

PM_{2.5} SIP Evaluation Report:
Holly Refining & Marketing Company – Woods Cross, LLC – Holly Refinery

Salt Lake City PM_{2.5} Serious Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

July 1, 2018

DAQ-2018-007649

PM_{2.5} SIP EVALUATION REPORT

Holly Refining & Marketing Company – Woods Cross, LLC – Holly Refinery

1.0 Introduction

The following is part of the Technical Support Documentation for Section IX, Part H.12 of the Utah SIP; to address the Salt Lake City PM_{2.5} Nonattainment Area. This document specifically serves as an evaluation of the Holly Refining & Marketing Company – Woods Cross, LLC – Holly Refinery.

1.1 Facility Identification

Name: Holly Refinery

Address: 393 South 800 West, Woods Cross, Utah, Davis County

Owner/Operator: Holly Refining & Marketing Company – Woods Cross, LLC

UTM coordinates: 4,526,227 m Northing, 424,000 m Easting, Zone 12

1.2 Facility Process Summary

The Holly Refinery (Holly) is a petroleum refinery capable of processing 60,000 barrels per day of crude oil, primarily heavier black wax and yellow wax crudes from eastern Utah. The source consists of two FCCUs, both controlled with wet gas scrubbers. A single sulfur recovery unit controls the sulfur content of the fuel gas. The source also has the usual assorted heaters, boilers, cooling towers, storage tanks, flares, and related fugitive emissions – primarily VOCs.

The two FCCUs are both complete burn units without cokers. There are no cogeneration units present. The refinery currently operates without flare gas recovery.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the Holly Refinery:

- Fluid Catalytic Cracking Unit (FCCU) #1, controlled with WGS
- FCC Feed Heater, 68.4 MMBtu/hr process furnace, fired on plant gas, restricted to 39.9 MMBtu/hr, equipped with low NO_x burners (LNB)
- Reformer charge and reheater furnace/waste heat boiler, 54.7 MMBtu/hr process furnace, fired on plant gas
- Prefractionator Reboiler Heater, 12.0 MMBtu/hr process furnace, fired on plant gas
- Reformer Reheat Furnace, 37.7 MMBtu/hr process furnace, fired on plant gas
- HF Alkylation Regeneration Furnace, 4.4 MMBtu/hr process furnace, fired on plant gas
- HF Alkylation Depropanizer Reboiler, 33.3 MMBtu/hr process furnace, fired on plant gas
- Crude Furnace #1, 99.0 MMBtu/hr process furnace, fired on plant gas, equipped with next generation ultra-low NO_x burner (NGULNB)
- Distillate Hydrosulfurization (DHDS) Unit Reactor Charge Heater, 8.1 MMBtu/hr process furnace, fired on plant gas
- DHDS Stripper Reboiler, 4.1 MMBtu/hr process furnace, fired on plant gas
- Asphalt Mix Heater, 13.2 MMBtu/hr process furnace, fired on plant gas
- Hot Oil Furnace, 99 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and selective catalytic reduction (SCR) system
- Straight Run Gas Plant (SRGP) Depentanizer Reboiler, 24.2 MMBtu/hr process furnace, fired

- on plant gas
- Naphtha Hydrodesulphurization (NHDS) Unit Reactor Charge Furnace, 50.2 MMBtu/hr process furnace, fired on plant gas, equipped with NGULNB
- Isomerization Reactor Feed Furnace 6.5 MMBtu/hr process furnace, fired on plant gas
- Sulfur Recovery (SRU) with Tailgas Incinerator
- Distillate Hydrodesulfurization Treatment (DHT) Reactor Charge Heater, 18.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB
- Gas Oil Hydrocracking (GHC) Unit Reactor Charge Heater, 14.9 MMBtu/hr process furnace, fired on plant gas, equipped with ultra-low NO_x Burners (ULNB)
- Fractionator Charge Heater, 47.0 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- Fractionator Charge Heater, 42.1 MMBtu/hr furnace, fired on plant gas, equipped with ULNB
- Reformate Splitter Reboiler Heater, 21.0 MMBtu/hr heater, fired on plant gas, equipped with ULNB
- Crude Unit Furnace, 60.0 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- FCCU #2, controlled with WGS and LoTO_x
- FCC Feed Heater 45 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- Hydrocracker/Hydroisom Unit Reactor Charger Heater, 99.0 MMBtu/hr reactor charger heater, fired on plant gas, equipped with LNB and SCR
- Hydrogen Reformer Feed Furnace, 123.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and SCR
- Hydrogen Reformer Feed Furnace, 123.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and SCR
- Vacuum Furnace Heater, 130.0 MMBtu/hr heater, fired on plant gas, equipped with LNB and SCR
- Boiler #4, 35.6 MMBtu/hr boiler, fired on plant gas
- Boiler #5, 70.0 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- Boiler #8, 92.7 MMBtu/hr boiler, fired on plant gas, equipped with LNB and SCR
- Boiler #9, 89.3 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- Boiler #10, 89.3 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- Boiler #11, 89.3 MMBtu/hr steam boiler, fired on plant gas, equipped with LNB and SCR
- Cooling Towers
- Flares
- Tank Farm
- Loading/Unloading
- Emergency Equipment (Diesel)
- Emergency Equipment (Natural Gas)

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the refinery, rather it is a listing of all significant emission units or emission unit groups (such as the tank farm). Emission units such as a fluidized catalytic cracking unit (FCCU) which may have multiple individual component parts, but which can be treated as a single unit for purposes of RACT analysis and discussion, will be treated in such a manner.

The most recent NSR permit issued to the refinery is DAQE-AN101230041-13, dated November 18, 2013.

1.4 Facility 2016 Baseline Actual Emissions and Current PTE

In 2016, Holly’s baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM _{2.5}	13.27
SO ₂	109.96
NO _x	181.71
VOC	157.86
NH ₃	17.82

The current PTE values for Holly, as established by the most recent AO issued to the source (DAQE-AN101230041-13) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM ₁₀	47.6
SO ₂	110.3
NO _x	341.1
VOC	252.2
NH ₃	18.2*

* NH₃ emissions not quantified in the AO, PTE is estimated

2.0 Modeled Emission Values

A full explanation of how the modeling inputs are determined can be found elsewhere. However, a shortened explanation is provided here for context.

The base year for all modeling was set as 2016, as this is the most recent year in which a complete annual emissions inventory was submitted from each source. Each source’s submission was then verified (QA-QC) – checking for condensable particulates, ammonia (NH₃) emissions, and calculation methodologies. Once the quality-checked 2016 inventory had been prepared, a set of projection year inventories was generated. Individual inventories were generated for each projection year: 2017, 2019, 2020, 2023, 2024, and 2026. If necessary, the first projection year, 2017, was adjusted to account for any changes in equipment between 2016 and 2017. For new equipment not previously listed or included in the source’s inventory, actual emissions were assumed to be 90% of its individual PTE.

While some facilities were adjusted by “growing” the 2016 inventory by REMI growth factors; most facilities were held to zero growth. This decision was largely based on source type, and how each source type operates. The refineries have reported to UDAQ as a production group that they are operating at capacity and are not planning any production or major emission increases in the time frame covered by the SIP BACT analysis. In addition, each of the refineries has previously agreed to accept SIP allowable CAPs on emissions of PM_{2.5} and PM_{2.5} precursors in the moderate PM_{2.5} SIP previously issued by UDAQ. For these reasons, UDAQ used zero growth for all projection years beyond the 2016 baseline inventory.

For Holly, between the years of 2016 and 2017, there were no NSR permitting actions that took

place – the last AO issued to the Holly refinery was in 2013. Thus, the only required changes to the emission inventory would be to apply the effects of growth, which in Holly’s case was no effect (as explained above). Therefore, the modified emission totals for 2017 are shown below in Table 2-1, and look exactly the same as the original 2016 actual emissions.

Table 2-1: Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM _{2.5}	13.27
SO ₂	109.96
NO _x	181.71
VOC	157.86
NH ₃	17.82

Since a value of zero (0) growth was applied for all projection years, the values listed above (the 2017 corrected values) would then be propagated through for each of the subsequent projection years – 2019, 2020, 2023, 2024 and 2026.

Next, the effects of BACT would be applied during the appropriate projection year. Any controls applied between 2016 and 2017 (such as any RACT or RACM required as a result of the moderate PM_{2.5} SIP), was already taken into account during the 2017 adjustment performed previously. Future BACT, meaning those items expected to be coming online between today and the regulatory attainment date (December 31, 2019), would be applied during the 2019 projection year. Notations in the appropriate projection year table of the emission inventory model input spreadsheet indicate the changes made and the source of those changes.

Similarly, Additional Feasible Measures (AFM) or Most Stringent Measures (MSM), which might be applied in future projection years beyond 2019 are similarly marked on the spreadsheet. The effects of those types of controls are applied on the projection year subsequent to the installation of each control – e.g. controls coming online in 2021 would be applied in the 2023 projection year, while controls installed in 2023 would be shown in 2024.

3.0 BACT Selection Methodology

The general procedure for identifying and selecting BACT is through use of a process commonly referred to as the “top-down” BACT analysis. The top-down process consists of five steps which consecutively identify control measures, and gradually eliminate less effective or infeasible options until only the best option remains. This process is performed for each emission unit and each pollutant of concern. The five steps are as follows:

1. **Identify All Existing and Potential Emission Control Technologies:** UDAQ evaluated various resources to identify the various controls and emission rates. These include, but are not limited to: federal regulations, Utah regulations, regulations of other states, the RBLC, recently issued permits, and emission unit vendors.
2. **Eliminate Technically Infeasible Options:** Any control options determined to be technically infeasible are eliminated in this step. This includes eliminating those options with physical or technological problems that cannot be overcome, as well as eliminating those options that cannot be installed in the projected attainment timeframe.
3. **Evaluate Control Effectiveness of Remaining Control Technologies:** The remaining control

options are ranked in the third step of the BACT analysis. Combinations of various controls are also included.

4. Evaluate Most Effective Controls and Document Results: The fourth step of the BACT analysis evaluates the economic feasibility of the highest ranked options. This evaluation includes energy, environmental, and economic impacts of the control option.
5. Selection of BACT: The fifth step in the BACT analysis selects the “best” option. This step also includes the necessary justification to support the UDAQ’s decision.

Should a particular step reduce the available options to zero (0), no additional analysis is required. Similarly, if the most effective control option is already installed, no further analysis is needed.

4.0 BACT for Refinery Process Heaters and Boilers

UDAQ has separated the analysis of process heaters and boilers into two groups. For those heaters and boilers with heat input ratings less than 30 MMBtu/hr; UDAQ has included its analysis in a separate document which addresses similar emission units which are common to many sources – such as small heaters and boilers. Please refer to the BACT analysis for Small Sources – Section 5 for details of the analysis for these smaller units. The remaining larger items are covered below. Of the 24 existing or proposed process heaters, approximately half meet the size criteria discussed above. Holly also has 6 boilers which will be covered in this analysis.

These items are:

- 4H1 FCC Feed Heater
- 6H1 Reformer Reheat Furnace
- 6H3 Reformer Reheat Furnace
- 7H3 HF Alkylation Depropanizer Reboiler
- 8H2 Crude Furnace #1
- 10H2 Hot Oil Furnace
- 12H1 NHDS Reactor Charge Furnace
- 20H2 Fractionator Charge Heater
- 20H3 Fractionator Charge Heater
- 24H1 Crude Unit Furnace
- 25H1 FCC Feed Heater
- 27H1 Reactor Charge Heater
- 30H1 Hydrogen Reformer Feed Furnace
- 30H2 Hydrogen Reformer Feed Furnace
- 33H1 Vacuum Furnace Heater
- Boiler #4
- Boiler #5
- Boiler #8
- Boiler #9
- Boiler #10
- Boiler #11

These units range in size from 33 MMBtu/hr to as large as 130 MMBtu/hr. All are or would be fired on a combination of refinery fuel gas and natural gas.

4.1 PM2.5

No add-on controls for particulates were considered by UDAQ for these boilers. Given that these emission units are fired on gaseous fuels, with inherently low particulate formation, no controls are expected to be cost effective. Holly did consider the usual particulate control options of good combustion practices, use of low sulfur fuels, wet gas scrubbers, electrostatic precipitators (ESPs), cyclones, and baghouse/fabric filtration; and determined that only good combustion practices and use of low sulfur gaseous fuels were technically feasible. Both refinery fuel gas¹ and natural gas are low sulfur fuels. Holly conducted an economic analysis of switching to using exclusively natural gas as fuel and found such a switch to not be economically feasible, with a control cost in excess of \$2.2 million/ton of particulate removed.

4.2 SO₂

Generally, SO₂ is formed from the combustion of sulfur present in the fuel. By limiting the sulfur content of the fuel, less SO₂ will be generated. Emissions of SO₂ can also be controlled by post combustion control devices or processes.

4.2.1 Available Control Technology

By consolidating all process heaters and boilers together into a single group for BACT consideration DAQ is able to consider controls on some emissions from this group which would ordinarily be dropped as being insignificant. However, it also limits the available options. In this particular case, only one option is available. The long term Subpart Ja refinery fuel gas H₂S limit of 60 ppmv as well as the existing short term Subpart J limit of 162 ppmv on a 3-hour average.

The normally available options of flue gas desulfurization (FGD) or fuel switching are not available in this case. Fuel switching is not possible given the requirements of eliminating the refinery fuel gas generated during production of gasoline and other petroleum derivatives. The refinery fuel gas cannot be flared, and too much is produced to allow for reforming into heavier products (the energy losses would negate any positive benefit gained). Desulfurization systems rely on a relatively high concentration of sulfur compounds in the exhaust stream to function effectively and efficiently. By meeting the fuel gas H₂S limits in Subparts J and Ja, the exhaust gas concentrations of SO₂ will naturally fall below the critical concentrations necessary for optimum control.

Two other add-on controls wet gas scrubbing (WGS) and Emerachem EMx™ can be considered available technologies. A typical WGS system consists of either a packed bed tower or venturi-type scrubber. The flue gas to be cleaned passes through the absorber where misting nozzles form a dense curtain of liquid. The liquid reagent helps to cool the flue gas, neutralize the SO₂ in the flue gas, as well as trap any particulate matter in the gas. Liquid collects in the bottom of the scrubber where caustic soda (NaOH) is added to prevent the formation of sulfuric acid (H₂SO₄). The scrubbed gas continues upward through the vessel passing through filters prior to release into the atmosphere. Waste collected at the bottom of the scrubber is pumped off for additional treatment. This waste contains sulfites such as NaHSO₃ and Na₂SO₃ along with residual catalyst fines and precipitated solids. Solids removal is done through a clarifier using flocculation to settle

¹ Refinery fuel gas is higher in sulfur content than natural gas. Pipeline quality natural gas has a very low sulfur content of approximately 4 ppm – typically in the form of mercaptans used as odorants. The sulfur content of refinery fuel gas varies depending on the performance/removal efficiency of the amine scrubbing units (SRUs) at the refinery. At the Holly refinery, the SRU is designed to produce fuel gas with an average H₂S content of 60 ppm on an annual average. However, short term spikes as high as 162 ppmv sulfur on a 3-hr average basis are allowed under the current rules of the SIP. By way of comparison, ultra-low sulfur diesel fuel (ULSD) is 15 ppm sulfur.

out the solids.

The EMx™ system uses a coated oxidation catalyst installed in the flue gas to remove both NO_x and CO without a reagent such as ammonia. The NO emissions are oxidized to NO₂ and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to de-absorb the NO₂ from the catalyst and reduce it to N₂ prior to exit from the stack. EMx™ prefers an operating temperature range between 500°F and 700°F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrates and nitrites on the surface of the catalyst. When all of the carbonate absorber coating on the surface of the catalyst has reacted to form nitrogen compounds, NO₂ is no longer absorbed, and the catalyst must be regenerated. Dampers are used to isolate a portion of the catalyst for regeneration. The regeneration gas consists of steam, carbon dioxide, and a dilute concentration of hydrogen. The regeneration gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the next set of dampers close to isolate and regenerate the next portion of the catalyst. This cycle repeats continuously. At any one time, four oxidation/absorption cycles are occurring and one regeneration cycle is occurring.

4.2.2 Evaluation of Technical Feasibility of Available Controls

WGS is available for control of emissions from sources with higher concentrations of SO₂ or acid gases in the exhaust stream, but for these types of sources they are just not commercially available. To some degree this can also be viewed as a technical concern, but in either case the end result is the same. As WGS is not commercially available for emission sources of this concentration, WGS will not be considered further.

The EMx system is complex enough that the technology has not been proven to run longer than one year without a turnaround. HollyFrontier requires that the refinery heaters are able to operate at least three years between turnarounds. This type of control imposes a technical limitation on the operation of the refinery and is considered technically infeasible by the refinery for control of SO₂ emissions. EMx will not be considered further.

This leaves only the use of low sulfur fuels and good combustion practices as technically feasible and available controls.

4.2.3 Evaluation and Ranking of Technically Feasible Controls

Both controls can be used in conjunction, so no ranking of control techniques is required.

4.2.4 Further Evaluation of Most Effective Controls

As mentioned previously, Holly conducted an analysis of switching to running exclusively on pipeline quality natural gas as fuel versus using refinery fuel gas or a combination of refinery fuel gas and natural gas. While Holly's analysis was conducted on particulate emissions and not SO₂, the difference in emission totals between particulate and SO₂ is approximately 3 tons (total particulate emissions from heaters and boilers ~ 10 tons/year, total emissions of SO from heaters and boilers ~ 13 tons/year), the economic analysis result is similar. Using exclusively natural gas as fuel is not economically feasible, with a control cost in excess of \$1.69 million/ton of particulate removed.

4.2.5 Selection of BACT Controls

UDAQ recommends that Holly continue to use good combustion controls and refinery fuel gas or natural gas as fuel for control of SO₂ emissions from the refinery process heaters and boilers.

4.3 NO_x

NO_x, or oxides of nitrogen, are formed from the combustion of fuel. There are three mechanisms for the formation of NO_x: fuel NO_x, which is the oxidation of the nitrogen bound in the fuel; thermal NO_x, or the oxidation of the nitrogen (N₂) present in the combustion air itself; and prompt NO_x, which is formed from the combination of combustion air nitrogen (N₂) with various partially-combusted intermediary products derived from the fuel. For combustion within the process heaters and boilers, fuel NO_x and thermal NO_x are the major contributors, with prompt NO_x contributing slightly only in the initial stages of combustion. All three processes are temperature dependent – combustion temperatures below 2700°F greatly inhibit NO_x formation.

4.3.1 Available Control Technology

The following technologies were identified as potential control methodologies for control of NO_x emissions by Holly: good combustion practices; low emission combustion (LEC); selective non-catalytic reduction (SNCR), the injection of ammonia or urea directly into the late stages of the combustion zone; selective catalytic reduction (SCR); flue gas recirculation (FGR); and EMx™ (previously known as SCONO_x™).

Low Emission Combustion (or LEC) is a summary term given to a host of different combustor designs and pre-combustion controls such as water or steam injection. These can be combined with a similar type of combustion control known as staged air/fuel combustion or overfire air injection. All serve the same general purpose – to reduce NO_x formation by lowering the overall flame temperature. The various combustor (burner) designs, ranging from low-NO_x, through ultra-low-NO_x and up to “next generation” ultra-low-NO_x reduce flame temperature through a combination of flame diffusion, internal flue gas recirculation and some degree of staged combustion design. Water injection uses the inherent high specific heat of the injected water to absorb some of the combustion energy without increasing the ambient gas temperature. Staged air/fuel combustion limits the total amount of combustion air so that reducing and oxidizing sections are created in the combustion chamber. Combustion happens in stages, with intermediary products needing to physically move between sections before continuing combustion. Combustion is slowed down, limiting the “flux” (energy output/time) which lowers the total temperature.

Low-NO_x Burners (LNB): Typically thought of as an advanced version of a standard burner, the LNB reduces NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. There are two main types of LNB: staged fuel and staged air burners. Staged fuel burners divide the combustion zone into two regions, limiting the amount of fuel supplied in the first zone with the standard amount of combustion air, and then supplying the remainder of the fuel in the second zone to combust with the un-combusted oxygen from the first zone. Staged air burners reverse this, limiting the combustion air in the first zone then supplying the remainder of the combustion air in the second zone to combust the remaining fuel. Staged fuel LNBs are more suited to natural gas-fired boilers as they are designed to restrict flame temperature.

Ultra-Low-NO_x Burners (ULNB): Most commonly a combination of LNB technology with some internal flue gas recirculation. The burner recirculates some of the hot flue gases from the flame or firebox back into the combustion zone. Since these high temperature flue gases are oxygen depleted, the burner lowers the speed at which fuel can be combusted without reducing the flame

temperature below the level needed for optimum combustion efficiency. Reducing oxygen concentrations in the firebox most directly impacts fuel NO_x generation.

Flue Gas Recirculation (FGR): External FGR involves recycling of flue gas back into the firebox as part of the fuel-air mixture at the burner. Although similar to the concept of ULNB, rather than using burner design features to recirculate gases from within the firebox, FGR uses external ductwork to route a portion of the exhaust stream back to the inlet side of the boiler and return it into the boiler windbox.

In the SCR process, a reducing agent, such as aqueous ammonia, is introduced into the exhaust, upstream of a metal or ceramic catalyst. As the exhaust gas mixture passes through the catalyst bed, the reducing agent selectively reduces the nitrogen oxide compounds present in the exhaust to produce elemental nitrogen (N₂) and water (H₂O). Ammonia is the most commonly used reducing agent. Adequate mixing of ammonia in the exhaust gas and control of the amount of ammonia injected (based on the inlet NO_x concentration) are critical to obtaining the required reduction. For the SCR system to operate properly, the exhaust gas must maintain minimum O₂ concentrations and remain within a specified temperature range (typically between 480°F and 800°F with the most effective range being between 580°F and 650°F), with the range dictated by the type of catalyst. Exhaust gas temperatures greater than the upper limit (850°F) will pass the NO_x and unreacted ammonia through the catalyst. The most widely used catalysts are vanadium, platinum, titanium, or zeolite compounds impregnated on metallic or ceramic substrates in a plate of honeycomb configuration. The catalyst life expectancy is typically 3 to 6 years, at which time the vendor can recycle the catalyst to minimize waste.

One final technology is CETEX, which is a process of descaling firebox steam tubes and the recoating these tubes – improving heat transfer and lowering total fuel consumption for a given amount of steam output.

4.3.2 Evaluation of Technical Feasibility of Available Controls

Most of the listed controls are technically feasible, although certain control techniques cannot be used in conjunction. For example, ULNB and FGR both use some degree of flue gas recirculation, making the use of both technologies redundant and counter-productive. FGR can only be applied on mechanical draft heaters/boilers with burners that can accommodate increased gas flows. All but one heater at the Holly refinery is naturally drafted, and this heater has a separate physical limitation. In order to physically connect FGR, a separation of at least three feet must exist between the windbox and the burner to prevent the accumulation of potentially explosive gas mixtures if a heater tube should fail. The burner on the mechanical draft heater is located closer than three feet to the windbox and cannot be moved farther away and still receive proper heater transfer. FGR is eliminated from further consideration. Next generation ULNB have proven less reliable than “normal” ULNB. They have been prone to plugging from impurities present in the fuel source. They also have not been shown to have any better emissions control than normal ULNB.

SCR and SNCR are opposed technologies as well, as SNCR is the use of ammonia injection without the added benefit of a catalyst bed to aid in pollutant reduction. Strictly speaking, SCR is simply the most commonly used catalytic reduction technique. More generally, NSCR (or non-selective catalytic reduction) represents those catalytic reduction techniques using alternative catalysts also capable of reducing NO_x. Often these catalysts reduce NO_x in addition to many other compounds and are not specifically designed or optimized for NO_x reduction. Efficient operation of these catalysts typically requires that the exhaust gases contain low oxygen

concentrations – perhaps as low as 0.5% and no more than 4%. Since this requires the use of lean burn engines, furnaces and boilers, NSCR was eliminated by Holly as a valid control technique.

SNCR was eliminated based on a lack of load responsiveness. The control technique is somewhat crude by current standards, using only ammonia injection to reduce NOx emissions and relying on turbulence, temperature and residence time to allow the reaction to come to completion. The technical limitation of this technique is that as load changes NOx emissions can vary and change fairly rapidly, yet the only control mechanism is to change the amount of ammonia being injected into the flue gas. Periods of too little ammonia will be followed by periods of too much ammonia, both scenarios leading directly to an increase in PM2.5 emissions.

The EMx process is highly sensitive to poisoning from sulfur compounds present in the exhaust gas. EMx has never been demonstrated in practice on refinery fuel gas-fired heaters or boilers and is not deemed commercially available for this fuel type. EMx is therefore eliminated from consideration.

Water/steam injection is of limited effectiveness on process heaters and boilers. While some NOx reduction is possible, the benefit gained is minimal on units already equipped with low-NOx burners or better. Water/steam injection is typically employed on turbines where the increased mass of the steam-laden exhaust gas increases the efficiency of the turbine by improving the momentum transfer to the power generator. It is not typically employed on process heaters or boilers.

Low excess air firing (overfire/staged air combustion) was also eliminated based on flame lengthening problems. Reducing the oxygen concentration causes the combustion flame to lengthen, potentially causing flame impingement – where the flame comes into physical contact with one or more surfaces of the unit. This can cause severe damage to the unit and hazardous safety situations for refinery workers. This technique has also been eliminated from further consideration.

4.3.3 Evaluation and Ranking of Technically Feasible Controls

The remaining control techniques and their control effectiveness are listed below:

Table 4-1 NOx Control Effectiveness

Technology	Range of Control (%)
ULNB + SCR	85-99
LNB + SCR	80-99
SCR	80-90
ULNB	65-75
LNB	50-60
CETEX	NA*

* Not applicable, see below

Based on these control efficiencies, the use of SCR in combination with some form of NOx controlling burner (either LNB or ULNB) is the top ranked control option. The use of SCR without a burner upgrade can also be applied, but is rarely found in practice. The second ranked option is the use of ULNB alone, followed by LNB. Holly already performs chemical descaling operations on the refinery boilers which are very similar in form and function to CETEX.

4.3.4 Further Evaluation of Most Effective Controls

Holly provided additional analysis for the technically feasible controls. Installing SCR can have adverse energy and environmental impacts. One potential source of concern with operation of SCR is the generation of ammonia slip. Unreacted ammonia, meaning any ammonia which does not react with the NO_x present in the exhaust stream, may react with SO₃ to form ammonium sulfate/sulfite. This can occur either in the exhaust stream or in the ambient air. The unreacted ammonia is referred to as “ammonia slip.” Ammonia slip itself often requires permit limitations as a precursor pollutant.

Another source of concern is handling and disposal of the spent catalyst, which becomes a solid waste product. Operation of the SCR system reduces air flow, requiring additional energy in the form of fan power upgrades. In addition, in order to install SCR, Holly would need to replace all of the existing natural draft heaters with mechanical draft heaters in order to accommodate the additional airflow requirements.

Installation of LNB or ULNB can change the heating pattern of the furnace or boiler by extending and cooling the flame.

Holly conducted an analysis for installing SCR on those heaters/boilers not already equipped with this control, and for installing LNB/ULNB. Holly concluded that the installation of SCR on naturally drafted heaters would require replacing or rebuilding those heaters as mechanical draft heaters. Such a change would not be economically feasible. Similarly, installation of LNB or ULNB often requires the use of more physical burners than originally installed, as each burner can have a lower heating duty. While larger duty burners can be installed, the selection is limited and the change in burner size can force physical changes in the process heater or boiler to prevent damage from the increased flame size.

4.3.5 Selection of BACT Controls

UDAQ recommends the existing NO_x controls remain as BACT. As a refinery, Holly has an existing plant-wide cap on emissions of NO_x from all combustion sources, rather than individual limitations on specific emission units. The plant-wide cap is as follows:

No later than January 1, 2019, NO_x emissions into the atmosphere from all emission points shall not exceed 347.1 tons per rolling 12-month period and 2.09 tons per day (tpd).

This is found in Section IX, Part H.12.g.ii of the moderate PM_{2.5} SIP, as well as Holly’s most recent NSR permit (condition II.B.8.a of DAQE-AN101230041-13). Both documents also contain additional monitoring, recordkeeping and reporting requirements to ensure compliance with these limits.

4.4 Consideration of VOC and Ammonia

UDAQ was unable to find any additional add-on controls or control techniques for further control of VOC emissions from the heaters and boilers listed in this section. While VOC controls do exist, primarily these controls are thermal or catalytic oxidation requiring relatively high VOC concentrations and often additional heat input in the form of fuel burning (negating the controls already achieved for other pollutants). Control techniques such as fuel switching are not helpful since gaseous fuels such as refinery fuel gas and natural gas (the only fuels used by Holly in these units) are already the best available. The only control technique remaining is the use of good

combustion practices. As GCP are already required or included as a part of the control techniques for the other pollutants listed previously no additional consideration is required.

There are few emissions of ammonia from the heaters and boilers naturally (some minor amounts of ammonia may be generated as part of the combustion process). At the Holly Refinery, five large process heaters (10H2 Hot Oil Furnace, 27H1 Reactor Charge Heater, 30H1 and 30H2 Hydrogen Reformer Feed Furnaces, and 33H1 Vacuum Furnace Heater) and all of the large boilers except Boiler #4 are equipped with SCR as NO_x control and thus subject to some degree of ammonia slip. For existing systems, an ammonia slip of 10 ppm is considered BACT for process heaters and boilers. This is discussed in greater detail in the BACT analysis for Small Sources – Section 2 - Ammonia Emissions from SCRs.

5.0 BACT for Flares

5.1 Flare Gas Emissions

The refinery flares emit PM_{2.5}, SO₂, NO_x and VOCs, as well as a minor amount of ammonia. However, rather than evaluate the flares based on the individual pollutant emissions, UDAQ has historically evaluated the emissions from the flares based on the gases sent to the flares. During development of the Moderate 2.5 SIP, UDAQ established that the refineries' flares were to be used primarily as safety devices and not as process control devices. Therefore, each refinery was required to meet the requirements of Subpart J and Ja for all hydrocarbon flares, and to install and operate a flare gas recovery or minimization process by January 1, 2019.

5.1.1 Available Control Technology

There are two parts to refinery flares, as outlined in the Refinery General RACT Evaluation. The first is setting all refinery hydrocarbon flares as subject to the requirements of 40 CFR 60 Subpart Ja. The second is requiring all refineries to have a flare gas recovery system in place and operating by January 1, 2019 that meets the flare event limits listed in 40 CFR 60.103a(c).

5.1.2 Evaluation of Technical Feasibility of Available Controls

Neither part is technically infeasible.

5.1.3 Evaluation and Ranking of Technically Feasible Controls

The refinery general requirement of subjecting all hydrocarbon flares to the requirements of Subpart Ja has already been accepted by all listed refineries. As discussed in the Refinery General RACT Evaluation, most refineries began economic evaluations of flaring events beginning in November of 2015 to determine whether a flare gas recovery program is viable regardless of any imposing of such requirement by DAQ.

For its part, Holly has implemented a program to evaluate flare events which exceed the thresholds listed in Subpart Ja. The refinery has initiated procedures to install and operate a flare gas recovery program by the implementation date of January 1, 2019 as outlined in IX.H.11.g.v.B.

5.1.4 Further Evaluation of Most Effective Controls

No additional analysis is required. The general requirements on refinery flares found at Section

IX Part H.11.g of the moderate PM2.5 SIP are the only viable techniques for the control of emissions from the refinery's flares. No additional analysis is required.

5.1.5 Selection of BACT Controls

DAQ recommends that Holly continue to implement the general refinery SIP requirement "Requirements on Hydrocarbon Flares" as outlined IX.H.11.g.v.B. There are no expected emission reductions versus the 2016 "true-up" emission inventory as the flare gas recovery system was already included in that inventory.

6.0 BACT for Cooling Towers

There are two main pollutants of concern from cooling towers used in refinery settings. Like all industrial cooling towers, some particulate emissions will result during the evaporation of the cooling water. For further details on BACT controls for particulate emissions from cooling towers please refer to the PM2.5 Serious SIP - BACT for Small Sources – Section 6 for the analysis.

Cooling towers found in refineries have a secondary concern. It is possible for the cooling water to pick up volatile compounds during the heat transfer process, and for these compounds to be released as VOCs. As the levels of VOCs in refinery cooling water can be large enough to deserve their own controls, a separate BACT analysis is provided.

6.1 VOCs

6.1.1 Available Control Technology

UDAQ employed the services of a contractor during review of the RACT evaluations for the moderate PM2.5 SIP. Only a single control technique was determined to be "available." During that review, it became apparent that UDAQ's contractor was making the same recommendation to all of the refineries located in the PM2.5 non-attainment area. Specifically, that each refinery apply the 40 CFR 63 Subpart CC requirements to all cooling towers servicing heat exchangers with high VOC content streams. These requirements are basically leak detection and repair programs that apply specifically to cooling towers by checking for the presence of VOCs in the cooling water on a periodic basis. If detected, then service or repair of the relevant heat exchanger is warranted.

6.1.2 Evaluation of Technical Feasibility of Available Controls

All the refineries located in the PM2.5 non-attainment area agreed to an application of the MACT CC language which was included in the moderate PM2.5 SIP in Section IX, Part H.11.g.

6.1.3 Evaluation and Ranking of Technically Feasible Controls

N/A This has become a refinery general SIP requirement.

6.1.4 Further Evaluation of Most Effective Controls

N/A This has become a refinery general SIP requirement.

6.1.5 Selection of BACT Controls

UDAQ recommends that Holly continue to follow the general refinery SIP requirements found in Section IX, Part H.11.g.

7.0 BACT for the SRUs

Holly identified several different types of SRU systems:
the traditional Claus unit with or without a tail gas treatment unit (TGTU),
the Superclaus process,
the Euroclaus process,
the Mobil Oil Direct Oxidation process,
the COPE, Oxyclaus, and SURE processes,
the Selectox process,
the Sulfreen process,
the Maxisulf, CBA, Clinsulf, and MCRC processes,
the Wellman-Lord, CANSOLV, and CLINTOX processes,
the Stretford, Z-SORB, LO-CAT, and CrystaSulf liquid-phase oxidation reduction technologies,
and,
the SCOT process.

However, primarily these processes are merely refinements on existing SRU technology and do little to treat or remove the SO₂ emissions being released to the ambient air. Rather, they attempt either 1) to reduce the load on the SRU by removing some amount of H₂S prior to the oxidation step of the SRU, or 2) attempt to improve the efficiency of the SRU by aiding in the oxidation/reduction process. There are a few notable exceptions, namely the last three types of processes, which will be discussed further below.

7.1 SO₂

Holly operates a single SRU meeting the established 95% sulfur recovery required under the PM₁₀ SIP (SIP Section IX, Part H.1). The existing system consists of an amine treatment unit followed by a conventional Claus SRU and tail gas incinerator. The SRU does not utilize a TGTU as Holly has opted to control emissions from the SRU with a wet gas scrubber (WGS) – either unit 4 or unit 25. The SRU does not operate if neither WGS is operational and able to receive the emissions. UDAQ considers this system to be a “well-controlled SRU”, even though in most cases a “well -controlled SRU” is one that is operating with a TGTU followed by tail gas incineration.

There are only two pollutants of concern from a well-controlled SRU: SO₂ and NO_x. The system is designed to remove sulfur (primarily in the form of H₂S) from the refinery fuel gas through a combination of catalytic treatment and combustion. A portion of the total H₂S is burned catalytically to form SO₂. Then, the H₂S and SO₂ react, at an optimal 2:1 ratio, to form elemental sulfur. After each catalytic stage, the liquid sulfur is recovered from condensers. The effluent gas from this process is sent to the TGTU, where the SO₂ is converted back to H₂S and captured by amine scrubbing. Any unreacted H₂S is combusted in the tail gas incinerator yielding SO₂. Through the heat of combustion, some NO_x is formed (thermal NO_x), but particulate and VOC emissions are very low.

In Holly’s case, the process is reversed, using amine treatment first, then the Claus unit form elemental sulfur. The effluent gas from the Claus unit is then sent to the tail gas incinerator to convert any remaining H₂S into SO₂. The exhaust gas from the incinerator is then sent through

the WGS which scrubs out the SO₂ and NO_x, through use of a LoTO_x system.

7.1.1 Available Control Technology

As mentioned in the opening paragraph, Holly identified three other processes/control systems to further reduce emissions from a well-controlled SRU.

- the Wellman-Lord, CANSOLV, and CLINTOX processes
- the Stretford, Z-SORB, LO-CAT, and CrystaSulf liquid-phase oxidation reduction technologies
- the SCOT process

The Wellman-Lord, CANSOLV, and CLINTOX processes are essentially wet scrubbers that use proprietary solvents for SO₂ removal. The processes can be used in conjunction with traditional SRUs, but the use of a SRU is not required. A combustion process to convert the H₂S in the inlet stream to SO₂ is required however. When they are used in conjunction with a traditional SRU, the stripped SO₂ can be returned to the front of the processing stream so that more elemental sulfur can be recovered. This type of technology serves as the basis of Big West Oil's backup caustic scrubbing system.

The Stretford, Z-SORB, LO-CAT, and CrystaSulf liquid-phase oxidation reduction technologies use indirect oxidation of H₂S to form elemental sulfur and water. These systems replace the traditional SRU. They all operate similarly, differing primarily only in the choice of chelating agent used.

The SCOT process is essentially the basis of the TGTU and, while an available control technology, has been specifically skipped by Holly in using WGS technology as a final form of treatment.

WGS is a final control option, where the exhaust from the SRU is sent to the WGS in-lieu of tail gas treatment.

7.1.2 Evaluation of Technical Feasibility of Available Controls

All controls are technically feasible and have been demonstrated in practice. The Stretford, Z-SORB, LO-CAT, and CrystaSulf processes replace the traditional SRU and have been eliminated for use as the sole control technique for this reason. The original PM₁₀ SIP and the current maintenance plan requirements of IX.H.1.g.iii.A.I require all refineries located in or affecting a PM₁₀ or PM_{2.5} nonattainment area to install, operate and maintain a SRU that is at least 95% efficient in SO₂ removal. As these processes do not meet the definition of a SRU, they cannot meet this requirement without a change in this particular requirement. They can serve as redundant backup processes or as add-on controls to the existing SRU.

7.1.3 Evaluation and Ranking of Technically Feasible Controls

Well-controlled SRUs can achieve 99.9% or better sulfur recovery efficiency rates. Holly's current SRU+WGS system meets this level of sulfur recovery, with estimated SO₂ emissions of just 12.5 tons following installation of the WGS². Operation of the other control/processing

²Holly received authorization to install the both WGS systems in the AO DAQE-AN101230041-13 which was issued on November 18, 2013. Holly's baseline actual emissions for 2016 are based on the 2014 triannual emission

systems are not expected to yield higher levels of SO₂ control than operation of a WGS.

7.1.4 Further Evaluation of Most Effective Controls

None of the control options will effectively reduce emissions below the levels already achieved. Although any of the control options could be applied in lieu of the existing controls, the costs of these alternative add-on measures would be well above any arbitrary \$/ton value considered viable. Either the system would require a redesign of the SRU process, or it would require removal of the existing WGS infrastructure as this system would no longer be economically or process viable.

7.1.5 Selection of BACT Controls

UDAQ recommends that Holly continue to control its SRU and TGI via WGS as BACT. The emissions from the WGS systems are monitored by CEM and are included in the daily plant-wide SO₂ emissions cap for the refinery. No additional limitations or requirements are necessary. The SO₂ emission cap is as follows:

No later than January 1, 2019, the emission of SO₂ from all emission points (excluding routine SRU turnaround maintenance emissions) shall not exceed 110.3 tons per rolling 12-month period and 0.31 tons per day (tpd).

8.0 BACT for the FCCU Regenerators

The fluidized catalytic cracking unit, or FCCU, is a reactor where pre-heated feedstock is combined with a very hot catalyst in order to “crack” or break the long-chain hydrocarbon molecules making up the feedstock. The long-chain molecules are broken down into shorter, lighter molecular weight hydrocarbons. These lighter materials then rise to the top of the reactor where they are removed and sent elsewhere in the refinery for further processing. The spent catalyst is removed from the recovered material through a series of two- or three-stage cyclones and sent to the regenerator section.

The regenerator in most FCCUs is a secondary vessel located alongside (in a side-by-side configuration) the main reactor vessel. The regenerator is used to remove residual carbon buildup from the surface of the catalyst. This residual carbon, also called “catalyst coke” or just coke, reduces catalyst performance simply by adhering and coating the active surfaces of the catalyst. The catalyst is quite hot when it exits the reactor, and simply introducing forced air is enough to cause the coke to combust. The additional heat from this combustion keeps the regenerator operating around 1300°F. Catalyst coke contains a high amount of entrapped impurities depending on the chemical nature of the feedstock. Sulfur, various nitrogen compounds, trace metals and other compounds may be present. These materials will be released during combustion of the coke and depending on the design of the regenerator may be altered during the combustion process as well. The regenerator is the primary point of emissions from the FCCU.

Holly’s refinery has two FCCUs. The older FCCU receives hydrotreated feedstocks from the

inventory as submitted by Holly Frontier. At that time (on or about April 15, 2015) Holly had not yet completed installation of the 2nd WGS which was primarily designed to control emissions from the SRU and the second FCCU (the 1st WGS primarily controlled FCCU #1). At the time of preparation of this technical support documentation, Holly’s estimated emissions from the SRU as controlled by WGS are approximately 12.5 tons for emission year 2017.

gas-oil hydrocracker (GHC). The GHC uses a hydrotreating catalyst to begin removal of sulfur and nitrogen from the feed by replacing these elements with hydrogen. Once hydrotreated, the modified and now heated feedstock is sent to the FCCU where catalyst additives are used to control both SO₂ and NO_x emissions. The new FCCU, which was added as part of the Heavy Crude Processing Project in DAQE-AN101230041-13 processes lower sulfur waxy crudes. This unit is not hydrotreated, but the difference in crude sulfur content is great enough that no hydrotreating is required (Holly's "standard" crude – Western Canadian Select – is approximately 34,000 ppm sulfur, black and yellow wax crudes are approximately 900 ppm sulfur).

Both FCCUs operate in complete combustion mode. Neither unit is equipped with a CO boiler. Cyclones are used to remove catalyst particles from the combustion gases exiting the regenerators, and a WGS is used for final control of particulate emissions.

8.1 PM2.5

8.1.1 Available Control Technology

For control of particulate emissions from a FCCU regenerator, a source can choose from the usual array of options, either high efficiency electrostatic precipitation (ESP) or fabric filtration (baghouse) being the primary choices depending on the electrical resistivity of the coke burn-off at the particular refinery. Two additional, more recent choices have also emerged: wet gas scrubbing (WGS) and a "flue gas blowback filter" (FGF). The FGF is an in-stack filter that operates in a similar fashion to a fabric filtration system, but on a smaller and faster cleaning scale. They are designed specifically for use with a FCCU, and have generally not been commercially applied in the U.S. but have seen successful application overseas. UDAQ has only found a single application of a FGF in the U.S., namely the one installed at Big West Oil's (BWO) refinery, located in North Salt Lake, Utah. BWO was required to install a FGF as part of consent decree requirements prior to its inclusion as RACT for BWO's FCCU catalyst regenerator during development of the moderate PM_{2.5} SIP.

The other control options normally available for combustion related activities, such as fuel switching or "good combustion controls," are inherently limited by the nature of the process. The chemical nature of the feedstock and the type of cracking catalyst do make some difference in the resulting particulates generated during the regeneration process, but an individual refinery is rather limited in which feedstocks it can accept based on physical configuration, geographical location, market forces (availability), and regulatory limits (on both the refinery emissions and the allowed final product). Ultimately, feedstock blending and catalyst changes have little to no effect on particulate emissions.

8.1.2 Evaluation of Technical Feasibility of Available Controls

All of the available controls are technically feasible; however the controls are mutually exclusive – they cannot (in most cases) be used together.

8.1.3 Evaluation and Ranking of Technically Feasible Controls

In terms of efficiency for control of particulate emissions, the available controls are all approximately equal.

- Pulse jet fabric filter
- FGF

- WGS
- ESP

Fabric filters have the highest efficiency but are designed only to control particulate emissions. Because of their high efficiency, they suffer from a problem other control options do not have. Catalytic coke burn-off can be extremely sticky, and the fabric in these baghouses can easily become fouled and lead to blown bags. Higher cost bags can avoid this problem, but this application leads to higher operating costs.

The FGF option has a control efficiency nearly as high as a well maintained pulse jet fabric filter. While the installation cost is higher than that of a fabric filter, BWO evaluated this option primarily through negotiations with EPA over its consent decree. The consent decree AO was issued May 18, 2015, and the FGF was installed in the early spring of 2016. Subsequent testing conducted during 2016 has shown a reduction in particulate emissions of approximately 98%.

Both the fabric filter and FGF control only the filterable fraction of particulate emissions,

While the WGS system has the added benefit of removing condensable particulates, it is primarily designed as a control device for removal of SO₂ emissions. Installation and operation of a WGS is also far more expensive than any of the other options. Wet scrubbing inherently involves water treatment and disposal/discharge, which must be included in the operating cost. WGS has an additional benefit over both of the above options in that it also controls the condensable fraction of particulate emissions – which can often be significantly larger than the filterable fraction.

Use of a high efficiency ESP is the typical default option. Holly used an ESP prior to the installation of the WGS system, and the nearby Chevron refinery still employs an ESP as the final particulate control system.

8.1.4 Further Evaluation of Most Effective Controls

Should Holly have chosen to use a FGF or fabric filter control, emissions of 0.2 lb/1000 lb of coke burned are possible, although these values are filterable particulate only. WGS is slightly less efficient, with reported values of 0.3-0.5 lb/1000 lb coke burned. The default ESP option is typically limited to 0.5-0.7 lb/1000 lb coke burned, although this meets the various requirements of both the moderate PM_{2.5} SIP as well as the emission limitations of 40 CFR 63 Subpart UUU and 40 CFR 60 Subpart Ja (limits are 1.0 lb/1000 lb coke burned). Holly did not provide an economic analysis of the various controls, as it has already elected to install WGS as a control system on both FCCUs.

Switching away from WGS to utilize FGF or fabric filtration would not provide better emission control (although some decrease in filterable emissions would be possible, condensable emissions would increase and the added benefit provided by WGS in control of additional pollutants would be lost. In addition, switching control technology would automatically be economically infeasible.

8.1.5 Selection of BACT Controls

UDAQ recommends that Holly continue to use the WGS system to control emissions of particulate from the FCCU catalyst regenerator.

8.2 SO₂

8.2.1 Available Control Technology

There exist several options for removing sulfur from FCCUs:

- Feed hydrotreating removes the sulfur from FCCU feedstocks prior to cracking operations.
- SO_x removing (deSO_x) catalyst injection prevents the sulfur from forming in the coke so it isn't burned off during regeneration forming SO₂.
- WGS allows for normal catalyst use, and then removes the SO₂ from the exhaust gases through wet contact scrubbing.

These options, while not necessarily mutually exclusive, do have impacts on the control options for other pollutants. Feed hydrotreating has some positive benefit on NO_x formation (see section 6.3 below). Using a SO_x reducing catalyst additive creates additional sulfate (condensable PM_{2.5}). The use of WGS prevents the use of fabric filtration for particulate control, but allows for the use of LoTO_x, a NO_x control option.

8.2.2 Evaluation of Technical Feasibility of Available Controls

All of the listed controls are technically feasible. Currently Holly uses a combination of feed hydrotreating and WGS for SO₂ control, which represents the baseline case for this refinery (see section 8.0 above for details).

8.2.3 Evaluation and Ranking of Technically Feasible Controls

Some combining of control options is possible. Feed hydrotreating and deSO_x catalysts can be used in combination. WGS systems do not gain any additional benefit when combined with either of the other two control methods.

The use of WGS technology can achieve the limits required by Subpart Ja: 50/25 ppmv (7-day/annual). As noted above in the summary for particulate control, WGS is a far more expensive option than either feed hydrotreating or deSO_x catalyst. It also has the added disadvantage of water waste treatment and/or disposal.

The use of SO_x reducing catalyst, can also meet the Subpart Ja limits. The known disadvantage of sulfate formation can be treated with effective particulate control systems.

Feed hydrotreating has also been demonstrated to meet the Subpart Ja limits. While Holly uses feed hydrotreating, this is done for refinery processing purposes rather than its effects on emission control.

As all three control options are viable, and have been deemed equally effective at reaching the required limits under Subpart Ja – further evaluation is required.

8.2.4 Further Evaluation of Most Effective Controls

Holly did not submit an economic analysis for any of these control options. However, since all three control options have similar control efficiencies and Holly has already chosen to install a WGS, no additional analysis is required.

8.2.5 Selection of BACT Controls

UDAQ recommends that Holly continue to use feed hydrotreating and WGS as needed to meet the Subpart Ja FCCU SO₂ limits. These limits have already been established in Section IX, Part H.11.g of the SIP. Monitoring, recordkeeping and reporting requirements are included as well. As a refinery, Holly has a daily limitation on total plantwide SO₂ emissions which include emissions from the FCCU catalyst regenerator. These limits are as follows:

No later than January 1, 2019, the emission of SO₂ from all emission points (excluding routine SRU turnaround maintenance emissions) shall not exceed 110.3 tons per rolling 12- month period and 0.31 tons per day (tpd).

8.3 NO_x

8.3.1 Available Control Technology

The available options for control of NO_x from FCCUs are listed below:

- Low-NO_x promoter catalysts
- Selective non-catalytic reduction (SNCR)
- Selective catalytic reduction (SCR)
- Feed hydrotreating
- LoTO_x in conjunction with WGS

Low-NO_x promoter catalysts and NO_x reducing additives (as found in another BACT analysis) can be considered the same technology for purposes of this review. Both are catalytic additives (meaning they are not consumed in the process) although they serve slightly different purposes. The promoter catalysts specifically serve as FCC catalysts – providing sites for the cracking of long chain hydrocarbon molecules into shorter ones, but helping prevent the formation of NO_x during the regeneration phase. The additives are supposed to prevent nitrogen from being trapped in the coke in the first place so that there is less “fuel-bound” nitrogen to form NO_x during the regeneration process.

8.3.2 Evaluation of Technical Feasibility of BACT Controls

All control options are technically feasible.

Although LoTO_x requires that a WGS system is simultaneously in use, this does not invalidate its technical feasibility.

Holly, and to some degree the other refineries as well, has extensively investigated the use of NO_x reducing additives and determined that they had no effect on NO_x emissions. Low-NO_x promoter catalysts are useful, and so only the promoter catalysts will be evaluated further.

The use of SNCR or direct ammonia injection into the FCCU regenerator exhaust cannot be used in conjunction with the WGS/LoTO_x system because of the rapid cooling provided by the WGS. The use of SCR would also be severely hampered by a WGS/LoTO_x system for much the same reason, although the injection of the ammonia would likely not harm the functionality of the WGS or LoTO_x systems.

8.3.3 Evaluation and Ranking of Technically Feasible Controls

None of the refineries provided detailed analysis for the evaluation of SNCR beyond stating that no ammonia injection into the FCCU was occurring. Expected control efficiencies would be rather low, based on residence time, exhaust temperatures, and overall emission reductions of SNCR-based systems.

The remaining options of feed hydrotreating, SCR, and WGS with LoTOx are all approximately equal in terms of overall control effectiveness.

8.3.4 Further Evaluation of Most Effective Controls

SCR has an additional drawback in the form of ammonia slip. In order to control NOx, ammonia is injected to reduce the NOx to N₂ and water. Ideally, a stoichiometric amount of ammonia would be added – just enough to fully reduce the amount of NOx present in the exhaust stream. However, some amount of ammonia will always pass through the process unreacted; and since the process possesses some degree of variability, a small amount of additional ammonia is added to account for minor fluctuations. The ammonia which passes through the process unreacted and exits in the exhaust stream is termed “slip” (sometimes “ammonia slip”). The amount varies from facility to facility, but ranges from almost zero to as high as 30 ppm in poorly controlled systems. In the case of SCR systems, the catalyst also degrades over time, and the degree of slip will gradually increase as increasing amounts of ammonia are needed to maintain NOx reduction performance.

WGS systems, with or without LoTOx, generate wastewater which must be treated before discharge or stored before disposal. Systems with LoTOx either have an acidic wastewater (nitric acid generated by N₂O₅ in the aqueous phase), or one with soluble solids from neutralization of that acid.

8.3.5 Selection of BACT Controls

UDAQ does not recommend any additional controls be installed. Holly should continue to meet the rolling 365-day limit on NOx emissions from the FCCU using WGS with LoTOx. As this limit has too long an averaging time, it does not serve as a limitation suitable for inclusion in SIP which is making adjustments on a 24-hour-based standard. However, the FCCU is a combustion source and is therefore included in Holly’s existing daily cap on NOx emissions. This would serve as a work practice standard and would not need to be included as an additional limitation.

8.4 VOC and Ammonia Considerations

UDAQ was unable to locate any additional controls to reduce emissions of VOCs from the FCCU regenerators. In 2016, Holly’s listed VOC emissions from these units were 0 tons. Holly has not tested the emissions from this emitting unit, and thus UDAQ is unable to comment. However, in a review of other refineries, no viable add-on control device or technique was found to further reduce the emissions of VOCs from FCC catalyst regenerators. Typical VOC reduction controls such as thermal or catalytic oxidation require relatively high VOC concentrations and often additional heat input in the form of fuel burning (negating the controls already achieved for other pollutants). Control techniques such as fuel switching are negated by the nature of the process – the catalytic coke must be removed to continue the cracking process in the FCCU. The only remaining technique is simply good combustion practices, which is already required by the other control systems already in place. No additional consideration is required.

There are two possible mechanisms for ammonia emissions from the FCCU regenerator. Most refineries emit some amount of ammonia from the coke burn-off process itself, as trapped ammonia salts present in the coke are released during the regeneration process. These emissions are typically relatively small. The second mechanism is the injection of ammonia for control of NOx emissions using either SCR or SNCR as a control process. The injection of ammonia is fairly common among refineries in the U.S., but does not occur among the refineries in Utah. None of the refineries located in the Salt Lake City PM2.5 NAA uses ammonia injection for NOx control.

Therefore, UDAQ recommends that no additional BACT limitations be required for these two pollutants.

9.0 BACT for Fugitives

In this context, fugitives are referring to fugitive VOC emissions. While Holly does have fugitive dust emissions from items such as roads, spill containment berms, and similar earthworks – particulate emissions from these items have been evaluated separately. Please refer to the PM2.5 Serious SIP - BACT for Small Sources – Section 12 for the evaluation.

Fugitive VOC emissions are those emissions that result from the various pipe connections; feedstock, intermediary, and product transfer activities; loading and unloading operations; and any and all equipment leaks. They do not typically include the VOC emissions from storage vessels (storage tanks), cooling towers, or wastewater treatment.

9.1 VOCs

9.1.1 Available Control Technology

The only available control option is the low-leak LDAR program as outlined in 40 CFR 60 Subpart VVa and incorporated by reference (with some source category modifications) in 40 CFR 60 Subpart GGGa. Each refinery (including Holly) became subject to the requirements of low-leak LDAR (Subpart GGGa) as part of the requirements of the moderate PM2.5 SIP.

9.1.2 Evaluation of Technical Feasibility of Available Controls

N/A Low-leak LDAR is technically feasible, and Holly became subject to its requirements on January 1, 2017.

9.1.3 Evaluation and Ranking of Technically Feasible Controls

N/A Holly is already implementing the requirements of 40 CFR 60 Subpart GGGa.

9.1.4 Further Evaluation of Most Effective Controls

N/A Holly is already implementing the requirements of 40 CFR 60 Subpart GGGa.

9.1.5 Selection of RACT Controls

UDAQ recommends that Holly continue to implement the general refinery SIP requirements regarding Leak Detection and Repair as outlined in Section IX, Part H.11.g.

10.0 BACT for Tanks

Although most of UDAQ's analysis of storage vessels, more commonly referred to as storage tanks (or just "tanks"), can be found in the BACT analysis for Small Sources – Section 13, the refineries as a group were evaluated for two additional BACT controls beyond the small source controls. First, the refineries have some tanks that are larger than the 30,000 gallon cut-off used in the small source analysis. Second, during development of the moderate PM2.5 SIP, the refineries were required to implement a tank degassing work practice standard.

10.1 VOC

10.1.1 Available Control Technology

Although tanks as a group were evaluated for tank degassing, individual tanks were not evaluated for working or breathing losses. While some VOCs are emitted during these periods, these can only be controlled on a tank by tank basis. Larger tanks are already subject to floating roof and specific seal requirements such as those found in 40 CFR 60 Subpart Kb.

Some additional VOC reductions could be gained by including slotted guide poles and geodesic domes, but these gains are relatively minor. In the case of slotted guide poles, such requirements are more easily handled through individual permitting requirements. Individual tanks can also be controlled by vapor recovery, vapor scrubbers, or vapor combustors. Geodesic domes have not been found to be economically or technically feasible.

10.1.2 Evaluation of Technical Feasibility of Available Controls

The use of slotted guide poles and vapor controls are technically both technically feasible. Tank degassing as a group control is also technically feasible, and was included as a requirement of the moderate PM2.5 SIP.

10.1.3 Evaluation and Ranking of Technically Feasible Controls

Tank degassing was required as of the moderate PM2.5 SIP. The remaining controls can be employed in conjunction with tank degassing. The various methods of vapor control (recovery, scrubbing, and combustion) are all similar in effectiveness and are employed primarily on a tank by tank basis. While some economy of scale could conceivably be achieved by combining the emissions from several tanks, tank vapors are primarily released during filling or unloading, and nearby tanks are rarely loaded or unloaded at the same time.

10.1.4 Further Evaluation of Most Effective Controls

Holly is already required to follow the tank degassing requirements of Section IX, Part H.11.g. The remaining vapor controls were all evaluated by Holly and were found not be economically feasible, with cost effectiveness values in excess of \$200,000/ton of VOC control.

10.1.5 Selection of BACT Controls

UDAQ recommends that Holly continue to implement the SIP general refinery requirements on tank degassing as outlined in Section IX, Part H.11.g.

11.0 BACT for Wastewater System

11.1 VOC

The wastewater treatment system at Holly consists primarily of a system of drains that route runoff water and stormwater to an American Petroleum Institute (API) Separator unit, which separates entrained oils and volatiles from the wastewater. From there the effluent wastewater is further treated with dissolved gas floatation and moving bed bio-film reactors. Holly also further treats the exhaust air from the system with carbon absorption.

11.1.1 Available Control Technology

Because of Holly's existing control system at the wastewater treatment plant, there are few available control options other than the baseline case. Essentially, the other control options are all alternatives to the existing controls. Holly currently uses carbon absorption as the primary control option. Alternatively, the use of regenerative thermal oxidation (RTO), non-regenerative thermal oxidation (flaring), or vapor recovery (refrigeration or alternative method), are all potentially available methods of controlling the recovered vapors.

11.1.2 Evaluation of Technical Feasibility of Available Controls

For destruction/control of the collected vapors, only the use of a RTO, carbon canisters, or flaring have been shown to be technically feasible control methods based on the volume of expected VOC emissions (approximately 10 tons VOC/year).

11.1.3 Evaluation and Ranking of Technically Feasible Controls

The various control options are all approximately equal in terms of overall capture and control efficiency – although the use of thermal destruction (either RTO or flaring) is slightly better than carbon canisters in terms of overall efficiency. The carbon canisters eventually become saturated, allowing for some VOC bleed through until the canister is replaced.

11.1.4 Further Evaluation of Most Effective Controls

Holly did not conduct an economic analysis of the available control options. Instead Holly focused primarily on the regulatory requirements that apply to wastewater systems at refineries. 40 CFR 60 Subpart QQQ, 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC are all applicable to refinery wastewater treatment plants. These three regulations are all similar and require closed drain systems and a control device for the main collection system.

11.1.5 Selection of BACT Controls

UDAQ recommends that Holly continue to operate the existing wastewater control system of API and carbon absorption as BACT for the wastewater treatment plant.

12.0 BACT for Loading/Unloading

Holly submitted an analysis for product loading and unloading operations. UDAQ has covered the analysis of loading and unloading operations in two different locations. For fugitive VOC emissions please refer to Section 9.0 of this document for further details. For more direct VOC emissions from loading/unloading operations please refer to the PM2.5 Serious SIP - BACT for Small Sources – Section 13B for additional details.

12.1 VOC

Loading and unloading operations are a source of VOC emissions. Although Stage I and II vapor recovery have already been covered in UDAQ's PM2.5 Serious SIP - BACT for Small Sources analysis, one additional VOC control option in common use at refinery loading racks is a vapor combustion unit or carbon capture system to treat the recovered VOC vapors.

12.1.1 Available Control Technology

Once vapors have been recovered from loading/unloading operations, the recovered vapors need to be treated. While some vapor recovery units (VRUs) can return the recovered vapors back into the system being controlled (depending on the system), some units require external treatment for final control. The use of regenerative thermal oxidation (RTO), non-regenerative thermal oxidation (flaring), or carbon capture via carbon canisters are all potentially available methods of controlling the recovered vapors.

12.1.2 Evaluation of Technical Feasibility of Available Controls

For destruction/control of the collected vapors, only the use of a RTO, carbon canisters, or flaring have been shown to be technically feasible control methods based on the volume of expected VOC emissions (typically less than 5 tons VOC/year).

12.1.3 Evaluation and Ranking of Technically Feasible Controls

The various control options are all approximately equal in terms of overall capture and control efficiency – although the use of thermal destruction (either RTO or flaring) is slightly better than carbon canisters in terms of overall efficiency. The carbon canisters eventually become saturated, allowing for some VOC bleed through until the canister is replaced.

12.1.4 Further Evaluation of Most Effective Controls

Holly conducted an economic analysis of installing and operating a RTO for loading/unloading operations. Based on expected annual emissions of 3.5 tons of VOC (based on Holly's 2016 baseline emissions) and an annualized cost of \$175,000 for this system, Holly concluded that use of an RTO was not economically viable. Holly also determined that flaring of the VOC emissions would be viewed as installation of a new hydrocarbon flare and therefore subject to the flaring provisions of IX.H.11.g. UDAQ confirmed this assessment and agreed that flaring was not a viable solution. The use of carbon canisters is potentially viable, but Holly has opted to continue to operate with vapor balancing, and submerged or bottom filling for control of VOCs from product loading.

12.1.5 Selection of BACT Controls

UDAQ recommends that Holly continue to control product loading and unloading operations using existing work practice standards (submerged/bottom filling and vapor balancing) as BACT.

13.0 BACT for Diesel- and Natural Gas-fired Emergency Engines

Holly submitted an analysis for both diesel and natural gas-fired emergency engines. The largest of these engines are a 540 hp diesel-fired standby generator and a pair of 142 kW natural gas-

fired emergency engines. UDAQ has covered the analysis of both diesel-fired and natural gas fired emergency engines in a separate document. Please refer to the PM2.5 Serious SIP - BACT for Small Sources – Section 8 for additional details.

14.0 Additional Ammonia Considerations

Holly has direct ammonia emissions beyond the ammonia slip from SCR control systems. Sour water containing ammonia is drained from process vessels throughout the refinery into an enclosed drain system which is then piped into Storage Tank 166. The sour water is then pumped to the sour water stripper where steam is used to strip the ammonia from the sour water. The ammonia vapors are then sent to the ammonia stripping unit.

14.1 Ammonia (NH₃)

14.1.1 Available Control Technology

The only add-on control system found to reduce ammonia emissions is the use of a WGS – specifically the packed tower style of wet scrubber. Venturi style scrubbers have not been shown effective. Condensers can convert ammonia vapors into a liquid which can then be removed through liquid disposal.

14.1.2 Evaluation of Technical Feasibility of Available Controls

The ammonia vapors from the sour water stripper are mixed with water in the ammonia stripping unit forming ammonia liquid. No add-on controls are considered technically feasible for further control, as this liquid is not primarily in the vapor phase. The ammonia liquid is stored in horizontal, high-pressure, storage vessels (Tanks 124 and 125) with no anticipated emissions.

14.1.3 Evaluation and Ranking of Technically Feasible Controls

Some ammonia emissions from the sour water stripper and ammonia stripper are inevitable and cannot be captured or collected. Efficiency concerns make the use of additional condensers or WGS non-viable from both a technical and economic basis. Only best management practices and good general maintenance are effective controls for these emissions.

14.1.4 Further Evaluation of Most Effective Controls

As no additional controls have been shown to be feasible, no additional analysis is required.

14.1.5 Selection of BACT Controls

UDAQ recommends that Holly continue to use the existing sour water stripper and ammonia stripper units to reduce ammonia emissions from the refinery. Best management practices and proper maintenance shall be considered BACT for these units. No additional limitations or requirements are necessary.

15.0 Additional Feasible Measures and Most Stringent Measures

15.1 Extension of SIP Analysis Timeframe

As outlined in 40 CFR 51.1003(b)(2)(iii):

If the state(s) submits to the EPA a request for a Serious area attainment date extension simultaneous with the Serious area attainment plan due under paragraph (b)(1) of this section, such a plan shall meet the most stringent measure (MSM) requirements set forth at § 51.1010(b) in addition to the BACM and BACT and additional feasible measure requirements set forth at § 51.1010(a).

Thus, with the potential for an extension of the SIP regulatory attainment date from December 31, 2019 to December 31, 2024, the SIP must consider the application of both Additional Feasible Measures (AFM) and Most Stringent Measures (MSM).

15.2 Additional Feasible Measures at Holly

As defined in Subpart Z, AFM is any control measure that otherwise meets the definition of “best available control measure” (BACM) but can only be implemented in whole or in part beginning 4 years after the date of reclassification of an area as Serious and no later than the statutory attainment date for the area. The Salt Lake City Nonattainment Area was reclassified as Serious on June 9, 2017. Therefore, any viable control measures that could only be implemented in whole or in part beginning 6/9/2021 (4 years after the date of reclassification) are classified as AFM.

After a review of the available control measures described throughout this evaluation report, UDAQ was unable to identify any additional control measures that were eliminated from BACT consideration due to extended construction or implementation periods.

15.3 Most Stringent Measures at Holly

As defined in Subpart Z, MSM is defined as:

... any permanent and enforceable control measure that achieves the most stringent emissions reductions in direct PM_{2.5} emissions and/or emissions of PM_{2.5} plan precursors from among those control measures which are either included in the SIP for any other NAAQS, or have been achieved in practice in any state, and that can feasibly be implemented in the relevant PM_{2.5} NAAQS nonattainment area.

