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PART 5 APPLICATIONS FOR PERMITS AND AUTHORIZATIONS

Section 5.1 – Air Emissions Permits and Authorizations

WAC 463-60-536

Applications for Permits and Authorizations – Air emissions permits and authorizations.

(1) The application for site certification shall include a notice of construction application pursuant to the requirements of Chapter 463-78 WAC.

(2) The application shall include requests for authorization for any emissions otherwise regulated by local air agencies as identified in WAC 463-60-297 Pertinent federal, state and local requirements.

(04-23-003, recodified as § 463-60-536, filed 11/4/04, effective 11/11/04. Statutory Authority: RCW 80.50.040 (1) and (12). 04-21-013, § 463-42-536, filed 10/11/04, effective 11/11/04.)

Section 5.1 Air Emissions Permits and Authorizations

5.1.1 Introduction

Tesoro Savage Petroleum Terminal LLC (Applicant) proposes to construct a facility in Vancouver to receive crude oil by rail and transfer it to vessels. The Vancouver Energy Terminal (Facility) will emit air pollutants and, therefore, must obtain an air quality permit before construction of the Facility can commence. Air permits are required for construction and operation of the emissions units associated with the stationary source. Emissions from mobile sources, including ships, trains, and vehicles, are regulated under other federal mobile source emission standards and are, therefore, not regulated or addressed under the stationary source air permitting process.

The Energy Facility Site Evaluation Council (EFSEC) is the lead state agency responsible for environmental permitting of facilities that have the capacity to receive more than an average of 50,000 barrels per day of crude or refined petroleum products that has been or will be transported over marine waters. EFSEC has responsibility for technical review of air quality concerns and for administering preconstruction permits.

Under Washington Administrative Code (WAC) 463-78-005, EFSEC has adopted by reference the general air quality regulations that the Washington State Department of Ecology (Ecology) has established in Chapters 173-400, 173-401, 173-406, and 173-460.[1] It should also be noted that regulations established by the Southwest Clean Air Agency (SWCAA) do not directly apply to the Facility. However, SWCAA regulations are discussed in this Application to demonstrate that even if the local regulations did apply, the Facility would be compliant.

5.1.1.1 Organization

This section constitutes a Notice of Construction (NOC) permit application. Although an air quality permit application typically begins with a project description, this permit application is a component of a broader Application for Site Certification. Section 2.3, Construction on Site, of this Application provides a detailed project description.

Key components of this air quality permit application are as follows.

- Section 5.1.2 describes the components of the project that emit air pollutants and presents estimated emissions. Emissions are based on equipment vendor information, emissions regulations, and the Best Available Control Technology (BACT) analysis. A more detail discussion of BACT is included in Attachment 1.
- Section 5.1.3 identifies and discusses potentially applicable air quality regulations.
- Section 5.1.4 describes an air quality dispersion modeling analysis used to estimate concentrations of criteria pollutants and toxic air pollutants (TAPs) in the vicinity of the project (i.e., Class II areas). Section 5.1.4 also compares predicted ambient concentrations with regulatory criteria.
- References are provided in Section 1.5, Sources of Information, of this Application.

[1] Because EFSEC has adopted the Ecology regulations by reference, this section cites directly the Ecology regulations for the reader’s convenience.

5.1.1.2 Summary of Findings

This permit application is summarized as follows.

- Emissions units at the Facility will employ BACT to ensure emissions of all regulated pollutants are less than major source thresholds.
- The Facility will comply with all federal and state emissions standards, including New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants.
- Predicted total concentrations of the criteria air pollutants emitted from the Facility are less than the National and Washington Ambient Air Quality Standards (NAAQS and WAAQS) established to protect human health and welfare. The maximum predicted concentrations attributable to the Facility are added to the existing background concentrations to ensure a conservative analysis.
- Estimated emissions or predicted concentrations of TAPs released from the Facility are below Ecology's Small Quantity Emissions Rates (SQER) or Ecology's Acceptable Source Impact Levels (ASIL) for all TAPs, demonstrating that the Facility emissions will be in compliance with Washington's TAP regulations.

5.1.2 Project Emissions

5.1.2.1 Criteria Pollutant Emissions

Criteria pollutants, including oxides of nitrogen (NO_X), sulfur dioxide (SO_2), carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM)[2], will be emitted by emissions units at the Facility. Facility emission units include natural gas-fired boilers, marine vapor combustion units (MVCUs), and emergency fire-water pumps, as well as fugitive VOC emissions from crude oil storage tanks and piping components. The following sections discuss the development of emission estimates for each of these emission units. Detailed supporting emission calculations are presented in the spreadsheets in Attachment 2.

5.1.2.1.1 Area 600 – Boiler Building

As described in greater detail in Part 2 of this Application, the Facility will receive crude oil from rail cars. The oil will be unloaded from the rail cars and pumped to storage tanks. Steam provided by natural gas-fired boilers to be located in Area 600 will be piped to the rail car unloading area where it will be used on an as-needed basis to heat up to 30 rail cars at a time, reducing the viscosity of the crude oil sufficiently for the rail car unloading process to be completed within a reasonable time period.

Three boilers, each with a nameplate heat input capacity of 62 million British thermal units per hour (MMBtu/hr) will be located near the rail car unloading area (these boilers are referred to as the Area 600 boilers). Typically, no more than two of these boilers will operate at any given time, with the third boiler kept as a redundant unit. To allow for uninterrupted steam supply, the third boiler may start up and begin producing steam for a limited period of time before one of the operating boilers is shut down. For the purposes of evaluating compliance with short-term

[2] Virtually all of the particulate matter from the Facility emissions units will be $PM_{2.5}$. For simplicity, this application generally refers to PM but the applicability and compliance will be assessed assuming PM is all $PM_{2.5}$.

(1-24 hour) ambient standards and ASILs, all three boilers were assumed operating for 24 continuous hours. For the purposes of evaluating compliance with annual ambient standards and ASILs, two boilers were assumed to combust a maximum of 755 million standard cubic feet of natural gas per year (MMscf/yr).

Unloading boiler emission rates were calculated assuming Cleaver Brooks 1500 CBEX Elite natural gas-fired boilers (manufacturer specification sheets are provided in Attachment 3), or equivalent, will be installed and operated. The Area 600 boilers could operate throughout the year (i.e., 8,760 hours per year), but at varying loads dictated by rail car arrival schedules, the viscosity of the crude oil contained in the rail cars, and the maximum annual quantity of natural gas to be combusted (755 MMscf/yr). The estimated annual and hourly unloading boiler emission rates and assumptions are presented in Tables 5.1-1 and 5.1-2, respectively.

Table 5.1-1. Area 600 Boilers Maximum Annual Emission Rates[1]

Pollutant	Tons	Basis[2]
NO_X	4.15	Activity: 61.745 MMBtu/hr, 755 MMscf/yr (assuming 1,000 Btu/scf) Emission Factor: 0.011 lb/MMBtu – BACT
CO	13.6	Activity: 61.745 MMBtu/hr, 755 MMscf/yr (assuming 1,000 Btu/scf) Emission Factor: 0.036 lb/MMBtu – BACT
PM	2.83	Activity: 61.745 MMBtu/hr, 755 MMscf/yr (assuming 1,000 Btu/scf)8,760 hr/yr Emission Factor: 0.0075 lb/MMBtu – BACT
VOC	1.89	Activity: 61.745 MMBtu/hr, 755 MMscf/yr (assuming 1,000 Btu/scf) Emission Factor: 0.005 lb/MMBtu – BACT
SO_2	1.39	Activity: 61.745 MMBtu/hr, 755 MMscf/yr (assuming 1,000 Btu/scf) Emission Factor: 0.00367 lb/MMBtu – based on annual average gas sulfur content (1.31 gr/100 scf) as determined by testing, plus a 25% safety factor
GHG (CO_2e)	44,200	Activity: 61.745 MMBtu/hr, 755 MMscf/yr (assuming 1,000 Btu/scf) Emission Factor: 117 lb/MMBtu – composite of the CO_2, CH_4, and N_2O emission factors from 40 CFR Part 98 Tables C-1 and C-2, using the GWP factors from Table A-1

Notes:
1) Annual emission rates assuming continuous capacity operation of two boilers.
2) Assumptions in “Basis” column used to calculate the maximum annual emissions.

Table 5.1-2. Area 600 Boiler Hourly Emission Rates[1]

Pollutant	lb	Basis[2]
NO_X	0.68	Emission Factor: 0.011 lb/MMBtu – BACT
CO	2.22	Emission Factor: 0.036 lb/MMBtu – BACT
PM	0.463	Emission Factor: 0.0075 lb/MMBtu – BACT
VOC	0.309	Emission Factor: 0.005 lb/MMBtu – BACT
SO_2	0.448	Emission Factor: 0.00725 lb/MMBtu – based on maximum hourly average gas sulfur content (2.59 gr/100 scf) as determined by testing, plus a 25% safety factor

Notes:
1) Hourly average emission rates for a single boiler, based on a maximum firing rate of 62 MMBtu/hr.
2) Assumptions in “Basis” column used to estimate the maximum hourly average emissions.

5.1.2.1.2 Marine Vapor Combustion Unit

Crude oil will be transferred from the storage tanks to marine vessels located at the dock at a rate of up to 32,000 barrels per hour (bbl/hr). The daily and annual loading rates will be approximately 47 percent of the maximum hourly loading rate (360,000 bbl/day and 131,400,000 bbl/yr).

A submerged loading configuration will be used to fill all marine vessel cargo compartments in accordance with U.S. Coast Guard (USCG) regulations. See 46 Code of Federal Regulation (CFR) §153.282. Vapors displaced from the tanks on the marine vessels will be collected and routed to a MVCU. Emission rates were calculated based on a system consisting of eight Jordan Technologies CEB units. Emissions from the vapors displaced from the tanks were calculated with a net heating value derived using the estimated composition of vapors in the tanks.

Vessels will arrive at the Facility with onboard cargo compartments filled with inert gas and with oxygen levels below 8 percent. The inert gas consists of cleaned exhaust from dedicated onboard inert gas generators (engines burning ultra-low sulfur distillate). Note that the inert gas is added to the compartments as the cargo is unloaded at its destination – not at the Facility, which is a loading facility.

When the vessel cargo compartments are filled with crude oil, the vapors from the cargo compartments, made up of hydrocarbon and inert gases, may be displaced through a hydrogen sulfide treatment system and then will be routed to a MVCU, that combusts the hydrocarbons in the vapors. In order to ensure adequate destruction of hydrocarbons by the MVCU, the vapor stream must consist of approximately 20 percent hydrocarbon. Based on a theoretical profile of VOC fraction in the displaced vapors as loading progresses (see Attachment 2), the hydrocarbon concentration of the displaced vapors will be less than 20 percent for the first 85 percent of the loading operation, and natural gas will be added if needed to the displaced vapors at the MVCU as an "assist gas" to increase the heating value of the vapors, and ensure adequate destruction. During the final 15 percent of the crude oil loading operation, the hydrocarbon content of the vapors will be greater than 20 percent, and the assist gas will no longer be needed. For calculating emission rates, the hydrocarbon content of the vapors was assumed to average 32 percent over all loading operations.

The MVCU will achieve a 99.8 percent destruction of the hydrocarbons in the delivered vapors. Performance tests conducted on similar units, combusting similar vapor streams, have confirmed that this level of destruction efficiency is achievable. The estimated maximum short-term and annual emission rates are summarized in Tables 5.1-3, 5.1-4, and 5.1-5. Table 5.1-3 presents the emissions from combusting displaced vapors in the MVCU, Table 5.1-4 presents the emissions from combusting the assist gas in the MVCU, and Table 5.1-5 presents the sum.

Table 5.1-3. Marine Vapor Combustion Unit Emissions due to Displaced Marine Vessel Vapors

Pollutant	Emission Factor (lb/MMBtu)	Emission Rates[1]		
		(lb/hr)	(lb/day)	(tpy)
NO_X[2]	0.023	3.32	79.6	6.81
CO[2]	0.010	1.44	34.6	2.96
PM[3]	0.0075	1.08	25.9	2.22
VOC[4]	--	4.21	101	8.64

Pollutant	Emission Factor (lb/MMBtu)	Emission Rates[1] (lb/hr)	(lb/day)	(tpy)
SO_2[5]	--	3.02	72.5	6.20
GHG (CO_2e)[6]	135.6	19,548	469,156	40,100

Notes:

1) Emission rates are based on the following maximum crude oil loading rates: 32,000 bbl/hr, 360,000 bbl/day, and 131,400,000 bbl/yr (i.e., 360,000 bbl/day * 365 days/yr). Based on information provided by the MVCU manufacturer, the hydrocarbon content of the displaced vapors was assumed to average 32 percent by volume over all loading operations. Atypical vapor speciation profile provided by the MVCU was used with the average hydrocarbon content to calculate a composite hourly maximum heat input for the displaced vapor (144 MMBtu/hr), and a composite daily/annual average heat input (68 MMBtu/hr).
2) NO_X, and CO emission factors provided by Jordan Technologies were combined with the composite heat inputs. An email documenting these emission factors is provided in Attachment 3.
3) The MVCU manufacturer did not provide a specific PM emission factor, but indicated that PM emission rates for the MVCU should be calculated using the PM emission factor from EPA's AP-42 Section 1.4 (Natural Gas Combustion). An email documenting this recommendation is provided in Attachment 3.
4) Uncontrolled VOC emissions were calculated using Equation 2 from AP-42 Section 5.2, assuming a worst-case true vapor pressure of 11 psia, a molecular weight of 44.9 lb/lb-mol, and worst-case vessel arrival condition emission factor of 0.86 lb/10^3 gal (from Table 5.2-3, based on the assumption that the previous vessel cargo was volatile, and that the condition of the arriving tanks is "unclean"). The controlled emission rates presented in the table reflect a destruction efficiency of 99.8% applied to the uncontrolled emission rates.
5) SO_2 emissions were based on the assumption that the H_2S content of the vapors displaced from the marine vessel cargo compartments during crude loading operations could be as high as 5,000 ppm, and would be reduced to a maximum of 100 ppm by a system designed to remove H_2S from the vapor. Because each mole of H_2S combusted yields one mole of SO_2, 100 ppm of H_2S will yield 100 ppm of SO_2. The ideal gas law was used to convert this maximum SO_2 concentration, combined with the hourly, daily, and annual maximum volumes of vapor displaced, to mass emission rates.
6) CO_2 emission factor provided by Jordan Technologies as a conservative estimate.

Table 5.1-4. Marine Vapor Combustion Unit Emissions due to Assist Gas

Pollutant	Emission Factor (lb/MMBtu)	Emission Rates[1] (lb/hr)	(lb/day)	(tons/yr)
NO_X[2]	0.023	0.704	6.73	1.23
CO[2]	0.010	0.306	2.93	0.534
SO_2[3]	0.00725	0.222	2.12	0.387
PM[4]	0.0075	0.230	2.19	0.401
VOC[5]	--	0	0	0
GHG (CO_2e)[6]	117	3,580	34,240	6,250

Notes:

1) Emission rates are based on information from Jordan Technologies that assist gas will be added to the displaced vapors from vessel loading at a rate of 30,600 ft^3/hr whenever the hydrocarbon content is less than 20%. The hydrocarbon content of the displaced vapors was assumed to be less than 20% for the first 85% of each loading operation, and greater than 20% for the remainder. The assist gas will be pipeline natural gas; a gross or higher heating value of 1,000 Btu/ft^3 was assumed. The worst-case hourly assist gas usage rate was assumed to be the maximum assist gas usage rate, 30,600 ft^3/hr. Daily and annual composite usage rates were calculated assuming the maximum assist gas usage rate of 30,600 ft^3/hr 85% of the time, and no added assist gas 15% of the time (i.e., a daily usage rate of 292,600 ft^3/day, and 106,803,600 ft^3/year).
2) NO_X and CO emission factors provided by Jordan Technologies were combined with the usage rates and gross heating value described above.
3) SO_2 emissions were based on maximum hourly average gas sulfur content (2.59 gr/100 scf) as determined by testing, plus a 25% safety factor
4) Calculated using an emission factor provided by Jordan Technologies and the usage rates and gross heating value described above.
5) The assist gas will be pipeline natural gas, which is comprised almost entirely of CH_4, which is not a VOC. The small fraction of natural gas that is VOC will be 99.8% combusted by the MVCU; the resulting VOC emissions were assumed to be negligible.
6) The GHG emission factor in units of CO_2e is a composite of the CO_2, CH_4, and N_2O emission factors from 40 CFR Part 98 Tables C-1 and C-2, using the GWP factors from Table A-1.

Table 5.1-5. Marine Vapor Combustion Unit – Total Emissions

Pollutant	Emission Rates[1]		
	(lb/hr)	(lb/day)	(tons/yr)
NO_X	4.02	86.3	8.04
CO	1.75	37.5	3.49
SO_2	3.24	74.6	6.59
PM	1.31	28.1	2.62
VOC	4.21	101	8.64
GHG (CO_2e)	25,150	526,100	50,530

Notes:
Total emission rates are the sum of the displaced vapor emission rates in Table 5.1-5 and the assist gas emission rates in Table 5.1-6. Estimated CO_2 emissions from the inerting gas are included in Table 5.1-5.

5.1.2.1.3 Crude Oil Storage Tanks

There will be six crude oil storage tanks located in the storage area. Each tank will have a storage capacity of approximately 360,000 bbl, and for purposes of emissions calculations a working capacity of 342,000 bbl.[3] Each tank will be approximately 50 feet tall (not counting the peak of the fixed roof), and approximately 240 feet in diameter. Annual throughput for each of the tanks will be 919,800,000 gallons per year, for a total Facility throughput of 131,400,000 bbl per year. Each tank is expected to turn over approximately 64 times per year, when the Facility is operating at full capacity. The tanks will feature an internal floating-roof design, with a pontoon-style internal deck. The edge of the deck will be equipped with a mechanical shoe primary seal, and a rim-mounted secondary seal to minimize the quantity of crude oil on the inside walls when the tank is drawn down. A figure showing a typical internal floating-roof sealing system similar to that proposed for the Facility is provided in Attachment 3 to this section.

Environmental Protection Agency's (EPA) TANKS 4.0.9d program (hereafter, "TANKS") was used to calculate fugitive emissions from the crude oil storage tanks. TANKS is a program that executes the equations in EPA's AP-42 Section 7.1 (Organic Liquid Storage Tanks), and uses the working volume of the tank to establish a total throughput for estimating fugitive emissions. Speciation information was developed for a range of crude oils[4], and provided to TANKS for the emission rate calculations that are detailed in Attachment 2. Tank emissions calculated by TANKS are summarized in Table 5.1-6, and the input data and results from TANKS are provided in Attachment 2 to this section.

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[3] Although the tanks could hold approximately 380,000 bbl, in actual operation internal floating roof tanks are never completely full, and the tanks are expected to operate at a normal fill capacity of 360,000 bbl. The working capacity of the tanks is slightly lower than the normal fill capacity. For purposes of emissions estimation a more accurate working capacity of 342,000 bbl is assumed, based on preliminary tank design drawings. Elsewhere in the ASC, the working capacity is referred to as "approximately 340,000 bbl".

[4] Six crude oils with Reid Vapor Pressures (RVPs) ranging from 0.98 to 8.41, as well as four Bakken crudes (413, 413-light, 423, and 430).

Two of the six crude oil storage tanks may be electrically heated. No combustion units will be used to heat the tanks; the electric heaters will be powered by electricity[5]. The maximum temperature of the heated tanks will be 150 °F, and only crude oil with an API gravity less than 35 is anticipated to require heating, and then only when ambient temperatures are sufficiently low to warrant heating of a particular crude to ensure it can be pumped out of the tank when necessary. Actual use of the heating system, and the temperature to which the tanks will be heated, will be determined by ambient temperatures and the API gravity of the crude oil.

AP-42 Section 7.1 and TANKS do not provide a means for estimating emissions from heated floating-roof tanks. Rather than making the assumption that fugitive emissions from the heated tanks would be the same as those from a non-heated tank, a spreadsheet was developed to perform AP-42 Section 7.1 calculations. After the spreadsheet was verified to produce results equivalent to TANKS for the unheated tanks, it was used to calculate emissions from the two heated tanks by changing the vapor pressures of the crude oil and the constituents of interest to reflect the maximum stock temperature of the heated tanks, which will be 150°F.

Crude oils with an API gravity less than 35 would potentially require heating to maintain a reduced viscosity for pumping, and then only when needed based on the ambient temperature. Three of the example crude oils that could be received and loaded at the proposed Facility have an API gravity less than 35. Fugitive emissions from the heated tanks were calculated based on the assumption that the worst-case (i.e., maximum-emitting) crude for each constituent of interest would be stored in the heated tanks throughout the year, and that the tanks would be heated to 150°F throughout the year, regardless of the ambient temperature.

Approximately once every 10 years, tanks will require inspection to ensure adequate operational condition. During this inspection process, a tank is completely drained and degassed. Degassing emission calculations were estimated by combining emissions from two calculations. To account for withdrawal losses while draining and refilling the portion of the tank above the level of the feet on the floating roof, emissions were estimated using TANKS for an internal floating roof tank (parameters specified in Attachment 2). For the losses associated with draining the tank below the legs that hold up the floating roof, working loss emissions were estimated using TANKS with a fixed roof with a height equal to the height of the legs (additional parameters specified in Attachment 2). Working and withdrawal loss emissions were then summed in order to determine the total VOC degassing emissions of approximately 1.6 tons.

Table 5.1-6. Total Crude Oil Storage Tank Emission Rates[3]

Pollutant	Hourly Average Emissions (lb/hr)	Annual Emissions (ton/yr)
VOC	4.96[1]	21.7[2]

Notes:

1) Hourly emission rate is the annual emission rate output from tanks divided by 8,760 hours per year.
2) Annual emission rate is a weighted composite of 80% of the worst-case Bakken crude oil and 20% of the worst-case non-Bakken crude oil for the four unheated tanks, and, for the two heated tanks, the worst-case heated sub-35 API gravity crude oil. Approximately every 10 years, the annual emissions will be approximately 1.6 tons higher due to tank inspection and maintenance.
3) Emissions are a combined total from all six tanks.

[5] The electrical supply for tank heating will be provided by Clark Public Utilities as described in section 2.17.6.

There will be three additional containment tanks located in Area 200 not intended to store crude oil (see section 2.3.3). In addition to collecting wash water, these tanks could be used to store spilled material. The containment tanks are fixed roof tanks with an estimated height of 24 feet and a 12-foot diameter. It is expected that the throughput for these additional tanks will result in roughly one tank turnover per week. The liquid itself will be almost entirely soapy water, with minimal crude oil present in the mixture. Because of this relatively small throughput and small fraction of crude oil present in the mixture, emissions from these containment tanks are considered to be negligible.

5.1.2.1.4 Emergency Diesel Engines

Three emergency fire water pumps powered by diesel engines will be used in the event that water is needed to fight a fire within the Facility at the same time that electrical power is not available from the grid. Each of the fire pump engines will have a capacity of 225 hp or less.

While specific makes and models have not been selected for the emergency fire pump engines, emission rates were calculated using emission factors provided by manufacturers for engines that are representative of the units that will be installed. All three engines will be fuelled with ultra-low sulfur diesel (ULSD). Planned operation of the units will be limited to a half hour per week for readiness testing, and one 8-hour test per year, as specified by the National Fire Protection Association's NFPA 25. Calculated emission rates from these engines are summarized in Table 5.1-7.

Table 5.1-7. Emergency Diesel Fire Water Pump Emission Rates

Pollutant	Emission Factor[1] (g/kW-hr)	Emission Rate[2]		
		(lb/hr)	(lb/day)	(ton/yr)
NO_X	0.335	0.124	0.124	0.00211
CO	1.60	0.592	0.592	0.0101
SO_2	--[3]	0.00254	0.00254	0.0000432
PM	0.17	0.0629	0.0629	0.00107
VOC	0.37	0.137	0.137	0.00233
GHG (CO_2e)	717.13[4]	265	265	4.51

Notes:

1) Provided by manufacturer/data.
2) Emissions are for a single diesel fire water pump engine, operated for a maximum of 1 hour per day and 34 hours per year.
3) Based on use of ULSD (15 ppm sulfur by weight).
4) Based on the CO_2, CH_4, and N_2O 40 emission factors for distillate fuel oil No. 2 from CFR Part 98 Subpart C, and a rated engine power output of 225 hp.

5.1.2.1.5 Fugitive Component Leaks

VOC emissions associated with minute vapor leakage from valve seals, pump seals, pressure relief valves, flanges, and similar equipment were calculated using anticipated component counts and EPA fugitive emissions factors. Fugitive emission factors were obtained from Protocol for Equipment Leak Estimates, EPA 453-R95-017, November 1995. Fugitive VOC emissions associated with leaks from gaseous and liquid streams are presented in Table 5.1-8. Calculation details are provided in Attachment 2.

Table 5.1-8. Short-term and Annual VOC Emissions from the Fugitive Equipment Leaks

Pollutant	Hourly Average Emissions[1] (lb/hr)	Annual Emissions[2] (ton/yr)
VOC	0.19	0.82

Notes:
1) Hourly emission is the worst-case crude emission rate divided by 8,760 hours per year.

5.1.2.1.6 Locomotive and Marine Vessel Emissions

Crude oil will be delivered to the Facility by rail for transport by marine vessel. Emissions from locomotives and vessels are not included in the Facility emissions inventory or dispersion modeling because they are mobile sources powered by off-road engines. These sources of emissions are specifically exempted by federal and state regulations from pre-construction permitting.[6]

5.1.2.1.7 Facility-wide Emissions Summary

Tables 5.1-9, 5.1-10, and 5.1-11 summarize the maximum estimated hourly, daily, and annual criteria pollutant and greenhouse gas (GHG) emissions from all Facility emissions units. Facility-wide potential annual GHG emissions are less than 100,000 tpy CO_2e.

Table 5.1-9. Hourly Emissions

Pollutant	Emission Rate (lb/hr)					
	Area 600 Boilers	MVCU	Component Leaks	Tanks	Fire Water Pumps	Total
NO_X	2.04	4.02	--	--	0.372	6.43
CO	6.67	1.75	--	--	1.78	10.2
SO_2	1.34	3.24	--	--	0.00762	4.59
PM	1.39	1.31	--	--	0.189	2.89
VOC	0.926	4.21	0.188	4.96	0.411	10.7
GHG (CO_2e)	21,670	25,150	53.8	59.5	796	47,730

[6] *See, e.g.*, WAC 173-400-030(79) ("Secondary emissions do not include any emissions which come directly from a mobile source such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel."); *See also in re* Cardinal FG Company, 12 E.A.D. 153, 171-172 (EAB 2005) (Ecology correctly concluded that emissions from a permanently situated non-road vehicle powered by a "nonroad engine" were not attributable to the stationary source); Letter from EPA AQMD Director to Ken Waid (Jan. 8, 1990) stating that "to and fro" vessel emissions are not attributable to a stationary source and that when determining PSD applicability you do not consider those emissions that "result from activities which do not directly serve the purposes of the terminal and are not under the control of the terminal owner or operator.")

Table 5.1-10. Daily Emissions

Pollutant	Emission Rate (lb/day)					
	Area 600 Boilers	MVCU	Component Leaks	Tanks	Fire Water Pumps	Total
NO_X	48.9	86.3	--	--	0.372	136
CO	160	37.5	--	--	1.78	199
SO_2	32.2	74.6	--	--	0.00762	107
PM	33.3	28.1	--	--	0.189	61.7
VOC	22.2	101	4.50	119	0.411	247
GHG (CO_2e)	520,140	526,100	1,290	1,428	796	1,050,000

Table 5.1-11. Annual Emissions

Pollutant	Emission Rate (tons/yr)					
	Area 600 Boilers	MVCU	Component Leaks	Tanks	Fire Water Pumps	Total
NO_X	4.15	8.04	--	--	0.00632	12.2
CO	13.6	3.49	--	--	0.0302	17.1
SO_2	1.39	6.59	--	--	0.000130	7.97
PM	2.83	2.62	--	--	0.00321	5.45
VOC	1.89	8.64	0.822	21.7	0.00689	33.15.7
GHG (CO_2e)	44,170	50,530	236	261	13.5	95,200

5.1.2.2 Toxic Air Pollutants

The Facility has the potential to emit non-criteria air pollutants that are regulated federally by the Clean Air Act (CAA) Section 112 and others regulated in Washington by Ecology and EFSEC under Chapter 173-460 WAC. Some of these pollutants are deemed “hazardous air pollutants” (HAPs) under the CAA Section 112; others are defined as TAPs under Chapter 173-460 WAC.

Table 5.1-12 compares calculated Facility-wide TAP emissions with Washington’s SQERs. If Facility-wide emissions of a given pollutant are greater than its SQER, dispersion modeling is required to determine compliance with ambient air quality criteria (ASILs). As shown in Table 5.1-12, eight TAPs exceed the applicable SQERs; compliance with the applicable ASILs will be assessed in section 5.1.4. Table 5.1-13 summarizes the calculated annual TAP emission rates.

Table 5.1-12 also identifies which of the TAPs are a federal HAP. The HAP emitted in greatest quantity from the Facility is hexane (1.75 tons per year). Aggregate HAP emissions are 2.04 tons per year.

The following sections discuss the estimation of TAP/HAP emissions from each emission unit. Detailed emission calculations are presented in Attachment 2 of this section.

Table 5.1-12. Facility-wide Toxic Air Pollutant Emissions

Compound	CAS	HAP?	WA TAP Averaging Period	Emission Rate	SQER	Model?
				lb/avg per	lb/avg per	
Acetaldehyde	75-07-0	Yes	Annual	4.23E-02	71	No
Acrolein	107-02-8	Yes	24-Hour	1.50E-04	0.00789	No
Arsenic	7440-38-2	Yes	Annual	3.20E-01	0.0581	Yes
Benzene	71-43-2	Yes	Annual	1.35E+02	6.62	Yes
Benzo(a)anthracene	56-55-3	No	Annual	2.97E-03	1.74	No
Benzo(a)pyrene	50-32-8	No	Annual	1.93E-03	0.174	No
Benzo(b)fluoranthene	205-99-2	No	Annual	2.88E-03	1.74	No
Benzo(k)fluoranthene	207-08-9	No	Annual	2.89E-03	1.74	No
Beryllium	7440-41-7	Yes	Annual	1.92E-02	0.08	No
1,3-Butadiene	106-99-0	Yes	Annual	2.16E-03	1.13	No
Cadmium	7440-43-9	Yes	Annual	1.76E+00	0.0457	Yes
Carbon monoxide	630-08-0	No	1-Hour	1.02E+01	50.4	No
Chromium, (hexavalent)	18540-29-9	No	Annual	8.96E-02	0.00128	Yes
Chrysene	218-01-9	No	Annual	2.90E-03	17.4	No
Cobalt	7440-48-4	Yes	24-Hour	7.60E-04	0.013	No
Copper	7440-50-8	No	1-Hour	3.36E-04	0.219	No
Cyclohexane	110-82-7	No	24-Hour	9.54E-01	789	No
Dibenzo(a,h)anthracene	53-70-3	No	Annual	1.95E-03	0.16	No
Diesel Engine Particulate	DEP	No	Annual	6.41E+00	0.639	Yes
7,12-Dimethylbenz(a)anthracene	57-97-6	No	Annual	2.56E-02	0.00271	Yes
Ethylbenzene	100-41-4	Yes	Annual	3.08E+01	76.8	No
Fluorene	86-73-7	No	24-Hour	4.73E-05	1.71	No
Formaldehyde	50-00-0	Yes	Annual	1.20E+02	32	Yes
Hexane	110-54-3	Yes	24-Hour	1.79E+01	92	No
Hydrogen Sulfide	7783-06-4	No	24-Hour	4.90E-01	0.263	Yes
Indeno(1,2,3-cd)pyrene	193-39-5	No	Annual	2.90E-03	1.74	No
Isopropyl benzene	98-82-8	Yes	24-Hour	3.93E-02	52.6	No
Manganese	7439-96-5	Yes	24-Hour	3.44E-03	0.00526	No
Mercury	7439-97-6	Yes	24-Hour	2.35E-03	0.0118	No
3-Methylchloranthrene	56-49-5	No	Annual	2.88E-03	0.0305	No
Naphthalene	91-20-3	Yes	Annual	9.80E-01	5.64	No
Nitrogen dioxide	10102-44-0	No	1-Hour	6.43E+00	1.03	Yes
Propylene	115-07-1	No	24-Hour	4.18E-04	394	No
Selenium	7782-49-2	Yes	24-Hour	2.17E-04	2.63	No
Sulfur dioxide	7446-09-5	No	1-Hour	4.59E+00	1.45	Yes
Toluene	108-88-3	Yes	24-Hour	4.29E-01	657	No
Vanadium	7440-62-2	No	24-Hour	2.08E-02	0.0263	No
Xylene (-m)	108-38-3	Yes	24-Hour	2.89E-01	29	No
Xylene (-o)	95-47-6	Yes	24-Hour	1.08E-01	29	No
Xylene (-p)	106-42-3	Yes	24-Hour	1.20E-01	29	No

Table 5.1-13. Facility-wide Annual Toxic Air Pollutant Emissions

Compound	CAS	Emission Rate
		lb/yr
Acetaldehyde	75-07-0	4.23E-02
Acrolein	107-02-8	5.10E-03
Arsenic	7440-38-2	3.20E-01
Benzene	71-43-2	1.35E+02
Benzo(a)anthracene	56-55-3	2.97E-03
Benzo(a)pyrene	50-32-8	1.93E-03
Benzo(b)fluoranthene	205-99-2	2.88E-03
Benzo(k)fluoranthene	207-08-9	2.89E-03
Beryllium	7440-41-7	1.92E-02
1,3-Butadiene	106-99-0	2.16E-03
Cadmium	7440-43-9	1.76E+00
Carbon monoxide	630-08-0	3.42E+04
Chromium, (hexavalent)	18540-29-9	8.96E-02
Chrysene	218-01-9	2.90E-03
Cobalt	7440-48-4	1.34E-01
Copper	7440-50-8	1.36E+00
Cyclohexane	110-82-7	3.48E+02
Dibenzo(a,h)anthracene	53-70-3	1.95E-03
Diesel Engine Particulate	DEP	6.41E+00
7,12-Dimethylbenz(a)anthracene	57-97-6	2.56E-02
Ethylbenzene	100-41-4	3.08E+01
Fluorene	86-73-7	1.61E-03
Formaldehyde	50-00-0	1.20E+02
Hexane	110-54-3	3.45E+03
Hydrogen Sulfide	7783-06-4	1.51E+02
Indeno(1,2,3-cd)pyrene	193-39-5	2.90E-03
Isopropyl benzene	98-82-8	1.43E+01
Manganese	7439-96-5	6.08E-01
Mercury	7439-97-6	4.16E-01
3-Methylchloranthrene	56-49-5	2.88E-03
Naphthalene	91-20-3	9.80E-01
Nitrogen dioxide	10102-44-0	2.44E+04
Propylene	115-07-1	1.42E-02
Selenium	7782-49-2	3.84E-02
Sulfur dioxide	7446-09-5	1.59E+04
Toluene	108-88-3	1.50E+02
Vanadium	7440-62-2	3.68E+00
Xylene (-m)	108-38-3	1.05E+02
Xylene (-o)	95-47-6	3.93E+01
Xylene (-p)	106-42-3	4.38E+01

5.1.2.2.1 Natural Gas-fired Boilers

Emissions of TAPs from the natural gas-fired Area 600 boilers were calculated using emission factors from EPA's AP-42 Section 1.4 (Natural Gas Combustion). TAP emission rates for compounds that are also criteria pollutants (i.e., CO, NO_2, SO_2) were calculated using the same emission factors used to calculate criteria pollutant emission rates. Table 5.1-14 presents short-term TAP emissions from three Area 600 boilers operating at full load and annual TAP emissions from two Area 600 boilers operating at full load.

