly, RCW 70.94.152(7) equipment approved under a Notice of Construction to be 'maintained and operate in good working order.' This is defined in Section II.H of the permit, based on the definitions of 'good industrial practice' and 'good air pollution control practice' found under 40 CFR Sections 60.11(d) and 63.6(e)(2). The federal standards define good air pollution control practice because most of their emission limits do not apply during periods of startup, shutdown and malfunction.

Any potential for malfunctions of US Oil's Claus unit (SRU-2) are minimized by the use of the Lo Cat unit (SRU-1) for ammonia bearing gases from the sour water stripper that can cause plugging in the Claus plant. If SRU-2 does malfunction, the sour gas stream can be diverted to SRU-1. Although it requires idling of the diesel hydrotreater, the largest source of sour gas, it can usually be accomplished within several hours.

Approved Test Methods - PSCAA Reg. I, §3.07 and WAC 173-400-105(4)

PSCAA Reg. I, §3.07(a) requires that 'testing of sources for compliance with emission standards shall be performed in accordance with current US EPA approved methods unless specific methods have been adopted by the Board.' Similarly, WAC 173-400-105(4) requires 'approved EPA methods from 40 CFR parts 51, 60, 61 and 63, or approved procedures contained in "*Source Test Manual - Procedures for Compliance Testing*," state of Washington, Department of Ecology, as of July 12, 1990.' Where an applicable requirement does not specify a test method, one has been listed under the Reference Test Method column in Section I of the permit, as appropriate. Non-EPA test methods are included under Section IX of the permit.

Vapor Combustion Unit Temperature
PSCAA Order of Approval No. 4841, 40 CFR 63.120(d)(5) and 60.113b(c)(2)

PSCAA Order of Approval No. 4841, Condition 3, states "US Oil shall operate the combustor with the temperature controller set to maintain 1200 °F during normal operations". Additional operational requirements stem from the Refinery MACT and NSPS standards, since the VCU controls emissions from three Group 1 tanks and nine Subpart Kb tanks. Section 63.120(d)(5) of the MACT standard requires US Oil to operate and maintain the VCU such that the temperature remains within the range specified in the Notification of Compliance Status Report. Similarly, §60.113b(c)(2) of the NSPS requires the VCU to be operated in accordance with the operating plan submitted for approval with the Notice of Construction. These submittals and the Order of Approval specified no averaging period for the minimum operating temperature. The operating permit establishes an operating cycle averaged temperature. The VCU operations vary, but typically it activates between ten and twenty times daily and operates for between 10 minutes and 2 hours each time. Compliance with the 1200 °F minimum cycle-averaged operating temperature will assure compliance with the underlying emission standard of 95% destruction during each activation.

Recordkeeping

The permit incorporates the recordkeeping provisions from WAC 173-401-615(2)(a), which specifies that "With respect to recordkeeping, the permit shall incorporate all applicable recordkeeping requirements and require, where applicable, the following:

(a) Records of required monitoring information that include the following:
(i) The date, place as defined in the permit, and time of sampling or measurements;
(ii) The date(s) analyses were performed;
(iii) The company or entity that performed the analyses;
(iv) The analytical techniques or methods used;
(v) The results of such analyses; and
(vi) The operating conditions existing at the time of sampling or measurement.

Inapplicable Requirements

US Oil requested to list in the permit a number of requirements it considers to be inapplicable to its facility. Pursuant to WAC 173-401-640(2), PSCAA has considered its request and listed those requirements determined to be inapplicable. The permit shield extends to these requirements. (Requirements not listed in the permit are not shielded.)

The permit includes a brief description of the requirement and the reason it was determined to be inapplicable. A complete finding is described below for each requirement.

Fugitive Dust (Particulate Matter)

WAC 173-400-040(8)(b) and (3)(b) apply to emission units identified as 'significant contributors' to PM_{10} nonattainment areas. US Oil has virtually no fugitive dust emissions. The PM_{10} SIP emission inventory shows none. Therefore, these requirements are inapplicable.

Boilers (Particulate Matter, SO_2, and NO_x)

US Oil installed boiler B-4 in June 1980 and boiler B-5 in April 1985. B-4 has a rated heat input of 99 MMBtu/hr and B-5 has a rated heat input of 80 MMBtu/hr. Both boilers predate the 40 CFR Part 60, Subpart Dc requirements which apply to units installed after 6/9/89. Both boilers are below the size threshold for 40 CFR Part 60, Subpart Db of 100 MMBtu/hr. B-4 also predates the Subpart Db requirements which apply to units installed after 6/19/84. Therefore these boilers are not ‘affected facilities’ as defined under Sections 60.40b and 60.40c and NSPS Subparts Db and Dc are inapplicable.

Claus Sulfur Recovery Unit (SO_2)

US Oil installed a Claus sulfur recovery unit rated at 10 ton/day in July 1993. Since it is rated at <20 ton/day, it is not an ‘affected facility’ as defined under §60.100 of 40 CFR Part 60, Subpart J. The Claus unit tail gas incinerator (H-580) burns fuel gas and is subject to the requirements for ‘fuel gas combustion devices’. However, the provisions specific to Claus units under Sections 60.104(a)(2), 60.105(a)(5), 60.105(e)(4), and 60.106(f) are inapplicable.

Fuel Gas H_2S (SO_2)

Section 60.107 of 40 CFR Part 60, Subpart J was adopted on 8/17/89 along with a number of other amendments for fluid catalytic cracking unit (FCCU) catalyst regenerators. The first three paragraphs of this section apply explicitly only to such units. Paragraphs (d), (e), and (f) do not contain such language. In consultation with John Keenan of EPA Region 10, these paragraphs were also determined to apply only to FCCU. US Oil does not have an FCCU. Therefore, these requirements are inapplicable.

The ‘reformer’ flare (F-2) at US Oil is reportedly used only for emissions resulting from process unit startups, shutdowns upsets or malfunctions of the second reformer (CRU-2), the diesel hydrotreater (DHU), and the sulfur recovery units (SRU-1, SRU-2). Therefore, it is an affected facility but exempt from the emission standards under 40 CFR Part 60, Subpart J (see §60.104(a)(1)).

Used Oil (TAC)

RCW 70.94.610 contains limits for contaminants in used oil burned in land-based facilities. US Oil does not burn used oil. Therefore, this requirement is inapplicable.

Cooling Towers (Inorganic HAP)

US Oil is a major HAP source and has cooling towers, but does not operate them with chromium-based water treatment chemicals. Therefore, Subpart Q of Part 63 is inapplicable.

Equipment Leaks (VOC and Organic HAP)

The only process unit directly subject to NSPS Subpart GGG is the Isomerization unit. An ‘isom stabilizer’ was installed in 1993, constituting a ‘modification’ under §60.14. All of the ‘equipment’ comprising this ‘affected facility’ under Subpart GGG is also ‘in organic HAP service’. Pursuant to §63.640(p), this equipment is required to comply only with the provisions specified in the Refinery MACT standard, which incorporates by reference NSPS Subpart VV and the test method for determining ‘in light liquid service’ found under §60.593(d) of NSPS

Subpart GGG. (This equipment is also subject to PSCAA Reg. II, Section 2.03.)

US Oil has no equipment 'in benzene service' as defined in 40 CFR 61.111 (i.e., equipment that could conceivably contain ≥10% benzene by weight). Therefore, it is not subject to Subpart J. Because it is not subject to Subpart J, it is also not subject to Subpart V of Part 61, which contains the emission standards for equipment subject to Subpart J.

Flares for Pumps, PRVs, Reformers (Organic HAP)

The flares at US Oil are used as control devices for pumps and pressure relief devices pursuant to 40 CFR 63.648(a) and 40 CFR 60.482-10. However, they are exempt from the continuous monitoring system provisions of §63.8, paragraphs (c)(4), (c)(6), (d) and (e) pursuant to §63.8(b)(1)(iii), which exempts flares subject to the control requirements in §63.11(b) unless otherwise specified in the relevant standard. Table 44 of Subpart UUU and Table 6 of Subpart CC specify that these provisions are inapplicable.