This is further refined and clarified in 40 CFR 51.1010(b), to include the following Steps:

- Step 1) The state shall identify the most stringent measures for reducing direct PM_{2.5} and PM_{2.5} plan precursors adopted into any SIP or used in practice to control emissions in any state.
- Step 2) The state shall reconsider and reassess any measures previously rejected by the state during the development of any previous Moderate area or Serious area attainment plan control strategy for the area.
- Step 3) The state may make a demonstration that a measure identified is not technologically or economically feasible to implement in whole or in part by 5 years after the applicable attainment date for the area, and may eliminate such whole or partial measure from further consideration.
- Step 4) Except as provided in Step 3), the state shall adopt and implement all control measures identified under Steps 1) and 2) that collectively shall achieve attainment as expeditiously as practicable, but no later than 5 years after the applicable attainment date for the area.

15.3.1 Step 1 – Identification of MSM

For purposes of this evaluation report UDAQ has identified for consideration the most stringent methods of control for each emission unit and pollutant of concern (PM_{2.5} or PM_{2.5} precursor). A summary is provided in the following table:

Table 15-1: Most Stringent Controls by Emission Unit

Emission Unit	Pollutant	Most Stringent Control Method
FCCU Regenerator	PM _{2.5}	GCP, fuel type, flue gas filter (FGF) / wet gas scrubber (WGS)
	SO ₂	DeSO _x catalyst, WGS
	NO _x	GCP, WGS-LoTO _x
Heaters/Boilers	NO _x	ULNB, SCR
	Ammonia	only if SCR is used, feedback controls
Flares	Flare Gas	flare minimization program
SRU	SO ₂	second tail gas treatment unit (TGTU), WGS
	NO _x	WGS
Cooling Towers	VOC	MACT CC requirements
Fugitives	VOC	NSPS GGGa LDAR requirements
Tanks	VOC	tank degassing requirements
Wastewater Treatment	VOC	IAF/API separator; with carbon canister control / oxidation

The above listed controls represent the most stringent level of control identified from all other state SIPs or permitting actions, but do not necessarily represent the final choice of MSM. That is determined in Step 4.

15.3.2 Step 2 – Reconsideration of Previous SIP Measures

Utah has previously issued a SIP to address the moderate PM_{2.5} nonattainment areas of Logan, Salt Lake City, and Provo. The SIP was issued in parts: with the section devoted to the Logan nonattainment area being found at SIP Section IX.A.23, Salt Lake City at Section IX.A.21, and Provo/Orem at Section IX.A.22. Finally, the Emission Limits and Operating Practices for Large Stationary Sources, which includes the application of RACT at those sources, can be found in the SIP at Section IX Part H. Limits and practices specific to PM_{2.5} may be found in subsections 11, 12, and 13 of Part H.

Accompanying Section IX Part H was a Technical Support Document (TSD) that included multiple evaluation reports similar to this document for each large stationary source identified and listed in each nonattainment area. UDAQ conducted a review of those measures included in each previous evaluation report which contained emitting units which were at all similar to those installed and operating at Holly.

There were several technologies that had been eliminated from further consideration at some point during many of the previous reviews. Some emitting units were considered too small, or emissions too insignificant to merit further consideration at that time. The cost effectiveness considerations may have been set at too low a threshold (a question of cost in RACT versus BACT). And many cases of technology being technically infeasible for application – such as applying catalyst controls to infrequently used emitting units which may never reach an operating temperature where use of the catalyst becomes viable and effective.

In one particular case, these previously rejected control technologies were already brought forward and re-evaluated using updated information (more recent permits, emission rates and cost

information) by Holly in its BACT analysis report. This was the deferment of VOC controls for the wastewater treatment systems at four Salt Lake City area refineries. Holly did include an analysis of the wastewater treatment system, and took into account previous steps (such as the API and carbon absorption) previously undertaken to reduce emissions. This updated analysis has been reviewed as part of the UDAQ BACT review in Section 11 above.

15.3.3 Step 3 – Demonstration of Feasibility

A control technology or control strategy can be eliminated as MSM if the state demonstrates that it is either technically or economically infeasible.

This demonstration of infeasibility must adhere to the criteria outlined under §51.1010(b)(3), in summary:

- 1) When evaluating technological feasibility, the state may consider factors including but not limited to a source's processes and operating procedures, raw materials, plant layout, and potential environmental or energy impacts
- 2) When evaluating the economic feasibility of a potential control measure, the state may consider capital costs, operating and maintenance costs, and cost effectiveness of the measure.
- 3) The SIP shall include a detailed written justification for the elimination of any potential control measure on the basis of technological or economic infeasibility.

This evaluation report serves as written justification of technological or economic feasibility/infeasibility for each control measure outlined herein. Where applicable, the most effective control option was selected, unless specifically eliminated for technological or economical infeasibility. Expanding on the previous table, the following additional information is provided:

Table 15-2: Feasibility Determination

Emission Unit	Pollutant	MSM Previously Identified	Is Method Feasible?
FCCU Regenerator	PM2.5	GCP, fuel type, FGF/WGS	See below
	SO2	deSOx catalyst, WGS	See below
	NOx	GCP, WGS-LoTOx	See below
Heaters/Boilers	NOx	ULNB, SCR	See below
	Ammonia	NH3 feedback	See below
Flares	Flare Gas	flare minimization program	Yes
SRU	SO2	TGTU or WGS	No, high cost
	NOx	WGS-LoTOx	No, high cost
Cooling Towers	VOC	MACT CC	Yes
Fugitives	VOC	LDAR	Yes
Tanks	VOC	tank degassing	Yes
WW Treatment	VOC	carbon canister / oxidation	Yes, see below

Most of the entries in the above table were determined to be feasible on a technological basis. However, in several cases two distinct paths exist that are mutually exclusive. Two control techniques could serve equally as BACT/BACM or MSM, but they are not simply interchangeable. Once a source has elected to follow a particular path for emission control, needing to change over to the alternative control path would involve considerable expense as well as complete removal of the existing system(s). In many cases this would also involve shutting

down operation of the source for an extended period of time – posing additional economic burden on the source.

One particular example of this is the application of WGS. Wet gas scrubbing has the capability of removing both particulates and acid gases (SO₂ and derivatives) and, if the LoTOx option has been pursued, NO_x as well. However, this control system is not compatible with other control systems such as fabric filtration (baghouses or FGF), catalytic controls (SCR), or tail gas treatment (as these are also catalytic controls). Holly has chosen the WGS solution for primary control of both the SRU and FCCUs at the refinery. This control choice has effectively eliminated the option of installing a TGTU on the SRU, or installing an alternate form of particulate control on the FCCUs.

16.0 New PM_{2.5} SIP – General Refinery Requirements

The new maintenance plan will incorporate several new requirements that apply specifically to those petroleum refineries listed in Section IX.H.12 of the SIP. Some subsections of IX.H.11.g also apply more broadly and could affect additional petroleum refineries in addition to those listed in IX.H.12. Where this greater applicability exists for a particular condition or limitation, such will be noted in the discussion for that requirement.

IX.H.11.g.i.A This condition covers SO₂ emissions from fluidized catalytic cracking units (FCCUs). The limit is 50 ppmvd @ 0% excess air on a 7-day rolling average basis, as well as 25 ppmvd @ 0% excess air on a 365-day rolling average basis.

The condition is based on 40 CFR 60 Subpart Ja, and includes the same limitation found in that subpart. Compliance is demonstrated by CEM, as outlined in 40 CFR 60.105a(g) – also from Subpart Ja.

IX.H.11.g.i.B This condition addresses PM emissions from FCCUs. The limit is 1.0 lb PM per 1000 lb coke burned. The emission limit applies on a 3-hour average basis.

The emission limit is derived from 40 CFR 60 Subpart Ja, although Subpart Ja does not specifically state that the limit applies on a 3-hour average. Instead it states that compliance will be demonstrated via a performance test using Method 5, 5b or 5f, using an average of three 60-minute (minimum) test runs.

Compliance is demonstrated by stack test as outlined in 40 CFR 60.106(b). This stack testing procedure is from Subpart J, rather than Subpart Ja. The equations utilized and reference methods involved are identical between the two subparts; however, the protocol to follow for testing is much more direct and straightforward in §60.106(b).

The condition also requires the installation of a continuous parameter monitoring system (CPMS) to monitor and record operating parameters for determination of source-wide PM₁₀ emissions for inclusion in the 24-hour PM_{2.5} Cap (see the individual source specific requirements of IX.H.12 for details on these Caps).

IX.H.11.g.ii This condition limits the H₂S content of gases burned within any refinery located within (or affecting) an area of PM_{2.5} nonattainment. The limit is 60 ppm H₂S or less as described in 40 CFR 60.102a on a rolling average of 365 days.

As the PM_{2.5} nonattainment areas encompasses the entirety of the PM₁₀ maintenance areas this

condition potentially affects more than just the four refineries listed in IX.H.12. There is at least one minor source refinery (Silver Eagle Refinery) which is affected by this requirement. The Silver Eagle Refinery was previously listed in the original PM10 SIP as Crysen Refining, Inc., but was delisted as the source is no longer a major source.

Compliance is demonstrated through continuous H₂S monitoring, as outlined in 40 CFR 60.107a. Both the limitation and the compliance methodology are based on 40 CFR 60 Subpart Ja.

IX.H.11.g.iii This condition places limits on heat exchangers in VOC service.

The condition requires that all heat exchangers in VOC service meet the requirements of 40 CFR 63.654, which requires use of the “Modified El Paso Method” for calculation of VOC emissions. Sources are allowed an option to use another EPA-approved method if allowed by the Director. An exemption is also given for heat exchangers that meet specific criteria that are outlined within the condition language.

IX.H.11.g.iv Leak Detection and Repair Requirements.

This condition subjects each source to the requirements of 40 CFR 60 Subpart GGGa – also known as Enhanced LDAR. The Sustainable Skip Period provisions of that subpart have also been retained.

IX.H.11.g.v This condition establishes new requirements on hydrocarbon flares.

First, it states that all hydrocarbon flares (defined as all non-dedicated SRU flare and header systems and all non-HF flare and header systems) are subject to Subpart Ja as of January 1, 2018 if not previously subject.

Second it requires that each major source refinery either: 1) install a flare gas recovery system designed to limit hydrocarbon flaring from each affected flare during normal operations below the values listed in Subpart Ja (specifically 40 CFR 60.103a(c)), or 2) limit flaring during normal operations to 500,000 scfd or less for each affected flare.

This requirement is based on Subpart Ja, and is designed to incorporate the flare gas recovery requirements of that subpart ahead of the normal implementation schedule. The refineries located in, or impacting, the nonattainment areas are relatively small. As a consequence, the possibility that they would trigger the flare gas recovery provisions of Subpart Ja in the near term (5-10 years) was very small. Although one of the refineries had elected to install a flare gas recovery system voluntarily, the system only addressed a part of the refinery’s total flaring capacity, and was not originally designed to Subpart Ja specifications.

IX.H.11.g.vi This condition requires that vapor control devices be employed during tank degassing operations. Some provisions are made for connecting and disconnecting degassing equipment. Notification must also be made to the Director prior to performing such an operation – unless an emergency situation is at play.

This condition applies to sources beyond just refineries – any owner/operator of any stationary tank meeting the outlined criteria must fulfill the requirements of this condition.

IX.H.11.g.vii No Burning of Liquid Fuel Oil in Stationary Sources – Establishes that no petroleum refineries in or affecting any PM nonattainment or maintenance area shall be allowed to burn liquid fuel oil in stationary sources except during natural gas curtailments or as specified in the individual subsections of Section IX, Part H. The use of diesel fuel meeting the specifications of 40 CFR 80.510 in standby or emergency equipment is exempt from this requirement.

This requirement addresses a provision of the original PM10 SIP, which prevented the refineries from burning liquid fuel oil in any capacity – including in emergency or standby equipment. This brings forward the original intent, maintains consistency with the PM10 maintenance plan provisions of IX.H.1.g, and addresses the problem of emergency and standby equipment.

IX.H.11.g.viii This is a placeholder provision, inserted in anticipation of future requirements for Tier III fuels. As it is unknown at this time whether the need to produce Tier III fuels will require addition emissions (in the form of emission offset credits or not), this placeholder provision has been included to allow for such future expansion.

16.1 Monitoring, Recordkeeping and Reporting

The new petroleum refinery requirements establish several specific emission limitations. Primarily these limits are monitored continuously – such as the SO₂ CEM on the FCCU or the H₂S monitor on fuel gas. Where continuous monitoring is used, the requirements of IX.H.11.f apply, which incorporates by reference R307-170, 40 CFR 60.13 and 40 CFR 60, Appendix B – Performance Specifications.

Under R307-170, paragraph 170-8 addresses Recordkeeping, while 170-9 addresses Reporting.

The FCCU PM limit is demonstrated by stack test. This stack test requirement is subject to the requirements of IX.H.11.e. In addition, any source with a direct stack emission limitation is subject to the requirements of R307-165.

These conditions are also subject to the general recordkeeping and reporting requirements of IX.H.11.c.

16.2 Discussion of Attainment Demonstration

PM Discussion: While the new PM limit on the FCCU might not appear to directly affect PM_{2.5} emissions, this would be incorrect. The limit is derived from the current NSPS (Subpart Ja). Under the NSPS, the assumption was that all particulate captured in the reference test method (Method 5, 5b or 5f) would be considered as PM_{2.5}. This is still the case, as compliance with the PM limit at the FCCU shall be demonstrated by stack test. Using a method 5 variant stack test allows the test to be overly conservative, as some particulate captured may fall outside the PM_{2.5} size range, and still be useful for SIP planning purposes. At the same time, it lowers the regulatory burden on the sources, by allowing each source to only have to comply with the requirements of the individual NSPS. The limit is expressed on a 3-hour block average, well below the 24-hour basis of the PM_{2.5} standard. Stack tests are required every three (3) years, which meets the minimum stack test frequency set by DAQ. Compliance is demonstrated via monitoring and use of emission factors. Stack testing serves to periodically adjust emission factors to account for significant changes in feedstocks, refinery turnarounds, or other large-scale changes that would affect the emission factor. As allowed under R307-165-2, the Director may

require stack testing at any time to demonstrate compliance.

SO₂ Discussion: This is a new limitation that did not previously appear in any form in the original PM₁₀ SIP. Although the limit is expressed on a 7-day rolling average basis, and therefore longer than the 24-hour PM_{2.5} standard, SO₂ emissions are eventually converted into sulfates – the particulate form. As this process takes some time to occur, and is not directly dependent on hourly or daily SO₂ emissions – but rather on area average SO₂ concentrations and relative chemistry – a 7-day rolling average is quite adequate to demonstrate attainment with the standard. This is especially true, given the overall daily SIP Cap – which still controls total SO₂ emissions from the entire refinery. The secondary limit, expressed on a 365-day basis simply serves to keep SO₂ emissions down over the long run, as well as maintaining consistency with the PM_{2.5} SIP requirements.

H₂S Discussion: Although the limit appears to be on a much longer averaging period than the 24-hour PM_{2.5} standard, the rolling 365-day calculation prevents the overall H₂S content from increasing. This in turn keeps the amount of sulfur being sent to each fuel burning device consistently low. This is also a fallback limit, like the SO₂ emissions from the FCCU discussed in the previous paragraph. Total SO₂ emissions are still controlled by the daily SIP Cap, regardless of the averaging period on fuel gas H₂S content.

17.0 New Maintenance Plan – Holly Specific Requirements

The Holly specific conditions in Section IX.H.12 address those limitations and requirements that apply only to the Holly Refinery in particular.

IX.H.12.e.i This condition establishes a source-wide Cap on PM_{2.5} emissions on a ton per day and ton per rolling 12-month period basis. Emissions are to be calculated on a filterable plus condensable basis from all sources, each day. These limits are 47.6 tons per rolling 12-month period and 0.134 tons per day.

The condition also includes the definition of a day as being from midnight until the following midnight. Compliance shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.12.e.ii This condition establishes a source-wide Cap on NO_x emissions on a ton per day and ton per rolling 12-month period basis. Emissions are to be calculated from all emission points daily. These limits are 347.1 tons per rolling 12-month period and 2.09 tons per day.

This condition includes the same definition of “day” as being from midnight until the following midnight. Compliance shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.12.e.iii This condition establishes a source-wide Cap on SO₂ emissions on a ton per day and ton per rolling 12-month period basis. Emissions are to be calculated from all

emission points daily. These limits are 110.3 tons per rolling 12-month period and 0.31 tons per day.

This condition includes the same definition of “day” as both of the previous conditions as being from midnight until the following midnight. Compliance shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.12.e.iv This condition addresses specific fuel sulfur requirements for the refinery, allowing the use of diesel-fired emergency equipment as an exception to IX.H.11.g.vii.

Holly currently has a number of small diesel-fired emergency engines listed in its AO. No specific provision has ever been made to allow for the use of diesel-fired emergency equipment at the refineries – and while it is clear that the provisions of the original PM10 SIP were meant for the burning of liquid fuel in heaters and boilers and not for the application of emergency equipment, such language was not included nor brought forward. This condition (and similar conditions for the other refineries) addresses that oversight.

17.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three conditions is addressed through a variety of methods, depending on the emission point in question. Stack testing, CEMs, parameter monitoring – all are viable options, and have been included in the language of IX.H.12.i.i through IX.H.12.i.iii. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H: specifically, 11.e for stack testing, 11.f for CEMs and other continuous monitors, and 11.c for recordkeeping and reporting.

Where necessary, additional monitoring, recordkeeping and/or reporting requirements have been directly included in the language of IX.H.12.i to address specific concerns. One example would be the use of leveling gauges on all fuel oil tanks to determine daily fuel oil consumption.

No specific monitoring, recordkeeping or reporting is required for IX.H.12.i.iv, as this condition serves merely as a specific exception to the general refinery requirement prohibiting the burning of liquid fuel oils. Such exception is authorized under the language of IX.H.11.g.vii itself.

18.0 References

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April 28, 2017

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UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

APR 28 2017

DIVISION OF AIR QUALITY

RE: Best Available Control Measure Analyses for HollyFrontier's Woods Cross Refinery

Dear Mr. Jenks:

Please find enclosed one copy of the report, Best Available Control Measure Analyses for HollyFrontier's Woods Cross Refinery.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call Regina Doyle at HollyFrontier at (801)397-7432 or me at (801) 272-3000 ext. 305.

Sincerely,

MSI TRINITY CONSULTANTS

Linda Conger
Managing Consultant

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UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

APR 28 2017

DIVISION OF AIR QUALITY

**BEST AVAILABLE CONTROL
MEASURE ANALYSES
HOLLYFRONTIER'S
WOODS CROSS REFINERY**

Prepared for:

HollyFrontier Woods Cross Refining LLC
1070 West 500 South
West Bountiful, Utah 84087

By

Meteorological Solutions Inc. a Trinity Consultants Company
Project No. 04171725

April 2017



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Appendices

- A List of Refinery Permitted Equipment
- B Cost Analyses and Vendor Quotes

1.0 INTRODUCTION

In 2006, the United States Environmental Protection Agency (EPA) strengthened the 24-hour PM_{2.5} standard from 65 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) to 35 $\mu\text{g}/\text{m}^3$. As such, all or portions of seven Utah counties failed to meet the new 24-hour PM_{2.5} standard. Ultimately, only three areas of the state (Salt Lake City including Davis County, Logan, and Provo) were designated as nonattainment for the 24-hour PM_{2.5} standard. Once an area is designated as nonattainment, the Clean Air Act requires that fine particle pollution be controlled by a state, a state implementation plan (SIP) detailing how and when the 24-hour PM_{2.5} standard would be met is required to be prepared and submitted to EPA for approval.

The moderate PM_{2.5} nonattainment areas were required to meet the new standard by 2014. However, as the SIP for Salt Lake City was nearing completion, the D.C. Circuit Court of Appeals found that EPA had incorrectly interpreted the Clean Air Act when determining how to implement the National Ambient Air Quality Standards (NAAQS) for PM_{2.5}. The January 4, 2013 court ruling held that the EPA should have implemented the PM_{2.5} NAAQS based on both Clean Air Act (CAA) Subpart 1 and Subpart 4 of Part D, title 1. Previously, EPA had (incorrectly) required states to develop their SIPs based on subpart 1 only. If a moderate PM_{2.5} nonattainment area is not able to attain the 24-hr PM_{2.5} standard by the December 31, 2015 attainment date, Subpart 4 allows EPA to re-classify that area as a serious PM_{2.5} nonattainment area.

As of the December 31, 2015 attainment date, all three of Utah's PM_{2.5} nonattainment areas were found to be exceeding the 24-hour PM_{2.5} standard, and as such, EPA reclassified each of the three areas to serious.

Once re-classified to serious, the attainment date for the area is December 14, 2019. A new serious area PM_{2.5} SIP is being prepared by the Utah Division of Air Quality (UDAQ) and the requirements of such are detailed in 40 Code of Federal Regulations (CFR) 51 Subpart Z. This rule requires the UDAQ to identify, adopt and implement Best Available Control Measures (BACM) on major sources of PM_{2.5} and PM_{2.5} precursors (sulfur dioxide, oxides of nitrogen, volatile organic compounds, and ammonia).

HollyFrontier's Woods Cross Refinery has potential to emit emissions of PM_{2.5} and/or PM_{2.5} precursors above the 70 tons or more per year and is thus classified as a major source which is subject to the implementation rule. As a major source subject to the rule, the UDAQ has requested assistance from HollyFrontier in determining acceptable pollution controls that meet BACM/Best Available Control Technology (BACT) controls.

This document provides a written evaluation of each available control strategy for HollyFrontier PM_{2.5} and precursor emission sources, taking into account technological, energy, environmental and economic feasibility, provides documentation to justify the elimination of any available control option, establishes BACM, and emission monitoring requirements for each emission unit.

2.0 FACILITY OVERVIEW

HollyFrontier Woods Cross Refining, LLC is located at 1070 West 500 South in Woods Cross, Utah. Its Universal Transverse Mercator (UTM) Coordinates for the facility, in NAD27, are 4526.227 kilometers North and 424.00 kilometers East in Zone 12 at an elevation of 4,260 feet above mean sea level. The refinery is located in Davis County which is non-attainment area for PM_{2.5}, maintenance for ozone (O₃) and particulate matter (PM₁₀), and attainment for sulfur dioxide (SO₂), nitrogen oxides (NO_x), volatile organic compounds (VOC), and carbon monoxide (CO). The refinery is located within four miles of Salt Lake County, which is in non-attainment for PM_{2.5}, PM₁₀, and SO₂, and a maintenance area for O₃. The facility is subject to emission limitations and emission caps as found in HollyFrontier approval order (AO) DAQE-AN101230041-13, PM₁₀ State Implementation Plan (SIP), and Consent Decree requirements.

The HollyFrontier Woods Cross Refinery is owned by HollyFrontier Woods Cross Refining, LLC. The Woods Cross Refinery is a 40,000 barrel per day (BPD) refinery permitted up to 60,000 BPD that produces a variety of products including gasoline, natural gas liquids (NGL), propane, butanes, jet fuels, fuel oils, and kerosene products.

The Standard Industrial Code (SIC) for the refinery is 2911 (Petroleum Refining). A list of the equipment permitted at the refinery is presented in Appendix A.

3.0 BEST AVAILABLE CONTROL MEASURE SELECTION PROCESS

According to 40 CFR Part 51, Subpart Z, BACM is “any technologically and economically feasible control measure that can be implemented in whole or in part within 4 years after the date of reclassification of a Moderate PM_{2.5} nonattainment area to Serious and that generally can achieve greater permanent and enforceable emissions reductions in direct PM_{2.5} emissions and/or emissions of PM_{2.5} plan precursors from sources in the area than can be achieved through the implementation of RACM on the same source(s). BACM includes BACT”. However, the UDAQ has indicated that for this analysis, that any technologically and economically feasible control measure has to be implemented by the end of 2018 to be considered BACT.

In the preparation of this BACM analyses, several sources of information were examined including EPA’s RBLC RACT/BACT/LAER Clearinghouse, state agency databases, vendor data, and published literature.

EPA’s established five-step procedure that starts with the most stringent emission limits and lists all control technologies was utilized for determining the appropriate BACM limit for NO_x, SO₂, PM_{2.5}, and VOC. This is referred to as “Top-Down” BACT and includes the following five steps as outlined in the Draft New Source Review Manual, dated 1990.

3.1 Step 1 - Identify All Existing and Potential Emission Control Technologies

The first step in the top-down procedure is to identify all available control technologies and emission reduction options for each subject pollutant. Available control technologies are those with a practical potential for application to the emission unit. HollyFrontier is a petroleum refinery. In order to identify the appropriate control technologies, the following sources were referenced:

- > US EPA RACT/BACT/LAER Clearinghouse (RBLC)
- > US EPA Control Technology Center
- > Recent Permit Actions
- > Vendor Information

3.2 Step 2 - Eliminate Technically Infeasible Options

The second step in performing the top-down BACT analysis is to eliminate technically infeasible options. Technically infeasible is defined as a control option that, based on physical, chemical, and engineering principles, would preclude the successful use of said control option on the emissions unit under review due to technical difficulties. Two key concepts in determining whether an undemonstrated technology is feasible are availability and applicability. A Technology is considered available if it can be obtained through commercial channels. An available technology is applicable if it can be reasonably installed and operated on the source type under consideration. Technically infeasible control options are then eliminated from further consideration.

3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The third step of the BACT analysis is to rank all the remaining control options not eliminated in Step 2, based on control effectiveness for the pollutant under review. The emission limit or removal efficiency used in the ranking process is the level the technology has demonstrated it can consistently achieve under reasonably foreseeable worst-cast conditions with an adequate margin of safety.

3.4 Step 4 - Evaluate Most Effective Controls and Document Results

In this step, an analysis is performed on each remaining control technology in order to determine whether the energy, economic, or environmental impacts from a given technology outweigh their benefits. Information including control efficiency, anticipated emission rate, expected emissions reduction, and economic, environmental, and energy impacts are to be considered.

If the top-ranked technology is chosen and there are no significant or unusual environmental impacts associated with that technology that have the potential to affect its selection, the BACT analysis is complete and no further information regarding economic, environmental, and energy impacts is required. However, if the top-ranked option is not chosen, an assessment of economic, environmental, and energy impacts (taking into consideration source-specific circumstances that distinguish it from other sources where the technology is in use or has been required) is performed on the next most cost-effective technology until the technology under consideration is not eliminated.

3.4.1 Energy Impact

The energy impact of each evaluated control technology is the energy benefit or penalty resulting from the operation of the control technology at the source. The costs of the energy impacts either in additional fuel costs or the cost of lost power generation impacts the cost-effectiveness of the control technology.

3.4.2 Environmental Impacts

The second evaluation to be reviewed is the environmental evaluation. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology.

3.4.3 Costs of Control

This third evaluation addresses the economic impact of the control technologies. The cost to purchase and to operate the control technology is analyzed. The capital and annual operating costs are estimated based on established design parameters or documented assumptions in the absence of established designed parameters. The cost-effectiveness describes the potential to achieve the required emissions reduction in the most economical way. It also compares the potential technologies on an economic basis. US EPA's Air Pollution Control Cost Manual was used as well as vendor estimates to determine control costs.

3.5 Step 5 - Selection of BACM

The fifth, and final step is selection of the BACT (BACM) emission limit corresponding to the most stringent and technically feasible technology that was not eliminated based upon adverse economic, environmental, and energy impacts. BACM is the technologically and economically feasible control option that can be implemented that achieves permanent and enforceable emissions reductions. It typically is the highest ranked control technology and must not be less stringent than any applicable federal New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), or state-specific standards.

4.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR NITROGEN OXIDES

BACMs were evaluated for oxides of nitrogen (NO_x) emissions from certain emission units in operation or proposed at the Woods Cross Refinery. These units include: process heaters, boilers, flares, sulfur reduction unit (SRU), fluidized catalytic cracking units (FCCU), and emergency diesel and natural gas-fired engines.

4.1 Process Heaters and Boilers

At the Woods Cross Refinery, there are 24 existing or proposed process heaters (4H1, 6H1, 6H2, 6H3, 7H1, 7H3, 8H2, 9H1, 9H2, 10H1, 10H2, 11H1, 12H1, 13H1, 19H1, 20H2, 20H3, 23H1, 24H1, 25H1, 27H1, 30H1, 30H2, 33H1) 10 asphalt tank in-line heaters (68H2-H7, 68H10-H13), and 6 boilers (Boiler #4, #5, #8, #9, #10, and #11). The list of the ratings for this equipment is presented in Appendix A.

4.1.1 Step 1 - Identify All Existing and Potential Emission Control Technologies

Nitrogen oxides (NO_x) are formed during the combustion of fuels by oxidation of chemically-bound nitrogen in the fuel and by thermal fixation of nitrogen in the combustion air. There are three different formation mechanisms: thermal, fuel, and prompt NO_x. Thermal NO_x is primarily temperature dependent (above 2000°F); fuel NO_x is primarily dependent on the presence of fuel-bound nitrogen and the local oxygen concentration. Prompt NO_x is formed in relatively small amounts from the reaction of molecular nitrogen in the combustion air with hydrocarbon radicals in the flame front.

There are a variety of options available for control of NO_x emissions from combustion sources. These include equipment or modifications to equipment that reduce NO_x formation, add-on control devices, or combinations of both. Table 4-1 lists potential NO_x control technologies for refinery heaters and boilers. Abbreviated descriptions of each control technology are provided in Table 4-1.

Table 4-1 Potential NO_x Control Technologies for Refinery Process Heaters and Boilers

Control Technology	Description
Low NO _x Burners (LNB)	Reducing NO _x emissions through burner design.
Next generation and ultra-low NO _x burners (ULNB)	Reducing NO _x emissions through burner design.
External flue gas recirculation (FGR)	Flue gas is recirculated by a fan and external ducting and is mixed with combustion air
Selective catalytic reduction (SCR)	Post combustion control. Injection of ammonia into a catalyst bed within the flue gas path.
Selective non-catalytic reduction (SNCR)	Post combustion control. Injection of ammonia directly into the flue gas at a specific temperature.
Non-selective catalytic reduction (NSCR)	Post combustion control. Precious metal catalysts promote reactions that reduce most NO _x in exhaust streams with low oxygen content.
LNB + FGR	Combination of low NO _x burners and flue gas recirculation.
ULNB + FGR	Combination of ultra-low NO _x burners and flue gas recirculation.
LNB + SNCR	Combination of low NO _x burners and post-combustion add-on SNCR.
ULNB + SNCR	Combination of ultra-low NO _x burners and post-combustion add-on SNCR.
LNB + SCR	Combination of low NO _x burners and post-combustion add-on SCR.
ULNB + SCR	Combination of ultra-low NO _x burners and post-combustion add-on SCR
EM _x [™]	Post-combustion control. The EM _x [™] system uses a coated oxidation catalyst in the flue gas to remove both NO _x and other pollutants with a reagent such as ammonia.
LNB + EM _x [™]	Combination of low-NO _x burners and post-combustion add-on EM _x [™] .
ULNB + EM _x [™]	Combination of ultra-low NO _x burners and post-combustion add-on EM _x [™] .
Water/Steam injection	Decreases NO _x formation by injecting steam with the combustion air or fuel to reduce flame temperature.
Low excess air	Reduce excess air level by maintaining CO at minimum threshold using in-situ CO analyzer in the flow gas stream.
Staged Air/Fuel Combustion or Overfire Air Injection (OFA)	A controlled portion of the total combustion-air flow, typically 10-20%, is directed through over-fire ports located above the highest elevation of burners in the furnace.
CETEX	CETEX descales and coats tubes which reduces fire box temperature by improving heat transfer in applications where the tubes are externally scaled.

4.1.1.1 Low NO_x Burners

Low-NO_x burner (LNB) technology uses advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. There are two general types of LNB: staged fuel and staged air burners. In a staged fuel LNB, the combustion zone is separated into two regions. The first region is a lean combustion region where a fraction of the fuel is supplied with the total quantity of combustion air. Combustion in this zone takes place at substantially lower temperatures than a standard burner. In the second combustion region, the remaining fuel is injected and combusted with left over oxygen from the first region. This technique reduces the formation of thermal NO_x.

4.1.1.2 Ultra-Low NO_x Burners

Ultra-low NO_x burners (ULNB) recirculate hot, oxygen-depleted flue gas from the flame or firebox back into the combustion zone. This reduces the average O₂ concentration within the flame without reducing the flame temperature below the temperatures that are necessary for optimal combustion efficiency. Reduced O₂ concentrations in the flame have a strong impact on fuel NO_x which makes these burners effective for controlling NO_x.

There are several types of ULNB currently available. These burners combine two NO_x reduction steps into one burner, typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without any external equipment. In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel rich zone. High pressure atomization of the fuel creates recirculation. Secondary air is routed into the burner block to optimize flame and complete combustion. This type of design is usually used with liquid fuels.

In staged fuel burners with IFGR, fuel pressure induces IFGR which creates a fuel lean zone and a reduction in oxygen partial pressure. This design is predominantly used for gas fuel operations.

4.1.1.3 External Flue Gas Recirculation

In external flue gas recirculation (FGR), flue gas is recirculated using a fan and external ducting and is mixed with the combustion air stream thereby reducing the flame temperature and decreasing NO_x formation. External flue gas recirculation only works with mechanical draft heaters with burners that can accommodate increased gas flows. Achievable emission reductions are a function of the amount of flue gas recirculated and is limited by efficiency losses and flame instability at higher recirculation rates. Flue gas recirculation has not been demonstrated to function efficiently on process heaters that are subject to highly variable loads and that burn fuels with variable heat value.

4.1.1.4 SCR

SCR is a process that involves the post combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of the catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, and the ammonia slip emissions.

The applicability of SCR is limited to heaters that have both a flue gas temperature appropriate for the catalytic reaction and space for a catalyst bed large enough to provide sufficient residence time for the reaction to occur. Optimum NO_x reduction occurs at catalyst bed temperatures of 600°F to 750°F for vanadium or titanium based catalysts and 470°F to 510°F for platinum catalysts¹.

Sulfur content of the fuel can be of concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide to sulfur trioxide which combined with water to form sulfuric acid. Sulfur trioxide and sulfuric acid react with excess ammonia to form ammonia salts. These salts may condense as the flue gas is cooled leading to increased particulate emissions.

The SCR process also causes the catalyst to deactivate over time. Catalyst deactivation occurs through physical deactivation and chemical poisoning. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required which results in ammonia slip. This slip leads to emissions trade-off between NO_x and ammonia.

4.1.1.5 SNCR

Selective non-catalytic reduction (SNCR) is a post-combustion NO_x control technology based on the reactions of ammonia and NO_x. SNCR involves injecting urea/ammonia into the combustion gas to reduce the NO_x to nitrogen and water. The optimum exhaust gas temperature range for implementation of SNCR is 1,600 to 1,750°F for ammonia and from 1,000 to 1,900°F for urea-based reagents. Operating temperatures below this range results in ammonia slip which form additional NO_x. In addition, the ammonia/urea must have sufficient residence time, approximately 3 to 5 seconds, at the optimum operating temperatures for efficient NO_x reduction. At optimum temperatures, NO_x destruction efficiencies range from 30 to 50%².

SNCR reduces both thermal and fuel-derived NO_x. The SNCR systems require rapid chemical diffusion in the fuel gas. The injection point must be selected to ensure adequate flue gas residence time.

Unreacted ammonia in the emissions is known as slip and is potentially higher in SNCR systems than in SCR systems due to higher reactant injection rates.

4.1.1.6 NSCR

Non-selective catalytic reduction (NSCR) is a flue gas treatment add-on NO_x control technology for exhaust streams with low oxygen (O₂) content. Precious metal catalysts are used to promote reactions that reduce NO_x, CO, and hydrocarbons (HC) to water, carbon dioxide, and nitrogen. One type of NSCR system injects a reducing agent into the exhaust gas stream prior to the catalyst reactor to reduce the NO_x. A second type of NSCR system has an afterburner and two catalytic reactors (one reduction catalyst and one oxidation catalyst). In this system, natural gas is injected into the afterburner to combust unburned HC (at a minimum temperature of 1700°F). The gas stream is cooled prior to entering the first catalytic reactor where CO and NO_x are reduced. A second heat exchanger cools the gas stream (to reduce any NO_x reformation) before the second catalytic reactor where remaining CO is converted to CO₂.

¹ Midwest Regional Planning Organization, Petroleum Refinery Best Available Retrofit Technology (BART) Engineering Analysis, March 30, 2005.

² EPA, 2003.

The control efficiency achieved for NO_x from NSCR ranges from 80 to 90 percent. The NO_x reduction efficiency is controlled by similar factors as for SCR, including the catalyst material and condition, the space velocity, and the catalyst bed operating temperature. Other factors include the air-to-fuel (A/F) ratio, the exhaust gas temperature, and the presence of masking or poisoning agents. The operating temperatures for NSCR system range from approximately 700° to 1500°F, depending on the catalyst. For NO_x reductions of 90 percent, the temperature must be between 800° to 1200°F. One source indicates that the O₂ concentration for NSCR must be less than 4 percent; a second source indicates that the O₂ concentration must be at or below approximately 0.5 percent.

4.1.1.7 Water/Steam Injection

The injection of water or steam decreases NO_x formation by reducing the flame temperature. Water or steam is delivered either by injecting it directly into the root of the flame or by feeding it with the gaseous fuel. Water or steam injection can impact combustion unit operation by worsening flame pattern, reducing unit efficiency, and affecting unit stability.

4.1.1.8 Low Excess Air

Minimizing the amount of excess air (i.e., oxygen) during the initial stages of combustion decreases the amount of NO_x formed. However, reducing the amount of oxygen can cause incomplete combustion, which increases carbon monoxide (CO) emissions. The combustion unit can be operated based on the CO concentration moderating the excess air and therefore, controlling the amount of NO_x generated. This CO level would be monitored by an in-situ CO analyzer in the flue gas stream. This technique requires a high level of instrumentation and automation required for burner control (e.g., actuators for draft & air control).

4.1.1.9 Overfire Air (Boilers only)

In this technique, which is only applicable to boilers, a controlled portion (typically 10-20%) of the total combustion-air flow is directed through over-fire ports located above the highest elevation of burners in the furnace. The removal of the air flow from the burners results in a fuel rich primary combustion zone to limit the NO_x formation. The combustion of the CO produced in the primary combustion zone is completed using the air supplied by the over-fire air ports.

4.1.1.10 CETEX

Removing the scale and applying a coating to the heat transfer surfaces can reduce the firebox temperature and decrease NO_x formation by improving heat transfer. This technique applies in units where the heat transfer tubes are externally scaled. Conversely, the layer of scaling acts as insulation protecting the tubes from damage. Removing the scale to reduce emissions will also reduce firing rate.

4.1.2 Step 2 - Eliminate Technically Infeasible Options

SNCR has been commercially installed throughout the world. Installations include coal-fueled heating plant boilers, electric utility boilers, municipal waste incinerators, cement kilns and many package boilers. The NO_x reduction efficiency of SNCR processes depends on many factors including:

- > Flue gas temperature in reaction zone
- > Uniformity of flue gas temperature in the reaction zone
- > Normal flue gas temperature variation with load
- > Residence time

- > Distribution and mixing of ammonia/urea into the flue gases
- > Initial NO_x concentration
- > Ammonia/urea injection rate
- > Heater configuration, which affects location and design of injection nozzles.

The problem with the use of SNCR is that as the load changes, the optimum injection temperature window moves. In petroleum refineries, the loads vary considerably depending, for example, upon product needs or feedstock run. If ammonia is injected at just the right temperature, then NO_x can be reduced by approximately 60%. If ammonia is injected too hot, then more NO_x is produced. If ammonia is injected too cold, then ammonia does not react resulting in ammonia being emitted to the atmosphere. The exhaust temperatures of the process heaters and boilers range from approximately 430°F to 1000°F. Thus, no process control method has been developed that can match the temperature and rate of ammonia injection with flue gas rate, temperature, and other variables to ensure optimum emission control. Thus, SNCR was eliminated as not technically feasible for use as a post-combustion control for NO_x emissions from the process heaters and boilers.

NSCR is a flue gas treatment add-on NO_x control technology for exhaust streams with low O₂ content. Efficient operation of the catalyst typically requires the exhaust gases contain no more than 0.5% oxygen³. A second source⁴ indicates that the NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. Thus, NSCR was eliminated based on not having lean burn furnaces.

The EM_x[™] catalyst is the latest generation of SCONO_x[™] technology. EM_x[™] is a multi-pollutant catalyst that does not require ammonia. The emissions of NO_x are oxidized to NO₂ and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to regenerate the catalyst. This gas absorbs the NO₂ from the catalyst and reduces it to N₂ before it exits the stack.

EM_x[™] operates in a temperature range between 300°F to 700°F. The potassium carbonate coating reacts with NO₂ to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. When all the potassium carbonate coating on the surface of the catalyst has reacted to form nitrogen compounds, NO_x can no longer be absorbed and the catalyst must be regenerated.

The EM_x[™] system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. The EM_x[™] system is typically used to control emissions from natural gas-fired combustion turbines, reciprocating engines, and industrial boilers in which the sulfur concentration in the exhaust stream is low. The higher concentration of sulfur in the refinery gas will poison the EM_x[™] catalyst.

EM_x[™] has not been demonstrated on refinery fuel gas-fired process heaters or boilers since the SCONO_x[™] catalyst is sensitive to contamination by sulfur in the combustion fuel. This technology has been demonstrated to function efficiently on combustion sources burning fuels like natural gas. SCONO_x[™] systems have been installed at combined-cycle and co-generation turbine plants with capacities ranging from 5.2 to 32MW. Thus, since EM_x[™] was not identified or has been demonstrated for use on refinery process heaters or boilers, EM_x[™] was determined to be technically infeasible and was eliminated for further consideration.

³ http://www.meca.org/resources/MECA_stationary_IC_engine_report_0515_final.pdf Accessed 2/16/2017.

⁴ <https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf>. Accessed 2/16/2017

External flue gas recirculation (FGR) only works with mechanical draft heaters with burners that can accommodate increased gas flows. All but one heater at the refinery is naturally drafted. Also, heaters with burners closer than three feet cannot physical install FGR and associated piping. There is a safety risk associated with FGR at the process heaters due to the potential for formation of explosive gas mixtures if a heater tube should fail. Few applications have been made to refinery process heaters due to this risk. Thus, external flue gas recirculation is not technically feasible for the process heaters and boilers at the Woods Cross Refinery.

Water/steam injection can impact combustion unit operation by worsening flame pattern, reducing unit efficiency, and affecting unit stability. The modest NO_x reductions at the heater may be offset by NO_x emissions resulting from steam generation elsewhere. Also, minimal NO_x reductions will be gained in units already fitted with low NO_x burners. Water/steam injection is predominantly used on gas turbines.

No data could be found on the effectiveness of water/steam injection on process heaters and limited data was found for use on boilers. Thus, steam injection was determined to be not technically feasible for the process heaters or boilers at the Woods Cross Refinery.

Low access air was also considered technically infeasible for use on refinery heaters and boilers since low oxygen operation results in longer flames that could cause flame impingement. Also, it is difficult to maintain safe operating conditions at low oxygen levels.

4.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Table 4-2 presents a summary of the control efficiencies for the remaining NO_x control technologies that can be applied to process heaters and boilers.

Table 4-2 NO_x Control Efficiencies

Technology	Range of Control (%)
ULNB + SCR	85-99
LNB + SCR	80-99
ULNB + SNCR	75-95
SCR	80-90
ULNB (including FGR)	66-76
LNB + SNCR	50-89
LNB+FGR	45-60
SNCR	30-50
LNB	50-60
FGR	50-60
Overfire Air (Boilers only)	30-50
CETEX (Process heaters only)	NA

According to data found in EPA's Petroleum Tier 2 BACT Analysis Report, Final Report (2001), Table 4-3 presents NO_x control technologies with typical emission limits ranked from most efficient to least efficient.

Table 4-3 Typical Emission Levels based on Control Technologies

Technology	Typical Emission Level	
	ppmv	lb/MMBtu
SCR + GCP	7	0.0085
SCR	18	0.022
GCP	29	0.035
No controls	89	0.11

GCP = Good Combustion Practices

Table 4-4 presents a summary of the permitted process heaters and boilers at the HollyFrontier's Woods Cross Refinery. Table 4-5 presents a summary of the potential technically feasible options for reducing NO_x for each process heater and boiler at the Refinery.

Table 4-4 Process Heaters and Boilers at HollyFrontier's Woods Cross Refinery

A.O. ID	Holly Source ID	Source Description	Status	Rating (MMBtu/hr)
II.A.3	4H1	FCC Feed Heater	In Service	68.4/39.9 (restricted to)
II.A.10	6H1	Reformer Reheat Furnace	In Service	54.7
II.A.11	6H2	Prefractionator Reboiler Heater	In Service	12.0
II.A.12	6H3	Reformer Reheat Furnace	In Service	37.7
II.A.16	7H1	HF Alkylation Regeneration Furnace	In Service	4.4
II.A.17	7H3	HF Alkylation Depropanizer Reboiler	In Service	33.3
II.A.19	8H2	Crude Furnace # 1	In Service	99.0
II.A.21	9H1	DHDS Reactor Charge Heater	In Service	8.1
II.A.22	9H2	DHDS Stripper Reboiler	In Service	4.1
II.A.24	10H1	Asphalt Mix Heater	In Service	13.2
II.A.25	10H2	Hot Oil Furnace	In Service	99.0
II.A.27	11H1	SRGP Depentanizer Reboiler	In Service	24.2
II.A.30	12H1	NHDS Reactor Charge Furnace	In Service	50.2
II.A.32	13H1	Isomerization Reactor Feed Furnace	In Service	6.5
II.A.38	19H1	DHT Reactor Charge Heater	In Service	18.1
II.A.41	20H2	Fractionator Charge Heater	In Service	47.0
II.A.42	20H3	Fractionator Charge Heater	In Service	42.1
II.A.46	23H1	Reformate Splitter Reboiler Heater	In Service	21.0
II.A.48	24H1	Crude Unit Furnace	In Service	60.0
II.A.50	25H1	FCC Feed Heater	In Service	45.0
II.A.54	27H1	Reactor Charge Heater	Not Built	99.0
II.A.57	30H1	Hydrogen Reformer Feed Furnace	Not Built	123.1
II.A.58	30H2	Hydrogen Reformer Feed Furnace	Not Built	123.1
II.A.60	33H1	Vacuum Furnace Heater	Not Built	130.0
II.A.81	68H2	North In-tank Asphalt Heater	In Service	0.8
II.A.82	68H3	South In-tank Asphalt Heater	In Service	0.8
II.A.83	68H4	Northwest In-tank Asphalt heater	In Service	0.8
II.A.84	68H5	Northeast In-tank Asphalt Heater	In Service	0.8
II.A.85	68H6	Southeast In-tank Asphalt Heater	Not Built	0.8
II.A.86	68H7	Southwest In-tank Asphalt Heater	Not Built	0.8
II.A.87	68H10	North In-tank Asphalt Heater	Not Built	0.8
II.A.88	68H11	South In-tank Asphalt Heater	Not Built	0.8
II.A.89	68H12	North In-tank Asphalt Heater	Not Built	0.8
II.A.90	68H13	South In-tank Asphalt Heater	Not Built	0.8
II.A.63	Boil. #4	Boiler #4	In Service	35.6
II.A.64	Boil. #5	Boiler #5	In Service	70.0
II.A.65	Boil. #8	Boiler #8	In Service	92.7
II.A.66	Boil. #9	Boiler #9	In Service	89.3
II.A.67	Boil.#10	Boiler #10	In Service	89.3
II.A.68	Boil.#11	Boiler #11	Not Built	89.3

Table 4-5 Technically Feasible Control Options for NO_x for Process Heaters and Boilers

Source ID	NO _x Reduction Technology								
	LNB	ULNB	FGR	SCR	SNCR	NSCR	Steam Injection	Low Access Air	CETEX
4H1	Equipped	--	No	No ³	No	No	No	No	No
6H1	Yes ¹	Yes ¹	Yes	Yes	No	No	No	No	No
6H2	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
6H3	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
7H1	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
7H3	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
8H2	--	Equipped	No	No ³	No	No	No	No	No
9H1	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
9H2	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
10H1	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
10H2	Proposed	--	No	Proposed	No	No	No	No	No
11H1	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
12H1	Yes	Equipped	No	No ³	No	No	No	No	No
13H1	Yes ¹	Yes ¹	No	No ³	No	No	No	No	No
19H1	Equipped	--	No	No ³	No	No	No	No	No
20H2	--	Equipped	No	No ³	No	No	No	No	No
20H3	--	Equipped	No	No ³	No	No	No	No	No
23H1	--	Equipped	No	No ³	No	No	No	No	No
24H1	--	Equipped	No	No ³	No	No	No	No	No
25H1	--	Equipped	No	No ³	No	No	No	No	No
27H1	Proposed	--	No	Proposed	No	No	No	No	No
30H1	Proposed	--	No	Proposed	No	No	No	No	No
30H2	Proposed	--	No	Proposed	No	No	No	No	No
33H1	Proposed	--	No	Proposed	No	No	No	No	No
68H2	No ²	No ²	No	No	No	No	No	No	No
68H3	No ²	No ²	No	No	No	No	No	No	No
68H4	No ²	No ²	No	No	No	No	No	No	No
68H5	No ²	No ²	No	No	No	No	No	No	No
68H6	No ²	No ²	No	No	No	No	No	No	No
68H7	No ²	No ²	No	No	No	No	No	No	No
68H10	No ²	No ²	No	No	No	No	No	No	No
68H11	No ²	No ²	No	No	No	No	No	No	No
68H12	No ²	No ²	No	No	No	No	No	No	No
68H13	No ²	No ²	No	No	No	No	No	No	No

Note: Proposed means unit will be equipped with these controls when constructed.

¹ This option is only feasible if there is space in the firebox for larger burners.

² LNB and ULNB are not available on such small (<1 mmBtu/hr) heaters.

³ Existing process heaters are naturally drafted.

Table 4-5 (Continued) Technically Feasible Control Options for NO_x for Process Heaters and Boilers

Source ID	NO _x Reduction Technology								
	LNB	ULNB	FGR	SCR	SNCR	NSCR	Steam Injection	Low Access Air	CETEX
Boiler 4	Yes	--	No	Yes	No	No	No	No	Yes
Boiler 5	Yes	Yes	No	Equipped	No	No	No	No	Yes
Boiler 8	Equipped	Yes	No	Equipped	No	No	No	No	Yes
Boiler 9	Yes	Yes	No	Equipped	No	No	No	No	Yes
Boiler 10	Yes	Yes	No	Equipped	No	No	No	No	Yes
Boiler 11	Proposed	Yes	No	Proposed	No	No	No	No	Yes

4.1.4 Step 4 - Evaluate Impacts and Document Results

As stated previously, several sources of information were examined including EPA's RBLIC RACT/BACT/LAER Clearinghouse, state agency databases, vendor data, and published literature to identify the most effective NO_x control technologies, most stringent emissions limitations to compare against current NO_x controls that have been or proposed to be implemented at the Woods Cross Refinery.

Table 4-6 presents a summary of BACT determinations for NO_x for process heaters with heat capacities between 10 and 100 MMBtu/hr. All units listed in Table 4-6 are fired on refinery gas. Table 4-7 presents a summary of BACT determination for NO_x for process heaters with heat capacities equal to or greater than 100 MMBtu/hr. These tables list the lowest emission rates identified in the past several years from select plants.

Table 4-6 BACT Determinations for NO_x from Process Heaters and Boilers with Heat Capacities between 10 and <100 MMBtu/hr

Facility	Permit Date	Size (MMBtu/hr)	Limit (lb/MMBtu)	Control
Sinclair Wyoming Refining Company	10/15/2012	50	0.025 (3-hr. avg.)	ULNB
Sinclair Wyoming Refining Company	10/15/2012	64.2	0.030	ULNB
Sinclair Wyoming Refining Company	10/15/2012	44.9, 33.4, 46.3	0.035 (30-day rolling avg)	ULNB
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	24, 32.4, 52, 86	0.04 (3 hr avg)	ULNB
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	68, 90	0.05 (3 hr avg.)	LNB
Tuscaloosa, Alabama	09/28/2009	57, 49, 34.7, 98.3, 69.3, 78.2, 60.9	0.025	NGULNB
Chevron Products Company, Pascagoula Refinery	04/14/2009	73.25, 73.95, 54.53	0.03 (30-day rolling avg.)	ULNB
Conoco Phillips Company, Ponca City Refinery	02/09/2009	45.0, 98	0.03 (annual average)	ULNB
Sunoco Inc., Tulsa Refinery	05/27/2008	44, 57.3	0.03 (3 hr avg.)	ULNB
Navajo Refining Company, Artesia Refinery	12/14/2007	9.6, 35	0.03 (3-hr roll. avg.)	ULNB
Arizona Clean Fuels Yuma LLC	04/14/2005	25, 23.2, 99.5	0.04 (3-hr avg.)	LNB

Table 4-7 BACT Determinations for NO_x from Process Heaters and Boilers with Heat Capacities ≥100 MMBtu/hr

Facility	Permit Date	Size (MMBtu/hr)	Limit (lb/MMBtu)	Control
Sinclair Wyoming Refining Company	10/15/2012	233	0.03 (3 hr avg.)	ULNB
Diamond Shamrock, Texas	12/30/2010	355.6	0.010/0.015 (annual/hourly)	SCR+LNB
Valero Delaware City Refinery	02/26/2010	240, 456	0.04	SCR+LNB
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	100, 135, 336	0.04 (3-hr avg.)	ULNB
Tuscaloosa, Alabama	09/28/2009	198, 254	0.025 (3-hr avg.)	NGULNB
ConocoPhillips, Ponca City Refinery	02/09/2009	125, 131.3	0.03 (annual avg.)	ULNB
Navajo Refining Company, Arteris Refinery	12/14/2007	120	0.035 (3-hr rolling avg)	ULNB
BP Products North America Inc., Whiting Indiana	10/2007	355, 331	0.04	ULNB
BP Products North America Inc., Whiting Indiana	10/2007	208	0.02	SCR+LNB

The top-ranked control option involves the use of LNB with SCR as the post-combustion control device for process heaters and boilers. This option is typically applied to process heaters and boilers approximately 100 MMBtu/hr or greater in rating. The NO_x emission level achievable with this control option is 0.0085 lb/MMBtu based on a three-hour average although emission levels reported in RBLC range from 0.01 to 0.04 lb/MMBtu.

The second ranked option is the use of ULNB; the third highest ranking option is the use of LNB.

Several sources of data indicate that ULNBs are capable of achieving lower NO_x emission levels than LNBs. Emission levels for NO_x reported by one refinery using ULNBs range from 0.050 to 0.031 lb/MMBtu. Controlled NO_x emissions of 0.025 lb/MMBtu have been reported for the Selas ULNx® burner. This emission level is reported for natural gas firing and a firebox temperature of 1250°C (2280°F). A John Zink burner for natural draft heaters was designed to meet 0.03 lb/MMBtu or 25 to 28 ppmv depending on fuel composition.

No additional controls were identified for small heaters such as the stab-in tank heaters which are rated at 0.8 MMBtu/hr.

The boilers at Hollyfrontier Woods Cross Refinery are chemically treated to remove scale on the boiler heat tubes which improves boiler efficiency and reduces NO_x emissions.

Table 4-8 presents a list of HollyFrontier's process heaters and boilers and the control technology being currently utilized.

Table 4-8 Current Control Technologies on HollyFrontier Process Heaters and Boilers

A.O. ID	Holly Source ID	Source Description	Control Technology
II.A.3	4H1	FCC Feed Heater	LNB
II.A.10	6H1	Reformer Reheat Furnace	GCP
II.A.11	6H2	Prefractionator Reboiler Heater	GCP
II.A.12	6H3	Reformer Reheat Furnace	GCP
II.A.16	7H1	HF Alkylation Regeneration Furnace	GCP
II.A.17	7H3	HF Alkylation Depropanizer Reboiler	GCP
II.A.19	8H2	Crude Furnace # 1	NGULNB
II.A.21	9H1	DHDS Reactor Charge Heater	GCP
II.A.22	9H2	DHDS Stripper Reboiler	GCP
II.A.24	10H1	Asphalt Mix Heater	GCP
II.A.25	10H2	Hot Oil Furnace	LNB + SCR
II.A.27	11H1	SRGP Depentanizer Reboiler	GCP
II.A.30	12H1	NHDS Reactor Charge Furnace	NGULNB
II.A.32	13H1	Isomerization Reactor Feed Furnace	GCP
II.A.38	19H1	DHT Reactor Charge Heater	LNB
II.A.41	20H2	Fractionator Charge Heater	ULNB
II.A.42	20H3	Fractionator Charge Heater	ULNB
II.A.46	23H1	Reformate Splitter Reboiler Heater	ULNB
II.A.48	24H1	Crude Unit Furnace	ULNB
II.A.50	25H1	FCC Feed Heater	ULNB
II.A.54	27H1	Reactor Charge Heater	LNB+SCR
II.A.57	30H1	Hydrogen Reformer Feed Furnace	LNB+SCR
II.A.58	30H2	Hydrogen Reformer Feed Furnace	LNB+SCR
II.A.60	33H1	Vacuum Furnace Heater	LNB+SCR, air preheat
II.A.81	68H2	North In-tank Asphalt Heater	GCP
II.A.82	68H3	South In-tank Asphalt Heater	GCP
II.A.83	68H4	Northwest In-tank Asphalt Heater	GCP
II.A.84	68H5	Northeast In-tank Asphalt Heater	GCP
II.A.85	68H6	Southeast In-tank Asphalt Heater	GCP
II.A.86	68H7	Southwest In-tank Asphalt Heater	GCP
II.A.87	68H10	North In-tank Asphalt Heater	GCP
II.A.88	68H11	South In-tank Asphalt Heater	GCP
II.A.89	68H12	North In-tank Asphalt Heater	GCP
II.A.90	68H13	South In-tank Asphalt Heater	GCP
II.A.63	Boil. #4	Boiler #4	
II.A.64	Boil. #5	Boiler #5	SCR
II.A.65	Boil. #8	Boiler #8	LNB+SCR
II.A.66	Boil. #9	Boiler #9	SCR
II.A.67	Boil.#10	Boiler #10	SCR
II.A.68	Boil.#11	Boiler #11	LNB+SCR

¹ lb/MMscf

4.1.4.1 Energy and Environmental Impacts

With the application of a SCR, additional adverse impacts are anticipated which include ammonia emissions and the handling and disposal of a spent catalysts as a solid waste stream. Ammonia that is injected in the SCR system and exits the unit without participating in the chemical reduction of NO_x emissions leads directly to emissions of ammonia and can lead indirectly to the formation of secondary particulate matter. These problems are less severe when the SCR catalyst is new and activity is greatest because the ammonia rate can be set near-stoichiometric levels. As the catalyst ages, the activity decreases requiring a higher ammonia injection rate to maintain the rate of NO_x reduction required for continuous compliance with NO_x emission levels.

Besides an environmental and air quality impact, an adverse energy impact is expected due to the electrical requirements of the SCR system operation and to the reduction in energy efficiency attributable to the power drop across the SCR catalysts grid.

4.1.4.2 Economic Impact

According to EPA, SCR reduces NO_x by 90 percent or greater in an uncontrolled mechanical draft process heater. SCR systems require mechanical draft operation due to the pressure drop across the catalyst. The only heater at HollyFrontier that is mechanically drafted is 6H1. All other heaters are naturally drafted.

In order to use an SCR system or systems on the process heaters at Holly Frontier, the refinery would need to replace all naturally draft heater with mechanical draft heaters which would not be economically feasible as well as limit refinery operations for a lengthy period of time. Thus, SCR is eliminated as technically infeasible for use on the naturally drafted heaters at HollyFrontier.

An analysis was performed to evaluate the technical feasibility and cost effectiveness of upgrading existing process heaters with LNB or ULNB. In conversations with representatives from John Zink, when upgrading the existing units to LNB or ULNB, the floor of each heater box would have to be reconstructed to insert the LNB or ULNB which are typically longer and wider than the existing burners. Also, LNB and ULNB have a lower heating duty per burner than traditional burners; therefore, in some cases, will result in a need for additional burners to achieve the firing rate needed for the process application. Most heaters at HollyFrontier are not designed to accommodate additional burners and would need to be reconstructed all together. If additional burners cannot be added and the heater is not reconstructed, then a process rate decrease would need to take place.

An additional consideration with retrofitting existing heaters to LNB or ULNB is the flame pattern. LNB and ULNB generally produce a longer flame in the fire box which can extend to contact process piping or the convection section of the heater. Contact with process piping can result in coking of the inside of the process pipes which results in a loss of heat transfer and eventual plugging. Flame extension into the convection section can result in heat transfer not consistent with engineered design resulting in process coking, inadequate heat transfer, heater box temperature, and loss of process control.

Thus, the application of LNB or ULNB on existing units (6H1, 6H2, 6H3, 7H1, 7H2, 7H3, 9H1, 9H2, 10H1, 11H1, and 13H1) is not technically possible due to space limitations in the firebox, lower heat duty, and a longer flame. It is not economically feasible to reconstruct all existing process heaters. Thus, for these reasons, retrofit of existing process heaters with LNB or ULNB has been determined to be technically and economically infeasible.

4.1.5 Selection of BACM

According to EPA, 7 ppmv of NO_x should generally be considered as LAER or the most stringent control measure for NO_x emissions from **new** refinery process heaters. Refiners can achieve this level of control through a combination of combustion controls (LNB with internal flue gas recirculation) and SCR. For boilers 100 MMBtu/hr or greater, the most stringent control is a NO_x limit of 5 ppm @ 3% O₂ using SCR. For boilers < 20 MMBtu/hr, the most stringent control is a NO_x limit of 9 ppm using LNB.

The Bay Area Air Quality Management District (BAAQMD), South Coast Air Quality Management District (SCAQMD), California Air Resources Board (CARB) BACT guidelines were reviewed for determining BACT emission rates for the refinery heaters with a firing rate greater than 50 MMBtu/hr. NO_x limits range from 5 ppmdv (the most stringent identified by SCAQMD) to 10 ppmdv, all corrected to 3% O₂. A 5 ppmdv emission rate at 3% O₂ equates to approximately 0.006 lb/MMbtu; a 10 ppmdv emission rate at 3% O₂ equates to approximately 0.012 lb/MMbtu. These limits were accomplished through the use of SCR and LNB. These controls are not practical for HollyFrontier for the reasons presented above (i.e. SCR requires mechanical draft) for the process heaters. Further, if SCR were practical, ammonia is a PM_{2.5} precursor which leads to higher PM_{2.5} emissions. Thus, these more stringent emission limits for the process heaters at HollyFrontier are not considered BACM.

The process heaters at HollyFrontier equipped with ULNB (20H2, 20H3, 23H1, 24H1, 25H1) have an emission limit of 0.04 lb/MMBtu which equates to approximately 30 ppbdv at 3% O₂; 10H2, and future heaters 27H1, 30H1, 30H2, 33H1 which are or will be equipped with LNB and SCR have an emission limit of 0.02 lb/MMbtu which equates to approximately 15 ppmdv at 3% O₂. Compliance with these limits is/will be verified every three years through stack testing. This represents BACM for these heaters.

For the stab-in heaters, only good combustion practices (GCP) were identified to control NO_x emissions from these small heaters which is considered BACM. Compliance for 68H6, 68H7, 68H10, 68H12, and 68H13 is verified every three years through stack testing.

The highest-ranking option, LNB and SCR, is used on Boilers #8 and #11. Boilers #5, #9, and #10 are equipped with SCR. The NO_x emission limit is 0.02 lb/MMBTU for Boilers #8-#11 and represents BACM. Boiler #5, equipped with SCR, has a NO_x emission limit of 0.03 lb/MMBtu which also represents BACM. Stack test are performed every three years to verify that these units are in compliance with the permissible limits. Boiler #4 is a limited use boiler and it was not technically or economically feasible to install a SCR on this unit.

The cost of installing and operating CEMS on each heater and boiler was examined. The estimated equipment cost including a shelter and a NO₂ CEMS with affiliated equipment plus installation is over \$201,600 per system. Total annual operating costs were estimated to be approximately \$72,820. See Appendix B for a detailed cost analysis. Based on potential to emit (PTE) emissions for process heaters, the average cost-per-ton to monitor for NO_x with a CEMS is \$17,255.

4.2 Flares

Flares are used at petroleum refineries to destroy organic compounds in excess refinery fuel gas, purged products, or waste gases released during startups, shutdowns, and malfunctions. Most flares have a natural gas pilot flame and use the fuel value of the gas routed to the flare to sustain combustion.

There are two flare stacks located at the Northwest corner of the refinery. During refinery upsets, process equipment may experience over-pressures which are relieved through a spring-loaded pressure safety valve ("PSV"). Piping headers connect these devices to the flare stack, which is used to safely burn the released hydrocarbons. A small, continuous flame of purchased natural gas acts as a pilot light to ignite the process vapors as they enter the flare tip for final destruction.

The South Flare (66-2) handles relief gases from the Crude #2 Unit (Unit 24), FCC #2 Unit (Unit 25), Poly Unit (Unit 26), Hydrocracker/Hydroisom Unit (Unit 27), SWS #2 Unit (Unit 28), Hydrogen Plant (Unit 30), Tank Farm (Unit 68), Crude Unloading (Unit 86), and Rail Unloading (Unit 87).

The North Flare (66-1) handles relief gases from the FCC Unit (Unit 4), Reformer Unit (Unit 6), Alkylation Unit (Unit 7), Crude Unit (Unit 8), DHDS Unit (Unit 9), SDA Unit (Unit 10), SRGP Unit (Unit 11), NHDS Unit (Unit 12), Isomerization Unit (Unit 13), Amine Treatment Unit (Unit 16), SRU (Unit 17), SWS Unit (Unit 18), DHT Unit (Unit 19), GHC Unit (Unit 20), NaHS Sour Gas Treatment Unit (Unit 21), Sour water stripper/ASU (Unit 22), BenZap Unit (Unit 23), Vacuum Unit (Unit 33), Tank Farm (Unit 68), and Loading/Unloading (Unit 87).

4.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

For safe flare operation, the design of the flares requires the use of a pilot light. The combustion of the natural gas to fuel the pilot light and the combustion of refinery gases produces NO_x .

A search of the RBLC, state databases, and emission control literature was conducted to find available control technologies to control flare emissions. Flares operate primarily as air pollution control devices. The only technically feasible control options for emissions of all pollutants from flares are:

- proper equipment design and work practices;
- good combustion practices;
- conversion from air assisted to steam assisted, and
- flare gas recovery systems.

No add-on controls for NO_x emissions from flares were identified.