Table 5.1-14. Area 600 Boiler TAP Emissions

Compound	CAS #	Emission Factor (lb/10^6 scf)	Emission Rate[1]		
			(lb/hr)	(lb/day)	(lb/yr)
Arsenic	7440-38-2	0.0002	3.70E-05	8.89E-04	1.51E-01
Benzene	71-43-2	0.0021	3.89E-04	9.34E-03	1.59E+00
Benzo(a)anthracene	56-55-3	0.0000018	3.33E-07	8.00E-06	1.36E-03
Benzo(a)pyrene	50-32-8	0.0000012	2.22E-07	5.33E-06	9.06E-04
Benzo(b)fluoranthene	205-99-2	0.0000018	3.33E-07	8.00E-06	1.36E-03
Benzo(k)fluoranthene	207-08-9	0.0000018	3.33E-07	8.00E-06	1.36E-03
Beryllium	7440-41-7	0.000012	2.22E-06	5.33E-05	9.06E-03
Cadmium	7440-43-9	0.0011	2.04E-04	4.89E-03	8.30E-01
Carbon monoxide	630-08-0	0.036	6.67E+00	1.60E+02	2.72E+04
Chromium, (hexavalent)[2]	18540-29-9	0.000056	1.04E-05	2.49E-04	4.23E-02
Chrysene	218-01-9	0.0000018	3.33E-07	8.00E-06	1.36E-03
Cobalt	7440-48-4	0.000084	1.56E-05	3.73E-04	6.34E-02
Copper	7440-50-8	0.00085	1.57E-04	3.78E-03	6.42E-01
Dibenzo(a,h)anthracene	53-70-3	0.0000012	2.22E-07	5.33E-06	9.06E-04
7,12-Dimethylbenz(a)anthracene	57-97-6	0.000016	2.96E-06	7.11E-05	1.21E-02
Formaldehyde	50-00-0	0.075	1.39E-02	3.33E-01	5.66E+01
Hexane	110-54-3	1.8	3.33E-01	8.00E+00	1.36E+03
Indeno(1,2,3-cd)pyrene	193-39-5	0.0000018	3.33E-07	8.00E-06	1.36E-03
Manganese	7439-96-5	0.00038	7.04E-05	1.69E-03	2.87E-01
Mercury	7439-97-6	0.00026	4.82E-05	1.16E-03	1.96E-01
3-Methylchloranthrene	56-49-5	0.0000018	3.33E-07	8.00E-06	1.36E-03
Naphthalene	91-20-3	0.00061	1.13E-04	2.71E-03	4.61E-01
Nitrogen dioxide	10102-44-0	0.011	2.04E+00	4.89E+01	8.30E+03
Selenium	7782-49-2	0.000024	4.45E-06	1.07E-04	1.81E-02
Sulfur dioxide	7446-09-5	0.00725	1.34E+00	3.22E+01	2.77E+03
Toluene	108-88-3	0.0034	6.30E-04	1.51E-02	2.57E+00
Vanadium	7440-62-2	0.0023	4.26E-04	1.02E-02	1.74E+00

Notes:

1) Short-term emissions from three in-service boilers combined, annual emissions from two in-service boilers combined, each with a maximum heat input rate of 62 MMBtu/hr.
2) Note: AP-42 provides a chromium emission factor for natural gas-fired external combustion, but does not include guidance for partitioning emissions between the carcinogenic chromium VI (hexavalent chromium) and the chromium III (trivalent chromium). EPA's 2002 National-Scale Air Toxics Assessment (NATA) released June 2009 includes a chromium speciation profile for gas-fired process heaters, which indicates 4 percent of total chromium is chromium VI and 96 percent is chromium III. ENVIRON assumed 4 percent of total chromium emissions were emitted as chromium VI.

5.1.2.2.2 Marine Vapor Combustion Unit

Emissions of TAPs from the MVCU were calculated using emission factors from EPA's AP-42 Section 1.4 (Natural Gas Combustion) for both the vapor displaced from the marine vessels and the assist gas. TAP emissions for compounds that are also criteria pollutants (i.e., CO, NO_2, SO_2) were calculated using the same emission factors or assumptions and methodology used to calculate criteria pollutant emission rates. Table 5.1-15 presents aggregate TAP emissions from the proposed MVCU.

Table 5.1-15. Marine Vapor Combustion Unit TAP Emissions

Compound	CAS #	Emission Factor (lb/10^6 scf)	Emission Rate[1]		
			(lb/hr)	(lb/day)	(lb/yr)
Arsenic	7440-38-2	0.0002	4.21E-05	9.21E-04	1.69E-01
Benzene	71-43-2	0.0021	4.42E-04	9.67E-03	1.77E+00
Benzo(a)anthracene	56-55-3	0.0000018	3.78E-07	8.29E-06	1.52E-03
Benzo(a)pyrene	50-32-8	0.0000012	2.52E-07	5.53E-06	1.01E-03
Benzo(b)fluoranthene	205-99-2	0.0000018	3.78E-07	8.29E-06	1.52E-03
Benzo(k)fluoranthene	207-08-9	0.0000018	3.78E-07	8.29E-06	1.52E-03
Beryllium	7440-41-7	0.000012	2.52E-06	5.53E-05	1.01E-02
Cadmium	7440-43-9	0.0011	2.31E-04	5.07E-03	9.29E-01
Carbon monoxide	630-08-0	--[2]	1.75E+00	3.75E+01	6.99E+03
Chromium, (hexavalent)[3]	18540-29-9	0.000056	1.18E-05	2.58E-04	4.73E-02
Chrysene	218-01-9	0.0000018	3.78E-07	8.29E-06	1.52E-03
Cobalt	7440-48-4	0.000084	1.77E-05	3.87E-04	7.09E-02
Copper	7440-50-8	0.00085	1.79E-04	3.91E-03	7.18E-01
Dibenzo(a,h)anthracene	53-70-3	0.0000012	2.52E-07	5.53E-06	1.01E-03
7,12-Dimethylbenz(a)anthracene	57-97-6	0.000016	3.36E-06	7.37E-05	1.35E-02
Formaldehyde	50-00-0	0.075	1.58E-02	3.45E-01	6.33E+01
Hexane	110-54-3	1.8	3.78E-01	8.29E+00	1.52E+03
Hydrogen Sulfide	7783-06-4	--[4]	3.21E-03	7.70E-02	6.59E-03
Indeno(1,2,3-cd)pyrene	193-39-5	0.0000018	3.78E-07	8.29E-06	1.52E-03
Manganese	7439-96-5	0.00038	7.99E-05	1.75E-03	3.21E-01
Mercury	7439-97-6	0.00026	5.47E-05	1.20E-03	2.20E-01
3-Methylchloranthrene	56-49-5	0.0000018	3.78E-07	8.29E-06	1.52E-03
Naphthalene	91-20-3	0.00061	1.28E-04	2.81E-03	5.15E-01
Nitrogen dioxide	10102-44-0	--[2]	4.02E+00	8.63E+01	1.61E+04
Selenium	7782-49-2	0.000024	5.05E-06	1.11E-04	2.03E-02
Sulfur dioxide	7446-09-5	--[2]	3.24E+00	7.46E+01	1.32E+04
Toluene	108-88-3	0.0034	7.15E-04	1.57E-02	2.87E+00
Vanadium	7440-62-2	0.0023	4.84E-04	1.06E-02	1.94E+00

Notes:

1) Displaced vapor volumes calculated for maximum hourly, daily, and annual averaging periods were combined with the natural gas-fired emission factors to calculate TAP emission rates; considering that, even for the worst-case hourly average scenario, which is when vessel loading is almost complete, the displaced vapor will not be 100% saturated by hydrocarbons. The maximum hourly assist gas flow rate (30,600 ft^3/hr) was used to calculate emission rates for TAPs that have a SQER with a 1-hour average basis. For TAPs that have a SQER with a 24-hour or annual average basis, 85% of the maximum assist gas flow rate was used.
2) The maximum hourly emission rate calculated for the criteria pollutant analysis was used. See Tables 5.1-3, 5.1-4, and 5.1-5.

3) AP-42 provides a chromium emission factor for natural gas-fired external combustion, but does not include guidance for partitioning emissions between the carcinogenic chromium VI (hexavalent chromium) and the chromium III (trivalent chromium). EPA's 2002 National-Scale Air Toxics Assessment (NATA) released June 2009 includes a chromium speciation profile for gas-fired process heaters, which indicates 4% of total chromium is chromium VI and 96% is chromium III. ENVIRON assumed 4% of total chromium emissions were emitted as chromium VI.
4) H_2S emissions were based on the assumption that the H_2S content of the vapors displaced from the marine vessel cargo compartments during crude loading operations could be as high as 5,000 ppm, and would be reduced to a maximum of 100 ppm by a system designed to remove H_2S from the vapor. Based on information from the MVCU manufacturer, the destruction efficiency of the unit is 99.8%. Therefore, a maximum of 0.2% of 100 ppm H_2S escapes destruction by the MVCU. The ideal gas law was used to convert this maximum H_2S concentration, combined with the hourly, daily, and annual maximum volumes of vapor displaced, to mass emission rates.

5.1.2.2.3 Crude Oil Storage Tanks

Emissions of TAPs from the crude oil storage tanks were calculated using the same methodology as the criteria pollutants. The TANKS program calculated emission rates for each of the TAPs included in the provided speciation information. Table 5.1-16 presents the estimated aggregate TAP emissions from the crude oil storage tanks.

Table 5.1-16. Crude Oil Storage Tank TAP Emissions

Components	CAS #	Emission Rate		
		(lb/hr)	(lb/day)	(lb/yr)
Benzene	71-43-2	1.46E-02	3.50E-01	1.28E+02
Cyclohexane	110-82-7	3.88E-02	9.30E-01	3.40E+02
Cyclopentane	287-92-3	6.73E-03	1.61E-01	5.89E+01
Ethylbenzene	100-41-4	3.36E-03	8.05E-02	2.94E+01
Hexane	110-54-3	6.18E-02	1.48E+00	5.42E+02
Hydrogen Sulfide	7783-06-4	1.58E-02	3.79E-01	1.39E+02
Isooctane	540-84-1	2.95E-03	7.07E-02	2.58E+01
Isopentane	78-78-4	6.62E-02	1.59E+00	5.80E+02
Isopropyl benzene	98-82-8	1.60E-03	3.84E-02	1.40E+01
Pentane	109-66-0	8.80E-02	2.11E+00	7.71E+02
Toluene	108-88-3	1.59E-02	3.82E-01	1.40E+02
1,2,4-Trimethylbenzene	95-63-6	4.91E-03	1.18E-01	4.30E+01
Xylene (-m)	108-38-3	1.15E-02	2.76E-01	1.01E+02
Xylene (-o)	95-47-6	2.83E-03	6.80E-02	2.48E+01
Xylene (-p)	106-42-3	3.16E-03	7.58E-02	2.77E+01

Notes:
1) Annual emission rate for the four unheated tanks is a weighted composite of 80% of the worst-case Bakken crude oil result from TANKS program, and 20% of the worst-case non-Bakken crude oil result from TANKS program, and for the two heated tanks the worst-case heated sub-35 API gravity crude oil calculated using the AP-42 Section 7.1 equations and component physical parameters adjusted to reflect 150 °F.

5.1.2.2.4 Emergency Diesel Engines

Emissions of TAPs from the emergency fire water pump engines were calculated based on EPA AP-42 emission factors for small internal combustion diesel engines (Section 3.3). Annual emissions were based on 34 hours[7] of operation for maintenance and testing purposes only. TAP emissions for compounds that are also criteria pollutants were calculated using the same emission factors or assumptions and methodology used to calculate criteria pollutant emission rates. Table 5.1-17 presents the estimated aggregate TAP emissions from the emergency fire water pump engines.

Table 5.1-17. Emergency Fire Water Pump Engine TAP Emissions

CAS #	Compound	Emission Factor ($lb/10^6$ Btu)	Emission Rate[1]		
			(lb/hr)	(lb/day)	(lb/yr)
83-32-9	Acenaphthene	1.42E-06	2.30E-06	2.30E-06	7.83E-05
208-96-8	Acenaphthylene	5.06E-06	8.20E-06	8.20E-06	2.79E-04
75-07-0	Acetaldehyde	7.67E-04	1.24E-03	1.24E-03	4.23E-02
107-02-8	Acrolein	9.25E-05	1.50E-04	1.50E-04	5.10E-03
120-12-7	Anthracene	1.87E-06	3.03E-06	3.03E-06	1.03E-04
71-43-2	Benzene	9.33E-04	1.51E-03	1.51E-03	5.14E-02
56-55-3	Benzo(a)anthracene	1.68E-06	2.72E-06	2.72E-06	9.26E-05
50-32-8	Benzo(a)pyrene	1.88E-07	3.05E-07	3.05E-07	1.04E-05
205-99-2	Benzo(b)fluoranthene	9.91E-08	1.61E-07	1.61E-07	5.46E-06
191-24-2	Benzo(g,h,i)perylene	4.89E-07	7.93E-07	7.93E-07	2.70E-05
207-08-9	Benzo(k)fluoranthene	1.55E-07	2.51E-07	2.51E-07	8.54E-06
106-99-0	1,3-Butadiene	3.91E-05	6.34E-05	6.34E-05	2.16E-03
630-08-0	Carbon monoxide	--[2]	1.78E+00	1.78E+00	6.04E+01
218-01-9	Chrysene	3.53E-07	5.72E-07	5.72E-07	1.95E-05
53-70-3	Dibenz(a,h)anthracene	5.83E-07	9.45E-07	9.45E-07	3.21E-05
none	Diesel Engine Particulate	--[2]	1.89E-01	1.89E-01	6.41E+00
206-44-0	Fluoranthene	7.61E-06	1.23E-05	1.23E-05	4.20E-04
86-73-7	Fluorene	2.92E-05	4.73E-05	4.73E-05	1.61E-03
50-00-0	Formaldehyde	1.18E-03	1.91E-03	1.91E-03	6.51E-02
193-39-5	Indeno(1,2,3-cd)pyrene	3.75E-07	6.08E-07	6.08E-07	2.07E-05
91-20-3	Naphthalene	8.48E-05	1.37E-04	1.37E-04	4.67E-03
10102-44-0	Nitrogen dioxide	--[2]	3.72E-01	3.72E-01	1.26E+01
85-01-8	Phenanthrene	2.94E-05	4.77E-05	4.77E-05	1.62E-03
115-07-1	Propylene	2.58E-04	4.18E-04	4.18E-04	1.42E-02
129-00-0	Pyrene	4.78E-06	7.75E-06	7.75E-06	2.64E-04
7446-09-5	Sulfur dioxide	--[2]	7.62E-03	7.62E-03	2.59E-01

[7] A half hour per week for readiness testing, and one 8-hour test per year, as specified by the National Fire Protection Association's NFPA 25 (Section 5.1.2.1.4).

CAS #	Compound	Emission Factor (lb/10^6 Btu)	Emission Rate[1]		
			(lb/hr)	(lb/day)	(lb/yr)
108-88-3	Toluene	4.09E-04	6.63E-04	6.63E-04	2.25E-02
108-38-3	Xylenes (m-xylene)[3]	2.85E-04	4.62E-04	4.62E-04	1.57E-02

Notes:

1) Emission rates for a single engine. Hourly emission rates are based on maximum operation, daily emission rates are based on one hour of operation per day, and annual emission rates are based on 34 hours of operation per year.
2) The emission rates calculated for the criteria pollutant analysis were used. See Table 5.1-9.

5.1.2.2.5 Fugitive Component Leaks

TAP emissions associated with normal equipment leakage at the Facility have been estimated using EPA fugitive emission factors for valve seals, pump seals, pressure relief valves, flanges, and similar equipment.[8] Emission estimates are based on equipment counts, which are, in turn, based on preliminary piping and instrumentation diagrams developed for the project. TAP emission rates were based on the calculated fugitive VOC emission rate for the components and a composite speciation profile that was derived from the composite fugitive unheated crude oil storage tank emission rates[9] (Flint 2016). Estimated TAP emissions from component leakage are presented in Table 5.1-18.

Table 5.1-18. Fugitive Component Leak TAP Emissions

Pollutant	CAS #	Emission Rate		
		(lb/hr)	(lb/day)	(lb/year)
Benzene	71-43-2	4.10E-04	9.85E-03	3.60
Cyclohexane	110-82-7	1.00E-03	2.40E-02	8.77
Cyclopentane	287-92-3	4.96E-04	1.19E-02	4.35
Ethylbenzene	100-41-4	1.63E-04	3.90E-03	1.43
Hexane (-n)	110-54-3	3.04E-03	7.30E-02	26.7
Hydrogen Sulfide	7783-06-4	1.38E-03	3.31E-02	12.1
Isooctane	540-84-1	4.06E-05	9.75E-04	0.356
Isopentane	78-78-4	5.93E-03	1.42E-01	52.0

[8] Protocol for Equipment Leak Estimates, U.S. EPA 453-R95-017, November 1995

[9] The calculated fugitive tank and component HAP and TAP emissions rates are based on the same crude oil speciation information. However, because different emission calculation methodologies were used, the speciation information was applied differently for the two emission unit groups.

The storage tank emissions were estimated using TANKS. Physical properties and weight fractions of specific HAP and TAP constituents were obtained for a range of crude oils that could be received and loaded at the proposed facility. The properties and weight fractions were provided to TANKS, which calculated speciated fugitive tank emissions for each crude oil. The speciated emission rates provided by TANKS were used to calculate a composite fugitive tank emission rate for each HAP and TAP.

Fugitive VOC emissions from components were calculated using information and methods from the "Protocol for Equipment Leak Estimates" (EPA 453-R95-017, November 1995). HAP and TAP emission rates were based on the calculated fugitive VOC emission rate for the components combined with a speciation profile based on the composite fugitive tank emission rates for each HAP and TAP.

Pollutant	CAS #	Emission Rate		
		(lb/hr)	(lb/day)	(lb/year)
Isopropyl benzene	98-82-8	3.74E-05	8.96E-04	0.327
Pentane	109-66-0	6.08E-03	1.46E-01	53.3
Toluene	108-88-3	6.26E-04	1.50E-02	5.49
1,2,4-Trimethylbenzene	95-63-6	1.23E-04	2.95E-03	1.08
Xylene (-m)	108-38-3	5.46E-04	1.31E-02	4.79
Xylene (-o)	95-47-6	2.30E-04	5.51E-03	2.01
Xylene (-p)	106-42-3	2.55E-04	6.13E-03	2.24

Notes:
See Attachment 2 for detailed emissions calculations.

5.1.3 Applicable Regulations

This section discusses federal, state, and local air quality regulations and guidelines that potentially apply to the Facility.

5.1.3.1 Emission Standards

5.1.3.1.1 New Source Performance Standards

EPA has established performance standards for a number of air pollution source categories in 40 CFR Part 60. These New Source Performance Standards (NSPS) represent a minimum level of control that is required on a new source. This section identifies those NSPS that apply to Facility emissions units.

Subpart A, General Provisions

Subpart A identifies monitoring, recordkeeping, and notification requirements that apply generally to all NSPS subparts. Subpart A specifies that any performance (emissions) tests required by a specific NSPS subpart must be conducted within 60 days of achieving maximum production rate at which the source will be operated, but not later than 180 days after initial start-up.

Consistent with NSPS requirements, the Applicant will notify EFSEC of commencement of construction of purpose-built facilities, and the actual date of initial start-up. None of the applicable NSPS subparts require performance tests. The Applicant will also maintain records of start-ups and shutdowns, malfunctions of control equipment, and periods of excess emissions if they occur.

Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

The provisions of Subpart Dc apply to steam-generating units with a maximum design heat input capacity less than 100 MMBtu/hr and greater than 10 MMBtu/hr. Each of the boilers associated with this project falls within this capacity range. The PM and SO_2 emission standards defined in Subpart Dc do not apply to units that are solely fuelled by natural gas. Therefore, only the recordkeeping and reporting requirements of this subpart are applicable. The provisions of this subpart require that the Applicant maintain a record of the volume of natural gas burned in each boiler during each calendar month.

Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels
The provisions of Subpart Kb apply to the crude oil storage tanks associated with the Facility. Subpart Kb regulates VOC emissions and establishes controls based on the vapor pressure of the stored liquid.

Because the Facility will receive, store, and load a range of crude oils, some of which may have true vapor pressures within the applicable ranges addressed by Subpart Kb, it is assumed that Subpart Kb will apply to the Facility tanks. Subpart Kb identifies three control options. The Facility will incorporate the option identified in §60.112b(a)(1): a fixed roof in combination with an internal floating roof that floats on the liquid surface. A series of regulations for seals and closure devices related to roof contact must be followed.

Subpart IIII--Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
The provisions of Subpart IIII apply to the emergency diesel fire water pump engines associated with the Facility. Subpart IIII regulates "NMHC+NOx" and PM and requires that the engine manufacturer certify that the engine will meet the standards in the rule; emission testing by the Facility is not required. Subpart IIII limits hours of non-emergency operation, mandates the use of ULSD fuel, and states that the owner or operator must keep records of the time of operation of the engine and the reason the engine was in operation during that time. Initial notification of installation is not required for emergency engines subject to Subpart IIII.

5.1.3.1.2 National Emissions Standards for Hazardous Air Pollutants
Under the provisions of Section 112 of the 1990 CAA Amendments, EPA was required to regulate emissions of a total of 189 HAPs from stationary sources.[10] EPA does this by specific industry categories to tailor the controls to the major sources of emissions and the HAPs of concern from that industry. The rules promulgated under Section 112 generally specify the Maximum Achievable Control Technology (MACT) that must be applied for a given industry category. Consequently, these rules are often called MACT standards.

MACT standards can require facility owners/operators to meet emission limits, install emission control technologies, monitor emissions and/or operating parameters, and use specified work practices. In addition, the standards typically include recordkeeping and reporting provisions. MACT standards are codified in 40 CFR Parts 61 and 63.

There are two types of HAP sources, "major" sources of HAP emissions and "area" sources of HAP emissions. Major sources are facilities that have a potential to emit more than 10 tons of a single HAP, or 25 tons of all HAPs combined. Area sources are facilities that are not a major source.

As reported in section 5.1.2.2, Facility-wide HAP emissions are less than 10 tons of a single HAP and less than 25 tons of aggregate HAPs. Therefore, the Facility will be an area source of HAP emissions. MACT standards that potentially apply to the proposed project are addressed below.

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[10] EPA has since removed three HAPs from the list: caprolactum, ethylene glycol monobutyl ether, and methyl ethyl ketone (MEK).

Parts 61 and 63, Subpart A, General Provisions
Subpart A under both parts establishes general requirements for reporting, testing, monitoring, and recordkeeping for any major source facility. The Facility must send notifications to EFSEC and EPA of anticipated and actual start-up dates as defined in §63.9 and submit reports summarizing operations, emissions, and compliance with regulations and limits as specified in the standard.

Part 61, Subpart M – National Emission Standards for Asbestos
Subpart M of 40 CFR 61 establishes requirements related to asbestos in the event of demolition or remodeling. The Facility will comply with these requirements.

Part 63, Subpart Y – National Emission Standards for Hazardous Air Pollutants for Marine Tank Vessel Loading Operations
The emission standard provisions of Subpart Y apply to existing and new marine terminals that are major sources of HAPs or are associated with a major source of HAPs (such as a refinery). As noted above, the Facility is not in itself a major source of HAPs and is not associated with a major source of HAPs. However, area sources, such as the Facility, are subject to the emission estimation (40 CFR §63.565(l)) and recordkeeping (40 CFR §63.567(j)(4)) requirements, and must meet the USCG's submerged fill standards (40 CFR §153.282). Because the Facility's crude oil throughput will be less than 200 million barrels per year, it will not be subject to the reasonably achievable control technology emission standards, per 40 CFR §63.560(b)(2).

Part 63, Subpart DDDDD -- National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
The provisions of Subpart DDDDD apply to boilers and process heaters at major sources of HAPs. Because the Facility is not a major source of HAPs, Subpart DDDDD does not apply to the Facility boilers.

Part 63, Subpart JJJJJ -- National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources
The Facility will be classified as an area source of HAPs and will operate boilers. However, gas-fired boilers are not subject to Subpart JJJJJJ. The Facility boilers will combust exclusively natural gas, so Subpart JJJJJ is not applicable.

Part 63, Subpart ZZZZ -- National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
The provisions of Subpart ZZZZ apply to stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A new stationary RICE located at an area source (such as the emergency fire water pump engines) must meet the requirements of Subpart ZZZZ by meeting the requirements of NSPS Subpart IIII for compression ignition engines. No further requirements apply for such engines under Subpart ZZZZ.

5.1.3.1.3 State Emission Limits
General standards for maximum emissions from industrial air pollution sources in Washington are outlined in WAC 173-400-040. This section limits visible emissions to 20 percent opacity except for 3 minutes per hour; controls nuisance dust particulate matter fallout, fugitive dust, and odors; and limits SO_2 emissions to no more than 1,000 ppm (hourly average, 7 percent O_2, dry

basis). WAC 173-400-050 identifies emission standards for combustion and incinerator units, and limits process emissions to 0.1 grain per dry standard cubic foot at 7 percent O_2.

Washington also requires BACT for new and modified emissions units. A BACT analysis identifies pollutant-specific alternatives for emission control, and the pros and cons of each alternative. The determination of which control scenario best protects ambient air quality is made on a case-by-case basis and considers the technical, economic, energy, and environmental costs. Chapter 173-460 WAC requires that BACT also be employed to control emissions of TAPs (i.e., t-BACT). Generally, the same technologies or operations that reduce criteria pollutants also reduce TAPs.

5.1.3.2 Consistency with SWCAA Regulations

In addition to the general State emissions standards addressed in the preceding section, SWCAA has other regulations that would apply if the Facility were not subject to EFSEC's jurisdiction. Although these regulations are not directly applicable, this section evaluates SWCAA's regulations to demonstrate that the Facility will be designed and operated consistent with those local requirements.

5.1.3.2.1 SWCAA General Regulations

The SWCAA regulations generally mirror Ecology's emission limits for new sources, limiting exhaust plume opacity to 20 percent opacity except for 3 minutes of any hour, particulate matter emissions to 0.1 grain per dry standard cubic foot, and SO_2 emissions to 1,000 ppm. The Facility will comply with all local general emissions requirements because BACT imposes more stringent requirements.

5.1.3.2.2 SWCAA VOC Standards

SWCAA has established emission standards and control requirements for sources that emit VOCs. The Facility, as a source of VOC emissions, would be subject to the provisions of SWCAA 490 if it were under the jurisdiction of SWCAA.

SWCAA 490-040(2), covering petroleum liquid storage tanks requires that all fixed-roof tanks storing volatile organic petroleum liquids with a true vapor pressure as stored greater than 78 mm of Hg (1.5 psi) at actual monthly average storage temperatures, and having a capacity greater than 150,000 liters (40,000 gallons), shall comply with one of the following.

- (i) Meet the equipment specifications and maintenance requirements of the federal standards of performance for new stationary sources - Storage Vessels for Petroleum Liquids (40 CFR 60, subpart K); or
- (ii) Be retrofitted with a floating roof or internal floating cover using a metallic seal or a nonmetallic resilient seal at least meeting the equipment specifications of the federal standards referred to in SWCAA 490-040 (2)(a)(i) or its equivalent; or
- (iii) Be fitted with a floating roof or internal floating cover meeting the manufacturer's specifications in effect when installed.

SWCAA 490-040 also requires that all seals be maintained in good operating condition and that seal fabric shall contain no visible holes, tears, or openings.

The Facility storage tanks will employ a fixed roof and internal floating cover and would, therefore, comply with 490-040 if under the jurisdiction of SWCAA. The Facility is not subject to the provisions of SWCAA 490-201 because that rule addresses petroleum storage in external floating roof tanks only.

5.1.3.2.3 SWCAA Maintenance Plan Requirements

Portions of the Portland-Vancouver metropolitan area (including the Facility site) have exceeded ozone and carbon monoxide ambient air quality standards in the past. Although the area currently meets ambient air quality standards, industrial sources in the area are still governed by "maintenance" plans intended to ensure air quality in the area does not deteriorate to the point where ozone and CO ambient standards are exceeded again. SWCAA administers those plans in the Washington portion of the maintenance area with certain elements of the maintenance plan integrated into the SWCAA regulations. Each SWCAA requirement is presented after a bullet below, and followed by an explanation of how the Facility complies with that requirement.

- SWCAA 400-111, Requirements for New Sources in a Maintenance Plan Area: SWCAA 400-111 implements portions of the State Implementation Plan (SIP) for the Vancouver CO and ozone maintenance areas.[11] Both maintenance areas cover the same geographic area, extending over the urban and industrial regions of Vancouver. SWCAA 400-111 requires that no approval to construct a new source shall be granted unless:

    a) Emissions from all units will comply with applicable emissions standards, including NSPS and MACT standards.

    b) Emissions from the new source will be minimized to comply with emissions levels and other requirements within the maintenance plan.

    c) BACT will be employed for all pollutants emitted from units associated with the new source.

    d) Emissions from the new source will not cause any violation of an ambient air quality standard.

    e) The source will employ control equipment and take measures to control emissions of TAPs to comply with WAC 173-460.

[11] Vancouver, WA, ozone and carbon monoxide maintenance plans are available for download from http://www.swcleanair.org/maintenanceplans.html

Although the EFSEC approval process supersedes SWCAA regulations, the Facility would comply with this regulation were it subject to SWCAA jurisdiction.

- SWCAA 400-111(2) indicates that a source located within the maintenance area may have to apply Lowest Achievable Emission Rate (LAER) emission limits if any ambient air quality standard is violated within the CO or O_3 maintenance areas.

According to SWCAA (2007)[12], the region has been in compliance with CO NAAQS since 1992 and future exceedance is not anticipated. Also, according to SWCAA (2006)[13], the region is in compliance with the ozone standards and future exceedance is not expected in the immediate future. Facility-wide emissions of ozone precursors and carbon monoxide are low and do not threaten compliance with the CO and ozone ambient standards. Consequently, this regulation would not apply to the Facility even if it were subject to SWCAA regulations.

- SWCAA 400-111(5) states that if a new source located within the maintenance area is designated as "major"[14] then emission offsets are required. Offsets are reductions in pollutant emissions equivalent to or greater than the proposed increases, provided by other stationary sources emitting the same pollutant.