Because the flares are exempt from the continuous monitoring provisions of §63.8(e), the records of monitoring system performance evaluations under §63.654(f)(4) are also inapplicable.

Storage Tanks (VOC and Organic HAP)

US Oil has storage tanks subject to 40 CFR Part 60, Subparts Ka and Kb. The 'affected facilities' under Subpart K are storage tanks for which construction, reconstruction, or modification commenced between 6/11/73 and 5/19/78. US Oil installed three storage tanks (TK-80017, TK-80018, and TK-80019) in April 1981. PSCAA originally permitted these as Subpart K tanks under Order of Approval No. 2046. That order was later amended to reflect that these are Subpart Ka tanks. Subpart K is inapplicable.

It is worth noting here that §63.640(n)(7) of the MACT standard exempts Group 2 tanks not subject to control requirements of Subpart Ka (TK-30004, TK-80019) from the other Subpart Ka requirements. Tanks TK-80017 and TK-80018 are subject to the control requirements of Subpart Ka but are only required to comply with the Group 1 storage vessel requirements per §63.640(n)(5).

Under §63.120(d)(5) of the MACT standard, §60.113b(c)(2) of Subpart Kb, and §60.473(c) of Subpart UU, US Oil is required to monitor the parameter(s) of the control device in accordance with the operating plan (submitted as part of the initial notification) to ensure the control device is properly operated and maintained. Continuous monitoring is not required by these regulations. The initial notification must include an explanation of the criteria used for selecting the monitoring parameter(s) and frequency, but no agency approval of the plan is required.

The general monitoring requirements under Subpart A of Parts 60 and 63 (§60.13 and §63.8) apply to 'continuous monitoring systems' and 'monitoring devices' required under the monitoring sections of the applicable subparts (Kb, UU and CC). Since the monitoring sections of the applicable subparts (§60.116b, §60.473, §63.120) do not require a 'continuous monitoring system' or 'monitoring device', the general monitoring requirements under Subpart A (§60.13, §63.8) are considered inapplicable. Similarly, references to 'continuous monitoring systems' and 'monitoring devices' in §60.7(b) and (f) are also considered inapplicable to the storage tanks.

Because the storage tanks are exempt from the continuous monitoring provisions of §63.8(c), the records of monitoring system performance evaluations under §63.654(f)(4) are also inapplicable.

The Group 1 storage tanks subject to Subpart Kb are exempted under §63.640(n)(8). Further, Table 6 of Subpart CC clarifies that storage tanks aren't subject to these provisions.

The design of the tanks connected to the gasoline tank truck loading rack closed vent system do not allow safe operation at the pressures described in 40 CFR 60.502(i). This requirement states that pressure-vacuum vents on the closed vent system must not begin to open at pressures less than 18" W.C. Although not an applicable requirement to the closed vent system, §60.502(h) provides further insight. It states that the closed vent system must be designed and operated to prevent pressures from exceeding 18" W.C. during loading operations. The intent of §60.502(i) is therefore to ensure that during normal operation the closed vent system operates at pressures which will not allow raw vapors to be vented through the pressure-vacuum vents.

Following the guidelines of API Standard 650, the pressure-vacuum vents on tanks connected to the closed vent system must be set to open at 3.5" W.C. to allow safe operation and prevent catastrophic tank failure. Vapors collected in this closed vent system are routed to a vapor combustion system (H-1501) which is activated when the closed vent system pressure reaches 2.5" W.C. H-1501 is deactivated when the pressure decreases to 0.5 " W.C.

The design and operation of this system ensures that the closed vent system pressure does not reach the release point of the pressure-vacuum vents. To further ensure that raw vapors are not emitted from the pressure-vacuum vents, a high pressure switch is installed in the closed vent system which activates a local area alarm in the event that the system pressure reaches 3.0" W.C. This warning system allows US Oil time to identify the cause of the high system pressure and make adjustments to return the system pressure to normal levels before pressures reach the release point of the pressure-vacuum vents. U.S. Oil also installed an automatic valve on the waste gas stream that allows increased flow rates when system pressure exceeds 2.7" W.C.

The design and operation of this system meets the intent of 40 CFR 60.502(i), which is to ensure that during normal operation the system pressure is maintained below the release point of the pressure-vacuum vents. To add to the robustness of the system, US Oil sends vapor combustor alarm signals to its DCS (Net-90) system which is monitored by the main control room 24-hours/day. In the event of a sustained high pressure signal or other system problem, a closed vent system warning will alarm the control room operator. The control room operator will then contact the B-area operator who will proceed in the identification and remedy of the cause of the high pressure alarm. Alarm events are recorded. These operational procedures, coupled with the closed vent system design, adds several layers of protection for ensuring that pressure-vacuum vents will not release during normal operation.

Gasoline Truck Loading Rack (VOC and Organic HAP)

U.S. Oil must comply with many of the requirements in 40 CFR Part 60, Subpart XX pursuant to 40 CFR 63.650, which requires compliance with §63.422 which requires compliance with §60.502. However, US Oil does not have any 'affected facilities' as defined under §60.500 of Subpart XX. Therefore, Subpart XX, in general, is inapplicable.

The gasoline loading rack at US Oil uses a vapor balance system to return vapors displaced during truck loading to the storage vessel providing the gasoline. The system is connected to trucks via flexible hoses with Camlock™ fittings. Check valves are located in the hard-piping near the hose connections to prevent vapor leakage when not in use. A hard-piped trunk line connects the fixed roof tanks with the loading rack.

The trunk line is also connected to a vapor combustor, which is required as a control device for nine gasoline storage tanks under 40 CFR Part 60, Subpart Kb, three tanks under WAC 173-491-040 and 40 CFR Part 63, Subpart CC, and 12 tanks under PSCAA Reg. II., §3.02.

The gasoline loading racks at most refineries and loading terminals employ a control device for the vapors displaced during truck loading. Therefore, the federal, state, and local emission limits were all written in units of milligrams of emissions per liter (or lb/1000 gal) of gasoline loaded. The truck loading operations at US Oil are not of the typical design for which the rules were developed.

The control device at U.S. Oil is activated by a pressure sensor in the trunk line which is triggered during the filling of storage tanks connected to the closed-vent system. It is not activated by gasoline truck loading and its efficiency has no effect on the efficiency of the vapor balance system used for the gasoline truck loading. A source test conducted in accordance with the reference test methods and procedures would intrinsically result in zero emissions.

Notwithstanding, the vapor combustor could be considered a control device for diesel truck loading, since diesel is loaded from two storage tanks (TK-28001 and TK-45001) not connected to the vapor balance system. There are no emission standards for diesel truck loading because the uncontrolled emissions are extremely low. The vapor combustor used by US Oil is a thermal oxidizer fueled by refinery fuel gas or natural gas (not a flare). The lower volatility of the diesel vapor does not adversely affect its performance as a control device for gasoline storage tanks.

For these reasons, the emission standards in the form of mg/l of gasoline transferred listed in §63.422(b), WAC 173-491-040(2)(c)(i), and PSCAA Reg. II, §2.05(c) are inapplicable. However, the vapor recovery (balance) system does prevent the emission of at least 90% by weight of the VOC as required by PSCAA Reg. II, §2.05(c).

Also inapplicable are the test methods and procedures for control devices under §63.425 and §60.503 via the MACT standard; the continuous monitoring requirements for control devices under §63.427(a)(iv) and (b), WAC 173-491-040(2)(c)(ii), and of PSCAA Reg. II, §2.05(d); and the recordkeeping and reporting requirements under §63.428(c) and (h)(1) are inapplicable.

Vapor balance systems are listed as a 'reference control technology for transfer racks' (see 40 CFR 63.111) and are allowed under §63.126(b)(3) of the Synthetic Organic Chemical Manufacturing Industry (SOCMI) MACT standard. Section 63.128(c)(4) of this standard exempts vapor balance systems from performance testing requirements. However, these specific sections of the SOCMI MACT standard aren't referenced by Petroleum Refinery MACT standard.