4.2.1.1 Proper Equipment Design and Work Practices

Proper equipment design and work practices include minimizing the quantity of gases combusted, minimizing exit velocity, ensuring adequate heat value of combusted gases, and installing an automatic pilot reignition. The flares at the Woods Cross Refinery are designed and operated in accordance with 40 CFR 60.18, general control device requirements which include a flame present at all times, no visible emissions, and heat content and maximum tip velocity specifications that meet the requirements of the rule. The use of pipeline-quality natural gas to fuel the pilot lights will reduce NO_x emissions.

4.2.1.2 Good Combustion Practices

A certain level of flame temperature control can be exercised for a flare by implementing fuel to air ratio control. Generation of NO_x is dependent on temperature. As the temperature rises, the generation rate of NO_x rises. Good combustion practices can be used to minimize emissions of NO_x .

4.2.1.3 Conversion from Air Assisted to Steam Assisted

Flares produce lower flame temperatures when operating with low heating value gases at low combustion efficiencies than when operating with high heating value gases at high combustion efficiencies. This leads to reduced formation of NO_x in the flame. In general, emissions were lower in steam assisted flare tests than in air assisted flare tests conducted under similar conditions.

4.2.1.4 Flare Gas Recovery Systems

Flaring can be reduced by installation of a flare gas recovery system. A flare gas recovery system includes a seal system to allow for recovery of process gases vented to the flare. Compressors recover the vapors and route them to the fuel gas treatment system for H_2S removal. After conditioning of the recovered vapors, the gases are combined with other plant fuel gas sources and combusted in heaters, boilers, and other devices that operate using fuel gas.

If the pressure in the flare gas headers exceeds the seal system settings, excess flare gases are allowed to flow to the flare for combustion. The pressure in the flare gas system increases due to additional process gas flow that cannot be recovered by the flare gas compressors. Once the pressure drops and the excess gases are combusted, the seal system re-establishes itself for continuous recovery of vapors.

The flare gas recovery system will not be sufficient to prevent flaring from process unit startup and shutdown events where large volumes of process gases will be sent to the flare. Also, during process upsets or malfunctions, the flare gases may not be entirely recovered due to the constraints of the flare gas recovery system. The flare gas recovery system will be sized for normal operating conditions.

4.2.2 Step 2 - Eliminate Technically Infeasible Options

None of the identified control options is considered technically infeasible for the flares at the Woods Cross Refinery.

4.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top-ranking control option is the installation of a flare gas recovery system. Flare gas recovery systems are achieved in practice. The second highest ranking control option includes proper equipment design and work practices which includes good combustion practices. The destruction efficiency of a properly operated flare is 98%. The flares at the Woods Cross refinery are steam assisted.

4.2.4 Step 4 - Evaluate Impacts and Document Results

HollyFrontier will install a flare gas recovery system to recover vent gas which is the highest ranked control option.

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. Because the flares are located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 CFR Part 60 Subpart Ja and the design and work practice requirements of 40 CFR 60.18.

Emissions from the HollyFrontier Woods Cross Refinery flares under normal operation will consist only of the emissions from the combustion of natural gas in the flare pilot flames and a small amount of purge gas that is circulated through the flare system for safety reasons (i.e., to prevent air from entering the flare lines).

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases.

Flare management plans have been developed for both the north and south flares. These plans contain procedures to minimize or eliminate discharges to the flare during startups and shutdowns. To verify that the procedures are followed, records are maintained.

The flares at the refinery are steam-assisted which leads to lower NO_x formation in the flare flame.

4.2.4.1 Energy, Environmental, and Economic Impacts

Since HollyFrontier has chosen the highest ranked control option, flare gas recovery, energy, environmental and costs analyses are not required.

4.2.5 Step 5 - Select BACT

Holly is utilizing the following design elements and work practices as BACM for the flares:

- Use of low sulfur fuel such as natural gas as fuel for pilot flame;
- Maintaining an acceptable net heating value and exit velocity of flared gases under all flow conditions in accordance with manufacturer specifications;
- Use of a thermocouple to monitor presence of the pilot flame;
- Implementation of good combustion, operating, and maintenance practices;
- Implementation of Flare Management Plans;
- Flare operation in accordance to 40 CFR Part 60, Ja and design and work practice standards as codified in 40 CFR Part 60.18; and,
- Installation of flare gas recovery system.

No more stringent measures were identified for the flares at the Woods Cross Refinery. The flare design includes steam assisted combustion. The flares will be equipped with a flare gas recovery system for non-emergency releases, and a continuous pilot light. Pilot and sweep fuel will be natural gas or treated refinery gas. The north and south flares are equipped with flow meters and gas combustion monitors.

The proposed BACM controls and compliance monitoring method conducted for HollyFrontier flares are summarized in Table 4-9.

Table 4-9 Proposed BACM Controls and Compliance Monitoring Methods for Flares

Pollutant	Unit	Control Technology	Monitoring Methods
NO _x	66	Flare gas recovery system	Flow meters, Btu monitor

4.3 Sulfur Recovery Unit Tail Gas Incinerator

The SRU off gas is routed to the tail gas incinerator followed by a wet scrubber (4V82 or 25 FCCU scrubber). The SRU does not operate if the scrubbers are not in operation. Oxides of nitrogen are formed during the combustion of natural gas in the incinerator by oxidation of chemically-bound nitrogen in the fuel and by thermal fixation of nitrogen in the combustion air.

4.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The available control technologies for NO_x control from the tail gas incinerator are the same technologies listed in Table 4-2 above as well as the application of LoTOx™ which is a low temperature oxidation process which utilizes ozone to oxidize insoluble NO and NO₂ to N₂O (a highly soluble species of NO_x) which can be effectively removed by a variety of air pollution control equipment including wet scrubbers.

4.3.2 Step 2 - Eliminate Technically Infeasible Options

The only options that are technically feasible for an SRU tail gas incinerator is combustion control utilizing LNB or ULNB and utilization of a LoTOx™ system. The other technologies are either based on lowering flame temperature, which is not compatible with the primary function of an incinerator, or add-on controls that have not been demonstrated as technically feasible for a thermal oxidizer. There are significant technical differences between thermal oxidizers and the combustion sources for which these technologies have been demonstrated in practice.

4.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Technically feasible NO_x control technologies are combustion control utilizing LNB or ULNB fired on natural gas and/or the application of a LoTOx™ system.

4.3.4 Step 4 - Evaluate Impacts and Document Results

The tailgas incinerator is a thermal incinerator that is used to facilitate the oxidation of the common reduced sulfur compounds to SO₂ prior to release to the atmosphere. The incinerator combusts natural or refinery gas which creates the NO_x emissions. The tailgas incinerator is equipped with low NO_x burners to reduce NO_x emissions that may form during the combustion of gaseous fuels.

During normal operation, the gases from the SRU tailgas incinerator which is equipped with LNBs are routed to either Unit 4 or Unit 25 wet gas scrubbers. These wet gas scrubbers are configured to include the LoTOx™ process which provides greater than 95% NO_x reduction.

A review of the RBLC Clearinghouse identified two refineries, Sunoco Tulsa Refinery and Valero's St. Charles Refinery, with NO_x limits on the tail gas treatment units. These limits ranged from 0.14 lb/MMBtu or 1 lb/hr and 9.4 lb/hr and were met utilizing good combustion practices and proper equipment design. No indication of burner type was presented for these tail gas treatment units.

4.3.4.1 Energy, Environmental and Economic Impacts

As mentioned above, the tailgas incinerator is a thermal incinerator that is used to facilitate the oxidation of the common reduced sulfur compounds to SO₂ prior to release to the atmosphere. The incinerator combusts natural or refinery gas which creates the NO_x emissions.

The tailgas incinerator on the SRU at HollyFrontier is equipped with LNBs which reduce NO_x emissions that may form during the combustion of gaseous fuels. There are energy and environmental impacts associated with the use of the tailgas incinerator and pipeline natural gas. Additional energy and fuel are both required leading to increased NO_x emissions. However, emissions from the tailgas incinerator are controlled through one of the FCCU wet scrubbers which utilizes LoTOx™ to further reduce NO_x emissions.

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. There are no other anticipated energy, environmental, or environmental impacts associated with the use of the wet gas scrubbers during normal SRU operation.

4.3.5 Step 5 - Select BACT

During normal operations, emissions from the three-stage Claus SRU followed by a tailgas incinerator are sent to one of the wet gas scrubbers. Thus, NO_x BACM for the three-stage Claus SRU is the use of good combustion practices, pipeline quality natural gas in tail-gas incinerator with proper equipment design, wet scrubbing, and LoTOx™. No other measures were identified as more stringent to control NO_x emissions. HollyFrontier is meeting the NO_x emission rates of 40 ppm NO_x per 365-day rolling average and 80 ppm NO_x per 7-day rolling average from the wet scrubbers.

The proposed BACM controls and compliance monitoring method conducted for HollyFrontier's SRU tailgas incinerator are summarized in Table 4-10.

Table 4-10 Proposed BACM Controls and Monitoring Method for SRU Tail Gas Incinerator

Pollutant	Unit	Control Technology	Monitoring
NO _x	17	Tailgas incinerator followed by wet scrubbing, good combustion practices, pipeline quality fuel, LoTOx	O ₂ CEMS

4.4 Fluidized Catalytic Cracking Unit (FCCU)

This BACM review was based on data summarized by EPA in the RBLC RACT/BACT/LAER Clearinghouse, review of state databases and review of recent consent decrees. While the emission limits imposed by consent decrees do not necessarily represent BACT or LAER, they do represent the most stringent emissions limitations placed upon FCCUs.

The two FCCU regenerators at HollyFrontier are full-burn units which is recognized by EPA as an inherently low NO_x design. The predominant NO_x species inside an FCCU regenerator is NO that is further oxidized to NO₂ upon release to the atmosphere. NO_x in the regenerator can be formed by two mechanisms, thermal NO_x produced from the reaction of molecular nitrogen with oxygen and fuel NO_x which is produced from the oxidation of nitrogen-containing coke specie deposited on the catalyst inside the reactor.

4.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following is a list of control technologies which were identified for controlling NO_x emissions from the FCCUs:

- > SNCR,
- > SCR,
- > LoTOx, and
- > Catalyst additives and low NO_x combustion promoters.

4.4.2 Step 2 - Eliminate Technically Infeasible Options

All the options are technically feasible.

4.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control options were ranked in order of reduction:

- > LoTox – 80 to 95% reduction with SCR
- > SCR – 80 to 90% reduction
- > SNCR – 60 to 80% reduction
- > Catalyst additives and low NO_x combustion promoters – 40 to 75% reduction.

4.4.3.1 SNCR

The SNCR system is a post-combustion control technology that reacts with urea or ammonia with flue gas without the presence of a catalyst to produce N₂ and H₂O. The typical operating temperature range for an SNCR is 1,600°F to 2,000°F. The SNCR temperature range is sensitive as the reagents can produce additional NO_x if the temperature is too high or removes too little NO_x if the reaction proceeds slowly if the temperature is too low. The NH₃ slip in SNCR applications can range from 10 to 100 ppmv. SNCR has been used successfully with CO boilers but are typically not used with full burn units due to low NO_x removal at temperatures below 1,400°F. In full burn units, such is utilized by HollyFrontier, the flue gas must be heated to 1,600 to 1,800°F to achieve NO_x removal rates of 50% and greater.

4.4.3.2 SCR

Selective catalytic reduction is a post combustion control technology that injects ammonia in flue gas in the presence of a catalyst (typically vanadium or tungsten oxides) to produce N_2 and H_2O . An SCR is similar to SNCR with the exception that a catalyst is used to accelerate the reactions at lower temperatures. The ideal temperature range for an SCR is 600°F to 750°F with guaranteed NO_x removal rates of 90+%. Design considerations include targeted NO_x removal level, service life, pressure drop limitation, ammonia slip, space limitation, flue gas temperature, composition and SO_2 oxidation limit. SCR suppliers typically guarantee the performance of the unit for NO_x removal, service life, pressure drop, ammonia slip and SO_2 oxidation. Ammonia slip, referring to the amount of ammonia which passes through the process unreacted, is typically guaranteed to 10 ppmv.

4.4.3.3 LoTOx™

The Belco LoTOx™ technology is a selective, low temperature technology that uses ozone to oxidize NO_x to water soluble nitric pentoxide (N_2O_5). These higher oxides of nitrogen are highly soluble. Inside a wet gas scrubber, the N_2O_5 forms nitric acid that is subsequently scrubbed by the scrubber nozzles and neutralized by the scrubber's alkali reagent. Since the process is applied at a controlled temperature zone in the wet gas scrubber, it can be used at any flue gas temperature. The controlled temperature zone in the wet gas scrubber is below 300°F. Since the LoTOx™ technology does not use a fixed catalyst bed, it can handle unit upsets without impacting overall reliability and mechanical availability.

The LoTOx™ technology generates ozone on demand based on the amount of NO_x in the flue gas. There is no storage of ozone required. Emission reductions using this process have been estimated to range from 80 to 95%.

4.4.3.4 Catalyst Additive and Combustion Promoters

Several vendors offer NO_x reducing catalyst additives and combustion promoters. Current NO_x additives affect the availability of nitrogen species to be oxidized and reduced and the performance of the additives is dependent on the application. Grace Davison's XNOx is a combustion promoter additive that can reduce NO_x emission from 50-75% in the regenerator. Grace Davison's DENOX promoter can reduce NO_x emissions up to 60%. Engelhardt's CLEANNOx and OxyClean reduce NO_x emissions by 45%. INTERCAT's COP-NP can reduce emissions from approximately 40-65%. The NO_x combustion promoters (catalysts and additives) are added directly into the FCCU reactor and regenerator. These additives can withstand the harsh environment of the regenerator but do not have the same life as catalyst.

A benefit associated with the use of additives is flexibility. Additives can be added and removed from the operation depending on the refiner's needs but are more expensive than FCC catalysts with an average cost approaching \$20 per pound. The additional cost associated with the recommended usage rate of these additives may triple the current catalyst cost resulting in negative process unit economics. Higher removal rates may require more additive and that can impact yields, product quality and unit throughput.

4.4.4 Step 4 - Evaluate Impacts and Document Results

SNCR is not feasible in this application because of the need to heat the flue gas to reach the optimum operating levels of the SNCR. The amount of NO_x reduction is also lower. Most EPA consent decree applications have achieved a 5 to 30% reduction with others in the industry achieving up to 70% depending on process conditions⁵. A drawback of using SNCR technology is the potential formation of ammonium sulfate salts and resultant fouling. These salts will exist as small particulates.

A SCR system can achieve between 80-90% reductions on uncontrolled NO_x emissions. SCRs operate in the temperature range of FCC regenerator flue gas. This control technology has a high NO_x reduction rate when compared to other NO_x control technologies. Although SCR offers high NO_x reduction rates, catalyst deactivation can occur from salt formation on the catalyst surface, cracks of the catalyst from the substrate material can occur from thermal stresses, and thermal degradation of the catalyst can occur at temperatures greater than 800°F. Other items that can lead to catalyst deactivation include erosion of the catalyst due to excessive catalyst fines loading and plugging of the catalyst system due to catalyst fines.

At the plants where SCR's have been installed, the majority of them have third stage separators or ESP's located before the SCR catalyst bed to protect against upsets in the FCC regenerator.

LoTOx™ in conjunction with wet scrubbing systems has been demonstrated to effectively reduce high levels of NO_x from a FCCU. The efficiency obtained from the combination of LoTOx™ and wet gas scrubbing systems is comparable to an SCR.

To apply SCR to the output of a wet gas scrubber with a LoTOx™ system is technically infeasible. The low temperature of the exhaust stream combined with the concentration of NO_x make further application of an add-on control like SCR impractical.

Combustion promoters will not reduce the NO_x emissions alone to meet NO_x BACT levels.

A review of the literature and the EPA's RBLC indicate that SCRs or LoTOx™ in conjunction with wet scrubbing systems are used for the reduction of NO_x in a number of FCCUs. BELCO, a subsidiary of DuPont, provided a list of locations where the LoTOx™ technology has been installed in FCCU regenerator applications. Table 4-11 presents a list of a few of these facilities. Table 4-12 presents the results of a search of the RBLC clearinghouse and a list of select refineries and the NO_x control technologies being utilized at these refineries.

⁵ Advances in Fluid Catalytic Cracking, Chapter 17, FCC NO_x Emissions and Controls, Jeffrey A. Sexton, 2010.

Table 4-11 LoTOx™ NO_x Reduction Technology Installations

Application	Location	Capacity	Start-up
Refinery FCCU (New EDV Scrubber with LoTOx technology)	HollyFrontier Woods Cross, UT	Confidential	2012, 2016
Refinery FCCU (New EDV Scrubber with LoTOx technology)	Petrochina, Sichuan	Confidential	2010
Refinery FCCU (New EDV Scrubber with LoTOx technology)	West Pacific, Dalian	Confidential	2010
Refinery FCCU (Retrofitted LoTOx Technology to existing EDV scrubber)	Valero, St. Charles, LA	100,000 bpsd	2010
Refinery FCCU (Retrofitted LoTOx addition to existing CANSOLV unit)	Valero, Delaware City, DE	75,000 bpsd	2010
Refinery FCCU (Retrofitted LoTOx addition to existing EXXON scrubber)	Flint Hills, Corpus Christi, TX	45,000 bpsd	2009
Refinery FCCU (New EDV Scrubber with LoTOx technology)	Petrobras, REFAP Brazil	7,000 m ³ /day	2009
Refinery FCCU (New EDV scrubber with LoTOx technology)	Valero, Houston, Texas	58,000 bpsd	April 2007
Refinery FCCU (Retrofitted LoTOx Technology to existing EDV® wet scrubber)	Marathon, Texas City, Texas	72,000 bpsd	February 2007
Refinery FCCU (New EDV scrubber with LoTOx technology)	BP, Texas City, Texas	130,000 bpsd	June 2007

Table 4-12 BACT Determinations for NO_x for FCCU

Facility	Permit ID/ Permit Date	NO _x Concentration Limit	Control
Alon Refining Krotz Springs Inc. Krotz Springs Refinery	LA-0261 04/26/2012	73.0 ppmvd @ 0% O ₂ 365-day rolling average 146.0 ppmvd @ 0% O ₂ 7-day rolling average	Consent Decree - LoTOx
Valero Energy Corp. Valero Delaware City Refinery	DE-0020 02/26/2010	20.0 ppmvd @ 0% O ₂ 365-day rolling average 40.0 ppmvd @ 0% O ₂ 7-day rolling average	LoTOx
Sunoco, Inc. Sun Company Inc. Toledo Refinery	OH-0308 02/23/2009	20.0 ppmvd @ 0% O ₂ 365-day rolling average 40.0 ppmvd @ 0% O ₂ 7-day rolling average	SCR
Shell Oil Company Deer Park Refinery Limited Partnership	TX-0290 09/27/2007	20.0 ppmvd @ 0% O ₂ 365-day rolling average 40.0 ppmvd @ 0% O ₂ 3-hour average	SCR
ExxonMobil Oil Corp. ExxonMobil Torrance Refinery	CA-1138 03/23/2007	20.0 ppmvd @ 0% O ₂ 365-day rolling average 40.0 ppmvd @ 0% O ₂ 7-day rolling average	SCR

4.4.4.1 Energy, Environmental, and Economic Impacts

There are environmental and economic impacts associated with a wet gas scrubber. Wet scrubbers will generate water vapor plumes, which during the winter months may reduce visibility. In addition, wet gas scrubbers generate wastewater, which must be managed and disposed of at the refinery. Lastly, wet gas scrubbers produce a significant amount of solid waste. Although wet gas scrubbers can be costly to install and annual operating costs can be comparatively high, wet gas scrubbers will be utilized to reduce NO_x emissions from the HollyFrontier FCCUs.

HollyFrontier is not proposing a SCR due to not being economically feasible because a third stage separator or ESP would have to be installed as part of the crude processing operations.

4.4.5 Step 5 - Select BACT

Thus, LoTOx™ systems in conjunction with wet gas scrubbers are utilized by HollyFrontier to reduce NO_x emissions in the regenerator flue gas from Units 4 and 25. The use of LoTOx™ in conjunction with wet gas scrubbers has a comparable removal efficiency as a SCR for NO_x.

The most stringent control identified as LAER in the RBL database was SCR that is being utilized at the Deer Park Refinery with emission limits of 20 ppmvd @ 0% O₂ based on a 365-day rolling average and 40-ppmvd @0% O₂ based on a 3-hour average. According to HollyFrontier's Consent Decree, HollyFrontier designed the NO_x Control system to achieve a NO_x concentration of 20 ppmvd or lower on a three-hundred sixty five (365) day rolling average basis and 40 ppmvd on a seven (7) day rolling average basis, each corrected to 0% O₂. These levels are consistent with RBL findings presented for several refineries as listed in Table 4-12.

After the 15-month demonstration period, the NO_x emission rates at HollyFrontier are slightly higher than the design and are 40 ppm NO_x per 365-day rolling average and 80 ppm NO_x per 7-day rolling average. Although these limits are slightly higher than the most stringent controlled facility, the use of LoTOx™ and wet gas scrubber achieves a NO_x control efficiency that is comparable to a SCR and is a top ranking control technology. Thus, the use of LoTOx™ and a wet gas scrubber to achieve the above listed emission rates has been determined to be BACM for the FCCUs operated by HollyFrontier.

The proposed BACM controls, NO_x emission limits, and compliance monitoring methods conducted for HollyFrontier's FCCUs are summarized in Table 4-13.

Table 4-13 Proposed BACM Controls, NO_x Emission Limits, and Monitoring Methods for FCCUs

Pollutant	Unit	Control Technology	NO _x Emission Limit	Monitoring Method
NO _x	4, 25	Wet Gas Scrubbers	40 ppm per 365-day rolling average 80 ppm per 7-day rolling average	CEMS, Annual Rata

4.5 Emergency Diesel Engines

Diesel emergency equipment at the Woods Cross refinery consists of a 135 kW portable diesel generator at the East Tank Farm, 224 HP diesel powered water well No. 3, 393 HP fire pump No. 1, 393 HP fire pump No. 2, 180 HP diesel fire pump, three 220 HP diesel-powered plant air backup compressors, 470 HP diesel standby generator at the Boiler House, 380 HP diesel standby generator at the Central Control Room, and a 540 HP diesel standby generator.

Diesel engines are classified as compression ignition (CI) internal combustion engines. In diesel engines, air is drawn into a cylinder as the piston creates space for it by moving away from the intake valve. The piston's subsequent upward swing then compresses the air, heating it at the same time. Next, fuel is injected under high pressure as the piston approaches the top of its compression stroke, igniting spontaneously as it contacts the heated air. The hot combustion gases expand, driving the piston downward. During its return swing, the piston pushes spent gases from the cylinder, and the cycle begins again with an intake of fresh air.

The predominant mechanism for NO_x formation from internal combustion engines is thermal NO_x, which arises from the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air.

4.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following technologies were evaluated for controlling NO_x emissions from the CI combustion engines. They are categorized as combustion modifications and post-combustion controls. Combustion modifications include: ignition timing retard, air-to-fuel ratio, and derating. Post combustion controls include SCR, NSCR catalyst, and NO_x absorption systems.

4.5.1.1 Ignition Timing Retard

As described above, the injection of diesel fuel into the cylinder of a CI engine initiates the combustion process. With ignition timing retard, this combustion modification lowers NO_x emissions by moving the ignition event to later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. Because the combustion chamber volume is not at its minimum, the peak flame temperature is reduced which reduces the formation of thermal NO_x.

4.5.1.2 Air-to-Fuel Ratio

Diesel engines are inherently lean-burn engines. The air-to-fuel ration can be adjusted by controlling the amount of fuel that enters each cylinder. By reducing the air-to-fuel ratio to near stoichiometric, combustion will occur under conditions of less excess oxygen and reduced combustion temperatures. Lower oxygen levels and combustion temperature reduce NO_x formation.

4.5.1.3 Derating

Derating involves restricting engine operation to lower than normal levels of power production. Derating reduces cylinder pressure and temperatures which reduces NO_x formation.

4.5.1.4 Selective Catalytic Reduction

Selective catalytic reduction systems introduce a liquid reducing agent such as ammonia or urea into the flue gas stream before the catalyst. The catalyst reduces the temperature needed to initiate the reaction between the reducing agent and NO_x to form nitrogen and water.

For SCR systems to function effectively, exhaust temperatures must be high enough (200°C to 500°C) to enable catalyst activation. For this reason, SCR control efficiencies are expected to be relatively low during the first 20 to 30 minutes after engine start up, especially during maintenance and testing. There are also complications controlling the excess ammonia (ammonia slip) from SCR use.

4.5.1.5 Non-Selective Catalytic Reduction

Non-selective catalytic reduction systems are used to reduce emission from rich-burn engines that are operated stoichiometrically or fuel-rich stoichiometric. In the engine exhaust, NSCR catalysts convert NO_x to nitrogen and oxygen. NSCR catalytic reactions require that O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel-ratios. Lean-burn engines are characterized by an oxygen-rich exhaust which minimizes the potential for NO_x reduction.

4.5.1.6 NO_x Absorption Systems (Lean NO_x Traps)

NO_x absorber development is a new catalyst advance for removing NO_x in a lean (i.e., oxygen rich) exhaust environment for both diesel and gasoline lean-burn direct-injection engines.

With this developing technology, NO is catalytically oxidized to NO_2 and stored in an adjacent chemical trapping site as a nitrate. The stored NO_x is removed in a two-step reduction step by temporarily inducing a rich exhaust condition. NO_x adsorbers (sometimes referred to as lean NO_x traps) employ precious metal catalyst sites to carry out the first NO to NO_2 conversion step. The NO_2 then is adsorbed by an adjacent alkaline earth oxide site where it chemically reacts and is stored as a nitrate. When this storage media nears capacity it must be regenerated. This is accomplished in by creating a rich atmosphere with injection of a small amount of diesel fuel. The released NO_x is quickly reduced to N_2 by reaction with CO on a rhodium catalyst site or another precious metal that is also incorporated into this unique single catalyst layer.

4.5.2 Step 2 - Eliminate Technically Infeasible Options

NSCR catalysts are effective to reduce NO_x emission when applied to rich-burn engines fired on natural gas, propane or gasoline. The proposed diesel engines are inherently lean-burn engines; thus, NSCR is eliminated from further consideration.

In addition, NO_x absorbers were eliminated from further consideration since NO_x adsorbers are experimental technology and no commercial applications of NO_x absorbers were identified in state or EPA's RBLC RACT/BACT/LAER Clearinghouse databases as being employed on stationary emergency generators or fire pumps. Also, the literature indicates that testing of these NO_x absorbers has raised issues about sustained performance of the catalyst. Current lean NO_x catalysts are prone to poisoning by both lube oil and fuel sulfur.

4.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control options, combustion modifications and the post-combustion control, SCR will be examined further. Combustion controls have been demonstrated to reduce NO_x emissions from CI engines by approximately 50%; the use of a SCR can reduce emissions in the range from 70 to 90%.

4.5.4 Step 4 - Evaluate Impacts and Document Results

The top control option, SCR, uses a reducing-agent like ammonia or urea (which is usually preferred) with a special catalyst to reduce NO_x in diesel exhaust to N₂. The SCR catalyst sits in the exhaust stream and the reducing agent is injected into the exhaust ahead of the catalyst. Once injected the urea becomes ammonia and the chemical reduction reaction between the ammonia and NO takes place across the SCR catalyst. With the use of an SCR, there is the potential for some ammonia to "slip" through the catalyst.

SCR systems have two key operating variables that work together to achieve NO_x reductions. These are the exhaust temperature and the injection of urea or ammonia. The exhaust temperature must be between 260°C and 540°C for the catalyst to operate properly. SCR systems will not begin injection of ammonia in the form of urea until the catalyst has reached the minimum operating temperature. Urea is a critical component in determining the control efficiency of the SCR. It must be injected in the exhaust stream upstream of the SCR system. In the catalyst, it reacts to reduce NO_x to form N₂ and H₂O. The reaction takes place because the catalyst lowers the reaction temperature necessary for NO_x.

Since SCR systems require an operating temperature between 260°C and 540°C, reaching these temperatures may be difficult in routine maintenance and testing operations where the engine is typically operated at low load for a short period of time. If the critical temperatures are not met while the engine is running, there will be no NO_x reduction benefit. To have NO_x reduction benefit, the engine would need to be operated with higher loads and for a longer period of time. This would be a challenge for HollyFrontier since each engine, with the exception of the generator at the East Tank Farm, is limited to 50 operating hours per year.

Urea handling and maintenance must also be considered. Urea crystallization in the lines can damage the SCR system and the engine itself. Crystallization in the lines is more likely in emergency standby engines due to their periodic and low hours of usage.

4.5.4.1 Energy, Environmental, and Economic Impacts

There are several downsides with using an SCR. First, an improperly functioning SCR system can create excess ammonia emissions. SCR systems also add significant equipment to the engine system which increases the possibility of failures and increasing on-going maintenance costs.

Cost evaluations were prepared to determine the cost of control per ton of NO_x removed from an SCR for the emergency generators and fire water pump. SCR retrofit information was obtained from Wheeler Machinery in Salt Lake City. Based on the cost information provided by Wheeler, the calculated costs per ton of NO_x removed are presented in Table 4-14 and in Appendix B.

Table 4-14 Cost Effectiveness of Installing SCR on Emergency Diesel Engines for NO_x Control

Equipment	Cost Effectiveness (\$/Ton)
135 kW generator (east tank farm)	\$ 16,201
224 HP (water well #3)	\$ 353,677
393 HP Fire Pump #1	\$ 353,998
393 HP Fire Pump #2	\$ 353,998
220 HP plant air backup compressor #1	\$ 353,456
220 HP plant air backup compressor #2	\$ 353,456
220 HP plant air backup compressor #3	\$ 353,456
470 HP diesel generator (boiler house)	\$ 354,736
380 HP diesel generator (central control room)	\$ 355,095
540 HP standby generator	\$ 723,683

In addition to the costs presented in Table 4-15, the cost of urea is \$1 per KW and its shelf life is approximately two years. This would increase the cost of operation a SCR for emergency standby engines since the low number of annual hours of operation could lead to the expiration of the urea. The urea would have to be drained and replaced, creating an extra maintenance step and an increased cost to HollyFrontier.

4.5.5 Step 5 - Select BACT

According to HollyFrontier’s approval order, the 135 kW generator at the tank farm is limited to 1,100 operating hours per year. However, since its commission date of 11/15/2010, this generator has run only 89.9 hours (as of 3/9/2017). Based on the economic costs to install a SCR system, the likelihood that the engine would not be at proper operating temperature for the SCR to be effective due to limited operating hours, and the extra maintenance and disposal costs if urea were used, SCR has been eliminated from further consideration.

Currently, California has the most aggressive emission reduction standards for diesel engines. The MSM identified includes the use of SCR systems to reduce NO_x on diesel engines 1000 HP or greater. SCR systems have not seen wide application on emergency standby engines less than 1000 HP. Maine Department of Environmental Protection requires **non**-emergency engines to install SCR technology for NO_x control if their potential annual NO_x emissions exceed 20 tons as best available control technology.

Periodic maintenance is performed on the engines in accordance with manufacturer specifications. For those engines subject to Subpart ZZZZ, oil is changed and hoses/belts inspected every 500 hours or annually.

Thus, the only control technologies for the diesel emergency generators and fire pumps (except the 135 kW generator at the East Tank Farm) are the work practice requirements to adhere to GCP and NO_x Tier standard for each engine and the best practice of performing periodic maintenance. These requirements have been determined to be BACM. These control strategies are technically feasible and will not cause any adverse energy, environmental, or economic impacts.

The proposed BACM controls, emission limitations, and compliance monitoring methods for HollyFrontier emergency diesel engines are summarized in Table 4-15.

Table 4-15 Proposed BACM Controls, Emission Limitations, and Compliance Monitoring Method for Emergency Diesel Engines

Pollutant	Units	Control Technology	Emission Limitations	Monitoring Method
NO _x	All emer. Engines except ETF gen.	Work Practice Requirements, Good Combustion Practice	600 hours total rolling 12-month period	Non-resettable hour meter
	ETF portable generator		1100 hours per rolling 12-month period	

4.6 Emergency Natural Gas-Fired Engines

HollyFrontier operates two natural gas-fired spark ignition emergency standby generators, each at 142 kW, at the Administration building. During combustion, the formation of NO_x is a result of thermal or fuel-bound reactions. The thermal formation of NO_x occurs when nitrogen and oxygen reacts at high temperatures. NO_x is also generated from the oxidation of nitrogen contained in the fuel. Since natural gas contains low concentrations of nitrogen, emissions of NO_x are primarily due to the thermal formation of NO_x in the combustion chamber.

4.6.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Four (4) control technologies were identified to reduce NO_x emissions from spark ignition engines which include:

- > SCR,
- > NSCR,
- > lean burn technology, and
- > good combustion practices.

4.6.1.1 Selective Catalytic Reduction

Selective catalytic reduction is a post-combustion NO_x control technology in which an aqueous urea solution is injected in the exhaust air stream which evaporates into ammonia. The ammonia and NO_x react on the surface of the catalyst forming water and nitrogen. SCR reactions occur in the temperature range of 650°F to 750°F. Precious metal catalysts are used to reduce NO_x.

4.6.1.2 Non-selective Catalytic Reduction

Non-selective catalytic reduction is a catalytic reactor that simultaneously reduces CO, NO_x, and HC emissions. The catalytic reactor is placed in the exhaust stream of the engine and requires fuel-rich air-to-fuel ratios and low oxygen levels.

4.6.1.3 Lean Burn Technology

Combustion is considered "lean" when excess air is introduced into the engine along with the fuel. The excess air reduces the temperature of the combustion process which reduces the amount of NO_x produced. In addition, since there is excess oxygen available, the combustion process is more efficient and more power is produced from the same amount of fuel.

4.6.1.4 Good Combustion Practices

Control of combustion temperature is the principal focus of combustion process control in natural gas-fired engines. There are combustion control tradeoffs, however. Higher temperatures favor complete consumption of the fuel and lower residual hydrocarbons and CO but result in increased NO_x formation. Lean combustion dilutes the fuel mixture and reduces combustion temperatures and therefore reduces NO_x formation. This allows a higher compression ratio or peak firing pressures resulting in higher efficiency. However, if the mixture is too lean, misfiring and incomplete combustion may occur.

Because the NO_x produced is primarily thermal NO_x, reducing the combustion temperature will result in less NO_x production. Thus, the main strategy for combustion control is to control the combustion temperature. This is most easily done by adding more air than what is required for complete combustion of the fuel. This raises the heat capacity of the gases in the cylinder so that for a given amount of energy released in the combustion reaction, the maximum temperature will be reduced.

4.6.2 Step 2 - Eliminate Technically Infeasible Options

The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich burn turbocharged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective NO_x reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 percent. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures. Thus, the add-on combustion control of NSCR is deemed technically infeasible. In addition, the operation of each generators is limited to 50 hours for testing (non-emergency) purposes. Since it is unlikely that these units will achieve normal operating temperature for any period of time, the add-on control using SCR, which requires a consistent operating temperature to be effective, is also technically infeasible.

4.6.3 Step 3 - Rank Remaining Control Technologies by Effectiveness

The remaining control technologies, lean burn technology and good combustion practices are both effective in reducing NO_x emissions.

4.6.4 Step 4 - Evaluate Most Effective Controls

In lean burn engines, the combustion process is enhanced by pre-mixing the air and fuel upstream of the turbocharger before introduction into the cylinder. This creates a more homogeneous mixture in the combustion chamber. The microprocessor-based engine will regulate the fuel flow and air/gas mixture and ignition timing to achieve efficient combustion.

Combustion controls are integral in the combustion process as they are designed to achieve an optimum balance between thermal efficiency-related emissions (CO and VOC) and temperature related emissions (NO_x). Combustion controls will not create any energy impacts or significant environmental impacts. There are no economic impacts from combustion controls because they are part of the design for modern engines.

EPA describes natural gas generators as Stationary Spark Ignition Internal Combustion Engines (SI ICE). Depending on the year of manufacturer, natural gas generators are regulated by 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. Here, the EPA provides emissions standards that manufacturers must meet, emissions standards owners/operators must meet, EPA certification requirements, testing requirements, and compliance requirements.

According to Subpart JJJJ, the NO_x Emission Standards for stationary emergency engines >25 HP is 2.0 g/HP-hr or 1 ppmvd @ 15% O₂. The HollyFrontier natural-gas fired emergency generators were manufactured in 2012 and as such, meet the Subpart JJJJ NO_x emission standards.

4.6.4.1 Energy, Environmental, and Economic Impacts

There are no energy, environmental or economic impacts associated with the use of lean burn technology and good combustion practices.

4.6.5 Step 5 - Select BACT

The most stringent controls identified is the use of natural gas, good combustion practices and maintenance in accordance with manufacturer recommendations with an emission rate of 1 ppmvd @ 15% O₂ or 2.0 g/HP-hr. BACT for NO_x emissions from 2012 model year SI ICE generators at HollyFrontier is the application of a lean burn engine fired on natural gas, good combustion practices, limited operating hours, and operation in accordance to manufacturer's recommendations. The generators are EPA certified and the manufacturer lists a NO_x emission rate of 2.0 g/HP-hr or 1 ppmvd @ 15% O₂. The engines are in compliance with the applicable emission limits of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ. Maintenance on the engines will be performed in accordance with manufacturer specifications which includes inspection of the air cleaner. The proposed controls and maintenance satisfy BACM.

The proposed BACM controls, emission limitations, and compliance monitoring methods for HollyFrontier the emergency natural gas-fired engines are summarized in Table 4-16.

Table 4-16 Proposed BACM Controls, Emission Limitations, and Monitoring for Emergency Natural Gas Engines

Pollutant	Units	Control Technology	Emission Limitation	Monitoring Method
NO _x	Nat. gas fired emergency engines	Work Practice Requirements, Good Combustion Practice	600 hours total rolling 12-month period for all emergency engines	Non-resettable hour meter

5.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR SULFUR DIOXIDE

BACM's were evaluated for oxides of sulfur dioxide (SO₂) emissions from certain process units in operation or proposed at the Woods Cross Refinery. These include: process heaters, boilers, flares, SRU, FCCUs, and emergency diesel and natural gas-fired engines.

5.1 Process Heaters and Boilers

Sulfur dioxide (SO₂) emissions from process heaters and boilers are a direct function of the sulfur content of the fuel that is burned. Reduced sulfur compounds in the fuel are readily oxidized to SO₂ and to a small extent SO₃. Both refinery gas and natural gas contain sulfur, mostly in the form of hydrogen sulfide (H₂S). In general, refinery fuel has higher sulfur content than pipeline quality natural gas.

5.1.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following is a list of control technologies which were identified for controlling SO₂ emissions:

- fuel specification - low sulfur fuels;
- wet flue gas desulfurization (wet FGD);
- advanced flue gas desulfurization (AFGD);
- dry absorption (dry FGD); and,
- Emerachem EMX.

5.1.1.1 Fuel Specifications

In general, sulfur combusted in the fuel will be converted to SO₂. By limiting the sulfur content of the fuel, emissions of SO₂ will be reduced. Emissions of SO₂ from process heaters and boilers can be controlled by fuel specifications or by using post-combustion controls.

Pipeline quality natural gas has very low sulfur content (approximately 4 ppmv) generally in the form of mercaptans used for odorization. The gas may also contain trace quantities of reduced sulfur compounds (a few grains/100 scf). SO₂ emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and do not require additional control equipment.

Refinery fuel gas has a higher sulfur content than the natural gas purchased from a pipeline. The refinery gas sulfur content is dependent on the removal efficiency of the fuel gas amine scrubbing units in a refinery. HollyFrontier operates an amine scrubbing system to produce refinery gas with less than 60 ppmv H₂S, on an annual average basis (40 CFR 60, Subpart Ja). On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the lean gas produced (e.g., as much as 162 ppmv sulfur on a 3-hour average basis). Based on natural gas usage, SO₂ emissions are determined based on 0.60 lb SO₂/MMscf.

5.1.1.2 Flue Gas Desulfurization

Flue gas desulfurization (FGD) is commonly used for control of SO₂ from solid fuel-combustion, such as coal. FGD technology can be achieved through a variety of wet or dry scrubbing processes. Generally speaking, it has control efficiencies of up to 95 percent on coal-fired combustion systems.

The simplest method for flue gas desulfurization is with the use of a wet scrubber. In a wet caustic scrubbing system, the flue gas and a caustic solution flow counter-current to each other. The sulfur reacts with the caustic solution and is stripped out of the flue gas.

The advanced FGD process accomplishes SO₂ removal by utilizing a single absorber which performs three functions which are prequenching the flue gas, adsorption of SO₂, and oxidation of the resulting calcium sulfite to wallboard-grade gypsum. Incoming flue gas is cooled and humidified with process water sprays before passing to the absorber.

In the absorber, two tiers of fountain-like sprays distribute reagent slurry over polymer grid packing that provides a large surface area for gas/liquid contact. The gas then enters a large gas/liquid disengagement zone above the slurry reservoir in the bottom of the absorber and exits through a horizontal mist eliminator. As the flue gas contacts the slurry, the SO₂ is absorbed, neutralized, and partially oxidized to form calcium sulfite and calcium sulfate.

Dry FGD systems spray lime slurry into an absorption tower where the SO₂ is absorbed by the slurry forming calcium sulfite and calcium sulfate. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter or an electrostatic precipitator (ESP).

5.1.1.3 Emerachem (EMx™)

Emerachem EMx™ is an add-on technology that utilizes a catalyst to absorb the SO₂ in the flue gas. The catalyst is periodically regenerated using hydrogen. The regenerated stream is treated in a sulfur recovery unit or adsorbed on carbon.

5.1.2 Step 2 - Eliminate Technically Infeasible Options

FGD is commonly used for control of SO₂ from solid fuel-combustion, such as coal. A review of the recent literature, recent permits, and the RBLC database did not result in AFGD and wet FGD or dry FGD as BACT. Limestone slurry scrubbing systems are usually applied to power plants for flue gas desulfurization. With wet caustic scrubbing, water contamination issues arise with the disposal of large volumes of sodium sulfite and sodium sulfate solution. In addition, based on available literature, FGD technology is not commercially demonstrated on refinery process heaters because it is cost-prohibitive compared to the cost of desulfurizing the fuel gas (in this case, via the use of an amine scrubbing system).

As mentioned above, Emerachem EMx™ is an add-on technology that utilizes a catalyst to absorb the SO₂ in the flue gas. This technology has not been proven to run longer than one year without a turnaround. HollyFrontier requires the refinery heaters to be able to operate at least three years between turnarounds. Thus, Emerachem EMx™ was not considered to be technically feasible on the refinery heaters at the refinery.

5.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top-performing feasible SO₂ control technology is the firing of 100% purchased natural gas in the heater, because of the very low sulfur content of natural gas. The next most effective control technology is the use of refinery fuel gas treated to sulfur levels that meet the requirements of 40 CFR 60, Subpart Ja.

5.1.4 Step 4 - Evaluate Impacts and Document Results

Several sources of information were examined including EPA's RBLC RACT/BACT/LAER Clearinghouse, state agency databases, vendor data, and published literature to identify the most effective SO₂ control technologies, most stringent emissions limitations to compare against current SO₂ controls that have been or proposed to be implemented at the Woods Cross Refinery. Table 5-1 presents a summary of select BACT determinations for SO₂ for process heaters and boilers. All units listed in Table 5-1 are fired on refinery gas.

Table 5-1 BACT Determinations for SO₂ for Process Heaters and Boilers

Facility	Permit Date	Size (MMBtu/hr)	H ₂ S Limit (lb/MMBtu)	Control
Lima Refining Company	12/23/2013	Crude distillation unit II	60 ppmv (365-day rolling average)	Refinery fuel gas sulfur removal
Sinclair Wyoming Refining Company	10/15/2012	50, 233	--	Follow Ja Fuel Gas H ₂ S limits (162 ppm in RFG, 3-hour basis and 60 ppm in RFG, 365-day rolling average)
ConocoPhillips Company Billings Refinery, Montana	11/19/2008	Crude heater, No 1 & No 2 H ₂ Heater	34 ppmv H ₂ S (rolling 365-day average) 162 ppmv H ₂ S 3-hour rolling avg. during startup/shutdown	Fuel gas cleanup-chemical absorption/amine system
Valero Refining - New Orleans LLC St. Charles Refinery	11/17/2009	24, 52, 83, 86, 100, 135, 336	--	Use of pipeline quality natural gas or refinery fuel gases with an H ₂ S concentration less than 100 ppmv (annual average)

As seen from Table 5-1, the only method indicated to control SO₂ emissions in process heaters and boilers is to limit the sulfur content in the gaseous fuel. HollyFrontier employs an amine treatment unit which uses methyl diethanolamine (MDEA) to remove H₂S out of plant fuel gas to a level of 60 ppm or less on an annual basis.

5.1.4.1 Energy, Environmental, and Economic Impacts

There are no anticipated energy or environmental impacts associated with top control option which is the treatment of the refinery fuel gas to limit the sulfur content of the fuel.

5.1.5 Selection of BACM

BACT for SO₂ is a refinery-wide permit limit on the sulfur content on the refinery gas system, including both short-term and long-term H₂S limits and the use of pipeline quality natural gas to supplement the refinery gas when needed.

The most stringent emission limit identified is at the Hyperion Energy Center which has a maximum refinery gas sulfur level of 35 ppmv, based on an hourly rolling 24-hour average, excluding periods of startup, shutdown, and malfunction. The Hyperion Energy Center is comprised of an Integrated Gasification Combined Cycle (IGCC) Power Plant with a petroleum refinery. A second facility, the Billings Refinery in Montana lists a H₂S limit of 34 ppmv based on a rolling 365-day average using a chemical absorption/amine system. Although this limit is more stringent than HollyFrontier's 60 ppmv limit based on a 365-day average, HollyFrontier utilizes an amine treatment system to limit sulfur content.

Thus, BACT has been determined to limit the sulfur content on the refinery gas to meet the limit of 60 ppmv on a 365 day basis and 162 ppmv based on a three-hour rolling average. The H₂S fuel content of the refinery gas is verified through a continuous emission monitor. These limits meet the applicable NSPS Subpart Ja and AO requirements.

The cost of installing and operating CEMS on each heater and boiler was examined. The estimated equipment cost including a shelter and a SO₂ CEMS with affiliated equipment plus installation is over \$201,600 per system. Total annual operating costs were estimated to be approximately \$72,820. See Appendix B for a detailed cost analysis. Based on PTE emissions from the process heaters, the average cost-per-ton to monitor for SO₂ with a CEMS is over \$1.6 million dollars.

The proposed BACM controls, SO₂ emission limits, and compliance monitoring methods conducted for HollyFrontier the process heaters and boilers are summarized in Table 5-2.

Table 5-2 Proposed BACM Controls, SO₂ Emission Limits, and Monitoring Methods for Process Heaters and Boilers

Pollutant	Units	Control Technology	Emission Limit	Monitoring
SO ₂	4H1, 6H1, 6H2, 6H3, 7H1, 7H3, 8H2, 9H1, 9H2, 10H1, 10H2, 11H1, 12H1, 13H1, 19H1, 20H2, 20H3, 23H1, 24H1, 25H1, 27H1, 30H1, 30H2, 33H1, 68H2, 68H3, 68H4, 68H5, 68H6, 68H7, 68H10, 68H11, 68H12, 68H13, Boilers #4, #5, #8, #9, #10, #11	Sulfur content on the refinery gas Pipeline quality natural gas (supplemental) as needed	H ₂ S content of 60 ppmv on a 365 consecutive operating day average. H ₂ S content to 162 ppmv on a 3-hour rolling average basis.	CEMS located at plant fuel gas mix drum/header

5.2 Flares

SO₂ emissions from flares result primarily from the combustion of sulfur-containing gases vented from the refinery processes. A minor contributor to SO₂ emissions from the flares is the natural gas combustion of the pilot flame.

5.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following control technologies were identified to control SO₂ emissions from flares:

- Maintain flared gas parameters (e.g. heat content, composition, velocity) to allow for good combustion,
- Meet the requirements of 40 CFR 60.18 and 40 CFR Part 60 Subpart Ja,
- Proper design including know-out pot and seal drum and monitor for continuous presence of flame,
- Good combustion, operating, and maintenance practices,
- Limit sulfur content of feedstock and fuels,
- Root cause analysis, and
- Flare gas recovery.

5.2.1.1 Maintain Flare Gas Parameters

The key parameters to be maintained to assure proper gas flow through the system and appropriate conditions for thermal destruction of combustible pollutants include flame presence, exit gas velocity, temperatures at flare inlet and outlet and combustion zone, pressure and pressure differentials of system components, and liquid levels in water seals and knockout drum.

5.2.1.2 Meet the Requirements of 40 CFR 60.18

If a flare is used as the control device, it has to meet the specifications described in the general control device requirements (Sec. 60.18). This includes that flares be designed and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, that a flame is present at all times, that either the heat content specifications and the maximum tip velocity specifications are met, to name a few of the requirements.

5.2.1.3 Proper Design

Flare design depends on the sources of the gas being vented into the flare heater and such gas characteristics as flowrate, composition, and temperature, the available gas pressure and utility costs. Safety, regulatory, and environmental requirements are considered as well.

5.2.1.4 Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option for improving combustion efficiency of the flare. Good combustion practices include proper operation, maintenance, and tune-up of the flare per manufacturer's specifications.

5.2.1.5 Limit Sulfur Content of Feedstock and Fuels

HollyFrontier processes sweeter crudes, those lower in sulfur content, than sour crudes which are pumped from wells in Mexico and Saudi Arabia, for example. Crudes, such as black and yellow wax crudes, are inherently low in sulfur, around 900 ppm. Western Canadian Select which is also processed by HollyFrontier has a sulfur content of 34,000 ppm.

Pipeline quality natural gas has very low sulfur content (approximately 4 ppmv) generally in the form of mercaptans used for odorization. The gas may also contain trace quantities of reduced sulfur compounds (a few grains/100 scf). SO₂ emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and do not require additional control equipment.

Refinery fuel gas has a higher sulfur content than the natural gas purchased from a pipeline. HollyFrontier operates an amine scrubbing system to produce refinery gas with less than 60 ppmv H₂S on an annual average basis (40 CFR 60, Subpart Ja). On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the lean gas produced (e.g., as much as 162 ppmv sulfur on a 3-hour average basis).

5.2.1.6 Root Cause Analysis

Developing and implementing procedures for conducting a root cause analyses (RCA) following process upsets and malfunctions that produce flare gas in excess of a designated volumetric flow rate threshold is an effective option for minimizing flaring during these events. Performing a RCA involves a specific evaluation of each flaring incident caused by process upset or malfunction, including the identification of the causes of flaring, assessment of measures to eliminate or reduce future flaring from the same cause, and implementation of any feasible measures identified.

5.2.1.7 Flare Gas Recovery System

Flaring can be reduced by installation of commercially available recovery systems. A flare gas recovery system is a system comprised of compressors, pumps, heat exchangers, knock-out pots and water seals, installed to prevent or minimize the combustion of vent gas in a flare.

5.2.2 Step 2 - Eliminate Technically Infeasible Options

The control technologies identified above have been determined to be technically feasible.

5.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top ranking control option is the installation of a flare gas recovery system. Flare gas recovery systems are achieved in practice. The second highest ranking control option includes proper equipment design and work practices, good combustion practices, and limiting of sulfur content of feedstock and fuels.

5.2.4 Step 4 - Evaluate Impacts and Document Results

HollyFrontier will install a flare gas recovery system to recover vent gas which is the highest ranked control option. Since this is the highest ranked control option, energy, environmental and costs analyses are not required.

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. Because the flares are located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 CFR Part 60 Subpart Ja and the design and work practice requirements of 40 CFR 60.18.

Flare management plans have been developed for both the north and south flare. These plans contain procedures to minimize or eliminate discharges to the flare during startups and shutdowns. To verify that the procedures are followed, records are maintained. A RCA is initiated for each event resulting in emissions of SO₂ greater than 500 pounds in any 24-hour period or a discharge to the flare in excess of 500,000 standard cubic feet above the baseline in any 24-hour period and corrective action is implemented for reportable flaring incidents.

The amount of H₂S is limited in the refinery fuel gas to 162 ppm for continuous, intermittent, routinely-generated refinery fuel gases and this limit is continuously monitored or intermittently monitored under an EPA approved alternative monitoring system.

Emissions from the HollyFrontier Woods Cross Refinery flares under normal operation will consist only of the emissions from the combustion of natural gas in the flare pilot flames and a small amount of purge gas that is circulated through the flare system for safety reasons (i.e., to prevent air from entering the flare lines).

5.2.4.1 Energy, Environmental, and Economic Impacts

Since HollyFrontier has chosen the highest ranked control option, flare gas recovery, energy, environmental and costs analyses are not required.

5.2.5 Step 5 - Selection of BACM

Holly is proposing the following design elements and work practices as BACM for the flares:

- Use of low sulfur fuel such as natural gas as fuel for pilot flame;
- Maintaining an acceptable net heating value and exit velocity of flared gases under all flow conditions in accordance with manufacturer specifications;
- Use of a thermocouple to monitor presence of the pilot flame;
- Implementation of good combustion, operating, and maintenance practices;
- Implementation of flare management plan;
- Conduct of Root Cause Analyses;
- Flare operation in accordance to 40 CFR Part 60, Ja and design and work practice standards as codified in 40 CFR Part 60.18; and,
- Installation of flare gas recovery system.

No other measures were identified as more stringent measures for the flares at the Woods Cross Refinery. The flare design includes steam assisted combustion. The flares will be equipped with a flare gas recovery system for non-emergency releases, and a continuous pilot light. Pilot and sweep fuel will be natural gas or treated refinery gas.

The north and south flares are equipped with flow meters and gas combustion monitors. H₂S and SO₂ CEMS are also installed on each flare. Records of discharges greater than 500 lb SO₂ in 24-hour period and in excess of 500,000 scf above baseline in 24-hour period would cause a root cause analysis to be prepared and corrective action taken.

The proposed BACM controls, SO₂ emission limits, and monitoring methods conducted for HollyFrontier the flares are summarized in Table 5-3.

Table 5-3 Proposed BACM Controls, SO₂ Emission Limits, and Monitoring Methods for Flares

Pollutant	Unit	Control Technology	Emission Limit	Monitoring Methods
SO ₂	66	Flare gas recovery system Low sulfur fuel, GCP Flare management plan	500 lb SO ₂ in 24-hour period 500,000 scf above baseline in 24-hr period	Flow meters, gas combustion monitors, and H ₂ S and SO ₂ CEMS

5.3 Sulfur Recovery Plant

Hydrogen sulfide that has been removed in the Amine Treatment Unit (Unit 16) is processed in a Claus SRU to convert the H₂S to elemental sulfur which is sold commercially. H₂S rich gases from the Sour Water Stripping Unit (SWS) (Unit 18) go to Unit 22, the ammonia stripper. Unit 22 removes ammonia and results in a feed to the SRU that produces higher recovery than would occur if the ammonia were left in the gas. The SO₂ and remaining H₂S are sent to catalytic reactors where additional sulfur is recovered. Any unconverted H₂S and SO₂ are sent to the SRU Tailgas Incinerator (17-1) where purchased natural gas is used to burn any remaining H₂S. It should be noted, however, that in October 2016, the effluent from the SRU Tailgas Incinerator is redirected to a Belco wet gas scrubber (Unit 4 or Unit 25). The SRU does not operate if the wet gas scrubber is not operational. The recovered elemental sulfur is stored in a sulfur pit as a liquid until sold. Liquid sulfur is pumped from the pit and loaded into trucks for shipment off-site.

5.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Control options for SO₂ emissions include equipment configuration as well as proprietary adaptations of the Claus SRU technology.

Equipment configurations are control options. Equipment configurations include:

- > Claus SRU without tail gas treatment unit (TGTU),
- > Claus SRU without incinerator,
- > Claus SRU with TGTU but without incinerator,
- > Claus SRU with TGTU and with incinerator, and
- > Claus SRU with TGTU and wet scrubbing.

In any of the configurations above (i.e. Claus SRU without TGTU), a Claus unit can be replaced with a different number of Claus units. For example, a three-stage Claus unit can be replaced with two-stage Claus unit. Also, the TGTU could be replaced with multiple TGTUs.

Other alternatives, which include a number of proprietary adaptations of the Claus SRU technology, were identified. These adaptations generally operate by extending the Claus reaction to improve the thermodynamically achievable sulfur conversion efficiency. The proprietary adaptations identified include:

- > the Superclaus process,
- > the Euroclaus process,
- > the Mobil Oil Direct Oxidation process,
- > the COPE, Oxyclaus, and SURE processes,
- > the Selectox process,
- > the Sulfreen process,
- > the Maxisulf, CBA, Clinsulf, and MCRC processes,
- > the Wellman-Lord, CANSOLV, and CLINTOX processes,
- > the Stretford, Z-SORB, LO-CAT, and CrystaSulf liquid-phase oxidation reduction technologies, and,
- > the Shell Claus Offgas Treating (SCOT) process.

5.3.1.1 Superclaus Process

The Superclaus process is a conventional Claus process with a proprietary catalyst replacing the conventional, activated alumina Claus catalyst in the final catalytic reactor stage. The proprietary catalyst in the Superclaus process oxidizes H₂S to form elemental sulfur and water.

5.3.1.2 Euroclaus Process

The Euroclaus process is an enhancement of the Superclaus process with a hydrogenation reactor inserted upstream of the final catalytic reactor stage. This hydrogenation reactor reduces SO₂ concentration in the final reactor stage.

5.3.1.3 Mobil Oil Direct Oxidation Process

The Mobil Oil Direct Oxidation Process also involves a hydrogenation reactor and a catalytic direct oxidation reactor added to the back end of a Claus SRU.

5.3.1.4 COPE, OxyClaus, and SURE Processes

Oxygen enrichment is used in order to improve temperature control in the first-stage thermal reactor in several proprietary adaptations of the Claus process. These include the COPE, OxyClaus, and SURE processes. The typical SRU reaches its ultimate capacity when maximum allowable front-end pressure prevents further increase in feed rate. The front-end pressure of an SRU is usually limited by either process seal leg depth, combustion air blower discharge pressure or the operating pressure of an upstream amine unit regenerator. Oxygen enrichment reduces process flow rate by reducing the quantity of nitrogen that enters with the combustion air. This reduction in process flow rate allows a corresponding increase in SRU feed rate.

5.3.1.5 Selectox

The Selectox process is similar to the conventional Claus process but has a catalytic oxidizer in place of the first-stage thermal reactor.

5.3.1.6 Sulfreen

The Sulfreen process utilizes a conventional Claus process with an additional Claus-type reactor after the final sulfur condenser. This additional reactor operates at a temperature below the sulfur dew point and adsorbs the sulfur on the Claus catalyst. Each of the two beds in the additional reactor is cycled between adsorption and regeneration. During the regeneration cycle, the hot gases are produced in an integral heater and, after desorbing the sulfur from the catalyst, are passed through an integral condenser.

5.3.1.7 Maxisulf, CBA, Clinsulf, and MCRC Processes

The Maxisulf, CBA, Clinsulf, and MCRC processes are similar to the Sulfreen process but without the integral heater and the recycle function in the sub-dew point part of the process.

5.3.1.8 Wellman-Lord, CANSOLV, and CLINTOX Processes

The Wellman-Lord, CANSOLV, and CLINTOX process are essentially wet scrubbers in which proprietary solvents are used for SO₂ removal. All of these technologies require an upstream combustion device in order to convert reduced sulfur compounds to SO₂. Also, any of these technologies can be used with or without SRU's upstream of the combustion device. When used in conjunction with an upstream Claus SRU, these technologies allow the SO₂ to be stripped from the solvent and returned to the front end of the SRU.

5.3.1.9 Stretford, Z-SORB, LO-CAT, and CrystaSulf Liquid-Phase Oxidation Reduction Technologies

Stretford, Z-SORB, LO-CAT, and CrystaSulf are proprietary liquid-phase oxidation-reduction technologies providing indirect oxidation of H₂S to form elemental sulfur and water. The Stretford process uses a vanadium-based chelating agent, the Z-SORB process uses a zinc-based chelating agent, and the LO-CAT and CrystaSulf technologies use proprietary, iron-based chelating agents.

5.3.1.10 Shell Claus Offgas Treating (SCOT) Process

The SCOT process removes sulfur from Claus SRU vent streams and is the basis for the TGTU.

5.3.2 Step 2 - Eliminate Technically Infeasible Options

Several of the identified proprietary technologies, Wellman-Lord CANSOLV, CLINTOX, LO-CAT, and CrystaSulf control strategies are considered technology infeasible because, based on available literature, they have not been demonstrated to function efficiently in removing sulfur from acid gas streams from refinery sour water strippers and amine regeneration units.

Any control strategy involving a combustion device to burn the acid gases to control SO₂ emissions is a technically infeasible control option because it would not meet the NSPS requirements set forth in 40 CFR 60, Subpart Ja.

Using a conventional Claus SRU without a TGTU, either with or without an incinerator, also is technically infeasible as a control option because it would not meet the NSPS requirements set forth in 40 CFR 60, Subpart Ja. The same applies to a Claus SRU that is replaced with any of the Claus adaptations that use oxygen enrichment (COPE, OxyClaus, and SURE) or the Superclaus, Euroclaus, Mobil Oil Direct Oxidation, Selectox, Sulfreen, Maxisulf, CAB, Clinsulf or MCRC processes.

5.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The SRU at the Woods Cross Refinery is comprised of a three-stage Claus SRU followed by tailgas incinerator and a wet scrubber. This control option will achieve an overall sulfur recovery efficiency of 99.8 percent.

Several other alternative control strategies similar to the one utilized by HollyFrontier were identified that would achieve similar control efficiencies. These include:

- > any number of SRU's in parallel, followed by any number of TGTU's in parallel,
- > one three-stage Claus SRU followed by any number of parallel TGTU's and a downstream incinerator,
- > three, three-stage Claus SRU's followed by any number of parallel TGTU's and a downstream incinerator.

5.3.4 Step 4 - Evaluate Impacts and Document Results

Each of the control options would allow sulfur to be emitted to the atmosphere at a rate that is the same as the control option proposed by HollyFrontier. The Claus SRU employs a three-stage reactor train to convert feed sulfur, in the form of H₂S, into elemental sulfur. The system is operated sub-stoichiometrically with air such that only one third of the H₂S is oxidized to SO₂. This oxidation reaction occurs primarily in the first reactor.

The second reaction begins in the first reactor and continues in the two catalytic reactors. Each of the three reactor states is followed by a condenser that cools, condenses, and removes the elemental sulfur.

In addition to the two primary chemical reactions described above, secondary reactions also occur due to impurities in the system. Hydrocarbons in the acid gas streams entering the thermal reactor are partially oxidized to form carbon dioxide and water. Carbon dioxide and unreacted hydrocarbons react with sulfur to form carbonyl sulfide (COS) and carbon disulfide (CS₂). These carbon-sulfur compounds may be partially hydrolyzed in the first catalytic reactor to form H₂S but mainly flow unreacted through the SRU.

Because the Claus process, from the third condenser of the Woods Cross Claus SRU, the resulting SRU off gas is routed to a tail gas incinerator and then to one of the wet gas scrubbers (4V82 FCC or 25 FCC Scrubber).

The EPA's RBLC database was reviewed to determine SO₂ control methods for SRU's. The results of this search are presented in Table 5-4.

Table 5-4 BACT Determinations for SO₂ for Sulfur Recovery Units

Facility	Permit Date	SO ₂ Concentration Limit	Control
Lima Refining Company	12/23/2013	19.18 lb/hr (12-hour average) 250 ppmv dry basis 0% excess air	Tail gas treatment unit and tail gas incinerator
Diamond Shamrock Refining Company Valero McKee Refinery	12/20/2013	No limits listed	SCOT technology and tail gas incinerators to achieve 99.8% sulfur recovery
BP Products, North America Inc.	09/20/2013	250 ppmv dry basis 0% excess air, 12-hour average	SRU followed by tail gas incinerator. Meets subpart J requirements
Valero Refining, Texas LP, Corpus Christi East Texas Refinery	08/19/2010	267.0 lb/hr	Minimize TGPU down time and operating rate
Valero Refining, Texas LP, Corpus Christi West Texas Refinery	03/29/2010	761.0 lb/hr	Minimize TGPU down time and operating rate
Valero Refining - New Orleans LLC St. Charles Refinery	11/17/2009	250 ppmvd 12-hour rolling average	Thermal oxidizers - comply with Subpart J requirements
Sunoco Company Inc. Toledo Refinery	01/29/2008	9.88 lb/hr 250 ppmv dry basis 0% excess air rolling 12-hour average	Tail gas treatment units and SRU Incinerator for H ₂ S
Navajo Refining Company, LLC Arteria Refinery	12/14/2007	192.0 ppmvd 12-hour rolling average @ 0% O ₂	Tail gas incinerator

5.3.4.1 Energy, Environmental, and Economic Impact

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. During normal operation, the use of a three-stage Claus SRU followed by the tailgas incinerator and a wet scrubber is a top ranked technology and besides waste generation, no adverse energy or economic impacts are anticipated.

5.3.5 Step 5 - Selection of BACM

The existing equipment and control options chosen by HollyFrontier are widely used and have demonstrated 99.8% sulfur recovery efficiency or better in the petroleum industry. The SO₂ BACM emission limit is based on the use of a three-stage Claus SRU followed by tail gas incinerator and a wet scrubber during normal operations. Amine scrubbing is used to reduce H₂S emissions in the fuel gas at HollyFrontier. The FCCU wet scrubbers (4V82 FCC Scrubber and 25FCC Scrubber) are equipped with CEMS to measure SO₂ emissions. The SRU is not operated if the wet scrubbers are not operational.

The most stringent controls identified for a SRU > 10 LTPD is a three-stage Claus, amine-based tail gas treating units with an expected control efficiency of 99.9% (10 ppmvd).

The proposed BACM controls, SO₂ emission limits, and monitoring methods conducted by HollyFrontier for the SRU are summarized in Table 5-5.

Table 5-5 Proposed BACM Controls, SO₂ Emission Limits, and Monitoring Methods for SRU

Pollutant	Unit	Control Technology	Emission Limit	Monitoring Methods
SO ₂	17	Three-stage Claus followed by tail gas incinerator and a wet scrubber	95% sulfur recovery based on 30-day average except during startup, shutdown, malfunction	Flow rate and H ₂ S concentration in the feed
			0.05 tons per day (wet scrubbers) 17.7 tons per year (wet scrubbers)	SO ₂ CEMS

5.4 FCCU

Depending on the feed sulfur content and FCCU design, sulfur emissions in the form of SO₂ and SO₃ from the regenerator can vary significantly. In the FCCU reactor, 70 to 95 percent of the incoming feed sulfur is transferred to the acid gas and product side in the form of H₂S. The remaining of the incoming feed sulfur is attached to the coke where it is oxidized into sulfur oxides and emitted in the FCCU regenerator flue gas.