Because the Facility is not a major source of carbon monoxide or ozone precursors, offsets would not be required even if the Facility were subject to SWCAA regulations.

- SWCAA 400-113(3) requires that allowable emissions from a proposed new source do not result in a significant increase in ambient concentrations within a maintenance area. This provision, therefore, requires that a source demonstrate that the project emissions will not result in exceedance of significant impact levels (1 $\mu g/m^3$ NO_2 annual average, 0.5 mg/m^3 CO 8-hour average, or 2 mg/m^3 CO 1-hour average) within the Vancouver maintenance area. If a significant impact level (SIL) is exceeded, then emission offsets must be obtained. Offsets must be sufficient enough to lower the modeled ambient concentration below the indicated impact level.

This regulation is intended to ensure that sources outside the maintenance area do not adversely affect compliance within the maintenance area. As noted above, the Facility is within the maintenance areas but its emissions are below the major source thresholds that trigger LAER and offsets.

[12] SWCAA (2007): Vancouver Air Quality Maintenance Area Second 10-year Carbon Monoxide Maintenance Plan, Supplement to the Washington State SIP, SWCAA, March 1, 2007.
[13] SWCAA (2006): Vancouver Portion of the Portland-Vancouver AQMA Ozone Maintenance Plan, Supplement to the Washington State SIP, SWCAA, November 2, 2006.
[14] A "major" stationary source is defined in SWCAA 400-030 (62)(a) as a source located in a maintenance plan or non-attainment area that emits or has the potential to emit 100 tons per year or more of any criteria pollutant (lower thresholds apply for PM and CO in non-attainment areas).

5.1.3.3 Preconstruction Permitting

5.1.3.3.1 Notice of Construction and Application for Approval

WAC 173-400-110 requires an NOC application for the construction of new air contaminant sources in Washington. SWCAA maintains a similar regulation (SWCAA 400-109) for new or modified sources in its jurisdiction. The NOC application provides a description of the facility and an inventory of pollutant emissions and controls. The reviewing agency, EFSEC, considers whether BACT has been employed and evaluates ambient concentrations resulting from these emissions to ensure compliance with ambient air quality standards. Pollutant emissions not governed by the Prevention of Significant Deterioration (PSD) permit process are addressed in an Order of Approval that results from the NOC application. In the case of the Facility, all pollutants are addressed in the NOC application.

5.1.3.3.2 Prevention of Significant Deterioration (PSD)

The PSD regulations were established by EPA to ensure that new or expanded major stationary sources that emit CAA-regulated pollutants above a significance rate do not cause air quality in areas that currently meet the standards (i.e., attainment areas) to deteriorate significantly. The Facility is not subject to PSD regulations because it will not emit any CAA-regulated pollutants above the applicable PSD significance rate (see Table 5.1-11).

5.1.4 Local Air Quality Impact Assessment

This section describes the local Air Quality Impact Assessment that has been conducted for the Facility. Computer-based dispersion modeling techniques were applied to simulate dispersion of toxic and criteria pollutant releases from Facility emissions units to estimate pollutant concentrations in the neighboring area. The results of the modeling analyses are used to assess compliance with NAAQS, WAAQS, and Ecology's ASILs for TAPs.

The dispersion modeling techniques employed in the analysis follow the EPA regulatory guidelines (40 CFR Part 51, Appendix W). These guidelines include recommendations for model selection, data preparation, and model application, but allow flexibility on a case-by-case basis.

Section 5.1.4.1 summarizes stack parameters used for the simulation. Section 5.1.4.2 describes the data used to characterize existing ambient air quality and discusses the meteorological data used in the dispersion modeling. Dispersion model selection and application are described in section 5.1.4.3, followed by a summary of the model results in section 5.1.4.4.

5.1.4.1 Stack Parameters, Building Dimensions, and Good Engineering Practice

In addition to emission rates, the modeling analysis requires estimates of the stack heights, building dimensions, and other parameters that characterize exhaust flows and/or atmospheric release characteristics from a facility. These release characteristics have an important influence on initial dispersion of emissions. The stack parameters used in the dispersion modeling simulation of Facility operations are presented in Table 5.1-19.

The effect of building wakes (i.e., downwash) on stack plumes was evaluated in accordance with EPA guidance. Direction-specific building data were generated for stacks below good engineering practice stack height, using the most recent version of the EPA Building Parameter Input Program – Prime (BPIP-Prime). The AERMOD model considers direction-specific downwash using both the Huber Snyder and Schulman-Scire algorithms, as represented in the BPIP-Prime. Figure 5.1-1 shows the major structures that were used in the BPIP-Prime analysis.

Table 5.1-19. Stack Parameters

Source	Stack Base Elevation Above Sea Level (m)	Stack Height (m)	Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
Area 600 Boiler1	9	19.8	504	10.7	1.07
Area 600 Boiler2	9	19.8	504	10.7	1.07
Area 600 Boiler3	9	19.8	504	10.7	1.07
VCU1	10	7.36	1,478	39.6	1.12
VCU2	10	7.36	1,478	39.6	1.12
VCU3	10	7.36	1,478	39.6	1.12
VCU4	10	7.36	1,478	39.6	1.12
VCU5	10	7.36	1,478	39.6	1.12
VCU6	10	7.36	1,478	39.6	1.12
VCU7	10	7.36	1,478	39.6	1.12
VCU8	10	7.36	1,478	39.6	1.12
Emergency Fire Water Pump 1	10	3.35	787	73.6	0.10
Emergency Fire Water Pump 2	11	3.10	787	73.6	0.10
Emergency Fire Water Pump 3	9	3.10	787	73.6	0.10

Note: m = meter; m/s = meter per second; K = Degrees Kelvin

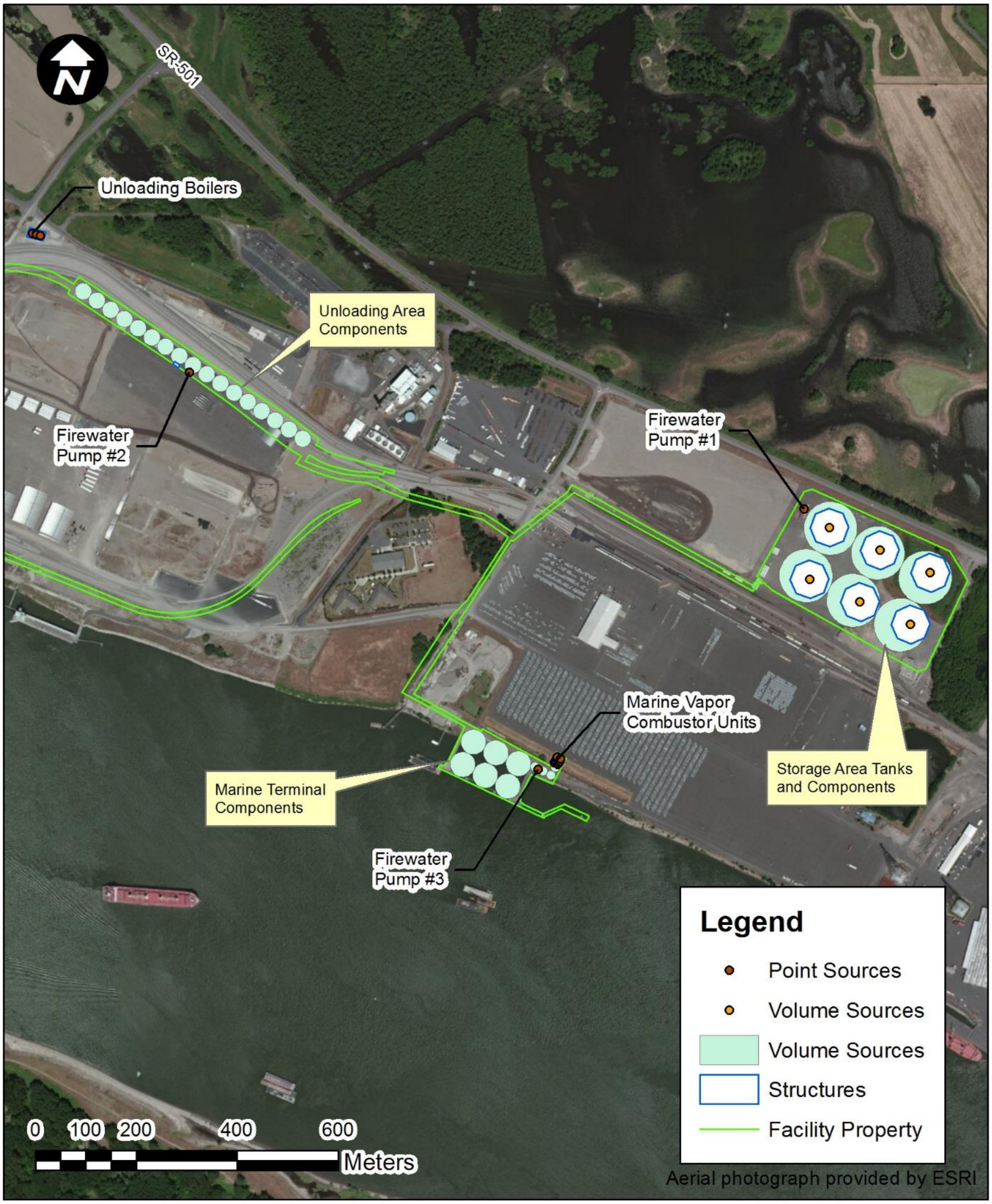

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Figure 5.1-1. Site Plan with Emission Units and Property Boundary

5.1.4.2 Local Meteorology and Air Quality

5.1.4.2.1 Local Meteorology

A meteorological database for the dispersion modeling was constructed using the best available surface and upper air data. A survey of available meteorological data was conducted for use in the simulations. For surface meteorological data, the closest and most representative National Weather Service (NWS) station was Pearson Field, located in Vancouver. The most appropriate upper air data was from McNary field airport in Salem, Oregon. A five-year meteorological database was created using the most recent available years of data: 2008 through 2012. Pearson Field was judged to be the best available source of meteorological data for air quality dispersion modeling. The meteorological station at Pearson Field is the station closest to the proposed project site that is part of the NWS Automatic Surface Observing System, and provides 1-minute wind speed and wind direction data that are used to resolve calm and variable wind conditions, as recommended by the EPA.

Figure 5.1-2 displays a wind rose constructed from the five years of hourly meteorological data. The average wind velocity for the five-year period is 2.32 meters per second and periods of calm winds occur 5.72 percent of the time.

Additional meteorological variables and geophysical parameters are required by the dispersion modeling analysis to estimate the surface energy fluxes and construct boundary layer profiles. Surface characteristics, including the surface roughness length, albedo, and Bowen ratio, were assigned on a sector-by-sector basis using land use within one kilometer of Pearson Field. The U.S. Geological Survey (USGS) 1992 National Land Cover Dataset (NLCD92) land use used in the analysis has a 30-meter mesh size and over 30 land use categories.[15]

The NLCD92 data were processed using the utilities that accompany the AERMOD modeling system. Land use was characterized in eight upwind sectors surrounding the site. Within each sector, a weighted average surface roughness length, albedo, and Bowen ratio was calculated from the characteristics recommended for each land use by the AERSURFACE program. Arithmetic averages were used for the albedo and Bowen ratio, while a geometric or logarithmic average was used for surface roughness length.

The EPA meteorological program, AERMET, was used to combine the Pearson Field observations with twice daily upper air soundings from Salem and derive the necessary variables for AERMOD. The upper air data were used to estimate the temperature lapse rate aloft and subsequently by AERMET to predict the development of the mixed layer height. The Bulk-Richardson option was used to estimate dispersion variables and surface energy fluxes during nocturnal periods, while solar radiation and wind speed were used by AERMET to estimate these same variables during the day. The sigma-theta data from the Pearson Field site were passed through by AERMET to AERMOD for the lateral dispersion algorithms.

[15] The USGS NLCD92 data is described and can be accessed at http://landcover.usgs.gov/natllandcover.php.

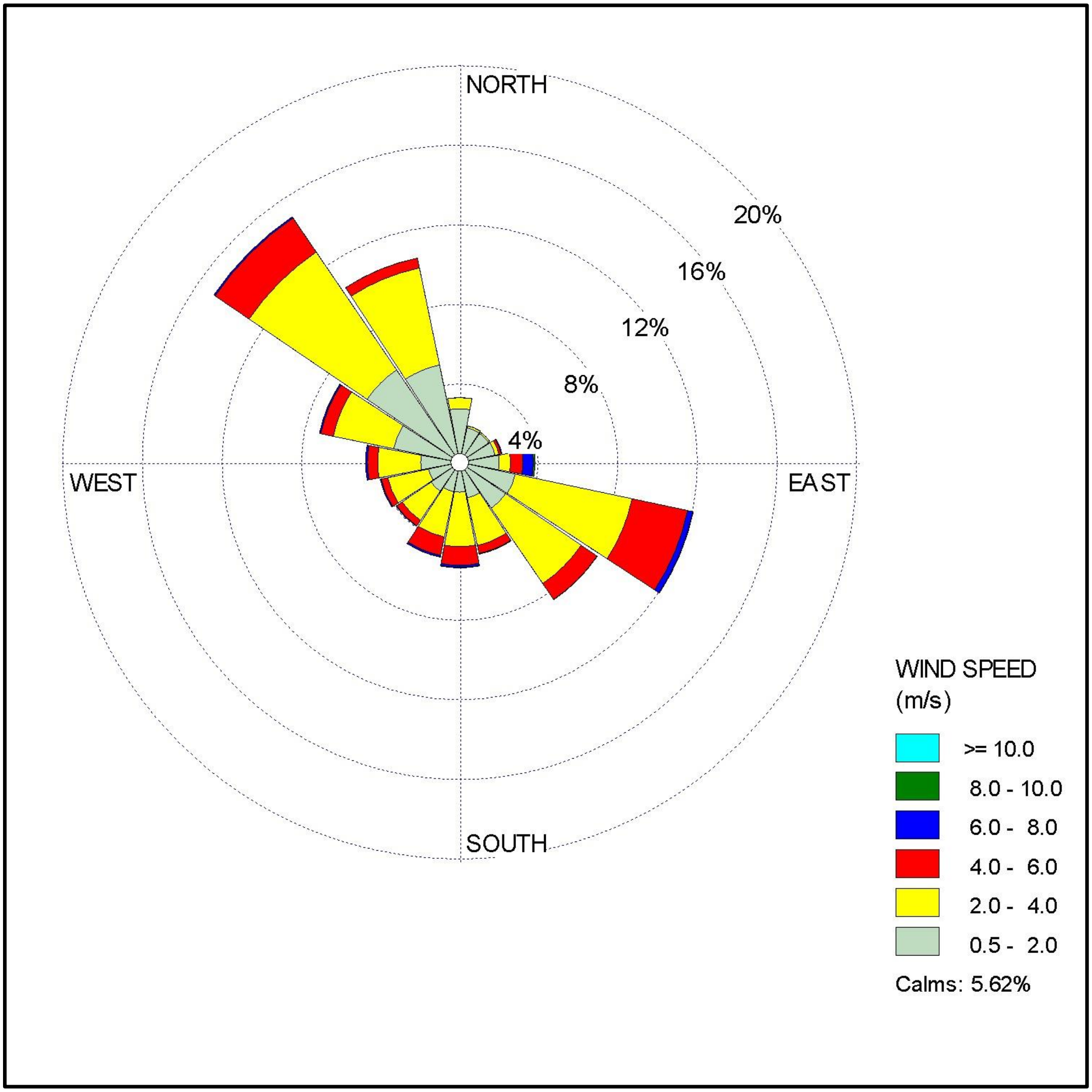

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Figure 5.1-2. Pearson Field Airport Windrose from 2008-2012

5.1.4.2.2 Background Air Quality

Ecology and EPA designate regions as being “attainment” or “nonattainment” areas for particular air pollutants based on monitoring information collected over a period of years. Attainment status is, therefore, a measure of whether air quality in an area complies with the health-based ambient air quality standards. The Facility is located in a region considered to be in attainment for all criteria pollutants, but it remains subject to maintenance plans that ensure continued compliance with ozone and carbon monoxide ambient standards.

Existing air quality at the Facility site can be inferred from several sources of information. First, conditions can be estimated from measurements collected by Ecology and the Oregon Department of Environmental Quality air quality monitoring networks. Current and archived air quality data are accessible from the EPA AirData website.[16] The 2012 AirData database files for several monitoring sites near the project site were accessed to characterize background air quality. The values reported at these sites represent the conservatively highest background air quality values in the region because monitoring sites are often specifically selected to identify the highest regional pollutant concentrations. Air quality values for each pollutant were estimated using measurements from the following monitors.

CO: SE Lafayette, Portland, Oregon, EPA AQS Site No. 41-051-0080 (about 10 miles southeast of the project site), 2012 maximum and second highest maximum values.

NO_2: SE Lafayette, Portland, Oregon, 2011 Annual mean, 2012 1-hour maximum and 98th percentile daily maximums.[17]

Ozone: Sauvie Island, Oregon, EPA AQS Site No. 41-009-0004 (about 8 miles north-northwest of the project site), 2011 8-hour maximum and fourth highest 8-hour maximum values.

$PM_{2.5}$: Fourth Plain Boulevard East, Vancouver, Washington, EPA AQS Site No. 53-011-0013 (about 10 miles east of the project site), 2012 24-hour maximum and 98th percentile concentrations, annual average estimated using annual average of 1-hour values.

PM_{10}: N. Roselawn Emerson Playfield, Portland, Oregon, EPA AQS Site No. 41-051-0246 (about 7 miles southeast of the project site), 2012 24-hour average maximum value and 98th percentile 24-hour average value, annual average estimated using annual average of 24-hour values.

SO_2: SE Lafayette, Portland, Oregon, EPA AQS Site No. 41-051-0080, 2012 maximum and 99th percentile 1-, 3-, and 24-hour values. Annual average estimated using annual average of 1-hour values.

Background concentrations can also be estimated using a tool provided by Ecology. Ecology provides the 2009-2011 “design values” for background air quality throughout the state using the output from the AIRPACT-3 regional air quality model, with adjustments from assimilated monitor data. The tool is a product of the Northwest International Air Quality Environmental

[16] U.S. EPA AirData website archive of monitoring data. http://www.epa.gov/airquality/airdata/.
[17] Reported in Oregon Department of Environmental Quality (2012): 2011 Oregon Air Quality Data Summaries, DEQ 11-AQ-021.

Science and Technology Consortium and is used to support air permitting and regulation in the State.[18] Use of this database may provide a more accurate estimate of the actual background air quality at the project site than the conservative measurements from the monitoring network. Design values were collected in July 2013 using the tool for project site coordinates (46.643 Lat., -122.705 Long.).

The background air quality values estimated from these sources of information are listed in Table 5.1-20.

Table 5.1-20. Existing Air Quality

Pollutant	Averaging Period	State Monitoring Network Maximum Value	State Monitoring Network Regulatory Value[1]	Design Value[2]
CO	1-hour	3.8 ppm	3.1 ppm (2nd high)	2.065 ppm
	8-hour	2.3 ppm	2.2 ppm (2nd high)	1.276 ppm
NO_2	1-hour	59 ppb	36 ppb (98th %-ile.)	37 ppb
	Annual	9 ppb	9 ppb	7 ppb
O_3	1-hour	0.068 ppm	0.064 ppm (4th high)	NA[3]
	8-hour	0.057 ppm	0.053 ppm (4th high)	0.056 ppb
$PM_{2.5}$	24-hour	31.2 μg/m^3	20.5 μg/m^3 (98th %-ile)	20 μg/m^3
	Annual	7.0 μg/m^3	NA[3]	5.8 μg/m^3
PM_{10}	24-hour	36 μg/m^3	34 μg/m^3 (98th %-ile)	31 μg/m^3
SO_2	1-hour	9.8 ppb	4.9 ppb (99th %-ile)	9.5 ppb
	3-hour	7.0 ppb	2.7 ppb (99th %-ile)	7.1 ppb
	24-hour	2.5 ppb	1.7 ppb (99th %-ile)	3.6 ppb
	Annual	1.5 ppb	NA[3]	3 ppb

Notes:
[1] Values that are applicable for comparison to the NAAQS.
[2] Facility site Design Value obtained from NW-Airquest/Dept. of Ecology
[3] NA: Not available

5.1.4.3 Dispersion Model Selection and Application

The most recent version (14134) of AERMOD was used for the air quality modeling. AERMOD is the preferred EPA guideline model for near-field simulation of industrial stack releases. AERMOD was used to model concentrations of pollutants having short-term (e.g., 1 to 24 hours) ambient standards with the appropriate averaging time selected. Modeling of pollutants with annual standards (i.e., $PM_{2.5,}$ SO_2 and NO_2) was conducted using AERMOD with the PERIOD option.

An analysis of the land use adjacent to the Facility site was conducted in accordance with Section 7.2.3 of the Guideline on Air Quality Models (EPA, 2005 and Auer, 1978). The land use analysis within 3 kilometers of the site was determined to be predominantly rural, such that rural

[18] NW-Airquest “design values” tool website: http://lar.wsu.edu/nw-airquest/index.html

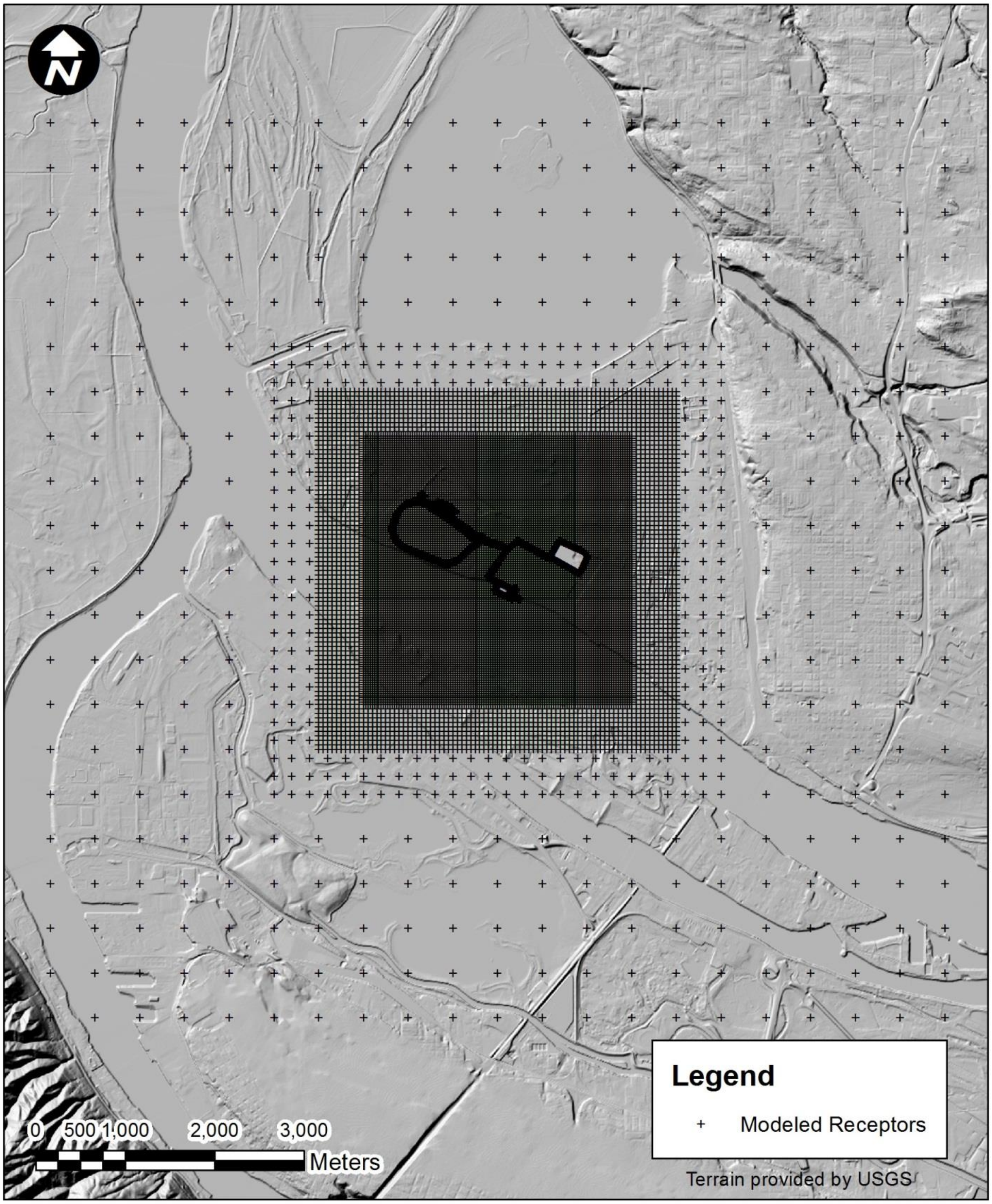
dispersion coefficients were selected for all Facility simulations. All AERMOD regulatory default settings were selected.

Concentrations attributable to Facility emissions units are calculated at simulated locations referred to as model receptors. The receptor grids used in the modeling analyses are as follows.

- 25-meter spacing along the property line and extending from the property line out to 3 km beyond the property line;
- 50-meter spacing from 3 km to 4 km from the property line;
- 200-meter spacing from 4 km to 5 km from the property line; and
- 500-meter spacing from 5 km to 10 km from the property line.

Actual Universal Transverse Mercator (UTM) NAD27 coordinates and digital terrain data provided by the USGS were used in all receptor grids.

Figure 5.1-3 shows the receptor grids used in the modeling overlaid on a topographic map.



BergerABAM

Figure 5.1-3. Modeling Receptor Grids

5.1.4.4 Dispersion Model Results

5.1.4.4.1 Criteria Pollutants

The criteria pollutant concentrations predicted using AERMOD to evaluate Facility operations are presented in Table 5.1-21. All maximum modeled concentrations occurred within 1 km of the Facility. In order to assess the significance of the predicted values, the maximum predicted criteria pollutant concentrations attributable to the Facility are compared with the EPA SILs; concentrations below the SILs are considered to be insignificant, and these pollutants do not require cumulative modeling with other sources to demonstrate compliance with ambient air quality standards.

Table 5.1-21. Project-only Modeling Results

Pollutant	Averaging Period	Design Concentration[1] (μg/m^3)	UTM Easting[2] (m)	UTM Northing[2] (m)	SIL[3] (μg/m^3)
CO	1-hour	90.6	520704	5055515	2,000
	8-hour	76.8	520704	5055515	500
NO_2	1-hour	22.1	520704	5055515	7.5
	Annual	0.588	520701	5055505	1
PM_{10}	24-hour	13.2	520698	5055496	5
$PM_{2.5}$	24-hour	10.5	520701	5055505	1.2
	Annual	0.295	520701	5055505	0.3
SO_2	1-hour	18.2	520704	5055515	7.8
	3-hour	17.2	520704	5055515	25
	24-hour	12.8	520704	5055515	5
	Annual	0.207	520701	5055505	1

Notes:
[1] Maximum concentration (highest 1st high) except for 1-hour NO_2, 24-hour $PM_{2.5}$, annual $PM_{2.5}$, and 1-hour SO_2, which are the highest of the 5-year averages of the maximum modeled concentrations predicted each year at each receptor.
[2] UTM Zone 10
[3] From WAC 173-400-113(4)(a)

Predicted CO, 3-hour average SO_2, and annual NO_2, $PM_{2.5}$, and SO_2 concentrations attributable to Facility emissions units are less than the SILs. A concentration less than the SIL indicates that emissions of that pollutant attributable to the Facility does not have the potential to significantly affect ambient air concentrations.

Short-term concentrations of NO_2, $PM_{2.5}$, PM_{10}, and SO_2 exceed their respective SILs; it is common to evaluate cumulative concentrations by adding existing "background" concentrations to the predicted concentrations attributable to the Facility. The background concentrations summarized in section 5.1.4.2.2, provide a conservative assessment of background air quality. Table 5.1-22 identifies cumulative concentrations based on the sum of these conservative background concentrations and the modeled design concentrations attributable to the Facility. The analysis indicates that when predicted design concentrations are added to the background concentrations, the resulting total concentrations comply with NAAQS/WAAQS.

Table 5.1-22. Comparison of Cumulative Concentrations with Ambient Air Quality Standards

Pollutant	Averaging Period	Modeled Design Concentration[1]	Background Concentration	Total Concentration[2]	NAAQS/ WAAQS
		(μg/m³)			
CO	1-hour	87.5	2,364	2,452	40,000
	8-hour	69.4	1,461	1,530	10,000
NO_2	1-hour	19.6	70	89.6	188
	Annual	0.588	13	13.6	100
PM_{10}	24-hour	10.1	31	41.1	150
$PM_{2.5}$	24-hour	6.59	20	26.6	35
	Annual	0.295	6	6.30	12
SO_2	1-hour	16.9	25	41.9	196
	3-hour	17.1	19	36.1	1,300
	24-hour	10.4	9	19.4	365
	Annual	0.207	8	8.21	52

Notes:

[1] The forms of the design concentrations are as follows:

CO, 1- & 8-hour average & SO2, 3- & 24-hour average – highest 2nd high concentration over the five modeled years of meteorological data

NO_2, 1-hour average – 98th percentile of the annual distribution of daily maximum 1-hour average concentrations averaged at each receptor over the five modeled years of meteorological data

NO_2 & SO_2, annual average – maximum annual average concentration

PM_{10}, 24-hour average – highest 6th high concentration over the five modeled years of meteorological data

$PM_{2.5}$, 24-hour average – 98th percentile of the annual distribution of 24-hour average concentrations averaged at each receptor over the five modeled years of meteorological data

$PM_{2.5}$, annual average – maximum annual average concentration averaged over the five modeled years of meteorological data

SO_2, 1-hour average – 99th percentile of the annual distribution of daily maximum 1-hour average concentrations averaged at each receptor over the five modeled years of meteorological data

[2] Total Concentration = Modeled Design Concentration + Background Concentration

5.1.4.4.2 Toxic Air Pollutants

WAC 173-460 regulates emissions of almost 400 substances as TAPs. When anticipated emissions of a given TAP exceed a prescribed "Small Quantity Emission Rate for that TAP, EFSEC requires permit applications to include dispersion modeling of TAP emissions and to include a comparison of calculated concentrations attributable to the project with the ASILs. If calculated concentrations are less than the ASILs, a permit can be granted without further analysis. Otherwise, the Applicant must revise the project or submit a health risk assessment demonstrating that toxic emissions from the project are sufficiently low to protect human health. Concentrations below the ASILs indicate insignificant potential for adverse health effects from these chemicals.

Table 5.1-12 identifies Facility-wide TAP emissions and was used to determine whether Facility-wide emissions of each TAP exceed its SQER. A dispersion modeling analysis for those TAPs emitted at rates exceeding the SQERs was conducted in the same manner as for the criteria pollutants.

Maximum predicted TAP concentrations attributable to the Facility emission units are compared with Ecology ASILs in Table 5.1-23. Predicted concentrations are less than the Ecology ASILs for all TAPs.

Table 5.1-23. Maximum Predicted TAP Concentrations

CAS #	Compound	Averaging Period	Maximum Predicted Concentration (μg/m^3)	ASIL (μg/m^3)
10102-44-0	Nitrogen dioxide	1-hour	22.6	470
7446-09-5	Sulfur dioxide	1-hour	18.6	660
7783-06-4	Hydrogen Sulfide	24-Hour	1.55E-01	2.00E+00
57-97-6	7,12-Dimethylbenz(a)anthracene	Annual	8.41E-07	1.41E-05
7440-38-2	Arsenic	Annual	1.05E-05	3.03E-04
71-43-2	Benzene	Annual	2.29E-02	3.45E-02
7440-43-9	Cadmium	Annual	5.78E-05	2.38E-04
18540-29-9	Chromium, (hexavalent)	Annual	2.94E-06	6.67E-06
N/A	Diesel Engine Particulate	Annual	1.45E-03	3.33E-03
50-00-0	Formaldehyde	Annual	3.94E-03	1.67E-01

Attachment 1

Tesoro Savage Vancouver Energy Distribution Terminal
Vancouver, Washington

Best Available Control Technology (BACT) Analysis

August 2014

Prepared by: ENVIRON

Job No. A13.0267.00

Best Available Control Technology (BACT) Analysis

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1 INTRODUCTION

In Washington, Best Available Control Technology (BACT) is required for new and modified industrial sources of criteria and toxic air pollutants (TAPs). This document presents a BACT analysis for new emission units associated with the Tesoro Savage Vancouver Energy Distribution Terminal (Facility). The basis for the emissions-related analyses is a maximum design throughput of 360,000 barrels of crude oil per day and year-round operation (365 days per year). The proposed project, as currently configured, will involve the following major emission units and processes:

- Three natural gas-fired package boilers,[1] each with a nominal heat input capacity of 62 million British thermal units per hour (MMBtu/hr), that will provide steam to heat crude oil railcars before unloading;
- Six crude oil tanks totaling approximately two million barrels of usable storage;
- Crude oil receiving and handling facilities for railcars, storage tanks, and vessels;
- Three nominal 225-hp diesel engines to power emergency fire water pumps; and
- Fugitive emissions from piping components.