Section 63.128(e) of the SOCMI MACT standard, which *is* referenced by the Refinery MACT standard, requires periodic monitoring and inspection of the closed-vent system using the procedures in §63.148. Similarly, the Marine Vessel Loading MACT standard (see §63.560(d)(2)) exempts vapor balancing systems from emission limits and performance testing requirements and requires annual monitoring of the closed-vent system.

Accordingly, the permit applies the storage tank closed-vent system requirements under 40 CFR Sections 63.646 and 60.112b, WAC 173-491-040, and PSCAA Reg. II, Sections 2.05 and 3.02, to the entire closed-vent system - including the sections extending to the gasoline tank truck loading rack, all of the connected storage vessels (and their fixed roofs), and the vapor combustor.

US Oil does not own or operate tank trucks. Therefore, the provisions under WAC 173-491-040(6)(b)(ii) and PSCAA Reg. II, §2.08 are inapplicable.

Gas Station (VOC)

U.S. Oil has two underground gasoline storage tanks for its own personnel. They were installed prior to 1/1/79 and the station throughput is <200,000 gallons per year. Therefore, the Stage 1 and 2 requirements under PSCAA Reg. II, §2.07 and WAC 173-491-040(4) and (5) are inapplicable.

40 CFR Part 63 Subpart UUU (Refinery MACT II) Bypass Lines

U.S. Oil has no bypass lines that could divert an affected vent stream away from a control device used to comply with the requirements of 40 CFR 63 Subpart UUU. The sulfur tank vent was evaluated and determined to be emergency equipment needed for safety reasons. See 40 CFR 63.1562(f)(4).

40 CFR Part 63, Subpart ZZZZ (RICE MACT)

U.S. Oil has six stationary reciprocating internal combustion engines (RICE) on-site (GE-1, GE-2, J-222, J-250, J-601A and J-601B). GE-1 is exempt from Subpart ZZZZ per §63.6590(b)(3) because it’s an emergency stationary CI RICE >500 brake horsepower (bhp). GE-2, J-222, J-601A, and J-601B are exempt from Subpart ZZZZ per §63.6590(c) because they are new stationary emergency CI RICE ≤500 bhp subject to Subpart IIII. Only J-250 is subject to the RICE MACT. During refinery-wide turnarounds, U.S. Oil brings in large portable generators to support these efforts. These generators are ‘non-road engines’ and are exempted under §63.6585(a).

40 CFR Part 51, Subpart P and Appendix Y, and WAC 173-400-151
Protection of Visibility

WAC 173-400-151 establishes Washington State implementation of 40 CFR Part 51, Subpart P and Appendix Y, Best Available Retrofit Technology (BART). The requirements of this section apply to certain existing stationary facilities. An "existing stationary facility" means a stationary source of air contaminants that meets all of these conditions:

(a) The stationary source must have the potential to emit 250 tons per year or more of any air contaminant. Fugitive emissions, to the extent quantifiable, must be counted in determining the potential to emit; and
(b) The stationary source was not in operation prior to 8/7/62 and was in existence on 8/7/78; and
(c) Is in one of the 26 source categories (includes petroleum refining).

Active emission units that meet the date criteria have actual emissions of ~5 tons per year and a potential to emit <250 tons per year and are therefore exempt from WAC 173-400-151 and 40 CFR Part 51, Subpart P and Appendix Y, Best Available Retrofit Technology requirements. The Washington State Department of Ecology indicated this status of U.S. Oil in their identification of BART eligible sources. (See http://www.wrapair.org/forums/ssjf/bart.html)

40 CFR part 63 subpart EEEE (Organic Liquids Distribution (OLD) MACT)

40 CFR Part 63 Subpart EEEE, the Organic Liquids Distribution (OLD) MACT, applies to certain equipment used to distribute specifically defined organic liquids into, out of, or within facilities that are major sources of hazardous air pollutant (HAP) emissions. The OLD MACT affected sources are storage tanks, containers, liquid transfer racks, equipment leak components, and transport vehicles that are in organic liquid service (as that term is defined in 40 CFR 63.2406). Equipment that is affected by another MACT standard, such as Subpart CC, is exempt from Subpart EEEE.

U.S. Oil performed a detailed review of the wide range of process chemicals and fuel additives in use at the refinery to determine if any of the equipment would be considered an affected source as per 40 CFR 63.2338. All but one of the chemicals was determined to be exempt based on one of the following criteria:

- ⇒ HAP content <5% - 40 CFR 63.2406 Organic Liquid (1)
- ⇒ HAP partial pressure <0.1 psia - 40 CFR 63.2406 Organic Liquid (3)(vi)
- ⇒ Products Regulated by 40C FR 63 Subpart CC - 40 CFR 63.2338(c)(1)

The one chemical material in use at the refinery that is defined as an organic liquid is Stadis 450, a jet fuel conductivity improver. This additive is transferred from a tote container by hand for use and does not involve the use of a transfer rack. Therefore, even though U.S. Oil is an OLD operation, it has no affected sources per 40 CFR 63.2338 and none of the OLD MACT requirements apply to the facility. *U.S. Oil decided not to list this as an inapplicable requirement because they may install an OLD MACT unit in the future.*

PSCAA Orders of Approval
Nos. 1911, 2046, 2331, 2459, 2501, 2573, 2586, 2597, 2633, 3186, 3900, 4177, 4841, 5431, 5433, 6827, 7761, 8217, and 9836

Certain Orders of Approval issued to US Oil were subsequently amended or superseded to resolve Prevention of Significant Deterioration issues, make technical changes, and correct typographical errors. Other Orders of Approval are now inapplicable because the emission units covered have been replaced or were never installed.

The emission units installed under Order of Approval No. 1911 for the aborted fluidized-bed catalytic cracker expansion and Order of Approval No. 2573 for the aborted hydrocracker expansion were re-permitted to assure that they did not trigger the Prevention of Significant Deterioration provisions. The permitting sequence is complicated because units installed under the aborted fluidized-bed catalytic cracker expansion (H-11, H-201, B-4) were first re-permitted under the aborted hydrocracker based expansion. Then the boilers (B-4, B-5), the light crude unit heater (H-11), and the light crude vacuum unit heater (H-201) were re-permitted under Order of Approval Nos. 5429, 5430, 5431 and 5432, respectively, to net them out of PSD review. The light crude unit heater (H-11) was later replaced and permitted under Order of Approval No. 5448.

The heavy crude unit heater (H-3) installed under Order of Approval No. 2459 was replaced under Order of Approval No. 2586. Then it was re-permitted under Order of Approval No. 2597 to allow the use of fuel oil with a higher ash content. Order of Approval No. 2597 was reissued on 1/9/02 to remove the fuel oil ash content that would trigger a source test. (This was enabled by the subsequent adoption of Regulation I, Section 9.08 that contains an ash content limit.) Order of Approval No. 2597 (dated 1/9/02) was cancelled and superseded by Order of Approval No. 9153 (dated 3/24/05) when H-3 was taken from the HCU and placed into service in the LCU.

Order of Approval No. 4841 for the storage tank vapor combustor was reissued to allow operation at the operating temperature during the initial performance test, which was 200 degrees lower than was allowed under initial approval.

Order of Approval No. 5433 for the Claus sulfur recovery unit was reissued to include provisions for startup and shutdown that weren't in the initial approval.

Order of Approval No. 2633 for the vacuum ejector/surface condenser in the heavy crude unit was reissued to remove the requirement to combust the noncondensable gases in the heavy crude unit heater. (Regulation II, Section 2.03 requires these gases to be "piped to an appropriate firebox, flare, or incinerator for combustion or collected, compressed and added to the fuel gas system or contained and treated so as to prevent their emission to the atmosphere.")

Order of Approval No. 3900 for the diesel hydrotreater expired prior to commencing construction. It was re-permitted under Order of Approval No. 4177, which was later reissued to correctly specify that the H_2S emission limit is for the fuel gas and not the exhaust.