5.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following is a list of control technologies which were identified for controlling SO₂ emissions from the FCCUs:

- > Control of sulfur in the FCCU feed
- > Feed hydrotreatment
- > Wet Gas Scrubbers
- > Wellman-Lord Flue Gas Desulfurization Process
- > DeSO_x Additives

5.4.1.1 Control of Sulfur in FCCU Feed

HollyFrontier processes sweeter crudes, those lower in sulfur content, than sour crudes which are pumped from wells in Mexico and Saudi Arabia, for example. Crudes, such as black and yellow wax crudes, are inherently low in sulfur, around 900 ppm. Western Canadian Select which is also processed by HollyFrontier has a sulfur content of 34,000 ppm.

5.4.1.2 Feed Hydrotreatment

At HollyFrontier, the Unit 4 feedstock is hydrotreated in Unit 20, the gas oil hydrocracker (GHC). The GHC unit desulfurizes gas oil to the FCCU which reduces sulfur in the unit products. In the feedstock hydrotreatment process, the FCCU feedstock is treated over a metal catalyst in a hydrogen environment before the cracking process. Depending on initial sulfur levels, flue gas emissions of SO₂ can be reduced by up to 90 percent with the additional benefit of reductions in nitrogen compound and trace metal emissions. The feed to Unit 25 is not hydrotreated but lower sulfur feed is used by this unit.

5.4.1.3 Wet Gas Scrubbers

Wet gas scrubbers are principally defined in Section 6.1.1.3. The water used in a wet gas scrubber is mixed with an alkaline reagent to react with the SO₂ to form sulfate and sulfite salts. These compounds are captured as a wet solid in the filtering section of the wet gas scrubber. The SO₂ removal efficiencies typically range from 95 to 99.9%.

5.4.1.4 Wellman-Lord Flue Gas Desulfurization Process

In the Wellmann-Lord flue gas desulfurization process, flue gas enters the absorber and gas is scrubber using an aqueous sodium sulfate solution. The scrubbed flue gas exits the absorber, passes through a set of demisters and is discharged to the atmosphere. The SO₂ removal efficiency using this process is between 85 to 98%.

5.4.1.5 DeSO_x Additives

DeSO_x additives are typically metal oxide catalysts that are added to the regenerator to convert SO₂ to SO₃. The metal oxide catalyst is introduced to the feed in the riser with the regenerated catalyst. The SO₃ is adsorbed to a sulfate and then recycled back to the reactor with the FCCU catalyst where it is reduced in the riser/reactor to H₂S which is controlled by a refinery's sulfur plant.

5.4.2 Step 2 - Eliminate Technically Infeasible Options

All options are technically feasible.

5.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The following lists the ranking of the remaining control options:

- > Wet Gas Scrubbers - 95-99.9%
- > Wellman-Lord Flue Gas Desulfurization Process - 85-98%
- > Feed hydrotreatment - ≤90%
- > DeSO_x additives - 30%
- > Control of sulfur in the FCCU feed - Baseline

5.4.4 Step 4 - Evaluate Impacts and Document Results

According to EPA's RBLC, wet scrubbers have been successfully applied to several refinery FCCUs to control emissions of SO₂. Recent consent decrees will require several refineries to install wet gas scrubbers to reduce SO₂ emissions. Several designs of wet scrubbers are available (plate or tray towers, spray chambers, and venturi) and emission control levels for SO₂ between 95-99.9% have been achieved.

The Wellman-Lord Flue Gas Desulfurization process has been used successfully in Japan, Germany, and the United States but no new units were identified that have been built in recent years.

DeSO_x additives are added to a regenerator to reduce the SO_x from the flue gas of the regenerator. This catalyst converts SO₂ in the regenerator to SO₃ and stabilizes it as a metal sulfate. This metal sulfate is then introduced to the feed in the riser with the regenerated catalyst. The riser has a reducing atmosphere as opposed to the oxidizing atmosphere in the regenerator. The metal sulfate is converted to H₂S in the riser/reactor and released with the products to the fractionator.

Although more than 70 refiners have successfully used DeSO_x additives worldwide, there are a number of operating variables that have been identified as having significant effects on the performance of SO_x reduction additives. Some of these include the presence of combustion promoters, the ratio of catalyst circulation rate to unit catalyst inventory, temperature, availability of oxygen in the regenerator, feed sulfur content, and SO_x concentration. Various scientific studies have shown that the fraction of sulfur in the feed has a direct impact on the coke sulfur content deposited on spent catalyst and, thus, on SO_x emissions. Since the sulfur content of the proposed feed is low and the amount of SO₂ control that can be achieved by using DeSO_x additives is significantly less than the top ranking option, DeSO_x additives are eliminated from further consideration.

Table 5-6 presents a summary of BACT determinations for SO₂ from FCCU units.

Table 5-6 BACT Determinations for SO₂ for FCCU

Facility	Permit Date	Emission Limit	Control
Krotz Springs Refinery	04/26/2012	25 ppmvd@0% O ₂ 365-day rolling average	None listed
Valero Delaware City Refinery	02/26/2010	25 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber
Valero Three Rivers Refinery	04/05/2007	25 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber
Valero Texas City Refinery	04/03/2007	25 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber
Map Texas City Plant	03/28/2007	20 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber
ExxonMobil Torrance Refinery	03/23/2007	25 ppmvd@0% O ₂ 365-day rolling average	Low sulfur feed
Chevron El Segundo Refinery	03/30/2007	25 ppmvd@0% O ₂ 365-day rolling average	Low sulfur feed
ConocoPhillips Ponca City Refinery	02/09/2007	25 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber
Valero St. Charles Refinery	02/08/2007	25 ppmvd@0% O ₂ 365-day rolling average	Wet gas scrubber

5.4.4.1 Energy, Environmental, and Economic Impacts

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. There are no other anticipated environmental, energy, or economic impacts associated with the use of the highest ranking control technology.

5.4.5 Step 5 - Selection of BACM

The top control option, wet gas scrubbers with a control efficiencies of up to 99% is utilized by HollyFrontier to reduce SO₂ emissions from the FCCU's (Unit 4 and 25) and is considered BACM.

No more stringent control technologies were identified to reduce SO₂ emissions from an FCCU. Marathon Ashland Petroleum Texas City list a 20 ppmvd @ 0% O₂ based on 365-day rolling average and a 7-day average of 50 ppmvd @0% O₂ emission rates based on control by a wet gas scrubber.

The proposed BACM controls, SO₂ emission limits, and monitoring methods conducted for the FCCU's at HollyFrontier are summarized in Table 5-7.

Table 5-7 Proposed BACM Controls, SO₂ Emission Limits, and Monitoring Methods for FCCU

Pollutant	Unit	Control Technology	Emission Limit	Monitoring Method
SO ₂	4, 25	Wet Scrubbers	≤25 ppmvd at 0% O ₂ based on a 365-day rolling average ≤50 ppmvd at 0% O ₂ based on a 7-day rolling average	SO ₂ CEMS

5.5 Emergency Diesel Engines

As presented above, diesel emergency equipment at the Woods Cross refinery consists of a 135 kW portable diesel generator at the East Tank Farm, 224 HP diesel powered water well No. 3, 393 HP fire pump No. 1, 393 HP fire pump No. 2, 180 HP diesel fire pump, three 220 HP diesel-powered plant air backup compressors, 470 HP diesel standby generator at the Boiler House, 380 HP diesel standby generator at the Central Control Room, and a 540 HP diesel standby generator.

Sulfur dioxide emissions occur from the reaction of various elements in the diesel fuel. Sulfur in diesel fuel oxidizes during combustion to SO₂ and sulfur trioxide (SO₃). In the presence of water vapor, these hydrolyze to H₂SO₄.

5.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Only one control option was found to reduce SO₂ emissions from the proposed CI combustion engines which is the use of low-sulfur diesel fuel.

5.5.2 Step 2 - Eliminate Technically Infeasible Options

The control option identified in Step 1 is technically feasible.

5.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of ultra-low sulfur diesel fuel containing no more than 15 parts per million by weight of sulfur is the only feasible SO₂ control technology for the emergency diesel combustion engines.

5.5.4 Step 4 - Evaluate Impacts and Document Results

Based on the emission standards of 40 CFR Part 60, Subpart IIII, the minimum standards that would meet BACT requirements for SO₂ emissions from IC engines at the Woods Cross Refinery include a maximum sulfur content of 15 ppmw or 0.0015 percent by weight.

5.5.4.1 Energy, Environmental, or Economic Impacts

There are no anticipated energy, environmental or economic impacts associated with the use of ultra-low sulfur diesel fuel.

5.5.5 Step 5 - Select BACT

The emergency generators at the Woods Cross Refinery will burn only ultra-low-sulfur diesel fuel with a maximum sulfur content of 15 ppmw and limited hours of operation. No more stringent control technologies were identified for control of SO₂ from emergency diesel generators.

BACM for SO₂ emissions from the emergency diesel generators and fire pumps is the use of ultra-low-sulfur diesel fuel, limited operating hours, the work practice requirements to adhere to GCP, and the best practice of performing periodic maintenance. These control strategies are technically feasible and will not cause any adverse energy, environmental, or economic impacts.

Maintenance is performed on the engines in accordance with manufacturer specifications. For those engines subject to Subpart ZZZZ, oil is changed and hoses/belts inspected every 500 hours or annually.

The proposed BACM, emission limitations, and monitoring methods for SO₂ for the emergency diesel engines are presented in Table 5-8.

Table 5-8 Proposed BACM Controls, Emission Limitation, and Monitoring Methods for SO₂ for the Emergency Diesel Engines

Pollutant	Units	Control Technology	Emission Limit	Monitoring Methods
SO ₂	All emer. Engines except ETF gen.	Ultra-low-sulfur diesel fuel	600 hours total rolling 12-month period	Non-resettable hour meter Sulfur content ≤0.0015% by weight
	ETF portable generator		1100 hours per rolling 12-month period	

5.6 Emergency Natural Gas-Fired Generators

SO₂ is generated during the combustion process from the thermal oxidation of the sulfur contained in the fuel.

5.6.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Only one control technology was identified to reduce SO₂ emissions and this is through the use of low sulfur fuels.

5.6.2 Step 2 - Eliminate Technically Infeasible Options

The above listed control technology is technically feasible.

5.6.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of low sulfur fuels is the highest ranking control technology for SI IC engines.

5.6.4 Step 4 - Evaluate Impacts and Document Results

The amount of sulfur in natural gas is regulated per 40 CFR 72.2. Pipeline-quality natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Thus, natural gas is a low sulfur content fuel.

5.6.4.1 Energy, Environmental, or Economic Impacts

There are no environmental, energy or economic impacts that would preclude the use of natural gas in these engines.

5.6.5 Step 5- Select BACT

BACT for SO₂ emissions for the SI IC engines at HollyFrontier is the use of natural gas and limiting hours of operation. No more stringent control technologies to reduce SO₂ emissions from natural-gas fired lean burn engines was identified. Maintenance is performed on the engines in accordance with manufacturer specifications.

The proposed BACM, emission limitations, and monitoring methods for SO₂ from the emergency natural gas-fired engines are presented in Table 5-9.

Table 5-9 Proposed BACM Controls, Emission Limitations, and Monitoring Methods for SO₂ for Natural Gas-Fired Emergency Engines

Pollutant	Units	Control Technology	Emission Limitations	Monitoring
SO ₂	Nat. gas fired emergency engines	Low sulfur fuels such as natural gas	600 hours total rolling 12-month period for all emergency engines	Non-resettable hour meter

6.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR PM_{2.5}

BACM's were evaluated for PM_{2.5} emissions for certain emission units in operation or proposed at the Woods Cross Refinery. These emission units include: process heaters, boilers, flares, cooling towers, SRU, FCCU, and emergency diesel and natural-gas fired engines.

6.1 Process Heaters and Boilers

PM_{2.5} is particulate matter 2.5 microns or smaller. Particulate matter emissions from process heaters and boilers with properly designed and tuned burners are inherently low when gaseous fuels are used. Filterable particulate matter in gas-fired sources that are properly tuned originates from the dust in the inlet air and metal erosion within the sources (e.g., tubes, combustion surfaces, etc.). Sources that are not properly tuned may also produce filterable particulate matter as a result of incomplete combustion of fuel hydrocarbons that agglomerate to form soot particles. These particles pass through the firebox and are emitted in the exhaust gas. Condensable particulate matter can also result from oxidation of fuel sulfur (to sulfur trioxide) and from incomplete combustion of hydrocarbons in the fuel.

6.1.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following is a list of control technologies identified for controlling PM_{2.5} emissions:

- good combustion practice;
- use of low sulfur gaseous fuels;
- proper design and operation;
- wet gas scrubber;
- electrostatic precipitator (ESP);
- cyclone; and
- baghouse/fabric filters.

6.1.1.1 Good Combustion Practices

By maintaining the heaters in good working order per manufacturer specifications with low sulfur gaseous fuels, emissions of PM_{2.5} are reduced. Proper combustor design and operation to achieve good combustion efficiency in heaters and boilers will minimize the generation of filterable particulate matter, CO and VOC's. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature, and combustion zone turbulence in combination with proper control of the air-to-fuel ratio, are essential elements of good combustion control.

6.1.1.2 Gaseous Fuel Specifications

A form of particulate matter control from combustion sources is the use of a specified gaseous fuel (e.g., natural gas). Whereas solid fuel (e.g., coal) produces a larger amount of particulate matter, gaseous fuels are considered "clean" with respect to generation of particulate matter emissions. Natural gas is processed to meet certain specifications such that the key combustion parameters (i.e., heating value, sulfur content, percent methane) are relatively consistent throughout the country.

Refinery fuel gas is a byproduct of refining operations that is processed and utilized on-site. As a result, refinery fuel does not meet pipeline natural gas composition specifications. With proper burner design and operation, refinery fuel gas-fired sources can achieve PM_{2.5} emission levels that approach those of natural gas.

6.1.1.3 Wet Gas Scrubber

A wet gas scrubber is an air pollution control device that removes PM_{2.5} and acid gases from waste streams from stationary point sources. PM_{2.5} and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers are particularly useful in removing PM_{2.5} with the following characteristics:

- Sticky and/or hygroscopic materials;
- Combustible, corrosive or explosive materials;
- Particles that are difficult to remove in dry form;
- PM_{2.5} in the presence of soluble gases; and
- PM_{2.5} in gas stream with high moisture content.

6.1.1.4 Electrostatic Precipitator

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper. Some precipitators remove the particles by washing with water. ESP's are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP.

6.1.1.5 Cyclone

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals around towards the bottom. As the particles proceed downward, the heavier material hits the outside wall and drops to the bottom where it is collected. The cleaned gas escapes through an inner tube.

6.1.1.6 Baghouse

A baghouse removes particulate from an exhaust stream by passing the gas through a fabric filter bags that are periodically cleaned using any of a number of techniques such as high-pressure reverse flow air pulses, high intensity sonic horns and shaking. A baghouse is generally capable of achieving the lowest particulate emission rates of any type of add-on particulate control device.

6.1.2 Step 2 - Eliminate Technically Infeasible Options

In a wet scrubber, the flue gas is introduced into a chamber filled with packing material that provides a large surface area for liquid-particle contact. Scrubbing liquid is evenly introduced above the packing and flows down through the bed. The liquid coats the packing and establishes a thin film. The particulate in the flue gas is extracted when it impacts the thin film of the scrubbing liquid. The spent scrubbing liquid must be treated and disposed of.

The flue gas follows a path around the packing material and the inertia of the entrained particulate causes the particles to fall out of the gas flow and impact the thin film of scrubbing liquid. The fine particulate generated from gaseous fuel combustion has little inertia so that the particles follow the gas stream through the packing without impacting the scrubbing liquid and being collected. Therefore, wet scrubbers are not a suitable control technology for application to gas fired refinery heaters and is eliminated based on technical infeasibility.

ESPs rely on the ability of a particle to acquire an electrical charge. Once charged, the particles migrate from the flue gas to oppositely charged plates where they deposit. The deposits are removed by "rapping" the plates and they settle by gravity to collection hoppers. The organic nature of the ultra-fine particulates generated by gaseous fuel combustion is such that acquiring the necessary electrical charge is difficult. ESPs also rely on gravity settling of the collected particulates. The fine particles produced in gas-fired heaters are such that gravity settling is unlikely to occur and any particles collected on the plates would likely be re-entrained in the flue gas as the plates are rapped. As such, ESPs are not used for particulate control for combustion devices burning natural/refinery gas and are eliminated based on technical infeasibility.

Cyclones use inertia to remove particles from the gas stream. The cyclone imparts centrifugal force on the gas stream, usually within a conical shaped chamber. Particles in the gas stream are forced toward the cyclone walls by the centrifugal force of the spinning gas. The collected particulate must be treated and disposed of as appropriate. The centrifugal force on the small particles resulting from gaseous fuel combustion is insufficient to separate them from the gas stream; the particulate follows the gas stream through the cyclone. Therefore, cyclones are not a suitable control technology for application to refinery heaters and were eliminated based on technical infeasibility.

The use of baghouses for post-combustion controls is common on residual oil and coal-fired combustion units that require significant particulate matter reduction, and which typically have much higher particulate loading, solid particle sulfur content, and larger sized particles. Baghouses have not been used for particulate control for combustion devices burning gaseous fuels such as natural gas or refinery fuel gas.

Particulate matter emissions are made up of two fractions: filterable and condensable. Due to the relatively high proportion of condensable particulate matter emissions (approximately 72% condensable according to AP-42), the majority of combustion particulate matter will not be collected by a fabric filter treating the flue gas. Also, due to the low particulate concentration, a cake will be slow to form resulting in poor collection efficiency.

Fabric filters rely on the build-up of a filter cake to act as a filtering medium for collection of particulate matter. Periodically, this filter cake is removed, and filtration efficiency declines until a filtering cake can be re-established. The ultra-fine size of particulate emissions from firing of gaseous fuels is such that no cake could be established in a fabric filter. Instead, the very fine particles would be expected to either pass through the bags uncontrolled, or they would "blind" filter bags fairly quickly, resulting in unacceptable pressure drops and requiring frequent bag replacement. Thus, baghouses are not technically feasible for control of PM_{2.5} from refinery-gas fired process heaters.

6.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

PM_{2.5} emissions from properly designed and controlled natural gas-fired equipment are generally considered the lowest achievable.

Combustion of refinery fuel gas will result in slightly higher PM_{2.5} emissions than combustion with pipeline-quality natural gas because of the higher molecular weight hydrocarbons (propane and butane) and the presence of sulfur compounds. The presence of higher molecular weight hydrocarbons in refinery fuel gas makes it more difficult to properly tune the burner to minimize the formation of particulates. The higher level of sulfur compounds in refinery fuel gas results in production of more SO₃, a compound that contributes to condensable particulate matter emissions.

The next most effective technically feasible PM control option is the use of good combustion practices in combination with use of low sulfur gaseous fuel.

6.1.4 Step 4 - Evaluate Impacts and Document Results

The concept of applying combustion controls and appropriate furnace design or “proper combustion” to minimize PM_{2.5} emissions include adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure the maximum amount of fuel is combusted. Optimization of these factors for PM_{2.5} control can result in an increase in the NO_x emissions. Heater and boiler designers strive to balance the factors under their control to achieve the lowest possible emissions of all pollutants. Thus, the only control technology identified in the RBLC database for the refinery fuel or natural gas-fired process heaters and boilers is a work practice requirement to adhere to good combustion practices and use of low sulfur gaseous fuel.

Table 6-1 presents a summary of BACT determinations for PM_{2.5} for process heaters and boilers. All units listed in Table 6-1 are fired on refinery gas.

Table 6-1 BACT Determinations for PM_{2.5} for Process Heaters and Boilers

Facility	Permit Date	Size (MMBtu/hr)	PM _{2.5} Limit (lb/MMBtu)	Control
Holly Refining & Marketing, Tulsa Refinery	04/20/2015	76, 127	0.0075 (three-hour average)	Use of gaseous fuel
Sasol Chemicals (USA) LLC, Lake Charles Chemical Complex GTL Unit	05/23/2014	13.4, 18, 31, 40, 56.8, 71.2, 73.8, 78	0.0075 (three-hour average)	Use of gaseous fuels and good combustion practices
BP Products North America Inc. BP-Husky Refining LLC	09/20/2013	225, 150	0.0075	None listed.
St. Charles Refinery Valero Refining	11/17/2009	15-95	0.0074 (Annual avg.)	Proper equipment design and operation, good combustion practices, gaseous fuels
Hunt Refinery Co.	09/28/2009	34.7-254	0.0075	None listed.
Marathon Petroleum CO LLC Garyville Refinery	12/27/2006	63.7-183.3	0.0075 (3-hr avg.)	Proper design, operations and good engineering practices
Arizona Clean Fuels Yuma LLC	04/14/2005	23.2 - 346	0.0075	None listed.
ExxonMobil Refining & Supply Baton Rouge Refinery	02/18/2004	22-82	0.0080	Good engineering design and proper combustion practices

6.1.4.1 Energy, Environmental, or Economic Impacts

For the process heaters and boilers, HollyFrontier calculated the cost of firing purchased pipeline-quality natural gas in place of RFG to be greater than \$2.2 million/ton PM_{2.5} reduced, based on a natural gas price of approximately \$0.22 Mscf. The cost to switch to pipeline-quality natural gas is not economically feasible. There are no additional environmental or energy impacts associated with firing the process heaters or boilers on pipeline-quality natural gas.

6.1.5 Selection of BACM

Consistent with all PM_{2.5} BACT determinations for RFG-fired sources found in the RBLC, HollyFrontier will utilize proper design, good combustion techniques, minimizing ammonia slip for heaters and boilers equipped with SCR for control of NO_x emissions, along with use of treated refinery gas or natural gas is considered BACM. The most stringent emission rate found was 0.0075 lb/MMBtu based on a 3-hour average utilizing proper equipment design, good combustion practices, and fuel specification.

6.2 Flares

Due to the combustion of natural gas in the pilot light and the combustion of refinery vent gases, flares emit small quantities of PM_{2.5}.

6.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Available technologies to control PM_{2.5} from flare emissions include:

- Air or steam assisted smokeless flare technology,
- Compliance with applicable federal NSPS (40 CFR 60.18) and NESHAP requirements (40 CFR 63.11),
- Good combustion practices,
- Opacity limits,
- Proper operation and maintenance,
- Use of natural gas or LPG as pilot fuel, a continuous pilot and a method for detection,
- Development of a flare management plan,
- Flares to be operated during period of emergency upsets or breakdowns, and
- Flare gas recovery system for non-emergency releases.

No add-on control technologies for flares were found or known to be in commercial use.

6.2.2 Step 2 - Eliminate Technically Infeasible Options

The control technologies listed above are technically feasible.

6.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top ranking control option is the installation of a flare gas recovery system. Flare gas recovery systems are achieved in practice. The second highest ranking control option includes proper equipment design and work practices which includes good combustion practices and use of clean gaseous fuels such as natural gas for pilot light fuel. The combustion efficiency of a properly operated flare is 98%.

6.2.4 Step 4 - Evaluate Impacts and Document Results

The flares at HollyFrontier incorporate steam-assisted smokeless flare design and are operated in accordance with good combustion practices to minimize PM_{2.5} emissions. The flares have been designed for and are operated without visible emissions. Each flare is equipped with an opacity monitor. Pilot fuel is pipeline quality natural gas; sweep gas is either pipeline quality-natural gas or refinery fuel gas.

HollyFrontier will install a flare gas recovery system to recover vent gas which is the highest ranked control option.

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. The flares at the refinery are subject to the requirements and limitations presented in 40 CFR Part 60 Subpart Ja and the design and work practice requirements of 40 CFR 60.18 and 40 CFR 63.11.

Flare management plans have been prepared for both the north and south flares. Procedures have been developed to minimize or eliminate discharges to the flare during planned startups and shutdowns.

Emissions from the HollyFrontier Woods Cross Refinery flares under normal operation will consist only of the emissions from the combustion of natural gas in the flare pilot flames and a small amount of purge gas that is circulated through the flare system for safety reasons (i.e., to prevent air from entering the flare lines).

6.2.4.1 Energy, Environmental, or Economic Impacts

Since HollyFrontier has chosen the highest ranked control option, flare gas recovery, energy, environmental and costs analyses are not required.

6.2.5 Step 5 - Select BACT

Holly is proposing the following design elements and work practices as BACM for the flares:

- Use of low sulfur fuel such as natural gas as fuel for pilot flame;
- Maintaining an acceptable net heating value and exit velocity of flared gases under all flow conditions in accordance with manufacturer specifications;
- Use of a thermocouple to monitor presence of the pilot flame;
- Implementation of good combustion, operating, and maintenance practices;
- Development of Flare Management Plan;
- Conduct of Root Cause Analyses;
- Flare operation in accordance to 40 CFR Part 60, Ja and design and work practice standards as codified in 40 CFR Part 60.18 and 40 CFR Part 63.11; and,
- Installation of flare gas recovery system.

No more stringent measures were identified for the flares at the Woods Cross Refinery. The flare design includes steam assisted combustion. The flares will be equipped with a flare gas recovery system for non-emergency releases, and a continuous pilot light. Pilot and sweep fuel will be natural gas or treated refinery gas. The north and south flares are equipped with flow meters and gas combustion monitors.

The proposed BACM controls, PM_{2.5} emission limits, and monitoring methods for the flares at HollyFrontier are summarized in Table 6-2.

Table 6-2 Proposed BACM Controls, PM_{2.5} Emission Limits, and Monitoring Methods for Flares

Pollutant	Unit	Control Technology	Emission Limit	Monitoring
PM _{2.5}	66	Flare gas recovery system Use of low sulfur fuel GCP Flare management plan	20% opacity	Flow meters, gas combustion monitors

6.3 Cooling Towers

The Woods Cross refinery has six (6) cooling water towers (Unit 54), labeled 4, 6, 7, 8, 10 and 11. These towers have a designed maximum circulation rate of 6,000 gallons per minute (gpm), 4,400 gpm, 3,000 gpm, 10,000 gpm, 8,500 gpm and 8,500 gpm, respectively. Cooling towers 10 and 11 are equipped with high efficiency drift eliminators that control drift to 0.0005% of circulating water.

Warm water is pumped into the top of the tower which cools as it falls downward and mixes with the rising air. The inside of the tower is filled with wooden or plastic grids so the falling water splashes and mixes with air. The water falls down into a concrete basin beneath the tower. Pumps then circulate the cool water to the units where it is used to cool hydrocarbons. Heat exchangers are used so the water does not become contaminated with the hydrocarbons. Warm water from the outlet of heat exchangers is piped back to the cooling tower, where it is cooled again.

Chemicals (no chromium based chemicals are used as per corporate policy) are added to the circulating water and react with water hardness to keep deposits from accumulating on the inside piping and exchangers. These chemicals also prevent algae and bacteria growth from forming inside pipes and exchangers.

6.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Particulate matter is emitted from wet cooling towers due to the presence of dissolved or suspended solids in water droplets from cooling tower drift. As the drifted droplet evaporates, the dissolved solids present in the droplet collected into a single particle. The size of the resulting particle depends on the size of the droplet, the mass of the dissolved solids present, and the density of the resultant particle.

Four control technologies were identified to limit PM_{2.5} drift from cooling towers. These include:

- Use of dry cooling heat exchanger units;
- High-efficiency drift eliminators;
- Limitation on total dissolved solid (TDS) concentrations in the circulating water; and
- Combination of drift eliminator efficiency rating and TDS limit.

6.3.2 Step 2 - Eliminate Technically Infeasible Options

Dry cooling or non-evaporative cooling towers have been adopted for heat rejection at combined-cycle power plants in arid or low precipitation climates. This type of cooling tower circulates the process water through a large bank of radiator coils. These coils are cooled by forced flow of ambient air on the outer finned surfaces of the radiator. Ambient airflow is driven by very large axial propeller fans, typically located below the radiator bank, so that the air is blown upward through the radiator and the warmer air exits the top of the tower. Because there is no contact between the water and the ambient air, and thus no opportunity for drift, a dry cooling tower would not be a source of particulate matter emissions.

Dry cooling has been employed at primary combined-cycle power plants as a means to reduce water consumption rather than as BACT for reducing PM₁₀ emissions. There is a very substantial capital cost penalty as well as significant process changes that would be required in utilizing this control technology. Because of the high capital cost and process design changes involved in using dry cooling, and that dry cooling has not been identified as being utilized at a refinery, this option was determined to be technically infeasible and was eliminated from further consideration.

6.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control options were ranked in order from most to less stringent:

1. Combinations of high-efficiency drift eliminators and TDS limit;
2. High-efficiency drift eliminators to control drift as low as 0.0005% of circulating water;
3. Limitation of TDS concentrations in the circulating water.

6.3.4 Step 4 - Evaluate Impacts and Document Results

All modern cooling towers are equipped with drift eliminators. The drift eliminator forces the exhaust air to make sharp turns before exiting. The momentum of entrained droplets carries the droplets to the drift eliminators surfaces where they coalesce and drip back into the tower. Typically, for cross-flow designs the drift rate will be less than 0.005% because of the use of higher efficiency eliminators; counterflow and forced-draft counterflow designs routinely achieve 0.001%.

Incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media needs to be reduced. This is necessary to use drift eliminator media with small passages without encountering a high pressure drop. Since reducing the air velocity reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the size of the media will be needed. These changes may also result in an energy penalty in the form of larger and higher powered fans to accommodate higher drift eliminator efficiency for the same heat injection duty.

6.3.4.1 Energy, Environmental, or Economic Impacts

In using drift eliminators, no significant energy or environmental impacts are expected.

The drift eliminators on cooling towers 4,6,7,8 have an effectiveness of 0.002%. To upgrade with more efficient drift eliminators, vendor costs estimates were obtained and are presented in Appendix B. To upgrade from 0.002% to 0.0005%, total PM_{2.5} emission reduction equated to 3.2 lbs at a capital cost of approximately \$419,000 for the four towers. The cost effective per ton of PM_{2.5} is, on average, over 95 million dollars per tower. Thus, it is not economically feasible to upgrade the existing cooling towers with high efficiency drift eliminator with a drift rate of 0.0005%.

6.3.5 Step 5 - Selection of BACM

HollyFrontier's cooling towers 10 and 11 have been upgraded with high-efficiency drift eliminators with a drift rate of 0.0005 percent. Cooling towers 4,6,7,8 are equipped with drift eliminators with a drift rate of 0.002 percent. Retrofit of these cooling towers with high-efficiency drift eliminators with a drift rate of 0.0005 percent has been determined to be economically infeasible. The TDS of the makeup water is monitored weekly which aids in the control of PM_{2.5} emissions.

For newly constructed cooling towers, BACT for PM_{2.5} was determined to be utilization of high-efficiency drift eliminators with a drift rate of 0.0005 percent. A drift rate of 0.0005 is the most effective drift eliminator commercially available although the cooling tower vendor indicated that 0.0006% will be coming out in the future. No more stringent measures were identified to control PM_{2.5} emissions from cooling towers.

The proposed BACM controls, PM_{2.5} emission limitations, and monitoring methods for the cooling towers at HollyFrontier are summarized in Table 6-3.

Table 6-3 Proposed BACM Controls, PM_{2.5} Emission Limitations, and Monitoring Methods for Cooling Towers

Pollutant	Unit	Control Technology	Emission Limitations	Monitoring
PM _{2.5}	54	High efficiency drift eliminators	0.0005 drift rate (CT 10&11) 0.002 drift rate (CT 4,6,7,8)	TDS monitored weekly

6.4 Sulfur Recovery Unit Incinerator

Particulate matter from refinery gas or natural gas combustion is usually composed of larger molecular weight hydrocarbons that have not been fully combusted.

6.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The available technologies available for control of PM_{2.5} emissions include:

- > proper equipment design,
- > good combustion practices,
- > clean gaseous fuels,
- > electrostatic precipitators,
- > fabric filters (baghouse), and
- > wet scrubbing.

6.4.2 Step 2 - Eliminate Technically Infeasible Options

Electric static precipitators and fabric filters are not technically feasible due to the temperature of exhaust gas that would go to these control devices. Significant negative impacts occur to fabric filters when temperature are greater than 400°F and to electrostatic precipitators when temperatures are greater than 350°F. The temperature of the exhaust gases from the SRU incinerator will be approximately 550°F. Thus, these two options are eliminated from further consideration and were considered to be not technically feasible.

6.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of proper equipment design, good combustion practices, use of clean gaseous fuels and the post-combustion control of wet scrubbing are technically feasible. Wet gas scrubbers have the potential to remove in excess of 95% of particulate emissions.

6.4.4 Step 4 - Evaluate Impacts and Document Results

As mentioned above, emissions from the SRU are sent to the tail gas incinerator and then to the wet scrubber. The use of a wet scrubber is highly efficient in removing PM_{2.5} from the effluent stream. The SRU does not operate when the wet gas scrubbers are not operational.

6.4.4.1 Energy, Environmental, or Economic Impacts

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. There are no other energy, environmental, or economic impacts anticipated with the use of a wet scrubber to remove PM_{2.5} from the effluent stream from the SRU during normal operations.

6.4.5 Step 5 - Select BACT

PM_{2.5} emissions from the SRU are controlled through the use of a tailgas incinerator followed by a wet gas scrubbers. The wet gas scrubber is estimated to have a high PM_{2.5} removal efficiency (>85%). Thus BACM for control of PM_{2.5} emissions from the SRU is proper equipment design, good combustion practice, use of clean gaseous fuels followed by the post-control technology of wet scrubbing.

No more stringent measures were identified to reduce PM_{2.5} emissions from a SRU.

The proposed BACM control technologies and monitoring methods for the SRU at the Woods Cross Refinery are summarized in Table 6-4.

Table 6-4 Proposed BACM Controls and Monitoring Methods for PM_{2.5} from the SRU

Pollutant	Unit	Control Technology	Monitoring Methods
PM _{2.5}	17	Wet scrubbers (normal operation) Proper equipment design, good combustion practices, use of clean gaseous fuels (emergency operation)	Differential pressures across the filter modules and the discharge pressure from the liquid circulation pump to ensure adequate scrubbing. These parameters are set in a performance test

6.5 FCCU

The main source of PM_{2.5} from a FCCU is catalyst fines and products of incomplete combustion that are released in the regenerator exhaust stack.

6.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Available control technologies to control PM_{2.5} emissions from the FCCU regenerator stacks include:

- > Wet Gas Scrubber;
- > Electrostatic Precipitator (ESP); and
- > Third Stage Separator (TSS)/Cyclone.

Descriptions of the ESP and the wet gas scrubber are presented in Sections 6.1.1.3 and 6.1.1.4. A third stage separator (TSS) is a specially designed cyclone or set of cyclones, for the flue gas from an FCCU regenerator. The TSS is in a separate vessel, outside the regenerator, that houses a number of small diameters, high efficiency cyclones arranged in parallel in the vessel. There is a flow distributor at the inlet to evenly distribute the regenerator flue gas to each small cyclone to create better efficiencies in particulate removal. The TSS is able to remove a significant amount of particulate that would normally go out the regenerator stack.

6.5.2 Step 2 - Eliminate Technically Infeasible Options

All of the control technologies are technically feasible.

6.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The following lists the ranking of the remaining control options:

- > Electrostatic Precipitators – Up to 95% reduction
- > Wet Gas Scrubber – 85 to 95 % reduction
- > Third Stage Separator – No efficiency percentages were found but the literature suggests that the TSS is able to reduce the amount of particulate to approximately 0.6 lbs per 1000 lbs of coke burned.

6.5.4 Step 4 - Evaluate Impacts and Document Results

ESP is a proven technology. The collected particulate is disposed of as a dry solid. The discharge doesn't have a vapor plume. There is a small pressure drop across the ESP. The particle collection process begins when the particle absorbs a charge sufficient amount to be attracted to the collection plates. However, the particle charging and collection process can be affected by several factors including particle size, particle resistivity, electric field and the temperature and composition of the flue gas stream.

There are reliability issues with electrostatic precipitators, so in many cases, multiple units are installed for redundancy which adds cost. Temperature and humidity affect the resistivity of PM. An ESP has a limited ability to handle high temperature excursions or FCCU upsets. In addition, any VOCs that might be in the stream because of an upset are dangerous to the unit. ESPs are also susceptible to changes in catalysts. Although ESP's are a viable option, HollyFrontier utilizes wet scrubbers which are more efficient in reducing PM_{2.5} from the FCCUs than are ESPs.

Wet gas scrubbers are also a proven technology. They have been demonstrated on a long-term basis to remove particles to very low levels. They have an excellent reliability so there is no need for multiple units. Wet scrubbers have a much broader operating range and are more able to handle upsets from the FCCU. A wet gas scrubber also has a lower operating temperature than an ESP which provides for improved removal of condensable PM. The waste from a wet gas scrubber can be disposed of as a wet solid.

The TSS removes a significant amount of catalyst fines from the flue gas stream. However, a TSS by itself will not reduce particulate to meet the NSPS standard of 0.5 lb/1000 lb coke burned. Thus, a TSS has been eliminated from further consideration as it does not meet the required NSPS standard.

A review of the RBLC database was performed and Table 6-5 presents a summary of BACT determinations for PM_{2.5} for FCCUs.

Table 6-5 BACT for PM_{2.5} for FCCU

Facility	Permit Date	PM _{2.5} Emission Limit	Control Method
Lion Oil Company	09/09/2011	1.0 lb/1000lb coke	Wet Gas Scrubber
ConocoPhillips Company Sweeny Refinery	12/29/2011	1.334 lb/ton of coke burn	Regenerator cyclones and Electrostatic Precipitator
Sunoco Company Inc. Toledo Refinery	01/29/2008	0.9 lb/1000 lb coke pound per 1000 lb of coke burnoff	Wet Gas Scrubber
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	2.0 lb/ton of coke	Wet Gas Scrubber

6.5.4.1 Energy, Environmental, or Economic Impacts

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. Because HollyFrontier has chosen the remaining highest ranking control option, the use of a wet gas scrubber, energy, environmental and costs analyses are not required.

6.5.5 Step 5 - Select BACT

According to the RBLC, wet scrubbers are used extensively as one method to reduce particulate from FCCUs and wet gas scrubbers are utilized by Holly to reduce PM emissions from the FCCU's. Thus, a wet gas scrubber is considered BACM for reduction of particulate from the FCCU regenerator stack. No more stringent measures were identified to control PM_{2.5} emissions from FCCU regenerator vents.

The proposed BACM controls, PM₁₀/PM_{2.5} emission limits, and monitoring methods for the FCCU at the Woods Cross Refinery are summarized in Table 6-6.

Table 6-6 Proposed BACM Controls, PM₁₀/PM_{2.5} Emission Limits, and Monitoring Methods for FCCU

Pollutant	Unit	Control Technology	PM ₁₀ Emission Limit	Monitoring Method
PM _{2.5}	4	Wet scrubber 4V82	0.5 lbs/1000 lbs coke burn-off	Annual stack test
	25	Wet Scrubber 25FCC	0.3 lbs/1000 lbs coke burn-off	Annual stack test

6.6 Emergency Diesel Engines

As presented above, diesel emergency equipment at the Woods Cross refinery consists of a 135 kW portable diesel generator at the East Tank Farm, 224 HP diesel powered water well No. 3, 393 HP fire pump No. 1, 393 HP fire pump No. 2, 180 HP diesel fire pump, three 220 HP diesel-powered plant air backup compressors, 470 HP diesel standby generator at the Boiler House, 380 HP diesel standby generator at the Central Control Room, and a 540 HP diesel standby generator.

Diesel particulate emissions are composed of a variety of liquid phase hydrocarbons and solid phase soot (carbon). The literature suggests that the majority of particulate emissions from diesel combustion are in the PM_{2.5} size or smaller range.

6.6.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following control options were evaluated for controlling PM_{2.5} emissions from the CI combustion engines. They include:

- > GCP,
- > use of low sulfur fuels,
- > diesel particulate filters, and
- > diesel oxidation catalysts.

6.6.1.1 Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion. The emergency generators and fire water pump engines are designed to achieve maximum combustion efficiency. The manufacturers provide operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency.

6.6.1.2 Ultra-Low Sulfur Diesel

Limiting the sulfur content of diesel fuel is a pollution prevention method to reduce the sulfate fraction (25-25%) of diesel particulate matter.

6.6.1.3 Diesel Particulate Filters

Diesel particulate filters (DPFs) are add-on devices that filter out particulate matter. In general, A DPF consists of a porous substrate that permits gases in the engine exhaust to pass through but collects or traps the diesel PM. This is typically referred to as regenerating the DPF. During regeneration, the collected PM, which is mostly carbon, is burned off.

Particulate filters can employ either an active or passive system, depending on the method used to clean the filters. Active DPFs use a source of energy beyond the heat in the exhaust stream itself to help regeneration. Active DPFs can be regenerated electrically, with fuel burners or microwaves, or by additional fuel injection to increase exhaust temperature. Active DPFs have a broader range of application and a much lower probability of getting plugged than passive DPFs.

A passive DPF is one in which a catalytic material, typically a platinum group metal, is applied to the substrate. The catalyst lowers the temperature at which trapped PM will oxidize to temperatures periodically reached in diesel exhaust. No additional energy is needed for regeneration.

6.6.1.4 Diesel Oxidation Catalyst

A diesel oxidation catalyst utilizes metal catalysts to oxidize particulate matter in the diesel exhaust. Diesel oxidation catalysts are commercially available and are reliable for reducing particulate matter emissions.

6.6.2 Step 2 - Eliminate Technically Infeasible Options

All options identified in Step 1 are technically feasible.

6.6.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Table 6-7 presents in descending order the control effectiveness of the identified control technologies.

Table 6-7 PM_{2.5} Control Technology Effectiveness for Diesel Engines

Control Technology	Control Effectiveness
DPF	≤85%
Oxidation Catalyst	30%
Ultra-low sulfur diesel	10-20%
GCP	Baseline

6.6.4 Step 4 - Evaluate Impacts and Document Results

The top ranked control option, diesel particulate filters can significantly reduce PM_{2.5} emissions. Typical operation of the emergency generators at the Woods Cross Refinery include weekly 15 minute testing and maintenance operations with low or no load to ensure that the engine is operating properly. The number of times that an engine can operate for maintenance and testing before regenerations is typically between 10 and 30 cold starts with 30 minute run times. For regeneration to occur on passive systems, the exhaust temperature needs to be between 300°C to 465°C. To reach this temperature and for a regeneration cycle to be completed, the engine should operate for about 30 minutes at a 30 percent load.

Active DPFs are independent of temperature and will work on emergency standby engines without the same regeneration concerns presented above. The active DPF uses an electrical current or fuel combustion to remove or burn off the collected PM.

6.6.4.1 Energy, Environmental, or Economic Impacts

A cost effectiveness evaluation for the top ranking option, in costs per ton of PM_{2.5} removed, is presented in Table 6-8 and in Appendix B.

The installation of a DPF causes engine efficiency to decrease with increasing backpressure due to thermodynamic reasons. The pressure drop of the DPF increases as it captures particulate matter from the engine. A rule of thumb is that the engine power will decrease by 1% for every 3-4 kPa increase in engine backpressure.

The DPF must be regenerated, continuously or intermittently which consumes energy. DPF regeneration, either active or passive, intermittent or continuous, comes with a fuel penalty.

Table 6-8 Cost Effectiveness of Installing DPF on Emergency Diesel Engines for PM_{2.5} Control

Equipment	Cost Effectiveness (\$/Ton)
135 kW generator (east tank farm)	\$ 33,930
224 HP (water well #3)	\$ 750,907
393 HP Fire Pump #1	\$ 736,568
393 HP Fire Pump #2	\$ 736,568
220 HP plant air backup compressor #1	\$ 755,935
220 HP plant air backup compressor #2	\$ 755,935
220 HP plant air backup compressor #3	\$ 755,935
470 HP diesel generator (boiler house)	\$ 745,363
380 HP diesel generator (central control room)	\$ 746,118
540 HP standby generator	\$ 22,265,725

Based on the economic impact presented in Table 6-8, DPF's are not cost effective for the emergency generators or the fire water pumps at the Woods Cross Refinery and have been eliminated from further consideration.

6.6.5 Step 5 - Select BACT

As mentioned above, California has the most aggressive emission reduction standards for diesel engines. The most stringent control includes the use of DPF's to reduce PM_{2.5} emissions. Several emergency standby engines were identified operating in California that had DPF's installed on them. In most cases, however, DPFs were installed to meet permit requirements or to address odor issues. Operational considerations using active DPF's are minimal and can be accommodated by normal maintenance and testing procedures.

As seen from Table 6-8, the installation of DPFs on the emergency diesel engines at HollyFrontier's Woods Cross Refinery is cost prohibitive. The use of ultra-low sulfur diesel, which will reduce PM_{2.5} emissions up to 20%, limited operating hours (50 hours per each unit except the generator at the East Tank Farm), the use of GCP and EPA Tier standards, and best practice of periodic maintenance is considered BACM for the diesel engines at HollyFrontier.

40 CFR 60, Subpart IIII applies to engines which commenced construction after 7/11/2005 and are manufactured after 4/1/2006 (for non-fire-pump engines), or an engine modified or reconstructed after 7/11/2005. Subpart IIII applies to the emergency diesel equipment at the refinery. Records of maintenance and hours of operation are kept. A non-resettable totalizer is installed on each emergency diesel engine. Maintenance is performed on the engines in accordance with manufacturer specifications. The oil/filter as well as the hoses/belts are inspected every 500 hours or annually.

The proposed BACM, emission limitations, and monitoring methods for the emergency diesel engines are presented in Table 6-9.

**Table 6-9 Proposed BACM Controls, PM_{2.5} Emission Limitations, and Monitoring for
Emergency Diesel Engines**

Pollutant	Units	Control Technology	Emission Limitations	Monitoring Method
PM _{2.5}	All emer. Engines except ETF gen.	GCP, ultra-low sulfur fuel	600 hours total rolling 12-month period	Non-resettable hour meter
	ETF portable generator		1100 hours per rolling 12-month period	

6.7 Emergency Natural Gas-Fired Generators

Particulate matter (PM) is a mixture of solid particles and liquid droplets; PM_{2.5} emissions are particles less than 2.5 microns in diameter. PM_{2.5} emissions from natural gas combustion in the generator will be low. PM_{2.5} emissions result from carryover of noncombustible trace elements present in the natural gas and solids or dust in the ambient air used for combustion.

6.7.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Only one method for PM_{2.5} emission control from natural-gas fired engines was identified which was good combustion practices using natural gas since there is little ash in natural gas that would contribute to the formation of PM_{2.5}.

6.7.2 Step 2 - Eliminate Technically Infeasible Options

The option identified in Step 1 are technically feasible.

6.7.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of good combustion practices and natural gas is the only feasible PM_{2.5} control technology for the emergency SI IC combustion engines at HollyFrontier.

6.7.4 Step 4 - Evaluate Impacts and Document Results

Natural gas generators are regulated by 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. Here, the EPA provides emissions standards manufacturers must meet, emissions standards owners/operators must meet, EPA certification requirements, testing requirements, and compliance requirements.

The natural-gas fired engines used at the administration building are limited to 50 hours per year for testing and maintenance. Manufacturer recommendations are followed in the operation and maintenance of these engines and records are kept. Each engine is equipped with a non-resettable hour meter. The operating standards for these engines are work practice standards which include annual oil changes and spark plug and hose inspection.

6.7.4.1 Energy, Environmental, or Economic Impacts

There are no environmental, energy or economic impacts that would preclude the use of natural gas.

6.7.5 Step 5 - Select BACT

BACT for PM_{2.5} emissions is the use of natural gas and good combustion practices. No more stringent control technologies were identified for use on lean-burn natural gas-fired engines. These engines meet the requirements as set forth in 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. Maintenance is performed on the engines in accordance with manufacturer specifications.

The proposed BACM, PM_{2.5} emission limits, and monitoring methods for the emergency natural gas-fired engines are presented in Table 6-10.

Table 6-10 Proposed BACM Controls, PM_{2.5} Emission Limitations, and Monitoring Methods for Natural Gas-Fired Emergency Engines

Pollutant	Units	Control Technology	Emission Limitations	Monitoring
PM _{2.5}	Nat. gas fired emergency engines	Low sulfur fuels and good combustion practices	600 hours total rolling 12-month period for all emergency engines	Non-resettable hour meter

7.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR VOLATILE ORGANIC COMPOUNDS

BACM's were evaluated for VOC emissions for certain emission units in operation or proposed at the Woods Cross Refinery. These emission units include: process heaters, boilers, flares, cooling towers, SRU incinerator, FCCU, tanks, leaking components, waste water treatment, product loading/unloading, and emergency diesel and natural gas-fired engines.

7.1 Process Heaters and Boilers

Emissions of VOC's from process heaters and boilers result from incomplete combustion of the heavier molecular weight components of the refinery gas fuel. Operating conditions such as low temperatures, insufficient residence time, low oxygen levels due to inadequate mixing, and/or a low air-to-fuel ratio in the combustion zone also result in VOC formation. In addition, VOC emissions are produced to some degree by the reforming of hydrocarbon molecules in the combustion zone.

7.1.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Control options for VOC generally consist of fuel specifications, combustion modification measures, or post-combustion controls. Six control technologies were identified for controlling VOC emissions. These control technologies are:

- Good Combustion Practice
- Fuel Specifications (use of natural gas or refinery gas)
- ULNB
- Catalytic Oxidation
- Thermal Oxidation
- EMx (formerly SCONO_x)

7.1.1.1 Good Combustion Practice

Combustion controls (proper design and operation) are the most typical means of controlling VOC emissions. Implementation of proper burner design to achieve good combustion efficiency in heaters and boilers will also minimize the generation of VOC.

Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature and combustion zone turbulence, in combination with proper control of air-to-fuel ratio, is essential for a low VOC emissions.

7.1.1.2 Fuel Specifications

Pipeline natural gas is a fuel predominantly comprised of methane. An odorant is added to allow easy leak detection of the otherwise odorless gas. It is processed to meet certain specifications such that key combustion parameters are relatively consistent throughout the United States. These parameters include percent methane, heating value, and sulfur content.

Refinery fuel gas is a byproduct of the refining operations and is consumed on-site. It may contain significant proportions of fuel components other than methane, such as hydrogen, ethane, propane, and butanes. Because it is a byproduct of various refinery processes with varying compositions between streams, expected VOC emissions for process heaters and boilers firing refinery gas may not be as low as expected for process heaters and boilers firing natural gas.

7.1.1.3 Ultra-Low NO_x Burners

ULNB technology has developed to provide increasing lower levels of NO_x emissions. However, when operated using good combustion practices, ULNB can also provide significant reductions in VOC emissions.

7.1.1.4 Catalytic Oxidation

The formation of VOC in combustion units depends on the efficiency of combustion. Catalytic oxidation decreases VOC emissions by allowing the complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 to 30 feet per second. The optimal range for oxidation catalysts is approximately 850 to 1,100 °F.

7.1.1.5 Thermal Oxidation

Thermal oxidizers combine temperature, time, and turbulence to achieve complete combustion. Thermal oxidizers are equivalent to adding another combustion chamber where more oxygen is supplied to complete the oxidation of CO and VOC. The waste gas is passed through burners, where the gas is heated above its ignition temperature. Thermal oxidation requires raising the flue gas temperature to 1,300 to 2,000°F in order to complete the CO and VOC oxidation.

7.1.1.6 Emerachem (EM_x[™])

EM_x[™] is the second generation of SCONO_x NO_x absorber technology. EM_x[™] is a catalyst-based post-combustion control, which simultaneously oxidizes CO to CO₂, VOC to CO₂ and water, and NO to NO₂, subsequently adsorbing the NO₂ onto the surface of a catalyst where a chemical reaction removes it from the exhaust stream.

7.1.2 Step 2 - Eliminate Technically Infeasible Options

Oxidation catalysts have traditionally been applied to the control of CO and to a lesser extent, VOC emissions from natural gas fired combustion turbines. Refinery fuel gas contains sulfur as H₂S, which when burned oxidizes to SO₂. Oxidation catalyst is not applied to sources where fuels containing sulfur are fired because much of the SO₂ formed by the combustion process is further oxidized to SO₃ which readily becomes sulfuric acid mist in the atmosphere. In addition, the precious metals which are the active components in oxidation catalyst are subject to irreversible poisoning when exposed to sulfur compounds.

The only application of oxidation catalyst used by a refinery gas fired combustion device was identified as a combustion turbine in Southern California which fired a mix of refinery gas and natural gas. No other applications of oxidation catalyst applied to refinery process heaters was found. Thus, based on the issues presented above with the use of a oxidation catalysts with sulfur bearing fuels, this control option is not considered technically feasible.

EMx™ has only been demonstrated on natural-gas fired combustion turbines and this technology has not been demonstrated on units that fire refinery fuel gas. As such, EMx™ is not considered to be demonstrated in practice for refinery fuel gas fired process heaters and is considered technically infeasible.

7.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Presented in Table 7-1 are the remaining control options ranked based on effectiveness.

Table 7-1 VOC Control Technologies by Control Effectiveness

Control Technology	Control Effectiveness
Thermal Oxidation	75-95%
ULNB	25-75%
GCP	baseline

7.1.4 Step 4 - Evaluate Impacts and Document Results

The top control strategy identified is the use of thermal oxidation which has a VOC control effectiveness ranging between 75 to 95%.

The second ranking control strategy identified for the refinery fuel gas-fired process heaters and boilers is the use of ultra-low NO_x burners with a control adherence to good combustion practices.

Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air supply, temperature, residence time, and mixing are incorporated in the combustion design and operation, VOC emissions are minimized.

Good combustion practice and proper equipment design is the industry standard for control of VOC emissions from refinery process heaters. VOC emissions are controlled by maintaining various operational combustion parameters.

Table 7-2 presents a summary of previous BACT determinations for VOC for process heaters and boilers. This table is not exhaustive, rather lists the lowest emission rates identified in the past several years from select plants. The top ranking option, thermal oxidation was not identified in RBLC as BACT for control of VOC emissions from process heaters and boilers.

Table 7-2 Summary of BACM Determinations for VOC for Process Heaters and Boilers

Facility	Permit Date	Size (MMBtu/hr)	Limit (lb/MMBtu)	Control Technology
Sasol Chemicals (USA) LLC, Lake Charles Chemical Complex GTL Unit	05/23/2014	13.4, 18, 31, 40, 56.8, 71.2, 73.8, 78	0.0054 (annual average)	Use of gaseous practices and tune ups
IPL Eagle Valley Generating Station, Indiana	10/11/2013	79.3	0.0053 (three-hour average)	Advanced ultra-low NO _x burner
BP Products North America Inc. BP-Husky Refining LLC	09/20/2013	225, 150	0.0054	None listed
Valero Refining – New Orleans LLC St. Charles Refinery	11/17/2009	Heaters/reboilers	0.0054 (annual average)	Proper design operation, and good engineering practices and use of gaseous fuels
Navajo Refining Company, Artesia Refinery	12/14/2007	9.6, 35	0.0050 (1-hour avg.)	Gaseous fuels
Marathon Petroleum CO LLC. Garyville Refinery	12/27/2006	Sources: 5-08, 9-08, 11-08 & 12-08, 1-08 & 2-08, 15-08	0.015 (3-hr average)	Proper design operation, and good engineering practices

7.1.4.1 Energy, Environmental, or Economic Impact

Depending on specific furnace and thermal oxidizer operational parameters (fuel gas heating value, excess oxygen in the flue gas, flue gas temperature, and oxidizer temperature) raising the flue gas temperature can require an additional heat input of 10 to 25% above the process heater heat input. In addition, depending on the design of the thermal oxidizer, emissions of NO_x, SO₂ and PM_{2.5} can be 10 to 25% higher than emissions without a thermal oxidizer. Installation costs and operating costs for a thermal oxidizer (mostly from the 10 to 25% increase in fuel consumption) can be significant. Thus, since this technology was not determined to meet BACT and causes adverse environmental impacts, the use of this technology has been determined to be technically infeasible for VOC control on process heaters and has been eliminated from further consideration.

The cost to fire all process heaters on a natural gas is \$1.2 million which is cost prohibitive.

As discussed in Section 4.1.4.2, the application of LNB or ULNB on existing units (6H1, 6H2, 6H3, 7H1, 7H2, 7H3, 9H1, 9H2, 10H1, 11H1, and 13H1) is not technically possible due to space limitations in the firebox, lower heat duty, and a longer flame. It is not economically feasible to reconstruct all existing process heaters. Thus, for these reasons, retrofit of existing process heaters with LNB or ULNB has been determined to be technically and economically infeasible.

The use of good combustion practices will not cause adverse energy, environmental, or economic impacts.

7.1.5 Step 5 - Selection of BACM

HollyFrontier will follow good combustion practices which has been selected as BACT for control of VOC emissions from the process heaters and boilers. Boiler #11 has an emission limit of 0.004 lb/MMBtu; no other units have VOC emission limits. No more stringent measures were identified to control VOC emissions from process heaters and boilers other than the use of good combustion practices.

The cost of installing and operating CEMS on each heater and boiler was examined. The estimated equipment cost including a shelter and a VOC CEMS with affiliated equipment plus installation is over \$201,600 per system. Total annual operating costs were estimated to be approximately \$72,820. See Appendix B for a detailed cost analysis. Based on PTE emissions from the process heaters, the average cost-per-ton to monitor for VOCs with a CEMS is over \$1.0 million dollars.

The proposed BACM, VOC emission limit, and monitoring methods for the process heaters and boilers are presented in Table 7-3.

Table 7-3 Proposed BACM Controls, VOC Emission Limits, and Monitoring for Process Heaters and Boilers

Pollutant	Units	Control Technology	Emission Limit (lb/MMBtu)	Monitoring
VOC	4H1, 6H1, 6H2, 6H3, 7H1, 7H3, 8H2, 9H1, 9H2, 10H1, 10H2, 11H1, 12H1, 13H1, 19H1, 20H2, 20H3, 23H1, 24H1, 25H1, 27H1, 30H1, 30H2, 33H1, 68H2, 68H3, 68H4, 68H5, 68H6, 68H7, 68H19, 68H11, 68H12, 68H13, Boilers #4, #5, #8, #9, #10	GCP	None	None
	Boiler #11	GCP	0.004	Stack test performed every 3 years

7.2 Flares

As mentioned previously, there are two flare stacks located at the Northwest corner of the refinery. During refinery operating upsets, process equipment may experience over-pressures which are relieved through a spring-loaded pressure safety valve ("PSV"). Piping headers connect these devices to the flare stack, which is used to safely burn the released hydrocarbons. A small, continuous flame of pipeline-quality natural gas purchased from Questar acts as a pilot light to ignite the process vapors as they enter the flare tip for final destruction. Emissions from flaring may include unburned VOC's and partially burned and altered hydrocarbons.

7.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

For safe flare operation, the design of the flares requires the use of a pilot light. The combustion of the natural gas to fuel the pilot light and the combustion of refinery gases produce VOC.

A search of the RBLC, state databases, and emission control literature was conducted to find available control technologies to control flare emissions. Flares operate primarily as air pollution control devices. The only technically feasible control options for emissions of all pollutants from flares are:

- proper equipment design and work practices;
- good combustion practices;
- conversion from air assisted to steam assisted, and
- flare gas recovery systems.

No add-on controls for VOC emissions from flares were identified.

7.2.1.1 Proper Equipment Design and Work Practices

Proper equipment design and work practices include minimizing the quantity of gases combusted, minimizing exit velocity, ensuring adequate heat value of combusted gases, and installing an automatic pilot reignition. The flares at the Woods Cross Refinery are designed and operated in accordance with 40 CFR 60.18, general control device requirements which include a flame present at all times, no visible emissions, and heat content and maximum tip velocity specifications that meet the requirements of the rule. The use of pipeline-quality natural gas to fuel the pilot lights will reduce VOC emissions.

7.2.1.2 Good Combustion Practices

A certain level of flame temperature control can be exercised for a flare by utilizing steam which improves mixing. Good combustion practices can be used to minimize emissions of VOC.

7.2.1.3 Conversion from Air Assisted to Steam Assisted

Flares produce lower flame temperatures when operating with low heating value gases at low combustion efficiencies than when operating with high heating value gases at high combustion efficiencies. This leads to reduced formation of VOC in the flame. In general, emissions are lower in steam assisted flare tests than in air assisted flare tests conducted under similar conditions.

7.2.1.4 Flare Gas Recovery Systems

Flaring can be reduced by installation of a flare gas recovery system. A flare gas recovery system include a seal system to allow for recovery of process gases vented to the flare. Compressors recover the vapors and vapors are sent to the fuel gas treatment system for H₂S removal. After conditioning of the recovered vapors, the gases are combined with other plant fuel gas sources and combusted in heaters, boilers, and other devices that operate using fuel gas.

If the pressure in the flare gas headers exceeds the seal system settings, excess flare gases are allowed to flow to the flare for combustion. The pressure in the flare gas system increases due to additional process gas flow that cannot be recovered by the flare gas compressors. Once the pressure drops and the excess gases are combusted, the seal system re-establishes itself for continuous recovery of vapors.

The flare gas recovery system will not be sufficient to prevent flaring from process unit startup and shutdown events where large volumes of process gases will be sent to the flare. Also, during process upsets or malfunctions, the flare gases may not be entirely recovered due to the constraints of the flare gas recovery system. The flare gas recovery system will be sized for normal operating conditions.

7.2.2 Step 2 - Eliminate Technically Infeasible Options

None of the identified control options is considered technically infeasible for the flares at the Woods Cross Refinery.

7.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top ranking control option is the installation of a flare gas recovery system. Flare gas recovery systems are achieved in practice. The second highest ranking control option includes proper equipment design and work practices which includes good combustion practices. The combustion efficiency is the percentage of hydrocarbon in the flare vent gas that is completely converted to CO₂ and water vapor. Destruction efficiency is the percentage of a specific pollutant in the flare vent gas that is converted to a different compound. The destruction efficiency of a properly operated flare is 98%.

7.2.4 Step 4 - Evaluate Impacts and Document Results

HollyFrontier will install a flare gas recovery system to recover vent gas which is the highest ranked control option.

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. Because the flares are located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 CFR Part 60 Subpart Ja and the design and work practice requirements of 40 CFR 60.18.

Emissions from the HollyFrontier Woods Cross Refinery flares under normal operation will consist only of the emissions from the combustion of natural gas in the flare pilot flames and a small amount of purge gas that is circulated through the flare system for safety reasons (i.e., to prevent air from entering the flare lines).

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. Because the flares are located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 CFR Part 60 Subpart Ja and the design and work practice requirements of 40 CFR 60.18.

Flare management plans have been developed for both the north and south flare. These plans contain procedures to minimize or eliminate discharges to the flare during startups and shutdowns. To verify that the procedures are followed, records are maintained.

The flares at the refinery are steam-assisted and have a destruction efficiency of 98% or greater.

7.2.4.1 Energy, Environmental, or Economic Impacts

Since HollyFrontier has chosen the highest ranked control option, flare gas recovery, energy, environmental and costs analyses are not required to be addressed.

7.2.5 Step 5 - Select BACT

HollyFrontier is proposing the following design elements and work practices as BACM for the flares:

- Use of low sulfur fuel such as natural gas as fuel for pilot flame;
- Maintaining an acceptable net heating value and exit velocity of flared gases under all flow conditions in accordance with manufacturer specifications;
- Use of a thermocouple to monitor presence of the pilot flame;
- Implementation of good combustion, operating, and maintenance practices;
- Implementation of Flare Management Plans;
- Flare operation in accordance to 40 CFR Part 60, Ja and design and work practice standards as codified in 40 CFR Part 60.18; and,
- Installation of flare gas recovery system.

No other measures were identified as more stringent to control VOC emission from the flares at the Woods Cross Refinery. The flare design includes steam-assisted combustion. The flares will be equipped with a flare gas recovery system for non-emergency releases, and a continuous pilot light. Pilot and sweep fuel will be natural gas or treated refinery gas.

The proposed BACM controls and monitoring methods conducted for the flares at HollyFrontier are summarized in Table 7-4.

Table 7-4 Proposed BACM Controls and Monitoring Methods for Flares

Pollutant	Unit	Control Technology	Monitoring
VOC	66	Flare gas recovery system	Flow meters and gas combustion monitors on gas line

7.3 Cooling Towers

VOC emissions are due to the evaporation of VOC's that may be present in the cooling water due to equipment or heat exchanger leaks. Small amounts of hydrocarbons may be present in the cooling water.

7.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Only one control technology was identified for controlling VOC emissions from cooling towers which is the implementation of a heat exchanger leak detection and repair (LDAR) program.

7.3.2 Step 2 - Eliminate Technically Infeasible Options

The implementation of a heat exchanger leak detection and repair program was determined to be technically feasible.

7.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The only identified, technically feasible control option is to implement a heat exchanger leak detection and repair program for the cooling towers. In using this option, no significant energy, environmental, or economic impacts are expected. This program involves monitoring cooling water for the presence of hydrocarbons, and finding and repairing leaks when hydrocarbons are found.

7.3.4 Step 4 - Evaluate Impacts and Document Results

Therefore, to satisfy BACT, HollyFrontier conducts monthly monitoring to identify leaks of strippable VOC from heat exchange systems. A leak is a total strippable VOC concentration in the stripping gas of 6.2 ppmv or greater. Monthly water samples are collected and analyzed from each cooling tower return line to determine the total strippable VOC concentration using the Texas El Paso method as required by 40 CFR Subpart CC. Monthly records kept including date of inspection, cooling tower/heat exchanger inspected, total strippable VOC concentration, repairs, and follow up testing.

7.3.4.1 Energy, Environmental, or Economic Costs

Since HollyFrontier has chosen the highest ranked control option, LDAR; energy, environmental and costs analyses are not required.

7.3.5 Step 5 - Select BACT

No more stringent measures than LDAR were determined to control VOC emissions from the cooling towers. BACM is based on the implementation of a heat exchanger LDAR program and compliance with 40 CFR Part 63, Subpart UUU. Monthly testing is conducted to determine total strippable VOC concentrations.

The proposed BACM controls, VOC emission limits, and monitoring methods conducted for the cooling towers at HollyFrontier are summarized in Table 7-5.

Table 7-5 Proposed BACM Controls, VOC Emission Limits, and Monitoring Methods for Cooling Towers

Pollutant	Unit	Control Technology	Emission Limit	Monitoring Methods
VOC	54	LDAR	Leaks of strippable VOC <6.2 ppmv (CT's 4,6,7,8)	Modified El Paso Method, Monthly testing Repair identified leak within 15 days
		LDAR	Leaks of strippable VOC < 3.1 ppmv (CT 10, 11)	

7.4 Sulfur Reduction Unit Incinerator

VOC's from the SRU incinerator result from incomplete fuel combustion of carbon and organic compounds in the fuel gas.