Table 1-1 provides a summary of proposed BACT for each emission unit.

Table 1-1.Summary of Proposed BACT

Emission Unit	Pollutant	Proposed Means of Achieving BACT
Unloading Area Boilers	NO_X	Ultra-Low NO_X Burners
	CO & VOCs	Good Combustion Practices
	PM & SO_2	Use of Pipeline Natural Gas
	TAPs	Good Combustion Practices & Use of Pipeline Natural Gas
Marine Vessel Loading	VOCs & TAPs	Use of a Marine Vapor Combustion Unit
Marine Vapor Combustion Unit	NO_X	Good Combustion Practices
	CO & VOCs	Good Combustion Practices
	PM & SO_2	Use of Pipeline Natural Gas
	TAPs	Good Combustion Practices & Use of Pipeline Natural Gas
Crude Oil Storage Tanks	VOCs & TAPs	Fixed-Roof Tank with an Internal Floating Roof with Primary and Secondary Seals
Fugitive Piping Component Leaks	VOCs & TAPs	Leak Detection and Repair Program that Meets the Requirements of 40 CFR 63 Subpart H

[1] Only two of the three boilers in the unloading area will be operated at any given time, except occasionally for a brief period when the third boiler is started up as one shuts down.

Emission Unit	Pollutant	Proposed Means of Achieving BACT
Emergency Firewater Pump Engines	NO_X	Compliance with 40 CFR 60 Subpart IIII
	CO & VOCs	Compliance with 40 CFR 60 Subpart IIII
	PM & SO_2	Use of Ultra-Low Sulfur Diesel and Compliance with 40 CFR 60 Subpart IIII
	TAPs	Use of Ultra-Low Sulfur Diesel and Compliance with 40 CFR 60 Subpart IIII

1.1 Project description

The Facility will unload crude oil delivered by railcar and load crude oil to vessels. As necessary, crude oil will be stored in onsite tanks. Steam, provided by natural gas-fired boilers, will be used as needed to heat, and thereby decrease the viscosity of, certain crude oils to allow it to flow more easily from railcars. A network of pipes, and associated components (i.e., valves, pumps, etc.), will be used to convey crude oil from the railcar unloading facility to the tanks, and from the tanks for the marine terminal, where crude oil will be loaded onto vessels.

1.2 BACT Review Process

BACT, as it applies to regulated pollutants not subject to major new source review, is defined in WAC 173-400-030 (and adopted by reference via WAC 463-78-005) as:

> "…an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation under chapter 70.94 RCW emitted from or which results from any new or modified stationary source, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. "

BACT as it applies to sources located in attainment areas and subject to major new source review is almost identically defined in 40 CFR 52.21 (the PSD regulations, adopted by reference in WAC 463-78-005).

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps described below:

- Step 1: Identify all available emission reduction alternatives with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Step 2: Eliminate all technically infeasible alternatives;
- Step 3: Rank remaining alternatives by effectiveness;
- Step 4: Evaluate the economic, energy, and environmental impacts starting with the most effective alternative; and
- Step 5: Select BACT, which will be the most effective practical alternative not rejected in the previous steps.

Formal use of these steps is not always necessary. However, both EPA and the Washington Department of Ecology have consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each emission unit. These options were identified by researching the EPA database known as the RACT/BACT/LAER[2] Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. An available technology is one that is commercially available; meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;

[2] RACT is an acronym for Reasonably Available Control Technology, and LAER is an acronym for Lowest Achievable Emission Rate

- Licensing and commercial demonstration; and
- Commercial sales.

Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams' physical and chemical characteristics.

2 NATURAL GAS-FIRED BOILER BACT ANALYSIS

Three natural gas-fired package boilers will provide steam to heat certain crude oil to facilitate transfer by reducing the viscosity of the oil. The boilers, each with a nameplate firing rate of 62 MMBtu/hr, will be used to heat railcars. Tesoro-Savage expects to operate only two of the boilers at a given time; there would be one redundant boiler.

Utilization of the boilers will be dependent upon the quantity of crude oil that must be heated to achieve a viscosity conducive to transfer operations. The boilers could operate throughout the year (i.e., 8,760 hours per year), but at varying loads dictated by railcar arrival schedules and the viscosity of the crude oil contained in the railcars.

Pollutant emissions from the natural gas boilers are expected to include NO_X, PM (including PM_{10} and $PM_{2.5}$), CO, SO_2, VOCs, and TAPs.

2.1 Identify Commercially-Available Emission Reduction Alternatives

Review of the federal RBLC database and selected state permit information indicates that several emission reduction alternatives have been identified in BACT determinations. Table A-1 lists a number of recent BACT determinations associated with natural gas-fired boilers with capacities less than 100 MMBtu/hr. The RBLC database survey results indicate that available BACT options for the pollutants emitted from natural gas-fired boilers include:

- Good Combustion Practices (GCP)
- Low-NO_X burners (LNB)
- Ultra-Low-NO_X burners (ULNB)
- Oxidation Catalysts
- Flue Gas Recirculation (FGR)
- Selective Catalytic Reduction (SCR)
- Low sulfur fuels

2.2 Eliminate Technically Infeasible Alternatives

All emission reduction alternatives identified in the previous section are considered technically feasible for natural gas-fired boilers, except SCR, which is not technically feasible because of the inconsistent operating schedule of the proposed boilers. SCR systems utilize a catalyst to promote the reduction reaction between NO_X and ammonia (NH_3) at a lower temperature than it would otherwise occur. While catalysts are available that promote the reaction over a range of temperatures, a consistent temperature is required. For boilers that operate at a given load for extended periods, such a system can provide a reduction in NO_X emissions. Boilers with fluctuating steam demands, such as those proposed for this project, variations in flue gas temperature can lead to ineffective NO_X reduction, and unacceptably high emissions of unreacted NH_3. For this reason, SCR is removed from consideration as BACT for reducing NO_X emissions from the proposed natural gas-fired boilers.

In the following sections, these controls will be ranked and evaluated for each pollutant for which BACT is required.

2.3 NO_X BACT

Several of the identified alternatives are commercially available combustion and post-combustion control technologies which are capable of reducing NO_X emission from a natural gas-fired boiler. These controls include low-NO_X burners and flue gas recirculation.

2.3.1 Ranking of Remaining Alternatives

In top-down order of decreasing stringency, the feasible NO_X controls are listed with the approximate emission factor achieved by each technology:

- Ultra-Low-NO_X Burners – 0.011 lb/MMBtu[3]
- Low-NO_X Burners with FGR – 0.032 lb/MMBtu[4]
- Low-NO_X Burners with GCP – 0.050 lb/MMBtu[4]
- Conventional Burners with GCP, Conventional Burners – 0.10 lb/MMBtu[4]

2.3.2 Consideration of Energy, Environmental and Cost Factors

Because Tesoro-Savage proposes to meet the most stringent emission rate, no evaluation of energy, environmental, or cost was conducted. However, were an environmental and/or energy evaluation performed, utilizing low-NO_X burners with SCR would be identified as having greater impacts than utilizing ultra-low-NO_X burners.

2.3.3 Proposed BACT Limits and Control Option

Tesoro-Savage proposes an emission factor of 0.011 lb/MMBtu as BACT for NO_X emitted by all three of the proposed natural gas-fired boilers, achieved using ultra-low NO_X burners.

2.4 CO and VOC BACT

The only post-combustion control available for reducing emissions of CO and VOCs emitted by the proposed boilers is an oxidation catalyst module. Based on the RBLC review presented in Table A-1, the range of BACT CO emission limits for recently permitted natural gas-fired boilers (since 2004) is from 0.037 lb/MMBtu to 0.08 lb/MMBtu, and the range for VOCs is 0.0044 lb/MMBtu to 0.0054 lb/MMBtu. BACT for CO and VOCs on most units in the RBLC is GCP.

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[3] Provided by Cleaver Brooks; equivalent to 9 parts per million by volume.

[4] From EPA’s AP-42, Section 1.4 (Natural Gas Combustion), Table 1.4-1.

2.4.1 Ranking of Available Control Technologies

The identified control technologies, GCP and oxidation catalyst, are considered technically feasible for gaseous fuel fired boilers. In top-down order of decreasing stringency, the feasible CO and VOC controls are listed with the approximate level of control that could be achieved:

- Oxidation Catalyst and GCP – CO - 0.0036 lb/MMBtu, VOC - 0.0025 lb/MMBtu
- GCP – CO - 0.036 lb/MMBtu, VOC - 0.005 lb/MMBtu

2.4.2 Consideration of Energy, Environmental and Cost Factors

The use of oxidation catalyst modules as add-on emission control is available and technically feasible for reduction in CO emissions from natural gas-fired boilers. These are in addition to combustion controls (i.e., GCP) in combination with Low-NO_X burners.

With respect to energy considerations, add-on post-combustion controls on boilers of the capacity range proposed will noticeably reduce the thermal efficiency of the unit. Catalyst modules increase the back-pressure downstream of the combustion chamber by between 0.05 and 0.5 in H_2O per inch of catalyst bed depth, depending upon design.[5] Secondary environmental impact issues associated with spent catalyst module disposal are common among boiler installations that employ post-combustion catalytic systems. While landfill disposal fees for spent catalyst are not expensive, the potential liability associated with disposal is difficult to assess from a monetary perspective. Catalyst recycling options are not fully developed, and have their own specific liabilities associated with transport, processing, and disposal of by-products.[6]

Prohibitively high annualized cost is the primary factor that argues against costly add-on control technologies for natural gas-fired boilers. Because the proposed boilers will not be operated at a consistent load, it is likely that the catalyst performance will be uneven (i.e., the maximum reduction of CO and VOCs may not be achieved at all times).

As demonstrated in the attached cost-effectiveness calculations, add-on CO and VOC control technology for the proposed boilers would be cost-prohibitive in terms of cost per ton abated. Assuming an oxidation catalyst could provide 90 percent reduction of CO and 50 percent reduction of VOCs consistently throughout the year (highly unlikely given the planned method of operation), implementation of a catalytic oxidizer on one of the boilers has an estimated annualized cost of over $138,000, and provides a combined CO and VOC reduction of 9.4 tons per year, compared with GCP. From these results, the cost-effectiveness of the catalytic oxidizer option is conservatively estimated to be just less than $15,000 per ton reduced. This cost is not economically feasible, and so catalytic oxidation is eliminated as a BACT alternative.

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[5] Cooper, C.D. and F.C. Alley, “Air Pollution Control: A Design Approach,” Waveland Press, 1994. Page 359.

[6] Electric Power Research Institute (EPRI), “Recycling and Disposal of Spent Selective Catalytic Reduction Catalyst,” Report No. 1004888, October 2003.

2.4.3 Proposed BACT Limits and Control Option

Tesoro-Savage proposes that BACT for CO and VOCs from the proposed natural gas-fired boiler is 0.036 lb/MMBtu (approximately 50 ppm) for CO, and 0.005 lb/MMBtu for VOC, both achieved by employing GCP.

2.5 PM and SO_2 BACT

This BACT analysis assumes that all PM emissions from the proposed boilers are $PM_{2.5}$, and that the PM, PM_{10}, and $PM_{2.5}$ emission rates are all equivalent. Any reference to PM emissions in this BACT analysis represents all definitions of particulate matter emissions: PM, PM_{10}, and $PM_{2.5}$.

2.5.1 Ranking of Available Control Technologies

For these pollutants, the commercially-available control measures that are identified in the most-stringent BACT determinations are use of low-sulfur, pipeline natural gas, and GCP. Based on review of the RBLC database, a summary of which is presented in Table A-1, add-on controls were not implemented to achieve BACT limits for these pollutants. The ranges of BACT emission limits for these pollutants are:

- SO_2 – 0.0006 lb/MMBtu to 0.082 lb/MMBtu
- PM – 0.0044 lb/MMBtu to 0.0075 lb/MMBtu

The two most-stringent available technologies are to be adopted for the proposed boilers, so further evaluation is unnecessary.

2.5.2 Proposed BACT Limits and Control Option

The use of pipeline natural gas and GCP are proposed as BACT for PM and SO_2 emissions from the natural gas-fired boilers. Boiler vendor information indicates that the hourly average PM emission factor will be 0.0075 lb/MMBtu, and mass balance calculations based on the sulfur content of the expected source of natural gas indicates that the daily average SO_2 emission factor will be approximately 0.00725 lb/MMBtu. However, Tesoro-Savage does not propose that these emission factors be used as numeric permit limits. Instead, BACT should be considered the use of pipeline natural gas and GCP.

2.6 Startup and Shutdown BACT

Boilers startup and shutdown operations will be conducted as prescribed by the boiler manufacturer. Periods of overlapping operation will be minimized to avoid unnecessary fuel use and the corresponding emissions. The proposed boilers are high-efficiency, natural gas-fired units that are capable of starting and shutting down quickly, and perform consistently across a broad range of operating levels. Large field-erected boilers typically experience increased emissions per unit of heat input during startup and shutdown that are not relevant.

2.7 Toxic Air Pollutant BACT

Toxic air pollutant (TAP) compounds emitted by a natural gas-fired boiler are, in general, either volatiles (VOCs) or particles (PM). The proposed BACT for VOC and PM are also proposed to be BACT for VOC and PM TAPs, respectively. BACT for TAPs that contain chlorine (e.g., hydrogen chloride) and sulfur (e.g., sulfuric acid) is proposed to be the same as that proposed for SO_2. For nitrogen-containing compounds (e.g., nitric oxide), BACT is proposed to be the same as that proposed for NO_X.

3 MARINE VESSEL LOADING BACT ANALYSIS

Crude oil will be transferred from the facility to vessels. During the loading process, vapors, and inert gas present in the tank before loading began will be displaced by the crude oil entering the tank, and some of the crude oil will volatilize as it is being loaded. To comply with US Coast Guard regulations (33 CFR 154 Subpart E), these vapors must be captured and diluted, enriched, or inerted. Inerting systems will be used on each vessel loaded at the facility.

Pollutant emissions from marine vessel loading are expected to include VOCs and TAPs.

3.1 Identify Commercially-Available Emission Reduction Alternatives

The federal RBLC database, facility permits, and other sources were reviewed to identify commercially-available alternatives to reduce emissions from marine vessel loading operations. indicates that emission reduction alternatives include:

- Volatility reduction
- Vapor balancing
- Vapor recovery units (VRU)
- Marine vapor combustion units (MVCU)

3.2 Eliminate Technically Infeasible Alternatives

Reducing the volatility of crude oil by heating and separating volatiles prior to transport is theoretically possible, but implementation of this technology is not yet at the research stage, and is, therefore, considered technically infeasible and removed from consideration.[7]

Vapor balancing is frequently used when tank trucks are loading underground tanks, where the vapors displaced from the underground tank are retrieved by the tank truck and returned to the loading terminal. However, vapor balancing is typically not used for marine loading because the on-shore source of the crude (i.e., railcars or tanks equipped with floating roofs) is not able to accept vapors from the vessel. Even if the shore-side vessel were properly equipped to receive the vapors, the temperatures of the supplying and receiving vessels may be different, which could pressurize or create a vacuum in one or both of the vessels. Also, vapors that remain from the previous contents of the marine vessel could potentially contaminate the on-shore vessel. For these reasons, vapor balancing is technically infeasible, and is removed from consideration.

Vapor combustion units and vapor recovery units are frequently used for various types of petroleum product loading to marine vessels, and are considered technically feasible.

[7] Rudd, Howard J, and Nikolas A. Hill. “Measures to Reduce Emissions of VOCs during Loading and Unloading of Ships in the EU.” European Commission, Directorate General – Environment. Report No. AEAT/ENV/R/0469. August 2001. http://ec.europa.eu/environment/air/pdf/vocloading.pdf

3.3 Ranking of Remaining Alternatives

In top-down order of decreasing stringency, the feasible VOC and TAP controls are listed with the approximate control efficiency achieved by each technology:

- MVCU – 99 percent control or greater
- VRU – 99 percent control or greater

3.4 Consideration of Energy, Environmental and Cost Factors

The Facility is designed to employ an MVCU system to reduce VOC and TAP emissions. Because this is the most effective alternative, no additional evaluation of energy, environmental, or cost is necessary. MVCU systems are typically employed to control VOCs from crude oil loading operations because they are able to adapt to shifting quantities and types of VOCs as the nature of the crude loaded changes. A VRU system is not as adaptable, and is, therefore, more often applied to smaller loading operations with more uniform products (e.g., gasoline).

3.5 Proposed BACT Limits and Control Option

Based on the analysis presented above, Tesoro-Savage proposes that BACT for reducing VOC and TAP emissions from the proposed marine vessel loading operations is the use of an MVCU system, designed and operated to achieve maximum destruction of VOCs and TAPs.

4 MARINE VAPOR COMBUSTION UNIT BACT ANALYSIS

Vapors displaced from vessels as they are filled with crude oil will consist primarily of hydrocarbons. Assist-gas is added to the vapor as needed to ensure good combustion efficiency during certain times that the vessels are being loaded. All vapors, including any additional gas, will be collected and routed to a marine vapor combustor unit (MVCU) for safe disposal. Pollutant emissions from the MVCU are expected to include NO_X, PM (including PM_{10} and $PM_{2.5}$), CO, SO_2, VOCs, and TAPs.

4.1 Identify Commercially-Available Emission Reduction Alternatives

A broad review of permitted MVCUs, thermal oxidizers (TOs), and flares included in the federal RBLC database indicates that emission reduction alternatives are limited to:

- Good combustion practices
- Proper design and operation
- Use of gaseous fuels and/or pipeline natural gas

By combusting the displaced vapors using a MVCU, loading operations will comply with U.S. Coast Guard safety requirements in 33 CFR 154 Subpart E. Pollutant emissions from the MVCU fall into two categories: 1) vapors, typically VOCs, that escape the MVCU without being destroyed as intended; and 2) combustion products of the destroyed vapors and any supplemental fuel used to ensure sufficient flame temperature. Proper design and operation of the MVCU are intended to minimize the quantity of vapors that escape destruction.

In most cases, the VOC stream that an MVCU, TO, or flare controls is of variable composition and concentration. As a result, the associated burner must be designed to handle a wide range of combustion conditions, and cannot be optimized. In contrast, gas-fired burners associated with boilers or process heaters can be designed to minimize specific pollutants, such as NO_X or CO. While NO_X emissions vary among MVCU, TO, and flare combustor designs, none can utilize a true “Low-NO_X burner” design similar to a boiler or process heater.

NO_X emissions associated with MVCU, TO, and flare designs are typically in the range of 20 to 40 ppmvd. BACT for current Low-NO_X burner designs associated with small (i.e., less than 100 MMBtu/hr) natural gas-fired boilers is typically in the range of 9 to 11 ppmvd. When a MVCU, TO, or flare manufacturer or vendor says their product incorporates a “Low-NO_X burner,” the burner in question does not incorporate the same technology as a burner intended for use in a boiler, and will not achieve the same NO_X emission rate. For purposes of this BACT analysis, minimizing NO_X emissions while maintaining an acceptable destruction efficiency is considered part of “good combustion practices, and “Low-NO_X burner” is not considered an available technology for the proposed MVCU.

A permit issued to the Tidewater Terminal Co. for a facility in Pasco, Washington, on September 23, 2013 by Ecology’s Eastern Regional Office, included BACT and tBACT (BACT for toxic air pollutants) determinations for an MVCU. The Tidewater Terminal Co. MVCU is described in the permit as a “98.6% efficient John Zink Company Marine Vapor Combustion System enclosed flare.” Conditions placed on this unit by the permit are:

- Propane is used to fuel the pilot and as an auxiliary fuel to maintain combustion,
- Combustion temperature must be maintained at 1,400°F,
- VOC emissions from the unit shall not exceed 7 milligrams per liter of gasoline (mg/L) transferred from the facility to barges, and
- No visible emissions except water vapor are allowed from the unit.

4.2 Eliminate Technically Infeasible Alternatives

Because no pollutant-specific emission reduction alternatives were identified, all pollutants will be considered together in this and the following sections.

The emission reduction alternatives identified in the previous section are all considered technically feasible for MVCUs.

4.3 Ranking of Remaining Alternatives

Good combustion practices, proper design and operation, and use of “clean fuels” (i.e., pipeline natural gas or propane) are all considered baseline controls for MVCUs; therefore, it is not possible to rank the remaining alternatives. However, the following is a comparison of the MVCU proposed for the Project to each of the BACT elements identified in the Tidewater Terminal permit.

The proposal that the Project’s MVCU combust natural gas as an assist gas and for pilot flames compares favorably with the corresponding Tidewater Terminal MVCU permit requirement. Both natural gas and propane are considered “clean fuels” that minimize emissions of criteria, toxic, and greenhouse gas (GHG) emissions. Therefore, requiring the Project MVCU to employ natural gas is equivalent to the Tidewater Terminal requirement to employ propane.

The Project’s MVCU will operate at a temperature that yields high destruction efficiency consistent with the aim of the Tidewater Facility MVCU combustion temperature. Optimal control temperature varies with unit design. At this time, we do not know the combustion temperature prescribed by the Project's MVCU manufacturer to achieve the designed-for destruction efficiency. Maintaining the proper combustion temperature is a component of the "good combustion practices," and "proper design and operation" proposed as BACT for the Project's MVCU. When such information is available, it will be incorporated into the portion of the facility Operations and Maintenance Plan (O&M Plan) covering the MVCUs. Therefore, the Project MVCU will be operated consistent with the Tidewater Terminal MVCU.

The Project's MVCU will meet the 7 milligrams of VOC or less per liter of product loaded emission rate that is required for the Tidewater Facility. According to the manufacturer, the proposed Project MVCU system is expected to achieve at least 99.8 percent destruction of delivered hydrocarbons. In the Tidewater Terminal permit, the expected destruction efficiency is 98.6 percent. In this regard, the Project MVCU will perform consistent with the Tidewater Terminal MVCU.

The Project's MVCU will be designed to ensure that no visible emissions except for water vapor are emitted from the unit. Elimination of visible emissions other than water vapor is the result of using "good combustion practices" and "proper design and operation," which were both proposed in the permit application as BACT and tBACT for the Project MVCU. In this regard, the performance of the Project MVCU will be consistent with the Tidewater Terminal MVCU.

4.4 Consideration of Energy, Environmental and Cost Factors

Because Tesoro-Savage proposes to use the most effective alternatives, no evaluation of energy, environmental, or cost was conducted.

4.5 Proposed BACT Limits and Control Option

Tesoro-Savage proposes that BACT for reducing criteria pollutant and TAP emissions from the proposed MVCU is achieved by implementing good combustion practices, proper design and operation, and use of pipeline natural gas as an assist gas and for pilot flames.

5 CRUDE OIL STORAGE TANK BACT ANALYSIS

The proposed project will include an onsite tank farm, which will store crude oil delivered by railcar when a ship or barge is not available for loading. The tank farm will consist of up to six storage tanks, each approximately 240 feet in diameter, 48 feet tall, and with a maximum storage capacity of approximately 360,000 barrels. Two of the six tanks will be electrically heated, as needed, to control the viscosity of certain crude oil during loading and unloading.

Fugitive emissions are expected to occur due to evaporative loss of crude oil during storage and as a result of changes in the level of oil in the tanks. Pollutant emissions from the tanks are expected to include VOCs and TAPs. For purposes of this BACT analysis, a maximum annual throughput of 131.4 million barrels per year was assumed.

5.1 Identify Commercially-Available Emission Reduction Alternatives

Tanks constructed after July 23, 1984 are subject to the requirements of the NSPS for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984 (40 CFR Part 60 Subpart Kb). As stated in Section 1.3, EPA guidance indicates that a BACT determination can be no less stringent than the applicable NSPS requirements. A review of NSPS Subpart Kb, permits issued to facilities with oil storage tanks, and permits included in the federal RBLC database indicates that emission reduction alternatives for crude oil storage tanks include:

- Fixed-roof tank operated under pressure
- Fixed-roof tank with an internal floating roof with primary and secondary seals, and a vapor collection system routed to a process or fuel gas system or a control device (e.g., thermal oxidizer or carbon adsorber assumed to be at least 95 percent effective at reducing VOCs)
- Fixed-roof tank with an internal floating roof with primary and secondary seals
- External floating roof tank with primary and secondary seals
- Fixed-roof tank with a vapor collection system routed to a process or fuel gas system or a control device (e.g., thermal oxidizer or carbon adsorber assumed to be at least 95 percent effective at reducing VOCs)
- Fixed-roof tank operated at atmospheric pressure

Some identified BACT determinations for crude oil storage tanks are summarized in Table 5-1.

Table 5-1. Summary of VOC BACT Determinations for Crude Oil Tanks

Facility	State	Date Permitted	Equipment	BACT
Enbridge Superior Terminal	WI	6/12/2014	3 crude oil tanks – 24.5 million gal ea.	External floating roof with primary and secondary seals
Holly Refinery	UT	11/18/2013	3 crude oil tanks – 67,155 bbl, 80,306 bbl, 106,811 bbl	Fixed roof, pending review of vapor pressure variation. If vapor pressure exceeds NSPS levels, internal floating roof with primary and secondary seals.
Plains Marketing – Cushing Terminal Crude Storage Facility	OK	10/12/2010	46 crude oil tanks – 31 x 270,000 bbl ea., 2 x 300,000 bbl ea., and 13 x 570,000 bbl ea.	External floating roof with primary and secondary seals.
Hyperion Energy Center	SD	8/20/2009	10 crude oil tanks – 21 million gal ea.	Internal floating roof for liquids with a true vapor pressure less than 0.3 psia; add capture system with thermal oxidizer for liquids with a true vapor pressure equal to or greater than 0.3 psia.
ConocoPhillips Wood River Refinery	IL	8/5/2008	2 crude oil tanks – 11 million gal ea.	Internal floating-roof tanks with primary and secondary seals to comply with 40 CFR 60 Subpart Kb & 40 CFR 63 Subpart CC

Facility	State	Date Permitted	Equipment	BACT
Marathon Petroleum Garyville Refinery	LA	9/23/2006	12 crude oil tanks – 21 million gal ea.	External floating-roof tanks that comply with 40 CFR 63 Subpart CC
Arizona Clean Fuels Yuma	AZ	9/15/2006	7 crude oil tanks - 7,560,000 gal ea.	Internal floating-roof tanks with closed-vent system routed to thermal oxidizer.
Valero Refining - St. Charles Refinery	LA	2/5/2005	51 heavy materials tanks - 2,100 to 425,000 bbl ea.	Fixed-roof tanks, comply with 40 CFR 63 Subpart CC.

5.2 Eliminate Technically Infeasible Alternatives

While some petroleum products (i.e., those that are gases at atmospheric pressure) are stored in pressure vessels, crude oil is not. Therefore, a fixed-roof tank operated under pressure is considered technically infeasible, and is removed from further consideration. The facility will not include a process or fuel gas system, therefore, a closed vent system could not be routed to such a system, and that alternative is removed from consideration.

A fixed-roof tank operated at atmospheric pressure is technically feasible; but, because NSPS Subpart Kb does not include fixed-roof tank designs as an option and BACT can be no less stringent than the applicable NSPS, such a design cannot be considered as BACT.

All other emission reduction alternatives identified in the previous section are considered technically feasible for controlling emissions from oil storage tanks.

5.3 Ranking of Remaining Alternatives

The least effective control is a tank with a fixed roof operated at atmospheric pressure. Using the EPA's TANKS 4.0.9d emission calculation program, the total annual VOC emissions from the tanks, assuming a fixed-roof tank design is used, would be approximately 793 tons per year (tpy). As discussed in the previous section, a fixed-roof tank design operated at atmospheric pressure cannot be considered in the BACT analysis because the requirements of NSPS Subpart Kb are more stringent. Nevertheless, a fixed-roof design is an emission baseline worth noting. When ranking the VOC emission reduction alternatives as presented below, the percent reduction relative to the BACT baseline (the least effective alternative that complies with NSPS Subpart Kb), as well as the percent reduction relative to a fixed-roof design operated at atmospheric pressure, are both provided along with the total VOC emissions associated with each alternative.

In top-down order of decreasing stringency, the feasible VOC control alternatives are as follows:

- Fixed-roof tank with an internal floating roof with primary and secondary seals and vapor collection system routed to a control device (e.g., thermal oxidizer or carbon adsorber system assumed to be at least 95 percent effective at reducing VOCs) – 95.27 percent incremental reduction compared to BACT baseline, 99.76 percent reduction compared to fixed-roof design at atmospheric pressure (1.9 tpy);

- Fixed-roof tank with an internal floating roof with primary and secondary seals – 90.55 percent incremental reduction compared to BACT baseline, 99.53 percent reduction compared to fixed-roof design at atmospheric pressure (3.7 tpy);
- External floating roof tank with primary and secondary seals – 90.00 percent incremental reduction compared to BACT baseline, 99.50 percent reduction compared to fixed-roof design at atmospheric pressure (4.0 tpy); and
- Fixed-roof tank with a vapor collection system routed to a control device (e.g., thermal oxidizer or carbon adsorber system assumed to be at least 99.5 percent effective at reducing VOCs) – BACT baseline, 95.00 percent reduction compared to fixed-roof design at atmospheric pressure (39.6 tpy).

The emission reductions presented above were calculated using USEPA's TANKS 4.0.9d program.

5.4 Consideration of Energy, Environmental and Cost Factors

The most stringent alternative is a fixed-roof tank with an internal floating roof with primary and secondary seals and vapor collection system routed to a control device (e.g., thermal oxidizer or carbon adsorber system assumed to be at least 95 percent effective at reducing VOCs). Based on review of the RBLC and other issued permits, it appears that this alternative has been determined to be BACT for a single permitted facility, Arizona Clean Fuels Yuma, which was first permitted in April 2005, and then again in September 2006. The facility has never been constructed. This combination of control alternatives (i.e., internal floating roof with vapor collection system) has been considered is several BACT analyses, but, outside of the Arizona Clean Fuels Yuma project, never identified as BACT for crude oil storage tanks.

There are several instances of fixed-roof tanks equipped with a vapor collection system routed to a control device employed as LAER for reducing VOC emissions from crude oil storage tanks in ozone nonattainment areas. The primary difference between BACT and LAER is that, while BACT takes the economic impact of an emission reduction alternative into account, cost is not considered when determining LAER. A fixed-roof tank with vapor collection and control system was considered for the Cushing Terminal Crude Oil Storage Facility in Oklahoma, and the cost-effectiveness was determined to be over $39,000 per ton of VOC reduced.[8]

The Hyperion Energy Center project in South Dakota considered applying a capture and thermal oxidizer system to between 59 and 89 tanks, 10 of which would contain crude oil; the calculated cost-effectiveness ranged between $12,000 and $22,000, depending upon the scenario. Because many more tanks containing substances more volatile than crude oil were involved in this analysis, it is not considered a good cost-effectiveness example for the proposed TSVEDT crude oil tanks. The Hyperion Energy Center project has not been constructed, and the permit has expired.

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[8] http://www.deq.state.ok.us/aqdnew/permitting/permissue/2003104-c4p.pdf

In June 2014, Enbridge Energy received a permit that included the construction and operation of three 24.5-million-gallon (584,232 bbl) crude oil storage tanks. The Wisconsin Department of Natural Resources (WDNR) deemed BACT for VOC emissions from the tanks to be an external floating roof with primary and secondary seals. The cost-effectiveness analysis submitted to WDNR indicated that an internal floating roof tank with a capture system controlled by a carbon adsorption system had an incremental cost-effectiveness of $16,334 per ton of VOC reduced. All capture system and control device combinations were rejected as economically infeasible.[9]

In light of these facts, the use of a vapor collection system routed to a control device to control VOC emissions from the proposed tanks is removed from consideration. Almost all recently constructed crude oil tanks in Washington use an internal floating roof with primary and secondary seals to control VOC emissions.

5.5 Proposed BACT Limits and Control Option

Tesoro-Savage proposes that BACT for VOC and TAP emissions from the proposed crude oil storage tanks is the use of properly designed and operated internal floating-roof tanks with primary and secondary seals. Tesoro-Savage believes that emission rate limits are not appropriate for a fugitive source, and, therefore, does not propose any such limits as BACT.

6 COMPONENT LOSSES BACT ANALYSIS

The Facility will include piping, valves, connectors, pumps, and other components to transfer crude oil from railcars to tanks, and from tanks to vessels. All components are subject to minute vapor leakage, and fugitive VOC and TAP emissions are expected to occur when components are in service.

6.1 Identify Commercially-Available Emission Reduction Alternatives

A broad review of permitted operations included in the federal RBLC database and other permitted sources indicates that fugitive emissions from leaking petroleum service components are reduced through a combination of proper equipment selection and a leak detection and repair (LDAR) program. Identified alternatives include:

- Use of components using leakless technology
- Implementation of an LDAR program

LDAR programs involve periodic monitoring of components with a hydrocarbon analyzer, identification of components that leak above the leak definition levels specified in the equipment leak standard, and subsequent repair of the leaking components. LDAR programs are frequently defined by regulations; those in the RBLC deemed to represent BACT for other facilities permitted in the past ten years include:

- 40 CFR 63 Subpart H (National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks)

[9] http://dnr.wi.gov/cias/am/amexternal/AM_PermitTracking2.aspx?id=3002436

- 40 CFR 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries)
- 40 CFR 63 Subpart UU (National Emission Standards for Equipment Leaks—Control Level 2 Standards)
- 40 CFR 60 Subpart VVa (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006)
- 40 CFR 60 Subpart GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006)
- 40 CFR 61 Subpart V (National Emission Standard for Equipment Leaks (Fugitive Emission Sources))
- Louisiana Refinery MACT (Louisiana Administrative Code §2121, §2122, and Chapter 51)

The RBLC findings are summarized in Table 6-1.