Order of Approval Nos. 2046, 2331 and 2501 were reissued to correctly reference the associated storage tank NSPS requirements.

The storage tanks proposed under Order of Approval No. 3186 were never installed.

Orders of Approval Nos. 6827, 7761 and 8217 for asphalt loading rack and storage tank demisters were reissued to delete the limit on pressure drop across the filter. The limits in the original approval orders were reflective of an unloaded filter. US Oil was complying with the limits, but doing so resulted in a lower capture efficiency (greater fugitive emissions) at the loading racks.

Order of Approval No. 9836 was canceled and superseded by Order of Approval No. 10053.

Registration

RCW 70.94.161(17) states that registration programs adopted pursuant to 70.94.151 shall not apply to operating permit sources. Therefore, WAC 173-491-030 and PSCAA Reg. I, Article 5 are inapplicable.

Transportation Demand Management

RCW 70.94.531 regarding transportation demand management does not apply to emission units. Therefore, it does not meet the definition of ‘applicable requirement’ under WAC 173-401-030(4). As such, it is inapplicable.

Insignificant Emission Units

As of the date of permit issuance, the emission units listed below are designated as insignificant for the reasons indicated. All units and activities listed in WAC 173-401-532 are also insignificant emission units. This designation does not exempt them from any applicable requirements. And the permit shield does not apply to insignificant emission units. An emission unit or activity that qualifies as insignificant solely on the basis of WAC 173-401-530(1)(a) shall not exceed the emission thresholds specified in WAC 173-401-530(4) until this permit is modified.

Where the permit does not require testing, monitoring, recordkeeping and reporting for insignificant emissions units or activities, US Oil may certify continuous compliance if there were no observed, documented, or known instances of noncompliance during the reporting period. Otherwise, the deviation must be reported as specified in Section V.P of the permit.

U.S. Oil also has an obligation under Sections 7.09(b) and 9.20 of Regulation I to promptly repair defective equipment or control equipment (including insignificant emission units) and to operate the equipment in good working order. Failure to comply with these requirements constitutes a permit deviation that must be reported as specified in Section V.P of the permit.

Emission Unit	Basis for IEU Designation
Tote Bins	WAC 173-401-530(1)(c) WAC 173-401-533(2)(a) <260 gal with lids or other appropriate closure, heated only to the minimum extent to avoid solidification if necessary
Tote Bins	WAC 173-401-530(1)(c) WAC 173-401-533(2)(b) <1,100 gal with lids or other appropriate closure, not for use with HAP, maximum vapor pressure 550 mm Hg
Fuel Tanks, Day Tanks	WAC 173-401-530(1)(c) WAC 173-401-533(2)(c) <10,000 gal with lids or other appropriate closure, not for use with HAP, maximum vapor pressure 80 mm Hg @ 21 °C
Railroad Cars, Tank Trucks, Portable Tanks	WAC 173-401-530(1)(c) WAC 173-401-533(2)(d) <40,000 gal for butane, propane, or LPG
Asphalt Containers, Space Heaters	WAC 173-401-530(1)(c) WAC 173-401-533(2)(g) <1 MMBtu/hr fired only on kerosene, No. 1 or No.2
Welding	WAC 173-401-530(1)(c) WAC 173-401-533(2)(i) not more than 1 ton/day of welding rod
Cooling Tower Chlorinator	WAC 173-401-530(1)(c) WAC 173-401-533(2)(p) not >20,000,000 gal/day, not for wastewater
Surface Coating	WAC 173-401-530(1)(c) WAC 173-401-533(2)(q) <2 gal/day
Space Heaters, Pressure Washers	WAC 173-401-530(1)(c) WAC 173-401-533(2)(r) <5 MMBtu/hr fired only on natural gas, propane or kerosene
TK-101, TK-107, TK-110, TK-113, TK-202, TK-206, TK-207, TK-757, Betz polymer tank by IAF, Betz polymer tank by clarifier	WAC 173-401-530(1)(c) WAC 173-401-533(2)(s) tanks with lids or other appropriate closure and pumping equipment for aqueous solutions of inorganic salts, bases and acids excluding: 99% or greater sulfuric or phosphoric acid; 70% or greater nitric acid, 30% or greater hydrochloric acid; and solutions with more than one liquid phase where the top phase contains >1% VOC

Emission Unit	Basis for IEU Designation
Asphalt Tanks: TK-240 Fuel Oil Tanks: TK-130, TK-241, TK-242 Railroad Cars	WAC 173-401-530(1)(c) WAC 173-401-533(2)(t) tanks with lids or other appropriate closures and pumping equipment for products with an initial boiling point not less than 150 °C or vapor pressure not more than 5 mm Hg @ 21 °C
Laboratory	WAC 173-401-530(1)(c) WAC 173-401-533(3)(c) chemical or physical analytical lab operations or equipment including fume hoods and vacuum pumps
Concrete Pond, Stormwater Pond, North Pond, South Pond, Equalization Pond	WAC 173-401-530(1)(c) WAC 173-401-533(3)(d) NPDES permitted ponds used solely for the purpose of settling suspended solids and skimming of oil and grease
Portable light plants	WAC 173-401-530(1)(c); WAC 173-401-533(2)(g)

Response to US Oil's Comments on the Draft AOP

I. A placeholder requirement should be added to the Title V Air Operating Permit noting that U.S. Oil will comply with the applicable requirements contained in 40 CFR 63, Subpart DDDDD once this rule is finalized.

Response: No change was made, as there is no applicable requirement to cite yet.

2. Should the Washington State registration and reporting program for GHG, which is authorized under Chapter 70.94 RCW (70.94.151) and therefore the requirements of that statute and any implementing rules, be included in the Title V Air Operating Permit? The rules, however, which are being written under WAC 173-441, are not yet final, and were deferred due to 2010 legislation to ensure consistency with the federal program. See [http://www.ecy.wa.gov/ laws-rules/activity/wac173441.html](http://www.ecy.wa.gov/laws-rules/activity/wac173441.html). If PSCAA agrees that these existing statutory and pending regulatory requirements are or will be "applicable requirements" the permit should reference the requirements including a placeholder to implement future effective regulations.

Response: No change was made, as there is no applicable requirement to cite yet.

3. Based on the scope of 40 CFR 60.4207(b) and 40 CFR 80.510(b), Requirement No. I.A.23 applies to the following stationary compression ignition (CI) engines at U.S. Oil: J-222, GE-2, J-601A and J-601B.

Response: This change was made.

4. In Note 1, which is located on page 23 of 329 and precedes Requirement No. I.B.13, delete CRU-1 from the list of units served by Flare F-2:

Response: This change was made.

5. This comment pertains to 40 CFR 60 Subpart Ja references requirements located throughout the draft Title V Air Operating Permit. Per the December 22, 2008 Federal Register (73 FR78549-78552) the following provisions contained in 40 CFR 60 Subpart Ja were stayed effective February 24, 2009 until further notice: 60.100a paragraph (c), the definition of "flare" in 60.101a, 60.102a paragraph (g) and 60.107a paragraphs (d) and (e). As such, U.S. Oil contends that none of the stayed provisions are "applicable requirements" and objects to the listing of any Ja requirements that are not applicable to an affected facility. References to Ja are repeated numerous times throughout the body of the draft Title V Air Operating Permit and need to deleted/corrected as appropriate.

For example, the last sentence of Note 2, which is located on page 23 of 329 and precedes Requirement No. I.B.13, contains the following sentence: "H-202, H-901 and F-l may become affected facilities, depending on the outcome." This sentence does not add any value to this note and should be removed as it is based on conjecture, not fact. Based on an electronic word search of the draft Title V Air Operating Penn it, references to Ja were found in the following locations and need to corrected as noted in the preceding paragraph:

- Requirement No. I.B.15
- In the Note preceding Requirement No. I.B.18
- In the Note preceding Requirement No. II.B.21
- Requirements No. II.B.21 and II.B.22
- In the Note preceding Requirement No. II.B.23
- Requirements No. II.B.23 through II.B.33
- Requirement No. II.H.3
- Requirement No. II.I.11 and II.I.12
- In the Note preceding Requirement No. V.P.12

A placeholder requirement should be added to the Title V Air Operating Permit noting that U.S. Oil will comply with the applicable requirements contained in 40 CFR 60, Subpart Ja upon the effective date of any newly applicable requirements in Subpart Ja or the lifting of the stay thereby making such requirements newly applicable.