7.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Since the tail gas incinerator is a combustion device, the only VOC emission control techniques identified were good combustion practices, engineering design, and use of clean burning fuels.

7.4.2 Step 2 - Eliminate Technically Infeasible Options

Good combustion practices, engineering design, and the use of clean burning fuels are all technically feasible.

7.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The only technically feasible control options for VOC from the SRU tail gas incinerator are good combustion practices and engineering design, and the use of clean-burning fuel.

7.4.4 Step 4 - Evaluate Impacts and Document Results

As mentioned above, emissions from the SRU are sent to the tail gas incinerator followed by a wet gas scrubber.

7.4.4.1 Energy, Environmental, or Economic Impacts

Wet scrubbers generate waste in the form of a slurry. Typically, the slurry is treated to separate the solid waste from the water. Once the water is removed, the remaining waste will be in the form of a solid which can generally be landfilled. There are no other anticipated energy, environmental, or economic impacts associated with the use of a wet scrubber to remove VOC from the effluent stream from the SRU during normal operations.

Although natural gas is considered a clean fuel, natural gas combustion in the tail gas incinerator will result in increased VOC combustion emissions. Economic impacts occur due to the cost to use natural gas to fire the tail gas incinerator. There are no other anticipated impacts associated with the use of the tailgas incinerator.

7.4.5 Step 5 - Select BACT

Emissions from the SRU tail gas incinerator are sent to one of the wet gas scrubbers. VOC BACM for the SRU tail gas incinerator and wet gas scrubber is good combustion practices, engineering design, and use of clean burning fuels utilizing natural gas. No other measures were identified as more stringent to control VOC emissions from SRU tailgas incinerators. Combustion is monitored through the use of an O₂ CEMS.

The proposed BACM controls and monitoring methods conducted for the SRU tailgas incinerator at the Woods Cross Refinery are summarized in Table 7-6.

**Table 7-6 Proposed BACM Controls and Monitoring Methods for SRU
Tail Gas Incinerator**

Pollutant	Unit	Control Technology	Monitoring
VOC	17	Good combustion practices, engineering design and use of clean burning fuels	O ₂ CEMS

7.5 FCCU

Fluidized catalytic cracking units are complex processing units at refineries that convert heavy components of crude oil into light, high-octane products that are required in the production of gasoline.

The FCCU consists of two vessels. In the reactor vessel, the conversion reaction occurs in the presence of a fine, powdered catalyst and steam, during which the catalyst becomes coated with petroleum coke. In the regenerator vessel, this coke is removed from the surface of the spent catalyst by burning it off in the presence of air so that the catalyst can be reused. The cracked products from the reactor vessel are separated in a fractionator column into intermediate streams for further processing. The catalyst regenerator exhaust contains VOCs.

7.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Three available control technologies to control VOC emissions from a full burn FCCU regenerator include:

- > Good combustion practices,
- > Combustion promoters, and
- > Catalytic reduction.

7.5.1.1 Good Combustion Practices

Full burn regenerators operate with excess oxygen in the flue gas. The minimum excess oxygen required to promote VOC oxidation is a function of bed temperature, gas residence time in the bed, and how efficiently the regenerator design utilizes the available oxygen. Assuming that the full burn unit is properly designed and as long as sufficient oxygen is present, the oxidation of CO to CO₂ should be complete, resulting in both reduced CO and VOC concentrations. Thus, good combustion design and operation will effectively control VOC emissions present in the FCCU regenerator exhaust gas.

7.5.1.2 Combustion Promoters

CO combustion promoters are an additive to the coke combustion process in the regenerator that hampers the formation of NO_x while enhancing the combustion of coke on the catalyst. The CO combustion promoters are readily fluidized, mixing with the catalyst. They are added to the circulating fluid bed (CFB) regenerator unit to improve the efficiency of VOC burning, reduce emissions of VOC and improve the efficiency of the unit. The CO combustion promoter accumulates in, or just above, in the fast fluidized bed combustion zone of the regenerator. There are several CO promoters that are available for use including Engelhard Corporations OxyClean™, Intercat, and Grace Davison's XNO_x all of which are effective in reducing VOC emissions while controlling NO_x emissions.

7.5.1.3 Catalytic Oxidation

Catalytic oxidation decreases VOC emissions by allowing the complete oxidation to take place at a faster rate and a lower temperature. The oxidation reaction typically requires a temperature of 650 to 1000°F to achieve optimal oxidation efficiencies. Catalytic oxidation cannot be used in waste streams with large amounts of particulate matter since the particulate deposits foul the catalyst and inhibit the control efficiency.

7.5.2 Step 2 - Eliminate Technically Infeasible Options

A review of the RBLC, state data bases, and air permits did not identify the use of catalytic oxidizers to control VOC emissions from an FCCU regenerator. The use of a catalytic oxidation system is not technically feasible due to the relatively low temperatures of the FCCU exhaust stream. The process of reheating the flue gas would result in the formation of additional combustion products including VOC. Thus, the use of this technology to control VOC emissions from FCCU exhaust gas has been determined to be technically infeasible.

7.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining technologies include the use of good combustion practices and combustion promoters.

7.5.4 Step 4 - Evaluate Impacts and Document Results

The FCCU regenerators at HollyFrontier utilize full burn combustion technology which minimizes VOC emissions to the fullest extent possible. The regenerative vent is continuously monitored through use of a CEMS to ensure the CO (hence VOC) emissions are controlled to the maximum extent possible. The use of good combustion practices to reduce VOC emissions from FCCU's has been achieved in practice and is used throughout the industry. In addition, HollyFrontier utilizes a combustion promoter, LoTOx to reduce NO_x emissions.

7.5.4.1 Energy, Environmental, and Economic Impacts

There are no anticipated environmental, energy, or economic impacts associated with use of good combustion practices and a combustion promoter.

7.5.5 Step 5 - BACT

The use of full burn technology for the FCCU regenerator, good combustion practices, and a combustion promoter are used by HollyFrontier to minimize VOC emissions from the FCCUs. Thus, the use of these technologies is considered BACT for VOC. No more stringent measures were identified to reduce VOC emissions from an FCCU.

The proposed BACM controls and monitoring methods conducted for the FCCU at the Woods Cross Refinery are summarized in Table 7-7.

Table 7-7 Proposed BACM Controls and Monitoring Methods for FCCU

Pollutant	Unit	Control Technology	Monitoring
VOC	4, 25	Good combustion practices, combustion promoter	O ₂ CEMS

CO emissions are continuously monitored and are limited to ≤500 ppmv based on a one-hour average at 0% O₂. By insuring CO emissions are within these limits, VOC emissions will also be controlled.

7.6 Storage Tanks

Storage tanks are used at the HollyFrontier Woods Cross Refinery to store raw materials, intermediates, blend stocks, and finished products. Emissions from storage tanks generally depend on several factors; tank size (capacity), dimensions (diameter and height), type (fixed roof, internal floating roof, external floating roof), vapor pressure of substance stored, and tank turnovers. Storage tanks that store chemicals that are not hydrocarbon based are assumed to have no emissions. The emissions from storage tanks include VOCs. There are 102 above-ground storage tanks for volatile organic compounds, 12 above ground-cylindrical storage tanks for water, and 25 pressurized storage vessels at the Woods Cross Refinery.

There are three types of storage vessels: fixed roof tanks, external floating roof tanks, and internal floating roof tanks. A typical fixed roof tank consists of a cylindrical shell with a cone- or dome-shaped roof that is permanently affixed to the tank shell. An external floating roof tank consists of a cylindrical shell equipped with a deck or roof that floats on the surface of the stored liquid, rising and falling with the liquid level. An internal floating roof tank has both a permanently affixed roof and a roof that floats inside the tank on the liquid surface or is supported on pontoons several inches above the liquid surface. The internal roof rises and falls with the liquid level.

For fixed roof or internal floating roof tanks, emissions occur as a result of the displacement of headspace vapor during filling operations or from tank rim seals in the case of external floating roof tanks (working losses). To a lesser degree, diurnal temperature variations and solar heating result in emission from storage tanks (breathing losses).

The nominal requirements to control VOC emissions are provided in the petroleum refinery NESHAP regulation, 40 CFR 63 Subpart CC, the Hazardous Organic NESHAP, 40 CFR Part 63 Subpart G, or in 40 CFR Part 60 Subpart Kb. Because high vapor pressure volatile organic liquids must be stored in "controlled tanks", the regulations define how these tanks are constructed and monitored. Tanks constructed after July 23, 1984 are required to operate in accordance with 40 CFR Part 60 Subpart Kb and are exempt from refinery MACT requirements (63.640(n)). Tanks constructed before that date and storing volatile organic liquids containing HAPS are required to meet the applicable Refinery MACT requirements of NESHAP 40 CFR 63 Subpart CC which refers to the control standards of 40 CFR Part 63 Subpart G.

7.6.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The available control technologies for tanks storing organic liquids include control equipment designed to minimize leakage from tanks, air pollution control equipment, and combinations of each. The control options that were identified include:

- Fixed roof tank (baseline),
- External floating roof, vapor-mounted primary and secondary seals,
- External floating roof, dome, vapor recovery $\geq 98\%$ efficiency for products ≥ 3 psia except for crude oil
- Internal floating roof, bolted construction, vapor-mounted primary seal with uncontrolled deck fittings,
- Internal floating roof, bolted construction, liquid-mounted primary seal with uncontrolled deck fittings,
- Internal floating roof, bolted construction, liquid-mounted primary seal with controlled deck fittings,
- Internal floating roof, bolted construction, liquid-mounted primary and secondary seals with controlled deck fittings,

- Internal floating roof, welded construction, liquid-mounted primary and secondary seals with controlled deck fittings,
- Fixed roof with add-on vapor recovery equipment, and
- External floating roof, welded deck type, liquid mounted primary and secondary seals,
- Operating the vessel under pressure such that it operates with no emissions, and
- Routing vapors to a process or a fuel gas system via hard piping, such that the vessel operates with no emissions.

7.6.2 Step 2 - Eliminate Technically Infeasible Options

The control options involving internal floating and external floating roof tank designs are not technically feasible for the asphalt tank due to the nature of the material being stored and due to the storage temperature of the material.

7.6.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The control options for the storage tanks are listed in ascending order of control effectiveness. As mentioned above, there are three major types of vessels used to store liquids. In addition, optional equipment designs exist within each major tank type (e.g. seal design, roof fabrication, fittings closure). Table 7-8 presents a hierarchy of tank control options.

Table 7-8 Hierarchy of Tank Control Options

Control Option	Equipment Description
1	Fixed roof tank (baseline)
2	External floating roof, vapor-mounted primary and secondary seals
3	Internal floating roof, bolted construction, vapor-mounted primary seal with uncontrolled deck fittings
4	Internal floating roof, bolted construction, liquid-mounted primary seal with uncontrolled deck fittings
5	Internal floating roof, bolted construction, liquid-mounted primary seal with controlled deck fittings
6	Internal floating roof, bolted construction, liquid-mounted primary and secondary seals with controlled deck fittings
7	Internal floating roof, welded construction, liquid-mounted primary and secondary seals with controlled deck fittings
8	Fixed roof with add-on vapor recovery equipment
9	External floating roof, welded deck type, liquid mounted primary and secondary seals
10	Operating the vessel under pressure
11	Routing vapors to a process or a fuel gas system via hard piping

Routing vapors to a process or a fuel gas system via hard piping, such that the vessel operates with no emissions, where technically feasible, is the highest ranking control which is nearly 100 percent effective in reducing emissions from storage tanks.

The second highest ranking control option is operating a vessel under pressure. This type of tank is only applicable to pressurized tanks, i.e. as bullets or spheres, storing certain products such as propane, butane, NGL liquids, etc.

The third highest ranking control option for reducing emissions from storage tanks is a fixed roof in combination with an internal floating roof with a vapor collection in a closed vent system routed to a control device. This design incorporates a roof structure that floats on the surface of the stored liquid with dual flexible seals along the edge of the roof. This design effectively eliminates working losses. As additional control, the headspace between the floating roof and the top of the tank is filled with sweep gas that is vented under a slight vacuum. The breathing losses that escape through the seals are carried with the sweep gas to an add-on control device such as a thermal oxidizer.

The fourth effective option includes an internal floating roof and dual rim seals. This option does not include sweep gas routed to a control device.

The fifth effective option used to control VOC emissions from storage tanks includes the use of an external floating roof with dual rim seals. This control option has overall effectiveness equivalent to a tank which is equipped with an internal floating roof and dual rim seals. This design is similar to the internal floating roof configuration discussed above but without the enclosed headspace. The floating roof and seals reduce volatilization losses.

The Mid-Atlantic Regional Air Management Association (MARAMA) report, *The Assessment of Control Technology Options for Petroleum Refineries in the Mid-Atlantic Region Final Report January, 2007* summarizes tank control technologies for reducing VOC emissions as follows:

Technology	Percent Reduction
Install internal floating roof in fixed roof tank	60-99
Install domed fixed roof on an external floating roof	96
Replace a vapor-mounted primary seal with a liquid-mounted primary seal	30-70 EFR 43-45 IFR
Install secondary seals on floating roof tanks	75-95%
Vapor balancing	80%
Incineration	95-99%
Apply tank standards to tanks storing organic liquids with vapor pressure 0.1-0.5 psia	Varies

7.6.4 Step 4 - Evaluate Impacts and Document Results

Under NSPS regulations, control equipment is required when storing volatile organic liquids with maximum vapor pressure of 0.75 psia. Otherwise, control requirements generally are triggered at 1.5 psia. Tanks storing volatile organic liquids below the vapor pressure threshold are required to keep records of types of products stored and their vapor pressures, periods of storage and tank design specifications.

Because high vapor pressure volatile organic liquids must be stored in "controlled tanks", the regulations define how these tanks are constructed and monitored. Tanks over 40,000 gallons and built, modified, or reconstructed between June 11, 1973 and May 19, 1978 are required to operate in accordance with 40 CFR Part 60 Subpart K. Subpart K is only applicable to Tanks 145 and 146 at the refinery.

Tanks over 40,000 gallons and built, modified, or reconstructed between May 18, 1978 and July 23, 1984 are required to operate in accordance with 40 CFR Part 60 Subpart Ka. Tanks constructed after July 23, 1984 are required to operate in accordance with 40 CFR Part 60 Subpart Kb and are exempt from refinery MACT requirements (63.640(n)). This rule applies to Tanks 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 98, 99, 159, and 323 at the facility. Tanks 85-97, and 99 are subject to Kb by size of tank and date of construction only and have no applicable requirements.

Tanks constructed before August 18, 1994 and storing volatile organic liquids containing HAPS are required to meet the applicable Refinery MACT requirements of NESHAP 40 CFR 63 Subpart CC which refers to the control standards of 40 CFR Part 63 Subpart G. For Group 1 storage vessels storing liquids for which the maximum true vapor pressure of the total organic hazardous air pollutants in the liquid is less than 76.6 kilopascals, the use of fixed roof and internal floating roof, an external floating roof, an external floating roof converted to an internal floating roof, a closed vent system and control device, routing the emissions to a process or a fuel gas system, or vapor balancing is required. Group 1 tanks at the Woods Cross refinery include 72, 100, 101, 103-108, 121, 126, 132, 145, and 146.

Compliance options for VOC emission controls on tanks includes using a fixed roof with an internal floating roof, an external floating roof meeting certain design specifications, and using a closed-vent system and control device that meet the requirements of 40 CFR Part 60 Subpart Kb. For tanks 85, 87-97, 99, 170, and 175-187, the applicable NSPS and/or NESHAP rules do not require any control of VOC emissions due to the low vapor pressure (<0.5 psia) of these tank contents. Thus, fixed roof tanks are appropriate for storage of these low vapor pressure products.

In addition, Utah Administrative Code R307-327 presents the requirements of petroleum liquid storage in ozone nonattainment and maintenance areas. R307-327-4 states (1) Any existing stationary storage tank, with a capacity greater than 40,000 gallons (150,000 liters) that is used to store volatile petroleum liquids with a true vapor pressure greater than 10.5 kilo pascals (kPa) (1.52 psia) at storage temperature shall be fitted with control equipment that will minimize vapor loss to the atmosphere. Storage tanks, except for tanks erected before January 1, 1979, which are equipped with external floating roofs, shall be fitted with an internal floating roof that shall rest on the surface of the liquid contents and shall be equipped with a closure seal or seals to close the space between the roof edge and the tank wall, or alternative equivalent controls. The owner/ operator shall maintain a record of the type and maximum true vapor pressure of stored liquid. (2) The owner/operator of a petroleum liquid storage tank not subject to (1) above, but containing a petroleum liquid with a true vapor pressure greater than 7.0 kPa (1.0 psia), shall maintain records of the average monthly storage temperature, the type of liquid, throughput quantities, and the maximum true vapor pressure.

The facility has several tanks that comply with this rule. Tanks equipped with internal floating roofs with secondary seals which have (or will be when constructed) include Tanks 12, 71, 72, 85, 98, 131, 138, and 323. Floating roof tanks erected prior to January 1, 1979 include Tanks 100-102, 104-109, 121, 126, 128, 129, 132, 135, 145, and 146.

7.6.4.1 Energy, Environmental, and Economic Impacts

The most effective control option of recovering vapors and routing them to a process or a fuel gas system via hard piping such that the tank operated with no emissions would result in adverse energy and environmental impacts due to the significant electrical power demand of the required compression system.

An economic analysis was performed for gathering vapors discharged from cone-roof tanks and processing these vapors for the recovery of condensable hydrocarbons by means of absorption which is the top ranking control over condensation, mechanical refrigeration, and adsorption using carbon beds for recovery of hydrocarbon vapors from storage tanks. This requires extensive processing equipment, the most common method involving compression, cooling, absorption, heating, stripping, and final condensation by cooling. This equipment must be designed to operate under conditions of varying compositions of the vapors and fluctuating vapor flow rates from the tanks. The recovered liquid can be used as feed stock for further processing or stored in tanks.

For the vapor recovery process, vapors from each tank are gathered, pass through a pressure-control valve into the main gathering header and are drawn into the suction of a compressor. After compression, the vapors are discharged into the absorption chamber where they are absorbed in circulating lean oil. The lean oil, enriched with these vapors pass from the bottom of the absorber and the recovered hydrocarbons from the top of the stripper are cooled and condensed.

The \$/ton of VOC reduced from the addition of an absorption system was estimated to be approximately \$280,000 (see Appendix B). This estimate does not include for vapor balancing between tanks. With the use of this option, additional steam, electricity, and cooling water as utilities are needed as well as extra labor costs to operate the system.

Although this option is theoretically possible, HollyFrontier is not aware of any petroleum refinery operating with this equipment on any cylindrical storage tanks. In addition, to the best of HollyFrontier's knowledge, EPA has never identified this as a control option for consideration in establishing MACT for storage tanks at refineries.

The second highest control option, use of a closed vent system routed to a thermal oxidizer or carbon absorber, for tanks storing relatively volatile materials, an internal floating roof is considered inherent to the process for product loss minimization. For tanks storing less volatile materials, an uncontrolled fixed roof is considered the baseline control.

The installation of a thermal oxidizer or carbon absorber would result in adverse energy and environmental impacts due to the auxiliary fuels needs for the required thermal oxidizer and the additional combustion emissions (NO₂, SO₂, PM_{2.5}, VOC) that result from a thermal oxidizer. If activated carbon were used, a solid waste could also be generated.

The cost of a vapor control system is a function of the vapor flow rate to the system. The flow rate is controlled by the rate at which liquids are pumped into the tank. Due to time constraints, detailed engineering and site-specific costs could not be obtained for the installation of a vapor control system. According to EPA estimates adjusted to 2011 dollars, the total annualized costs of installing a vapor control system by incineration is approximately \$425,000. If carbon adsorption were used for vapor control, the projected annualized costs would be approximately \$595,000. Like above, although this option is theoretically possible, HollyFrontier is not aware of any petroleum refinery operating with this equipment on any cylindrical storage tanks. In addition, to the best of Holly's knowledge, EPA has never identified this as a control option for consideration in establishing MACT for storage tanks at refineries.

The use of internal floating roof and dual rim seals does not result in any adverse energy or environmental impacts. Because of the low volatility off the products being stored in fixed roof tanks, the installation of internal floating roofs and seals or an external floating roof is not warranted. The capitol cost to install internal floating roof to a fixed roof tank ranges from \$240,000 to \$480,900 per tank (MARAMA). For an external floating roof, the estimated capitol cost would be over \$210,000. This control option has overall effectiveness equivalent to a tank which is equipped with an internal floating roof and dual rim seals.

A closed vent system and a control device have been eliminated from further consideration. In addition, since the emissions from the proposed fixed roof tanks are not significant, i.e., less than one ton per year, a floating roof is not proposed for the lower vapor pressure product tanks. The MARAMA report estimated to apply tank standards to tanks storing organic liquids with vapor pressures between 0.1 to 0.5 psia, the cost effectiveness ranges from \$20,500 to \$34,000 per ton VOC reduced.

Vapor balancing can be accomplished through a network of vapor lines interconnecting the vapor spaces of all tanks. Under the most favorable conditions of perfectly balanced pumping, where the input rate and the output rate were equal, it is not possible to eliminate all filling losses. However, control of losses caused by unbalanced pumping and breathing requires variable-space vapor storage with a capacity equal to the volume of the maximum breathing plus unbalanced pumping. The primary operating consideration is the potentially adverse effect of the interchange of vapors between tanks storing different products.

In the case where the pump-out rate is equal to the input rate, a simple interconnection pipe system would only recover the filling losses estimates to be approximately 30% of the total loss. The addition of a vapor tank prevent all vapor losses but adds an additional cost to the system. Other items to consider include the size of the vapor recovery tank and if there is adequate space for the installation of this tank.

The estimated capital costs to install a vapor-balancing system with a network of interconnecting vapor lines and a vapor tank are estimate to be close to \$150,000⁶. Annual operating costs are estimated to be approximately \$38,000. The installation of a vapor balancing system to control less than a ton of VOC emissions from the fixed roof tanks is not economically feasible.

7.6.5 Step 5 - Proposed BACM

Based on the analyses presented above, the top options, vapor recovery from fixed roof tanks, installation of a thermal oxidizer or utilization of carbon adsorption, vapor control systems for higher VOC product tanks, closed vent system and control device for fixed roof tanks, and vapor balancing has been determined to be not economically feasible.

The proposed BACM for refinery tanks is compliance with the equipment design and work practices requirements as set forth in 40 CFR 63, Subpart G and 40 CFR 60, Subpart Kb. The floating roof tanks consist of a shell and a roof that floats on the hydrocarbon liquid. The quantity of loss for floating roof depends on the rim seal design and emission control on the roof fittings. Thus, for 12, 71, 72, 85, 98, 131, 138 and 323, HollyFrontier is utilizing Control Option 7 (above) for reducing VOC emissions from these tanks. This includes the use of internal floating roofs, welded construction, liquid-mounted primary and secondary seals with controlled deck fittings, and vapor-mounted wiper seals.

Floating roof tanks are used to store hydrocarbons having a greater tendency of vapor generation on exposure to high temperature, i.e. higher vapor pressure. The floating roof helps in vapor suppression. As seen from Table 7-9, Control Option 9, external floating roof, welded deck type, liquid mounted primary and secondary seals is the most effective control option. This option will be utilized for storage tanks 100-102, 104-109, 121, 126, 128, 132, 135, 145 and 146. This type of tank roof minimizes the vapor space between it and the liquid surface. Since there is no large vapor space for the liquid to evaporate into, vapor losses are also minimized.

During tank degassing operations, which occurs infrequently at the refinery, VOC vapors are routed to a portable (mobile) thermal oxidizer which is at least 98% efficient. Control is maintained until the VOC concentration is less than 10,000 ppmv VOC or 10% of the lowest explosive level (lel) which meets R307 requirements.

Table 7-9 presents a list of the current and proposed tanks, tank type, the vapor pressure of the material stored, and the control method. The 25 pressurized storage tanks (i.e. bullets or spheres) are not sources of emissions at the Woods Cross Refinery. The monitoring conducted on the tanks must comply with LDAR requirements.

⁶ C.A Day, Economics of Vapor Recovery from Storage Tanks, Journal of Air Pollution Control, 5:1 17-63.

Table 7-9 Proposed BACM for HollyFrontier Storage Tanks

Tank ID	Product Stored	Vapor Pressure of Stored Material (psia)	Control Method
Tank 11	Empty-Out of Service	--	--
Tank 12	Reformer Charge	2.5	IFR
Tank 14	Kerosene	0.02	Fixed Roof
Tank 15	Fuel Oil	0.02	Fixed Roof
Tank 19	Stove Oil (Ultra Low Sulfur)	0.02	Fixed Roof
Tank 20	Stove Oil (Ultra Low Sulfur)	0.02	Fixed Roof
Tank 21	Out of service	--	Hor. Elliptical
Tank 23	Diesel ULSD	0.02	Fixed Roof
Tank 24	Diesel ULSD	0.02	Fixed Roof
Tank 28	Diesel ULSD	0.02	Fixed Roof
Tank 29	Caustic	0.00	Fixed Roof
Tank 31	Residual oil no. 6	0.02	Fixed Roof
Tank 35	Gas Oil	0.02	Fixed Roof
Tank 37	Fuel Oil	0.02	Fixed Roof
Tank 42A	Jet Fuel Additive	0.02	Fixed Roof
Tank 47	Diesel ULSD	0.02	Fixed Roof
Tank 48	Light Cycle Oil	0.02	Fixed Roof
Tank 50	Empty-Out of Service	--	Hor. Dish
Tank 51	Empty-Out of Service	--	Hor. Flat
Tank 52	Fuel Oil	0.02	Fixed Roof
Tank 53	Fuel Oil	0.02	Fixed Roof
Tank 54	Fuel Oil	0.02	Fixed Roof
Tank 55	Fuel Oil	0.02	Fixed Roof
Tank 56	Fuel Oil	0.02	Fixed Roof
Tank 57	Fuel Oil	0.02	Fixed Roof
Tank 58	Fuel Oil	0.02	Fixed Roof
Tank 59	Empty-Out of Service	0.00	Fixed Roof
Tank 60	Caustic	0.00	Fixed Roof
Tank 61	out of service	0.00	Fixed Roof
Tank 63	Stove Oil (Ultra Low Sulfur)	0.02	Fixed Roof
Tank 64	out of service	0.00	Fixed Roof
Tank 65	out of service	0.00	Fixed Roof
Tank 70	Gas Oil	0.02	Fixed Roof
Tank 71	Black Wax	1.9	IFR, 40 CFR 63, Sub. CC
Tank 72	Gasoline (RVP 8 WX)	5	IFR, 40 CFR 63, Sub. CC
Tank 73	out of service	0.00	Fixed Roof
Tank 74	out of service	0.00	Fixed Roof
Tank 75	out of service	0.00	Fixed Roof
Tank 76	out of service	0.00	Fixed Roof
Tank 77	Biodiesel	<0.5	Fixed Roof
Tank 78	Biodiesel	<0.5	Fixed Roof
Tank 79	Asphalt	<0.5	Fixed Roof
Tank 81	NaHS	0.33	Umbrella
Tank 82	NaHS	0.33	Umbrella

IFR = Internal floating roof

EFR – External floating roof

Table 7-9 (Continued) Proposed BACM for HollyFrontier Storage Tanks

Tank ID	Source Description	Vapor Pressure of material Stored (psia)	Applicability
Tank 83	Caustic	0.00	Umbrella
Tank 85	Poly Gasoline	2.1	IFR, 40 CFR 60, Sub. Kb
Tank 86	Gas Oil	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 87	Gas Oil	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 88	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 89	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 90	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 91	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 92	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 93	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 94	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 95	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 96	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 97	Hydroisom feed/lube	0.02	Fixed roof, 40 CFR 60, Sub. Kb
Tank 98	Gasoline Blendstock	2.1	IFR, 40 CFR 60, Sub. Kb
Tank 99	Distillate fuel oil no. 2	0.02	Fixed Roof, 40 CFR 60, Sub. Kb
Tank 100	Reformate	2.1	EFR
Tank 101	Gasoline (RVP 7 WX)	2.1	EFR
Tank 102	Gas Oil	0.02	EFR
Tank 103	Crude Oil (heavy)	1.9	Fixed Roof
Tank 104	Isomerate	2.6	EFR, 40 CFR 63, Sub. CC
Tank 105	Isomerate	2.6	EFR, 40 CFR 63, Sub. CC
Tank 106	Gasoline (RVP 8 WX)	5	EFR, 40 CFR 63, Sub. CC
Tank 107	Gasoline (RVP 8 WX)	5	EFR, 40 CFR 63, Sub. CC
Tank 108	Gasoline (RVP 11 WX)	5	EFR, 40 CFR 63, Sub. CC
Tank 109	Alkylate	2.1	EFR, 40 CFR 63, Sub. CC
Tank 113	Caustic	0.00	Flat
Tank 114	Caustic	0.00	Flat
Tank 116	Caustic	0.00	Flat
Tank 117	API Trap Sludge	0.00	Open
Tank 118	Recovered Slop	5	Flat
Tank 121	Crude Oil (RVP 8 WX)	4.9	EFR, 40 CFR 63, Sub. CC
Tank 122	Propane	190	Hor. Ell.
Tank 123	Propane	190	Hor. Ell.
Tank 124	Ammonia	124.6	Hor. Ell.
Tank 125	Ammonia	124.6	Hor. Ell.
Tank 126	Crude Oil (RVP 4 WX)	1.9	EFR, 40 CFR 63, Sub. CC
Tank 127	Diesel ULSD	0.02	Fixed Roof
Tank 128	Jet Fuel	0.02	EFR
Tank 129	Out of service	--	EFR
Tank 130	NHDS Charge	0.33	Hor. Ell.
Tank 131	Stove Oil WX Input	0.02	IFR
Tank 132	Gasoline (RVP 8 WX)	5	EFR, 40 CFR 63, Sub. CC
Tank 133	Isobutane	72.2	Hor. Sphere

IFR = Internal floating roof

EFR - External floating roof

Table 7-9 (Continued) Proposed BACM for HollyFrontier Storage Tanks

Tank ID	Source Description	Vapor Pressure of material Stored (psia)	Applicability
Tank 134	Isobutane	72.2	Hor. Sphere
Tank 135	Naptha WX Input	11.1	EFR
Tank 136	Propane	190	Hor. Ell
Tank 138	Stove Oil WX Input	0.02	IFR
Tank 139	SDA Charge	0.02	Fixed Roof
Tank 140	SDA Charge	0.02	Fixed Roof
Tank 141	Solvent	142	Hor. Sphere
Tank 145	Gasoline (RVP 8 WX)	5	EFR, 40 CFR 60, Sub. K
Tank 146	Gasoline (RVP 8 WX)	5	EFR, 40 CFR 60, Sub. K
Tank 147	Propane	190	Hor. Ell
Tank 148	Propane	190	Hor. Ell
Tank 149	Butane	51.6	Hor. Ell
Tank 150	Butane	51.6	Hor. Ell
Tank 151	Butane	51.6	Hor. Ell
Tank 152	Olefin	110	Hor. Ell
Tank 153	Olefin	110	Hor. Ell
Tank 159	NGL	200	Sphere, 40 CFR 60, Sub. Kb
Tank 170	Finished Diesel	<0.5	Fixed Roof
Tank 171	Propane	190	Hor. Ell
Tank 172	Propane	190	Hor. Ell
Tank 173	Propane	190	Hor. Ell
Tank 174	Propane	190	Hor. Ell
Tank 300	Chemical	0.1	Fixed Roof
Tank 301	Chemical	0.1	Fixed Roof
Tank 302	Chemical	0.02	Fixed Roof
Tank 303	Chemical	0.02	Fixed Roof
Tank 304	Out of service	--	Fixed Roof
Tank 305	Out of service	--	Fixed Roof
Tank 306	Out of service	--	Fixed Roof
Tank 307	Out of service	--	Fixed Roof
Tank 308	Out of service	--	Fixed Roof
Tank 310	Out of service	--	Fixed Roof
Tank 312	Out of service	--	Fixed Roof
Tank 313	Out of service	--	Fixed Roof
Tank 323	Ethanol	4.5	IFR, 40 CFR 60, Sub. Kb
Tank 324	Olefin	110	Hor. Ell.
Tank 54-V4	Sulfuric Acid	0.00	Hor. Ell.
Tank 54-V5	Sulfuric Acid	0.00	Hor. Ell.
Tank 54-V7	Phosphate	0.00	Dome

IFR = Internal floating roof

EFR - External floating roof

Monitoring conducted on the tanks include annual seal gas inspections which are typically conducted in March and annual visual inspections conducted in September. Once every 5 years the primary seals are inspected. The tank valves are included in the LDAR program.

HollyFrontier will install leg covers on tank legs (that are set at high legs). Guidepole covers have been installed on certain tanks per the Consent Decree.

The most stringent controls identified is the installation of an internal or floating roof or approved emission control systems on tanks with products with vapor pressures ≤ 1.5 psia. The external floating roofs must be equipped with a primary and secondary seal and must rest on the surface of the liquid tank contents. For internal floating roof tanks, depending on the date of installation, the tank must be equipped with either a liquid mounted primary seal, mounted in full contact with the liquid in the annular space between the tank shell and floating roof, a metallic shoe primary seal, or a vapor mounted primary and a secondary seal. The SCAQMD requires domed roofs be installed on all external floating roof tanks that contain organic liquids having true vapor pressure ≥ 3 psia.

According to European Commission, Integrated Pollution Prevention & Control (ECIPPC) report, Reference Document on Best Available Techniques for Mineral Oil and Gas Refineries, 2003, the costs to install IFR on tanks storing products with a vapor pressure ≤ 1.5 psia ranges from \$240,000 to \$480,900 per tank (in 2003 dollars). Tanks storing low vapor pressure liquids inevitably generate fewer VOC emissions than tanks storing high vapor pressure liquids. For this reason, to implement control devices on storage tanks containing low vapor pressure emissions would not be cost effective. See Appendix B.

To install a domed fixed roof on an external floating roof tank, the average cost was estimated by ECIPPC to range from \$21,640 to \$240,500 (in 2003 dollars). To place domes over external floating roofs is not economical. Although the \$/ton VOC removed for Tank 135 is less than \$10,000 (see Appendix B), this cost does not include any engineering fees and the likelihood that the existing tank and roof could not support a dome. According to the ECIPPC report, the costs to install and operate a vapor recovery system or to incinerate is more costly than the installation of domes, so these options have been determined to not be cost-effective.

7.7 Equipment Leaks

The Wood Cross Refinery is required to monitor equipment in hydrocarbon service that is greater than 10% VOC. Equipment that is monitored includes pumps, valves, compressors, flanges, and pressure relief devices. Numbered tags are used to identify equipment included in the Leak Detection and Repair (LDAR) Program. These components are sources of VOC emissions due to leakage.

The facility's leak detection and repair program is regulated under the Utah Administrative Code (R307-326-9 Leaks from Petroleum Refinery Equipment), 40 CFR Part 60 Subparts GGG and GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries), 40 CFR Part 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries), and the July 2, 2008 Consent Decree.

7.7.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Potential enhancements to a LDAR program work practice requirements include the following:

- > Lowering the definition of a "leaking" component threshold concentration as measured at the leak interface. This has the potential of broadening the repair obligations for leaking components to include components that would not normally require repair under NSPS or NESHAP rules.
- > Increase leak monitoring frequencies which could accelerate the identification and repair of leaking components.

In addition, equipment specifications and maintenance practices are designed and implemented to reduce leaks. For certain applications, components with inherently leakless features are available. These components reduce VOC emissions. Some leakless designs include the following:

- > Magnetic drive or diaphragm pumps without external seals
- > Pumps with double mechanical seals
- > Magnetic-drive centrifugal pumps
- > Diaphragm valves
- > Connectors welded around the entire circumference such that the joint cannot be disassembled by unscrewing or unbolting the components

Another control option would be to take an enforceable limit on the number of leaking components.

7.7.2 Step 2 - Eliminate Technically Infeasible Options

Each control option that was identified in Step 1 is technically feasible.

7.7.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The most effective of the identified control options is a combination of each option. This includes an LDAR program with enhanced work practices relative to the NSPS or NESHAP plus enforceable limits on leaking components.

7.7.4 Step 4 - Evaluate Impacts and Document Results

The most effective control strategy listed above has been implemented by HollyFrontier at the Woods Cross Refinery. The LDAR program at the refinery meets the requirements of NSPS, NESHAP, and consent decree requirements.

The following leak rate goals have been set to be achieved through the LDAR program at the Woods Cross Refinery: (1) A facility wide component leak rate goal has been set at less than or equal to 2.0% of total components; and, (2) Each process unit leak rate goal is less than or equal to 2.0% of total components.

The following leak definitions are utilized at the refinery:

1. All units have a leak definition for recordkeeping, reporting, and repair of 2,000 ppm for pumps and compressors and 500 ppm for valves.
2. Internal leak definitions for first attempt at repair is 200 ppm will be utilized for all valve components subject to NSPS and NESHAP regulations.

EPA Method 21 is used to determine the presence of leaking sources. Monitoring and leak rate calculations are divided into groups. Most of these groups are based on units, fluid types, and regulatory requirements. Each month, the LDAR technicians complete the scheduled monitoring and results of monitoring are entered into the LDAR database at the end of each shift. Work Requests for identified leaks that were not repaired by the LDAR technician are initiated by the end of the monitoring shift. Operations personnel perform a visual inspection of pumps subject to MACT and NSPS regulations each week. Any observed leaks are reported to the facility LDAR Coordinator within 24 hours. Olfactory, visual and auditory leak checks are performed daily and repairs are reported and fixed within 24 hours.

Leaks are defined by the various regulatory requirements. The LDAR Technician will make an initial attempt to repair on leaking components and leaking components are tagged. The VOC reading for each leaking component is recorded on the tag by the technician. Table 7-10 defines actions for various leak rates.

Table 7-10 Repair Actions for Leaking Valves and Pumps

Component	Requirement	Leak Rate (ppm)	First Attempt	Final Repair	Report as Leak
Valves	Consent Decree	200-499	5 days	-	No
		500-9,999	5 days	30 days	No
		>9,999	5 days	15 days	Yes
	40 CFR GGGa	>499	5 days	15 days	Yes
	R307-326-9	>9,999	5 days	15 days	Yes
Pumps	Consent Decree	2,000-9,999	5 days	30 days	No
		>9,999	5 days	30 days	Yes
	40 CFR GGGa	>1,999	5 days	15 days	Yes
	R307-326-9	>9,999	5 days	15 days	Yes

Components are re-monitored within 5 days after a repair attempt. After the first attempt, valves with leaks less than 500 ppm require no further action. For valves found to be leaking greater than 10,000 ppm that cannot be repaired, a drill and tap repair or similarly effective repair method will be performed, unless it can be documented that there is a safety, mechanical, or major environmental concern with repairing the leak with such a method. The initial repair attempt will be made within 15 days and a second, if necessary, within 30 days of identification of the leak, as stated in paragraph 132 (b) of the Consent Decree.

Gas/vapor and light liquid valves that leak, and are repaired, will be monitored for two consecutive months before going back to quarterly monitoring. A chronic leaker is a valve that has leaked greater than 10,000 ppm at least twice in any 4 consecutive quarters. Chronic leaking, non-control valves, are replaced, repacked, or similarly repaired at the next process unit turnaround.

All process units are subject to the R307-326-9, Leaks from Petroleum Refinery Equipment and 40 CFR Part 60 Subpart GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries). Those that contain HAP are subject to 40 CFR Part 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries).

Leakless designs, including pumps with double mechanical seals have been installed on Units 4, 8, 24, 25, 26, and 28.

7.7.4.1 Energy, Environmental, and Economic Impacts

There are no anticipated energy, environmental and economic impacts associated with the top ranking control of operation of a LDAR program.

7.7.5 Step 5 - Selection of BACM

The LDAR program in operation at the Woods Cross Refinery incorporates the effective control technologies listed above and is considered the BACM. The LDAR program at the refinery meets the requirements of NSPS, NESHAP, and consent decree requirements. A LDAR program is the most stringent control measure identified at refineries for controlling VOC emissions from equipment leaks. Monitoring is performed on components based on the requirements presented in Table 7-11. No more stringent controls were identified other than the implementation of an effective LDAR program.

Table 7-11 LDAR Monitoring Frequencies

Equipment	Type	Requirements		Comments
		State and Federal*	Consent Decree (7/2/08)	
Leak Detection Monitoring				
Valves	Light Liquid	Monthly	Quarterly	
	Heavy Liquid	As noticed	Exempt	<10% VOC
	Gas	Monthly	Quarterly	
	Plant Gas	Monthly	Quarterly	>10% VOC
	Natural Gas	Exempt	Exempt	<10% VOC
Pumps	Light Liquid	Monthly	Monthly	
	Heavy Liquid	As noticed	Exempt	<10% VOC
Compressor	Seals	Auto-sensors	Quarterly	
Drains	Process	None	NA	
All	Unsafe to Monitor	When possible	When possible	
All	Difficult to Monitor	Annual	Annual	
Visual Monitoring				
Pumps	Light Liquid	Weekly	NA	
	Heavy Liquid	None	NA	<10% VOC
Drains	Process	Monthly	NA	NSPS Subpart QQQ

7.8 Wastewater Treatment Plant

The Waste Water Treatment Plant (WWTP) (Unit 56) treats plant wastewater and storm water runoff from process areas. Wastewater is collected and routed through a grit collector then to a main process lift station. The main process lift station supplies process waste water to two American Petroleum Institute (API) separators. Oil is skimmed off the separators and gravity fed to an API oil collection drum then to Tank 118. The sludge from the API separators is collected and dewatered in a sludge thickening vessel and later sent for disposal.

The effluent water from the API separators is pumped to two equalization tanks (Tanks 155 and 158). From the equalization tanks, waste water is pumped into two dissolved gas floatation units (DGF). The DGFs work to remove emulsified oil from the waste water by adding a polymer and inducing small N₂ bubbles into the water to bring oil to the surface. This skimmed oil, or float, is gravity fed to a storage tank before being pumped to the sludge thickening vessel.

Finally the waste water is sent to a series of moving bed bio-film reactors (MBBR) for biological polishing before being discharged to the South Davis County Public Owned Treatment Works (POTW). All process tanks and equipment at the WWTP are covered to control fugitive emissions.

7.8.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Emission control technologies for control of VOC emissions from the wastewater treatment plant include equipment design and work practice requirements that are set forth in the following regulations:

- 40 CFR Part 60, Subpart QQQ requires water seal controls or more effective controls for the wastewater system drains and sumps and a floating roof or a closed-vent system and a control device, such as a catalytic oxidizer for the API separators.
- 40 CFR Part 61, Subpart FF generally requires the same controls for the wastewater collection system drains and sumps as Subpart QQQ.
- 40 CFR Part 63, Subpart CC requires compliance with the requirements of 40 CFR Part 61, Subpart FF.

Per the above regulations, identified controls include water seal controls on drains, wastewater stripping, floating roofs for treatment vessels, and carbon absorption and incineration for removal of VOC from vent streams. Inspection and maintenance programs as well as performance-based work standards are also control strategies that can be implemented to reduce VOC emissions.

7.8.2 Step 2 - Eliminate Technically Infeasible Options

Water stripping, floating roofs, and incineration are technically infeasible for application to wastewater drains. The requirements of Subpart QQQ and Subpart FF are technically feasible.

7.8.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Equipment control strategies can require the installation of new equipment or devices, or can include physical changes to the wastewater system. Potential control strategies include:

- > Collecting and venting the emissions to a control device can achieve a control efficiency of greater than 95 percent. Potential emission control devices for wastewater collection systems (predominately junction box vents) include: carbon absorption, thermal oxidation, catalytic oxidation, and condensation.

- > Installing water seals on process drains and vents open to the atmosphere would help prevent emissions from the downstream sewer lines from escaping back out of the drain or vent opening. The overall control efficiency of this method is estimated at an average of 65%, and varies depending on the proper maintenance of the water seal.
- > Some control measures, such as water seals, can require an extensive inspection and maintenance (I&M) program in order to be effective. An effective I&M program is designed to inspect (on a regular basis), maintain and repair (as necessary) the pertinent components of a pollution control system for proper operation.
- > By establishing performance-based standards, such as setting an emission limit of 500 ppm VOC from a drain or vent, equivalent emission reduction can be achieved without specifying a particular control technology.

For wastewater treatment plant vessels, the most effective control strategy includes wastewater stripping to reduce VOC concentrations in wastewater entering the API separators, floating roofs for the equalizations tanks, and closed vent systems and oxidation of the VOC-containing vent streams from the API separators and dissolved gas floatation (DGF) units. Hard piping from the process units to the wastewater separator, from process units to a drain box enclosure, from those process units identified as the largest contributors to process drain emissions, or from junction boxes that are completely covered and sealed with no openings are also most effective in reducing VOC emissions.

Less effective control options would omit the use of a wastewater stripper or use floating roofs rather than closed vent systems and oxidation systems for the API separators and DGF units.

7.8.4 Step 4 - Evaluate Impacts and Document Results

During wastewater treatment, volatilization/stripping, sorption, and biodegradation primarily determine the fate of VOCs. Of these, volatilization and stripping result in air emissions. Biodegradation and sorption onto sludge serve to suppress air emissions. Stripping is the pollutant loss from the wastewater due to water movement caused by mechanical agitation, head loss, or air bubbles, while volatilization may be defined as quiescent or wind-driven loss. The magnitude of emissions from volatilization/stripping depends on factors such as the physical properties of the pollutants (vapor pressure, Henry's Law constants, solubility in water, etc.), the temperature of the wastewater, and the design of the individual collection and treatment units (including wastewater surface area and depth of the wastewater in the system). Wastewater unit design is important in determining the surface area of the air-water interface and the degree of mixing occurring in the wastewater (CARB, 2003).

In 2015, HollyFrontier upgraded their wastewater treatment system to include covered oil-water separators with fixed roofs and venting VOC vapors that accumulate under the headspace of the fixed roofs through a closed system to carbon absorption units, equipping new drains with a water seals, and covering new junction boxes. Monthly visual inspections are performed on the individual drain systems and semi-annual inspections are performed on the closed vent system and sealed junction boxes and oil/water separators. Carbon adsorber monitoring is performed at intervals no greater than 20 percent of the design carbon replacement intervals. The piping used for the new sewer lines associated with the upgrade are compliant with Subpart QQQ.

Performance based standards exist at the refinery with emission limits of 500 ppm above background for the carbon adsorber and closed vent system. The closed vent systems are designed and operated with no detectable emissions which are verified semi-annually. Sealed junction boxes are also used and inspected semi-annually.

7.8.4.1 Energy, Environmental, and Economic Impacts

There are no energy, environmental, and economic impacts anticipated with the top ranking control options that have been utilized on the wastewater treatment plant.

7.8.5 Step 5 - Select BACT

VOC emissions from the wastewater treatment system meet the requirements of Subpart QQQ and Subpart FF. Emissions from the wastewater system control device comply with 40 CFR 60 Subpart QQQ and are monitored in accordance with 40 CFR 60.695. 40 CFR Part 61, Subpart FF requires that the oil water separators be equipped with a fixed roof and vapors directed to a control device which HollyFrontier has installed. No more stringent requirement were found than compliance with 40 CFR 60 Part QQQ and 40 CFR Part 61, Subpart FF.

The proposed BACM controls, VOC emission limits, and monitoring methods conducted for the wastewater treatment at the Woods Cross Refinery are summarized in Table 7-12. The most stringent measures identified for control of VOC emission from wastewater treatment include installing covers and seals on the collection components to reduce fugitive VOC emissions, and maintaining or installing a control device such as carbon canisters to destroy VOCs released during treatment. HollyFrontier has included the most stringent measures for the design of their wastewater treatment unit.

Table 7-12 Proposed BACM Controls, VOC Emission Limits, and Monitoring Methods for Wastewater Treatment

Pollutant	Unit	Control Technology	Emission Limit	Monitoring Methods
VOC	56	Carbon adsorber	500 ppm (above background)	Monitored at intervals $\leq 20\%$ of design carbon replacement interval
		Closed vent system	500 ppm (above background)	Method 21, semi-annual inspections
		Individual drain system water seal	None	Monthly visual inspections
		Sealed junction boxes and oil-water separators	None	Semiannual visual inspections

7.9 Product Loading

Unit 87 consists of truck and rail loading/unloading operations. Truck loading and unloading operations consist of sixteen crude/gas/oil/NGL truck unloading bays, one NaSH truck loading spot, three caustic truck unloading spots, two sulfur truck loading arms, one fuel oil truck loading spot, one fuel oil truck unloading spot, one asphalt truck loading spot, one diesel truck unloading spot, one light cycle oil truck unloading spot, two propane truck loading spots, one kerosene truck loading spot, one gasoline truck unloading spot, fourteen fuel oil or asphalt loading spots, twenty-four lube oil loading spots, and, two dedicated ethanol unloading areas.

The rail operations consist of two NaSH/caustic rail car loading/unloading spots, four fuel oil/asphalt rail car loading/unloading spots, four oil/diesel/caustic rail car loading/unloading spots and ethanol rail car unloading spots, four NGL rail car loading/unloading spots, five NGL/olefin rail car loading/unloading spots, and, two biodiesel rail car unloading spots.

7.9.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Several control technologies were identified to reduce product loading emissions. They include use of submerged or bottom loading, installation of a vapor balance system and vapor recovery or destruction technologies which include carbon adsorption, condensation, and incineration.

7.9.2 Step 2 - Eliminate Technically Infeasible Options

All control technologies identified in Step 1 are technically feasible.

7.9.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Vapor recovery through carbon adsorption or condensation provides the most effective control of emissions by collecting the vented material for recycle or reuse. Vapor destruction through incineration provides control of emissions by combustion of the hydrocarbon to form CO₂ and H₂O vapor. Individually, each identified control technology has approximately the same control effectiveness. Each technology, when applied to the exhaust stream from a loading rack will reduce VOC emissions in excess 98%.

The use of submerged or bottom loading as a means of control offers the low cost way to control loading emissions. A significant reduction in vapor generation is possible by decreasing the turbulence created when liquid is introduced into a compartment. This can be done through the use of bottom or submerged loading rather than splash loading.

In vapor balancing, hydrocarbon vapors are collected from the compartment where the liquid is being loaded and returned to the tank from which the liquid is being sent. This balancing works since the volume of displaced vapors is almost identical to the volume of liquid removed from the tank. This technique is most effective when loading tank trucks from fixed roof tanks. Vapor balancing cannot be applied when loading from floating roof tanks since there is no closed vapor space in the tank to which vapors can be returned.

7.9.4 Step 4 - Evaluate Impacts and Document Results

VOC emissions from loading/unloading are a function of the vapor pressure of the liquid and the design of the equipment. Liquids with very low vapor pressure, diesel, kerosene, caustic, NaSH, asphalt will have limited VOC emissions.

At the refinery, HollyFrontier only load/unloads fuels such as oil, gas oil, asphalt, NaSH, kerosene, diesel, and ethanol, all of which have low volatility. The majority of the crude and refined products are brought in and shipped out via pipeline which is a closed system. For products with low vapor pressures that are loaded at the rail and truck spots, the reduction of VOC emissions from excess vapors is accomplished through the use of submerged or bottom loading as well as vapor balancing. For truck loading, control of VOC emissions is through vapor balancing. For VOC emissions from LPG railcar unloading, a vapor recovery system consisting of recovery of LPG emissions by pumping back into the tank.

Gasoline, diesel, and jet fuel from the HollyFrontier Woods Cross Refinery are sent to the Holly Energy Partners Terminal via pipeline. A loading rack is utilized to load these products into tanker trucks. The Terminal has four loading bays for local sales of diesel, jet fuel, and gasolines. A limit of 4.5 million barrels per year of fuels dispensed is specified in the DAQE-AN0101230023B-07 for the Terminal. The Terminal is equipped with a John Zink Model JZ1017886 VRU that captures and recovers hydrocarbon vapors that are displaced during bulk loading operations at the Woods Cross Terminal. The VRU consists of two carbon collection beds operated and regenerated alternately. The two beds vent to the atmosphere through a common stack. John Zink has provided a guarantee to limit hydrocarbon emissions from exceeding 10 milligrams per liter of product loaded for any consecutive six-hour period during normal operation.

In the event the VRU is not operational, a natural-gas fired John Zink VCU is also available as a backup to control emissions of volatile hydrocarbons. Hydrocarbon vapors from gasoline truck loading flow to a condensate collection tank. This tank is important to the operation of the VCU. It allows any condensed liquid and overflow of the transport vehicles to be removed prior to the combustion step. The design basis for the VCU is based on a maximum truck loading rate of 4,500 gallons per minute (gpm), a maximum vapor flow to the combustor of 601 standard cubic feet per minute (SCFM), ambient temperatures ranging from 20 to 100°F, and a maximum hydrocarbon concentration of 60 volume percent. Available pressure at inlet of vapor combustion is 12" W.C. The VCU operation is limited to 1,056 hours per year.

7.9.4.1 Energy, Environmental, and Economic Costs

Routing the emissions from low VOC products that are loaded or unloaded from trucks and railcars at the refinery to a regenerative thermal oxidizer (RTO) was examined. Based on HollyFrontier's 2015 annual emission inventory, VOC emissions from loading/unloading sulfur, asphalt, kerosene, stove oil, fuel oil, ethanol, crude, and gas oil were approximately 3.5 tons per year. The cost effectiveness for installation of a regenerative thermal oxidizer is approximately \$175,000 per year including the increase in VOC emissions from combustion. In addition, additional energy in the form of natural gas will be needed to fuel the RTO leading to increased VOC emissions. Thus, it was determined that use of a RTO was not cost, energy, or environmentally effective and was not considered BACT for this analysis.

7.9.5 Step 5 - Proposed BACM

BACM for HollyFrontier is the delivery of crude and high VOC products through pipeline and the use of a VRU and VCU at the terminal loadout. BACM for the tanker and railcar loading and unloading at the Woods Cross Refinery is the use of submerged or bottom loading as well as vapor balancing.

The most stringent measures identified for product loading for tank truck and rail car loading includes a submerged pipe fill and vapor collection system vented to a thermal incinerator with a destruction efficiency >98.5%. As mentioned above, the installation of a thermal incinerator would increase VOC emissions and is not cost effective. Thus, the installation of a thermal incinerator does not represent BACT for emissions of VOC from railcar and tanker truck loading/unloading at the Woods Cross Refinery.

7.10 Diesel Emergency Engines

Diesel emergency equipment at the Woods Cross refinery consists of a 135 kW portable diesel generator at the East Tank Farm, 224 HP diesel powered water well No. 3, 393 HP fire pump No. 1, 393 HP fire pump No. 2, 180 HP diesel fire pump, three 220 HP diesel-powered plant air backup compressors, 470 HP diesel standby generator at the Boiler House, 380 HP diesel standby generator at the Central Control Room, and a 540 HP diesel standby generator.

VOC emissions are primarily the result of incomplete combustion of the diesel fuel. These emissions occur when there is a lack of available oxygen, the combustion temperature is too low, or if the residence time in the cylinder is too short.

7.10.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following control options were evaluated for controlling VOC emissions from the CI combustion engines. They include: good combustion practices and the post-combustion control technologies of diesel oxidation catalysts.

7.10.1.1 Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion. The emergency generators are designed to achieve maximum combustion efficiency. The manufacturer provided operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency.

7.10.1.2 Diesel Oxidation Catalyst

A diesel oxidation catalyst (DOC) is a flow-through metal or ceramic substrate coated with platinum or other precious metals. The diesel oxidation catalyst sits in the exhaust stream and all exhaust from the engine passes through it. The catalyst promotes the oxidation of unburned CO and HC (as VOC) in the exhaust producing CO₂ and water. Diesel oxidation catalysts are commercially available and reliable for controlling VOC emissions from diesel engines.

7.10.2 Step 2 - Eliminate Technically Infeasible Options

The control technologies identified in Step 1 are technically feasible.

7.10.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The control effectiveness of each identified control technology is as follows:

- > Diesel oxidation catalyst - 95%
- > Combustion controls - baseline

7.10.4 Step 4 - Evaluate Impacts and Document Results

For diesel engines, oxidation catalysts are often combined with particulate filters. This can be done by applying the catalysts, which are typically platinum based, to a particulate filter. Another common approach is to locate the oxidation catalyst separately, upstream of the particulate filter. The oxidation catalyst creates heat by oxidizing unburned hydrocarbons and shifts NO_x creating a favorable environment for the particulate filters to regenerate.

7.10.4.1 Energy, Environmental, and Economic Impacts

The highest ranking control option, DOC, can reduce VOC emissions up to 95%. A cost effectiveness evaluation for this top ranking option, in costs per ton of VOC removed, is presented in Table 7-13 and in Appendix B. Costs for DOCs were obtained from Wheeler Machinery.

Table 7-13 Cost Effectiveness of Installing DOC on Emergency Diesel Engines for VOC Control

Equipment	Cost Effectiveness (\$/Ton)
135 kW generator (east tank farm)	\$ 67,074
224 HP (water well #3)	\$ 1,481,981
393 HP Fire Pump #1	\$ 1,456,046
393 HP Fire Pump #2	\$ 1,456,046
220 HP plant air backup compressor #1	\$ 497,006
220 HP plant air backup compressor #2	\$ 497,006
220 HP plant air backup compressor #3	\$ 497,006
470 HP diesel generator (boiler house)	\$ 1,475,701
380 HP diesel generator (central control room)	\$ 1,466,543
540 HP standby generator	\$ 1,678,418

As seen from Table 7-13, it is not cost effective to install DOC on the emergency diesel generators.

7.10.5 Step 5 - Proposed BACM

As mentioned above, California has the most aggressive emission reduction standards for diesel engines. The MSC method includes the use of DOCs to reduce VOC emissions as well as the use of ultra-low sulfur fuel, limited hours of operation, and good combustion practices and engine maintenance. (See RBLC ID NJ-0085 and NJ-0084 which indicates these controls to be LAER).

40 CFR 60, Subpart IIII applies to engines which commenced construction after 7/11/2005 and are manufactured after 4/1/2006 (for non-fire-pump engines), or an engine modified or reconstructed after 7/11/2005. Subpart IIII applies to the emergency diesel equipment at the refinery. Records of maintenance and hours of operation are kept. A non-resettable totalizer is installed on each emergency diesel engine. Maintenance is performed on the engines in accordance with manufacturer specifications. Oil/filters are changed and belts/hoses inspected every 500 hours or annually.

Based on the economic evaluation presented in Table 7-13, DOC's are not cost effective for the emergency generators or the fire water pumps at the Woods Cross Refinery and have been eliminated from further consideration. The cost effectiveness of an oxidation catalyst includes general maintenance, assuming proper operation of the system. If poisoning of the catalyst occurs, replacement of the catalyst will occur more frequently which increases the cost of control. In addition, engine valves/heads beyond the typical maintenance schedule will add to the maintenance costs.

Thus, for the emergency diesel equipment at HollyFrontier, BACM was determined to be limited hours of operation of the diesel engines (50 hours per year for each engine with the exception of the East Tank Farm portable diesel generator which is permitted to operate 1,100 hours per year), the use of ultra-low sulfur diesel, good combustion practices, and best practice of periodic maintenance. Engines will be maintained and operated in accordance with manufacturer recommendations.

The most stringent measure identified was any engine certified or verified to achieve the CARB applicable standard, which, for units in the size of HollyFrontier's, is 4 g/KW-hr.

The proposed BACM, emission limitations, and monitoring methods for the emergency diesel engines are presented in Table 7-14.

Table 7-14 Proposed BACM Controls, VOC Emission Limitations, and Monitoring Methods for Emergency Diesel Engines

Pollutant	Units	Control Technology	Emission Limitations	Monitoring
VOC	All emer. Engines except ETF gen.	GCP	600 hours total rolling 12-month period	Non-resettable hour meter
	ETF portable generator		1100 hours per rolling 12-month period	

7.11 Emergency Natural Gas-Fired Engines

Combustion is a thermal oxidation process where carbon and hydrogen contained in the fuel combine with oxygen in the combustion zone to form H₂O and CO₂. VOC's are generated during the combustion process due to incomplete thermal oxidation of the carbon contained in the fuel. In properly designed and operated generators, low levels of VOC's are typically emitted.

7.11.1 Step 1- Identify all Control Technologies

Three potential control technologies were identified to reduce VOC emissions. They are:

- > good combustion practices,
- > oxidation catalysts, and
- > NSCR as an add-on control device.

7.11.1.1 Good Combustion Practices

Optimization of the design, operation, and maintenance of an engine is one way to reduce VOC emissions by maximizing the thermal oxidation of carbon which minimizes the formation of VOC.

7.11.1.2 Oxidation Catalysts

An oxidation catalyst is a flow through exhaust device that contains a honeycomb structure covered with a layer of chemical catalyst. This layer contains small amounts of precious metal-usually platinum or palladium-that interact with and oxidize pollutants in the exhaust stream (CO and unburned HCs), thereby reducing emissions.

7.11.1.3 Non-Selective Catalytic Reduction

NSCR is a catalytic reactor that simultaneously reduces VOC emissions. The catalytic reactor is placed in the exhaust stream of the engine and requires fuel-rich air-to-fuel ratios and low oxygen levels.

7.11.2 Step 2 - Eliminate Technically Infeasible Options

The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich burn turbocharged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective VOC reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 percent. Lean-burn engines cannot be retrofitted with NSCR control because of the reduced exhaust temperatures. Thus, NSCR was eliminated from consideration since the engines operated by HollyFrontier at the administration building are designed for lean burning. The remaining control technologies are technically feasible.

7.11.3 Step 3 - Rank Remaining Control Technologies by Effectiveness

The use of an oxidation catalyst is the remaining top ranking control technology which provides a 90% control efficiency for VOCs. Good combustion practice is the second ranking control technology for VOC reduction.

7.11.4 Step 4 - Evaluate Most Effective Controls

Combustion controls are integral in the combustion process as they are designed to achieve an optimum balance between thermal efficiency-related emissions (CO and VOC) and temperature related emissions (NO_x). Combustion controls will not create any energy impacts or significant environmental impacts. There are no economic impacts from combustion controls because they are part of the design for modern engines.

Natural gas generators are regulated by 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. Here, the EPA provides emissions standards manufacturers must meet, emissions standards owners/operators must meet, EPA certification requirements, testing requirements, and compliance requirements.

According to Subpart JJJJ, the VOC emission standards for stationary emergency engines >25 HP is 1.0 g/HP-hr or 86 ppmvd @ 15% O₂. The HollyFrontier natural-gas fired emergency generators were manufactured in 2012 and as such, meet the Subpart JJJJ VOC emission standard of 1.0 g/HP-hr.

7.11.4.1 Energy, Environmental, and Economic Costs

Catalytic oxidation is relatively expensive for the size of the engines and the frequency of their use at the Woods Cross Refinery. The capitol cost to install an oxidation catalysts is approximately \$59,000. Annual costs are approximately \$18,700. The cost in \$/ton of VOC removed is estimated to be over \$6 million dollars. (See Appendix B). Thus, it is not economically feasible to install oxidation catalysts on the emergency natural-gas fired generators at the Woods Cross Refinery. There are no additional energy or environmental costs associated with operating an oxidation catalyst on the natural-gas fired emergency generators. There is no fuel penalty associated with the use of an oxidation catalysts since this control technology does not increase the fuel usage in an SI engine.

7.11.5 Step 5 - Select BACT

The most stringent control measure identified is the use of an oxidation catalyst achieving a VOC emission rate of 0.15 g/bhp-hr. This emission rate has been achieved in practice.

BACT for VOC emissions from 2012 model year SI ICE generators at HollyFrontier is the application of a lean burn engine fired on natural gas, good combustion practices, limited operating hours, and operation in accordance to manufacturer's recommendations. The generators are EPA certified and the manufacturer lists a VOC emission rate of 1.0 g/HP-hr or 86 ppmvd @ 15% O₂. The engines are in compliance with the applicable emission limits of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ. The proposed controls satisfy BACM.

The proposed BACM controls, VOC emission limitations, and compliance monitoring method conducted by HollyFrontier for the emergency natural gas-fired engines are summarized in Table 7-15.

Table 7-15 Proposed BACM Controls, Emission Limitation, and Monitoring for Emergency Natural Gas Engines

Pollutant	Units	Control Technology	Emission Limitation	Monitoring Method
VOC	Nat. gas fired emergency engines	Work Practice Requirements, Good Combustion Practice	600 hours total rolling 12-month period for all emergency engines 1.0 g/HP-hr	Non-resettable hour meter

8.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS FOR AMMONIA

BACM's were evaluated for ammonia emissions for certain emission units in operation or proposed at the Woods Cross Refinery. These emission units include: process heaters and boilers equipped with SCR, waste water treatment, FCCU, and sour water stripper.

8.1 Process Heaters and Boilers

Ammonia emissions from process heaters and boilers are a result of the ammonia slip from units that utilize SCR or SNCR to control NO_x emissions. Ammonia slip refers to emissions of unreacted ammonia that result from the incomplete reaction of the NO_x and the reagent.

8.1.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

A search of EPA's BACT/RACT/LAER Clearinghouse, state databases, and published literature did not identify application of emission controls to control ammonia emissions from process heaters and boilers. Ammonia slip emissions can occur when a process heater or boiler is equipped with an SCR and SNCR.

As discussed more fully in Section 4.1.1.4, SCR uses a catalyst to react injected ammonia to chemically reduce NO_x. It can achieve up to a 90% removal efficiency and is one of the most effective NO_x abatement techniques.

In SNCR, which is discussed in more detail in Section 4.1.1.5, ammonia or urea is injected within a boiler or in ducts in a region where temperature is between 900°C and 1100°C. This technology is based on temperature ionizing the ammonia or urea instead of using a catalyst. This temperature "window" is important because outside of it either more ammonia "slips" through or more NO_x is generated than is being chemically reduced. The temperature "window" is different for urea and ammonia. Reduction of the NO_x by SNCR can have up to a 50% removal efficiency.

8.1.2 Step 2 - Eliminate Technically Infeasible Options

There are no ammonia emissions from the combustion of natural gas or refinery gas from the boilers or process heaters except for those units that are equipped with a post-control add-on devices such as SCR or SNCR. As discussed above, SNCR was eliminated from due to the optimum exhaust gas temperature range for the boilers and process heaters were below implementation of SNCR which is 1,600 to 1,750°F for ammonia and from 1,000 to 1,900°F for urea-based reagents.