Table 6-1. Summary of BACT Determinations for Component Losses from the RBLC

Facility	State	Date Permitted	BACT Determination
Valero Refining - St. Charles Refinery	Louisiana	11/17/2009	LA Refinery MACT, 40 CFR 63 Subpart H, 40 CFR 61 Subpart V
Sunoco Toledo Refinery	Ohio	2/23/2009	40 CFR 63 Subpart CC, 40 CFR 60 Subparts VV & GGG
Marathon Petroleum Garyville Refinery	Louisiana	12/27/2006	40 CFR 63 Subpart CC, 40 CFR 60 Subpart GGG, LA Refinery MACT
ConocoPhillips Wood River Refinery	Illinois	8/5/2008	40 CFR 63 Subpart H
Arizona Clean Fuels Yuma	Arizona	4/14/2005	40 CFR 63 Subpart H[1]

[1] In addition, the following leak definitions have been included: 100 ppmv for valves and connectors in gas/vapor and light liquid service and 500 ppmv for all other components. All pumps must be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. All compressors must be equipped with a seal system that includes a barrier fluid system that prevents leakage of process fluid to the atmosphere. Other requirements exist for other connector types and valves. The percent of leaking components cannot exceed the following: 1.0% for pumps in light liquid service and compressors on a source-wide basis, 1.0% for the total number of pressure relief devices on a source-wide basis, 0.3% for total number of connectors in gas/vapor service and connectors in light liquid service on a source-wide basis, 0.3% of the total number of valves in gas/vapor service and valves in light liquid service on a source-wide basis, and not more than 0.025% of valves in gas/vapor service and valves in light liquid service shall be leaking with a concentration in excess of 10,000 ppmv.

6.2 Eliminate Technically Infeasible Alternatives

Proper equipment selection and implementing an LDAR program based on any of the regulations identified in the previous section are considered technically feasible for reducing fugitive VOC and TAP emissions from component leaks.

6.3 Ranking of Remaining Alternatives

There are many LDAR programs available, some codified in regulations (e.g., NSPS, NESHAP, etc.), some developed by state agencies for consent decrees, and others developed by industry groups. Some of the non-regulatory alternatives include:

- Remote sensing technology
- Enhanced LDAR standards
- Audio/visual/olfactory methods

The effectiveness of these alternative programs has not been quantified, but none is thought to be any more effective than a regulatory LDAR program that includes implementation of EPA Method 21 (Determination of Volatile Organic Compound Leaks). All of the regulations identified in the previous section that require implementation of a formal LDAR program include Method 21.

A comparison of fugitive component emissions regulations compiled by the Louisiana Department of Environmental Quality (LDEQ) is provided in Table A-2. Taken as a whole, the requirements of 40 CFR 63 Subpart H are the most stringent. Implementation of an LDAR program and proper equipment selection are considered baseline alternatives, so there is no ranking.

6.4 Consideration of Energy, Environmental and Cost Factors

Because Tesoro-Savage proposes to use the most effective alternatives, no evaluation of energy, environmental, or cost was conducted.

6.5 Proposed BACT Limits and Control Option

Tesoro-Savage proposes that implementation of an LDAR program that meets the requirements of 40 CFR 63 Subpart H represents BACT for VOC and TAP component leaks at the Facility. Tesoro-Savage believes that emission rate limits are not appropriate for a fugitive source, and, therefore, does not propose any such limits as BACT. It should be noted that the proposed facility is not subject to the requirements of Subpart H as a result of the regulatory applicability criteria, but would meet the requirements of the rule, as appropriate, because it represents the most stringent implementation of an LDAR program.

7 EMERGENCY ENGINE BACT ANALYSIS

7.1 Process Description

Three pumps powered by nominal 225 hp diesel engines will be installed to provide water for fire suppression. Other than plant emergency situations, the engine will be operated a maximum of 34 hours per year for routine testing, maintenance, and inspection purposes.

The fire pump engines will emit criteria pollutants and TAPs associated with diesel engines. Although the engine make and model have not yet been specified, the engines will comply with the emission standards for stationary fire pump engines in 40 CFR Part 60 Subpart IIII (Stationary Compression Ignition Reciprocating Engine NSPS).

7.2 NO_X BACT

7.2.1 Available Control Technologies and Technical Feasibility

There are a limited number of technically-feasible NO_X control technologies that are commercially available for internal combustion engines. Two general types of control options have emerged as technically feasible: combustion process modifications, and post combustion controls. In practice, the high temperature and relatively low volumetric flow of the engine exhaust eliminates post-combustion controls from consideration. Table A-3 summarizes recent BACT determinations for internal combustion engines.

7.2.1.1 Combustion Process Modifications

This option is incorporated in the engine design. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix. Currently available new engines include these features as standard equipment; accordingly this measure is deemed the baseline case for purposes of the BACT analysis.

7.2.1.2 Selective Catalytic Reduction (SCR)

In this technology, nitrogen oxides are reduced to gaseous nitrogen by reaction with ammonia in the presence of a supported precious metal catalyst. The SCR system includes a catalyst module downstream of the engine exhaust. Just upstream of the catalyst, a reagent liquid (typically ammonia or urea solution) is injected directly into the exhaust stream. The method is considered feasible with lean-burn internal combustion engines.

7.2.1.3 Non-Selective Catalytic Reduction (NSCR)

Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize nitrogen oxides to molecular nitrogen. It operates in regimes with less than four percent oxygen in the exhaust, which corresponds to fuel-rich operation. The method is not feasible with lean-burn internal combustion engines.

7.2.2 Energy and Environmental Considerations

Several factors distinguish the two technically-feasible options with regard to energy and environmental impacts. One drawback associated with SCR systems is the environmental risk of handling and using ammonia reagent solutions. Most SCR catalyst modules can operate well without excess reagent. However, this requires particular attention to the controlled injection of the reagent in response to changes in load, temperature, and other parameters. Absent an emergency situation, the proposed fire pump engines will only operate infrequently for brief testing and maintenance checks (Subpart IIII limits these checks to 100 hours per year). These short, transient operating periods significantly reduce the effectiveness of the post-combustion controls.

Further, it should be assumed that ammonia emissions associated with SCR operation will occur under some or all operating conditions. This represents an additional air pollutant that is not emitted when SCR is not used for these engines. Also, the handling and storage of substantial volumes of the required ammonia or urea reagent solutions can pose an additional safety risk to facility personnel, and the risk of environmental harm in the event of an accidental release.

The SCR catalyst requires periodic cleaning due to fouling of the surfaces due to the presence of trace contaminants, such as sulfur compounds, particulate, and organic species. This requirement generates a secondary waste stream of contaminated cleaning solutions that must be disposed as hazardous waste.

When SCR or any add-on emission control technology is used, additional auxiliary equipment such as pumps and motors must be added. Also, the presence of the catalyst module adds an increment of pressure drop to the exhaust train. To avoid a substantial drop-off in engine performance, the SCR modules must be designed to minimize the increase in back pressure. However, the energy requirements of auxiliary equipment and even minor back-pressure increases reduce the net energy efficiency of the plant. In contrast, the implementation of combustion process controls does not require an add-on system with increased energy use by auxiliary equipment, or the use of catalyst and ammonia materials. There is some additional complexity in the engine controls for this option. Proper engine tuning and fuel/air ratio is needed across the full load range to achieve reduced emissions while avoiding a reduction in engine efficiency. The automatic fuel/air ratio controller helps accomplish this objective.

7.2.3 Ranking of Control Options

With regard to NO_X emission abatement, the ranking of the technically-feasible options is straightforward. The use of SCR offers the highest potential level of control for the proposed diesel-fired emergency engines. Up to 90 percent reduction in NO_X mass emission at all load levels is claimed for typical internal combustion engines.

The option offering the next highest control level is combustion process modifications, as would be implemented as standard equipment (i.e. no additional cost) in the selected engines. Advanced combustion design allows the engines to operate at rated horsepower, while burning an optimized fuel mix. This feature includes ignition timing retard to reduce cylinder temperatures for lean mixtures. The controls are also designed to optimize the air/fuel ratio and ignition timing in response to actual operating conditions.

7.2.4 Economic Analysis for Controls

Since advanced NO_X controls is a standard feature of the currently available new engines, the emissions reported by vendors for this package are taken as the base case in this BACT analysis. Addition of SCR is then analyzed as the next incremental control technology, in terms of both control level and cost.

The annualized operating costs for addition of SCR to the fire water pump engine would be about $44,000 per year. The estimated total capital investment is almost $127,000, based on purchased equipment cost estimates. Capital recovery is the single largest annual expense, based on 7 percent prevailing interest rate, and 10-year service period. Additional maintenance charges are also encountered for operation of the systems and annual catalyst cleaning. This investment would provide about 0.11 tons of NO_X reduction per year, assuming 90 percent emission control efficiency. Cost-effectiveness is more than $385,000 per ton, which represents a prohibitively high cost for this BACT option (see attached calculations).

7.2.5 Proposed BACT

A cost-effectiveness analysis has shown that use of SCR is cost prohibitive as a more-stringent control for the proposed fire water pump engines. The proposed BACT for these engines is the suite of combustion modifications supplied as standard equipment with the candidate types of engines which enable the manufacturer to certify the engine under Subpart IIII. As required by Subpart IIII, non-emergency hours of operation would be limited to 34 hours per year.

7.3 CO and VOC BACT

As for NO_X, CO and VOC emissions for the proposed fire water pump engines would be certified by the manufacturer to achieve the applicable standards in Subpart IIII, and would be operated no more than 34 hours per year in a non-emergency mode, which is less than the 100-hour limit imposed by Subpart IIII.

7.3.1 Technically-Feasible Controls

For CO emissions, the commercially available control means for IC engines are:

Combustion Process Modifications - This option is implemented in the design of the internal combustion engine. Typical design features include an electronic fuel/air ratio control and ignition retard, turbocharging, intercoolers, and lean-burn fuel mix. Currently available engines include these features as standard equipment, so these measures are used as the base case for the BACT cost-effectiveness analysis.

Catalytic Oxidation – This control technology employs a module containing an oxidation catalyst that is located in the exhaust path of the engines. In the catalyst module, CO and VOCs diffuse through the surfaces of a ceramic honeycomb structure coated with noble metal catalyst particles. Oxidation reactions on the catalyst surface forms carbon dioxide and water. Typical vendor indications are that 95 percent reduction in CO and 50 percent reduction in VOC emissions should be achieved.

7.3.2 Cost-Effectiveness Analysis

Given the low number of routine operating hours per year, the cost of catalytic oxidation for CO and VOC control will be prohibitive. The estimated annualized cost to add catalytic oxidation to the fire water pump engines is approximately $30,300. This investment would reduce CO and VOC emissions by 0.013 and 0.0017 tons per year, respectively, assuming a 95 percent reduction in emissions and 34 hours per year of non-emergency operation. Cost-effectiveness for this equipment would be more than $2,100,000 per ton of CO and VOC abated for the fire pump engines, which represents a prohibitively high cost for this BACT option.

7.3.3 Proposed BACT

Based on the cost-effectiveness analysis for application of catalytic oxidation as a more-stringent increment of control, the proposed BACT for the fire pump engines is the suite of combustion modifications supplied by the manufacturer as standard equipment that enable the engine to meet the emission standards in Subpart IIII. Annual emissions would be limited by restricting non-emergency hours of operation to 100 hours per year as required by Subpart IIII.

7.4 SO_2 and PM BACT

The proposed fire pump engines will use ultra-low sulfur diesel (ULSD) fuel which has a sulfur content of no more than 0.0015 percent (15 ppm) by weight. Given the low emission rates expected as a result of using ULSD fuel, there are no available technologies beyond good combustion controls that are considered to provide feasible or cost-effective emission control. Use of engines certified by manufacturers to meet Subpart IIII emission standards, use of ULSD fuel, and limitation of non-emergency operation to a maximum of 34 hours per year (less than the 100-hour limit imposed by Subpart IIII) will provide low emissions of SO_2 and PM, and are proposed as BACT measures for these pollutants.

8 TAPS BACT

The majority of TAPs emitted by the proposed emission units can be classified as either volatile organic compounds (i.e., VOCs) or particles (i.e., PM). The proposed BACT for VOC and PM are also proposed to be BACT for VOC TAPs and PM TAPs, respectively. BACT for TAPs that contain chlorine (e.g., hydrogen chloride) and sulfur (e.g., sulfuric acid) is proposed to be the same as that proposed for SO_2, and BACT for nitrogen-containing TAPs (e.g., NO_2) is proposed to be the same as that proposed for NO_X.

Table A-1. Recent RBLC Entries for Natural Gas-Fired Boilers Less Than 100 MMBtu/hr

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
FL-0335	09-05-12	Klauser Holding USA, Inc.	Suwannee County, FL	Boiler	46 MMBtu/hr	NO_X – 0.036 lb/MMBtu CO – 0.039 lb/MMBtu PM_{10}/$PM_{2.5}$ – 2 gr of s/100 scf SO_2 – 2 gr of s/100 scf VOC – 0.003 lb/MMBtu	LNB, FGR, GCP	BACT-PSD, Other Case-by-Case
NJ-0079	07-25-12	CPV Shore, LLC	Middlesex, NJ	Boiler	91.6 MMBtu/hr	NO_X – 0.01 lb/MMBtu CO – 0.038 lb/MMBtu PM_{10}/$PM_{2.5}$ – 0.005 lb/MMBtu SO_2 – 0.0018 lb/MMBtu VOC – 0.0015 lb/MMBtu	LSF, LNB, GCP	LAER, Other Case-by-Case, BACT-PSD
OH-0350	07-18-12	Republic Steel	Lorain, OH	Boiler	65 MMBtu/hr	NO_X – 0.07 lb/MMBtu CO – 0.04 lb/MMBtu PM_{10} – 0.0074 lb/MMBtu SO_2 – 0.0006 lb/MMBtu VOC – 0.0054 lb/MMBtu	GCP	BACT-PSD
CA-1189	01-24-12	Petrorock – Tunnell Lease	Santa Barbara, CA	Boiler	2 MMBtu/hr	NO_X – 20 ppmvd @ 3% O_2	LNB	Other Case-by-Case
CA-1192	06-21-11	Avenal Power Center, LLC	Kings, CA	Auxiliary Boilers	37.4 MMBtu/hr	NO_X – 9 ppmvd CO – 50 ppmvd PM_{10} – 0.0034 gr/dscf	ULNB, LSF, Operational Restriction of 46,675 MMBtu/yr	BACT-PSD
CA-1185	06-07-11	Santa Barbara Airport	Santa Barbara, CA	Boiler	3 MMBtu/hr	NO_X – 12 ppmvd @ 3% O_2 CO – 100 ppmvd @ 3% O_2	GCP, FGR	Other Case-by-Case

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
LA-0246	12-31-10	Valero Refining – New Orleans, LLC	St. Charles, LA	Boiler	99 MMBtu/hr	NO_X – 0.04 lb/MMBtu CO – 0.082 lb/MMBtu PM_{10} – 0.0075 lb/MMBtu SO_2 – 0.026 lb/MMBtu VOC – 0.0054 lb/MMBtu	GCP	BACT-PSD
OR-0048	12-29-10	Portland General Electric	Morrow, OR	Boiler	91 MMBtu/hr	NO_X – 0.05 lb/MMBtu PM_{10} – 2.5 lb/MMcf	LNB, CF	BACT-PSD
MO-0082	10-05-10	Archer Daniels Midland	Audrain County, MO	Boiler	85.6 MMBtu/hr	VOC – 0.0055 lb/MMBtu	GCP	BACT-PSD
LA-0240	06-14-10	Flopam, Inc.	Iberville Parish, LA	Boiler	25.1 MMBtu/hr	NO_X – 9 ppmv CO – 0.037 lb/MMBtu PM_{10} – 0.005 lb/MMBtu VOC – 0.008 lb/MMBtu	ULNB, LSF, GCP	LAER (NO_X, VOC), BACT-PSD
CA-1191	03-11-10	City of Victorville	Victorville, CA	Auxiliary Boilers	35 MMBtu/hr	NO_X – 9 ppmvd CO – 50 ppmvd $PM_{2.5}$ – 0.2 gr/100 dscf	Restricted Hours of Operation (500), LSF	BACT-PSD
NV-0049	08-20-09	Harrah's Operating Company, Inc.	Clark County, NV	Boilers	14.3, 16.8, 24, 31.4, 33.5, and 35.4 MMBtu/hr	NO_X – 0.0353, 0.03, 0.0108, 0.0306, 0.0367, and 0.035 lb/MMBtu CO – 0.0705, 0.0173, 0.037, 0.0172, 0.0075, and 0.0073 lb/MMBtu PM_{10} – 0.0075, 0.0077, 0.0075, 0.0076, 0.0075, and 0.0076 lb/MMBtu SO_2 – 0.0006, 0.0042, 0.0006, 0.0006, 0.0006, and 0.0006 lb/MMBtu VOC – 0.0054 lb/MMBtu	LNB, FGR, LSF, GCP	BACT-PSD (NO_X, SO_2), Other Case-by-Case
NH-0015	02-27-09	Concord Steam Corp.	Merrimack County, NH	Auxiliary Boiler	76.8 MMBtu/hr	NO_X – 0.049 lb/MMBtu	LNB, FGR, Restricted Hours of Operation (700)	LAER

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
OK-0135	02-23-09	Pryor Plant Chemical Co.	Mayes County, OK	Boilers	80 MMBtu/hr	NO_X – 0.05 lb/MMBtu CO – 0.0825 lb/MMBtu PM_{10} – 0.00625 lb/MMBtu SO_2 – 0.0025 lb/MMBtu VOC 0.00625 lb/MMBtu	LNB, GCP	BACT - PSD
OK-0137	02-09-09	ConocoPhillips	Kay County, OK	Boilers	95 MMBtu/hr	NO_X – 0.036 lb/MMBtu CO – 0.04 lb/MMBtu	ULNB, GCP	BACT-PSD
OK-0129	01-23-09	AEC, Inc.	Mayes County, OK	Auxiliary Boiler	33.5 MMBtu/hr	NO_X – 0.07 lb/MMBtu CO – 0.15 lb/MMBtu SO_2 – 0.0009 lb/MMBtu VOC – 0.016 lb/MMBtu	LNB, LSF, GCP	BACT-PSD
MD-0040	11-12-08	Competitive Power Ventures, Inc.	Charles County, MD	Boiler	93 MMBtu/hr	NO_X – 0.011 lb/MMBtu CO – 0.02 lb/MMBtu PM_{10}/$PM_{2.5}$ – 0.005 lb/MMBtu VOC – 0.002 lb/MMBtu	LNB, FGR, LSF	LAER ($PM_{2.5}$, VOC), BACT-PSD
OH-0323	06-05-08	Titan Tire Corp.	Williams County, OH	Boiler	50.4 MMBtu/hr	NO_X – 0.049 lb/MMBtu CO – 0.082 lb/MMBtu PM_{10} – 0.0019 lb/MMBtu VOC – 0.0054 lb/MMBtu	None	BACT-PSD (NO_X, CO, VOC)
NV-0047	02-26-08	Nellis AFB	Clark County, NV	Boilers	6.5 MMBtu/hr (representative of 125 regulated units)	NO_X – 25 ppmvd @ 3% O_2 CO – 50 ppmvd @ 3% O_2 PM_{10} – 0.0077 lb/MMBtu SO_2 – 0.0015 lb/MMBtu VOC – 0.0062 lb/MMBtu	LNB, FGR, LSF	BACT-PSD (SO_2), Other Case-by-Case
MD-0037	01-28-08	Medimmune, Inc.	Frederick County, MD	Boilers/Heaters	29.4 MMBtu/hr	NO_X – 0.011 lb/MMBtu	ULNB	LAER
MN-0070	09-07-07	Minnesota Steel Industries, Inc.	Itasca County, MN	Boilers/Heaters	99 MMBtu/hr	NO_X – 0.0035 lb/MMBtu CO – 0.08 lb/MMBtu PM_{10} – 0.0025 gr/dscf	None	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
AL-0230	08-17-07	Thyssen-Krupp Steel and Stainless USA, LLC	Mobile County, AL	Boilers	64.9 MMBtu/hr	NO_X – 0.035 lb/MMBtu CO – 0.04 lb/MMBtu PM_{10} – 0.0076 lb/MMBtu SO_2 – 0.0006 lb/MMBtu VOC -0.0055 lb/MMBtu	ULNB, FGR	BACT-PSD
GA-0130	07-27-07	Kia Motors	Troup County, GA	Boilers	30 MMBtu/hr	NO_X – 30 ppm @ 3% O_2	LNB	BACT-PSD
AL-0231	06-12-07	Nucor Corp.	Morgan County, AL	Boiler	95 MMBtu/hr	NO_X – 0.035 lb/MMBtu CO – 0.061 lb/MMBtu PM_{10} – 0.0076 lb/MMBtu SO_2 – 0.0006 lb/MMBtu VOC -0.0026 lb/MMBtu	ULNB	BACT-PSD
OH-0309	05-03-07	Daimler Chrysler Corp.	Lucas County, OH	Boiler	20.4 MMBtu/hr	NO_X – 0.035 lb/MMBtu CO – 0.083 lb/MMBtu PM_{10} – 0.0075 lb/MMBtu SO_2 – 0.0006 lb/MMBtu VOC -0.0054 lb/MMBtu	LNB, FGR	LAER (NO_X, VOC), BACT-PSD
MS-0085	01-31-07	Dart Container Corp., LLC	Clarke County, MS	Boiler	33.5 MMBtu/hr	VOC – 0.0055 lb/MMBtu	None	BACT-PSD
FL-0285	01-26-07	Progress Energy Florida (PEF)	Pinellas County, FL	Auxiliary Boiler	99 MMBtu/hr	CO – 0.08 lb/MMBtu	LSF	BACT-PSD
FL-0286	01-10-07	Florida Power And Light Company	West Palm Beach County, FL	Auxiliary Boiler	99.8 MMBtu/hr	NO_X – 0.05 lb/MMBtu CO – 0.08 lb/MMBtu PM_{10}/SO_2 – 2 gr/100 scf	LSF	BACT-PSD
NV-0044	01-04-07	Harrah's Operating Company, Inc.	Clark County, NV	Boilers	35.4 MMBtu/hr	NO_X – 0.035 lb/MMBtu CO – 0.036 lb/MMBtu PM_{10} – 0.0075 lb/MMBtu SO_2 – 0.001 lb/MMBtu VOC -0.005 lb/MMBtu	LNB, FGR, LSF, GCP	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
TX-0501	07-11-06	Texstar FS, LP	Henderson County, TX	Boiler	93 MMBtu/hr	NO_X – 0.090 lb/MMBtu CO – 0.076 lb/MMBtu PM_{10} – 0.0069 lb/MMBtu SO_2 – 0.00054 lb/MMBtu VOC -0.0049 lb/MMBtu	None	BACT-PSD
WA-0316	06-14-06	Northwest Pipeline Co.	Skagit County, WA	Boiler	4.19 MMBtu/hr	NO_X – 0.04 lb/MMBtu	GCP	BACT-PSD
CA-1128	05-16-06	Cottage Health Care	Santa Barbara County, CA	Boiler	25 MMBtu/hr	NO_X – 9 ppmv @ 3% O_2 CO – 50 ppmv @ 3% O_2	ULNB	BACT-PSD
NV-0048	05-16-06	Kern River Gas Transmission Co.	Clark County, NV	Boiler	3.85 MMBtu/hr	NO_X – 0.1 lb/MMBtu CO – 0.083 lb/MMBtu PM_{10} – 0.0078 lb/MMBtu SO_2 – 0.0015 lb/MMBtu VOC -0.005 lb/MMBtu	LSF, GCP	BACT-PSD (SO_2), Other Case-by-Case
NY-0095	05-10-06	Caithness Bellport, LLC	Suffolk County, NY	Auxiliary Boiler	29.4 MMBtu/hr	NO_X – 0.011 lb/MMBtu CO – 0.036 lb/MMBtu PM_{10} – 0.0033 lb/MMBtu SO_2 – 0.0005 lb/MMBtu	LNB, FGR, LSF, GCP	BACT-PSD
AR-0090	04-03-06	Nucor Steel	Mississippi, AR	Boilers	12.6 MMBtu/hr	NO_X – 0.075 lb/MMBtu CO – 0.084 lb/MMBtu PM_{10} - SO_2 - VOC -	LNB, GCP	BACT-PSD (except SO_2)
CA-1127	09-27-05	Genentech, Inc.	San Mateo County, CA	Boiler	97 MMBtu/hr	NO_X - CO -	ULNB	BACT-PSD
AK-0062	08-19-05	BP Exploration Alaska	North Slope Borough, AK	Reboiler	1.34 MMBtu/hr	NO_X - CO - SO_2 -	LSF, GCP	BACT-PSD

TABLE A-2. FUGITIVE EMISSIONS REGULATIONS COMPARISON TABLE

Item of Comparison	**40 CFR 63 Subpart H - SOCMI HON MACT**	**40 CFR 63 Subpart UU – Equipment Leaks Control Level 2**	**40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT**	**40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT**	**LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements**	**40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)**	**40 CFR 63 Subpart CC - Refinery MACT Modified HON Option**	**LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT**	**LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment**	**40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT**	**40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)**	**40 CFR 63 Subpart TT – Equipment Leaks Control Level 1**	**RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB**	**LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III**	**40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)**
Stream Applicability	> 5% VHAP by weight In organic HAP service > 300 hrs	> 5% VHAP by weight or as defined in the referencing Subpart	Elastomer Product Process Units	> 5% VHAP by weight In organic HAP service > 300 hrs	5% wt of the sum of Class I and II organics TAPs or >10% wt of the sum of Class I, II and III organic TAPs	> 10% VOC by weight	> 5% VHAP by weight In organic HAP service > 300 hrs	5% wt of the sum of Class I and II organics TAPs or >10% wt of the sum of Class I, II and III organic TAPs	>10% VOC by weight For sources in non-attainment areas for ozone	>10% wt VTAP (vinyl chloride or benzene)	> 10% VOC by weight	> 5% VHAP by weight or as defined in the referencing Subpart	> 10% by weight	>10% VOC by volume (2121)	"In Gasoline Service" (R) or "In Hydrogen Fluoride Service", as defined
Leak Definition	**Valves-Gas/LL:** 500 **HL:** No visual/500 **Pumps-LL:** 1,000 **HL:** No visual/2,000 **Compressors:** 500 **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 500 **Connectors:** 500 **Agitators:** 10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 500 **HL:** No visual/500 **Pumps-LL:** 5,000 – polymers 2,000 – food/med 1,000 – other **HL:** 5,000 – polymers 2,000 – food/med 2,000 – other **Compressors:** 500 **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 500 **Connectors:**500 **Agitators:** 10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 500 **HL:** No visual/500 **Pumps-LL:** 1,000 **HL:** No visual/2,000 **Compressors:** 500 **CVS:** 500 **PRVs-Gas:**500 **Liquid:** 500 **Connectors:** 500 **Agitators:** No visual leak **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 500 **HL:** No visual/500 **Pumps-LL:** No visual/2,000 **HL:** No visual/2,000 **Compressors:** 500 **CVS:** 500 **PRVs-Gas:**500 **Liquid:** No visual/ 500 **Connectors:** 500 **Agitators:** No visual/10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 200 / 500 **HL:** No visual/1,000 **Pumps-LL:** 2,000 **HL:** No visual/2,000 **Compressors:** 5,000 **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 1,000 **Connectors:** 1,000 **Agitators-HL:** 10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 500 **HL:** No visual/10,000 **Pumps-LL:** 5,000 – monomer 2,000 – other **HL:** No visual/10,000 **Compressors:** Seal system failure **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 10,000 **Connectors-Gas/ LL:** 500 **HL:** No visual/10,000 **Agitators:** No visual leak **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 1,000 **HL:** No visual/1,000 **Pumps-LL:** 2,000 **HL:** Reciprocating pumps exempt **Compressors:** 500 **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 500 **Connectors:** 1,000 **Agitators:** 10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 1,000 **HL:** No visual/1,000 **Pumps-LL:** 2,000 **HL:** No visual/2,000 **Compressors:** 5,000 **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 1,000 **Connectors:** 1,000 **Agitators-HL:** 10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 1,000 **HL:** No visual/1,000 **Pumps-LL:** 5,000 **HL:** No visual/5,000 **Compressors:** 5,000 **CVS:** No visual **PRVs-Gas:** 1,000 **Liquid:** No visual/ 1,000 **Connectors:** No visual /1,000 **Agitators:** 10,000 **Process Drains:** 1,000 **Sampling Points:** No visual leak	**Valves-Gas/LL:** 10,000 **HL:** No visual /10,000 **Pumps-LL:** 10,000 **HL:** No visual /10,000 **Compressors:** No visual leak **CVS:** 500 **PRVs-Gas**:500 **Liquid**: 10,000 **(HH)All:** 10,000 **Connectors:** No visual leak **Agitators:** No visual leak **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 10,000 **HL:** No visual/10,000 **Pumps-LL:** 10,000 **HL:** No visual/10,000 **Compressors:** Seal system failure **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 10,000 **Connectors:** No visual/10,000 **Agitators:** No visual leak **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 10,000 **HL:** No visual/10,000 **Pumps-LL:** 10,000 **Pumps-HL:** No visual/10,000 **Compressors:** Seal system failure **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 10,000 **Connectors:** No visual/10,000 **Agitators:** No visual leak/10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 10,000 **HL:** No visual/10,000 **Pumps-LL:** 10,000 **HL:** No visual/10,000 **Compressors:** 10,000 **CVS:** 10,000 **PRVs-Gas:** 10,000 **Liquid:** 10,000 **Connectors:** Visual **Agitators:** No visual leak **Process Drains:** No visual leak **Sampling Points:** No visual leak	**All equipment:** 10,000 Subpart III – annually or after reinstallation	**All equipment:** Evidence of potential leak detected by visual, audible, or olfactory means.
Leak Definition	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/500 **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/500 **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** 500 **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/500 **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/1,000 **Open-ended lines:** 1,000	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/1,000 **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/1,000 **Open-ended lines:** 1,000	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**All equipment:** 10,000	

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Monitoring Frequency: Light Liquid valves	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking Every 2 years if <0.25%	Monthly if > 4% Quarterly if < 4%	Monthly If ND leak for 2 successive months = quarterly	**Monthly:** ->5% (with connectors) ->4%(without) **Quarterly:** - <5% (with connectors) - <4% (without) **Semiannual:** - <4% (with) - <3% (without) **Annual:** - <3% (with) - <2% (without)	Monthly if > 4% Quarterly if < 4%	Quarterly	Monthly	Monthly If ND leak for 2 successive months = quarterly	Monthly If ND leak for 2 successive months = quarterly	Monthly If ND leak for 2 successive months = quarterly	Quarterly Annually (pipeline valves)	Monthly (63 R) -or- Once per shift (63 YY)
Monitoring Frequency: Gas Valves	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking Every 2 years if <0.25%	Monthly if > 4% Quarterly if < 4%	Monthly If ND leak for 2 successive months = quarterly	**Monthly:** ->5% (with connectors) ->4%(without) **Quarterly:** - <5% (with connectors) - <4% (without) **Semiannual:** - <4% (with) - <3% (without) **Annual:** - <3% (with) - <2% (without)	Monthly if > 4% Quarterly if < 4%	Quarterly	Monthly	Monthly If ND leak for 2 successive months = quarterly	Monthly If ND leak for 2 successive months = quarterly	Monthly If ND leak for 2 successive months = quarterly	Quarterly	Monthly (63 R) -or- Once per shift (63 YY)
Monitoring Frequency: Gas Pressure Relief Valves	Monitor within 5 days of a release	Monitor within 5 days of a release	Monitor within 5 days of a release	Monitor within 5 days of a release	Monitor within 5 days of a release	Monitor within 5 days of release	Monitor within 5 days of a release	Monitor within 5 days of a release	Quarterly and within 24 hours of an atmospheric release	Monitor within 5 days of release	Monitor within 5 days of release	Monitor within 5 days of release	Monitor within 5 days of release	Quarterly and within 24 hours of an atmospheric release	Monitor within 5 days of detection by sight, sound, or smell
Monitoring Frequency: Liquid Pressure Relief Valves	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of a release or detection by sight, smell, or sound	Monitor within 5 days of a release or detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 24 hours of an atmospheric release	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 24 hours of an atmospheric release	Monitor within 5 days of detection by sight, smell, or sound
Monitoring Frequency: Light Liquid Pumps	Monthly monitor & weekly visual Pump repair not required unless leak > 2000 ppm	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Quarterly if <3% leaking Monthly if <10% or 3 leaking, whichever is greater	Quarterly monitor & weekly visual	Quarterly monitor & weekly visual (seals)	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Quarterly monitor & weekly visual Pump seals (annually)	Monthly (63 R) -or- Once per shift (63 YY)