Response: This change (the deletion of Subpart Ja references) was made. However, if the stay is lifted or these provisions are amended, the permit may need to be reopened for cause per AOP term VI.F. Per Section 7.09(c) of Regulation I, a fee in the amount of $10,000 plus the publication costs will be assessed for this action.

6. In the Note, which is located on page 26 of 329 and precedes Requirement No. I.B.18, delete the last sentence of this note, which reads as follows: "F-1 may become affected facility, depending on the outcome."

Response: This change (the deletion of Subpart Ja references) was made. However, if the stay is lifted or these provisions are amended, the permit may need to be reopened for cause per AOP term VI.F. Per Section 7.09(c) of Regulation I, a fee in the amount of $10,000 plus the publication costs will be assessed for this action.

7. This comment is on the following Notes/Requirements contained within the draft Title V Air Operating Permit that apply 40 CFR 60 Subpart QQQ requirements to vacuum tank trucks:
   a. Note that is located on the top of page 38 of 329 and precedes Requirement No. 1.F. 10.
   b. Requirements No. I.F.11 through I.F.16
   c. Note that is located on the top of page 133 of 329 and precedes Requirement No. II.F.9.
   d. Requirement No. I1.F.9

These notes/requirements apply 40 CFR Part 60, Subpart QQQ requirements to various types of equipment including vacuum tank trucks. U.S. Oil disagrees with PSCAA's assessment that vacuum trucks are regulated by 40 CFR 60 Subpart QQQ. Based on the rationale outlined in the following paragraphs, U.S. Oil requests that vacuum tank trucks be excluded from the list of equipment regulated by 40 CFR 60 Subpat1 QQQ. Further, U.S. Oil requests that Section VIII of the draft Title V Air Operating Permit be amended to show that 40 CFR 60 Subpart QQQ doesn't apply to vacuum tank trucks.

Trucks are containers and could only be QQQ affected facilities if they were used to store petroleum liquids or oily wastewater (see definition of "storage vessel" that includes containers).

Vacuum trucks are used at U.S. Oil for transporting and not storing petroleum liquids and oily wastewater. If EPA had intended to include trucks or containers as affected facilities under QQQ, they would have done so expressly, like they did in FF (trucks are containers subject to requirements to have covers). The preambles to the original proposed and final rules for QQQ say nothing about trucks or containers. The proposed rule for QQQ states quite specifically what it does cover:

> Affected Facility
> The affected facilities to which these standards would apply include: (1) Individual drain systems; (2) oil-water separators; (3) air flotation systems; and (4) individual drain systems with their ancillary downstream wastewater components including sewer lines, oil-water separators and air flotation systems. Individual drain systems include all process drains and sewer lines connected to the same junction box. The standards would not apply to separate stormwater drain systems used for the collection of storm water runoff from plant premises. Each modified individual drain system which has a catch basin (as defined in § 60.691) in the existing configuration would be exempt from the proposed requirements for individual drain systems.
>
> Each oil-water separator and air flotation system would constitute a separate affected facility. Oil-water separators include skimmers, sludge pumps, sludge hoppers, conditioning tanks, and other auxiliary tanks, basins, and equipment. Air flotation systems include flocculation tanks and other auxiliary tanks, basins and conditioning equipment, but would not include air flotation systems that are not used for oil separation. An example of an air flotation system not included in these standards is one used following a biological treatment system.
>
> The affected facilities were defined in a way to provide for maximum emission reductions (considering the costs of these reductions) for the emission points covered by the proposed standards. Because refinery wastewater systems are highly interrelated sources of VOC emissions, VOC controls on entire wastewater systems appear environmentally prudent and within the range of reasonable costs. Thus, an affected facility would include all the emission points covered by the proposed standards that are functionally related; that is, each individual drain system together with its ancillary downstream treatment components (including sewer lines, oil-water separators and air flotation systems). However, because the emission points covered by the standards are often constructed or modified on an individual basis, the affected facilities also include each individual drain system, each oil-water separator, and each air flotation system.
>
> Emission Points to be Regulated
>
> The emission points to be regulated include: drain openings; junction box covers; sewer lines; oil-water separators; air flotation tanks; flocculation tanks and other auxiliary tanks, basins, and conditioning equipment; any connections or openings of these components from which VOC vapors might be emitted; and VOC control devices used to comply with the standards.

52 FR 416334. U.S. Oil disagrees with PSCAA's analysis in that the "other auxiliary equipment" in 60.692-3(a)(1) can only be read to regulate the type of equipment that can be controlled with a "fixed roof." It is an unreasonable interpretation to say that this could include trucks

("containers") when the rule applies only to the specifically identified equipment. Plus, the definition of "oil water separator" found in 60.691 provides definitive clarification as it includes only the "auxiliary equipment located between individual drain systems and the oil water separator." It is inappropriate to apply QQQ to containers regulated under FF for facilities > 10 Mg just because they are specifically regulated under FF but not mentioned under QQQ (especially since U.S. Oil is <10 Mg!). The Applicability Determination Index (ADI) saying that trucks are containers under FF and therefore are subject to FF controls (a requirement for a "cover" if at a facility >10 Mg) is not germane to an interpretation of QQQ. The intent of QQQ was not to regulate "all of the equipment downstream of any individual drain system", rather it was to regulate the specific equipment noted above, which doesn't mention trucks.

Response: No change was made. In the rulemaking process, it's not possible to anticipate all of the site-specific implications associated with an older refinery. However, the clear intent of this rulemaking was to ensure that wastewater from new individual drain systems is regulated under Subpart QQQ until the water portion is discharged from the oil-water separator and the slop oil portion is returned to a process unit. The affected facilities specifically include all auxiliary equipment located between individual drain systems and the oil-water separator. Our determination that transport tanks are auxiliary equipment regulated under Subpart QQQ isn't based on the Benzene Waste NESHAP (Subpart FF) but it is supported by it.

8. Requirement No. I.F.30 and preceding note, which are located on page 47 of 329, should be relocated to the Inapplicable Requirements located in Section VIII.

Response: No change was made. Section 2.03(b) of PSCAA Regulation II is an applicable requirement.

9. In Requirement No. II.A.8, delete J-601A and J-601B from the list of applicable equipment. As a result, the list of equipment contained in the last sentence of the note preceding Requirement No. II.A.8 will need to be adjusted as necessary to accurately reflect the list of equipment subject to Requirements No. II.A.8 through II.A.11.

Basis: 40 CFR 60.4211(c) which has been analyzed as follows:
Requirement: "If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b),"

Analysis: While J-60lA and J-60l B both qualify as 2007 model year and later stationary, CI internal combustion engines, both of these engines are exempt since they are required to meet the emission standards specified in 40 CFR 60.4205(c) not 40 CFR 60.4205(b).

Requirement: "or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c),

Analysis: The starting model year that applies to J-60lA and J-60lB per 40 CFR 60 Subpart IIII Table 3 is 2010 since both engines have a rating of 150 horsepower. While J-60lA and J-

601B are required to comply with the emission standards specified in 40 CFR 60.4205(c), both of these engines are exempt since their model year is 2007, which precedes the applicable model year of 2010 as stated in 40 CFR Subpart IIII Table 3.

Requirement: "you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications."

Analysis: Per 40 CFR 60.4205(c), J-60lA and J-601 B are required to meet the emission standards contained in 40 CFR 60 Subpart IIII Table 4. However, based on the applicability analysis contained in the above-mentioned paragraphs, J-601 A and J-601 B are exempt from the 40 CFR 60.4211(c) requirement to purchase engines certified to meet the emission standards as well as the requirement to install and configure the engines according to the manufacturer 's specifications.