8.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

SCR is the remaining control technology that utilizes ammonia to reduce NO_x emissions. SCR is being utilized or proposed for certain large process heaters and boilers (10H2, 27H1, 30H1, 30H2, 33H1, and boilers #5, #8, #9, #10, #11) to reduce NO_x emissions at the Woods Cross Refinery.

8.1.4 Step 4 - Evaluate Impacts and Document Results

Ammonia slip associated with SCR system operation results from the gradual decline in catalyst activity over time, necessitating the use of increasing amounts of ammonia injection to maintain NO_x concentrations at or below the required emission limits. The parameters of NO_x concentration, ammonia slip limit, and catalyst life are integrally related. According to representative from Haldor Topsoe Inc., catalyst performance is generally specified as being a particular NO_x concentration guaranteed for 3 years. However, according to discussions with Topsoe, with burning natural gas or other clean fuels, catalyst life can be expected to last 6 to 8 years. With fresh catalyst, high performance is seen resulting in high NO_x reduction and low ammonia slip and as the catalysts deactivates, the ammonia injection rate will increase slightly and consequently also will the ammonia slip.

Stack testing on the boilers at the Woods Cross Refinery shows ammonia concentrations as non-detect. According to RBLC, an ammonia slip of 10 ppmv at 3% O₂ is a typical limit for process heaters and boilers equipped with SCR. Table 8-1 presents a summary of the BACM for ammonia for process heaters and boilers.

Table 8-1 Summary of BACM Determinations for Ammonia for Process Heaters and Boilers

Facility	Permit Date	Size (MMBtu/hr)	Limit (lb/MMBtu)	Control Technology
M&G Resins USA, LLC Project Jumbo, Texas	12/01/2014	142.82	10 ppmvd (hourly and annual)	Ammonia slip is 10 ppmvd – four heaters with LNB and SCR
Formosa Plastics Corp. Olefins Plant, Texas	08/08/2014	None listed	15 ppmvd (one-hour avg) 10 ppmvd (annual)	Ammonia slip is 15 ppmvd on an hourly basis and 10 ppmvd on an annual basis. Cracking furnaces and PDH reactors will use low-NO _x burners, Selective Catalytic Reduction (SCR), good engineering design/combustion practices.
Diamond Shamrock Refining Company, Valero Com McKee Refinery, Texas	12/30/2010	355.65	10 ppmv @3% O ₂	Ammonia slippage from SCR is limited to 10 ppmv at 3% oxygen.
Valero Delaware City Refinery, Delaware	02/26/2010	240, 446, 504	10 ppmvd@3% O ₂	Ammonia slip from SCRs.

8.1.4.1 Energy, Environmental, and Economic Impacts

The environmental impacts of SCR include ammonia emissions and disposal of spent catalyst after a catalyst's lifetime. The catalysts typically used for SCR contain metals that may require special handling and disposal measures in accordance with Resource Conservation and Recovery Act (RCRA) regulations. Higher injection rates of ammonia are required to increase the control efficiency of SCR; however, these higher injection rates correspond with higher levels of ammonia slip, which can contribute to haze. Control of NO_x emissions should be balanced with limiting ammonia slip through proper catalyst use, ensuring good mixing of the ammonia reagent in the flue gas, and careful control of the ammonia injection rate when fuel loads change, thus changing the ammonia and flue gas NO_x reaction dynamics.

Ammonia storage and handling must be conducted with care because ammonia is a hazardous material. The use of SCR may cause a 1 to 2 percent increase in sulfur trioxide (SO₃) emissions as a result of the catalyst oxidizing SO₂ to SO₃. The SO₃ can further react with ammonia, forming ammonium sulfate and ammonium bisulfate salts, which can contribute to PM_{2.5} emissions.

8.1.5 Step 5 - Select BACT

As seen from table 8-1, an ammonia slip of 10 ppmvd @3% O₂ on an annual basis is considered BACM for process heaters and boilers utilizing SCR. HollyFrontier will maintain, analyze or replace the catalyst, as needed, to insure high NO_x emission reduction and low ammonia slip. Catalysts will be analyzed when ammonia injection rates are being increased to control NO_x within applicable limits. No other measures were identified as more stringent to control of ammonia slip from process heaters or boilers.

The cost of installing and operating an ammonia CEMS to measure slip from boilers with SCR was examined. From cost data provided by MSI/Mechanical Systems Inc. the estimated equipment cost including a shelter (estimated to be approximately \$50,000), the ammonia CEMS and affiliated equipment including installation is \$191,800 per system. Total annual operating costs were estimated to be approximately \$70,700. See Appendix B for a detailed cost analysis.

8.2 Wastewater Treatment

The Waste Water Treatment Plant (WWTP) (Unit 56) treats plant wastewater and storm water runoff from process areas. Wastewater is collected and routed through a grit collector then to a main process lift station. The main process lift station routes process waste water to two American Petroleum Institute (API) separators. Oil is skimmed off the separators and gravity fed to an API oil collection drum then to Tank 118. The sludge from the API separators is collected and dewatered in a sludge thickening vessel and later sent for disposal.

The effluent water from the API separators is pumped to two equalization tanks (Tanks 155 and 158). From the equalization tanks, waste water is pumped into two dissolved gas floatation units (DGF). The DGFs work to remove emulsified oil from the waste water by adding a polymer and inducing small N₂ bubbles into the water to bring oil to the surface. This skimmed oil, or float, is gravity fed to a storage tank before being pumped to the sludge thickening vessel.

Finally the waste water is sent to a series of moving bed bio-film reactors (MBBR) for biological polishing before being discharged to the South Davis County Public Owned Treatment Works (POTW). All process tanks and equipment at the WWTP are covered to control fugitive emissions.

8.2.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The minimum emission standards that would meet BACT requirements for ammonia emissions are equipment design and work practice requirements. The work practice requirements are presented in 40 CFR Part 60 Subpart QQQ and 40 CFR Part 61 Subpart FF.

Under Title 40 CFR Part 60, Subpart QQQ, performance standards have been established for individual drain systems, including:

- > Each drain shall be equipped with a water seal
- > Junction boxes shall be equipped with a cover and may have an open vent
- > Sewer lines shall not be open to the atmosphere
- > Regular inspection and maintenance requirements.

Also under Title 40 CFR Part 60, Subpart QQQ, performance standards have been established for closed vent systems and control devices, including:

- > Any control device shall operate with an efficiency of 95 percent or greater to reduce VOC emissions vented to them
- > All control devices shall be operated with no detectable emissions, as indicated by an instrument reading of 500 parts per million VOC above background.

Under 40 CFR Part 61, Subpart FF, the benzene NESHAP regulations require that petroleum refineries use maximum achievable control technology (MACT) to control emissions of benzene from waste operations, including certain wastewater systems. This includes use of carbon absorption or collection and venting of wastewater gases to the refinery flare system (vent flap system) to control benzene emissions from wastewater systems in compliance with the refinery NESHAP requirements.

VOC emissions from wastewater collection systems can be controlled in a variety of ways including enclosing or controlling all openings, changing the operation of the units that are feeding the wastewater collection system, having an inspection and maintenance (I&M) program, or a combination of controls.

8.2.2 Step 2 - Eliminate Technically Infeasible Options

Water stripping, floating roofs for treatment vessels, and incineration are technically infeasible for application to process drains. The requirements of Subpart QQQ and Subpart FF are technically feasible.

8.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Equipment control strategies can require the installation of new equipment or devices, or can include physical changes to the wastewater system. Potential control strategies include:

- > Enclosing open weirs and lines with hard piping is the most stringent control option and could result in the greatest amount of VOC emission reductions.
- > Collecting and venting the emissions to a control device can achieve a control efficiency of greater than 95 percent. Potential emission control devices for wastewater collection systems (predominately junction box vents) include: carbon absorption, thermal oxidation, catalytic oxidation, and condensation.
- > Installing water seals on process drains and vents open to the atmosphere would help prevent emissions from the downstream sewer lines from escaping back out of the drain or vent opening. The overall control efficiency of this method is estimated at an average of 65%, and varies depending on the proper maintenance of the water seal.
- > Some control measures, such as water seals, can require an extensive inspection and maintenance (I&M) program in order to be effective. An effective I&M program is designed to inspect (on a regular basis), maintain and repair (as necessary) the pertinent components of a pollution control system for proper operation.
- > By establishing performance-based standards, such as setting an emission limit of 500 ppm VOC from a drain or vent, equivalent emission reduction can be achieved without specifying a particular control technology.

8.2.4 Step 4 - Evaluate Impacts and Document Results

In 2015, HollyFrontier upgraded their wastewater treatment system to include covering oil-water separators with fixed roofs and venting VOC vapors that accumulate under the headspace of the fixed roofs through a closed system to carbon adsorption units, equipping new unit drains with water seals, and covering new junction boxes. Monthly visual inspections are performed on the individual drain systems and semi-annual inspections are performed on the closed vent system and sealed junction boxes and oil/water separators.

The waste water fugitives from the DGF's and MBBR are controlled through carbon adsorption. Carbon adsorber monitoring is performed at intervals no greater than 20 percent of the design carbon replacement intervals. Large carbon systems are in place on the DGF and MBBR units. Carbon is replaced within 24 hours if monthly monitoring detects a breakthrough of the carbon bed.

Performance based standards exist at the refinery with emission limits for VOC of 500 ppm above background for the American Petroleum Institute (API) carbon adsorber and the closed vent system.

8.2.4.1 Energy, Environmental, and Economic Impacts

No significant negative energy, environmental, or economic issues result from the wastewater treatment system meeting the requirements of 40 CFR Part 60 Subpart QQQ and 40 CFR Part 61 Subpart FF.

8.2.5 Step 5- Select BACT

Ammonia emissions from the wastewater treatment system built after the compliance date meet the requirements of 40 CFR 60 Subpart QQQ and 40 CFR Part 61 Subpart FF. Emissions from the wastewater system control device comply with Subpart QQQ and are monitored in accordance with 40 CFR 60.695. Subpart FF requires that the oil water separators be equipped with a fixed roof and vapors directed to a control device which HollyFrontier has installed. In addition, HollyFrontier has covered each new unit drain system opening and vapors from the drain system are vented from the drain to a control device. No more stringent control measures were found other than compliance with Subparts QQQ and FF.

8.3 FCCU

Fluidized catalytic cracking units (FCCUs) are complex processing units at refineries that convert heavy components of crude oil into light, high-octane products that are required in the production of gasoline. The FCCU is named because the catalyst comes in such small particles that it flows like a fluid. During the reaction phase, the catalyst becomes coated with petroleum coke, which must be burned off in the catalyst regenerator so that the catalyst can be reused. The catalyst regenerator exhaust contains ammonia, among several other pollutants including SO₂, NO_x, PM_{2.5} and VOC.

An FCCU consists of two vessels. In the reactor vessel, the conversion reaction occurs in the presence of a fine, powdered catalyst and steam. During the conversion reaction the catalyst becomes coated with petroleum coke. In the regenerator vessel, this coke is removed from the surface of the spent catalyst by burning it off in the presence of air so that the catalyst can be reused. The cracked products from the reactor vessel are separated in a fractionator column into intermediate streams for further processing.

FCCU particulate emissions (PM) can be classified as primary or secondary PM emissions. Secondary PM emissions are not particulate matter when emitted, but are precursors to the atmospheric formation of PM_{2.5}. Most of the secondary PM_{2.5} formed consists of ammonium sulfate and ammonium nitrate particles formed by reactions between ammonia and NO_x and SO₂ in air.

8.3.1 Steps 1 - 4

No specific control technologies were identified for control of ammonia emissions from a FCCU. As such, the ammonia BACM is based on the reduction of secondary PM_{2.5} emissions. PM_{2.5} control strategies for an FCCU are presented in Section 6.5 above.

8.3.2 Step 5 - Select BACT

As presented in Section 6.5.5, according to the RBLC, wet scrubbers are used extensively as one method to reduce particulate from FCCUs and a wet gas scrubber are utilized by Holly to reduce PM and ammonia emissions from the FCCU's. Thus, a wet gas scrubber is considered BACM for reduction of ammonia from the FCCU regenerator stack. Stack testing has been performed for ammonia on the wet gas scrubbers and ammonia concentrations were between 0.4 to 0.6 ppm.

No more stringent measures were identified to control ammonia emissions from FCCU regenerator vents.

8.4 Sour Water Stripper and Ammonia Stripping Unit

Sour water containing ammonia is drained from process vessels throughout the refinery into an enclosed drain system which collects to storage Tank 166. Sour water is then pumped to the sour water stripper (Unit 18) where steam is used to strip the ammonia from the sour water. The ammonia vapors are sent to the ammonia stripping unit (Unit 22).

8.4.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

There are various control technologies available to control ammonia emissions which include both add-on control devices and pollution prevention techniques. The wet scrubber, specifically the packed tower scrubber, has been successfully used to control ammonia emissions, demonstrating control efficiencies up to 99%. Condensers are also used to remove ammonia by converting the gas to a liquid. With regards to ammonia leakage, good management practices can reduce the amount of ammonia that escapes.

8.4.2 Step 2 - Eliminate Technically Infeasible Options

Since the ammonia vapors from the sour water stripper are mixed with water to form ammonia liquid (35% aqua ammonia) at the ammonia stripping unit, no add-on control technologies are considered to be technically feasible and thus are eliminated from this analysis.

The remaining control, good management practices is considered to be technically feasible.

8.4.3 Steps 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Good management practices is the remaining top ranking control to reduce ammonia emissions from the ammonia stripping unit at HollyFrontier.

8.4.4 Step 4 - Evaluate Impacts and Document Results

As mentioned above, the ammonia vapors are mixed with water to form ammonia liquid which is further diluted with water to either 20% or 30% strength. This ammonia liquid is stored in Tanks 124 and 125 from which it is loaded for sale by truck. Tanks 124 and 125 are horizontal elliptical high pressure tanks with no anticipated emissions.

Best management practices are observed at the Woods Cross Refinery to reduce ammonia emissions from the sour water stripper and ammonia stripping unit. These practices include following manufacturer operation and maintenance recommendations, maintaining pumps and blowers, maintaining proper air and water flows, and safe guarding against potential hazards due to leaks and spills of ammonia.

8.4.4.1 Energy, Environmental, and Economic Impacts

No significant negative energy, environmental, or economic issues result from the use of best management practices for the control of fugitive ammonia emissions from the ammonia stripping unit.

8.4.5 Step 5 - Select BACT

The use of best management practices for control of ammonia emissions is considered best available control measures for the sour water stripper and ammonia stripping unit. No other measures were identified as more stringent to control ammonia emissions.

APPENDIX A

List of Refinery Permitted Equipment

Emission Unit Information - HollyFrontier Woods Cross Refinery

A.O.	Source	Source Description	Status	Capacity	Control Technology
II.A.3	4H1	FCC Feed Heater	In Service	68.4 MMbtu/hr	LNB
II.A.6	4V82	FCC Scrubber	In Service		
--	FCC 34"	FCC Flue gas bypass 34" stack	Decom.		
II.A.10	6H1	Reformer Reheat Furnace	In Service	54.7 MMbtu/hr	
II.A.11	6H2	Prefractionator Reboiler Heater	In Service	12.0 MMbtu/hr	
II.A.12	6H3	Reformer Reheat Furnace	In Service	37.7 MMbtu/hr	
II.A.16	7H1	HF Alkylation Regen. Furnace	In Service	4.4 MMbtu/hr	
II.A.17	7H3	HF Alkylation Deprop. Reboiler	In Service	33.3 MMbtu/hr	
--	8H1	Crude Furnace # 1	Decom.		
II.A.19	8H2	Crude Furnace # 1	In Service	99.0 MMbtu/hr	NGULNB
II.A.21	9H1	DHDS Reactor Charge Heater	In Service	8.1 MMbtu/hr	
II.A.22	9H2	DHDS Stripper Reboiler	In Service	4.1 MMbtu/hr	
II.A.24	10H1	Asphalt Mix Heater	In Service	13.2 MMbtu/hr	
II.A.25	10H2	Hot Oil Furnace	In Service	99.0 MMbtu/hr	LNB + SCR
II.A.27	11H1	SRGP Depentanizer Reboiler	In Service	24.2 MMbtu/hr	
II.A.30	12H1	NHDS Reactor Charge Furnace	In Service	50.2 MMbtu/hr	NGULNB
II.A.32	13H1	Isom. Reactor Feed Furnace	In Service	6.5 MMbtu/hr	
II.A.35	TGI-SRU	Tail Gas Incinerator - Sulfur Recovery Unit	In Service		
II.A.38	19H1	DHT Reactor Charge Heater	In Service	18.1 MMbtu/hr	LNB
II.A.40	20H1	Reactor Charge Heater	Decom.		
II.A.41	20H2	Fractionator Charge Heater	In Service	47.0 MMbtu/hr	ULNB
II.A.42	20H3	Fractionator Charge Heater	In Service	42.1 MMbtu/hr	ULNB
II.A.46	23H1	Reformate Splitter Reboiler Heater	In Service	21.0 MMbtu/hr	NGULNB
II.A.48	24H1	Crude Unit Furnace	In Service	60.0 MMbtu/hr	ULNB
II.A.50	25H1	FCC Feed Heater	In Service	45.0 MMbtu/hr	ULNB
II.A.51	25FCC	FCC Scrubber	In Service		
II.A.54	27H1	Reactor Charge Heater	Not Built	99.0 MMbtu/hr	LNB+SCR
II.A.57	30H1	Hydrogen Reformer Feed Furnace	Not Built	123.1 MMbtu/hr	LNB+SCR
II.A.58	30H2	Hydrogen Reformer Feed Furnace	Not Built	123.1 MMbtu/hr	LNB+SCR
II.A.60	33H1	Vacuum Furnace Heater	Not Built	130.0 MMbtu/hr	LNB+SCR, air preheat
II.A.78	66-1	Process Flare South	In Service		
II.A.79	66-2	Process Flare North	In Service		
II.A.81	68H2	North In-Tank Asphalt Heater	In Service	0.8 MMbtu/hr	
II.A.82	68H3	South In-Tank Asphalt Heater	In Service	0.8 MMbtu/hr	
II.A.83	68H4	Northwest In-Tank Asphalt Heater	In Service	0.8 MMbtu/hr	
II.A.84	68H5	North East In-Tank Asphalt Heater	In Service	0.8 MMbtu/hr	
II.A.85	68H6	South East In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	
II.A.86	68H7	Southwest In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	
II.A.87	68H10	North In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	
II.A.88	68H11	South In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	
II.A.89	68H12	North In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	
II.A.90	68H13	South In-Tank Asphalt Heater	Not Built	0.8 MMbtu/hr	

Emission Unit Information - HollyFrontier Woods Cross Refinery

Unit ID	Source ID	Source Description	Status	Capacity	Control Technology
II.A.63	Boiler #4	Boiler #4	In Service	35.6	
II.A.64	Boiler #5	Boiler #5	In Service	70.0	SCR
II.A.65	Boiler #8	Boiler #8	In Service	92.7	LNB+SCR
II.A.66	Boiler #9	Boiler #9	In Service	89.3	SCR
II.A.67	Boiler #10	Boiler #10	In Service	89.3	SCR
II.A.68	Boiler #11	Boiler #11	Not Built	89.3	LNB+SCR
II.A.70	CWT#4	Cooling Tower #4	In Service		
II.A.71	CWT#6	Cooling Tower #6	In Service		
II.A.72	CWT#7	Cooling Tower #7	In Service		
II.A.73	CWT#8	Cooling Tower #8	In Service		
II.A.74	CWT#10	Cooling Tower #10	In Service		
II.A.75	CWT#11	Cooling Tower #11	In Service		
II.A.219	ETF	East Tank Farm Portable Diesel Gen.	In Service		
II.A.223		Water Well #3	In Service	224 HP	
II.A.223		Fire Pump #1 (Caterpillar)	In Service	393 HP	
II.A.223		Fire Pump #2 (Caterpillar)	In Service	393 HP	
II.A.223		Fire Pump (Detroit Diesel)	In Service	180 HP	
II.A.223		Backup Diesel Compressor #1	In Service	220 HP	
II.A.223		Backup Diesel Compressor #2	In Service	220 HP	
II.A.223		Backup Diesel Compressor #3	In Service	220 HP	
II.A.223		Boiler House Cummins Generator	In Service	470 HP	
II.A.223		Central Control Generator	In Service	380 HP	
II.A.223		Standby Generator	In Service	540 HP	
II.A.224		Admin. Building Standby	In Service	142 KW	
II.A.224		Admin. Building Standby	In Service	142 KW	
II.A.220, II.A.221	Unit 87	Loading/Unloading	In Service		
II.A.76	Unit 56	Wastewater Treatment	In Service		
--	Tank 4		Removed		
II.A.91	Tank 11	Empty-Out of Service	No service	8,961 bbl	Vertical floating roof
II.A.92	Tank 12	Reformer Charge	In Service	9,868 bbl	Internal floating roof
II.A.93	Tank 14	K-1 Kerosene	In Service	2,539 bbl	Vertical floating roof
II.A.94	Tank 15	Fuel Oil #5 WX Input	In Service	4,692 bbl	Vertical floating roof
II.A.95	Tank 19	Stove Oil WX Input	In Service	6,986 bbl	Vertical floating roof
II.A.96	Tank 20	Stove Oil WX Input	In Service	7,372 bbl	Vertical floating roof
II.A.97	Tank 21	Olefin	In Service	--	--
II.A.98	Tank 23	Distillate fuel oil no. 2	In Service	10,481 bbl	Vertical floating roof
II.A.99	Tank 24	Distillate fuel oil no. 2	In Service	14,035 bbl	Vertical floating roof
II.A.100	Tank 28	Stove Oil WX Input	In Service	28,340 bbl	Vertical floating roof
II.A.101	Tank 29	Caustic	In Service	--	--
II.A.102	Tank 31	Residual oil no. 6	In Service	22,480 bbl	Vertical floating roof
II.A.103	Tank 35	Gas Oil	In Service	98,703 bbl	Vertical floating roof
II.A.104	Tank 37	Fuel Oil	In Service	2,865 bbl	Vertical floating roof
II.A.105	Tank 42A	Jet Fuel Additive	In Service	--	--
II.A.106	Tank 47	#2 ULSD	In Service	--	--

Emission Unit Information - HollyFrontier Woods Cross Refinery

A.O. ID	Source ID	Source Description	Status	Capacity	Control Technology
II.A.107	Tank 48	Light Cycle Oil	In Service	27,194 bbl	Vertical floating roof
--	Tank 49		Removed		
II.A.108	Tank 50	Empty-Out of Service	No Service	690 bbl	Horizontal
II.A.109	Tank 51	Empty-Out of Service	No Service	580 bbl	Horizontal
II.A.110	Tank 52	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.111	Tank 53	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.112	Tank 54	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.113	Tank 55	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.114	Tank 56	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.115	Tank 57	Fuel Oil #5 WX Input	In Service	913 bbl	Vertical floating roof
II.A.116	Tank 58	Residual oil no. 6	In Service	13,647 bbl	Vertical floating roof
II.A.117	Tank 59	Empty-Out of Service	No Service	24,656 bbl	Vertical floating roof
II.A.118	Tank 60	Caustic	In Service		Vertical floating roof
II.A.119	Tank 61	#2 ULSD	In Service		
II.A.120	Tank 63	Stove Oil WX Input	In Service	29,490 bbl	Vertical floating roof
II.A.121	Tank 64	#2 Raw Diesel	In Service		
II.A.122	Tank 65	#2 Raw Diesel	In Service		
II.A.123	Tank 70	Gas Oil	In Service	76,819 bbl	Vertical floating roof
II.A.124	Tank 71	Black Wax	In Service	79,944 bbl	Internal floating roof
II.A.125	Tank 72	Gasoline (RVP 8 WX Input)	In Service	124,381 bbl	Internal floating roof
II.A.126	Tank 73	#2 Raw Diesel	In Service		
II.A.127	Tank 74	#2 Raw Diesel	In Service		
II.A.128	Tank 75	#2 Raw Diesel	In Service		
II.A.129	Tank 76	#2 Raw Diesel	In Service		
II.A.130	Tank 77	Stove Oil WX Input	In Service	4,798 bbl	Vertical floating roof
II.A.131	Tank 78	Stove Oil WX Input	In Service	4,798 bbl	Vertical floating roof
II.A.132	Tank 79	Asphalt WX Input	In Service	9,400 bbl	Vertical floating roof
II.A.133	Tank 81	NaHS	In Service		
II.A.134	Tank 82	NaHS	In Service		
II.A.135	Tank 83	Caustic	In Service		
--	Tank 84	Chemical	Removed		
II.A.136	Tank 85	Poly Gasoline	Not Built		
II.A.137	Tank 86	Gas Oil	In Service		
II.A.138	Tank 87	Gas Oil	Not Built		
II.A.139	Tank 88	Hydroisom feed/lube	Not Built		
II.A.140	Tank 89	Hydroisom feed/lube	Not Built		
II.A.141	Tank 90	Hydroisom feed/lube	Not Built		
II.A.142	Tank 91	Hydroisom feed/lube	Not Built		
II.A.143	Tank 92	Hydroisom feed/lube	Not Built		
II.A.144	Tank 93	Hydroisom feed/lube	Not Built		
II.A.145	Tank 94	Hydroisom feed/lube	Not Built		
II.A.146	Tank 95	Hydroisom feed/lube	Not Built		
II.A.147	Tank 96	Hydroisom feed/lube	Not Built		
II.A.148	Tank 97	Hydroisom feed/lube	Not Built		
II.A.149	Tank 98	Gasoline Blendstock	Not Built		
II.A.150	Tank 99	Distillate fuel oil no. 2	In Service	72,821 bbl	Vertical floating roof

Emission Unit Information - HollyFrontier Woods Cross Refinery

A.O. ID	Source ID	Source Description	Status	Capacity	Control Technology
II.A.151	Tank 100	Gasoline (RVP 5 WX Input)	In Service	53,357 bbl	External floating roof
II.A.152	Tank 101	Gasoline (RVP 7 WX Input)	In Service	53,571 bbl	External floating roof
II.A.153	Tank 102	Gas Oil	In Service	53,000 bbl	External floating roof
II.A.154	Tank 103	Gas Oil	In Service	23,648 bbl	Vertical fixed roof
II.A.155	Tank 104	Gasoline (RVP 6)	In Service	24,429 bbl	External floating roof
II.A.156	Tank 105	Gasoline (RVP 6)	In Service	24,500 bbl	External floating roof
II.A.157	Tank 106	Gasoline (RVP 8 WX Input)	In Service	24,524 bbl	External floating roof
II.A.158	Tank 107	Gasoline (RVP 8 WX Input)	In Service	24,500 bbl	External floating roof
II.A.159	Tank 108	Gasoline (RVP 11 WX Input)	In Service	24,452 bbl	External floating roof
II.A.160	Tank 109	Gasoline (RVP 11 WX Input)	In Service	24,500 bbl	External floating roof
II.A.161	Tank 113	Caustic	In Service		
II.A.162	Tank 114	Caustic	In Service		
II.A.163	Tank 116	Caustic	In Service		
II.A.164	Tank 117	API Trap Sludge	In Service		
II.A.165	Tank 118	Recovered Slop	In Service		
II.A.166	Tank 121	Crude Oil (RVP 8 WX Input)	In Service	100,129 bbl	External floating roof
II.A.167	Tank 122	Propane	In Service		
II.A.168	Tank 123	Propane	In Service		
II.A.169	Tank 124	Ammonia	In Service		
II.A.170	Tank 125	Ammonia	In Service		
II.A.171	Tank 126	Crude Oil (RVP 4 WX Input)	In Service	64,667 bbl	External floating roof
II.A.172	Tank 127	Distillate fuel oil no. 2	In Service	29,504 bbl	Vertical fixed roof
II.A.173	Tank 128	Empty-Out of Service	No Service	10,095 bbl	External floating roof
II.A.174	Tank 129	NHDS Charge	In Service		
II.A.175	Tank 130	Caustic	In Service		
II.A.176	Tank 131	Stove Oil WX Input	In Service	64,537 bbl	Internal floating roof
II.A.177	Tank 132	Gasoline (RVP 8 WX Input)	In Service	24,548 bbl	External floating roof
II.A.178	Tank 133	Isobutane	In Service		
II.A.179	Tank 134	Isobutane	In Service		
II.A.180	Tank 135	Naptha WX Input	In Service	44,154 bbl	External floating roof
II.A.181	Tank 136	Propane	In Service		
II.A.182	Tank 138	Stove Oil WX Input	In Service	44,238 bbl	Internal floating roof
II.A.183	Tank 139	SDA Charge	In Service	15,022 bbl	Vertical fixed roof
II.A.184	Tank 140	SDA Charge	In Service	14,810 bbl	Vertical fixed roof
II.A.185	Tank 141	Solvent	In Service		
II.A.186	Tank 143	Empty-Out of Service	No Service	3,022 bbl	Vertical fixed roof
II.A.187	Tank 145	Gasoline (RVP 8 WX Input)	In Service	3,976 bbl	External floating roof
II.A.188	Tank 146	Gasoline (RVP 8 WX Input)	In Service	3,976 bbl	External floating roof
II.A.189	Tank 147	Propane	In Service		
II.A.190	Tank 148	Propane	In Service		
II.A.191	Tank 149	Butane	In Service		
II.A.192	Tank 150	Butane	In Service		
II.A.193	Tank 151	Butane	In Service		
II.A.194	Tank 152	Olefin	In Service		
II.A.195	Tank 153	Olefin	In Service		
II.A.196	Tank 159	NGL	In Service		

Emission Unit Information - HollyFrontier Woods Cross Refinery

A.O. ID	Source ID	Source Description	Status	Capacity	Control Technology
II.A.197	Tank 170	Finished Diesel	Not Built		
II.A.198	Tank 171	Propane	In Service		
II.A.199	Tank 172	Propane	In Service		
II.A.200	Tank 173	Propane	Not Built		
II.A.201	Tank 174	Propane	Not Built		
II.A.203	Tank 300	Chemical	In Service		
II.A.202	Tank 301	Chemical	In Service		
II.A.204	Tank 302	Chemical	In Service		
II.A.205	Tank 303	Chemical	In Service		
II.A.206	Tank 304	Chemical	In Service		
II.A.207	Tank 305	Chemical	In Service		
II.A.208	Tank 306	Chemical	In Service		
II.A.209	Tank 307	Chemical	In Service		
II.A.210	Tank 308	Chemical	In Service		
II.A.211	Tank 310	Chemical	In Service		
II.A.212	Tank 312	Chemical	In Service		
II.A.213	Tank 313	Chemical	In Service		
II.A.214	Tank 323	Ethanol	In Service		
II.A.215	Tank 324	Olefin	In Service		
II.A.216	Tank 54-V4	Chemical	In Service		
II.A.217	Tank 54-V5	Chemical	In Service		
II.A.218	Tank 54-V7	Chemical	In Service		
II.A.225	Tank W-2	Water	In Service		
II.A.225	Tank 167	Water	In Service		
II.A.225	Tank 155	Water	In Service		
II.A.225	Tank 157	Water	In Service		
II.A.225	Tank 158	Water	In Service		
II.A.225	Tank 154	Water	In Service		
II.A.225	Tank 166	Water	In Service		
II.A.225	Tank 119	Water	In Service		
II.A.225	Tank 156	Water	In Service		
II.A.225	Tank 62	Water	In Service		
II.A.225	Tank 168	Water	In Service		
II.A.225	Tank 111	Water	In Service		

APPENDIX B

Cost Analyses

Fixed Roof Tanks - HollyFrontier

Cost to Install Vapor Recovery System on Fixed Roof Tanks

DAO ID	Storage Vessel ID	SCC	Type of Material Stored	Storage Capacity (10 ³ gal)	Shell Height (ft)	Tank Diameter (ft)	Maximum Height (ft)	Average Height (ft)	Throughput		VOC Emissions (tons/yr)				Net Reduction - 75%	\$/ton VOC Removed
									Annual Turnovers	Annual Total (10 ³ gal)	Standing Loss	Working Loss	Total Loss			
6168	4	40399999	Diesel	34	14	21	13	9.4	0	0	0.000	0.000	0.000	0.00E+00		
6180	11	40399999	Fuel Oil	376	32	47	29	19.3	0	0	0.000	0.000	0.000	0.00E+00		
6631	14	40399999	Kerosene	98	20	30	18.5	10.2	1.84	154	0.000	0.000	0.000	4.75E-06		
6167	15	40399999	Fuel Oil	197	27	37	24.5	12.3	11.69	2082	0.000	0.008	0.008	6.39E-03		
6167	19	40399999	Jet/Stove Oil	294	37	38	34.6	16.8	5.28	1273	0.000	0.000	0.000	1.72E-04		
6177	20	40399999	Jet Kerosene	293	37	38	34.5	10.5	7.15	1742	0.000	0.000	0.000	3.67E-04		
6170	23	40399999	Diesel	381	35	45	32	23.3	97.33	51879	0.000	0.041	0.041	3.26E-02		
6179	24	40399999	Diesel	581	35	55	32.7	15.9	107.12	52500	0.000	0.039	0.039	3.15E-02		
6178	28	40399999	Stove Oil	1190	35	78	33.3	25.5	20.05	21272	0.000	0.013	0.014	1.10E-02		
6161	31	40399999	Fuel Oil	999	41	72	32.8	19.2	10.52	8109	0.000	0.005	0.005	3.83E-03		
6166	35	40399999	Gas Oil	2564	35	115	33	22.3	4.61	14112	0.002	0.021	0.022	1.77E-02		
6162	37	40399999	Fuel Oil	144	25	32	24	9.4	215.99	1725	0.000	0.010	0.010	7.97E-03		
6176	47	40399999	Diesel	1264	42	72	41.5	15.1	27.69	32381	0.000	0.022	0.022	1.76E-02		
6158	48	40399999	Light Cycle Oil	1142	42	72	37.5	19.5	3.68	3107	0.000	0.001	0.001	5.39E-04		
6189	49	40399999	Fuel Oil	2249	38	102	36.8	18.3	0.00	0	0.000	0.000	0.000	0.00E+00		
6183	52	40399999	Fuel Oil	38	32	15	29	16	15.33	339	0.000	0.003	0.003	2.47E-03		
6184	53	40399999	Fuel Oil	38	32	15	29	16	14.17	422	0.000	0.005	0.005	3.93E-03		
6163	54	40399999	Fuel Oil	38	32	15	29	16	14.16	401	0.000	0.003	0.003	2.32E-03		
6174	55	40399999	Fuel Oil	38	32	15	28.4	16	10.11	312	0.000	0.002	0.002	1.41E-03		
6195	56	40399999	Fuel Oil	38	32	15	28.4	16	15.71	433	0.000	0.005	0.005	3.98E-03		
6184	57	40399999	Fuel Oil	38	32	15	28.5	16	16.29	484	0.000	0.009	0.009	6.90E-03		
6165	58	40399999	Fuel Oil	573	32	58	29	16.8	14.17	7338	0.000	0.003	0.003	2.50E-03		
6190	59	40399999	Gas Oil/Fuel Oil	1179	41	72	38.7	18.2	0.00	0	0.000	0.000	0.000	0.00E+00		
6162	63	40399999	Jet Fuel/Naphtha	999	41	72	32.8	19.2	5.94	2349	0.000	0.002	0.002	2.00E-03		
6175	70	40399999	Gas Oil/Fuel Oil	2992	35	129	30.6	11.3	5.36	9020	0.000	0.003	0.003	2.08E-03		
172808	77	40399999	Stove Oil/Diesel	209	30	35	29	17	4.88	683	0.000	0.001	0.001	5.44E-04		
172810	78	40399999	Stove Oil/Diesel	209	30	35	29	17	7.70	1119	0.000	0.001	0.001	9.19E-04		
0	79	40399999	Asphalt	395	44	40	42	21	12.42	3018	0.000	0.044	0.044	3.50E-02		
6159	103	40399999	Gas Oil/Crude	1034	36	70	35.9	17.3	5.38	4867	0.000	0.004	0.004	3.12E-03		
6164	127	40399999	Diesel	1287	37	78	36	13.5	19.84	21069	0.000	0.013	0.013	1.02E-02		
6185	139	40399999	Fuel Oil/SDA Charge	631	36	55	35.5	19.1	2.14	376	0.000	0.001	0.001	1.11E-03		
6171	140	40399999	SDA Charge	631	36	55	35.5	19.1	4.11	1895	0.000	0.001	0.001	9.48E-04		
6169	143	40399999	Diesel	156	32	30	29.5	13.7	0.00	0	0.000	0.000	0.000	0.00E+00		
6643	137	40399999	Propane	4330	95	100	73.7	15			0.000	0.000	0.000	0.00E+00		

0.261 \$ 6,337,724 Medium cost for less than 1 ton of VOC
 \$ 1,707,966

Assumptions:

2015 Actual Emission Estimates

Cost to Install IFR on Fixed Roof

Range - 337000 2164000 Reference: European Commission, Integrated Pollution Prevention and Control Report, Reference Document on Best Available Techniques for Mineral Oil and Gas Refineries, 2003

Mean - 1,250,500.00 2003\$

Mean - 1,655,573.65 2017\$ 2003 dollars to reflect cost in 2017

Low - 446,164 2017\$

HollyFrontier

Cost to fire all units on natural gas

NG cost	0.22 Mscf	based on company records
Usage	5,530,074 Mscf	2016 - total refinery fuel gas and purchased natural gas
Cost	\$ 1,216,616.28	annual cost
PM _{2.5} \$/ton	\$ 2,295,502.42	

Assumptions:

Emissions from 2015 Annual Inventory

Process Unit	PM _{2.5} TPY
4-1	0.070
6-1	0.100
6-2	0.010
6-3	0.020
7-1	0.050
7-2	0.000
8-1	0.120
9-1	0.010
9-2	0.000
10-2	0.030
11-1	0.010
12-1	0.060
13-1	0.000
17-1	0.010
19-1	0.000
20-1	0.000
20-2	0.000
45-1	0.000
51-4	0.010
51-5	0.030
51-6	0.000
51-7	0.000
51-8	0.000
51-9	0.000
Total	0.53

Cost to Retrofit Emergency Diesel Engines with Diesel Particulate Filters, SCR, and Oxidation Catalysts
 HollyFrontier Woods Cross Refinery

	Rating (HP)	Rating (KW)	DPF Retrofit ¹ (\$/KW)	SCR Retrofit ¹ (\$/KW)	OC Retrofit ¹ (\$/KW)	DPF Retrofit Cost	SCR Retrofit Cost	OC Retrofit Cost	Uncontrolled			Controlled			Emission Reduction			Cost Effectiveness (\$/ton)					
									PM _{2.5} PTE	NO _x PTE	VOC PTE	PM _{2.5} PTE	NO _x PTE	VOC PTE	PM _{2.5} PTE	NO _x PTE	VOC PTE	PM _{2.5}	NO _x	VOC			
Diesel Emergency Equipment																							
135 kW generator (east tank farm)	181.0	135.0	47	350	118	\$ 6,345	\$ 47,250	\$ 15,930	0.220	3.070	0.250	0.0330	0.15350	0.0125	0.187	2.917	0.238	\$	33,930	\$	16,201	\$	67,074
224 HP (water well #3)	224.0	167.0	47	350	118	\$ 7,851	\$ 58,463	\$ 19,710	0.012	0.174	0.014	0.0018	0.00870	0.0007	0.010	0.165	0.013	\$	750,907	\$	353,677	\$	1,481,981
393 HP Fire Pump #1	393.0	293.1	47	350	118	\$ 13,774	\$ 102,571	\$ 34,581	0.022	0.305	0.025	0.0033	0.01525	0.0013	0.019	0.290	0.024	\$	736,568	\$	353,998	\$	1,456,046
393 HP Fire Pump #2	393.0	293.1	47	350	118	\$ 13,774	\$ 102,571	\$ 34,581	0.022	0.305	0.025	0.0033	0.01525	0.0013	0.019	0.290	0.024	\$	736,568	\$	353,998	\$	1,456,046
220 HP plant air backup compressor #1	220.0	164.1	47	350	118	\$ 7,711	\$ 57,419	\$ 19,358	0.012	0.171	0.041	0.0018	0.00855	0.0021	0.010	0.162	0.039	\$	755,935	\$	353,456	\$	497,006
220 HP plant air backup compressor #2	220.0	164.1	47	350	118	\$ 7,711	\$ 57,419	\$ 19,358	0.012	0.171	0.041	0.0018	0.00855	0.0021	0.010	0.162	0.039	\$	755,935	\$	353,456	\$	497,006
220 HP plant air backup compressor #3	220.0	164.1	47	350	118	\$ 7,711	\$ 57,419	\$ 19,358	0.012	0.171	0.041	0.0018	0.00855	0.0021	0.010	0.162	0.039	\$	755,935	\$	353,456	\$	497,006
470 HP diesel generator (boiler house)	470.0	350.5	47	350	118	\$ 16,473	\$ 122,668	\$ 41,357	0.026	0.364	0.030	0.0039	0.01820	0.0015	0.022	0.346	0.028	\$	745,363	\$	354,736	\$	1,475,701
380 HP diesel generator (central control room)	380.0	283.4	47	350	118	\$ 13,318	\$ 99,178	\$ 33,437	0.021	0.294	0.024	0.0032	0.01470	0.0012	0.018	0.279	0.023	\$	746,118	\$	355,095	\$	1,466,543
540 HP standby generator	540.0	402.7	47	350	118	\$ 18,926	\$ 140,937	\$ 47,516	0.001	0.205	0.030	0.0002	0.01025	0.0015	0.001	0.195	0.028	\$	22,265,725	\$	723,683	\$	1,678,418

Assumptions:

- ¹ Includes component and installation costs
- Source - Discussion with Steve Loci on 3/27/2017, Wheeler Machinery, 801-974-0511
- Diesel Particulate Filters - \$47KW includes installation and labor costs
- SCR - \$300 KW plus \$50 KW for installation and labor costs
- Oxidation Catalysts - \$118 KW which includes installation and labor costs
- Urea - \$1 KW
- PTE emissions based on 50 operating hours per year and Title V permit application
- DPF - 85% reduction, 95% VOC reduction
- SCR - 95% NOx reduction
- Assumed maintenance and labor costs to be unchanged

**Cost to Retrofit Emergency NG Engines with Oxidation Catalyst
HollyFrontier Woods Cross Refinery**

	Rating (HP)	OX Cat Retrofit Capitol Cost	OX Cat Retrofit Annual Cost	Uncontrolled VOC PTE TPY	Controlled VOC PTE TPY	Emission Reduction VOC PTE TPY	Cost Effectiveness (\$/ton) VOC
Diesel Emergency Equipment							
224 HP Generac MG150 Administration Bldg East	224.0	\$ 59,220	\$ 18,714	0.014	0.0042	0.010	\$ 6,018,665
224 HP Generac MG150 Administration Bldg West	224.0	\$ 59,220	\$ 18,714	0.014	0.0042	0.010	\$ 6,061,522

Assumptions:

Source - Memorandum - Control Costs for Existing Stationary SI Rice, June 29, 2010
 Contacted Generac who was unable/hesitant to provide actual cost estimates.
 PTE emissions based on 50 operating hours per year and Title V permit application
 Assumed maintenance and labor costs to be unchanged
 70% control efficiency with CO oxidation catalyst (EPA)

HollyFrontier Woods Cross Refinery

Cost Analysis - Upgrading Cooling Towers from Low Efficiency Drift Eliminators to High Efficiency Drift Eliminators

Drift Eliminator					mobe/demobe/shipping	Capitol Cost	Total Annual Cost ¹	PM _{2.5} Emissions Before Control (tn/yr)	PM _{2.5} Emissions After Control (tn/yr)	Emission Reduction (tn/yr)	PM _{2.5} Cost Effectiveness (\$/ton)
CT ID	Dimension 1	Dimension 2	Ft^2	30 \$/ft^2 for .0005 % circ							
4	63.0	36.0	2268.0	\$ 68,040.00	\$ 50,000.00	\$ 118,040	\$ 118,040	0.0014	0.0003	0.0010	\$ 116,335,401
6	36.0	36.0	1296.0	\$ 38,880.00	\$ 50,000.00	\$ 88,880	\$ 88,880	0.0013	0.0003	0.0010	\$ 93,020,814
7	50.2	28.2	1413.0	\$ 42,390.83	\$ 50,000.00	\$ 92,391	\$ 92,391	0.0012	0.0003	0.0009	\$ 105,542,074
8	61.0	38.0	2318.0	\$ 69,540.00	\$ 50,000.00	\$ 119,540	\$ 119,540	0.0025	0.0006	0.0019	\$ 63,609,192

Assumptions:

Maintenance, labor, and inspections costs would remain unchanged.

Cooling Towers (CT) would have to be upgraded one at a time or else the refinery would have to be shut down if all CT's were upgraded at once.

Cooling tower vendor recommended \$50,000 (+/- 20%) as number to demolish and build new towers. It will be less on the smaller towers and maybe a little more on the larger towers.

Existing cooling tower have 0.002% version drift eliminators in all cooling towers.

CF80's (0.0005%) run about \$30/sqft installed (quote from Cooling Tower Depot).

Cost information obtained from:

Brian S Fuqua

Regional Sales Director

Cooling Tower Depot, Inc.

517 D SE 2nd Street

Lees Summit, MO 64063

816-331-5536 Office

816-318-9493 Fax

816-585-3025 Cell

bfuqua@ctdinc.com

www.coolingtowerdepot.com



HollyFrontier Cost Analysis for Tanks
Cost of Vapor Control By Carbon Absorption

Cost Parameters	Consumer (1982 dollars)	Consumer (2017 dollars)	Comments
Capital Cost	\$ 631,000.00	\$ 993,935.41	
Annualized capital charges	\$ 114,000.00	\$ 179,572.80	
Annual taxes, insurance and administration	\$ 4,100.00	\$ 39,757.42	4% of capitol cost
Operating Costs			
Maintenance	\$ 31,600.00	\$ 49,696.77	5% of capitol cost
Labor	\$ 45,000.00	\$ 70,884.00	
Energy	\$ 60,000.00	\$ 94,512.00	
Total Annualized Cost	\$ 255,000.00	\$ 434,422.99	
Cost effectiveness in & per megagram of VOC emissions reduction	\$ 28,650.00	\$ 45,128.76	

Assumptions:

EPA 450/3-81-003, VOC Emissions from VOL Storage Tanks-Background Information for Proposed Standards, Table 8-12

CPI data found at: <http://www.usinflationcalculator.com/inflation/consumer-price-index-and-annual-percent-changes-from-1913-to-2008/>

HollyFrontier Cost Analysis for Tanks

Cost of Vapor Control By Incineration Techniques

Cost Parameters	Consumer (1982 dollars)	Consumer (2017 dollars)	Comments
Capital Cost	\$ 631,000.00	\$ 993,935.41	
Annualized capital charges	\$ 114,000.00	\$ 179,572.80	
Annual taxes, insurance and administration	\$ 4,100.00	\$ 39,757.42	4% of capitol cost
Operating Costs			
Maintenance	\$ 31,600.00	\$ 49,696.77	5% of capitol cost
Labor	\$ 27,200.00	\$ 42,845.44	
Energy	\$ 4,900.00	\$ 7,718.48	
Total Annualized Cost	\$ 181,800.00	\$ 319,590.91	
Cost effectiveness in & per megagram of VOC emissions reduction	\$ 20,700.00	\$ 32,606.12	

Assumptions:

EPA 450/3-81-003, VOC Emissions from VOL Storage Tanks-Background Information for Proposed Standards, Table 8-12

CPI data found at: <http://www.usinflationcalculator.com/inflation/consumer-price-index-and-annual-percent-changes-from-1913-to-2008/>

Total emissions all tanks for 2013 - 45.8 tons VOC

Tank 145 (gasoline) had the highest emissions in 2013 - 10.5 tons

HollyFrontier External Floating Roof Tanks
 Cost to Install Dome on Fixed Roof Tanks

Storage Vessel ID	SCC	Type of Material Stored	Storage Capacity (10 ³ gal)	Tank Diameter (ft)	Shell			Tank Construction	Roof		Rim-Seal		Throughput		VOC Emissions (ton/yr)			96% Control - Net Reduction	\$/ton VOC Removed	
					Condition	Paint Color/ Shade	Paint Condition		Type (pontoon or double deck)	Fitting Category	Primary Seal	Secondary Seal	Annual Turnovers	Annual Total (10 ³ gal)	Standing Loss	Withdrawal Loss	Total Loss			
100	40399999	Reformate	2241	110	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	18 14	24547	1 70	0 03	1 73	1.658	\$	104,650
101	40399999	Cat Gas	2250	110	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	16 70	19904	3 87	0 02	3 89	3 737	\$	46,430
102	40399999	Gas Oil	2226	110	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	8 42	13908	0 00	0 00	0 00	0.001	\$	171,887,160
104	40399999	Isomorate	1028	70	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	13 88	10437	1 48	0 01	1 49	1 434	\$	120,985
105	40399999	Hi Reformate	1029	70	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	15 26	11152	0 82	0 02	0 93	0.898	\$	193,341
106	40399999	Gasoline	1030	70	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	31 18	24716	2 33	0 04	2 38	2 282	\$	76,046
107	40399999	Gasoline	1029	70	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	23 95	18323	3 15	0 03	3 18	3.057	\$	56,771
108	40399999	Gasoline	1027	70	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	22 05	16379	5 05	0 03	5 08	4 874	\$	35,604
109	40399999	Alkylate	1029	70	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	23 50	16291	1 31	0 03	1 34	1 285	\$	135,010
121	40399999	Crude Oil	4205	150	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Weather shield	8 24	26151	1 07	0 08	1 16	1.110	\$	156,276
126	40399999	Crude Oil	2716	114	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Weather shield	13 19	24876	0 73	0 10	0 83	0.801	\$	216,602
128	40399999	Out of Service	424	48	Light Rust	White	Good	Welded	Pontoon	Detail	Mechanical shoe	Rim-mounted	0 00	0	0 00	0 00	0 00	0.000		
129	40399999	Out of Service	2313	112	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	0 00	0	0 00	0 00	0 00	0.000		
132	40399999	Gasoline	1031	70	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	20 37	14161	3 13	0 02	3 15	3 025	\$	57,358
135	40399999	NHDS Charge	1854	100	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	9 95	15888	24 75	0 01	24 76	23.772	\$	7,300
145	40399999	Gasoline	187	32	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	11 91	1257	2 21	0 00	2 22	2 129	\$	81,489
146	40399999	Gasoline	187	32	Light Rust	White	Good	Welded	Pontoon	Detail	Liquid mounted	Rim-mounted	2 59	264	2 13	0 00	2 13	2.049	\$	84,676

Cost to Install Dome:

2015 Actual Emission Estimates

Average Investment Cost = \$21,640 - \$240,500

Mean - \$ 131,070.00 2003 \$

\$ 173,527 42 2017 \$

Reference. European Commission, Integrated Pollution Prevention and Control Report, Reference Document on Best Available Techniques for Mineral Oil and Gas Refineries, 2003

Fixed Roof Tanks - HollyFrontier
 Cost to Install IFR on Fixed Roof Tanks

AQ ID	Storage Vessel ID	SCC	Type of Material Stored	Storage Capacity (10 ³ gal)	Shell Height (ft)	Tank Diameter (ft)	Maximum Height (ft)	Average Height (ft)	Shell				Roof				Throughput			VOC Emissions (tons/yr)				
									Color/ Shade	Paint Condition	Color/ Shade	Paint Condition	Type	Height (ft)	Radius (ft)	Slope (ft/ft)	Annual Turnovers	Annual Total (10 ³ gal)	Standing Loss	Working Loss	Total Loss	Net Reduction - 75%	\$/ton VOC Removed	
0169	4	40399999	Diesel	34	14	21	13	9.4	White	Good	White	Good	Cone	0.7	10.5	0.07	0	0	0.000	0.000	0.000	0.000	0.00E+00	
0180	11	40399999	Fuel Oil	378	32	47	29	19.3	White	Good	White	Good	Cone	0.5	23.5	0.02	0	0	0.000	0.000	0.000	0.000	0.00E+00	
0031	14	40399999	Kerosene	98	20	30	18.5	10.2	White	Good	White	Good	Cone	0.5	15	0.03	1.84	154	0.000	0.000	0.000	0.000	4.46E-06	107,090,073,714
0167	15	40399999	Fuel Oil	197	27	37	24.5	12.3	White	Good	White	Good	Cone	0.5	18.5	0.03	11.69	2082	0.000	0.008	0.008	0.008	5.99E-03	79,634,022
0187	19	40399999	Jet/Stove Oil	294	37	38	34.8	16.8	White	Good	White	Good	Cone	1.2	19	0.06	5.28	1273	0.000	0.000	0.000	0.000	1.61E-04	2,958,631,266
0177	20	40399999	Jet Kerosene	293	37	38	34.5	10.5	White	Good	White	Good	Cone	1.2	19	0.06	7.15	1742	0.000	0.000	0.000	0.000	3.44E-04	1,385,277,891
0170	23	40399999	Diesel	381	35	45	32	23.3	White	Good	White	Good	Cone	1.4	22.5	0.08	97.33	51879	0.000	0.041	0.041	0.041	3.05E-02	15,627,837
0179	24	40399999	Diesel	581	35	55	32.7	15.9	White	Good	White	Good	Cone	1	27.5	0.04	107.12	52500	0.000	0.039	0.039	0.039	2.95E-02	16,160,255
0178	28	40399999	Stove Oil	1190	35	78	33.3	25.5	White	Good	White	Good	Cone	2.4	39	0.08	20.05	21272	0.000	0.013	0.014	0.014	1.03E-02	46,325,992
0181	31	40399999	Fuel Oil	999	41	72	32.8	19.2	White	Good	White	Good	Cone	1.2	36	0.03	10.52	8109	0.000	0.005	0.005	0.005	3.59E-03	132,960,672
0186	35	40399999	Gas Oil	2564	35	115	33	22.3	White	Good	White	Good	Cone	2.3	57.5	0.04	4.61	14112	0.002	0.021	0.022	0.022	1.66E-02	28,829,042
0182	37	40399999	Fuel Oil	144	25	32	24	9.4	White	Good	White	Good	Cone	1	16	0.06	215.99	1725	0.000	0.010	0.010	0.010	7.47E-03	63,873,048
0178	47	40399999	Diesel	1264	42	72	41.5	15.1	White	Good	White	Good	Cone	0.8	36	0.02	27.69	32381	0.000	0.022	0.022	0.022	1.65E-02	28,962,299
0158	48	40399999	Light Cycle Oil	1142	42	72	37.5	19.5	White	Good	White	Good	Cone	2.3	36	0.06	3.68	3107	0.000	0.001	0.001	0.001	5.05E-04	944,460,087
0189	49	40399999	Fuel Oil	2249	38	102	38.8	18.3	White	Good	White	Good	Cone	0.2	51	0	0.00	0	0.000	0.000	0.000	0.000	0.00E+00	
0183	52	40399999	Fuel Oil	38	32	15	29	16	White	Good	White	Good	Cone	0.2	7.5	0.03	15.33	339	0.000	0.003	0.003	0.003	2.31E-03	206,457,114
0184	53	40399999	Fuel Oil	38	32	15	29	16	White	Good	White	Good	Cone	0.2	7.5	0.03	14.17	422	0.000	0.005	0.005	0.005	3.69E-03	129,438,574
0183	54	40399999	Fuel Oil	38	32	15	29	16	White	Good	White	Good	Cone	0.2	7.5	0.03	14.16	401	0.000	0.003	0.003	0.003	2.17E-03	219,587,851
0174	55	40399999	Fuel Oil	38	32	15	28.4	16	White	Good	White	Good	Cone	0.2	7.5	0.03	10.11	312	0.000	0.002	0.002	0.002	1.32E-03	362,140,074
0185	58	40399999	Fuel Oil	38	32	15	28.4	16	White	Good	White	Good	Cone	0.2	7.5	0.03	15.71	433	0.000	0.005	0.005	0.005	3.73E-03	127,969,958
0184	57	40399999	Fuel Oil	38	32	15	28.5	16	White	Good	White	Good	Cone	0.2	7.5	0.03	16.29	484	0.000	0.009	0.009	0.009	6.47E-03	73,766,386
0185	58	40399999	Fuel Oil	573	32	58	29	16.8	White	Good	White	Good	Cone	0.5	29	0.02	14.17	7338	0.000	0.003	0.003	0.003	2.34E-03	203,549,123
0190	59	40399999	Gas Oil/Fuel Oil	1179	41	72	38.7	18.2	White	Good	White	Good	Cone	0.8	36	0.02	0.00	0	0.000	0.000	0.000	0.000	0.00E+00	
0182	63	40399999	et.Fuel/Naphth	999	41	72	32.8	19.2	White	Good	White	Good	Cone	0.8	36	0.02	5.94	2349	0.000	0.002	0.002	0.002	1.87E-03	254,786,896
0175	70	40399999	Gas Oil/Fuel Oil	2992	35	129	30.8	11.3	White	Good	White	Good	Cone	1.3	64.5	0.02	5.38	9020	0.000	0.003	0.003	0.003	1.95E-03	244,740,749
0209	77	40399999	Stove Oil/Diesel	209	30	35	29	17	White	Good	White	Good	Cone	0.5	17.5	0.03	4.88	683	0.000	0.001	0.001	0.001	5.10E-04	935,154,735
02010	78	40399999	Stove Oil/Diesel	209	30	35	29	17	White	Good	White	Good	Cone	0.5	17.5	0.03	7.70	1119	0.000	0.001	0.001	0.001	8.61E-04	553,974,761
0	79	40399999	Asphalt	395	44	40	42	21	White	Good	White	Good	Cone	1.4	20	0.07	12.42	3018	0.000	0.044	0.044	0.044	3.29E-02	14,526,244
0159	103	40399999	Gas Oil/Crude	1034	36	70	35.9	17.3	White	Good	White	Good	Cone	2.2	35	0.06	5.38	4867	0.000	0.004	0.004	0.004	2.93E-03	163,092,919
0184	127	40399999	Diesel	1287	37	78	36	13.5	White	Good	White	Good	Cone	2.4	39	0.06	19.84	21069	0.000	0.013	0.013	0.013	9.52E-03	50,121,183
0185	139	40399999	Oil/SDA Chem	631	36	55	35.5	19.1	White	Good	White	Good	Cone	0.6	27.5	0.02	2.14	376	0.000	0.001	0.001	0.001	1.04E-03	459,079,938
0171	140	40399999	SDA Charge	631	36	55	35.5	19.1	White	Good	White	Good	Cone	0.6	27.5	0.02	4.11	1895	0.000	0.001	0.001	0.001	8.89E-04	536,784,118
0189	143	40399999	Diesel	156	32	30	29.5	13.7	White	Good	White	Good	Cone	0.9	15	0.06	0.00	0	0.000	0.000	0.000	0.000	0.00E+00	
0043	137	40399999	Propane	4330	95	100	73.7	15	Earthen	Good	NA	NA	Dome	10	50	0.2			0.000	0.000	0.000	0.000	0.00E+00	

Assumptions:

2015 Actual Emission Estimates

Cost to Install IFR on Fixed Roof

Range - \$240,000 - \$480,900

Mean - 360450 2003\$

Mean - 477210 2017\$

Reference European Commission, Integrated Pollution Prevention and Control Report, Reference Document on Best Available Techniques for Mineral Oil and Gas Refineries, 2003

2003 dollars to reflect cost in 2017

HollyFrontier Cost Analysis for Installation of RTO for Product Loading

	RTO	Factor	Basis for Cost and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 146,220	EPA ¹ - Based on 2017 costs, 1000 scfm estimate	
Instrumentation	\$ 14,622	10% of PE	EPA
Sales Tax	\$ 4,387	3% of PE	
Freight	\$ 7,311	5% of PE	
Total Purchased Equipment Cost (PEC)	\$ 172,540		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 51,762	30% of PEC	
Total Direct Installation (DI)	\$ 51,762		
Total Direct Cost (DC)	\$ 224,301		
Indirect Installation Costs			
Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests,	\$ 106,975	62% of PEC	
Total Indirect Cost	\$ 106,975		
Total Installed Cost (TIC)	\$ 331,276		
VOC Emissions Before Control, tn/yr	3.57		
Control Efficiency (%)	98		
VOC Emissions After Control, tn/yr	1.47		
VOC Emission Reduction, tn/yr	2.10		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 9,938	3% of capitol cost	
Maintenance	\$ 9,938	3% of capitol cost	
Replacement Parts	\$ 9,938	3% of capitol cost	
Natural Gas	\$ 263,325	\$3.30/kft3	
Electricity	\$ 1,400	0.006/KWh	
Total Direct Costs, \$/year	\$ 294,540		
Indirect Costs			
Overhead	\$ 15,901	60% of labor costs	
Taxes, Insurance, and Administration	\$ 13,251	4% of total installed cost	
Capitol Recovery	\$ 43,553	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 72,705		
Total Annual Cost	\$ 367,245		
Cost Effectiveness, \$ per ton VOC reduction	\$ 174,995.23		
¹ EPA - CICA Fact Sheet Regenerative Thermal Oxidizer; EPA Cost Manual			

Assumptions:

Based on 1000 scfm - estimated

5.5 Lb/MMscf

VOC emission factor AP-42 Section 1.4

**HollyFrontier Woods Cross Refinery
CEMS Installation and Monitoring Costs for NO₂, SO₂, and VOC**

	CEMS	Factor	Basis for Cost and Factor
Direct Costs:			
Purchased Equipment:			
Primary Equipment (PE) and Monitoring Shelter	\$ 120,000	Estimate - Provided by HollyFrontier	
Sales Tax	\$ 8,400	7% of PE	Estimate based on monitoring experience
Freight	\$ 6,000	5% of PE	Estimate based on monitoring experience
Total Purchased Equipment Cost (PEC)	\$ 134,400		
Direct Installation	\$ 33,600	25% of PEC	Estimate based on monitoring experience
Total Direct Installation (DI)	\$ 33,600		
Total Direct Cost (DC)	\$ 168,000		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 33,600	25% of PEC	Estimate based on monitoring experience
Total Indirect Cost	\$ 33,600		
Total Installed Cost (TIC)	\$ 201,600		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 30,000	500 hours per year at @\$60/hr (includes benefits) ¹	
Raw materials	\$ -		
Replacement Parts	\$ 6,048	3% of capitol cost	
Total Direct Costs, \$/year	\$ 36,048		
Indirect Costs			
Taxes, Insurance, and Administration	\$ 8,064	4% of total installed cost	
Capitol Recovery	\$ 28,708	10%, 10 years, CRF-.1424	
Total Indirect Costs, \$/year	\$ 36,772		
Total Annual Cost	\$ 72,820		

¹ EPA estimate - SCR cost manual spreadsheet 2016
Shelter and equipment costs provided by HollyFrontier.

HollyFrontier Woods Cross Refinery
Ammonia CEMS Installation on SCR for Slip Monitoring

	CEMS	Factor	Basis for Cost
	Addition		and Factor
Direct Costs:			
Purchased Equipment:			
Primary Equipment (PE) and Monitoring Shelter	\$ 137,000	Estimate - Provided by MSI/Mechanical Systems including options	
Sales Tax	\$ 9,590	7% of PE	Estimate based on monitoring experience
Freight	\$ 6,850	5% of PE	Estimate based on monitoring experience
Total Purchased Equipment Cost (PEC)	\$ 153,440		
Direct Installation			
	\$ -		Included in cost estimate
Total Direct Installation (DI)	\$ -		
Total Direct Cost (DC)	\$ 153,440		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 38,360	25% of PEC	Estimate based on monitoring experience
Total Indirect Cost	\$ 38,360		
Total Installed Cost (TIC)	\$ 191,800		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 30,000	500 hours per year at @\$60/hr (includes benefits) ¹	
Raw materials	\$ -		
Replacement Parts	\$ 5,754	3% of capitol cost	
Total Direct Costs, \$/year	\$ 35,754		
Indirect Costs			
Taxes, Insurance, and Administration	\$ 7,672	4% of total installed cost	
Capitol Recovery	\$ 27,312	10%, 10 years, CRF-.1424	
Total Indirect Costs, \$/year	\$ 34,984		
Total Annual Cost	\$ 70,738		

¹ EPA estimate - SCR cost manual spreadsheet 2016
Cost estimate provided by MSI/Mechanical Systems Inc.



April 20, 2017

Meteorological Solutions, Inc.
4525 Wasatch Blvd.
Suite 200
Salt Lake City, Utah 84124

Attn: Ms. Linda Conger

Re: Ammonia Slip Monitoring – SCR outlet

Dear Ms. Conger:

MSI/Mechanical Systems, Inc. is pleased to provide a budgetary proposal for supplying an ammonia (NH₃) tunable diode laser (TDL) analyzer, optics, and associated ancillary equipment for ammonia slip measurement downstream of an SCR. Proposal is based on an installation location that provides a minimum 5 meter (17 feet) path length (stack diameter). Proposal is also based on installation in a non-rated electrical area.

Equipment Includes:

- Tunable Diode Laser Ammonia Analyzer (1)
 - Unisearch LASIR LAS-RR101-FC-NH3 tunable diode laser analyzer
 - Internal flow through audit module (calibration cell)
 - Continuous laser background correction software
 - Continuous audit cell background subtraction software

- Unisearch SPSO24-15-F3-A single pass optics including
 - Launcher with 3" optics
 - Receiver with 3" optics
 - Fused silica windows (2)
 - NEMA 4X enclosures (2)
 - Aluminum mounting flanges (2)

MSI purge panel with blower failure and plugged filter alarms - launcher

MSI purge panel with blower failure and plugged filter alarms - receiver

Fiber optic cable from analyzer to launcher (250 feet maximum)

Coax cable from receiver to analyzer (200 feet)

Alarm cables from purge panels to site data system (200 + 250 = 450 feet)

Calibration Gas System

Cylinder bracket (1)

Calibration gas regulator (1) - Concoa 4322391

Teflon regulator outlet tubing - 20 feet

Services

Installation, startup, and informal training

Three days on site/one trip

Includes travel hours

Includes travel expenses

Includes all onsite expenses (lodging, meals, etc.)

Other Items

Operation and Maintenance Manuals (3)

Work by Others

1. Furnish and install two 6" NH3 monitor ports on stack with Class 150 flanges and two holed mounting orientation. Alignment is critical on these ports. Installation must be verified on completion of port installation work.
2. Install NH3 tunable diode laser purge panels on 6" mounting flanges. Tunable diode laser launcher and receiver optics will be installed on purge panels by MSI after blowers on purge panels are operational. Purge panels supplied by MSI. Purge panels must be energized prior to MSI startup technician arrival on site.
3. Run 120 Vac power circuits from local power source to:
NH3 analyzer in rack
NH3 launcher purge panel on stack
NH3 receiver purge panel on stack
4. Install analyzer in rack. Analyzer rests on sliding tray provided by MSI. Tray has connections for zero air and three calibration gases.
5. Install NH3 calibration regulator, cylinder bracket, and cylinder. Pipe regulator output to MSI NH3 analyzer sliding tray using Teflon tubing provided by MSI.
6. Provide instrument air to MSI NH3 analyzer sliding tray (0.3 scfm).