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51-Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51-Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Monitoring Frequency: Compressors	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Quarterly Or Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Quarterly Or Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Quarterly monitor (seals)	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Quarterly monitor & weekly visual (seals)	Monthly (63 R) -or- Once per shift (63 YY)
Monitoring Frequency: Flanges/ Connectors	Initial monitor Monitor annually if >0.5% leaking Monitor biennially if <0.5% leaking Monitor every 4 years if <0.5% leaking for 2 years HL connectors: Monitor within 5 days of detection by sight, smell, or sound	Initial monitor Monitor annually if >0.5% leaking Monitor every 4 years if <0.5% and >0.25% Monitor at least 50% of connectors within four years if <0.25% HL connectors: Monitor within 5 days of detection by sight, smell, or sound	Monitor annually if >0.5% leaking Monitor biennially if <0.5% leaking Monitor every 4 years if <0.5% leaking for 2 years	Initial monitor Monitor annually if >0.5% leaking Monitor biennially if <0.5% leaking Monitor every 4 years if <0.5% leaking for 2 years HL connectors: Monitor within 5 days of detection by sight, smell, or sound	Annually (random 200 or 10% by unit) If <2% leaking = annually If >2% leaking = quarterly until <2% obtained for 4 qrts otherwise monitor all connectors Monitor within 90 days after welding (xray, etc.) or breaking the seal (OVA)	Monitor within 5 days of detection by sight, smell, or sound	**2 Options**(if monitoring connectors): **Random 200** - monitor within 1st 12months after Phs III date - every 6 mos. if >2% - annual if <2% and >1% - biannaul if <1% and >.5% - every 4 years if <0.5% **Inspection Alternative** - monitor all gas/ vapor connctors within 12 months after Phs III date - inspect all light liquid connectors (> 3 drops/minute) - annual if >2% leaking - biannual if ,2% and >1% leaking - every 4 years if <1% leaking	Annually (random 200 or 10% by unit) If <2% leaking = annually If >2% leaking = quarterly until <2% obtained for 4 qrts otherwise monitor all connectors Monitor within 90 days after welding (xray, etc.) or breaking the seal (OVA)	Weekly visual (no records) Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monthly (63 R) -or- Once per shift (63 YY)
Monitoring Frequency: Process Drains	NA	NA	NA	NA	NA	NA	NA	NA	Annually monitor	NA	NA	NA	NA	Annually monitor	NA
Monitoring Frequency: Heavy Liquid Equipment	Monitor within 5 days of detection by sight, smell, or sound. Repaired systems do not require monitoring	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound. Repaired systems do not require monitoring	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound. Repaired systems do not require monitoring	Monitor within 5 days of detection by sight, smell, or sound	Monitor if leak suspected by sight, smell, or sound	NA	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor if leak suspected by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51-Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51-Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Monitoring Frequency: Closed Vent Systems	Hard piping: Initial monitoring Annual visual Duct Work: Annual monitor	Hard piping: Initial monitoring Annual visual Duct Work: Annual monitor	Hard Piping: Annual visual Duct Work: Annual monitor	Hard piping: Initial monitoring Annual visual Duct Work: Annual monitor	Annually monitor	Hard piping: Initial monitoring Annual visual Duct work: Annual monitor	Hard piping: Initial monitoring Annual visual Duct Work: Annual monitor	Annually monitor	NA	Annually monitor	Hard piping: Initial monitoring Annual visual Duct work: Annual monitor	Hard piping: Initial monitoring Annual visual Duct work: Annual monitor	Hard piping: Initial monitoring Annual visual	Monitor if leak suspected by sight, smell, or sound	Hard piping: Initial monitoring Annual visual Duct Work: Annual monitor
Monitoring Frequency: Open-ended valves/lines	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve Monitor annually	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve Monitor if leak suspected by sight, smell, or sound	Requires cap, plug, blind flange, or 2nd valve
Monitoring Frequency: Sampling Points/ Connections	Requires closed purge, closed loop, or closed vent system Return or recycle purge	Requires closed purge, closed loop, or closed vent system Return or recycle purge	Requires closed purge, or closed loop system	Requires closed purge, closed loop, or closed vent system Return or recycle purge	Requires closed purge, or closed vent system Return or recycle purge Zero emissions to atm	Requires closed purge system, or closed vent system Return or recycle purge	Requires closed purge, closed loop, or closed vent system Return or recycle purge	Requires closed purge, or closed vent system Return or recycle purge Zero emissions to atm	NA	Requires closed purge, closed vent system Return or recycle purge Zero purge to atm	Requires closed purge system, or closed vent system Return or recycle purge	Requires closed purge system, or closed vent system Return or recycle purge	Requires closed purge system, or closed vent system Return or recycle purge	Monitor within 5 days of detection by sight, smell, or sound	Requires closed purge, closed loop, or closed vent system Return or recycle purge
Monitoring Frequency: Agitators	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Within 5 days of detection by sight, smell, or sound	NA	Monthly monitor & weekly visual	Within 5 days of detection by sight, smell, or sound	NA	NA	NA	Monthly monitor & weekly visual	NA	Monitor within 5 days of detection by sight, smell, or sound	Monthly monitor & weekly visual
Monitoring Frequency: Surge Control Vessels and Bottoms Receivers	Requires closed vent system	NA	Requires closed vent system Exempt from requirements if contains a latex and located downstream of stripping operation.	Requires closed vent system	Requires closed vent system	NA	Requires closed vent system	Requires closed vent system	NA	Requires closed vent system	NA	NA	NA	Monitor within 5 days of detection by sight, smell, or sound	Requires closed vent system
Monitoring Frequency: Visual Leaks	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound			Monitor within 5 days of detection by sight, smell, or sound		Monitor immediately any component leaking based on sight, smell, or sound			Monitor within 5 days of detection by sight, smell, or sound	NA	Monitor immediately any component leaking based on sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound
Monitoring Frequency: Instrument-ation Systems	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	NA	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	NA	NA	NA	Monitor within 5 days of detection by sight, smell, or sound	NA	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Skip periods	**Valves only:** Initial performance of 2% leaks = quarterly Initial performance of 1% leaks = semi-annually **Pumps only:** No skip period only avoid QIP requirements Batch process monitoring Historical performance acceptable without prior approval	**Valves only:** Monthly if >2% Quarterly if <2% Semiannually if <1% Annually if <0.5% Biennally if <0.25% **Pumps only:** No skip period only avoid QIP requirements	**Valves only:** Initial performance of 2% leaks = quarterly Initial performance of 1% leaks = semi-annually **Pumps only:** No skip period only avoid QIP requirements Batch process monitoring	**Valves only:** Initial performance of 2% leaks = quarterly Initial performance of 1% leaks = semi-annually **Pumps only:** No skip period only avoid QIP requirements Batch process monitoring Historical performance acceptable without prior approval	**Valves only:** Not Allowed	**Valves only:** 2 consecutive quarters <2% = skip 1 quarter 5 consecutive quarters <2% = skip 3 quarters	**Valves (with connectors):** Initial performance of 5% leaks = quarterly Initial performance of 4% leaks = semi-annually **Valves (without connectors):** Initial performance of 4% leaks = quarterly Initial performance of 3% leaks = semi-annually **Pumps only:** No skip period only avoid QIP requirements Historical performance acceptable without prior approval	**Valves only:** 2 consecutive quarters <2% = semi-annual 2 consecutive semi-annual < 2% = annual >2% leaking = increase monitoring Historical performance acceptable without prior approval	**Valves only:** 2 consecutive quarters < 2% = skip 1 quarter 5 consecutive quarters < 2% = skip 3 quarters Total leaking FECs cannot be > 4% Historical performance acceptable without prior approval	**Valves only:** 2 successive months ND = first month of every qtr until leak detected 2 consecutive qtrs < 2% = skip 1 qtr 5 consecutive qtrs < 2% = skip 3 qtrs Vinyl Chloride NESHAP allows 200 or 90% valves if <2%	**Valves only:** 2 consecutive quarters <2% = skip 1 quarter 5 consecutive quarters <2% = skip 3 quarters	**Valves only:** 2 consecutive quarters <2% = skip 1 quarter 5 consecutive quarters <2% = skip 3 quarters Monthly if >2%	**Valves only:** 2 consecutive quarters <2% = skip 1 quarter 5 consecutive quarters <2% = skip 3 quarters	**Valves only:** 2 consecutive quarters <2% = skip 1 qtr for valves and pumps (LL) 5 consecutive quarters <2% = skip 3 qtrs	None for 63 R
Light/heavy liquid definition and exemptions	Light liquid has VP > 0.3 kPa @ 20 degC	Light liquid has VP > 0.3 kPa @ 20 degC	Light liquid has VP > 0.2 kPa @ 20 degC	Light liquid has VP > 0.3 kPa @ 20 degC & is 20%w of total process stream	Light liquid has VP > 0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86	Light liquid has VP > 0.3 kPa @ 20 degC & is 20%w of total process stream	Light liquid has VP > 0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86	Light liquid has VP > 0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86		Light liquid has VP >0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86	Light liquid has VP > 0.3 kPa @ 20 degC & is 20%w of total process stream	Light liquid has VP > 0.3 kPa @ 20 degC	Light liquid has VP > 0.3 kPa @ 20 degC	NA	
Liquid dripping definition										Visible leakage including spraying, misting, clouding and ice formation				Per HON	
Materials included in VOC definition					Consistent with LAC 33:III.2117	TOC excluding methane, ethane, 1-1-1-TCE, methylene chloride, and various CFCs		Consistent with LAC 33:III.2117			TOC excluding methane, ethane, 1-1-1-TCE, methylene chloride, and various CFCs		Consistent with LAC 33:III.2117		
Monitoring Method	Method 21 Calibrate within 2000 ppm	Method 21 Calibrate within 2000 ppm	Method 21	Method 21 Calibrate within 2000 ppm	LAC 33:III.6077	Method 21	LAC 33:III Chapter 60, 61 or 63	LAC 33:III.6077	Method 21	Method 21	Method 21	40 CFR 264.1063 (b)	Method 21	Visual, audible, or olfactory	
Monitoring Distance	Consistent with EPA protocol	Consistent with EPA protocol	Consistent with EPA protocol	Consistent with EPA protocol	Not specified	Consistent with EPA protocol	Consistent with EPA protocol	Not specified	Consistent with EPA protocol	Consistent with EPA protocol	Consistent with EPA protocol	Consistent with EPA protocol	Not specified	NA	

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Comments			Comply with Subpart H of SOCMI HON This table outlines HON requirements for Elastomer MACT	Comply with HON except for specific deviations These two regulations are carbon copies of each other											
Post repair inspection	Valves, after repair, monitored at least once within 3 months Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Valves, after repair, monitored at least once within 3 months Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Valves, after repair, monitored at least once within 3 months Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Valves, after repair, monitored at least once within 3 months If monitoring connectors, monitor repaired connector within 2st 3 months after repair. Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Valves, after repair, monitored at least once within 3 months	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	No visible leak or holds a test pressure
Repair periods (1st/Final Attempt)	5 day/15 days	5 day/15 days	5 days/15 days	5 days/15 days	5 days*/15 days *Includes monitoring	5 days/15 days	5 day/15 days	5 days/15 days	15 days	5 days/15 days	5 days/15 days	5 days/15 days	5 days/15 days	15 days	5 days/15 days
Calibration gas	Zero air, and mixtures dependent on phase monitored	Zero air, methane or n-hexane and air at a concentration of approximately 2,000 ppm	Zero air, air mixtures dependent of phase monitored	Zero air, methane or n-hexane and air at a concentration of approximately 2,000 ppm	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Zero air, methane or n-hexane and air at a concentration no more than 2,000 ppm above leak definition and highest scale with a calibration gas of approximately 10,000 ppm	Zero air, and mixtures dependent on phase monitored	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Not specified in rule	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Not specified in rule	NA
Calibration Frequency	Before use on each day	Before use on each day	Before use on each day	Before use on each day	Before use on each day	Before use on each day	Before use on each day	Before use on each day	Not specified in rule	Before use each day	Before use on each day	Before use on each day	Before use on each day	Not specified in rule	NA
Criteria for unsafe to monitor exemption	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves, connectors & CVS:** Immediate danger Follow written plan to monitor when safe	**Valves:** Immediate danger Follow written plan to monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves, connectors & CVS:** Immediate danger Follow written plan to monitor when safe	No criteria, but monitor when safe	**Valves:** Immediate danger Follows written plan to monitor when safe	**Valves:** Immediate danger Follow written plan to monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves:** Immediate danger Follow written plan to monitor when safe	No criteria, but monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51-Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Criteria for inaccessible components exemption	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Random 200 option** - only accessible connectors **Inspection Alternative** - only accessible connectors	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)				**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)			**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)
Criteria for difficult to monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor
Exemptions	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor <.75" FECs in instrumentation systems PRVs equipped with rupture disk	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor <.75" FECs in instrumentation systems PRVs equipped with rupture disk	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals Vapor pressure <0.0435 psia R&D facilities (< 100 FEC) Insulated components	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor	Vacuum service Unsafe to monitor Dual Mechanical seals Vapor pressure <0.0435 psia R&D facilities (< 100 FEC) Check valves	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system Difficult to monitor Open ended lines for emergency PRVs equipped with rupture disk
Exemptions (Continued)	Unmanned sites: Monthly visual inspections allowed Compressors operated <300 hrs or tied to CVS or VRU	Open ended lines for emergency PRVs equipped with rupture disk	Open ended lines for emergency PRVs equipped with rupture disk	Open ended lines for emergency PRVs equipped with rupture disk	Open ended lines for emergency PRVs equipped with rupture disk		Unmanned sites: Monthly visual inspections allowed Compressors operated <300 hrs or tied to CVS or VRU	Open ended lines for emergency PRVs equipped with rupture disk	Components of shutdown repair list						Unmanned sites: Monthly visual inspections allowed Compressors operated <300 hrs or tied to CVS or VRU

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Delay of repair	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connector, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VOTAP service **Valves, connectors & agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device Drill and tap required on non-control valves, if feasible, before placing on delay of repair All components on delay of repair must be monitored per routine monitoring **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VOC service **Valves:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VOTAP service **Valves, connectors & agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Requires a PU shutdown Isolated or bypassed to reduce leakage Shutdown would create more emissions than repair would eliminate	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VHAP service **Valves:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VOC service **Valves:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VOC service **Valves:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Requires a PU shutdown Isolated or bypassed to reduce leakage Shutdown would create more emissions than repair would eliminate	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)
Delay of repair beyond PU shutdown	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion		**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion		**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.
Tagging	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components and affected components	Leaking components	Leaking components	Physical tag required	Leaking components	None
Use of background concentration data	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Not specified in rule	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance		Not specified in rule	NA

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Recordkeeping	Leak and repair records Component Inventory Connector monitoring schedule DMS records Valves records Exemption data Batch Process Monitoring HL determinations Visual inspection dates Compliance tests CVS system design and operation QIP	Leak and repair records Component Inventory Connector monitoring schedule DMS records Valves records Exemption data Batch Process Monitoring HL determinations Visual inspection dates Compliance tests CVS system design and operation QIP	Leak and repair records Component Inventory Connector monitoring schedule DMS records Valves records Exemption data Batch Process Monitoring HL determinations Visual inspection dates Compliance tests CVS system design and operation QIP	Leak and repair records Component Inventory Connector monitoring schedule DMS records Valves records Exemption data Batch Process Monitoring HL determinations Visual inspection dates Compliance tests CVS system design and operation QIP	Leak and repair records Component Inventory Connector monitoring schedule Valves records Exemption data CVS system design and operation DORs must be signed within 30 days of leak identifcation	Leak and repair records Component Inventory CVS design and operation records Valve records Exemption data	Leak and repair records Component Inventory Connector monitoring schedule DMS records Valves records Exemption data HL determinations Visual inspection dates Compliance tests CVS system design and operation QIP	Leak and repair records Component Inventory Connector monitoring schedule Valves records Exemption data CVS system design and operation	Leak and repair records Component inventory Calibration records	Leak and repair records CVS design and operation records Component Inventory Valve records Exemption data	Leak and repair records Component Inventory CVS design and operation records Valve records Exemption data	Leak and repair records Component Inventory CVS design and operation records Valve records Exemption data	Leak and repair records Component Inventory CVS design and operation records Valve records Exemption data Compliance Test Results	Leak and repair records Component inventory Calibration records	Maintain log book of inspections, and leaking components, with summary descriptions.
Recordkeeping Period	2 years	Per referencing Subpart	2 years	5 years	5 years	2 years	2 years	5 years	2 years	2 years	2 years	Per referencing Subpart (5 years)	2 years	2 years	5 years
Reporting	LDAR Performance reports semi-annually after Not. of Comp. Initial Notification Initial Notification of Compliance	LDAR Performance reports semi-annually after Not. of Comp. Initial Notification Initial Notification of Compliance	LDAR performance report semi-annually after Not. of Comp. Initial Notification Initial Notification of Compliance	LDAR Performance reports semi-annually after Not. of Comp. Initial Notification Initial Notification of Compliance	Initial notification Quarterly LDAR Performance reports 3 months after initial report	Initial report LDAR Performance reports semi-annually	LDAR Performance reports semi-annually after Not. of Comp. Initial Notification Initial Notification of Compliance	Initial notification Quarterly LDAR Performance reports 3 months after initial report	Quarterly LDAR Performance reports, including repair data	Initial report Semi-annual reports starting 6 months after initial	Initial report LDAR Performance reports semi-annually	Per referencing Subpart	LDAR Performance reports semi-annually	Quarterly LDAR Performance reports, including repair data	63 Subpart R: Quarterly 63 Subpart YY: Records only

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51-Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Effective dates	Group I Oct 24, 1994 Oct 24, 1995 Apr 24, 1997 Group II Jan 23, 1995 Jan 23, 1996 Jul 23, 1997 Group III Apr 24, 1995 Apr 24, 1996 Oct 24, 1997 Group IV Jul 24, 1995 July 24, 1996 Dec 24, 1997 Group V Oct 23, 1995 Oct 23, 1996 Apr 23, 1997		One year after promulgation for compressors 6 months after promulgation for other equipment		Jan 1, 1995, unlessotherwise specified in Air Toxics Compliance Plan, but no later than Dec 20, 1996	Nov. 16, 2007	New Sources - upon startup Existing Sources - Phase I- Aug 18, 1998 Phase II - Aug 18, 1999 Phase III - Feb 18, 2001	Jan 1, 1995, unlessotherwise specified in Air Toxics Compliance Plan, but no later than Dec 20, 1996	Jan1, 1996	June 6, 1984 Vinyl Chloride NESHAP Oct 21, 1976	Jan 5, 1981		As required by permit		

Note: For this table –

CVS = closed vent systems; DMS = dual mechanical seal system; Gas = in gas/vapor service; HL = in heavy liquid service; Liquid = in liquid service;
LL = in light liquid service; ND = no leak is detected; PRVs = pressure relief valves/devices; PU = process unit; QIP = quality improve program;
SurgeCtrlVessel = surge control vessel; TOC = total volatil organic compounds; VRU = vapor recovery unit.

Table A-3. Recent BACT Determinations For Internal Combustion Emergency Fire Pump Engines ≤ 500 HP

Permit or RBLC ID	Permit Issuance Date	Company	Location	Unit Description	Maximum Power Output	Limit(s)	Control Option	Basis
OH-0352	06-18-13	Arcadis, US, Inc.	Lucas County, OH	Emergency Fire Pump	300 HP	NO_x – 1.7 lb/hr CO – 1.7 lb/hr PM_{10} – 0.1 lb/hr SO_2 – 0.003 lb/hr VOC – 0.25 lb/hr CO_2e – 87 ton/yr	Purchased certified to the standards in NSPS Subpart IIII	BACT-PSD
PA-0286	01-31-13	Moxie Energy, LLC	Lycoming County, PA	Fire Pump	Not Provided	NO_x – 2.6 g/HP-hr CO – 0.5 g/HP-hr PM_{10}/ $PM_{2.5}$ – 0.09 g/HP-hr VOC – 0.1 g/HP-hr	Not provided	Other Case-by-Case
IN-0158	12-03-12	St. Joseph Energy Center, LLC	St. Joseph County, IN	Diesel Fire Water Pumps	371 BHP	NO_x – 3 g/HP-hr CO – 2.6 g/HP-hr PM_{10}/ $PM_{2.5}$ – 0.15 g/HP-hr SO_2 – 0.0015% S diesel fuel VOC – 0.16 lb/hr CO_2e – 172 ton/yr	GCP, ULSD	BACT-PSD
IA-0105	10-26-12	Iowa Fertilizer Company	Lee County, IA	Fire Pump	14 gal/hr	NO_x – 3.75 g/kW-hr CO – 3.5 g/kW-hr PM_{10}/ $PM_{2.5}$ – 0.2 g/kW-hr VOC – 0.25 g/kW-hr VE – 5% CO_2e – 91 ton/yr	GCP	BACT-PSD
WY-0070	08-28-12	Black Hills Power, Inc.	Laramie County, WY	Diesel Fire Pump	327 HP	NO_x – not provided CO – not provided SO_2 – not provided	EPA Tier 3 rated, ULSD	BACT-PSD
VA-0319	08-27-12	Gateway Green Energy	Prince George County, VA	Firewater Pump	1.86 MMBtu/hr	PM_{10}/ $PM_{2.5}$ – 0.15 g/HP-hr CO_2e – 30.5 ton/yr	GCP, ULSD	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	Unit Description	Maximum Power Output	Limit(s)	Control Option	Basis
SC-0113	02-08-12	Pyramax Ceramics, LLC	Allendale County, SC	Fire Pump	500 HP	NO_x – 4 g/kW-hr CO – 3.5 g/kW-hr SO_2 – not provided VOC – 4 g/kW-hr	Purchase of certified engine based on NSPS, Subpart IIII, ULSD, Sulfur content less than 0.0015%, operating hours less than 100 hr/yr for maintenance and testing	BACT-PSD
TX-0612	11-10-11	Lower Colorado River Authority	Llano County, TX	Diesel Fire Water Pumps	617 HP	CO_2e – 7027.8 lb/hr	Best work practice	BACT-PSD
LA-0254	08-16-11	Entergy Louisiana, LLC	Jefferson Parish, LA	Emergency Fire Pump	350 HP	CO – 2.6 g/HP-hr PM_{10}/ $PM_{2.5}$ – 0.15 g/HP-hr VOC – 1 g/HP-hr	ULSD, GCP	BACT-PSD
CA-1192	06-21-11	Avenal Power Center, LLC	Kings County, CA	Emergency Firewater Pump	288 HP	NO_x – 3.4 g/HP-hr CO – 0.447 g/HP-hr PM_{10} – not provided	Equipped with a turbocharger and an intercooler/ aftercooler, ULSF not to exceed 15 ppmvd fuel sulfur, operational limit of 50 hr/yr	BACT-PSD
LA-0251	04-26-11	Flopam, Inc.	Iberville Parish, LA	Fire Pump	444 HP	NO_x – 5.82 lb/hr CO – 0.65 lb/hr PM_{10} – 0.01 lb/hr	GCP	BACT-PSD
FL-0322	12-23-10	Southeast Renewable Fuels (SRF), LLC	Hendry County, FL	Emergency Diesel Fire Pump	Not Provided	CO – 2.6 g/HP-hr PM – 0.15 g/HP-hr	Not provided	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	Unit Description	Maximum Power Output	Limit(s)	Control Option	Basis
MI-0399	12-21-10	Detroit Edison	Monroe County, MI	Diesel Quench Pump	252 HP	NO_x – 7.8 g/HP-hr CO – 2.6 g/HP-hr $PM_{10}/PM_{2.5}$ – 0.4 g/HP-hr VE – 20% opacity	GCP	BACT-PSD, Each – Test Protocol
NH-0018	07-26-10	Laidlaw Berlin BioPower, LLC	Coos County, NH	Fire Pump	2.27 MMBtu/hr	PM_F – 0.3e-5 lb/MMBtu	Not provided	MACT
ID-0018	06-25-10	Idaho Power Company	Payette County, ID	Fire Pump	235 kW	NO_x – 4 g/kW-hr CO – not provided PM – 0.2 g/kW-hr VOC – 4 g/kW-hr	Tier 3 engine-based	BACT-PSD
CA-1191	03-11-10	City of Victorville	San Bernardino County, CA	Emergency Firewater Pump	135 kW	NO_x – 3.8 g/kW-hr CO – 3.5 g/kW-hr $PM_{2.5}$ – 0.2 g/kW-hr	Operational restriction of 50 hr/yr, operate as required for fire safety testing	BACT-PSD
MI-0389	12-29-09	Consumers Energy	Bay County, MI	Fire Pump	525 HP	CO – 2.6 g/HP-hr PM_{10} – 0.31 lb/MMBtu	Engine design and operation 15 ppm sulfur fuel	BACT-PSD
				Fire Booster Pump	40 kW	CO – 5 g/kW-hr PM_{10} – 0.31 lb/MMBtu	Engine design and operation 15 ppm sulfur fuel	BACT-PSD
OK-0129	01-23-09	Associated Electric Cooperative, Inc.	Mayes County, OK	Emergency Diesel Fire Pump	267 HP	NO_x – 4.59 lb/hr CO – 2.6 g/HP-hr PM_{10} – 0.24 lb/hr SO_2 – 0.11 lb/hr VOC – 0.66 lb/hr	GCP, LSDF	BACT-PSD
OH-0317	11-20-08	Ohio River Clean Fuels, LLC	Columbiana County, OH	Fire Pump	300 HP	NO_x – 4.89 lb/hr CO – 1.72 lb/hr PM_{10} – 0.27 lb/hr VOC – 0.26 lb/hr VE – 20%	GCP, Turbocharger, Low temperature aftercooler	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	Unit Description	Maximum Power Output	Limit(s)	Control Option	Basis
MD-0040	11-12-08	Competitive Power Ventures, Inc./CPV Maryland, LLC	Charles County, MD	Emergency Firewater Pump	300 HP	NO_x – 3 g/HP-hr CO – 2.6 g/HP-hr $PM_{10}/PM_{2.5}$ – 0.15 g/HP-hr SO_2 – not provided VOC – 0.66 lb/hr	Not provided	BACT-PSD
FL-0304	09-08-08	Florida Municipal Power Agency (FMPA)	Osceola County, FL	Emergency Fire Pump	> 300 HP	NO_X – 3 g/bhp-hr CO – 2.6 g/bhp-hr PM – 0.15 g/bhp-hr	Not provided	BACT-PSD
LA-0224	03-20-08	Southwest Electric Power Co.	Caddo Parish, LA	Diesel Fire Pump	310 HP	NO_x – 9.61 lb/hr CO – 2.07 lb/hr PM_{10} – 0.68 lb/hr SO_2 – 0.64 lb/hr VOC – 0.77 lb/hr	Low-Sulfur fuel, limited operation hours, and proper engine maintenance	BACT-PSD
MN-0070	09-07-07	Minnesota Steel Industries, LLC	Itasca County, MN	Diesel Fire Water Pumps	Not Provided	SO_2 – 0.05% in fuel VE – 5%	Limited Sulfur in fuel, limited hours	BACT-PSD
CA-1144	04-25-07	Caithness Blythe II, LLC	Riverside County, CA	Fire Pump	303 HP	NO_x – 7.5 lb/hr CO – 0.7 lb/hr PM_{10} – 0.1 lb/hr	Fuel with less than 0.05% sulfur by weight	BACT-PSD
IA-0084	11-30-06	ADM Corn Processing	Clinton County, IA	Fire Pump Engine	500 HP	VOC – 3 g/HP-hr	GCP	BACT-PSD
NC-0101	09-29-05	Forsyth Energy Projects, LLC	Forsyth County, NC	Emergency Firewater Pump	11.40 MMBtu/hr	NO_x – 36.48 lb/hr CO – 9.69 lb/hr PM_{10} – 1.14 lb/hr SO_2 – 0.58 lb/hr VOC – 1.04 lb/hr	Emergency use only	BACT-PSD
LA-0192	06-06-05	Cresent City Power, LLC	Orleans County, LA	Firewater Pump	425 HP	NO_x – 8.9 lb/hr CO – 1.88 lb/hr PM_{10} – 0.14 lb/hr SO_2 – 0.61 lb/hr VOC – 0.05 lb/hr	Good engine design and proper operating practices	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	Unit Description	Maximum Power Output	Limit(s)	Control Option	Basis
OH-0252	12-28-04	Duke Energy Hanging Rock ,LLC	Lawrence County, OH	Firewater Pump	265 HP	NO_x – 8.2 lb/hr CO – 1.8 lb/hr PM – 0.66 lb/hr SO_2 – 0.10 lb/hr VOC – 0.66 lb/hr	500 hr/yr	BACT-PSD

Crude Oil Speciation Summary

Annual Emissions

Un-Heated		Losses(lbs)												
Components	CAS #	RVP 0.98	RVP 3.25	RVP 3.27	RVP 3.59	RVP 3.96	RVP 8.41	Bakken 423	Bakken 430	Bakken 413	Bakken 413 11psi	Max	Max case	Max 80% Bakken 20% Other
Crude oil		4,462.70	4,665.66	4,270.00	4,182.34	4,760.18	5,119.85	5,565.87	4,583.12	5,067.80	7,591.59	7,591.59	Bakken 413 11psi	7,097.24
Hexane	110-54-3	23	23	22	21	23	22	-	-	96	109	108.61	Bakken 413 11psi	91.53
Benzene	71-43-2	13	13	12	12	13	12	-	-	10	11	13.10	RVP 0.98	11.44
Isooctane	540-84-1	5	5	4	4	5	4	-	-	-	-	4.83	RVP 0.98	0.97
Toluene	108-88-3	19	19	18	17	19	17	-	-	16	16	19.49	RVP 0.98	16.70
Ethylbenzene	100-41-4	4	4	4	4	4	4	-	-	4	4	4.48	RVP 0.98	4.29
Xylene (-m)	108-38-3	17	16	15	14	16	14	-	-	14	14	16.56	RVP 0.98	14.34
Isopropyl benzene	98-82-8	4	4	4	4	4	4	-	-	-	-	4.44	RVP 0.98	0.89
1,2,4-Trimethylbenzene	95-63-6	15	14	13	13	14	13	-	-	-	-	14.61	RVP 0.98	2.92
Cyclohexane	110-82-7	37	37	34	33	37	34	-	-	23	25	36.92	RVP 3.96	27.73
Unidentified Components		4,325.16	4,528.63	4,144.00	4,059.86	4,623.05	4,995.48	5,225.41	4,202.03	4,564.89	6,982.03	6,982.03	Bakken 413 11psi	6,584.72
Isopentane	78-78-4	0.00	0.00	0.00	0.00	0.00	0.00	108	181	121	158	181.12	Bakken 430	144.90
Pentane	109-66-0	0.00	0.00	0.00	0.00	0.00	0.00	184	186	190	241	241.02	Bakken 413 11psi	192.82
Cyclopentane	287-92-3	0.00	0.00	0.00	0.00	0.00	0.00	18	14	12	15	18.41	Bakken 423	14.73
Xylene (-p)	106-42-3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9	9	8.65	Bakken 413 11psi	6.92
Xylene (-o)	95-47-6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8	8	7.76	Bakken 413 11psi	6.21

Heated		Losses(lbs)				
Components	CAS #	RVP 0.98	RVP 3.25	RVP 3.96	Max	Max case
Crude oil		4,788	6,600	7,539	7,539	RVP 3.96
Hexane (-n)	110-54-3	64	79	88	88	RVP 3.96
Benzene	71-43-2	74	90	99	99	RVP 3.96
2,2,4-Trimethylpentane (isooctane)	540-84-1	9	10	11	11	RVP 3.96
Toluene	108-88-3	72	81	87	87	RVP 3.96
Ethylbenzene	100-41-4	22	24	24	24	RVP 3.96
Xylene (-m)	108-38-3	75	79	82	82	RVP 3.96
Isopropyl benzene	98-82-8	5	5	5	5	RVP 3.96
1,2,4-Trimethylbenzene	95-63-6	15	15	16	16	RVP 3.96
Cyclohexane	110-82-7	86	104	114	114	RVP 3.96
Unidentified Components		4,366	6,113	7,014	7,014	RVP 3.96
Isopentane	78-78-4	-	-	-	-	-
Pentane (-n)	109-66-0	-	-	-	-	-
Cyclopentane	287-92-3	-	-	-	-	-
Xylene (-p)	106-42-3	-	-	-	-	-
Xylene (-o)	95-47-6	-	-	-	-	-

Unloading Area Boiler Emissions

Maximum hourly heat input:	61.745 MMBtu/hr	3	Total Boilers
Maximum annual heat input	754,960 MMBtu/yr	3	Active on a short-term basis
Assumed heating value of natural gas	1,000 Btu/scf	2	Active on an annual basis
Maximum annual gas usage rate	755.0 MMscf/yr		

Emission factors

Pollutant	Emission Factor (lb/MMBtu)	Basis
NO_X	0.0110	Low NO_X burner, BACT
CO	0.036	Proper combustion, BACT
SO_2	0.00725	2.59 gr S/100 scf NG daily max plus 25% saftey factor
SO_2	0.00367	1.31 gr S/100 scf NG annual average plus 25% saftey factor
PM_{10}	0.0075	BACT
$PM_{2.5}$	0.0075	Assumed equal to PM_{10}, BACT
VOC	0.005	Proper combustion, BACT
CO2e	117	

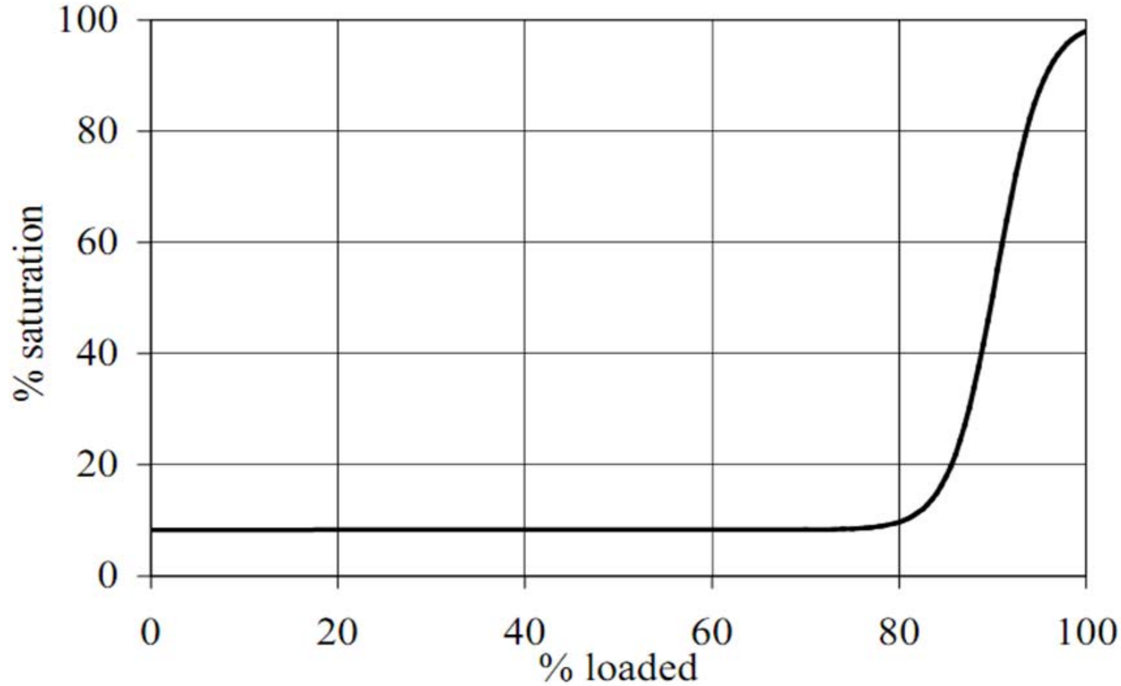
Emission calulations

Averging Period	Units	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	CO2e
1-Hour	lb/hr	2.038	6.67	1.343	1.389	1.389	0.926	21,672.5
24-hour	lb/day	48.902	160.04	32.222	33.342	33.342	22.228	520,139.9
Annual[1]	tpy	4.152	13.59	1.386	2.831	2.831	1.887	44,165.2

VCU Inerting Gas Air Calculations and VOC Profile Claculations

A theoretical profile of the fraction of VOC in the gases displaced while loading ships.