Response: This change was made.

10. Delete Requirements No. II.B.21, 1I.B.22 along with the Note that precedes Requirement No. 1I.B.21.

Response: This change (the deletion of Subpart Ja references) was made. However, if the stay is lifted or these provisions are amended, the permit may need to be reopened for cause per AOP term VI.F. Per Section 7.09(c) of Regulation I, a fee in the amount of $10,000 plus the publication costs will be assessed for this action.

11. In the Note, which is located on page 113 of 329 and precedes Requirement No. II.B.23, delete CRU-1 from the list of units served by Flare F-2:

Response: This change was made.

12. In the Note which is located on page 113 of 329 and precedes Requirement No. II.B.23, change the phrase "catalytic reforming unit" to read "catalytic reforming units".

Response: This change was made.

13. In Requirement No. II.C.2, delete J-601A and J-601B from the list of applicable equipment. As a result, the list of equipment contained in the last sentence of the note preceding Requirement No. II.C.2 will need to be adjusted as necessary to accurately reflect the list of equipment subject to Requirements No. II.C.2 through II.C.5.

Response: This change was made.

14. In Requirement No. II.F.26, Tk # 1807 should be removed from the list of equipment contained in the "Applies to" column.

Response: This change was made.

15. In Requirement No. II.F.53 the first sentence needs to be corrected to read as follows by removing the colon:
"Shall record; the identity of each waste stream at the facility and whether or not it is controlled for benzene emissions."

Response: This change was made.

16. In the note located on page 161 of 329 and preceding Requirement No. II.F.86, the regulatory citation "PSCAA Regulation II, Article 2.03(g)" should be added to the exception language contained in the square brackets [ ] to further clarify the basis for this exception.

Response: This change was made.

17. In Note 4 which is located on page 189 of 329 and precedes Requirement No. II.F.152, the word "to" needs to be inserted between "apply" and "all" in the first sentence:

Response: This change was made.

18. In Requirement No. II.F.156, the following tanks need to be added to the applicability column: Tk-80020, Tk-80021, Tk-80022, Tk-300001, and Tk-300002.

Response: This change was made.

19. In Requirements No. II.F.232 through II.F.235 as well as the Note preceding Requirement No. II.F.232, GE-2 should be added to the list of applicable equipment.

Response: This change was made.

20. In Requirement II.F.232, delete J-601A and J-601B from the list of applicable equipment. As a result, the list of equipment contained in the last sentence of the note preceding Requirement No. II.F.232 will need to be adjusted as necessary to accurately reflect the list of equipment subject to Requirements No. II.F.232 through II.F.235.

Response: This change was made.

21. In Requirement No. II.F.238, need to add the following wording from the rule at 40 CFR 63.6640(f)(2) for completeness and continuity with the rest of the paraphrase:
(2) There is no time limit on the use of emergency stationary RICE in emergency situations.

Response: This change was made.

22 . In Requirement II.H.2, need to remove the words "truck flushing" leaving "Emulsion rack" in the Applies to section.

Response: This change was made.

23. In Requirement II.H.5, remove GE-1 from the list of applicable equipment since GE-1 is not required to meet 40 CFR 63 Subpart ZZZZ and 40 CFR 63 Subpart A per 40 CFR 63.6590(b)(3) since GE- 1 is an existing compression ignition emergency stationary RICE with a site rating of more than 500 brake horsepower located at a major source of HAP emissions.

Response: This change was made.

24. Delete Requirements No. II.I.11 and II.I.12.

Response: This change (the deletion of Subpart Ja references) was made. However, if the stay is lifted or these provisions are amended, the permit may need to be reopened for cause per AOP term VI.F. Per Section 7.09(c) of Regulation I, a fee in the amount of $10,000 plus the publication costs will be assessed for this action.

25. In Requirement No. V.N.13, add the following sentence to the paragraph located within the Requirement Paraphrase column:
"You can keep the records offsite for the remaining 3 years."

Response: This change was made.

26. In Requirement V.P.3 the word "in" needs to be inserted between "updates" and "the" in the first sentence of the paraphrase.

Response: This change was made.

27. In Note 3, which is located on page 290 of 329 and precedes Requirement No. V.P.12., delete the last sentence of this note, which reads as follows:
"H-202, H-901 and F- l may become affected facility, depending on the outcome."

Response: This change (the deletion of Subpart Ja references) was made. However, if the stay is lifted or these provisions are amended, the permit may need to be reopened for cause per AOP term VI.F. Per Section 7.09(c) of Regulation I, a fee in the amount of $10,000 plus the publication costs will be assessed for this action.

28. In Requirement No. V.P.22, the title should be changed to "HAP Equipment Leaks".

Response: This change was made.

29. In Section No. VIII, the MACT standards contained in 40 CFR 63 Subpart LLLLL and titled "National Emissions Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing Manufacturing" should be listed as an inapplicable requirement since U.S. Oil does not have or utilize any asphalt blowing operations that would trigger the applicability of this standard. The inapplicability of this requirement should also be explained in the Statement of Basis as well.

Response: This change was made. However, a significant modification to the permit may be required prior to the installation of any blowing still in the future, per AOP term VI.E.

30. In Requirements No. VIII.A.10 through VIII.A.17, the last digit of these requirement numbers has been cut off. These requirements are identified in the 1st column of the table located in Section VIII.

Response: This change was made.

31. In Requirement No. VIII.A.24, the last sentence of the paragraph located within the Reason for Inapplicability column is incorrect and needs to be worded to read as follows:
"The operation of the loading rack does not activate the control device for the storage tanks except (possibly) when diesel is loaded from a ~~floating~~ fixed roof tank."

Response: This change was made.

32. In Requirement No. VIII.A.25 the last sentence of the paragraph located within the Reason for Inapplicability column is incorrect and needs to be worded to read as follows: "The operation of the loading rack does not activate the control device for the storage tanks except (possibly) when diesel is loaded from a floating fixed roof tank."

Response: This change was made.

33. In Requirement No. VIII.A.26 the last sentence of the paragraph located within the Reason for Inapplicability column is incorrect and needs to be worded to read as follows:
"The operation of the loading rack does not activate the control device for the storage tanks except (possibly) when diesel is loaded from a floating fixed roof tank."

Response: This change was made.

34. In Requirement No. IX.C the Modified EI Peso Method was cited but not included in either the draft hard copy of the Title V Air Operating Permit provided to U.S. Oil nor the draft copy of U.S. Oil's Title V Air Operating Permit posted on PSCAA's web site for public comment. For c1arity, Attachment #1 to this enclosure contains a copy of the Modified El Peso Method that was provided via email from Gerry Pade to Karl lams on August 18, 2010 and intended to be included as Requirement No. IX.C.

Response: Per 40 CFR 63.654(c)(1), this method was incorporated by reference under 40 CFR 63.14(n)(1), which provides a link to the actual text of the method. Accordingly, it is not being included as an Appendix to the permit.

Responses to US Oil's Comments on the Draft Statement of Basis

Page 1, 1st paragraph at the top of page
Correct this paragraph to read as follows: "This document summarizes the legal and factual basis for the ~~he~~ draft permit conditions in U.S. Oil 's operating permit (including references to the applicable statutory or regulatory provisions), as required under WAC 173-401-700(8)."

Response: This change was made.

Page 1, 5th paragraph in the middle of the page
Correct the first sentence to read as follows: "US Oil receives all of its crude oil by ship or barge at its marine terminal."

Response: This change was made.

Page 2, 3rd paragraph in the middle of the page
Correct the second sentence to read as follows: "In reforming, the hydrotreated naphtha feed is pressurized ~~hydrogen is mixed with the hydrotreated naphtha feed, vaporized~~ and passed through a series of furnaces and reactors."

Response: This change was made.

Page 3, 1st paragraph at the top of the page
Correct the third sentence of this paragraph to read as follows: "The sulfur slurry is recovered and typically distributed as an ingredient in soil amendment products."