7. Install fiber optic cable from analyzer to launcher. Install coax cable from receiver to analyzer. Install alarm cable from each purge panel to data system.
8. Provide 4-20 mA stack temperature input to analyzer.
9. Provide 4-20 mA stack pressure input to analyzer.
10. Wire NH3 analyzer and purge panels to site compliance data system. The following inputs/outputs will be available:

Analog output from analyzer - 4-20 mA
NH3 ppm (0-10 ppm)
NH3 ppm (0-100 ppm)
NH3 laser power (0-100 percent)
Water (0-100 percent)

Digital output from analyzer
Malfunction
Power fail

Digital outputs from purge panels
Launcher purge panel blower failure
Launcher purge panel plugged filter
Receiver purge panel blower failure
Receiver purge panel plugged filter

11. Procure permanent NH3 calibration cylinders with ranges of 40 ppm, 100 ppm, and 160 ppm.

Total cost for work as described above is Seventy Two Thousand Three Hundred Dollars (\$72,300.00). Final pricing may vary slightly based on actual installation location of launcher and receiver and cannot be guaranteed until drawings of the proposed location of the optics are submitted for MSI review.

Payment terms are:

- 10% - contract award
- 10% - installation drawings
- 70% - shipment
- 10% - completion of startup

State and local sales taxes are not included. Freight to site is not included for purge panels and analyzer. Travel and living expenses for MSI startup technician are included.

MSI offers the following optional bids for consideration:

1. Provide laptop computer and Unisearch LasIRView software and key to interface with and make changes to the Unisearch NH3 analyzer - Add \$2,205.00.
2. Provide OPM-15 power meter for NH3 analyzer - Add \$1,050.00.
3. Provide VFL-2000 visible laser alignment tool for NH3 optics - Add \$825.00.
4. Provide safety shutters for purge panels that automatically close off and isolate optics in the event of purge air failure - Add \$6,920.00 total for two purge panels.
5. Provide weather hoods (2) for purge panels for outdoor installation of optics - Add \$1,220.00 total for two purge panels.
6. Provide two additional NH3 calibration gas regulators, cylinders brackets, outlet Teflon tubing to simplify quarterly linearity testing - Add \$2,480.00.
7. Add for additional footage of cables:
 - a. Fiber optic cable – No charge up to 300 feet
 - b. Coax cable – \$3.00/ft
 - c. Alarm cable – \$1.50/ft

We appreciate the opportunity to submit this proposal. If you have questions, feel free to email or call at any time.

Sincerely,

MSI/Mechanical Systems, Inc.



Chuck Arnold



HOLLYFRONTIER

HOLLYFRONTIER WOODS CROSS REFINING LLC
1070 West 500 South • West Bountiful, Utah 84087-1442
(801) 299-6600 • Fax (801) 299-6609

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

OCT 27 2017

DIVISION OF AIR

October 24, 2017

Bryce C. Bird, Director
Division of Air Quality
195 North 1950 West
Salt Lake City, Utah 84114-4820

CERTIFIED MAIL: 7013 3020 0001 4514 0706

RE: Response to Request DAQE-066-17

Dear Mr. Bird:

In response to your letter of September 21, 2017, we have reviewed our prior submittals to you related to the BACT analysis for control of PM_{2.5} and PM_{2.5} precursors. In the course of these analyses, there were no potential controls that we excluded because implementation could not occur prior to December 31, 2019. In addition, there were no potential controls that were eliminated due to an extended implementation timeframe. The measures that were considered included all those that were deemed feasible.

If you have any further questions regarding our submitted analyses, please don't hesitate to ask.

Sincerely,

Michael S. Astin, P.E.
Environmental Manager



HOLLYFRONTIER

HOLLYFRONTIER WOODS CROSS REFINING LLC

1070 West 500 South • West Bountiful, Utah 84087-1442
(801) 299-6600 • Fax (801) 299-6609

April 25, 2018

Mr. John Jenks
Environmental Engineer
Utah Division of Air Quality
195 North 1950 West
P.O. Box 144820
Salt Lake City, Utah 84114-4820

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

7017 0190 0000 7884 0134

APR 27 2018

DIVISION OF AIR QUALITY

RE: Letter – Best Available Control measure Analysis for Ammonia for HollyFrontier’s Woods Cross Refinery

Dear Mr. Jenks:

In response to your letter dated April 9, 2018, HollyFrontier has prepared an addendum to the Best Available Control Measures (BACM) analysis requested in April 2017. Please find the attached response as prepared by MSI Trinity Consultants.

Please contact me at regina.harris@hollyfrontier.com or 801.397.7432 if you have any questions.

Sincerely,

Regina Harris
Environmental Specialist



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April 24, 2018

Mr. John Jenks
Environmental Engineer
Utah Division of Air Quality
195 North 1950 West
P. O. Box 144820
Salt Lake City, Utah 84114-4820

RE: Addendum - Best Available Control Measure Analyses for Ammonia for HollyFrontier's Woods Cross Refinery

Dear Mr. Jenks:

HollyFrontier understands that at the time of the first request for Best Available Control Measures (BACM) information, the Utah Division of Air Quality (UDAQ) was under the assumption that emissions of ammonia (NH₃) did not significantly contribute to nonattainment. However, since that time, the results of the PM_{2.5} precursor demonstration now indicate that ammonia does contribute to nonattainment in the Salt Lake Non-Attainment Area (NAA). Thus, this letter supplements the NH₃ BACM that was provided to the UDAQ in April 2017. As indicated in the original BACM analysis, the units that have the potential to emit NH₃ emissions include the process heaters, boilers and associated boiler pollutant control devices, wastewater treatment, fluidized catalytic cracking units (FCCUs), the sour water stripper, and ammonia stripping unit.

This addendum includes addition information regarding NH₃ emissions from combustion of natural gas in the process heaters, boilers, and natural gas-fired emergency engines.

Process Heaters and Boilers

While the original BACM indicated that ammonia emissions do not result from combustion of natural gas (Section 8.1.2), further research conducted in this area does indicate that NH₃ emissions may occur as a byproduct of incomplete combustion. From a review of current literature and EPA databases, two NH₃ emission factors were identified from combustion of natural gas. According to the EPA's WebFIRE database, the NH₃ emission factor presented for natural gas combustion is 0.0031 lb/MMBtu. In the August 1994 final report prepared for the EPA titled, Development and Selection of Ammonia Emission Factors, Table 7-4 lists the NH₃ emission factor from natural gas combustion as 3.2 lb/10⁶ ft³.

Step 1 – Identify All Existing and Potential Emission Control Technologies

The various control technologies available to control ammonia emissions from the process boilers and heaters includes both pollution prevention techniques and add-on control devices. Control options for NH₃ consist of good combustion practices, fuel specifications (use of natural gas or refinery gas), thermal oxidation, and wet scrubbing (i.e. ammonia scrubber).

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Step 2 – Eliminate Technically Infeasible Options

Based on the emission factors presented above, the concentration of NH₃ from each process heater and boiler is estimated to be less than 1 ppm. In discussions with Gulf Coast Environmental Systems¹, waste streams with NH₃ concentrations of 100 ppm or greater are typically required for an add-on device, such as an ammonia scrubber or thermal oxidizer, to be technically and cost effective.

The ballpark equipment cost estimates provided by Gulf Coast Environmental Systems for an ammonia scrubber and thermal oxidizer for a 50 MMBtu/hr process heater/boiler were \$200,000 and \$350,000, respectively. Cost evaluations were prepared to determine the cost of control per ton of NH₃ removed from a 50 MMBtu/hr process heater/boiler. The \$/ton of NH₃ reduced with the use of an ammonia scrubber was approximately \$148,000, and approximately \$270,000 with the use of a thermal oxidizer which is economically not feasible (see Attachment 1). In addition, a review of the EPA's RBLC database and an internet search did not identify the use of any type of add-on device to control NH₃ emissions from natural gas or refinery fuel combustion from process heaters or boilers. Thus, for these reasons, add-on control devices such as an ammonia scrubber or thermal oxidizer were determined to be technically and economically infeasible for reducing NH₃ emissions from the process heaters/boilers at HollyFrontier's Woods Cross Refinery and as such were eliminated from further consideration.

Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control technologies include the use of good combustion practices and use of natural or refinery gas.

Step 4 – Evaluate Impacts and Document Results

Good combustion practices and natural and/or refinery fuel gas are utilized at the refinery. There are no energy, environmental or economic impacts associated with the use of good combustion practices and the use of natural or refinery gas.

Step 5 – Select BACT

The most stringent controls identified to reduce NH₃ emissions are the use of natural or refinery gas and good combustion practices which satisfy BACM for NH₃ for existing units 4H1, 6H1, 6H2, 6H3, 7H1, 7H3, 8H2, 9H1, 9H2, 10H1, 10H2, 11H1, 12H1, 13H1, 19H1, 20H2, 20H3, 24H1, 25H1, 68H2, 68H3, boilers #4, #5, #8, #9, and #10, and for proposed units 23H1, 27H1, 30H1, 30H2, 33H1, 68H2-H7, 68H10-H13, and boiler #11. Good combustion practices and the use of natural or refinery gas is currently being utilized at the Woods Cross Refinery to minimize pollutant emissions including emissions of NH₃. Good operating practices will be followed in order to minimize ammonia emissions during periods of startup and shutdown.

It should be noted that NO_x emissions on existing boilers #5, #8, #9, and #10 and for proposed units 10H2, 27H1, 30H1, 30H2, 33H1, and boiler #11 are (or will be) controlled through SCRs. A discussion of the ammonia slip from the SCR's can be found in Section 8.1 of the original BACM analysis.

¹ Conversation with Chad Clark, Technical Director Gulf Coast Environmental Systems on April 19, 2018.

Emergency Natural-Gas Fired Engines

HollyFrontier operates two natural gas-fired spark ignition emergency standby generators, each at 142 kW, at the Administration building. Emissions of NH₃ from the natural gas emergency generators are a byproduct of incomplete combustion of the natural gas.

Step 1 – Identify All Existing and Potential Emission Control Technologies

The control technologies available to minimize ammonia emissions include good combustion practices, the use of natural gas, and the add-on control technologies of SCR, and Non-selective Catalytic Reduction (NSCR).

Step 2 – Eliminate Technically Infeasible Options

As presented in the Section 4.6.2 of the original BACM analyses for NO_x submitted by HollyFrontier to the UDAQ in April 2017 and reiterated here, the NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich burn turbocharged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective NO_x reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 percent. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures. Thus, the add-on combustion control of NSCR is deemed technically infeasible.

SCR is a catalytic post-combustion control technology designed to control NO_x emissions. Ammonia is vaporized and injected directly into the exhaust stream, where it reacts with NO_x and oxygen in the presence of the catalyst to form N₂ and water vapor. Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream (ammonia slip). Since the operation of each generators is limited to 50 hours for testing (non-emergency) purposes, it is unlikely that the engines would reach the required operating temperature for a SCR to be effective. In addition, if SCR was feasible, increased NH₃ emissions would be likely. Thus, since it is unlikely that the natural gas emergency generators will achieve normal operating temperature for any period of time, the add-on control technology using SCR, which requires a consistent operating temperature to be effective, is technically not feasible and, if it were feasible, would result in increased NH₃ emissions.

Steps 3- 5

The remaining control technologies include good combustion practices and use of natural gas which are currently in use at the Refinery. There are no energy, environmental or economic impacts associated with these pollution control techniques. The proposed BACM for NH₃ for the emergency natural gas-fired engines is limited hours of operation, use of natural gas, and good combustion practices. Manufacturer specifications will be followed. Operating hours are tracked through non-resettable hour meters installed on each engine. Extremely low concentrations of NH₃, based on the use of the emission factor of 3.2 lb/10⁶ scf for natural gas combustion, are expected.

If you have any questions concerning the information in this letter, feel free to contact me.

Mr. John Jenks - Page 4
April 24, 2018

Sincerely,

MSI TRINITY CONSULTANTS

A handwritten signature in black ink, appearing to read "Linda Conger". The signature is written in a cursive, flowing style.

Linda Conger
Managing Consultant

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Analysis\04 Report\Addendum - NH3 BACM\NH3 BACM Addendum_HollyFrontier.docx

ATTACHMENT 1

Economic Viability Analysis for use of Ammonia Scrubber and Thermal Oxidizer

NH₃ Cost Analysis to Add Ammonia Scrubber

	Ammonia	Factor	Basis for Cost
	Scrubber Add-on		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 200,000.00	Estimate for 50 MMBtu/hr heater/boiler	
Instrumentation and Controls	\$ 20,000	10% of PE	EPA ¹
Sales Tax	\$ 6,000	3% of PE	EPA ¹
Freight	\$ 10,000	5% of PE	EPA ¹
Total Purchased Equipment Cost (PEC)	\$ 236,000		
Direct Installation			
Foundations	\$ 28,320	12% of PEC	EPA ¹
Handling and Erection	\$ 94,400	40% of PEC	EPA ¹
Electrical	\$ 2,360	1% of PEC	EPA ¹
Piping	\$ 4,720	2% of PEC	EPA ¹
Insulation and Ductwork	\$ 2,360	1% of PEC	EPA ¹
Painting	\$ 2,360	1% of PEC	EPA ¹
Total Direct Installation (DI)	\$ 134,520		
Total Direct Cost (DC)	\$ 370,520		
Indirect Installation Costs			
Engineering and Project Management	\$ 23,600	10% of PEC	EPA ¹
Construction and Field Expenses	\$ 23,600	10% of PEC	EPA ¹
Contractor Fees	\$ -	0% of PEC	EPA ¹
Startup Expenses	\$ 2,360	1% of PEC	EPA ¹
Performance Tests	\$ 2,360	1% of PEC	EPA ¹
Contingencies	\$ 7,080	3% of PEC	EPA ¹
Total Indirect Cost	\$ 59,000		
Total Installed Cost (TIC)	\$ 429,520		
Assumptions:			
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002.			

NH₃ Cost Analysis to Add Ammonia Scrubber

	Ammonia	Basis for Cost and Factor
	Scrubber Add-on	
Total Installed Cost	\$ 429,520	
NH3 Emissions Before Control, lb/MMBtu	0.0031	
Annual Capacity Factor	100%	
NH3 Emissions Before Control, tn/yr	0.680	
NH3 Emissions After Control, lb/MMBtu	0.00003	
Control Efficiency (%)	99	
NH3 Emissions After Control, tn/yr	0.01	
NH3 Emission Reduction, tn/yr	0.67	
Annual Costs, \$/year (Direct + Indirect)		
Direct Costs		
Operating Labor	\$ 8,590	2% of capitol cost
Raw materials	\$ -	
Replacement Parts	\$ 8,590	2% of capitol cost
Total Direct Costs, \$/year	\$ 17,181	
Indirect Costs		
Overhead	\$ 6,872	80% of labor costs
Taxes, Insurance, and Administration	\$ 17,181	4% of total installed cost - EPA ¹
Capitol Recovery	\$ 58,372	6%, 10 years, CRF-.1359
Total Indirect Costs, \$/year	\$ 82,425	
Total Annual Cost	\$ 99,606	
Cost Effectiveness, \$ per ton NH3 reduction	\$ 147,958.54	
Assumptions:		
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002. Table		

NH₃ Cost Analysis to Add Thermal Oxidizer

	Thermal Oxidizer Add-on	Factor	Basis for Cost and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 350,000.00	Estimate for 50 MMBtu/hr heater/boiler	
Instrumentation and Controls	\$ 35,000	10% of PE	EPA ¹
Sales Tax	\$ 10,500	3% of PE	EPA ¹
Freight	\$ 17,500	5% of PE	EPA ¹
Total Purchased Equipment Cost (PEC)	\$ 413,000		
Direct Installation			
Foundations	\$ 49,560	12% of PEC	EPA ¹
Handling and Erection	\$ 165,200	40% of PEC	EPA ¹
Electrical	\$ 4,130	1% of PEC	EPA ¹
Piping	\$ 8,260	2% of PEC	EPA ¹
Insulation and Ductwork	\$ 4,130	1% of PEC	EPA ¹
Painting	\$ 4,130	1% of PEC	EPA ¹
Total Direct Installation (DI)	\$ 235,410		
Total Direct Cost (DC)	\$ 648,410		
Indirect Installation Costs			
Engineering and Project Management	\$ 41,300	10% of PEC	EPA ¹
Construction and Field Expenses	\$ 41,300	10% of PEC	EPA ¹
Contractor Fees	\$ -	0% of PEC	EPA ¹
Startup Expenses	\$ 4,130	1% of PEC	EPA ¹
Performance Tests	\$ 4,130	1% of PEC	EPA ¹
Contingencies	\$ 12,390	3% of PEC	EPA ¹
Total Indirect Cost	\$ 103,250		
Total Installed Cost (TIC)	\$ 751,660		
Assumptions:			
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002.			

NH₃ Cost Analysis to Add Thermal Oxidizer

	Thermal	Basis for Cost and Factor
	Oxidizer Add-on	
Total Installed Cost	\$ 751,660	
NH3 Emissions Before Control, lb/MMBtu	0.0031	
Annual Capacity Factor	100%	
NH3 Emissions Before Control, tn/yr	0.680	
NH3 Emissions After Control, lb/MMBtu	0.00016	
Control Efficiency (%)	95	
NH3 Emissions After Control, tn/yr	0.03	
NH3 Emission Reduction, tn/yr	0.65	
Annual Costs, \$/year (Direct + Indirect)		
Direct Costs		
Operating Labor	\$ 15,033	2% of capitol cost
Raw materials	\$ -	
Replacement Parts	\$ 15,033	2% of capitol cost
Total Direct Costs, \$/year	\$ 30,066	
Indirect Costs		
Overhead	\$ 12,027	80% of labor costs
Taxes, Insurance, and Administration	\$ 30,066	4% of total installed cost - EPA ¹
Capitol Recovery	\$ 102,151	6%, 10 years, CRF-.1359
Total Indirect Costs, \$/year	\$ 144,244	
Total Annual Cost	\$ 174,310	
Cost Effectiveness, \$ per ton NH3 reduction	\$ 269,829.65	
Assumptions:		
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002. Table		



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July 26, 2017

Mr. John Jenks
Environmental Engineer
Utah Division of Air Quality
195 North 1950 West
P. O. Box 144820
Salt Lake City, Utah 84114-4820

RE: Addendum - Best Available Control Measure Analyses for HollyFrontier's Woods Cross Refinery

Dear Mr. Jenks:

Please find in this addendum to the Best Available Control Measure (BACM) Analyses prepared for HollyFrontier's Woods Cross Refinery the additional information requested by the Utah Division of Air Quality (UDAQ) on June 28, 2017. In this request, three areas were indicated where additional information was needed. These areas were: (1) economics and selection of BACM; (2) lack of additional feasible measures/most stringent measures, and (3) individual issues.

Economics and Individual Issues

The economic evaluations presented in the BACM analysis for HollyFrontier were based on potential to emit (PTE) emissions for refinery sources utilizing permit conditions, permit emission factors and permit limitations. The quantities of emission reductions provided in the analyses were based on the estimated control that would be achieved with the application of a control technology (such as more efficient burners or add-on devices) and the difference between the current PTE emissions without that control technology and future estimated emissions after the application of a control technology. Since detailed engineering designs and associated vendor costs for plant modifications that would be needed for the application of a control technology were not available, due to the short response time, generalized control efficiencies, obtained from published literature and EPA guidance were used to estimate the potential control efficiencies or emission reductions that are associated with the application of a control technology.

Cost estimates that were provided in the BACM analyses were based on information obtained from vendors, economic information provided by HollyFrontier from the purchase and installation of similar equipment, or information as found in EPA guidance documentation. The \$/ton threshold that was used by HollyFrontier to indicate whether the application of a control technology was economically feasible ranged from \$15,000 to \$20,000 depending on pollutant and emission unit.

Per UDAQ’s additional information request to HollyFrontier, replacement costs for the emergency engines were obtained from Wheeler Machinery and the economic viability of replacing Tier 2 or older equipment with newer Tier 3 or 4 diesel engines was examined. Per Wheeler Machinery, the estimated cost to replace a 200HP or 400HP engine with a newer engine was \$75,000 and \$115,000, respectively. This cost is for equipment only and doesn’t include engineering or installation costs. The economic viability analysis for replacing Tier 2 or older diesel engines at HollyFrontier is presented in Attachment 1. According to the analysis in Attachment 1, it would be not be economically viable for HollyFrontier to replace existing engines with Tier 3 or Tier 4 engines.

In order to further clarify the BACM and economic analysis for heater controls, as stated in HollyFrontier’s BACM analyses, the application of low NO_x burners (LNB) or ultra low NO_x burners (ULNB) on existing units (6H1, 6H2, 6H3, 7H1, 7H2, 7H3, 9H1, 9H2, 10H1, 11H1, and 13H1) was not technically possible due to space limitations in the firebox, lower heat duty, and a longer flame. In addition, in order to use a selective catalytic reduction (SCR) system on process heaters at HollyFrontier, the refinery would need to replace all naturally draft heaters with mechanical draft heaters. Only 6H1 is mechanically drafted.

The economic feasibility of converting the above list of heaters to mechanical draft and then reducing NO_x emissions through the addition of SCR was examined. The cost guidance information provided in EPA-453/R-93-034 Alternative Control Techniques Document-NO_x Emissions from Process Heaters (Revised) was used for this analysis. The 1991 capital costs were escalated to average 2017 dollars using the Chemical Engineering plant index. The results of this analysis are presented in Table 1 and in Attachment 2.

Table 1 Economic Viability to Convert Natural Draft to Mechanical Draft Process Heaters with Application of SCR

Unit	Rating MMBtu/hr	\$/ton NO _x
6H1 ¹	54.7	\$ 80,097
6H2	12.0	\$ 170,826
6H3	37.7	\$ 107,763
7H1	4.4	\$ 255,031
7H3	33.3	\$ 113,666
9H1	8.1	\$ 199,858
9H2	4.1	\$ 262,329
10H1	13.2	\$ 164,447
11H1	24.2	\$ 129,106
13H1	6.5	\$ 218,220

¹ Application of SCR only.

The results of Table 1 indicate that it is not economically feasible to convert the listed process heaters from natural draft and then apply a SCR to reduce NO_x emissions. Thus, for technical and economic reasons, no control technology modifications are proposed by HollyFrontier on these units.

Lack of Additional Feasible Measures/Most Stringent Measures

In the UDAQ's original request for BACM/BACT, the January letter indicated that "Should the area not be able to meet the PM_{2.5} standards by the statutory Serious Area attainment date (December 31, 2019), whether by modeled prediction or actual ambient monitoring, the standard of control measure feasibility would rise once more to what are called Most Stringent Measures (MSM)". In HollyFrontier's BACM analyses, most stringent measures (MSM) were identified and included in the selection of BACM. However, at this time, HollyFrontier does not believe that providing additional MSM analysis is appropriate since nonattainment has not been demonstrated/modeled.

Other Individual Issues

Presented in Attachment 3 are the monitoring recommendations and emission limitations for emission sources at HollyFrontier.

If you have any questions or concerns regarding the information in this letter, please feel free to contact HollyFrontier.

Sincerely,

MSI TRINITY CONSULTANTS



Linda Conger
Managing Consultant

ATTACHMENT 1

Economic Viability Analysis for Diesel Engine Replacement

**Cost to Replace Tier 2 or older Emergency Diesel Engines with Tier 4 Units
HollyFrontier Woods Cross Refinery**

	Year	Rating (HP)	Rating (KW)	Replacement Cost	Uncontrolled (Tier 1)			Uncontrolled (Tier 4)			Emission Reduction			Cost Effectiveness (\$/ton)				
					PM _{2.5} PTE TPY	NO _x PTE TPY	VOC PTE TPY	PM _{2.5} PTE TPY	NO _x PTE TPY	VOC PTE TPY	PM _{2.5} PTE TPY	NO _x PTE TPY	VOC PTE TPY	PM _{2.5}	NO _x	VOC		
Diesel Emergency Equipment																		
224 HP (water well #3)	2002	224.0	167.0	\$ 75,000	0.0049	0.085	0.0123	0.0002	0.004	0.00172	0.005	0.081	0.011	\$	15,812,110	\$	922,373	\$ 7,078,677
393 HP Fire Pump #1	1982	393.0	293.1	\$ 115,000	0.0086	0.149	0.0216	0.0003	0.006	0.00303	0.008	0.143	0.019	\$	13,819,167	\$	806,118	\$ 6,186,488
393 HP Fire Pump #2	1982	393.0	293.1	\$ 115,000	0.0086	0.149	0.0216	0.0003	0.006	0.00303	0.008	0.143	0.019	\$	13,819,167	\$	806,118	\$ 6,186,488
220 HP plant air backup compressor #1	1997	220.0	164.1	\$ 75,000	0.0048	0.083	0.0121	0.0002	0.004	0.00169	0.005	0.080	0.010	\$	16,099,603	\$	939,144	\$ 7,207,380
220 HP plant air backup compressor #2	1997	220.0	164.1	\$ 75,000	0.0048	0.083	0.0121	0.0002	0.004	0.00169	0.005	0.080	0.010	\$	16,099,603	\$	939,144	\$ 7,207,380
220 HP plant air backup compressor #3	<2000	220.0	164.1	\$ 75,000	0.0048	0.083	0.0121	0.0002	0.004	0.00169	0.005	0.080	0.010	\$	16,099,603	\$	939,144	\$ 7,207,380
380 HP diesel generator (central control room)	1997	380.0	283.4	\$ 115,000	0.0084	0.144	0.0209	0.0003	0.006	0.00293	0.008	0.138	0.018	\$	14,291,928	\$	833,696	\$ 6,398,131

Assumptions:

Cost estimate for engine only provided by Wheeler Machinery. Cost does not include engineering or installation costs.
PTE emissions based on 50 operating hours per year and Title V permit application

ATTACHMENT 2

Economic Viability to Convert Natural Draft to Mechanical Draft Process Heaters with Application of SCR

HollyFrontier BACM Analysis - Cost to Convert from Natural Draft to Mechanical Draft

HollyFrontier Source ID	Source Description	MMBtu/hr	GJ/hr	Cost to Convert from ND to MD						SCR Capitol Cost (1991\$)	SCR Cost (2017\$)
				Capital Cost to Convert from ND to MD 1991\$	Capital Cost 2017\$	Capital Recovery Factor	Capital Recovery	O&M Cost	Total Annual Cost		
6H1	Reformer Reheat Furnace	54.7	57.7	243,313.6	416,247.8	0.131	54,725.67	11,446.81	66,172.49	1,481,294	2,534,117
6H2	Prefractionator Reboiler Heater	12.0	12.7	97,922.6	167,520.6	0.131	22,024.57	4,606.82	26,631.39	595,141	1,018,135
6H3	Reformer Reheat Furnace	37.7	39.8	194,616.1	332,938.8	0.131	43,772.72	9,155.82	52,928.53	1,184,212	2,025,886
7H1	HF Alkylation Regeneration Furnace	4.4	4.6	53,634.7	91,755.3	0.131	12,063.42	2,523.27	14,586.69	325,754	557,283
7H3	HF Alkylation Depropanizer Reboiler	33.3	35.1	180,651.1	309,048.1	0.131	40,631.72	8,498.82	49,130.55	1,099,065	1,880,221
9H1	DHDS Reactor Charge Heater	8.1	8.5	77,350.8	132,327.6	0.131	17,397.61	3,639.01	21,036.62	469,974	804,005
9H2	DHDS Stripper Reboiler	4.1	4.3	51,409.6	87,948.8	0.131	11,562.96	2,418.59	13,981.55	312,228	534,143
10H1	Asphalt Mix Heater	13.2	13.9	103,685.6	177,379.7	0.131	23,320.78	4,877.94	28,198.72	630,217	1,078,140
11H1	SRGP Depentanizer Reboiler	24.2	25.5	149,163.7	255,181.3	0.131	33,549.64	7,017.48	40,567.13	907,166	1,551,931
13H1	Isomerization Reactor Feed Furnace	6.5	6.9	67,783.2	115,959.8	0.131	15,245.68	3,188.90	18,434.57	411,781	704,453

Assumptions:

Cost estimates based on guidance as found in EPA-453/R-93-034, Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)

Capitol Cost model for ND-to-MD conversion is: $TIC = 21350 (HQ)^{0.6}$ where HQ is heater capacity in GJ/hr.

Capitol recovery based on pretax marginal rate of return (10 percent) and equipment economic life of 15 years

Maintenace costs associated with ND-to-MD Conversion are estimated as 2.75 percent of the ND-to-MD capitol cost

HollyFrontier Costs to Upgrade Process Heaters to Mechanical Draft then Add SCR

Unit	Rating MMBtu/hr	Baseline Emission Factor		SCR Emission Factor		\$/ton
		(lb/MMBtu)	NO _x (TPY)	(lb/MMBtu)	NO _x (TPY)	
6H1	54.7	0.098	23.49	0.025	5.87	\$ 80,097
6H2	12.0	0.098	5.15	0.025	1.29	\$ 170,826
6H3	37.7	0.098	16.19	0.025	4.05	\$ 107,763
7H1	4.4	0.098	1.89	0.025	0.47	\$ 255,031
7H3	33.3	0.098	14.30	0.025	3.57	\$ 113,666
9H1	8.1	0.098	3.48	0.025	0.87	\$ 199,858
9H2	4.1	0.098	1.76	0.025	0.44	\$ 262,329
10H1	13.2	0.098	5.67	0.025	1.42	\$ 164,447
11H1	24.2	0.098	10.39	0.025	2.60	\$ 129,106
13H1	6.5	0.098	2.79	0.025	0.70	\$ 218,220

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NOx emissions from Process Heaters (Revised)
 Convert from natural draft to mechanical draft
 Cost includes addition of SCR

HollyFrontier Woods Cross Refinery
NO_x Cost Analysis to Upgrade Process Heaters and Add SCR - 6H1

	MD/SCR	Factor	Basis for Cost
	Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 2,534,117	Include costs add SCR since MD already	
Sales Tax	\$ 152,047	6% of PE	OTC-LADCO 2008
Freight	\$ 126,706	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 2,812,870		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 1,125,148	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 1,125,148		
Total Direct Cost (DC)	\$ 3,938,018		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 1,715,851	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 1,715,851		
Total Installed Cost (TIC)	\$ 5,653,868		
NO _x Emissions Before Control, lb/MMBtu	0.098		
NO _x Emissions Before Control, tn/yr	23.48		
NO _x Emissions After Control, lb/MMBtu	0.0245		
Control Efficiency (%)	75		
NO _x Emissions After Control, tn/yr	5.87		
NO _x Emission Reduction, tn/yr	17.61		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 169,616	3% of capitol cost	
Raw materials	\$ -		
Replacement Parts	\$ 169,616	3% of capitol cost	
Total Direct Costs, \$/year	\$ 339,232		
Indirect Costs			
Overhead	\$ 101,770	60% of labor costs	
Taxes, Insurance, and Administration	\$ 226,155	4% of total installed cost	
Capitol Recovery	\$ 743,314	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 1,071,238		
Total Annual Cost	\$ 1,410,471		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 80,096.82		

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NO_x emissions from Process Heaters (Revised)

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 6H2

	MD/SCR	Factor	Basis for Cost
	Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 1,185,656	Include costs to convert to MD and add SCR	
Sales Tax	\$ 71,139	6% of PE	OTC-LADCO 2008
Freight	\$ 59,283	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 1,316,078		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 526,431	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 526,431		
Total Direct Cost (DC)	\$ 1,842,509		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 802,808	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 802,808		
Total Installed Cost (TIC)	\$ 2,645,317		
NO _x Emissions Before Control, lb/MMBtu	0.098		
NO _x Emissions Before Control, tn/yr	5.15		
NO _x Emissions After Control, lb/MMBtu	0.025		
Control Efficiency (%)	75		
NO _x Emissions After Control, tn/yr	1.29		
NO _x Emission Reduction, tn/yr	3.86		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 79,360	3% of capitol cost	
Raw materials	\$ -		
Replacement Parts	\$ 79,360	3% of capitol cost	
Total Direct Costs, \$/year	\$ 158,719		
Indirect Costs			
Overhead	\$ 47,616	60% of labor costs	
Taxes, Insurance, and Administration	\$ 105,813	4% of total installed cost	
Capitol Recovery	\$ 347,780	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 501,208		
Total Annual Cost	\$ 659,927		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 170,825.76		

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NO_x emissions from Process Heaters (Revised)

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 6H3

	MD/SCR	Factor	Basis for Cost
	Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 2,349,825	Include costs to convert to MD and add SCR	
Sales Tax	\$ 140,990	6% of PE	OTC-LADCO 2008
Freight	\$ 117,491	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 2,608,306		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 1,043,322	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 1,043,322		
Total Direct Cost (DC)	\$ 3,651,628		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 1,591,067	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 1,591,067		
Total Installed Cost (TIC)	\$ 5,242,695		
NO _x Emissions Before Control, lb/MMBtu	0.098		
NO _x Emissions Before Control, tn/yr	16.18		
NO _x Emissions After Control, lb/MMBtu	0.025		
Control Efficiency (%)	75		
NO _x Emissions After Control, tn/yr	4.05		
NO _x Emission Reduction, tn/yr	12.14		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 157,281	3% of capitol cost	
Raw materials	\$ -		
Replacement Parts	\$ 157,281	3% of capitol cost	
Total Direct Costs, \$/year	\$ 314,562		
Indirect Costs			
Overhead	\$ 94,369	60% of labor costs	
Taxes, Insurance, and Administration	\$ 209,708	4% of total installed cost	
Capitol Recovery	\$ 689,257	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 993,333		
Total Annual Cost	\$ 1,307,895		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 107,763.10		

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NO_x emissions from Process Heaters (Revised)

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 7H1

	MD/SCR	Factor	Basis for Cost
	Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 649,038	Include costs to convert to MD and add SCR	
Sales Tax	\$ 38,942	6% of PE	OTC-LADCO 2008
Freight	\$ 32,452	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 720,432		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 288,173	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 288,173		
Total Direct Cost (DC)	\$ 1,008,605		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 439,464	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 439,464		
Total Installed Cost (TIC)	\$ 1,448,069		
NO _x Emissions Before Control, lb/MMBtu	0.098		
NO _x Emissions Before Control, tn/yr	1.89		
NO _x Emissions After Control, lb/MMBtu	0.025		
Control Efficiency (%)	75		
NO _x Emissions After Control, tn/yr	0.47		
NO _x Emission Reduction, tn/yr	1.42		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 43,442	3% of capitol cost	
Raw materials	\$ -		
Replacement Parts	\$ 43,442	3% of capitol cost	
Total Direct Costs, \$/year	\$ 86,884		
Indirect Costs			
Overhead	\$ 26,065	60% of labor costs	
Taxes, Insurance, and Administration	\$ 57,923	4% of total installed cost	
Capitol Recovery	\$ 190,378	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 274,366		
Total Annual Cost	\$ 361,250		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 255,031.23		

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NO_x emissions from Process Heaters (Revised)

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 7H3

	MD/SCR	Factor	Basis for Cost
	Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 2,189,269	Include costs to convert to MD and add SCR	
Sales Tax	\$ 131,356	6% of PE	OTC-LADCO 2008
Freight	\$ 109,463	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 2,430,089		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 972,035	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 972,035		
Total Direct Cost (DC)	\$ 3,402,124		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 1,482,354	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 1,482,354		
Total Installed Cost (TIC)	\$ 4,884,478		
NO _x Emissions Before Control, lb/MMBtu	0.098		
NO _x Emissions Before Control, tn/yr	14.29		
NO _x Emissions After Control, lb/MMBtu	0.025		
Control Efficiency (%)	75		
NO _x Emissions After Control, tn/yr	3.57		
NO _x Emission Reduction, tn/yr	10.72		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 146,534	3% of capitol cost	
Raw materials	\$ -		
Replacement Parts	\$ 146,534	3% of capitol cost	
Total Direct Costs, \$/year	\$ 293,069		
Indirect Costs			
Overhead	\$ 87,921	60% of labor costs	
Taxes, Insurance, and Administration	\$ 195,379	4% of total installed cost	
Capitol Recovery	\$ 642,162	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 925,462		
Total Annual Cost	\$ 1,218,531		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 113,666.06		

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NO_x emissions from Process Heaters (Revised)

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 9H1

	MD/SCR	Factor	Basis for Cost
	Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 936,333	Include costs to convert to MD and add SCR	
Sales Tax	\$ 56,180	6% of PE	OTC-LADCO 2008
Freight	\$ 46,817	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 1,039,330		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 415,732	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 415,732		
Total Direct Cost (DC)	\$ 1,455,061		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 633,991	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 633,991		
Total Installed Cost (TIC)	\$ 2,089,053		
NO _x Emissions Before Control, lb/MMBtu	0.098		
NO _x Emissions Before Control, tn/yr	3.48		
NO _x Emissions After Control, lb/MMBtu	0.025		
Control Efficiency (%)	75		
NO _x Emissions After Control, tn/yr	0.87		
NO _x Emission Reduction, tn/yr	2.61		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 62,672	3% of capitol cost	
Raw materials	\$ -		
Replacement Parts	\$ 62,672	3% of capitol cost	
Total Direct Costs, \$/year	\$ 125,343		
Indirect Costs			
Overhead	\$ 37,603	60% of labor costs	
Taxes, Insurance, and Administration	\$ 83,562	4% of total installed cost	
Capitol Recovery	\$ 274,648	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 395,813		
Total Annual Cost	\$ 521,156		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 199,857.86		

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NO_x emissions from Process Heaters (Revised)

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 9H2

	MD/SCR	Factor	Basis for Cost
	Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 622,092	Include costs to convert to MD and add SCR	
Sales Tax	\$ 37,326	6% of PE	OTC-LADCO 2008
Freight	\$ 31,105	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 690,522		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 276,209	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 276,209		
Total Direct Cost (DC)	\$ 966,731		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 421,218	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 421,218		
Total Installed Cost (TIC)	\$ 1,387,949		
NO _x Emissions Before Control, lb/MMBtu	0.098		
NO _x Emissions Before Control, tn/yr	1.76		
NO _x Emissions After Control, lb/MMBtu	0.025		
Control Efficiency (%)	75		
NO _x Emissions After Control, tn/yr	0.44		
NO _x Emission Reduction, tn/yr	1.32		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 41,638	3% of capitol cost	
Raw materials	\$ -		
Replacement Parts	\$ 41,638	3% of capitol cost	
Total Direct Costs, \$/year	\$ 83,277		
Indirect Costs			
Overhead	\$ 24,983	60% of labor costs	
Taxes, Insurance, and Administration	\$ 55,518	4% of total installed cost	
Capitol Recovery	\$ 182,474	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 262,975		
Total Annual Cost	\$ 346,252		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 262,329.22		

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NO_x emissions from Process Heaters (Revised)

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 10H1

	MD/SCR	Factor	Basis for Cost
	Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 1,255,520	Include costs to convert to MD and add SCR	
Sales Tax	\$ 75,331	6% of PE	OTC-LADCO 2008
Freight	\$ 62,776	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 1,393,627		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 557,451	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 557,451		
Total Direct Cost (DC)	\$ 1,951,078		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 850,113	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 850,113		
Total Installed Cost (TIC)	\$ 2,801,191		
NO _x Emissions Before Control, lb/MMBtu	0.098		
NO _x Emissions Before Control, tn/yr	5.67		
NO _x Emissions After Control, lb/MMBtu	0.025		
Control Efficiency (%)	75		
NO _x Emissions After Control, tn/yr	1.42		
NO _x Emission Reduction, tn/yr	4.25		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 84,036	3% of capitol cost	
Raw materials	\$ -		
Replacement Parts	\$ 84,036	3% of capitol cost	
Total Direct Costs, \$/year	\$ 168,071		
Indirect Costs			
Overhead	\$ 50,421	60% of labor costs	
Taxes, Insurance, and Administration	\$ 112,048	4% of total installed cost	
Capitol Recovery	\$ 368,273	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 530,742		
Total Annual Cost	\$ 698,813		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 164,446.87		

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NO_x emissions from Process Heaters (Revised)

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 11H1

	MD/SCR	Factor	Basis for Cost
	Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 1,807,112	Include costs to convert to MD and add SCR	
Sales Tax	\$ 108,427	6% of PE	OTC-LADCO 2008
Freight	\$ 90,356	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 2,005,894		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 802,358	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 802,358		
Total Direct Cost (DC)	\$ 2,808,252		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 1,223,596	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 1,223,596		
Total Installed Cost (TIC)	\$ 4,031,848		
NO _x Emissions Before Control, lb/MMBtu	0.098		
NO _x Emissions Before Control, tn/yr	10.39		
NO _x Emissions After Control, lb/MMBtu	0.025		
Control Efficiency (%)	75		
NO _x Emissions After Control, tn/yr	2.60		
NO _x Emission Reduction, tn/yr	7.79		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 120,955	3% of capitol cost	
Raw materials	\$ -		
Replacement Parts	\$ 120,955	3% of capitol cost	
Total Direct Costs, \$/year	\$ 241,911		
Indirect Costs			
Overhead	\$ 72,573	60% of labor costs	
Taxes, Insurance, and Administration	\$ 161,274	4% of total installed cost	
Capitol Recovery	\$ 530,067	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 763,914		
Total Annual Cost	\$ 1,005,825		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 129,105.76		

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NO_x emissions from Process Heaters (Revised)

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 13H1

	MD/SCR	Factor	Basis for Cost
	Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 820,413	Include costs to convert to MD and add SCR	
Sales Tax	\$ 49,225	6% of PE	OTC-LADCO 2008
Freight	\$ 41,021	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 910,658		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 364,263	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 364,263		
Total Direct Cost (DC)	\$ 1,274,922		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 555,502	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 555,502		
Total Installed Cost (TIC)	\$ 1,830,423		
NO _x Emissions Before Control, lb/MMBtu	0.098		
NO _x Emissions Before Control, tn/yr	2.79		
NO _x Emissions After Control, lb/MMBtu	0.025		
Control Efficiency (%)	75		
NO _x Emissions After Control, tn/yr	0.70		
NO _x Emission Reduction, tn/yr	2.09		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 54,913	3% of capitol cost	
Raw materials	\$ -		
Replacement Parts	\$ 54,913	3% of capitol cost	
Total Direct Costs, \$/year	\$ 109,825		
Indirect Costs			
Overhead	\$ 32,948	60% of labor costs	
Taxes, Insurance, and Administration	\$ 73,217	4% of total installed cost	
Capitol Recovery	\$ 240,646	10%, 15 years, CRF-.13147	
Total Indirect Costs, \$/year	\$ 346,810		
Total Annual Cost	\$ 456,636		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 218,220.27		

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NO_x emissions from Process Heaters (Revised)

ATTACHMENT 3

Monitoring Recommendations and Emission Limitations

Summary of Allowable Limits and Monitoring Requirements at the Woods Cross Refinery

Emissions Unit	Parameter	Allowable Limit	Monitoring Approach	Comment			
Unit 4 - FCCU	VOC	≤500 ppmv one-hour average at 0% O ₂ 1-hr avg.	CEMS CEMS CEMS CEMS Stack Test, COMS/AMP	Must comply with LDAR program			
	CO	≤40 ppmdv at 0% O ₂ per 365-day rolling average					
	NO _x	≤80 ppmdv at 0% O ₂ per 7-day rolling average					
	SO ₂	≤25 ppmdv at 0% O ₂ per 365-day rolling average ≤50 ppmdv at 0% O ₂ per 7-day rolling average					
4H1 - FCC Feed Heater	PM ₁₀ Opacity	0.50 lb/1000 lb coke burned 10%	CEMS	Stack test no later than October 31 of each year			
4V82 FCC Scrubber	H ₂ S Opacity	≤60 ppm (annual average) 15%					
Unit 6 - Catalytic Reforming Unit	SO ₂	0.05 tons per day	COMS	CEMS located at plant fuel gas mix drum/header			
	SO ₂	17.7 tons per year					
	VOC						
	6H1-Reformer Charge Heater	Opacity PM ₁₀ H ₂ S			10% ≤60 ppm (annual average)		
6H2 - Prefractionator Reboiler Heater	Opacity PM ₁₀ H ₂ S	10% ≤60 ppm (annual average)	CEMS	PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header			
6H3 - Reformer Reheater Furnace	Opacity PM ₁₀ H ₂ S	10% ≤60 ppm (annual average)					
Unit 7 - Alkylation Unit	VOC		CEMS	Must comply with LDAR program			
	7H1 - HF Alkylation Regeneration Furnace	Opacity PM ₁₀ H ₂ S			10% ≤60 ppm (annual average)		
	7H3 - HF Alkylation Depropanizer Reboiler	Opacity PM ₁₀ H ₂ S			10% ≤60 ppm (annual average)		
	Unit 8 - Crude Unit	VOC				CEMS	Must comply with LDAR program
8H2 - Crude Furnace		Opacity PM ₁₀ NO _x H ₂ S	10% 0.00051 lb/MMBtu 0.04 lb/MMBtu 3-hour average ≤60 ppm (annual average)				
Unit 9 - Distillate Hydrosulfurization Unit		VOC		CEMS	Stack test no later than October 31 of each year Stack test performed every 3 years CEMS located at plant fuel gas mix drum/header		
		9H1-DHDS Reactor Charge Heater	Opacity PM ₁₀ H ₂ S				
	9H2-DHDS Stripper Reboiler	Opacity PM ₁₀ H ₂ S	10% ≤60 ppm (annual average)				
	Unit 10 - Solvent Deasphalting Unit	VOC				CEMS	Must comply with LDAR program
10H1 - Asphalt Mix Heater		Opacity PM ₁₀ H ₂ S	10% ≤60 ppm (annual average)				
10H2 - Hot Oil Furnace		Opacity PM ₁₀ NO _x H ₂ S	10% 0.00051 lb/MMBtu 0.02 lb/MMBtu 3-hour average ≤60 ppm (annual average)				
Unit 11 - Straight Run Gas Plant		VOC		CEMS	CEMS located at plant fuel gas mix drum/header		
	11H1 - SRGP Depentanizer Reboiler	Opacity PM ₁₀ H ₂ S	10% ≤60 ppm (annual average)				
	Unit 12 - Naphtha Hydrodesulphurization Unit	VOC				CEMS	Must comply with LDAR program
		12H1 - NHDS Reactor Charge Furnace	Opacity PM ₁₀ NO _x H ₂ S				
Unit 13 - Isomerization Unit		VOC		CEMS	Must comply with LDAR program		
		13H1 - Isomerization Reactor Feed Furnace	Opacity PM ₁₀ H ₂ S				
	Unit 16 - Amine Treatment Unit	VOC				CEMS	Must comply with LDAR program
		Unit 17 - Sulfur Recovery Unit	VOC				
Sulfur			≤20 long tons per day				
Sulfur			95% recovery on a 30-day average except during SSM				

Summary of Allowable Limits and Monitoring Requirements at the Woods Cross Refinery

Emissions Unit	Parameter	Allowable Limit	Monitoring Approach	Comment	
Unit 18 - Sour Water Stripping Unit Unit 19 - Distillate Hydrodesulfurization Treatment 19H1 - DHT Reactor Charge Heater	Sulfur	≤1.6 tn/day except during SSM	CEMS, CPMS		
	SO ₂ TRS, Temp				
	VOC			Must comply with LDAR program	
	VOC			Must comply with LDAR program	
	Opacity	10%	CEMS	CEMS located at plant fuel gas mix drum/header	
	PM ₁₀	0.00051 lb/MMBtu			
	H ₂ S	≤60 ppm (annual average)			
	Unit 20 - Gas Oil Hydrocracking Unit 20H1-Reactor Charge Heater	VOC			Must comply with LDAR program
		Opacity	10%	CEMS	Stack test no later than October 31 of each year CEMS located at plant fuel gas mix drum/header
		PM ₁₀	0.00051 lb/MMBtu		
H ₂ S		≤60 ppm (annual average)			
20H2-Fractionator Charge Heater		Opacity	10%	CEMS	Stack test no later than October 31 of each year CEMS located at plant fuel gas mix drum/header
		PM ₁₀	0.00051 lb/MMBtu		
	H ₂ S	≤60 ppm (annual average)			
20H3-Fractionator Charge Heater	Opacity	10%	CEMS	Stack test no later than October 31 of each year Stack test performed every 3 years CEMS located at plant fuel gas mix drum/header	
	PM ₁₀	0.00051 lb/MMBtu			
	NO _x	0.04 lb/MMBtu 3-hour average			
Unit 21 - NaSH Sour Gas Treatment Unit Unit 22 - Sour Water Stripper/Ammonia Stripping Unit Unit 23 - Benzene Saturation Unit 23H1-Reformate Splitter Reboiler Heater	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header	
	VOC			Must comply with LDAR program	
	VOC			Must comply with LDAR program	
	VOC			Must comply with LDAR program	
	Opacity	10%	CEMS	Stack test no later than October 31 of each year	
	PM ₁₀	0.00051 lb/MMBtu			
	H ₂ S	≤60 ppm (annual average)			
	Unit 24- Crude Unit 24H1 - Crude Unit Furnace	VOC			Must comply with LDAR program
		Opacity	10%	CEMS	Stack test no later than October 31 of each year Stack test performed every 3 years
		PM ₁₀	0.00051 lb/MMBtu		
NO _x		0.04 lb/MMBtu 3-hour average			
Unit 25 - FCCU 25H1 - FCC Feed Heater		H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
	VOC			Must comply with LDAR program	
	NO _x	≤40 ppmdv at 0% O ₂ per 365-day rolling average ≤80 ppmdv at 0% O ₂ per 7-day rolling average	CEMS		
	SO ₂	≤25 ppmdv at 0% O ₂ per 365-day rolling average ≤50 ppmdv at 0% O ₂ per 7-day rolling average	CEMS		
	PM ₁₀	0.50 lb/1000 lb coke burned	Stack Test	Stack test no later than October 31 of each year	
	Opacity	10%			
	PM ₁₀	0.00051 lb/MMBtu			
	NO _x	0.04 lb/MMBtu 3-hour average		Stack test performed every 3 years	
25FCC Scrubber	H ₂ S	≤60 ppm (annual average)			
	Opacity	15%	Stack Test	Stack test no later than October 31 of each year	
	SO ₂	0.05 tons per day			
	SO ₂	17.7 tons per year			
	PM ₁₀	0.30 lb/1000 lb coke burned	Flow meter		
Flow					
Unit 26 - Poly Gasoline Unit Unit 27 - Hydrocracker/Hydroisom Unit 27H1 - Reactor Charge Heater	VOC			Must comply with LDAR program	
	VOC			Must comply with LDAR program	
	Opacity	10%	CEMS	Stack test no later than October 31 of each year Stack test performed every 3 years	
	PM ₁₀	0.00051 lb/MMBtu			
	NO _x	0.02 lb/MMBtu 3-hour average			
	NO _x	40 ppmv or 0.04 lb/MMBtu (30-day rolling average)	CEMS	NO _x CEMS or Excess O ₂ operating curve	
	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header	
	Unit 28 - Sour Water Stripping Unit Unit 30 - Hydrogen Plant 30H1 - Hydrogen Reformer Feed Furnace	VOC			Must comply with LDAR program
		VOC			Must comply with LDAR program
		Opacity	10%	CEMS	Stack test no later than October 31 of each year Stack test performed every 3 years
PM ₁₀		0.00051 lb/MMBtu			
NO _x		0.02 lb/MMBtu 3-hour average			
NO _x		40 ppmv or 0.04 lb/MMBtu (30-day rolling average)	CEMS		
H ₂ S		≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header	
30H2 - Hydrogen Reformer Feed Furnace		Opacity	10%	CEMS	Stack test no later than October 31 of each year Stack test performed every 3 years
		PM ₁₀	0.00051 lb/MMBtu		
		NO _x	0.02 lb/MMBtu 3-hour average		
	NO _x	40 ppmv or 0.04 lb/MMBtu (30-day rolling average)	CEMS		
	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header	
	VOC			Must comply with LDAR program	
Unit 33 - Vacuum Unit 33H1 - Vacuum Furnace Heater	VOC			Must comply with LDAR program	
	Opacity	10%		Air preheater package installed (ILB.11.c)	

Summary of Allowable Limits and Monitoring Requirements at the Woods Cross Refinery

Emissions Unit	Parameter	Allowable Limit	Monitoring Approach	Comment
Emergency Natural Gas Engines				
SO₂ Emissions (all sources)		110.3 tons per rolling 12-month period 0.31 tons per day		
SO₂ Emissions (All sources except 4V82 FCC and 25FCC)		0.21 tons per day 74.9 tons per year		
PM₁₀ All Sources		100.3 tons per rolling 12-month period		
PM₁₀ Combustion Sources		47.5 tons per rolling 12-month period 0.13 tons per day		
NO_x All Sources		347.1 tons per rolling 12-month period 2.09 tons per day		

*all these are
south coast
agmd*

DRAFT

BOARD MEETING DATE: December 2, 2016

AGENDA NO. ##

PROPOSAL: Amend BACT Guidelines and Approve Charter for BACT Scientific Review Committee

SYNOPSIS: Periodically, staff proposes updates to Parts A and C of the Policy and Procedures of the BACT Guidelines for major and non-major polluting facilities as well as reports new Lowest Achievable Emission Rate and BACT determinations added to Parts B and D for major and non-major polluting facilities. Additionally, for the first time, the BACT Guidelines need to incorporate policy and procedures and determinations for facilities subject to prevention of significant deterioration for greenhouse gases. These actions are to amend the BACT Guidelines to make them consistent with recent changes to SCAQMD rules and regulations as well as state and federal requirements and approve a charter for the BACT Scientific Review Committee.

COMMITTEE: Stationary Source, September 16 and November 18, 2016;
Recommended for Approval

RECOMMENDED ACTIONS:

1. Determine that proposed amendments to the BACT Guidelines are exempt from the California Environmental Quality Act;
2. Approve Proposed Amendments to BACT Guidelines; and
3. Approve Proposed Charter for the SCAQMD BACT Scientific Review Committee detailing goals and objectives and membership of the BACT Scientific Review Committee.

Wayne Natri
Acting Executive Officer

NMM:AHB:JA

*I didn't print all this
- it is 333 pages. If it has
useful info, the web address
is [www.agmd.gov/search?g=
refinery_bact](http://www.agmd.gov/search?g=refinery_bact)
(leave a space)*

Background

SCAQMD's New Source Review (NSR) regulations require permit applicants to use Best Available Control Technology (BACT) for new sources, relocated sources and modifications to existing sources that may result in an emission increase of any nonattainment air contaminant, any ozone depleting compound (ODC) or ammonia. Regulation XIII–New Source Review also requires the Executive Officer to periodically publish BACT Guidelines that establish the procedures and the BACT requirements for commonly permitted equipment.

The BACT Guidelines are separated into parts for major polluting facilities and non-major polluting facilities. A facility is a major polluting facility if it emits, or has the potential to emit, a criteria air pollutant at a level that equals or exceeds the Regulation XXX Title V emission thresholds. Major polluting facilities that are subject to NSR are required by the Clean Air Act (CAA) to have the Lowest Achievable Emission Rate (LAER). The federal CAA requirement for LAER is implemented through BACT in the SCAQMD. The Part B BACT and LAER determinations for major polluting facilities are only examples of past determinations that help in determining LAER for new permit applications. The California Health & Safety Code (H&SC) Section 40405 defines state BACT similar to federal LAER and requires the application of BACT for all new and modified permitted sources subject to NSR. For non-major polluting facilities, minor source BACT (MSBACT) is as specified in Part D of the BACT Guidelines and determined in accordance with state law at the time an application is deemed complete. In updating Part D with new or more stringent MSBACT, SCAQMD must follow a more rigorous process than for major polluting facilities, including a cost-effectiveness analysis, notification of the public, presentation at a BACT Scientific Review Committee (BACT SRC) meeting and Board approval. SCAQMD also follows the criteria and process specified in H&SC Section 40440.11.

The BACT SRC was established as a standing committee by the Board on September 8, 1995. The BACT SRC was intended to enhance the public participation process with technical review and comments by a focused committee at periodic intervals, prior to the updates of the BACT Guidelines. Staff is proposing the establishment of a Charter that will provide BACT SRC members with an outline of the BACT SRC's mission, goals and objectives, and membership.

Proposed Amendments to the BACT Guidelines

The proposed amendments are to update the Overview, Parts A, B, C and D and to add Parts E and F of the BACT Guidelines to maintain consistency with recent changes to SCAQMD rules and state and federal requirements. The proposed amendments will not result in more stringent requirements than would otherwise occur. Therefore, it was not necessary for staff to evaluate the achieved-in-practice status nor cost effectiveness of the underlying technologies. The BACT SRC and other interested parties were provided with a detailed description of the proposed amended BACT Guidelines at

scheduled public meetings on May 11, 2016, September 27, 2016 and November 9, 2016. The proposed amendments to the Guidelines were posted on the SCAQMD website, and a 30-day public comment period commenced after the first two BACT SRC meetings. Comments by BACT SRC members and the general public along with staff responses are included in Attachment G.

Overview

The Overview consists of five chapters which provide an introduction to the BACT Guidelines and a summary of how BACT is implemented in the SCAQMD. The proposed amendments to the Overview section are primarily administrative in nature and intended to update and clarify content. A summary of the proposed Overview amendments is included in Attachment A with the complete proposed amended Overview included in Attachment B.

Part A – Policy and Procedures for Major Polluting Facilities

Part A describes the policy and procedures for major polluting facilities and explains what BACT is, why it is required, when it is required and how it is determined for major polluting facilities. The proposed amendments to Part A are to maintain consistency with existing and recent changes to SCAQMD rules and state and federal requirements. A summary of the proposed Part A amendments is included in Attachment A with the complete proposed amended Part A included in Attachment B.

Part B - LAER/BACT Determinations for Major Polluting Facilities

Part B consists of three sections: Section I contains listings of LAER/BACT determinations made by SCAQMD; Section II contains listings of LAER/BACT determinations for equipment in other air districts; and Section III contains listings of emerging control technologies. The proposed Part B LAER/BACT determinations of Section I are summarized below with the complete proposed determinations included in Attachment C. The other portions of Section I, and Sections II and III, are not included because they are not being updated.

Section I – SCAQMD LAER/BACT Determinations

Four new listings include “Flare, Oil and Gas Production” and three listings under “I.C. Engine-Emergency, Compression Ignition with PM Trap”.

The new “Flare, Oil and Gas Production” listing is for a Flare Industries/Bekaert CEB enclosed ground flare with clean enclosed burner rated at 27 MMBtu per hour. This flare is operated by Linn Operating, Inc., for process gas disposal and is located in the City of Brea. The flare was permitted with NO_x, VOC and CO emission levels of 15 ppm, 10 ppm and 10 ppm, respectively, all corrected to 3% O₂, which are below current BACT requirements for this type of flare. The flare commenced operation and was source tested in early 2013 and has operated since that time. The source test showed the flare complied with the NO_x, VOC and CO emission limits. In addition, a similar 17

MMBtu per hour flare by the same manufacturer has been included in the CARB BACT Clearinghouse with the same emission limits.

The “I.C. Engine-Emergency, Compression Ignition with PM Trap” listings are for three separate engines rated at 374 horsepower (hp), 755 hp and 2220 hp, all equipped with a CARB-verified diesel particulate filter and certified to meet the applicable EPA tier emission standards. These engines were permitted between 2011 and 2014 and have operated since that time.

Part C – Policy and Procedures for Non-Major Polluting Facilities

Part C describes the policy and procedures for non-major polluting facilities and explains what BACT is, why it is required, when it is required and how it is determined for non-major polluting facilities. The proposed updates to Part C are to maintain consistency with recent changes to SCAQMD rules and state and federal requirements. A summary of the proposed Part C amendments is included in Attachment A with the complete proposed amended Part C included in Attachment B.

Part D BACT Determinations for Non-Major Polluting Facilities

Part D consists of BACT determinations for minor sources which are determined in accordance with state law at the time an application is deemed complete. The proposed amendments to Part D are intended to maintain consistency with recent changes to SCAQMD rules and state and federal requirements. The proposed amendments will not result in more stringent requirements than would otherwise occur through rule compliance. Therefore, it was not required for staff to evaluate the achieved-in-practice status nor cost effectiveness of the underlying technologies. The proposed amendments comply with the requirements of California H&SC Section 40440.11. The proposed Part D BACT determinations are summarized below with the complete proposed amended Part D included in Attachment D.

Boilers

Background

SCAQMD Rules 1146 and 1146.1, addressing emissions of oxides of nitrogen from industrial, institutional, and commercial boilers, steam generators, and process heaters, were most recently approved by the Board on November 1, 2013. These rules apply to most gaseous fuel-fired boilers, steam generators and process heaters rated at greater than 2,000,000 Btu per hour, with the exception of utility boilers, refinery boilers and process heaters rated at greater than 40,000,000 Btu per hour, thermal fluid heaters and sulfur plant reaction boilers.

Proposal

Updated NOx concentration emissions requirements and additional subcategories are being proposed to the Boiler BACT listing to maintain consistency with the requirements in Rules 1146 and 1146.1.

Staff is recommending incorporating these limits into the BACT Guidelines now that the compliance deadlines have passed and all NOx emission limits are now required by these rules. Subcategories for "Propane Fired, > 2 MMBtu/hr and < 20 MMBtu/hr," "Natural Gas or Propane Fired, ≥ 20 MMBtu/hr and < 75 MMBtu/hr," "Natural Gas or Propane Fired, ≥ 75 MMBtu/hr," "Atmospheric Unit, ≥ 2 and ≤ 10 MMBtu/hr," "Landfill Gas Fired, < 75 MMBtu/hr" and "Digester Gas Fired, < 75 MMBtu/hr" will be added to the listing to maintain consistency with the definitions in Rules 1146 and 1146.1.

Portable Internal Combustion Engines

Background

The BACT Guidelines for portable compression ignition I.C. engines reflect the federal emission standards for non-road engines. EPA has established a multiple-tiered system for the emission standards for non-road I.C. engines, which includes portable engines. The Tier 4 emission standards were introduced in 2004 and have been completely phased in for most non-road engines as of January 1, 2015. The current BACT Guidelines list the Tier 2 and Tier 3 requirements for Compression Ignition engines.

Proposal

Staff is proposing to update the BACT Guidelines for portable I.C. Engines to reflect the requirements of the current Tier 4 standards. CARB adopted the same Tier 4 emission standards and schedule on December 7, 2005. These standards are only applicable to the Compression Ignition subcategory of this listing and will not affect the Spark Ignition engine requirements. However, until further notice, CARB has extended the deadline of the Tier 4 Final requirements, which will now be subject to higher Tier 4 Interim emission levels and are being incorporated into the BACT Guidelines for Portable, Compression-Ignition Engines $75 \leq \text{HP} < 175$ and $\text{HP} \geq 750$. Final Tier 4 requirements will be added to NOx, NMHC, "NOx+NMHC", CO and PM BACT emission standards for all the other listed ratings of Compression-Ignition portable I.C. Engines. These updates are all current requirements in 40 CFR Section 10301 Subpart B, 13 CCR Section 2420 et seq. and 17 CCR Section 93116.

Formatting changes in this BACT Listing were done to maintain consistency with the new standards. Most notably, the previous "NMHC+NOx" standard has been changed to separate NOx and NMHC standards for three of the four HP rating categories.

Stationary, Emergency, Internal Combustion Engines

Background

The BACT guidelines for the subcategories "Compression Ignition, Fire Pumps" as well as "Compression Ignition, Other" under the "I.C. Engine, Stationary, Emergency" listing reflect the federal emission standards for non-road engines as well as the CARB ATCM for Stationary Compression Engines 17 CCR Section 93115. As with the portable engines, EPA has established a tiered system for stationary I.C. engine

emission standards, which was adopted into the CARB ATCM. Currently, all I.C. engines rated greater than or equal to 50 HP and less than 750 HP are subject to the Tier 3 emission standards. Engines under these two subcategories that are rated greater than or equal to 750 HP are subject to the Tier 2 standards. In addition, these two subcategories are both subject to the requirements of SCAQMD Rule 1470 that was last amended on May 4, 2012. SCAQMD Rule 1470 sets emission standards for PM, primarily limited to new engines located at or near sensitive receptors, and NO_x + NMHC and CO that are consistent with EPA and CARB's tiered-emission standards.

The "Spark Ignition" subcategory is subject to the New Source Performance Standards (NSPS) under 40 CFR 60 Subpart JJJJ. The current BACT listing applies to all ratings of spark ignition I.C. engines and limits VOC emissions to 1.5 grams VOC/bhp-hr. Subpart JJJJ requires emergency spark ignition engines rated at greater than or equal to 130 HP to meet an emission standard of 1.0 grams VOC per brake horsepower-hour (/bhp-hr).

Proposal

Staff is proposing to add "Compliance with Rule 1470" for NO_x+NMHC and CO emission standards to the subcategories "Compression Ignition, Fire Pumps," and "Compression Ignition, Other". The current BACT listing already includes this requirement for the PM emission standard. In addition, staff is proposing to remove outdated diesel fuel standards from the SO_x emission standards for these two subcategories. The current SO_x standard required by SCAQMD Rule 431.2, which is also currently listed, will remain.

Staff is also proposing to remove the outdated Tier 2 references under the NO_x+NMHC standard and leave the current Tier 3 standards for "Compression Ignition, Fire Pumps".

For the Spark Ignition subcategory, staff proposes to separate the listing into two ratings: $50 \leq \text{HP} < 130$ and $\text{HP} \geq 130$. Engines rated $50 \leq \text{HP} < 130$ will be subject to the same existing requirements. Engines rated $\text{HP} \geq 130$ will be subject to the NSPS standard of 1.0 gram VOC/bhp-hr.

Staff is also proposing to delete previous footnotes for situations that are no longer applicable to the current standards due to compliance dates that have passed or rule changes.

Stationary, Non-Emergency, Non-Electrical Generators, Internal Combustion Engines

Background

Currently, Part D of the BACT Guidelines has a listing for "I.C. Engine, Stationary, Non-Emergency." Due to recent amendments to SCAQMD Rule 1110.2, "Emissions from Gaseous- and Liquid-Fueled Engines," staff has recognized the need for two major

categories under this listing and will be proposing two separate listings, “I.C. Engine, Stationary, Non-Emergency, Non-Electrical Generators,” and “I.C. Engine, Stationary, Non-Emergency, Electrical Generators.” At this time, only the former category will be added to the guidelines since analysis for the latter category is still in progress. The existing listing for “I.C. Engine, Stationary, Non-Emergency,” will remain until both new categories are implemented.