Figure 4 - concentration of hydrocarbon in vent gas as a function of % loaded (Courtesy John Zink Ltd)



20% VOC content required to stop assist gas
85% fraction of time that assist gas will be used (based on figure above)

VOC Profiles

	Jordan	90% air	50% air	Average Air %
Methane	1.41%	0.25%	1.23%	0.44%
Ethane	10.87%	1.90%	9.52%	3.43%
Propane	30.64%	5.37%	26.83%	9.66%
Butane	11.66%	2.04%	10.21%	3.68%
Pentane	2.09%	0.37%	1.83%	0.66%
Hexane	0.35%	0.06%	0.31%	0.11%
Heptane	0.08%	0.01%	0.07%	0.03%
Air	42.90%	90%	50%	82.00%
Total	100.00%	100.00%	100.00%	100.00%

Assuming the VOC concentration profile provided by Jordan would hold for other VOC/air combinations, concentration and heating value profiles for 90% air and 50% air profiles. These profiles were used to construct an approximation of the tank filling profile: 0% to 80% filled - constant 90% air, 80% to 100% filled - average of 50% air.

Inerting Gas Calculations

Estimated that the "air" portion of the displaced gases are actually ship exhaust, and that 12% of that gas is CO2. Using the assumption that during 80% of the loading operation, the displaced gases were 90% "air," and an average of 50% "air" during the last 20% of the loading operation:

Fraction of the displaced gases assumed to be ship exhaust: 82%

			hourly max	
Total daily volume displaced	2,021,231	cf/day	179,665	cf/hr
Fraction that is ship exhaust	82%		82%	
Daily volume of ship exhaust emitted	1,657,409	cf/day	147,325	cf/hr
Assumed CO2 fraction of ship exhaust	12%		12%	
Daily volume of CO2 emitted	198,889	cf/day	17,679	cf/hr

Use ideal gas law to convert the volume of CO2 to a mass:

m = MPV/RuT

V	5,632	m3 CO2/day	500.61	m3 CO2/hr
M	44	kg/kmol	44	kg/kmol
P	101.325	kPa	101.325	kPa
Ru	8.314	kJ/kmolK	8.314	kJ/kmolK
T	293.15	K	293.15	K
m	10,302	kg/day	915.7	kg/hr

Additional mass of CO2 attributable to the inerting gas present in the tanks:

4,145	tons CO2/yr	22,712	lbs CO2/day	2,019	lbs CO2/hr

Note: For a more conservaitve estimate of the quantity of inerting gas, the fraction of "air" in the displaced gases was assumed to be greater than when calculating the quantity of VOCs in the displaced gases.

VCU Emissions Summary

Displaced Tank Loading Vapors

Hourly

32,000	bbl/hr (maximum hourly)	768000	bbl/day	max daily
1,344,000	gal/hr (maximum hourly)			
179,665	ft3/hr (maximum hourly)			
144.2	MMBtu/hr (maximum hourly)			

Daily/Annual

360,000	bbl/day (annual average)		0.46875	fraction of max daily	
15,120,000	gal/day		131400000	bbl/yr	
2,021,231	ft3/day		100	ppm H_2S in vapor (maximum)	
67.6	MMBtu/hr		0.01%	H_2S in vapor	
1,622	MMBtu/day	PV=mRuT/M			
24	hours/day	m= PVM/RuT			
84,218	ft3/hr	P	0.987	atm	
365	days/year	Ru	1.31443	ft^3*atm/lb-mol/K	
591,959	MMBtu/yr	T	286	K	(SO_2 MW)
737,749,295	ft3/yr	M	64	lb/lb-mol	

Emissions from Displaced Vapor Combustion

Pollutant	Emission factor (lb/MMBtu)	Emissions (lb/hr)	Emissions (lb/day)	Emissions (tons/year)
NO_X	0.023	3.32	79.6	6.81
CO	0.010	1.44	34.6	2.96
SO_2	-	3.02	72.5	6.20
PM_{10}	0.0075	1.08	25.9	2.22
$PM_{2.5}$	0.0075	1.08	25.9	2.22
VOC	-	4.21	101.0	8.64
CO_2e	136	19,548	469,156	40,135

VCU Emissions Summary (continued)

Assist gas

30,600	cf/hr	(natural gas)	
292,613	cf/day	85%	assist gas usage (annual)
106,803,563	cf/yr		
1,000	Btu/cf	(heating value of gas)	
30.6	MMBtu/hr		
293	MMBtu/day		
106,804	MMBtu/yr		
106,803,563	cf/yr		

Emissions from Assist Gas Combustion

Pollutant	Emission factor (lb/MMBtu)	Emissions (lb/hr)	Emissions (lb/day)	Emissions (tons/year)
NO_X	0.023	0.704	6.73	1.23
CO	0.010	0.306	2.93	0.534
SO_2	0.00725	0.222	2.12	0.387
PM_{10}	0.0075	0.230	2.19	0.401
$PM_{2.5}$	0.0075	0.230	2.19	0.401
VOC	0	0	0	0
CO_2e	117	3,580	34,236	6,248

CO_2e Emissions from Inerting Gas		
4,145	tons per year of CO_2	
22,712	lbs CO_2 / day	
2,019	lbs CO_2 / hr (max)	

Total

Pollutant	Emission factor (lb/MMBtu)	Emissions (lb/hr)	Emissions (lb/day)	Emissions (tons/year)
NO_X	-	4.02	86.3	8.04
CO	-	1.75	37.5	3.49
SO_2	-	3.24	74.6	6.59
PM_{10}	-	1.31	28.1	2.62
$PM_{2.5}$	-	1.31	28.1	2.62
VOC	-	4.21	101	8.64
CO_2e	-	25,147	526,104	50,528

Calculated Tank Loading Vapor Displacment Rate

Hourly worst case airflow	179,665 scf/hr
Daily/Annual Average Airflow	84,218 scf/hr
MVCU Control Efficiency	99.8%

Ideal Gas Law

PVM=mRuT --> V=mRuT/PM --> m=PVM/RuT

T =	293.15	K
P =	1	atm
Ru=	1.314	atm-ft^3/lbmol-K

VOC Profile from Jordan Technologies

	As Provided	Extrapolated[a]
Methane	1.41%	0.79%
Ethane	10.87%	6.09%
Propane	30.64%	17.17%
Butane	11.66%	6.53%
Pentane	2.09%	1.17%
Hexane	0.35%	0.20%
Heptane	0.08%	0.04%
Air	42.90%	68.00%
Total	100.00%	100.00%

Compound	MW (lb/lb-mol)	68% Air Condition Vol %	lb-mol/hr (shortterm)	lb-mol/hr (long term)	Heat of combustion[b] KJ/kg	Heat of combustion[c] Btu/lbmol	Mixture Btu/lbmol
Methane	16	0.790	3.69	1.73	55,530	381,986	3018.4
Ethane	30	6.092	28.41	13.32	51,900	669,404	40778.6
Propane	44	17.171	80.09	37.54	50,330	952,093	163486.5
i-Butane	58	6.535	30.48	14.29	49,150	1,225,607	80087.3
n-Pentane	72	1.171	5.46	2.56	47,760	1,478,416	17316.4
n-Hexane	86	0.196	0.91	0.43	47,760	1,765,885	3463.7
n-Heptane	100	0.045	0.21	0.10	48,100	2,067,973	927.1
Air	28.97	68	317.17	148.67	--	--	--
			Short Term	***Long Term***		**Total**	**309,078**
Flowrate	lb-mol/hr		466	219			
Startup Heat Input Rate	MMBtu/hr		144	68			
Carbon	(lb-mol C/hr)		457	214			
CO2 From Carbon	(lb CO2/hr)		20,106	9,425			
VOC to Combustor	lb C/hr		1406	659			
lb/MMBtu			0.0195	0.0195			

Notes:

a - Based on information provided by the MVCU manufacturer, the hydrocarbon content of the displaced vapors was assumed to average 32 percent by volume over all loading operations.

b - Higher Heat Values from at 25C (Table A-27). Thermodynamics an Engineering Approach (4th edition) by Y.A. Cengel and M.A. Boles, McGraw-Hill, New York, 2002.

c - Converted Heat of Combustion (KJ/Kg) to (Btu/lb)

CO2e From Displaced Vapor Combustion

Loading Crude Oil Into Ships and Ocean Barges
AP-42 Section 5.2 (Transporation and Marketing of Petroleum Liquids

CL = total loading loss (lb/1000 gal loaded)
Ca = 0.86 (Arrival EF, From AP-42, Table 5.2-3 - assume previous cargo was volatile and tank arrived uncleaned)
Cg = 1.84 (0.44*P -0.42) * (M*G)/T
where
P = true vapor pressure, psia
M = molecular weight of vapors
G = vapor growth factor = 1.02
T = temperature of liquid, degrees F = 68, degrees R = 527.67 °R

$$C_L = C_a + C_g = 0.86 + \left(1.84 * (0.44 * \mathrm{P} - 0.42) * \frac{M * G}{T}\right)$$

	P (psia)	M (lb/lb-mole)	CL (lb/1000 gal)	Throughput (bbl/hr)	Throughput (bbl/day)	PTE (lb/hr)	PTE (lb/day)	PTE (ton/yr)	Control Efficiency	PTE, controlled (lb/hr)	PTE, controlled (lb/day)	PTE, controlled (ton/yr)	Combusted (tpy)	CO2e (tpy)
Crude oil	11	44.8630473	1.5653	32,000	360,000	2,104	23,667	4,319	99.8%	4.21	47.3	8.64	4,311	12,944

Crude Oil Storage Tank Emissions

Tanks Operating Information	
6	Tanks
360,000	tank capacity (bbl)
15,120,000	tank capacity (gallons)
340,000	bbl/day (working volume)
20,683,333	bbl/yr/tank
868,700,000	gal/yr/tank
24	hours/day
365	days/year

Assumptions

5000	ppm H2S
50	Vapor molecular weight of crude
34	molecular weight of H2S

		Per unheated ta	*Per heated tank*	*Total*	*Total*	*Total*
Components	**CAS #**	**Annual Losses (lbs)**	**Annual Losses (lbs)**	**Hourly Losses (lbs/hr)**	**Daily Losses (lbs/day)**	**Annual Losses (lbs/yr)**
Crude oil		7,097.24	7,539.07	4.96E+00	1.19E+02	4.35E+04
Hexane	110-54-3	91.53	87.69	6.18E-02	1.48E+00	5.42E+02
Benzene	71-43-2	11.44	41.08	1.46E-02	3.50E-01	1.28E+02
Isooctane	540-84-1	0.97	10.97	2.95E-03	7.07E-02	2.58E+01
Toluene	108-88-3	16.70	36.38	1.59E-02	3.82E-01	1.40E+02
Ethylbenzene	100-41-4	4.29	6.12	3.36E-03	8.05E-02	2.94E+01
Xylene (-m)	108-38-3	14.34	21.64	1.15E-02	2.76E-01	1.01E+02
Isopropyl benzene	98-82-8	0.89	5.23	1.60E-03	3.84E-02	1.40E+01
1,2,4-Trimethylbenzene	95-63-6	2.92	15.66	4.91E-03	1.18E-01	4.30E+01
Cyclohexane	110-82-7	27.73	114.30	3.88E-02	9.30E-01	3.40E+02
Unidentified Components		6,584.72	7,199.99	4.65E+00	1.12E+02	4.07E+04
Isopentane	78-78-4	144.90	0.00	6.62E-02	1.59E+00	5.80E+02
Pentane	109-66-0	192.82	0.00	8.80E-02	2.11E+00	7.71E+02
Cyclopentane	287-92-3	14.73	0.00	6.73E-03	1.61E-01	5.89E+01
Xylene (-p)	106-42-3	6.92	0.00	3.16E-03	7.58E-02	2.77E+01
Xylene (-o)	95-47-6	6.21	0.00	2.83E-03	6.80E-02	2.48E+01
Hydrogen Sulfide	7783-06-4	22.39	24.48	1.58E-02	3.79E-01	1.39E+02

Methane Emissions

Note: While crude oil that reaches the facility will likely be stabalized, it can be considered unstabilized for conservative CH4 emissions estimations. CH4 emissions were estimated using equation Y-22 from Federal GHGMRR 40 CFR 98 Y - Petroleum Refineries.

EQ Y-22:
CH4 = (0.1 * Qref)
where
CH4 = Annual methane emissions from storage tanks (metric tons/year)
Qref = Quantity of crude oil (MMbbl/year)

12.41	**Tons of Methane per year (total)**	2.068333333	per tank
260.61	**Tons of CO2e per year (total)**	43.435	per tank

Emergency Diesel Firewater Pumps Emission Calculations

Operating Information					
225	hp	167.8	kw/hr	1.6214	MMBtu/hr
12.1	gal/hr	134,000	BTU/gal		
34	hours/year				
1	hr/day				
3	Engines				

SO2 Calcs

15	ppm S (ULSD)
7	lb/gal (density of diesel fuel)
84.7	lb/hr (mass fuel use rate)
0.00127	lb/hr S
32	lb/lbmol (MW of S)
64	lb/lbmol (MW of SO2)
0.002541	lb/hr SO2

Emissions

Pollutant	Emission factor (g/kW-hr)	Emission Factor Description	Emissions (lb/hr)	Emissions (lb/day)	Emissions (tons/year)
NO_X	0.335	Manufacturer	0.372	0.372	0.00632
CO	1.60	Manufacturer	1.78	1.78	0.0302
SO_2	-	15 ppm ULSD fuel	0.00762	0.00762	0.000130
PM_{10}	0.17	Manufacturer	0.189	0.189	0.00321
$PM_{2.5}$	0.17	Manufacturer	0.189	0.189	0.00321
VOC	0.37	Manufacturer	0.411	0.411	0.00698
CO2e	717.13	40 CFR Part 98	796	796	13.5

Single Engine

Emissions (lb/hr)	Emissions (lb/day)	Emissions (tons/year)
0.124	0.124	0.00211
0.592	0.592	0.0101
0.00254	0.00254	0.0000432
0.0629	0.0629	0.00107
0.0629	0.0629	0.00107
0.137	0.137	0.00233
265	265	4.51

CO2 Emission Factor Conversion From 40 CFR Part 98							
74.21	kg/MMBtu	163.6	lb/MMBtu	74209	g/Mmbtu	717.1	g/kw-hr

Fugitive Emissions due to Leaking Components

Summary of Fugitive Components by Type

Components Distribution

Fugitive Component Type	Service	Total Number of Components	Number of Components Estimated to be Leakers (1.5% of Total)	Number of Components Estimated to be Pegged Leakers	Unloading Area Components	Tank Area Components	Dock Area Components
Valves	All	2,753	42	1	2,050	509	194
Pump Seals	All	61	1	1	50	10	1
Connectors	All	360	6	1	270	90	0
Flanges	All	2,630	40	1	2,253	316	61
Others	All	1,486	23	1	1,185	172	129

Summary of Fugitive Component Emission Factors

Fugitive Component Type	Service	Non-Leakers		Screening Value Leakers				Pegged Leakers	
		Zero Emission Factor (lb/hr/source)	Non-Leaking Hours (hr/yr)	Leak Rate/Screening Correlation	Screening Value (SV) (ppmv)	Screening Value Emission Factor (lb/hr/source)	Screening Value Leaking Hours (hr/yr)	10,000 ppmv Pegged Emission Factor (lb/hr/source)	Pegged Leaking Hours (hr/yr)
Valves	All	1.7E-05	8,760	(kg/hr/source) = 2.29E-06 x $(SV)^{0.746}$	250	0.00031	8,760	0.14112	730
Pump Seals	All	5.3E-05	8,760	(kg/hr/source) = 5.03E-05 x $(SV)^{0.610}$	1,000	0.00750	8,760	0.16317	730
Connectors	All	1.7E-05	8,760	(kg/hr/source) = 1.53E-06 x $(SV)^{0.735}$	250	0.00020	8,760	0.06174	730
Flanges	All	6.8E-07	8,760	(kg/hr/source) = 4.61E-06 x $(SV)^{0.703}$	250	0.00049	8,760	0.18743	730
Others	All	8.8E-06	8,760	(kg/hr/source) = 1.36E-05 x $(SV)^{0.589}$	250	0.00078	8,760	0.16097	730

Summary of Fugitive Component Emissions

Emissions Distribution

Fugitive Component Type	Service	Non-Leaker Emissions (lb/yr)	Screening Value Leaker Emissions (lb/yr)	Pegged Leaker Emissions (lb/yr)	Total Emissions (lb/yr)	Total Emissions (ton/yr)	Unloading Area Emissions (ton/yr)	Tank Area Emissions (ton/yr)	Dock Area Emissions (ton/yr)
Valves	All	408.45	114.02	103.02	625.49	0.31	0.233	0.058	0.022
Pump Seals	All	27.81	65.69	119.11	212.62	0.11	0.087	0.017	0.002
Connectors	All	51.28	10.26	45.07	106.62	0.05	0.040	0.013	0.000
Flanges	All	15.51	172.75	136.82	325.08	0.16	0.139	0.020	0.004
Others	All	113.04	143.15	117.50	373.69	0.19	0.149	0.022	0.016
Total		**616.09**	**505.87**	**521.53**	**1,643.49**	**0.82**	**0.65**	**0.13**	**0.04**

Fugitive Emissions due to Leaking Components (continued)

Summary of Toxic Emissions

Pollutant	CAS #	Weight Fraction	Hourly Emissions (lb/hr)	Total Emissions (ton/yr)	Emissions Distribution: Unloading Area Emissions (ton/yr)	Tank Area Emissions (ton/yr)	Dock Area Emissions (ton/yr)
1,2,4-Trimethylbenzene	95-63-6	0.00065	1.2E-04	0.0005	0.0004	0.0001	0.0000
Benzene	71-43-2	0.00219	4.1E-04	0.0018	0.0014	0.0003	0.0001
Cyclohexane	110-82-7	0.00534	1.0E-03	0.0044	0.0035	0.0007	0.0002
Cyclopentane	287-92-3	0.00265	5.0E-04	0.0022	0.0017	0.0003	0.0001
Ethylbenzene	100-41-4	0.00087	1.6E-04	0.0007	0.0006	0.0001	0.0000
Hexane (-n)	110-54-3	0.01622	3.0E-03	0.0133	0.0105	0.0021	0.0007
Hydrogen Sulfide	7783-06-4	0.00735	1.4E-03	0.0060	0.0048	0.0010	0.0003
Isooctane	540-84-1	0.00022	4.1E-05	0.0002	0.0001	0.0000	0.0000
Isopentane	78-78-4	0.03162	5.9E-03	0.0260	0.0205	0.0041	0.0014
Isopropyl benzene	98-82-8	0.00020	3.7E-05	0.0002	0.0001	0.0000	0.0000
Pentane	109-66-0	0.03241	6.1E-03	0.0266	0.0210	0.0042	0.0014
Toluene	108-88-3	0.00334	6.3E-04	0.0027	0.0022	0.0004	0.0001
Xylene (-m)	108-38-3	0.00291	5.5E-04	0.0024	0.0019	0.0004	0.0001
Xylene (-o)	95-47-6	0.00122	2.3E-04	0.0010	0.0008	0.0002	0.0001
Xylene (-p)	106-42-3	0.00136	2.6E-04	0.0011	0.0009	0.0002	0.0001

Notes:

Non-Leaker Emissions = Petroleum Zero Emission Factor x (Total Number of Components - Number of Components Estimated to be Leakers) x Non-Leaking Hours

Screening Value Leaker Emissions = Petroleum Screening Value Emission Factor x [Number of Components Estimated to be Leakers - (Number of Components Estimated to be Pegged Leakers x Pegged Leaking Hours / 8,760)] x Screening Value Leaking Hours

Pegged Leaker Emissions = 10,000 ppmv Petroleum Pegged Emission Factor x Number of Components Estimated to be Pegged Leakers x Pegged Leaking Hours

CO2e Emissions	
0.904	Ratio of lowest molecular weight pollutant (cyclopentane) emissions from components to emissions from tanks
235.627	Tons CO2e per year from components (scaled from tanks emissions)

Emissions Estimation Basis

The key assumptions for this calculation are:

1) Each component in VOC service will be included in a leak detection and repair (LDAR) program requiring weekly visual inpsections and monthly inspections with portable instrument.

2) 1.5% of the total components in VOC service are assumed to be leakers.

3) The screening values are assumed to be one half the Phase II regulatory leak definition (2,000 ppm [pumps] and 500 ppm [valves, connectors, instrumentation, pressure valves], 40 CFR 63, Subpart H), which is considered BACT for this project.

4) The durations of pegged leakers for the remaining equipment types are assumed to be one month for all equipment.

5) Toxic emissions are based on the average composition of TAPs in crude oil.

6) Component counts for valves, pumps, connectors, flanges, and others were provided by Savage.

7) Zero emission rates, screening correlation equations, and pegged emission rates are from Tables 2-12, 2-10, and 2-14 (Petroleum Industries), Protocol for Equipment Leak Emission Estimates (EPA, November 1995).

Vapor Pressure and Liquid Density Values

Vapor Pressure Constants[1]

$$A = 12.82 - 0.962 \times \ln(RVP)$$

$$B = 7261 - 1216 \times \ln(RVP)$$

True Stock Vapor Pressure Equation (from AP42, Clausius-Clapeyron derivation)[1]

$$P = exp \;\; A - \frac{B}{(T + 459.7)}$$

True Stock Vapor Pressure (psi at 55.06°F) at Given RVP

RVP (psi)	0.98	3.25	3.27	3.59	3.96	6.1	8.05	8.41	9.8	13.9
Vapor Pressure (psi)	0.269	1.44	1.45	1.66	1.90	3.48	5.13	5.45	6.76	11.0

Liquid Density at Given RVP and Specific Gravity

RVP (psi)	**0.98**	**3.25**	**3.27**	**3.59**	**3.96**	**6.1**	**8.05**	**8.41**	**9.8**[2]
Specific Gravity (at 60°F)	0.937	0.929	0.844	0.816	0.928	0.811	0.819	0.811	0.814
Liquid Density (lb/gal at 60°F)	7.81	7.74	7.04	6.80	7.73	6.76	6.83	6.76	6.79

[1] Manual of Petroleum Measurement Standards Chapter 19.4 – Recommended Practice for Speciation of Evaporative Losses, second edition, September 2005

[2] Due to limited information, the specific gravity and liquid density associated with the 9.8 RVP was used for the 13.9 RVP tank run

<u>TANKS 4.0.9d</u>

Tank Parameters and Speciation Profiles for Bakkens

Tank Parameters	
Diameter (ft)	240
Volume (gal)	14,357,570
Turnovers per year	64.063766
Net Throughput (gal/yr)	919,800,000
Number of Columns	25
Effective Column Diameter	0.9
External Shell and Roof Color	White

Speciation Profiles for Bakken 423 and Bakken 430		
Pollutant	**Bakken 423 – Percent of Total Liquid Weight**	**Bakken 430 – Percent of Total Liquid Weight**
Isopentane	0.81	1.512
Pentane (-n)	1.781	1.977
Cyclopentane	0.236	0.198

Speciation Profiles for Bakken 413 and Bakken 413 at 11 psi	
Pollutant	**Percent of Total Liquid Weight**
Isopentane	0.96
Pentane (-n)	1.93
Cyclopentane	0.16
Benzene	0.209
Cyclohexane	0.477
Ethylbenzene	0.107
Xylene (-p)	0.219
Xylene (-m)	0.35
Xylene (-o)	0.198
Hexane (-n)	1.749
Toluene	0.378

Un-heated Tanks Summary

The following tank parameters and speciation profiles were used for the un-heated tanks (RVP 0.98, 3.25, 3.27, 3.59, 3.96 and 8.41). The average annual stock temperature input of 55.0606°F was used for the un-heated tanks. Weight fractions for the following pollutants were revised: benzene, toluene, ethylbenzene, and xylene (-m).

Tank Parameters	
Diameter (ft)	240
Volume (gal)	14,357,570
Turnovers per year	64.063766
Net Throughput (gal/yr)	919,800,000
Number of Columns	25
Effective Column Diameter	0.9
External Shell and Roof Color	White

Speciation Profiles for RVP 0.98, 3.25, 3.27, 3.59, 3.96 and 8.41		
Pollutant	**Weight Fraction of Component**	**Vapor Pressure at 55.0606°F**
Hexane (-n)	0.4	1.68
Benzene	0.25	1.02
Isooctane	0.1	0.52
Toluene	0.42	0.28
Ethylbenzene	0.1	0.09
Xylene (-m)	0.37	0.08
Isopropyl benzene	0.1	0.04
1,2,4-Trimethylbenzene	0.33	0.02
Cyclohexane	0.7	1.06

Heated Tanks Summary

The following tank parameters and speciation profiles were used for the heated tanks (RVP 0.98, 3.25, and 3.96). The average annual stock temperature input of 55.0606°F was changed to 150°F for the tanks that are heated. In addition, the vapor pressure calculation for each pollutant was adjusted with the new average liquid temperature of 150°F. Pollutant weight fractions were the defaults provided for crude oil in TANKS, except for benzene, toluene, ethylbenzene, and xylene (-m), which are the maximum 5-year average weight fractions for the worst-case heavy sour crudes from CrudeMonitor.ca.

Tank Parameters	
Diameter (ft)	240
Volume (gal)	14,357,570
Turnovers per year	64.063766
Net Throughput (gal/yr)	919,800,000
Number of Columns	25
Effective Column Diameter	0.9
External Shell and Roof Color	White

Speciation Profiles for RVP 0.98, 3.25, and 3.96		
Pollutant	**Weight Fraction of Component**	**Vapor Pressure at 150°F**
Hexane (-n)	0.4	13.29
Benzene	0.25	9.16
Isooctane	0.1	5.07
Toluene	0.42	3.33
Ethylbenzene	0.1	1.42
Xylene (-m)	0.37	1.22
Isopropyl benzene	0.1	0.76
1,2,4-Trimethylbenzene	0.33	0.39
Cyclohexane	0.7	9.09

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Bakken 413 - Internal Floating Roof Tank

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude oil (Bakken 413)	306.57	3,854.74	906.48	0.00	5,067.80
Isopentane	21.29	37.01	62.94	0.00	121.23
Pentane (-n)	29.23	74.40	86.42	0.00	190.04
Cyclopentane	1.48	6.17	4.38	0.00	12.02
Benzene	0.53	8.06	1.55	0.00	10.14
Cyclohexane	1.25	18.39	3.69	0.00	23.33
Ethylbenzene	0.02	4.12	0.07	0.00	4.22
Xylene (-p)	0.04	8.44	0.13	0.00	8.62
Xylene (-m)	0.07	13.49	0.19	0.00	13.75
Xylene (-o)	0.03	7.63	0.09	0.00	7.75
Hexane (-n)	7.27	67.42	21.50	0.00	96.19
Toluene	0.26	14.57	0.78	0.00	15.62
Unidentified Components	245.11	3,595.05	724.74	0.00	4,564.90

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Bakken 413 11 psi - Internal Floating Roof Tank

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude oil (Bakken 413 11psi)	949.68	3,833.91	2,808.01	0.00	7,591.59
Isopentane	30.74	36.81	90.90	0.00	158.45
Pentane (-n)	42.21	73.99	124.82	0.00	241.02
Cyclopentane	2.14	6.13	6.32	0.00	14.59
Benzene	0.76	8.01	2.25	0.00	11.02
Cyclohexane	1.80	18.29	5.33	0.00	25.43
Ethylbenzene	0.03	4.10	0.10	0.00	4.24
Xylene (-p)	0.06	8.40	0.19	0.00	8.65
Xylene (-m)	0.09	13.42	0.28	0.00	13.79
Xylene (-o)	0.04	7.59	0.12	0.00	7.76
Hexane (-n)	10.50	67.06	31.06	0.00	108.61
Toluene	0.38	14.49	1.13	0.00	16.00
Unidentified Components	860.90	3,575.62	2,545.51	0.00	6,982.03

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Bakken 423 - Internal Floating Roof Tank

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude oil (Bakken 423)	437.71	3,833.91	1,294.24	0.00	5,565.87
Isopentane	19.47	31.05	57.56	0.00	108.09
Pentane (-n)	29.24	68.28	86.44	0.00	183.96
Cyclopentane	2.37	9.05	7.00	0.00	18.41
Unidentified Components	386.65	3,725.53	1,143.23	0.00	5,255.41

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Bakken 430 - Internal Floating Roof Tank

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude oil (Bakken 430)	193.39	3,817.91	571.82	0.00	4,583.12
Isopentane	31.19	57.73	92.21	0.00	181.12
Pentane (-n)	27.85	75.48	82.34	0.00	185.67
Cyclopentane	1.70	7.56	5.04	0.00	14.30
Unidentified Components	132.66	3,677.14	392.24	0.00	4,202.03

Un-Heated Summary

The following annual emission reports were developed for RVP 0.98, 3.25, 3.27, 3.59, 3.96, and 8.41.