Response: This change was made.

Page 6, 3rd paragraph from the top of the page
Correct the third sentence of this paragraph to read as follows: "Due to concern that noncondensable gases from the overhead system of the vacuum distillation columns could qualify as 'fuel gas' under Subpart J, U,S Oil installed a compressor to route these streams to the fuel gas treating system instead of firing it directly in a process heater."

Page 7, 1st full paragraph on this page
Replace the fifth sentence of this paragraph with the following information to more accurately discuss the catalytic reformer test results: "Separate testing was performed during the primary and secondary regeneration on both catalytic reformer units. All of the HCl test results were below the detection limit with the exception of one HCl test result that was slightly above the detection limit. Based on these test results operating limits for colorimetric testing have been established as appropriate. ~~All results were below the detection limit as per the MACT standard, the colorimetric tube limit is now 27 ppm~~."

Response: This change was made.

Page 7, 4th full paragraph from the top of the page
This paragraph should be corrected to accurately reflect the fact that while the EPA citations are still pending, U.S. Oil is currently in settlement negotiations with EPA, DOJ and PSCAA to resolve EPA's citations.

Response: No change was made, as the actual enforcement actions have yet to be determined.

Page 8, Notice of Violation No. 3-003625

The column titled "Written Warning or NOV # Issued" needs to include the date that this NOV was issued to be consistent with the other entries located within this table. Notice of Violation No. 3-003625 was issued on 11/4/08.

Response: This change was made.

Page 9, Notice of Violation No. 3-005304
The column titled "CP # Issued" needs to be updated as follows to reflect the current status of this Notice of Violation: 10-137CP 7/7/10

Page 9, Notice of Violation No. 3-005305
The column titled "CP # Issued" needs to be updated as follows to reflect the current status of this Notice of Violation: 10-138CP 7/7/10
The column titled "Amount Paid" needs to be updated as follows to reflect that this Notice of Violation is closed: $1000 7/27/10

Page 10
The heading located toward the top of the page and titled "Opacity and Particulate Matter" is incorrect and needs to be changed to read "VOC and Organic HAP.

Response: This change was made by eliminating a running header.

Pages 10 and 11
This comment pertains to the following EPA Violations that are dated 10/5/07 and identified as "OPEN" in the column titled "CP # Issued": Violation I, Violation 2, Violation 3, Violation 4, Violation 5, Violation 6, Violation 7, Violation 8, Violation 9 and Violation 10.

As part of EPA's Petroleum Refinery Initiative, U.S. Oil has been in negotiations with EPA, DOJ and PSCAA regarding the resolution of these violations and is close to reaching a settlement agreement. Rather than allowing the Statement of Basis to show these violations as "OPEN", presumably for the duration of the next Title V Air Operating Permit cycle, U.S. Oil strongly recommends that these negotiations be completed prior to the re-issuance of our Title V Air Operating Permit. This will allow the Statement of Basis to accurately reflect that these violations are closed.

Response: No change was made as these violations are not yet closed.

Page 11
The heading located toward the top of the page and titled "Opacity and Particulate Matter" is incorrect and needs to be changed to read "VOC and Organic HAP.

Response: This change was made by eliminating a running header.

Page 12
The heading located toward the top of the page and titled "Opacity and Particulate Matter" is incorrect and needs to be changed to read "VOC and Organic HAP.

Response: This change was made by eliminating a running header.

Page 12, Notice of Violation No. 2-000766
This violation should be removed from this table as it occurred on 9/1/02 which precedes the issuance date of our current Title V Air Operating Permit, which was December 31, 2002.

Response: This change was made.

Page 12, Notice of Violation No. 2-000763
This violation should be removed this table as it occurred on 7/7/01 and 8/7/01, which precedes the issuance date of our current Title V Air Operating Permit, which was December 31, 2002.

Response: This change was made.

Page 13
The heading located toward the top of the page and titled "Opacity and Particulate Matter" is incorrect and needs to be changed to read "VOC and Organic HAP.

Response: This change was made by eliminating a running header.

Page 13
The heading located toward the middle of the page and titled "Asbestos" should be bolded and un-italicized to match other headings contained in this table. Further, the box containing this heading should be shaded to match other heading boxes contained in this table.

Response: This change was made.

Page 13, Notice of Violation No. 4-042514
The column titled "CP # Issued" needs to be updated as follows to reflect the current status of this Notice of Violation: 10-136CP 7/7/10

The column titled "Amount Paid" needs to be updated as follows to reflect that this Notice of Violation is closed: $1750 7/27/10

Response: This change was made.

Notice of Violation No. 3-002309
A period needs to be inserted at the end of the sentence, which is located in the column titled "Description of Violation".

Response: This change was made.

Page 13
The heading located toward the bottom of the page and titled "O&M, OM&M, Startup, Shutdown and Malfunction Plans PSCAA Reg. I, Section 7.09, MACT Subpart A" should be bolded and un-italicized to match other headings contained in this table. Further, the box containing this heading should be shaded to match other heading boxes contained in this table.

Response: This change was made.

Page 13
The heading located toward the top of the page titled "Opacity and Particulate Matter" is incorrect and needs to be removed.

Response: This change was made by eliminating a running header.

Page 13, Notice of Violation No. 5-00349
This violation should be removed from this table as it occurred on 7/31/02, which precedes the issuance date of our current Title V Air Operating Permit, which was December 31, 2002.

Response: This change was made.

Page 14
The heading located toward the top of the page titled "Reporting" should be bolded and un-italicized to match other headings contained in this table. Further, the box containing this heading should be shaded to match other heading boxes contained in this table.

Response: This change was made.

Page 14, Notice of Violation No. 3-004277
A period needs to be inserted at the end of the sentence, which is located in the column titled "Description of Violation".

Page 14, 2nd paragraph from the bottom of the page
Correct the last sentence in this paragraph to read as follows: "A small amount of diesel is burned in internal combustion engines for ~~pumping products~~, testing pumps in stormwater or firewater service, etc."

Response: This change was made.

Page 15
The 2008 Emissions table located toward the top of the page contains a column titled "Marine Terminal". The superscript identified as "2" should be added after the word "Terminal" to note that emissions in this column are based on AP-42 emission factors.

Response: This change was made.

Page 15
The emissions table located toward the top of the page should be updated to reflect the most current emissions, which was data reported to PSCAA for calendar year 2009. If year 2008 data is to be retained, the "less than" sign should be removed from the SO_2 row for residual oil burning.

Response: This change (2009 data) was made.

Page 16, 3rd paragraph from the top of the page.
The language contained within this paragraph as well as throughout the draft Statement of Basis should be corrected to accurately reflect the stayed provisions of 40 CFR 60 Subpart Ja as well as any changes made based on comment #5 (located in Enclosure #1) regarding Subpart Ja.

Response: This change (the deletion of Subpart Ja references) was made. However, if the stay is lifted or these provisions are amended, the permit may need to be reopened for cause per AOP term VI.F. Per Section 7.09(c) of Regulation I, a fee in the amount of $10,000 plus the publication costs will be assessed for this action.

Page 16, 4th paragraph from the top of the page.
This paragraphs discusses PSCAA's basis for applying 40 CFR Part 60, Subpart QQQ requirements to vacuum tank trucks. U.S. Oil disagrees with PSCAA's assessment that vacuum trucks are regulated by 40 CFR 60 Subpart QQQ. Based on the rationale outlined in the following paragraphs, U.S. Oil requests that the finding discussion contained in this paragraph be amended to discuss why 40 CFR 60 Subpart QQQ is not applicable to vacuum tank trucks and that the analysis contained in the attachment titled "SOB Attachment, Subpart QQQ" be deleted.