Annual Emission Report: RVP 0.98 – Internal Floating Roof Tank

Individual Tank Emission Totals

Components	Losses (lbs)				
	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 0.98)	13.39	4,409.73	39.58	0.00	4,462.70
Hexane (-n)	1.39	17.64	4.10	0.00	23.12
Benzene	0.52	11.02	1.55	0.00	13.10
2,2,4-Trimethylpentane (isooctane)	0.11	4.41	0.31	0.00	4.83
Toluene	0.24	18.52	0.72	0.00	19.49
Ethylbenzene	0.02	4.41	0.06	0.00	4.48
Xylene (-m)	0.06	16.32	0.18	0.00	16.56
Isopropyl benzene	0.01	4.41	0.02	0.00	4.44
1,2,4-Trimethylbenzene	0.01	14.55	0.04	0.00	14.61
Cyclohexane	1.53	30.87	4.52	0.00	36.91
Unidentified Components	9.50	4,287.58	28.08	0.00	4,325.16

Annual Emission Report: RVP 3.25 – Internal Floating Roof Tank

Individual Tank Emission Totals

Components	Losses (lbs)				
	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 3.25)	74.20	4,372.06	219.40	0.00	4,665.66
Hexane (-n)	1.43	17.49	4.24	0.00	23.16
Benzene	0.54	10.93	1.60	0.00	13.08
2,2,4-Trimethylpentane (isooctane)	0.11	4.37	0.33	0.00	4.81
Toluene	0.25	18.36	0.75	0.00	19.36
Ethylbenzene	0.02	4.37	0.06	0.00	4.45
Xylene (-m)	0.06	16.18	0.19	0.00	16.43
Isopropyl benzene	0.01	4.37	0.03	0.00	4.41
1,2,4-Trimethylbenzene	0.01	14.43	0.04	0.00	14.48
Cyclohexane	1.58	30.60	4.67	0.00	36.85
Unidentified Components	70.18	4,250.96	207.50	0.00	4,528.63

Un-Heated Summary

Annual Emission Report: RVP 3.27 – Internal Floating Roof Tank

Individual Tank Emission Totals

Components	Losses (lbs)				
	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 3.27)	74.87	3,973.75	221.38	0.00	4,270.00
Hexane (-n)	1.43	15.89	4.24	0.00	21.57
Benzene	0.54	9.93	1.60	0.00	12.08
2,2,4-Trimethylpentane (isooctane)	0.11	3.97	0.33	0.00	4.41
Toluene	0.25	16.69	0.75	0.00	17.69
Ethylbenzene	0.02	3.97	0.06	0.00	4.05
Xylene (-m)	0.06	14.70	0.19	0.00	14.95
Isopropyl benzene	0.01	3.97	0.03	0.00	4.01
1,2,4-Trimethylbenzene	0.01	13.11	0.04	0.00	13.17
Cyclohexane	1.58	27.82	4.67	0.00	34.07
Unidentified Components	70.85	3,863.68	209.48	0.00	4,144.00

Annual Emission Report: RVP 3.59 – Internal Floating Roof Tank

Individual Tank Emission Totals

Components	Losses (lbs)				
	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 3.59)	85.91	3,842.39	254.03	0.00	4,182.34
Hexane (-n)	1.44	15.37	4.27	0.00	21.08
Benzene	0.55	9.61	1.61	0.00	11.77
2,2,4-Trimethylpentane (isooctane)	0.11	3.84	0.33	0.00	4.28
Toluene	0.25	16.14	0.75	0.00	17.15
Ethylbenzene	0.02	3.84	0.06	0.00	3.92
Xylene (-m)	0.06	14.22	0.19	0.00	14.47
Isopropyl benzene	0.01	3.84	0.03	0.00	3.88
1,2,4-Trimethylbenzene	0.01	12.68	0.04	0.00	12.74
Cyclohexane	1.59	26.90	4.70	0.00	33.19
Unidentified Components	81.86	3,735.95	242.05	0.00	4,059.86

Un-Heated Summary

Annual Emission Report: RVP 3.96 – Internal Floating Roof Tank

Individual Tank Emission Totals

Components	Losses (lbs)				
	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 3.96)	99.40	4,366.89	293.90	0.00	4,760.18
Hexane (-n)	1.46	17.47	4.31	0.00	23.23
Benzene	0.55	10.92	1.63	0.00	13.10
2,2,4-Trimethylpentane (isooctane)	0.11	4.37	0.33	0.00	4.81
Toluene	0.26	18.34	0.76	0.00	19.36
Ethylbenzene	0.02	4.37	0.06	0.00	4.45
Xylene (-m)	0.06	16.16	0.19	0.00	16.41
Isopropyl benzene	0.01	4.37	0.03	0.00	4.40
1,2,4-Trimethylbenzene	0.01	14.41	0.04	0.00	14.47
Cyclohexane	1.60	30.57	4.74	0.00	36.92
Unidentified Components	95.31	4,245.92	281.82	0.00	4,623.05

Annual Emission Report: RVP 8.41 – Internal Floating Roof Tank

Individual Tank Emission Totals

Components	Losses (lbs)				
	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 8.41)	329.52	3,816.02	974.31	0.00	5,119.85
Hexane (-n)	1.68	15.26	4.97	0.00	21.92
Benzene	0.64	9.54	1.88	0.00	12.06
2,2,4-Trimethylpentane (isooctane)	0.13	3.82	0.38	0.00	4.33
Toluene	0.30	16.03	0.88	0.00	17.20
Ethylbenzene	0.02	3.82	0.07	0.00	3.91
Xylene (-m)	0.07	14.12	0.22	0.00	14.41
Isopropyl benzene	0.01	3.82	0.03	0.00	3.86
1,2,4-Trimethylbenzene	0.02	12.59	0.05	0.00	12.66
Cyclohexane	1.85	26.71	5.48	0.00	34.04
Unidentified Components	324.80	3,710.32	960.36	0.00	4,995.48

Heated Summary

The following annual emission reports were developed for RVP 0.98, 3.25, and 3.96.

Annual Emission Report: RVP 0.98 – Internal Floating Roof Tank

Individual Tank Emission Totals

Components	Losses (lbs)				
	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 0.98)	131.05	4,269.47	387.49	0.00	4,788.01
Hexane (-n)	11.84	17.08	35.01	0.00	63.93
Benzene	5.10	10.67	15.09	0.00	30.87
2,2,4-Trimethylpentane (isooctane)	1.13	4.27	3.34	0.00	8.74
Toluene	3.12	17.93	9.21	0.00	30.26
Ethylbenzene	0.32	4.27	0.94	0.00	5.52
Xylene (-m)	1.00	15.80	2.97	0.00	19.77
Isopropyl benzene	0.17	4.27	0.50	0.00	4.94
1,2,4-Trimethylbenzene	0.29	14.09	0.85	0.00	15.22
Cyclohexane	14.17	29.89	41.90	0.00	85.96
Unidentified Components	93.91	4,151.21	277.69	0.00	4,522.81

Annual Emission Report: RVP 3.25 – Internal Floating Roof Tank

Individual Tank Emission Totals

Components	Losses (lbs)				
	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 3.25)	598.58	4,231.81	1,769.89	0.00	6,600.28
Hexane (-n)	15.69	16.93	46.38	0.00	78.99
Benzene	6.76	10.58	20.00	0.00	37.34
2,2,4-Trimethylpentane (isooctane)	1.50	4.23	4.42	0.00	10.15
Toluene	4.13	17.77	12.20	0.00	34.11
Ethylbenzene	0.42	4.23	1.24	0.00	5.89
Xylene (-m)	1.33	15.66	3.93	0.00	20.92
Isopropyl benzene	0.22	4.23	0.66	0.00	5.12
1,2,4-Trimethylbenzene	0.38	13.96	1.12	0.00	15.47
Cyclohexane	18.77	29.62	55.51	0.00	103.91
Unidentified Components	549.39	4,114.59	1,624.43	0.00	6,288.40

Heated Summary

Annual Emission Report: RVP 3.96 – Internal Floating Roof Tank

Individual Tank Emission Totals

Components	Losses (lbs)				
	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Crude Oil (RVP 3.96)	837.15	4,226.63	2,475.29	0.00	7,539.07
Hexane (-n)	17.89	16.91	52.90	0.00	87.69
Benzene	7.71	10.57	22.80	0.00	41.08
2,2,4-Trimethylpentane (isooctane)	1.71	4.23	5.04	0.00	10.97
Toluene	4.71	17.75	13.92	0.00	36.38
Ethylbenzene	0.48	4.23	1.41	0.00	6.12
Xylene (-m)	1.52	15.64	4.48	0.00	21.64
Isopropyl benzene	0.25	4.23	0.75	0.00	5.23
1,2,4-Trimethylbenzene	0.43	13.95	1.28	0.00	15.66
Cyclohexane	21.41	29.59	63.31	0.00	114.30
Unidentified Components	781.04	4,109.55	2,309.39	0.00	7,199.99

TANKS 4.0.9d

Degassing Emissions - Tank Parameters

Internal Floating Roof Tank Parameters[1]	
Diameter (ft)	240
Volume (gal)	14,357,570
Turnovers per year	1
Net Throughput (gal/yr)	14,357,570
Number of Columns	25
External Shell and Roof Color	White

Vertical Fixed Roof Tank Parameters[2]	
Shell Height (ft)	48
Shell Diameter (ft)	240
Maximum Liquid Height (ft)	4
Average Liquid Height (ft)	1
Net Throughput (gal/yr)	1,353,647.4
Turnovers per Year	1
External Shell and Roof Color	White

[1] Speciation profile is the same as Bakken 413 and Bakken 413 at 11 psi
[2] Speciation profile is the same as RVP tank runs

TANKS 4.0.9d

Degassing Emissions

Emission Type	Tank Type	VOC (lb/yr)
Withdrawal Losses	Internal Floating Roof	50.83
Working Losses	Fixed Roof	3,153.64
Total VOC Degassing Emissons		3,204.47
		1.60 tpy

Cleaver-Brooks Boiler Expected Emission Data

Producing Steam Firing **Nat Gas**

BACKGROUND INFORMATION

Date	07/29/13	Boiler Model	CBEX Elite
Author	L.C. Banks	Altitude (feet)	700
Customer	ICPE	Operating Pressure (psig	125.00
City & State	---	Furnace Volume (cuft)	507.00
		Furnace Heat Release (btu/hr/cu ft)	121,785
		Heating Surface (sqft)	4466
		Nox System	9

Nat Gas		**Firing Rate**			
		25%	**50%**	**75%**	**100%**
Horsepower		375	750	1125	1500
Input , Btu/hr		15,389,000	30,672,000	46,050,000	61,745,000
CO	ppm	50	50	50	50
	lb/MMBtu	0.036	0.036	0.036	0.036
	lb/hr	0.56	1.12	1.68	2.25
	tpy	2.460	4.903	7.361	9.870
NOx	ppm	9	9	9	9
	lb/MMBtu	0.0106	0.0106	0.0106	0.0106
	lb/hr	0.16	0.32	0.49	0.65
	tpy	0.714	1.422	2.136	2.864
NO	ppm	7.7	7.7	7.7	7.7
	lb/MMBtu	0.009	0.009	0.009	0.009
	lb/hr	0.14	0.28	0.41	0.56
	tpy	0.57	1.14	1.71	2.29
NO_2	ppm	1.4	1.4	1.4	1.4
	lb/MMBtu	0.002	0.002	0.002	0.002
	lb/hr	0.02	0.05	0.07	0.10
	tpy	0.14	0.28	0.43	0.57
SOx	ppm	1.00	1.00	1.00	1.00
	lb/MMBtu	0.0017	0.0017	0.0017	0.0017
	lb/hr	0.0264	0.0526	0.0789	0.1058
	tpy	0.116	0.230	0.346	0.464
VOCs	ppm	12.5	12.5	12.5	12.5
(Non-Methane Only)	lb/MMBtu	0.005	0.005	0.005	0.005
VOCs does not include	lb/hr	0.077	0.153	0.230	0.309
any background VOC	tpy	0.337	0.672	1.008	1.352
emissions.					
PM10 (Filterable)	ppm	N/A	N/A	N/A	N/A
	lb/MMBtu	0.00750	0.00750	0.00750	0.00750
	lb/hr	0.115	0.230	0.345	0.463
	tpy	0.506	1.008	1.513	2.028
PM10 (Condensable)	lb/MMBtu	0.00250	0.00250	0.00250	0.00250
	tpy	0.011	0.34	0.011	0.68
PM2.5 (Filterable)	lb/MMBtu	0.008	0.008	0.008	0.008
	tpy	0.033	1.01	0.033	2.03
PM2.5 (Condensable)	lb/MMBtu	0.0025	0.0025	0.0025	0.0025
	tpy	0.011	0.34	0.011	0.68
Exhaust Data					
Temperature, F		377	401	424	448
Flow	ACFM	5,036	9,938	14,738	20,304
	SCFM (70 Degrees Fah.)	3,266	6,263	9,033	12,112
	DSCFM	2,928	5,589	8,021	10,755
	lb/hr	14,697	28,183	40,649	54,503
Velocity	ft/sec	8.72	17.21	25.53	35.17
	ft/min	523	1,033	1,532	2,110

Notes:

1) All ppm levels are corrected to dry at 3% oxygen.
2) Emission data based on actual boiler efficiency.
3) % H2O , by volume in exhaust gas is **17.24** % O2, by volume **2.47**
4) Water vapor in exhaust gas is **98.91** lbs/MMBtu of fuel fired
5) CO2 produced is **116.31** lbs/MMBtu of fuel fired
6) Particulate is exclusive of any particulates in combustion air or other sources of residual particulates from mater
PM level indicated on this form is based on combustion air and fuel being clean and turndown up to 4:1.
7) Heat input is based on high heating value (HHV).
8.) Emission produced in tons per year (tpy) is based on 24 hours per day for 365 days = 8,760 hours per year
9.) Exhaust data is based on a clean and properly sealed boiler.
10.) Emission data is based on a burner turndown of 4 to 1.
11.) Maximum flame temperature is 2800 degrees fahrenheit.

14) Fuel High Heating Value = **1000** Btu/FT^3

Cleaver-Brooks Boiler Expected Emission Data

Producing Steam Firing **Nat Gas**

BACKGROUND INFORMATION

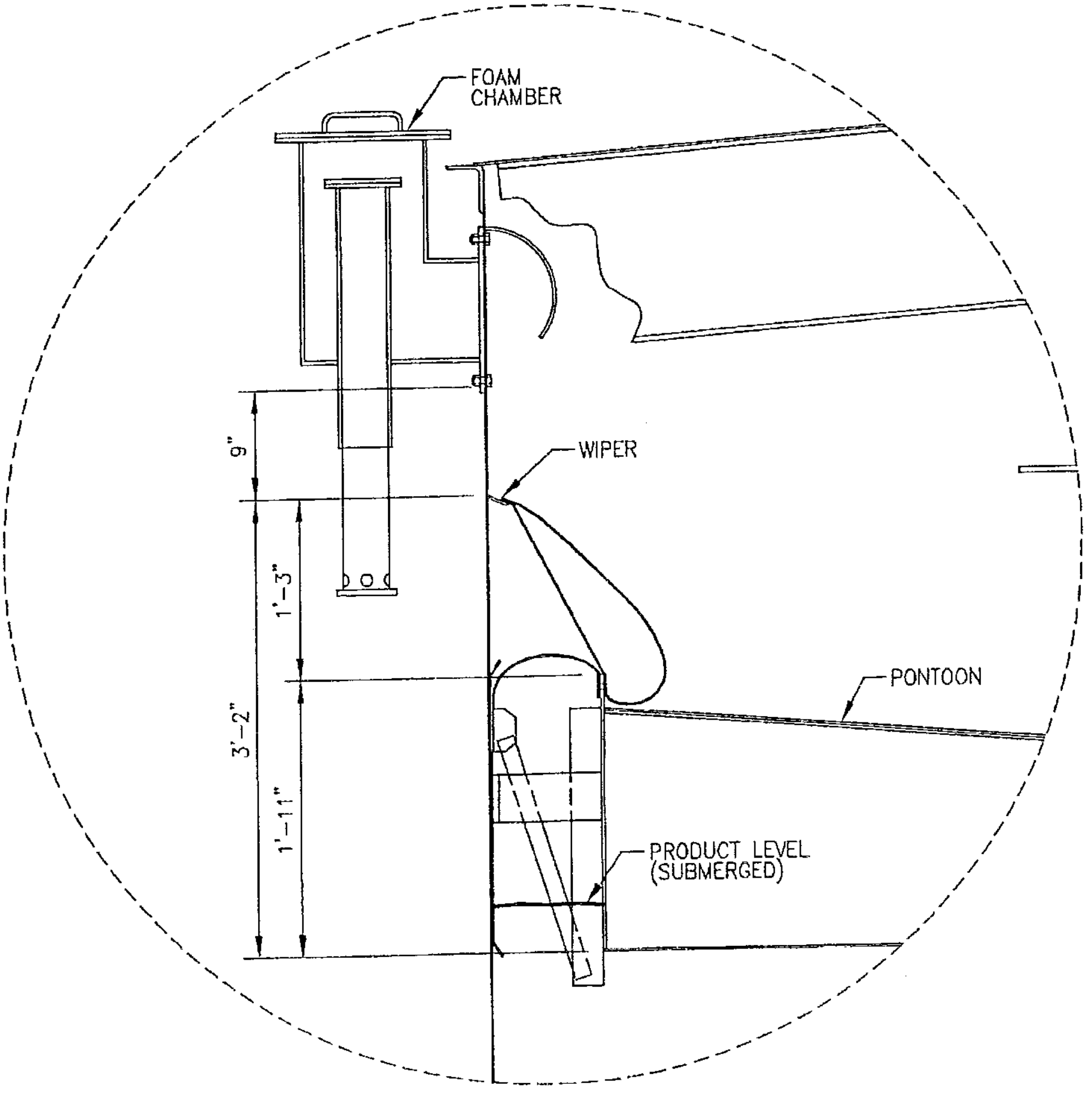
Date	06/17/13	Boiler Model	CBEX Elite
Author	L.C. Banks	Altitude (feet)	700
Customer	----	Operating Pressure (psig	125.00
City & State	----	Furnace Volume (cuft)	110.00
		Furnace Heat Release (btu/hr/cu ft)	113,809
		Heating Surface (sqft)	860
		Nox System	7

Nat Gas		Firing Rate			
		25%	**50%**	**75%**	**100%**
Horsepower		75	150	225	300
Input , Btu/hr		3,080,000	6,176,000	9,323,000	12,519,000
CO	ppm	50	50	50	50
	lb/MMBtu	0.036	0.036	0.036	0.036
	lb/hr	0.11	0.23	0.34	0.46
	tpy	0.492	0.987	1.490	2.001
NOx	ppm	7	7	7	7
	lb/MMBtu	0.0082	0.0082	0.0082	0.0082
	lb/hr	0.03	0.05	0.08	0.10
	tpy	0.111	0.223	0.336	0.452
NO	ppm	6.0	6.0	6.0	6.0
	lb/MMBtu	0.007	0.007	0.007	0.007
	lb/hr	0.02	0.04	0.07	0.09
	tpy	0.09	0.18	0.27	0.36
NO_2	ppm	1.1	1.1	1.1	1.1
	lb/MMBtu	0.001	0.001	0.001	0.001
	lb/hr	0.00	0.01	0.01	0.02
	tpy	0.02	0.04	0.07	0.09
SOx	ppm	1.00	1.00	1.00	1.00
	lb/MMBtu	0.0017	0.0017	0.0017	0.0017
	lb/hr	0.0053	0.0106	0.0160	0.0215
	tpy	0.023	0.046	0.070	0.094
VOCs	ppm	4.0	4.0	4.0	4.0
(Non-Methane Only)	lb/MMBtu	0.002	0.002	0.002	0.002
VOCs does not include	lb/hr	0.006	0.012	0.019	0.025
any background VOC	tpy	0.027	0.054	0.082	0.110
emissions.					
PM10 (Filterable)	ppm	N/A	N/A	N/A	N/A
	lb/MMBtu	0.00750	0.00750	0.00750	0.00750
	lb/hr	0.023	0.046	0.070	0.094
	tpy	0.101	0.203	0.306	0.411
PM10 (Condensable)	lb/MMBtu	0.00250	0.00250	0.00250	0.00250
	tpy	0.011	0.07	0.011	0.14
PM2.5 (Filterable)	lb/MMBtu	0.008	0.008	0.008	0.008
	tpy	0.033	0.20	0.033	0.41
PM2.5 (Condensable)	lb/MMBtu	0.0025	0.0025	0.0025	0.0025
	tpy	0.011	0.07	0.011	0.14
Exhaust Data					
Temperature, F		379	404	430	455
Flow	ACFM	1,049	2,169	3,373	4,662
	SCFM (70 Degrees Fah.)	679	1,361	2,055	2,759
	DSCFM	611	1,225	1,849	2,482
	lb/hr	3,055	6,126	9,248	12,417
Velocity	ft/sec	8.01	16.56	25.76	35.60
	ft/min	481	994	1,546	2,136

Notes:

1) All ppm levels are corrected to dry at 3% oxygen.
2) Emission data based on actual boiler efficiency.
3) % H2O , by volume in exhaust gas is **15.51** % O2, by volume **4.41**
4) Water vapor in exhaust gas is **99.62** lbs/MMBtu of fuel fired
5) CO2 produced is **116.31** lbs/MMBtu of fuel fired
6) Particulate is exclusive of any particulates in combustion air or other sources of residual particulates from mater
   PM level indicated on this form is based on combustion air and fuel being clean and turndown up to 4:1.
7) Heat input is based on high heating value (HHV).
8.) Emission produced in tons per year (tpy) is based on 24 hours per day for 365 days = 8,760 hours per year
9.) Exhaust data is based on a clean and properly sealed boiler.
10.) Emission data is based on a burner turndown of 4 to 1.
11.) Maximum flame temperature is 2800 degrees fahrenheit.

14) Fuel High Heating Value = **1000** Btu/FT^3


FOAM CHAMBER
WIPER
PONTOON
PRODUCT LEVEL (SUBMERGED)
9"
1'-3"
3'-2"
1'-11"

From: Phanindra Kondagari [mailto:PKondagari@flareindustries.com]
Sent: Tuesday, July 23, 2013 3:06 PM
To: Russ Bafford
Cc: Jon Sachs; Dave Gibson; Timothy Egan
Subject: 497-005 TSPT marine vapor control system using CEB combustion technology

Dear Mr. Bafford,

Per your request here are the emission numbers for the CEB.

	Guaranteed
Nox Emissions	**≤ 0.023 lb/MMBTU**
CO Emissions	**≤ 0.01 lbs./MMBTU**

Please let me know if you need any additional information.

Thanks & Regards

Phanindra Kondagari
Sr.Project Manager
Enclosed Combustion Group

Flare Industries
16310 Bratton Lane, Bldg. 3, Suite 350 | Austin, Texas 78728 USA
Office: +1 (512) 836-9473 Ext. 172 pkondagari@flareindustries.com | www.flareindustries.com

From: Phanindra Kondagari [mailto:PKondagari@flareindustries.com]
Sent: Friday, December 13, 2013 12:28 PM
To: Chris S Drechsel (Christopher.S.Drechsel@tsocorp.com)
Cc: Dave Gibson; Jon Sachs; Timothy Egan; davidcorpron@savageservices.com; Irina Makarow (Irina.Makarow@abam.com); Eric Albright; Eric Hansen; Price, Douglas B (Douglas.B.Price@tsocorp.com)
Subject: Tesoro Savage Vancouver Energy Distribution Terminal VCU Emission Factors - Particulate Matter

Hello Chris,

Due to the nature of the equipment (CEB), Flare Industries does not guarantee PM emissions as the PM rate is largely dependent on the Particulate loading in the combustion air , however based on our past experience we believe that using EPA AP-42 PM emission factors (Section 1.4 for Natural Gas Combustion) of 7.6 Lb/MMSCF will provide an conservative estimate.

Please let us know if you need any additional information.

Thanks & Regards

Phanindra Kondagari
Sr.Process Engineer
Enclosed Combustion Group

Flare Industries
16310 Bratton Lane, Bldg. 3, Suite 350 | Austin, Texas 78728 USA
Office: +1 (512) 836-9473 Ext. 172 | Mobile: +1 (512) 574-6396
pkondagari@flareindustries.com | **www.flareindustries.com**

1.0 INTRODUCTION (Continued)

Table 1-2
SUMMARY OF TEST RESULTS
Spec Services
Oxy Flare
November 1, 2012

PARAMETER	INLET	EXHAUST		PERMIT LIMIT
		As Found	Defaulted [1]	
O_2, %	0.21	10.23		
CO_2, %	1.69	6.76		
N_2, %	0.73	83.01		
H_20, %		10.5		
Flow Rate, wscfm (Faciliy flow monitor)	61.12	1,514		
Flow Rate, dscfm (Facility flow monitor)	61.12	1,355		
Temperature, °F (as measured at sampling ports)	74.9	1,831		
Temperature, °F (as measured at by set thermocouple)		2,154		>2000
Btu/scf	1316			
MMBtu/Hr	4.83			27
NOx:				
ppm		4.38		
ppm @ 3% O_2		7.34		15
lb/hr (as NO_2)		0.04		
lb/day (as NO_2)		1.0		
lb/MMBtu (as NO_2)		0.009		
lb/MMCF (as NO_2)		11.78		
CO:				
ppm		6.6	20	
ppm @ 3% O_2		11.0	33.6	50
lb/hr		0.04	0.12	
lb/day		0.95	2.88	
lb/MMBtu		0.008	0.025	
lb/MMCF		10.78	32.75	
Hydrocarbons:				
CH_4, ppm	795,150	< 10.00		
TGNMO, ppm (as CH_4)	587,040	4.90		
TGNMO, lb/hr (as CH_4)	90.9	0.02		
TGNMO, lb/MM Btu (as CH_4)	-	0.003		
TGNMO, lb/day (as CH_4)	2181.0	0.40		
TGNMO, ppm @ 3% O_2 (as CH_4)		8.22		
Destruction Eff. % (DRE)		99.98		98
lb/MMCF		4.58		7
Particulate (as PM_{10}):				
gr/dscf		0.0037		0.112
lb/hr		0.054		
lb/MM Btu		0.011		
lb/day		1.28		
lb/MMCF		14.60		
Total Sulfur Compounds,				
Total Reduced Sulfur Inlet, ppm	< 0.5			150 (Rule 431.1)
SOx Exhaust, lb/hr (as H_2S) [2]		< 0.0002		
SOx Exhaust, lb/day (as H_2S) [2]		< 0.004		5
lb/MMCF		< 0.04		

Notes:
The results in this table are the averages of all measurements.
(1) Values presented reflect 20% of the selected analyzer range.
(2) The exhaust SOx lb/hr and lb/day results are calculated from inlet reduced sulfur concentrations.

Table 2.
Kirby Inland Marine
Barge Cleaning Terminal
Corpus Christi, Nueces County, Texas
Clean Enclosed Burner (EPN CEB-DEGAS)
Destruction Removal Efficiency (DRE)
Test Date 04/16/09

Test ID		Test 1	Test 2	Test 3	Average
Sampling Date		04/16/09	04/16/09	04/16/09	-
Sampling Time		11:19 - 12:19	18:15 - 19:15	19:59 - 20:59	-
Sampling Duration		60	60	60	60
VOC Inlet *	lb/hr	629.781	337.914	382.254	449.983
VOC Stack *	lb/hr	0.054	0.028	0.031	0.037
DRE	%	99.991	99.992	99.992	99.992

* Note: VOC Stack and Inlet are minus Methane and Ethane.

ENTECH ENGINEERING INC.

P. O. Box 890746 . Houston, Texas 77289-0746 . (281)332-3118

Table 3.
Kirby Inland Marine
Barge Cleaning Terminal
Corpus Christi, Nueces County, Texas
Clean Enclosed Burner (EPN CEB-DEGAS)
Stack Sampling Parameters and Emission Rates Summary
Test Date 04/16/09

Test ID	Test 1	Test 2	Test 3	Average
Sampling Date	04/16/09	04/16/09	04/16/09	-
Sampling Time	11:19 - 12:19	18:15 - 19:15	19:59 - 20:59	-
Sampling Duration	60	60	60	60

Process Operational Data

Fuel F Factor	dscf/MMBtu	13514.76	13823.18	13849.61	13729.18
Fuel Higher Heating Value	Btu/cu.ft	450.04	413.63	415.51	426.39
Inlet Fuel Flow	SCFM	774	456	512	581
	SCFH	46461	27331	30732	34841
Firing Rate	MMBtu/hr	20.91	11.30	12.77	14.99

Stack Condition Data

Excess Oxygen (O_2)	vol%, dry	6.39	5.33	5.39	5.70

Outlet Emission Data

NOx	ppmv, dry	7.87	5.65	5.35	6.29
	lb/MMBtu	0.018	0.013	0.012	0.014
	lb/hr	0.383	0.141	0.152	0.225
CO	ppmv, dry	7.69	1.91	2.86	4.15
	lb/MMBtu	0.011	0.003	0.004	0.006
	lb/hr	0.228	0.029	0.049	0.102

Table 5.
Kirby Inland Marine
Barge Cleaning Terminal
Corpus Christi, Nueces County, Texas
Clean Enclosed Burner (EPN CEB-DEGAS)
Destruction Removal Efficiency (DRE)
Test Date 04/17/09

Test ID		Test 1	Test 2	Test 3	Average
Sampling Date		04/17/09	04/17/09	04/17/09	-
Sampling Time		10:15 - 11:15	11:35 - 12:35	12:55 - 13:55	-
Sampling Duration		60	60	60	60
VOC Inlet *	lb/hr	706.563	649.074	637.927	664.521
VOC Stack *	lb/hr	0.045	0.043	0.042	0.043
DRE	%	99.994	99.993	99.993	99.993

* Note: VOC Stack and Inlet are minus Methane and Ethane.

Table 6.
Kirby Inland Marine
Barge Cleaning Terminal
Corpus Christi, Nueces County, Texas
Clean Enclosed Burner (EPN CEB-DEGAS)
Stack Sampling Parameters and Emission Rates Summary
Test Date 04/17/09

Test ID		Test 1	Test 2	Test 3	Average
Sampling Date		04/17/09	04/17/09	04/17/09	-
Sampling Time		10:15 - 11:15	11:35 - 12:35	12:55 - 13:55	-
Sampling Duration		60	60	60	60
Process Operational Data					
Fuel F Factor	dscf/MMBtu	8970.76	8963.91	8970.90	8968.52
Fuel Higher Heating Value	Btu/cu.ft	2449.88	2489.56	2459.06	2466.17
Inlet Fuel Flow	SCFM	107	97	97	101
	SCFH	6448	5840	5831	6039
Firing Rate	MMBtu/hr	15.80	14.54	14.34	14.89
Stack Condition Data					
Excess Oxygen (O_2)	vol%, dry	7.45	8.00	7.68	7.71
Outlet Emission Data					
NOx	ppmv, dry	11.73	9.08	9.33	10.05
	lb/MMBtu	0.020	0.016	0.016	0.017
	lb/hr	0.309	0.229	0.227	0.255
CO	ppmv, dry	1.27	0.53	0.76	0.85
	lb/MMBtu	0.001	0.001	0.001	0.001
	lb/hr	0.020	0.008	0.011	0.013

1.0 INTRODUCTION (Continued)

Table 1-2
SUMMARY OF TEST RESULTS
Warren E&P
NWU Flare
July 11, 2011

PARAMETER	INLET	EXHAUST As Found	EXHAUST Defaulted [1]	PERMIT LIMIT
O_2, %	0.00	8.73		
CO_2, %	6.33	7.43		
N_2, %	0.91	83.85		
H_20, %		12.7		
Flow Rate, wscfm (Faciliy flow monitor)	113.75	2,002		
Flow Rate, dscfm (Facility flow monitor)	113.75	1,749		
Temperature, °F (as measured at sampling ports)	77	2,056		
Temperature, °F (as measured at by set thermocouple)		2,103		>1400
Btu/scf	1016			
MMBtu/Hr	6.93			17
NOx:				
ppm		4.45		
ppm @ 3% O_2		6.54		15
lb/hr (as NO_2)		0.06		
lb/day (as NO_2)		1.4		
lb/MMBtu (as NO_2)		0.008		
lb/MMCF (as NO_2)		8.30		
CO:				
ppm		6.7	20	
ppm @ 3% O_2		9.9	29.4	50
lb/hr		0.05	0.16	
lb/day		1.25	3.72	
lb/MMBtu		0.007	0.022	
lb/MMCF		7.62	22.71	
Hydrocarbons:				
CH_4, ppm	888,000	< 10.00		
TGNMO, ppm (as CH_4)	142,100	4.75		
TGNMO, lb/hr (as CH_4)	40.9	0.02		
TGNMO, lb/MM Btu (as CH_4)	-	0.003		
TGNMO, lb/day (as CH_4)	982.6	0.50		
TGNMO, ppm @ 3% O_2 (as CH_4)		6.98		
Destruction Eff. % (DRE)		99.95		98
lb/MMCF		3.08		7
Particulate (as PM_{10}):				
gr/dscf		0.0013		0.112
lb/hr		0.020		
lb/MM Btu		0.003		
lb/day		0.49		
lb/MMCF		2.98		
Total Sulfur Compounds,				
Total Reduced Sulfur Inlet, ppm	< 0.50			
SOx Exhaust, lb/hr (as H_2S) [2]		< 0.0003		
SOx Exhaust, lb/day (as H_2S) [2]		< 0.01		5
lb/MMCF		< 0.04		

Notes:
The results in this table are the averages of all measurements.
(1) Values presented reflect 20% of the selected analyzer range.
(2) The exhaust SOx lb/hr and lb/day results are calculated from inlet reduced sulfur concentrations.