Trucks are containers and could only be QQQ affected facilities if they were used to store petroleum liquids or oily wastewater (see definition of "storage vessel" that includes containers). Vacuum trucks are used at U.S. Oil for transporting and not storing petroleum liquids and oily wastewater. If EPA had intended to include trucks or containers as affected facilities under QQQ, they would have done so expressly, like they did in FF (trucks are containers subject to requirements to have covers). The preambles to the original proposed and final rules for QQQ say nothing about trucks or containers. The proposed rule for QQQ states quite specifically what it does cover:

Affected Facility
The affected facilities to which these standards would apply include: (1) Individual drain systems; (2) oil-water separators; (3) air flotation systems; and (4) individual drain systems with their ancillary downstream wastewater components including sewer lines, oil-water separators and air flotation systems. Individual drain systems include all process drains and sewer lines connected to the same junction box. The standards would not apply to separate storm water drain systems used for the collection of stormwater runoff from plant premises. Each modified individual drain system which has a catch basin (as defined in §60.691) in the existing configuration would be exempt from the proposed requirements for individual drain systems.

Each oil-water separator and air flotation system would constitute a separate affected facility. Oil-water separators include skimmers, sludge pumps, sludge hoppers, conditioning tanks, and other auxiliary tanks, basins, and equipment. Air flotation systems include flocculation tanks and other auxiliary tanks, basins and conditioning equipment, but would not include air flotation systems that are not used for oil separation. An example of an air flotation system not included in these standards is one used following a biological treatment system.

The affected facilities were defined in a way to provide for maximum emission reductions (considering the costs of these reductions) for the emission points covered by the proposed standards. Because refinery wastewater systems are highly interrelated sources of VOC emissions, VOC controls on entire wastewater systems appear environmentally prudent and within the range of reasonable costs. Thus, an affected facility would include all the emission points covered by the proposed standards that are functionally related; that is, each individual drain system together with its ancillary downstream treatment components (including sewer lines, oil-water separators and air flotation systems). However, because the emission points covered by the standards are often constructed or modified on an individual basis, the affected facilities also include each individual drain system, each oil-water separator, and each air flotation system.

Emission Points to be Regulated
The emission points to be regulated include: drain openings; junction box covers; sewer lines; oil-water separators; air flotation tanks; flocculation tanks and other auxiliary tanks, basins, and conditioning equipment; any connections or openings of these components from which VOC vapors might be emitted; and VOC control devices used to comply with the standards.

52 FR 416334. U.S. Oil disagrees with PSCAA's analysis in that the "other auxiliary equipment" in 60.692-3(a)(1) can only be read to regulate the type of equipment that can be controlled with a "fixed roof." It is an unreasonable interpretation to say that this could include trucks ("containers") when the rule applies only to the specifically identified equipment. Plus, the definition of "oil water separator" found in 60.691 provides definitive clarification as it includes only the "auxiliary equipment located between individual drain systems and the oil water separator." It is inappropriate to apply QQQ to containers regulated under FF for facilities >10 Mg just because they are specifically regulated under FF but not mentioned under QQQ (especially since U.S. Oil is <10 Mg!). The Applicability Detem1ination Index (ADI) saying that trucks are containers under FF and therefore are subject to FF controls (a requirement for a "cover" if at a facility > 10 Mg) is not germane to an interpretation of QQQ. The intent of QQQ was not to regulate "all of the equipment downstream of any individual drain system", rather it was to regulate the <u>specific equipment</u> noted above, which doesn't mention trucks.

Response: No change was made. In the rulemaking process, it's not possible to anticipate all of the site-specific implications associated with an older refinery. However, the clear intent of this rulemaking was to ensure that wastewater from new individual drain systems is regulated under Subpart QQQ until the water portion is discharged from the oil-water separator and the slop oil portion is returned to a process unit. The affected facilities specifically include all auxiliary equipment located between individual drain systems and the oil-water separator. Our determination that transport tanks are auxiliary equipment regulated under Subpart QQQ isn't based on the Benzene Waste NESHAP (Subpart FF) but it is supported by it.

Page 17, 2nd and 3rd paragraphs from the top of the page.
The 2nd paragraph was amended as follows to reflect that U.S. Oil submitted a timely and complete Part 2 application per section 112(j). The Subpart B proposed rulemaking date was corrected in the 3rd paragraph to reflect 75 FR 15655, which was published on March 30, 2010.

The renewal doesn't incorporate case-by-case MACT detel111inations for
process heaters and boilers because US Oil submitted <u>timely and complete</u> Part 2 applications under 40 CFR Pm1 63, Subpart B for the process heaters (H-201 and H-90 1) subject to Subpart

DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters), which was vacated and remanded the US Court of Appeals for the District of Columbia vacated and remanded on 6/1 9/07. (Their existing large gaseous fuel boilers and process heaters were subject only to an initial notification requirement.)

The Agency decided to await the outcome of recent proposed rulemakings under Subpart DDDDD (proposed on 6/4/10) and Subpart B (proposed on ~~5/30/10~~ 3/30/10). Both rulemakings are expected to go final by the end of the year. The Subpart DDDDD proposal is substantially different from the vacated rule. The Subpart B proposal will finally address the Federal Clean Air Act Section 112(j) 'MACT hammer' provisions as they pertain to vacated rules.

Response: This change was made.

Page 17, Last paragraph on the page
This paragraph should be changed to read as follows to more accurately reflect that attainment status of the Tacoma area: "The permit does not contain requirements applicable only to sources located in carbon monoxide and ozone nonattainment areas because they were not applicable as of the date of permit renewal."

Response: Changes were made to reference the requirements that were not considered applicable as of the date of permit renewal.

Page 23, 2nd full paragraph from the top of the page
The first sentence needs to be corrected to read as follows: "Heater H-3, retrofit with smaller burners for the ~~LCVU~~ LCU, was tested on 8/18/05."

Response: This change was made.

Page 24, 1st paragraph on this page
The fifth sentence needs to corrected to read as follows: "Given the cost of each test ~~(~$500)~~ (~$5000) and the number of emission units to be tested, annual testing was not considered appropriate."

Response: This change was made.

Page 34, 1st paragraph on this page
A grammatical correction needs to be made to the second to last sentence to read as follows: "The VCU operations vary, but typically it activates between ten and twenty times daily and operates for between 10 minutes ~~and2~~ and 2 hours each time."

Response: This change was made.

Attachment B
This Consent Order and Assurance of Discontinuance should be removed from the Statement of Basis as it is for violations preceding the issuance date of our current Title V Air Operating Permit, which was December 31, 2002. Further, there is no reference to this Order in either the draft Statement of Basis nor the Title V Air Operating Permit.

On May 31, 2003 U.S. Oil & Refining Co. successfully fulfilled our obligation to produce and offer diesel fuel for sale with a sulfur content of 30 ppm or less. With the implementation of this remaining action item, U.S. Oil had complied with and completed all of the requirements outlined in this Order within the specified deadlines.

It is important to note that by June 1, 2006 U.S. Oil was manufacturing ultra low sulfur diesel fuel in accordance with the low sulfur fuel mandates contained in 40 CFR Part 80. The ultra low sulfur diesel has a sulfur limit of 15 ppm, which is significantly less than the 30 ppm availability limit identified in this Order.

As such, U.S. Oil requests that this Order be removed from the Statement of Basis and rescinded since U.S. Oil has already fulfilled the compliance obligations stipulated under this order. Further, the 30 ppm diesel fuel sulfur limit contained in this Order has been superseded by EPA's ultra low sulfur diesel fuel requirements contained in 40 CFR Part 80.

Response: This change was made.

Administrative Modification: May 3, 2012

On April 5, 2012, we received a request to change the Responsible Official to Daniel Yoder. The administrative modification fee was paid on April 19, 2012.

Puget Sound Clean Air Agency Response:

This change was made.

Administrative Modification: May 11, 2017

On April 27, 2017, we received a request to change the Responsible Official to Brady Winder. The administrative modification fee was paid on May 8, 2017.

Puget Sound Clean Air Agency Response:

This change was made.

Administrative Modification: September 24, 2019

On June 12, 2019, we received a request to change the Responsible Official to Andrew Troske. The administrative modification fee was paid on June 12, 2019.

Puget Sound Clean Air Agency Response:

This change was made.