Qualifying engines under “I.C. Engine, Stationary, Non-Emergency” are subject to the requirements of Rule 1110.2. On February 1, 2008, the current NOx, VOC and CO concentration limits were adopted and fully implemented by 2010 for all engines, except landfill and digester gas (biogas) fired units. In 2012, a compliance deadline of January 1, 2016, was established for biogas-fired units to meet the same NOx, VOC and CO limits; however, the recent Rule 1110.2 amendment on December 4, 2015, extended the compliance date until January 1, 2017. In addition, an exemption was provided to biogas units with ongoing technology demonstration projects to extend the compliance date until January 1, 2018.

Proposal

Staff proposes to establish the category of “I.C. Engine, Stationary, Non-Emergency, Non-Electrical Generators.” The category of “I.C. Engine, Stationary, Non-Emergency” will remain unchanged. The new listing will incorporate the existing Rule 1110.2 limits and requirements listed below for all engines rated greater than 50 bhp.

ppmvd NOx @ 15% O ₂	ppmvd VOC ¹ @ 15% O ₂	ppmvd CO @ 15% O ₂
11	30	250

¹measured as carbon

Due to the extension allowed for biogas engines, the existing BACT limits will still apply for NOx, VOC and CO. A footnote will be added to indicate the compliance deadlines for biogas-fueled engines to meet the SCAQMD Rule 1110.2 limits for these contaminants. In addition, the SOx category will continue to require compliance with Rule 431.1.

Liquid Transfer and Handling

Background

Part D of the BACT Guidelines for Liquid Transfer and Handling currently lists three different subcategories for Marine, Loading and Tank Truck and Railcar Bulk Loading Classes A, B and C. The listing does not include a subcategory for Gasoline Transfer and Dispensing beyond the Bulk Loading subcategories.

Proposal

Staff is proposing to add an additional subcategory to Part D of the BACT Guidelines for "Gasoline Transfer and Dispensing." The subcategory will only be subject to VOC emission requirements, which will specify "Compliance with SCAQMD Rule 461." These facilities are already subject to the requirements of this rule, last amended on April 6, 2012. This proposal will incorporate the existing rule requirements into the BACT Guidelines for minor sources.

Non-Refinery Process Heater

Background

SCAQMD Rules 1146 and 1146.1, both titled "Emissions of Oxides of Nitrogen from (Small) Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters," were most recently approved by the Board on November 1, 2013. These rules apply to most gaseous fuel-fired boilers, steam generators and process heaters rated at greater than 2,000,000 Btu per hour, with the exception of utility boilers, refinery boilers and process heaters rated at greater than 40,000,000 Btu per hour, thermal fluid heaters and sulfur plant reaction boilers.

Proposal

To maintain consistency with the current requirements of Rules 1146 and 1146.1, staff is proposing to specify in the BACT listing for Process Heater-Non-Refinery under NOx "Compliance with SCAQMD Rules 1146 and 1146.1." This proposal will incorporate the existing rule requirements into the BACT Guidelines for minor sources.

Oil and Gas Production

Background

SCAQMD Rules 1148, Thermally Enhanced Oil Recovery Wells, and 1148.1, Oil and Gas Production Wells, apply to oil and gas production operations and specifically Rule 1148.1 was recently amended and approved by the Board on September 4, 2015.

Proposal

To maintain consistency with the current requirements of Rules 1148 and 1148.1, staff is proposing to specify in the BACT listing for Oil and Gas Production under VOC "Compliance with SCAQMD Rules 1148 and 1148.1." This proposal will incorporate the existing rule requirements into the BACT Guidelines for minor sources.

Proposed New Part E-Policy and Procedures for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases

Background

For the first time, GHG emissions from the largest stationary sources are covered by the Prevention of Significant Deterioration (PSD) and Title V Operating Permit Programs beginning January 2, 2011. These permitting programs, required under the Clean Air Act, are proven tools for protecting air quality and the same tools will be used to reduce

GHG emissions. The SCAQMD is currently required to implement the GHG BACT requirements through its permitting program.

40 CFR 52.21, amended in both May 2010 and October 2015, established an approach to permit GHG emissions under PSD and Title V. Through this rule, permitting focused on the major industrial sources, which emit nearly 70 percent of the greenhouse gas pollution from stationary sources. At this time, lesser-emitting sources are not subject to these requirements.

The requirements of this rule apply only to GHG as defined by EPA as a total group of six GHG which are: carbon dioxide (CO₂), nitrous oxide (N₂O), methane (CH₄), hydrofluorocarbons (HFC), perfluorocarbons (PFC) and sulfur hexafluoride (SF₆). All other attainment air contaminants, as defined in SCAQMD Rule 1702 subdivision (a), shall be regulated for the purpose of PSD.

Proposal

To maintain consistency with current federal GHG permitting requirements, staff is proposing to add Part E to the BACT Guidelines. This part summarizes the requirements of GHG BACT regulations according to EPA, describes the Top-Down Process, explains how to calculate GHG emissions and explains PSD Applicability for GHGs for new and modified sources. 40 CFR 52.21 was recently revised to address the U.S. Supreme Court decision in *Utility Air Regulatory Group v. Environmental Protection Agency*, 134 S. Ct. 2427 (2014)19, regarding the applicability of PSD and GHG BACT. The guidance in this chapter is applicable to the EPA requirements in place as of the date of these guidelines, as well as SCAQMD Rule 1714, which incorporates most of 40 CFR 52.21 by reference. Proposed Part E is included in Attachment B.

Proposed New Part F—BACT Determinations for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases

Background

Similar to Part B, proposed new Part F will consist of Section I with listings of GHG BACT determinations made by SCAQMD, Section II with listings of GHG BACT determinations for equipment in other air districts, and Section III with listings of emerging GHG BACT control technologies.

Proposal

Staff is proposing to add Part F and bring new GHG BACT determinations for Board approval as they become available for inclusion into Part F. At this time, there are no GHG BACT listings to be proposed; however, staff is in the process of identifying potential GHG BACT for future listings. Proposed Part F is included in Attachment B.

Proposed Amendments to List of Abbreviations and Index of Equipment Categories

Staff is proposing to update the List of Abbreviations by the addition of the following: California Air Resources Board (CARB), Carbon Capture and Sequestration (CCS), Carbon Dioxide (CO₂), Carbon Dioxide Equivalent (CO₂e), Greenhouse Gas (GHG), Global Warming Potential (GWP), Maximum Individual Cancer Risk (MICR), Lead (Pb), Particulate Matter less than 2.5 microns in diameter (PM_{2.5}), Prevention of Significant Deterioration (PSD), Potential to Emit (PTE), RECLAIM Trading Credit (RTC), South Coast Air Quality Management District (SCAQMD replaced AQMD) and Best Available Control Technology for Toxics (T-BACT).

To be consistent with the function of the Index of Equipment Categories, staff is proposing to rename it to List of Equipment Categories. The proposed amendments to this list are administrative in nature and consist of having the same equipment categories as those in Parts B, D and F and included in Attachment B.

Proposed Charter for BACT Scientific Review Committee

Staff is proposing the establishment of a Charter for the BACT SRC, which details the BACT SRC's goals and objective, the composition and selection of the BACT SRC membership, the desired qualifications of its membership and the operational guidelines for the BACT SRC. The proposed Charter for the BACT SRC is included in Attachment E.

Presentation to BACT Scientific Review Committee

The proposed amendments to the BACT Guidelines were presented to the BACT SRC at the publicly noticed May 11, 2016 meeting. A 30-day period was provided to the BACT SRC and general public to review and submit comments. At the September 16, 2016 Stationary Source Committee, staff was directed to hold a follow-up BACT SRC meeting; a meeting was held on September 27, 2016 to address additional comments on the Proposed Amended BACT Guidelines. At the request of BACT SRC members and the public an additional 30-day comment period was provided to review and submit comments. The proposed amended BACT Guidelines along with staff response to comments was, for the third time, presented to the BACT SRC at a publicly noticed meeting on November 9, 2016. Comments by BACT SRC members and the general public along with staff responses are included in Attachment G.

California Environmental Quality Act (CEQA)

SCAQMD staff has reviewed the proposed amendments to the BACT Guidelines, pursuant to CEQA Guidelines, pursuant to CEQA Guidelines Section 15002(k)(1) and Section 15061, and determined them to be exempt from CEQA pursuant to CEQA Guidelines Section 15061(b)(3). Since the proposed amendments are only updating the BACT Guidelines with current, already existing requirements, it can be seen with

certainty that the proposed project has no potential to adversely impact air quality or any other environmental topic area.

Socioeconomic Analysis

The proposed amendments of the BACT Guidelines are to maintain consistency with recent changes to SCAQMD rules and state and federal requirements. These proposed amendments are administrative in nature and will therefore not result in more stringent requirements than would otherwise occur and would not result in any adverse socioeconomic impacts.

Benefits to SCAQMD

Emission reductions realized through permitted sources that apply the latest BACT will benefit air quality, achieve emissions reductions needed to attain air quality standards and improve public health in the SCAQMD's jurisdiction. In addition, the successful implementation of BACT for permitted stationary sources will contribute towards achieving the air quality objectives of SCAQMD's Air Quality Management Plan.

Resource Impacts

Existing SCAQMD resources will be sufficient to implement the proposed changes to the BACT Guidelines.

Recommendation

This Board letter serves as staff's report to the Board on proposed amendments to the BACT Guidelines. The updated BACT Guidelines with these amendments are scheduled to be made available at SCAQMD's website at <http://www.aqmd.gov/home/permits/bact>, pending Board approval.

These actions are to determine that proposed amendments to the BACT Guidelines are exempt from the California Environmental Quality Act, approve proposed amendments to the BACT Guidelines, and approve the proposed Charter for the SCAQMD BACT Scientific Review Committee.

Attachments

- A. Summary of Proposed Amendments to BACT Guidelines
- B. Proposed Amended BACT Guidelines Overview, Parts A, C, E and F
- C. Proposed Amended BACT Guidelines Part B
- D. Proposed Amended BACT Guidelines Part D
- E. Proposed Charter for BACT Scientific Review Committee
- F. Notice of Exemption from the California Environmental Quality Act
- G. Comments and Responses

Single underline/~~Single Strikeout~~ text shows new language
added/deleted as of October 7, 2016 Board Package.

Double underline/~~Double Strikeout~~ text shows new language
added/deleted subsequent to October 7, 2016 Board Package.

PROPOSED BACT GUIDELINES

ATTACHMENT A

SUMMARY

Attachment A

SUMMARY OF PROPOSED AMENDMENTS TO BACT GUIDELINES

The following summarizes the key proposed amendments to the BACT Guidelines:

Overview

Chapter 1 - Introduction

-  Toxic BACT (T-BACT) reference
-  Description for addition of Parts E and F to address Prevention of Significant Deterioration (PSD) requirements for GHG emissions established by U.S. EPA
-  BACT Docket information updated
-  Hyperlinks added for Web pages and email

Chapter 2 – Applicability Determination

-  Added PM_{2.5} and updated SO_x threshold levels on Table 1
-  Clarification of GHG BACT emission threshold applicability in Table 1
-  Updated map of SCAQMD, Figure 1

Chapter 3 – When is BACT Required?

-  Carbon monoxide attainment and BACT requirement
-  Added reference to Lead Rules 1420.1 and 1420.2
-  Chlorobromomethane added to Table 2 – Class I Substances (ODCs)
-  Added PM_{2.5} to Table 3

Chapter 4 – What is BACT?

-  PSD Rules BACT applicability

Chapter 5 – Review of Staff BACT Determinations

-  Background, goals and objectives and membership of the Scientific Review Committee

Part A

Chapter 1 – How is LAER Determined for Major Polluting Facilities?

-  Added section on Federal PM_{2.5} New Source Review and SCAQMD Rule 1325
-  Super “Clean” Materials clarified as Super “Compliant” Materials to be consistent with SCAQMD Rule 109 definition
-  Added section on Other Considerations for Pollution Prevention, Monitoring and Testing and Capture Efficiency

- F
P
1 Clean Fuels Policy clarified as also including electricity as a clean fuel, as well as zero and near-zero emission technologies ~~Industrial Electrification~~

Part B

The following LAER/BACT listings will be included in Part B:

- F
P
1 I.C Engines (3), Emergency, Compression Ignition with Diesel Particulate Filter
 - 374 BHP
 - 755 BHP
 - 2220 BHP

- F
W
P
1 Flare, Oil and Gas Operations

Part C

Chapter 1 – How is MSBACT Determined for Minor Polluting Facilities?

- F
P
1 Clarified that dates on Part D Determinations do not exempt equipment from complying with new requirements or limits implemented after that date
- F
W
P
1 Updated Maximum Cost Effectiveness Values
- F
W
P
1 Added section on BACT Top-Down Cost Methodology
- F
P
1 Clean Fuels Policy clarified as also including Industrial Electrification
- P
D
P
1 Updated Figure 2 flowchart: The Ongoing BACT Update Process

Chapter 2 – How to Use Part D of the MS BACT Guidelines?

- P
D
P
1 Super “Clean” Materials clarified as Super “Compliant” Materials to be consistent with definition
- P
D
P
1 Added section on Other Considerations for Pollution Prevention, Monitoring and Testing and Capture Efficiency

Part D

All of the following Part D listings are proposed to be updated to the current SCAQMD and state and federal requirements. In certain cases, new listings, categories and subcategories were created for consistency with the requirements.

- P
D
P
1 Boiler
- P
D
P
1 I.C. Engine, Portable
- P
D
P
1 I.C. Engine, Stationary Emergency

- I.C. Engine, Stationary, Non-Emergency, Non-Electrical Generators
- Liquid Transfer and Handling
- Oil and Gas Production
- Process Heater - Non-Refinery

Part E

Part E was added to address the policies and procedures set forth in EPA's GHG Program under 40 CFR 52.21, which is incorporated by reference under SCAQMD Rule 1714.

The following sections were added under Part E:

- Background
- Permitting Guidance for GHG
- Federal PSD Applicability for GHG
- SCAQMD PSD Applicability for GHG
- Top-Down BACT Process
- GHG Control Measures White Papers

Part F

This section is reserved for future GHG BACT listings. There are currently no proposed GHG listings.

PROPOSED BACT GUIDELINES
ATTACHMENT B
OVERVIEW, and PARTS A, C, E and F

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Best Available Control Technology Guidelines

OVERVIEW

- Part A: Policy and Procedures for Major Polluting Facilities**
- Part B: LAER/BACT Determinations for Major Polluting Facilities**
- Part C: Policy and Procedures for Non-Major Polluting Facilities**
- Part D: BACT Guidelines for Non-Major Polluting Facilities**
- Part E: Policy and Procedures for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases**
- Part F: BACT Determinations for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases**

August 17, 2000 (Revised June 6, 2003; December 5, 2003; July 9, 2004; July 14, 2006; ~~October 7, 2016~~ December 2, 2016)

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OVERVIEW

Chapter 1 - Introduction

The South Coast Air Quality Management District (SCAQMD) Regulation XIII – New Source Review (NSR) and Regulation XX – RECLAIM, require applicants to use Best Available Control Technology (BACT) for new sources, relocated sources, and for modifications to existing sources that may result in an emission increase of any nonattainment air contaminant, any ozone depleting compound (ODC), or ammonia. Regulation XIII requires the Executive Officer to periodically publish BACT Guidelines that establish the procedures and the BACT requirements for commonly permitted equipment. SCAQMD Regulation XIV – Toxics and Other Non-Criteria Pollutants, requires applicants to use Best Available Control Technology for Toxics (T-BACT) for new, relocated or modified permit units that result in a cumulative increase in Maximum Individual Cancer Risk (MICR) of greater than one in a million (1.0×10^{-6}) at any receptor location. Additionally, Regulation XVII – Prevention of Significant Deterioration (PSD) also sets forth BACT requirements for new sources, relocated sources and modifications to existing sources that emit attainment air contaminants. Regulation XIII requires the Executive Officer to periodically publish BACT Guidelines that establish the procedures and the BACT requirements for commonly permitted equipment. PSD BACT is incorporated into these BACT Guidelines. As of the publication date of these guidelines, there is currently not a requirement for SCAQMD to publish T-BACT guidelines and T-BACT must be established during the permitting process. The BACT Guidelines were first published in May 1983, and later revised in October 1988.

Historically, the BACT Guidelines were first published in May 1983, and later revised in October 1988. The Guidelines consisted of two parts: Part A – Policy and Procedures, and Part B – BACT Determinations. Part A provided an overview and general guidance while Part B contained specific BACT information by source category and pollutant. Since the October 1988 revision, Part A was amended once in 1995, and Part B was updated with six LAER determination times between 1997 and 1998.

On December 11, 1998, the Governing Board approved a new format for listing BACT determinations in Part B of the Guidelines. While the previous Part B of the BACT Guidelines specified BACT requirements and set out source category determinations which could be interpreted as definitive, the new format simply provides listings of recent BACT determinations by SCAQMD permitting staff and others as well as information on new and emerging technologies. Part B of the SCAQMD BACT Guidelines now follows the same outline as the permit listings in the California Air Resources Board State BACT Clearinghouse Database, which is managed under the direction of the California Air Pollution Control Officers Association's (CAPCOA) Engineering Managers Committee, and coordinates the ~~submission of~~ In addition, BACT determinations made by the districts SCAQMD are submitted to the U.S. Environmental Protection Agency (USEPA) RACT/BACT/LAER Clearinghouse by ARB staff, California Air Pollution Control Officer Association (CAPCOA) BACT Clearinghouse and the United States Environmental Protection Agency (USEPA) RACT/BACT/LAER Clearinghouse. Further information on the new format of the Guidelines, including reasons for the change in direction, may be found in Board Letters presented at the October 1998

Board Meeting, Agenda No. 41, and the December 1998 Board Meeting, Agenda No. 28.

The public participation process ~~was also enhanced to~~ includes technical review and comments by a focused BACT Scientific Review Committee (BACT SRC) at periodic intervals, prior to the updates of the SCAQMD BACT Guidelines. ~~At the same time,~~ ~~†~~The Board established a 30-day notice period for the BACT SRC and interested persons to review and comment on SCAQMD BACT determinations that result in BACT requirements that are more stringent than previously imposed BACT.

As a result of amendments ~~being proposed to~~ SCAQMD's New Source Review (NSR) regulations in September 2000, the BACT Guidelines ~~was/were~~ be separated into two sections: one for major polluting facilities and another for non-major (minor) polluting facilities. (See Chapter 2 in the Overview for how to determine if a facility is major or minor).

The BACT Guidelines for major polluting facilities include:

- 15 Part A: Policy and Procedures for Major Polluting facilities, ~~and~~
- 16 Part B: LAER/BACT Determinations for Major Polluting Facilities.

The BACT Guidelines for non-major polluting facilities include:

- 17 Part C: Policy and Procedures for Non-Major Polluting Facilities, ~~and~~
- 18 Part D: BACT Guidelines for Non-Major Polluting Facilities.

Both the format of the guidelines and the process for determining BACT are significantly different between major and non-major polluting facilities. Major polluting facilities that are subject to NSR are required by the Clean Air Act to have the Lowest Achievable Emission Rate (LAER). LAER is determined at the time the permit is issued, with little regard for cost, and pursuant to USEPA's LAER policy as to what is achieved in practice. The Part B BACT and LAER determinations for major polluting facilities are only examples of past determinations that help in determining LAER for new permit applications.

For non-major polluting facilities, BACT will be determined in accordance with state law at the time an application is deemed complete unless a more stringent rule requirement becomes applicable prior to permit issuance. For the most part, it will be as specified in Part D of the BACT Guidelines. Changes to Part D for minor source BACT (MSBACT) to make them more stringent will be subject to public review and SCAQMD Board approval, in view of cost for considerations of cost.

For the 2016 amendment to the Guidelines, additional parts have been added to address PSD requirements for greenhouse gas (GHG) emissions established by U.S. EPA in 40 CFR 52.21 in 2011. The requirements are incorporated by reference in SCAQMD Rule 1714. The BACT Guidelines for GHG requirements include:

- 19 Part E: Policy and Procedures for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases; and
- 20 Part F: BACT Determinations for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases.

In order to distinguish between BACT for major sources and ~~BACT for minor~~ various sources, this document will use the following nomenclature for BACT:

LAER for BACT at major polluting facilities

MSBACT for BACT at non-major polluting facilities

PSD/CHG BACT for BACT at facilities subject to PSD/CHG BACT requirements for criteria pollutants

Written comments about the BACT Guidelines are welcome at any time and will be evaluated by SCAQMD staff and included in the BACT Docket at the SCAQMD library. These comments should be addressed to:

South Coast Air Quality Management District
BACT Docket
Science and Technology Advancement
21865 Copley Dr.
Diamond Bar, CA 91765-0934

Comments may also be submitted via email to BACTTeam@aqmd.gov, and should include BACT Docket in the subject line.

The BACT Guidelines are available without charge from SCAQMD's web site at www.aqmd.gov/home/permits/bact. A hardcopy of the BACT Guidelines may be obtained for a fee by submitting a request to contacting Subscription Services at www.aqmd.gov/contact/subscription-services or at the above address or by calling (909) 396-3720. Revisions to the guidelines will be mailed to all persons that have purchased annual updates to the BACT Guidelines. The BACT Guidelines are also available without charge from SCAQMD's Internet web site at <http://www.aqmd.gov/home/permits/bact> <http://www.aqmd.gov/bact>.

Chapter 2 – Applicability Determination

This chapter explains how to determine whether a facility is a major or minor polluting facility, and how a facility can become a minor polluting facility.

MAJOR POLLUTING FACILITY EMISSION THRESHOLDS

A facility is a major polluting facility (or a major stationary source as it is called in the federal Clean Air Act [CAA]) if it emits, or has the potential to emit (PTE), a criteria air pollutant at a level that equals or exceeds emission thresholds specified given in the CAA¹ based on the attainment or nonattainment status. Table 1 presents shows those emission thresholds for each criteria air pollutant for each air basin in SCAQMD. The map in Figure 1 shows the location of the three air basins in SCAQMD. If a threshold for any one criteria pollutant is equaled or exceeded, the facility is a major polluting facility, and will be subject to LAER for all pollutants subject to NSR. Currently Although Table 1 is part of determining GHG BACT applicability, Table 1 does not include emission thresholds that trigger GHG BACT for SCAQMD Rule 1714 and 40 CFR 52.21. Subpart E of the BACT Guidelines should be referenced for a detailed explanation of how GHG BACT emission thresholds are determined.

A facility includes all sources located within contiguous properties owned or operated by the same person, or persons under common control. Contiguous means in actual contact or separated only by a public roadway or other public right-of-way. However, on-shore crude oil and gas production facilities under the same ownership or use entitlement must be included with offshore crude oil and gas production facilities located in Southern California Coastal or Outer Continental Shelf waters.

The following mobile source emissions are also considered as part of the facility²:

1. Emissions from in-plant vehicles; and
2. All emissions from ships during the loading or unloading of cargo and while at berth where the cargo is loaded or unloaded; and
3. Non-propulsion ship emissions within Coastal Waters under SCAQMD jurisdiction.

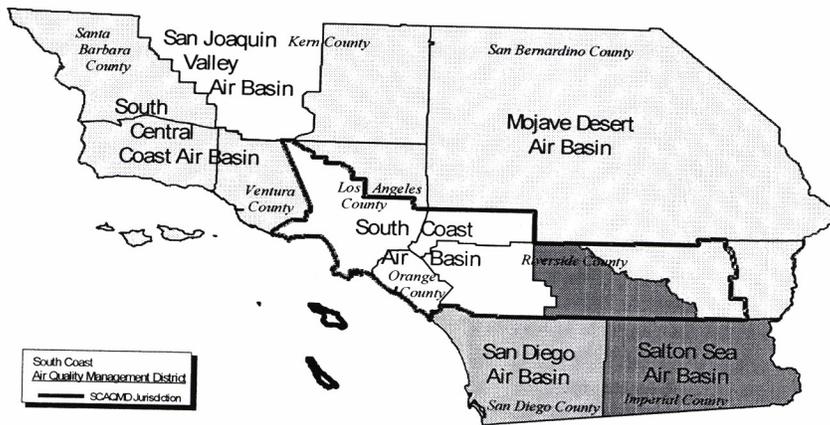
¹ The major source emission thresholds are higher for air basins that comply with the national ambient air quality standard and lower depending on how far an air basin is from compliance with the standard for a pollutant. The lowest thresholds apply to extreme non-attainment air basins, the only example ones of which are the South Coast Air Basin and San Joaquin Valley Air Basin for ozone (VOC and NOx).

² In accordance with Rule 1306(g).

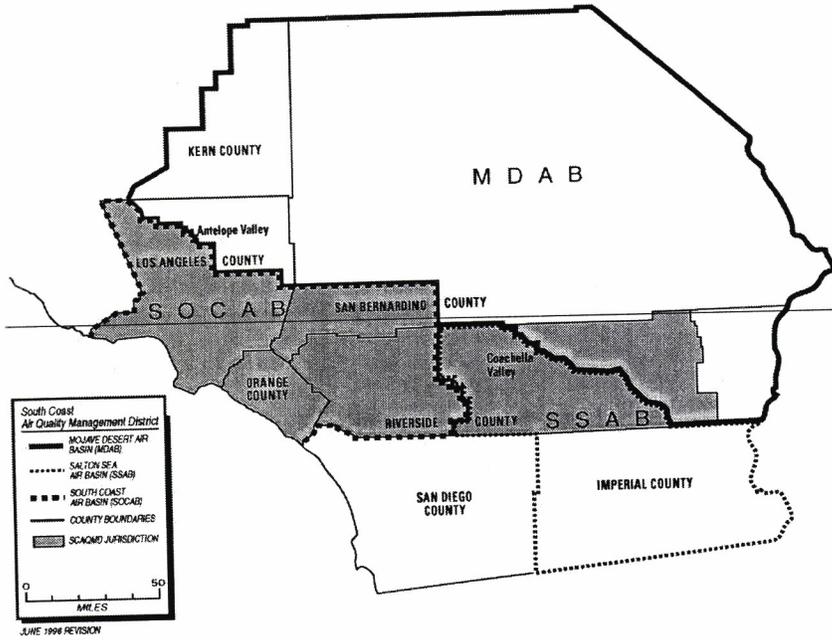
Table 1
Actual or Potential Emission Threshold Levels (Tons per Year)
for Major Polluting Facilities

Pollutant	South Coast Air Basin	Riverside County Portion of Salton Sea Air Basin	Riverside County Portion of Mojave Desert Air Basin
VOC	10	25	100
NO _x	10	25	100
³ SO _x	70 ⁴⁰⁰	70 ⁴⁰⁰	100
CO	50	100	100
PM ₁₀	70	70	100
PM _{2.5}	70 ⁴⁰⁰	---	---

Figure 1: Map of SCAQMD



³ The threshold for SO_x, as a precursor for PM, is 70 tons per year for serious PM₁₀ areas, which the SCAB previously was, and 70 tons per year for serious PM_{2.5} areas, which the SCAB currently is. Rule 1302 previously currently specified 100 tons per year, which was in error, and was being changed/erected at the November 2016 Board Meeting.



POTENTIAL TO EMIT

Potential to emit (PTE) is based on permit conditions that limit emissions or throughput. If there are no such permit conditions, PTE is based on:

- the maximum rated capacity; and
- the maximum daily hours of operation; and
- physical characteristics of the materials processed.

The PTE must include fugitive emissions associated with the source. RECLAIM emission allocations are not considered emission limits because RECLAIM facilities may purchase RTCs and increase their emissions without modifying their permit. For PSD purposes, as well as Rule 1325 for PM_{2.5}, which incorporates federal requirements, fugitive emissions are included only for major source categories specifically identified in 40 CFR 52.21.

LIMITING POTENTIAL TO EMIT

A facility's PTE can be capped by an enforceable permit condition that limits emissions. This condition will likely involve monitoring, recordkeeping and reporting to ensure that emissions remain below the permit limit.

Chapter 3 - When is BACT Required?

This chapter explains when BACT is required by identifying the air pollutants subject to BACT, the permit actions that trigger BACT review, and the calculation procedures to determine emission increases.

POLLUTANTS SUBJECT TO NSR, PSD AND BACT

The SCAQMD's New Source Review (NSR) programs include *Regulation XIII - New Source Review* and *Rule 2005 - New Source Review for RECLAIM*. Rule 2005 applies only to NO_x and SO_x emissions from RECLAIM facilities, while Regulation XIII applies to other non-attainment air pollutants from RECLAIM facilities, all non-attainment air pollutants from all other facilities, and ammonia and ozone-depleting compound (ODC) emissions from all facilities. ODCs are defined as Class I substances listed in 40 CFR, Part 82, Appendix A, Subpart A, and are listed in Table 2. Rule 1325 specifically applies to PM_{2.5}.

Although the SCAQMD is in attainment with the ambient air quality standards for SO₂ and NO₂, NO_x is a precursor to ozone, and both SO_x and NO_x are precursors to PM₁₀ and PM_{2.5}, which are non-attainment air pollutants. Therefore, SO_x and NO_x are treated as non-attainment air pollutants as well, including ozone. The net result is that VOC, NO_x, SO_x, and PM₁₀ and PM_{2.5} are subject to NSR in all of SCAQMD.

while CO is only subject to NSR in the South Coast Air Basin (SOCAB).

The South Coast Air Basin has historically been had a persistent designated nonattainment for CO problem. However, there has been considerable improvement in CO air quality in the Basin from 1976 to 2005. In 2001, the Basin met both the federal and state 8-hour CO standards for the first time at all monitoring stations. The 2003 AQMP revision to the CO plan served a dual purpose; it replaced the 1997 attainment demonstration that lapsed at the end of 2000, and it provided the basis for a CO maintenance plan in the future. The Basin was designated as attainment for CO in 2007. Therefore, CO is no longer a nonattainment pollutant, since the state standard for CO is the same as the federal. Therefore, CO is in attainment with state and federal ambient air quality standards.

The SCAQMD's Regulation XVII - Prevention of Significant Deterioration sets forth BACT requirements for stationary sources that emit attainment air contaminants. The BACT requirement applies to any net emission increase of a criteria pollutant from a permit unit at any source. Similar to the Regulation XIII NSR requirements, precursors to attainment air contaminants, would also be treated as attainment air contaminants, unless they also qualify as a nonattainment air contaminant, or nonattainment precursor as well. As explained in the SCAQMD Staff Report for Regulation XVII dated September 28, 1998 for the October 7, 1988 Board meeting, the PSD BACT requirement is applicable to all permit units regardless if the source is classified as a minor or major facility.

~~Lead (Pb) is a criteria air pollutant and is subject to BACT in areas of non-attainment, or is subject to PSD in areas of attainment. Although the SCAQMD complies with the ambient air quality standards for lead (Pb), Pb can be a component of a source's PM₁₀ emissions and is therefore subject to BACT for PM₁₀. BACT for Pb will be BACT for PM₁₀ or compliance with Rules 1420 or, 1420.1 or 1420.2, whichever is more stringent. In addition, non-attainment pollutants include inorganic gases such as hydrogen chloride (HCl) and hydrogen fluoride (HF), which are precursors to PM₁₀, and hydrogen sulfide (H₂S), a precursor to SO₂.~~

The applicability of the various pollutants to NSR in the various air basins is summarized in Table 3. See Figure 1 in the previous chapter for a map of SCAQMD that shows the location of the three air basins in SCAQMD.

Table 2
Class I Substances (ODCs)*

<p>A. Group I: CFCl_3 Trichlorofluoromethane (CFC-11) CF_2Cl_2 dichlorodifluoromethane (CFC-12) $\text{C}_2\text{F}_3\text{Cl}_3$ Trichlorotrifluoroethane (CFC-113) $\text{C}_2\text{F}_4\text{Cl}_2$ Dichlorotetrafluoroethane (CFC-114) $\text{C}_2\text{F}_5\text{Cl}$ Monochloropentafluoroethane (CFC-115) All isomers of the above chemicals</p> <p>B. Group II: CF_2ClBr Bromochlorodifluoromethane (Halon-1211) CF_3Br Bromotrifluoromethane (Halon-1301) $\text{C}_2\text{F}_4\text{Br}_2$ Dibromotetrafluoroethane (Halon-2402) All isomers of the above chemicals</p> <p>C. Group III: CF_3Cl Chlorotrifluoromethane (CFC-13) C_2FCl_5 (CFC-111) $\text{C}_2\text{F}_2\text{Cl}_4$ (CFC-112) C_3FCl_7 (CFC-211) $\text{C}_3\text{F}_2\text{Cl}_6$ (CFC-212) $\text{C}_3\text{F}_3\text{Cl}_5$ (CFC-213) $\text{C}_3\text{F}_4\text{Cl}_4$ (CFC-214) $\text{C}_3\text{F}_5\text{Cl}_3$ (CFC-215) $\text{C}_3\text{F}_6\text{Cl}_2$ (CFC-216) $\text{C}_3\text{F}_7\text{Cl}$ (CFC-217) All isomers of the above chemicals</p> <p>D. Group IV: CCl_4 Carbon Tetrachloride</p> <p>E. Group V: $\text{C}_2\text{H}_3\text{Cl}_3$ 1,1,1 Trichloroethane (Methyl chloroform) All isomers of the above chemical except 1,1,2-trichloroethane</p> <p>F. Group VI: CH_3Br Bromomethane (Methyl Bromide)</p> <p>H. Group VIII: CH_2BrCl (Chlorobromomethane)</p>	<p>G. Group VII: CHFBr_2 CHF_2Br (HBFC-2201) CH_2FBr C_2HFBr_4 $\text{C}_2\text{HF}_2\text{Br}_3$ $\text{C}_2\text{HF}_3\text{Br}_2$ $\text{C}_2\text{HF}_4\text{Br}$ $\text{C}_2\text{H}_2\text{FBr}_3$ $\text{C}_2\text{H}_2\text{F}_2\text{Br}_2$ $\text{C}_2\text{H}_2\text{F}_3\text{Br}$ $\text{C}_2\text{H}_2\text{FBr}_2$ $\text{C}_2\text{H}_3\text{F}_2\text{Br}$ $\text{C}_2\text{H}_4\text{FBr}$ C_3HFBr_6 $\text{C}_3\text{HF}_2\text{Br}_5$ $\text{C}_3\text{HF}_3\text{Br}_4$ $\text{C}_3\text{HF}_4\text{Br}_3$ $\text{C}_3\text{HF}_5\text{Br}_2$ $\text{C}_3\text{HF}_6\text{Br}$ $\text{C}_3\text{H}_2\text{FBr}_5$ $\text{C}_3\text{H}_2\text{F}_2\text{Br}_4$ $\text{C}_3\text{H}_2\text{F}_3\text{Br}_3$ $\text{C}_3\text{H}_2\text{F}_4\text{Br}_2$ $\text{C}_3\text{H}_2\text{F}_5\text{Br}$ $\text{C}_3\text{H}_3\text{FBr}_4$ $\text{C}_3\text{H}_3\text{F}_2\text{Br}_3$ $\text{C}_3\text{H}_3\text{F}_3\text{Br}_2$ $\text{C}_3\text{H}_3\text{F}_4\text{Br}$ $\text{C}_3\text{H}_4\text{FBr}_3$ $\text{C}_3\text{H}_4\text{F}_2\text{Br}_2$ $\text{C}_3\text{H}_4\text{F}_3\text{Br}$ $\text{C}_3\text{H}_5\text{FBr}_2$ $\text{C}_3\text{H}_5\text{F}_2\text{Br}$ $\text{C}_3\text{H}_6\text{FBr}$</p> <p>H. Group VIII: CH_2BrCl (Chlorobromomethane)</p>
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* 40 CFR, Part 82, Appendix A, Subpart A

Table 3
 Applicability of NSR and BACT to Various Pollutants in
 South Coast Air Basin (SOCAB), Salton Sea Air Basin (SSAB),
 and Mojave Desert Air Basin (MDAB)

Air Basin	VOC	NOx	SOx	CO	PM ₁₀	PM _{2.5}	NH ₃	Pb	ODC
SOCAB	<input type="checkbox"/>								
SSAB	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>		<input type="checkbox"/>		<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
MDAB	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>		<input type="checkbox"/>		<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

PERMIT ACTIONS SUBJECT TO NSR, PSD AND BACT

SCAQMD's NSR and PSD regulations are preconstruction permit review programs that require the Executive Officer to deny a permit to construct unless the proposed equipment includes BACT when:

- new equipment is installed;
- existing stationary permitted equipment is relocated; or
- existing permitted equipment is modified such that there is an emission increase.

If the new equipment is to replace the same kind of equipment, NSR⁴ still requires BACT unless it is an identical replacement, which does not require a new permit according to paragraph (c)(3) of Rule 219 -Equipment Not Requiring a Written Permit Pursuant to Regulation II, as amended May 19, 2000.

BACT is not required for a change of operator, provided the facility is a continuing operation at the same location, without modification or change in operating conditions.

In case of relocation of a non-major facility, the facility operator may opt out of installing MSBACT, provided that the owner/operator meets the conditions specified in Rule 1302 (ai) and Rule 1306 (d)(3).⁵

PSD applies to GHG if the source is otherwise subject to PSD for another regulated NSR pollutant and the source is new with has a GHG PTE ≥ 75,000 tons per year CO₂e, or an existing source with a modification resulting in a similar GHG emissions increase.

It is SCAQMD policy that BACT is required only for emission increases greater than or equal to one (1.0) pound per day.

CALCULATION PROCEDURES FOR EMISSION INCREASES

The calculation procedures for determining whether there is an increase in emissions from an equipment modification that triggers BACT are different for NOx

⁴ See Rules 1303(a) and 1304(a).

⁵ USEPA has expressed concerns with this provision of the NSR Rules for minor polluting facilities as of September 2000. Staff will continue to work with USEPA to resolve this issue.

and SOx pollutants from RECLAIM facilities and than for all other cases. In general, the calculation procedures for RECLAIM facilities are less likely to result in an emission increase that requires BACT.

For NOx and SOx emissions from a source at a RECLAIM facility, there is an emission increase if the maximum hourly potential to emit is greater after the modification than it was before the modification.⁶

For modifications subject to Regulation XIII, there are two possible cases⁷:

1. If the equipment was previously subject to NSR, an emission increase occurs if the new potential to emit in one day is greater than the previous potential to emit in one day.
2. If the equipment was never previously subject to NSR, an emission increase occurs if the new potential to emit in one day exceeds the actual average daily emissions over the two-year period, or other appropriate period, prior to the permit application date. However, for the installation of air pollution controls on any source constructed prior to the adoption of the NSR on October 8, 1976 for the sole purpose of reducing emissions, Rule 1306(f) allows the emission change to be calculated as the post-modification potential to emit minus the pre-modification potential to emit.

The potential to emit is based on permit conditions that directly limit the emissions, or, if there are none, then the potential to emit is based on:

- a) maximum rated capacity; and
- b) the maximum daily hours of operation; and
- c) the physical characteristics of the materials processed.

⁶ See Rule 2005(d).

⁷ See Rule 1306(d)(2).

Chapter 4 - What is BACT?

This chapter explains the definitions of BACT found in SCAQMD rules, state law and federal law.

NSR RULES (REGULATION XIII)

New sources, relocations, and modifications of existing sources that increase nonattainment air contaminant emissions are subject to New Source Review (NSR) regulations which require BACT, among other requirements. Both federal and state laws require this strategy. The federal Clean Air Act (CAA) requirement for Lowest Achievable Emission Rate (LAER) is implemented through BACT in the SCAQMD. Federal LAER applies to major sources only. Although federal LAER applies to any emissions increase at a major stationary source of ozone precursors, SCAQMD has interpreted this provision as a 1.0 lb/day increase in emissions from all sources subject to NSR. According to SCAQMD's rules, BACT requirements may not be less stringent than federal LAER for major polluting facilities. The California Health & Safety Code (H&SC) Section 40405 defines state BACT similar to federal LAER and requires the application of BACT for all new and modified permitted sources subject to NSR.

PSD RULES (REGULATION XVII)

New sources, relocations, and modifications of existing sources that emit attainment air contaminant emissions and certain other specified pollutants are subject to Prevention of Significant Deterioration (PSD) regulations, which require BACT. Pursuant to Rule 1701, the BACT requirement applies to a net emission increase from a permit unit located at minor and major stationary sources. The intention of the PSD requirement is to implement a similar requirement as Regulation XIII to maintain national ambient air quality standards for attainment air contaminants.

DEFINITION OF BACT

Definitions of BACT are found in: Rule 1302 -*Definitions of Regulation XIII - New Source Review*, which applies to all cases in general, except for Rule 1702 - Definitions, which applies only to attainment air contaminants, and Rule 2000 - General, which applies to NO_x and SO_x emissions from ~~nearly 400~~ RECLAIM facilities. While the definitions are not identical, they are essentially the same. Section (f) of Rule 1302 - Definitions defines BACT as:

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) means the most stringent emission limitation or control technique which:

- (1) *has been achieved in practice for such category or class of source; or*
- (2) *is contained in any state implementation plan (SIP) approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source*

- (3) *demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.*

The first two requirements in the BACT definition are required by federal law, as LAER for major sources. The third part of the definition is unique to SCAQMD and some other areas in California, and allows for more stringent controls than LAER.

Rule 1303(a)(2), ~~as proposed to adopted, will further requires~~ that economic and technical feasibility be considered in establishing the class or category of sources and the BACT requirements for non-major polluting facilities.

REQUIREMENTS OF HEALTH & SAFETY CODE SECTION 40440.11

Senate Bill 456 (Kelley) was chaptered into state law in 1995 and became effective in 1996. H&SC Section 40440.11 specifies the criteria and process that must be followed by the SCAQMD to update its BACT Guidelines to establish more stringent BACT limits for listed source categories. After consultation with the affected industry, the CARB, and the U.S. EPA, and considerable legal review and analysis, staff concluded that the process specified in SB 456 to update the BACT Guidelines should be interpreted to apply only if the SCAQMD proposes to make BACT more stringent than LAER or to establish BACT for non-major sources. This is because the CAA requires the SCAQMD staff to apply current LAER for major polluting facilities, even if the proposed LAER determination has not gone through the SB456 process. Therefore, the SB 456 requirements do apply to BACT requirements for non-major polluting facilities, but do not apply to federal LAER determinations for major polluting facilities.

CLEAN FUEL GUIDELINES REQUIREMENTS

In January 1988, the SCAQMD Governing Board adopted a Clean Fuels Policy that included a requirement to use clean fuels as part of BACT. The implementation of this policy is further described in Parts A and C of these guidelines.

Chapter 5 - Review of Staff BACT Determinations

New BACT determinations and guideline updates proposed by SCAQMD staff are subject to public notification requirements. In addition to allowing the public to comment on these items, the SCAQMD has established a BACT Scientific Review Committee (BACT SRC) to review and comment on technical matters of the proposals.

The SCAQMD has included provisions for an applicant to request a review of particular circumstances regarding a permit application and reconsideration of the BACT determination. Additional avenues are available to permit applicants for further review of staff BACT determinations through SCAQMD management, BACT Review Committee, Hearing Board, and the Governing Board.

BACT SCIENTIFIC REVIEW COMMITTEE (BACT SRC)

The BACT SRC was established as a standing committee by action of the SCAQMD Governing Board on September 8, 1995 to enhance the public participation process and include technical review and comments by a focused committee at periodic intervals, prior to the updates of the SCAQMD BACT Guidelines. A 30-day notice period applies for the BACT SRC and interested persons to review and comment on SCAQMD BACT determinations that result in BACT requirements that are more stringent than previously imposed. BACT SRC members, include but are not limited to, representatives from CARB, U.S. EPA, neighboring Air Pollution Control Districts (APCD), with the balance of the committee created by invitation of recognized experts from industry, public utilities, suppliers of air pollution control equipment and advocacy groups. Whenever a committee member resigns or is no longer able to serve, SCAQMD seeks out an appropriate replacement to join the committee. A list of current BACT SRC members can be accessed at:

www.aqmd.gov/home/permits/bact/scientific-review-committee/src-members.

The overall purpose of the BACT Scientific Review Committee (SRC) is to:

- Comment on proposed new &and more stringent BACT determinations in permit applications under 30-day public review.
- Comment on proposed BACT listings for all parts of the BACT Guidelines.

Except for the above, the BACT SRC's purpose is not to comment on past permitting decisions or change them.

Specifically, the role of the BACT SRC-Role is to review and comment in writing on the appropriateness of new BACT determinations under 30-Day public review. During this comment period, SCAQMD, State, and Federal required permit issuance timelines are still in effect. SCAQMD BACT staff will commit to sending the BACT

SRC newly proposed BACT listings at least seven days prior to the next scheduled BACT SRC meeting. Meetings will typically consist of a presentation by BACT Team (BACTTeam@aqmd.gov) staff of new BACT forms and technical data and a general discussion of the proposed BACT listings, as well as addressing any preliminary written comments received from the public and BACT SRC prior to the meeting. SCAQMD staff will respond in writing to preliminary comments about new BACT proposals within two-weeksthirty days of the subject BACT SRC meeting. New issues raised during the BACT SRC meetings regarding newly proposed BACT listings will be addressed at the subsequent BACT SRC meeting to allow time for SCAQMD staff to research the comments. SCAQMD Engineering and Compliance staff may also respond to specific issues raised at the following BACT SRC meeting.

In addition to newly proposed BACT listings, the BACT SRC will be tasked with reviewing and commenting on updates to the policy and procedure sections of the BACT Guidelines prior to the guidelines being presented to the SCAQMD Governing Board for approval.

MEETING WITH SCAQMD MANAGEMENT

SCAQMD management, starting with the Senior Engineering Manager of the permitting team, can consider unique and site-specific characteristics of an individual permit. The allowance flexibility for considering site-specific characteristics has been taken into account in these guidelines designed into the guidelines and can be reviewed with the manager of the section processing the permit. It is also possible to request review at the next level, with the Assistant Deputy Executive Officer of Engineering and Compliance. The Senior Engineering Managers and the Assistant Deputy Executive Officers are authorizedempowered to make case-by-case decisions on an individual permit. Further review can be obtained through a meeting with the Deputy Executive Officer (DEO) of Engineering and Compliance. Ultimately, all permitting decisions are the responsibility of the Executive Officer.

THE BACT REVIEW COMMITTEE

Beyond meetings with SCAQMD management, an applicant may also request, prior to permit issuance or denial, that the proposed BACT for an individual permit be reviewed by the BACT Review Committee (BRC). The BRC is composed of five senior-level SCAQMD officials - the DEO of Public Affairs; the DEO of Science and Technology Advancement; the DEO of Engineering and Compliance; the DEO of Planning, Rule Development and Area Sources; and General Counsel. This committee can review pending individual applications and decide if the BACT determination is appropriate. The BRC can be accessed without any fee or legal representation, and will meet upon demand.

THE SCAQMD HEARING BOARD

After the permit is issued or denied, the applicant can seek further independent review of an individual BACT determination through the SCAQMD Hearing Board. In order to access this venue, the permit applicant would need to submit a petition and fee to appeal the final BACT determination by SCAQMD (once the permit is denied

or issued)⁸. The Hearing Board is an independent, quasi-judicial body composed of five members, who can review a permitting decision by the Executive Officer. In this venue, legal counsel represents the SCAQMD. Although not required, many petitioners choose to have legal counsel to represent their position.

THE SCAQMD GOVERNING BOARD

Any applicant may petition the SCAQMD Governing Board to review a pending application pursuant to SCAQMD Regulation XII and Health and Safety Code Section 40509. While the Governing Board has the authority to hear and consider any pending permit application, it has rarely done so. It is important to note that this action must be taken while the permit application is pending with staff. Once staff reaches its decision, the only avenue of appeal is through the Hearing Board and ultimately to court.

~~but this circumstance is extremely rare and cases has only agreed to consider two pending permit applications in the last sixteen years are typically handled during the prior stages of review.~~

⁸ Applicants must file an appeal petition with the Hearing Board within thirty days of the receipt of the permit or the notification of permit denial. See Rule 216 - *Appeals*, Regulation V - *Procedure Before the Hearing Board*, and Rule 303 - *Hearing Board Fees* for more information.

PART A - POLICY AND PROCEDURES FOR MAJOR POLLUTING FACILITIES

Chapter 1 - How is LAER Determined for Major Polluting Facilities?

This chapter explains the criteria used for determining LAER⁹ and the process for updating Part B of the BACT Guidelines for major polluting facilities.

CRITERIA FOR DETERMINING LAER FOR MAJOR POLLUTING FACILITIES

SCAQMD staff determines LAER requirements on a permit-by-permit basis based on the definition of LAER. In essence, LAER is the most stringent emission limit or control technology that is:

- found in a state implementation plan (SIP), or
- achieved in practice (AIP), or
- is technologically feasible and cost effective.

For practical purposes, at this time, nearly all SCAQMD LAER determinations will be based on AIP LAER because it is generally more stringent than LAER based on SIP, and because state law constrains SCAQMD from using the third approach, as such a determination must go through the SB456 process, which may take more time than allowed for the permit decision.

Based on Governing Board policy, LAER also includes a requirement for the use of clean fuels. Terms such as "achieved in practice" and "technologically feasible" have not been defined in the rule, so the purpose of this section is to explain the criteria SCAQMD permitting staff uses to make a LAER determination.

LAER Based on a SIP

The most stringent emission limit found in an approved state implementation plan (SIP) might be the basis for LAER. This means that the most stringent emission limit adopted by any state as a rule, regulation or permit¹⁰, and approved by USEPA, is eligible as a LAER requirement. No other parameters are required to be evaluated when this category is chosen. This does not include future emission limits that have not yet been implemented.

⁹ In order to distinguish between BACT for major polluting facilities and BACT for minor polluting facilities, this document uses the term LAER when referring to BACT for major polluting facilities.

¹⁰ Some states incorporate individual permits into their SIP as case-by-case Reasonably Available Control Technology requirements.

Achieved in Practice LAER

Regulatory Documents

An emission limit or control technology may be considered achieved in practice (AIP) for a category or class of source if it exists in any of the following regulatory documents or programs:

- SCAQMD BACT Guidelines
- CAPCOA BACT Clearinghouse
- USEPA RACT/BACT/LAER Clearinghouse
- Other districts' and states' BACT Guidelines
- BACT/LAER requirements in New Source Review permits issued by SCAQMD or other agencies

However, staff will check with the permitting authority (other than SCAQMD) on the status of the BACT or LAER requirement. If it is found that an emission limit is not being achieved or a control technology is not performing as expected in the equipment referenced in any of the above sources or in other equipment used as the basis for the BACT or LAER determination, then it will not be considered as AIP.

New Technologies/Emission Levels

New technologies and innovations of existing technologies occasionally evolve without a regulatory requirement, but still deserve consideration. They may have been voluntarily installed to reduce emissions, and may or may not be subject to an air quality permit or an emission limit. -Therefore, in addition to the above means of being determined as AIP, a control technology or emission limit may also be considered as AIP if it meets all of the following criteria:

Commercial Availability:

At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guaranty must be available with the purchase of the control technology, as well as parts and service.

Reliability:

All control technologies must have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment must have at least 183 cumulative days of operation. During this period, the basic and/or control equipment must have operated: 1) at a minimum of 50% design capacity; or 2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.

Effectiveness:

The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification shall be based on a performance test or tests deemed to be acceptable by SCAQMD, when possible, or other performance data.

Technology Transfer

LAER is based on what is AIP for a category or class of source. However, USEPA guidelines require that technology that is determined to be AIP for one category of source be considered for transfer to other source categories. There are two types of potentially transferable control technologies: 1) exhaust stream controls, and 2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, technology transfer must be considered between source categories with similar processes.

Federal PM_{2.5} New Source Review and SCAQMD Rule 1325

PM_{2.5} NSR applies to a new major polluting facility, major modifications to a major polluting facility, and any modification to an existing facility that would constitute a major polluting facility. A major polluting facility would be a facility located in areas federally designated pursuant to 40 CFR 81.305 as non-attainment for PM_{2.5} for the South Coast Air Basin (SOCAB) which has actual emissions of, or the potential to emit, 4970 tons or more per year of PM_{2.5}, or its precursors for serious areas. For major modifications, LAER applies on a pollutant-specific basis to emissions of PM_{2.5} and its precursors, for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase.

Significant means in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates¹¹:

Nitrogen oxides: 40 tons per year

Sulfur dioxide: 40 tons per year

PM_{2.5}: 10 tons per year

Ammonia: 40 tons per year¹²

A facility subject to the Federal PM_{2.5} NSR will be required to comply with the following:

- Lowest Achievable Emission Rate (LAER)
- Emission increases offset
- Certification of compliance with Clean Air Act; and
- Analysis conducted of benefits of the proposed project outweigh the environmental and social costs associated with that project.

Please refer to SCAQMD Rule 1325 for specific requirements.

¹¹ SCAQMD Rule 1325(b)(12), as amended on December 5, 2014

¹² Ammonia is being added to Rule 1325 as a precursor to PM_{2.5} pursuant to EPA's 2016 PM_{2.5} SIP implementation Rule. PAR 1325, scheduled for hearing in November 2016, would set a significance threshold of 40 tons per year for ammonia.

Cost in LAER Determinations

USEPA guidelines do not allow for routine consideration of the cost of control in LAER determinations. However, USEPA guidelines say that LAER is not considered achievable if the cost of control is so great that a new source could not be built or operated with a particular control technology. If a facility in the same or comparable industry already uses the control technology, then such use constitutes evidence that the cost to the industry is not prohibitive.

State law (H&SC 40405) also defines BACT as the lowest achievable emission rate, which is the more stringent of either (i) the most stringent emission limitation contained in the SIP, or (ii) the most stringent emission limitation that is achieved in practice. There is no explicit reference or prohibition to cost considerations, and the applicability extends to all permitted sources. SCAQMD rules implement both state BACT and federal LAER requirements simultaneously, and furthermore specify that SCAQMD BACT must meet federal LAER requirements for major polluting facilities.

If a proposed LAER determination results in extraordinary costs to a facility, the applicant may bring the matter to SCAQMD management for consideration as described in Overview, Chapter 6.

Clean Fuel Requirements

In January 1988, the SCAQMD Governing Board adopted a Clean Fuels Policy that included a requirement to use clean fuels as part of BACT/LAER. A clean fuel is one that produces air emissions equivalent to or lower than natural gas for NO_x, SO_x, ROG, and fine respirable particulate matter (PM₁₀). Besides natural gas, other clean fuels are methanol, liquid petroleum gas (LPG), and hydrogen. The burning of landfill, digester, refinery and other by-product gases is not subject to the clean fuels requirement. However, the combustion of these fuels must comply with other SCAQMD rules, including the sulfur content of the fuel.

The requirement of a clean fuel is based on engineering feasibility. Engineering feasibility considers the availability of a clean fuel and safety concerns associated with that fuel. Some state and local safety requirements limit the types of fuel, which can be used for emergency standby purposes. Some fire departments or fire marshals do not allow the storage of LPG near occupied buildings. Fire officials have, in some cases, vetoed the use of methanol in hospitals. If special handling or safety considerations preclude the use of the clean fuel, the SCAQMD has allowed the use of fuel oil as a standby fuel in boilers and heaters, and for emergency standby generators. The use of these fuels must meet the requirements of SCAQMD rules limiting NO_x and sulfur emissions.

Special Permitting Considerations

Although the most stringent, AIP LAER for a source category will most likely be the required LAER, SCAQMD staff may consider special technical circumstances that apply to the proposed equipment which may allow deviation from that LAER. The permit applicant should bring any pertinent facts to the attention of the SCAQMD permitting engineer for consideration.

Case-Specific Situations

SCAQMD staff may consider unusual equipment-specific and site-specific characteristics of the proposed project that would warrant a reconsideration of the LAER requirement for new equipment. Here are some examples of what may be considered.

Technical infeasibility of the control technology:

A particular control technology may not be required as LAER if the applicant demonstrates that it is not technically feasible to install and operate it to meet a specific LAER emission limitation in a specific permitting situation.

Operating schedule and project length:

If the equipment will operate much fewer hours per year than what is typical, or for a much shorter project length, it can affect what is considered "achieved-in-practice" AIP.

Availability of fuel or electricity:

Some LAER determinations may not be feasible if a project will be located in an area where natural gas or electricity is not available.

Process requirements:

Some LAER determinations specify a particular type of process equipment. SCAQMD staff may consider requirements of the proposed process equipment that would make the LAER determination not technically feasible.

Equivalency

The permit applicant may propose alternative means to achieve the same emission reduction as required by LAER. For example, if LAER requires a certain emission limit or control efficiency to be achieved, the applicant may choose any control technology, process modification, or combination thereof that can meet the same emission limit or control efficiency.

Super Clean-Compliant Materials

SCAQMD will accept the use of super clean-compliant materials in lieu of an add-on control device controlling volatile organic compound (VOC) emissions from coating operations. For example at this time, if a permit applicant uses only surface coatings that contain less than 5% VOC by weight meet the super compliant material definition in SCAQMD Rule 109, an add-on control device would not be required for VOC LAER. This policy does not preclude any other LAER requirements for other contaminants.

Equipment Modifications

As a general rule, it is more difficult to retrofit existing equipment with LAER as a result of NSR modification when compared to a new source. The equipment being modified may not be compatible with some past LAER determinations that specify a particular process type. There may also be space restrictions that prevent installation of some add-on control technology.

Other Considerations

Although multiple process and control options may be available during the LAER determination process, considerations should be made for options that reduce the formation of air contaminants from the process, as well as ensuring that emissions are properly handled. In addition to evaluating the efficiency of the control stage, these additional considerations are needed to ensure that the system is capable of reducing or eliminating emissions from the facility on a consistent basis during the operational life of the equipment.

Pollution Prevention

The Pollution Prevention Act of 1990 (42 U.S.C. §§13101-13109) established a national policy that pollution should be prevented or reduced at the source whenever feasible. In many cases, air pollution control is a process that evaluates contaminants at the exhaust of the system. Pollution prevention is the reduction or elimination of waste at the source by the modification of the production process. Pollution prevention measures may consist of the use of alternate or reformulated materials, a modification of technology or equipment, or improvement of energy efficiency changes that result in an emissions reduction. These measures should be considered as part of the LAER determination process if the measures will result in the elimination or reduction of emissions, but are not required to include projects which are considered to fundamentally redefine the source. New and different emissions created by a process or material change will also need to be considered as part of the LAER determination process, in contrast to the overall emissions reductions from the implementation of pollution prevention measures. U.S. EPA policy defined pollution prevention as source reduction and other practices that reduce or eliminate the creation of pollutants through increased efficiency in the use of raw materials, energy, water, or other resources, and protection of natural resources by conservation¹³. U.S. EPA further specifies that pollution prevention does not include recycling (except in-process recycling), energy recovery, treatment or disposal. For purposes of these BACT Guidelines, and to be consistent with federal definitions, source reduction and pollution prevention shall may include, but not be limited to, a consideration of the feasibility of:

- equipment or technology modifications,
- process or procedure modifications,
- reformulation or redesign of products,
- substitution of raw materials, or
- improvements in housekeeping, maintenance or inventory control,

that reduce the amount of air contaminants entering any waste stream or otherwise released into the environment, including fugitive emissions.

¹³ U.S. EPA Pollution Prevention Law and Policies (www.epa.gov/p2/pollution-prevention-law-and-policies#define)

Monitoring and Testing

In order to ensure that LAER determinations continue to meet their initial emission and efficiency standards, periodic or continuous parameter monitoring and testing requirements may be required during the permitting process. Equipment and processes may experience some change over time, due to aging or operational methods of the equipment, which may affect emission rates or control efficiencies. In addition to other rule requirements, additional monitoring and testing requirements may need to focus on aspects directly related to the BACT determination, and may be made enforceable by permit conditions. Monitoring and testing requirements should be specific to characterize operating conditions (e.g. temperatures, pressures, flows, production rates) and measurement techniques when LAER is established to ensure clarity and consistency with the standard.

Capture Efficiency

An integral part of controlling air pollutants emitted from a process with add-on air pollution control equipment is capturing those emissions and directing them to the air pollution control device. Emissions which are designed to be collected by an exhaust system but are vented uncontrolled into the atmosphere can have a much greater impact than controlled emissions. When applicable, the evaluation of a process and its associated control equipment should address the qualification and quantification of capture efficiency. By addressing capture efficiency during LAER determinations, a standard can be established to evaluate the capture efficiency of other systems, as well as ensure that the capture efficiency is maintained consistently over time.

If applicable, LAER determinations may include the percentage capture efficiency and the methods and measurements (e.g. EPA Method 204, capture velocity measurements, design using ACGIH's Industrial Ventilation, static pressures) used to determine and verify it. For various circumstances, several SCAQMD rules (Table 4) already require an assessment of collection efficiency of an emission control system following EPA Method 204, EPA's "Guidelines for Determining Capture Efficiency", SCAQMD's "Protocol for Determination of Volatile Organic Compounds (VOC) Capture Efficiency," or other methods approved by the Executive Officer, and are appropriate to include as LAER requirements. The capture efficiency for any LAER Determination shall be no less stringent than any applicable rule requirement. Other considerations that may affect capture, such as cross-drafts, thermal drafts and the volume of combustion products, should also be addressed during this process.

Table 4

SCAQMD Regulation XI and XIV Rules with Capture Efficiency Requirements or Considerations

<u>1103</u>	<u>1125</u>	<u>1136</u>	<u>1162</u>	<u>1420.1</u>
<u>1104</u>	<u>1126</u>	<u>1141</u>	<u>1164</u>	<u>1420.2</u>
<u>1106</u>	<u>1128</u>	<u>1141.2</u>	<u>1171</u>	<u>1425</u>
<u>1107</u>	<u>1130</u>	<u>1144</u>	<u>1175</u>	<u>1469</u>
<u>1115</u>	<u>1130.1</u>	<u>1145</u>	<u>1178</u>	<u>1469.1</u>
<u>1122</u>	<u>1131</u>	<u>1155</u>	<u>1407</u>	
<u>1124</u>	<u>1132</u>	<u>1156</u>	<u>1420</u>	

LAER APPLICATION CUT-OFF DATES

For applications submitted by major polluting facilities, LAER requirements will be determined based on information available up to the date the permit to construct is issued. This requirement allows interested parties to comment on possible technologies that could provide lower emissions.

Applications for a Registration Permit for equipment issued a valid Certified Equipment Permit (CEP), which is valid for one year, will only be required to comply with LAER as determined at the time the CEP was issued. However, SCAQMD staff will reevaluate the LAER requirements for the CEP upon annual-renewal of the Title V permit CEP by the equipment manufacturer.

LAER UPDATE PROCESS

SCAQMD will update Section I – SCAQMD LAER/BACT Determinations of Part B of the BACT Guidelines on an ongoing basis with actual LAER determinations for SCAQMD permits issued to major polluting facilities. The process will depend on whether or not the LAER requirement is more stringent than previous SCAQMD LAER determinations for the same equipment category.

When SCAQMD permitting staff makes a LAER determination that is no more stringent than previous SCAQMD LAER determinations, the permitting team will issue the permit and forward information regarding this LAER determination to the BACT/NSR Team.¹⁴ The BACT/NSR Team will review this LAER determination with the BACT SRC prior to listing in the BACT Guidelines.

Whenever permitting staff makes a LAER determination that is more stringent than what SCAQMD has previously required as LAER, the permit to construct may be subject to a public review. In any event depending on Rule 212, the permitting team will forward the preliminary LAER determination to the BACT/NSR Team, who will prepare and send a public notice of the preliminary determination to the BACT SRC, potentially interested persons, and anyone else requesting the information. Staff will consider all comments filed during the 30-day review period before making a permit decision. Staff will make every effort to conduct the public review consistent with the requirements of state law. However, if the 30-day review period conflicts with the deadline of the Permit Streamlining Act¹⁵ for issuing the permit, the permit will be issued in accordance with state law. The 30-day public review may also be done in parallel with other public reviews mandated by Rule 212 - Standards for Approving Permits and Issuing Public Notice or Regulation XXX - Title V Permits in applicable cases.

On a quarterly periodic basis, the SCAQMD BACT/NSR Team will provide standing status reports to the SCAQMD Governing Board's Stationary Source Committee and to the Governing Board.

¹⁴ To reduce the burden on SCAQMD of preparing hundreds of LAER Determination Forms each month, forms will not be prepared for routine LAER determinations after Part B, Section I of the guidelines has sufficient entries to demonstrate typical LAER requirements.

¹⁵ The requirements of the Permit Streamlining Act are also found in SCAQMD's Rule 210.

In summary, as technology advances, many categories in the SCAQMD's BACT Guidelines will be updated with new listings. This on-going process will reflect new lower emitting technologies not previously identified in the Guidelines.

CLEAN FUEL GUIDELINES REQUIREMENTS

In January 1988, the SCAQMD Governing Board adopted a Clean Fuels Policy that included a requirement to use clean fuels as part of BACT/LAER. A clean fuel is one that produces air emissions equivalent to or lower than natural gas for NO_x, SO_x, ROG, and fine respirable particulate matter (PM₁₀). Besides natural gas, other clean fuels are methanol, liquid petroleum gas (LPG), and hydrogen and electricity. Industrial electrification (e.g., replacement of I.C. Engines, etc.) is Utilization of zero and near-zero emission technologies are also integrated into the Clean Fuels Policy. The burning of landfill, digester, refinery and other by-product gases is not subject to the clean fuels requirement. However, the combustion of these fuels must comply with other SCAQMD rules, including the sulfur content of the fuel.

The requirement of a clean fuel is based on engineering feasibility. Engineering feasibility considers the availability of a clean fuel and safety concerns associated with that fuel. Some state and local safety requirements limit the types of fuel, which can be used for emergency standby purposes. Some fire departments or fire marshals do not allow the storage of LPG near occupied buildings. Fire officials have, in some cases, vetoed the use of methanol in hospitals. If special handling or safety considerations preclude the use of the clean fuel, the SCAQMD has allowed the use of fuel oil as a standby fuel in boilers and heaters, fire suppressant pump engines and for emergency standby generators. The use of these fuels must meet the requirements of SCAQMD rules limiting NO_x and sulfur emissions.

Chapter 2 - How to Use Part B of the BACT Guidelines

This chapter explains the LAER information found in Part B - LAER/BACT Determinations for Major Polluting Facilities. Part B is a listing of LAER/BACT determinations for major polluting facilities contained in SCAQMD and other air pollution control agencies' permits, and data on new and emerging technologies. These LAER/BACT determinations and data are guides and will be used, along with other information, to determine LAER as outlined in Chapter 1. For a listing of equipment types, refer to the Index-List of Equipment Categories. LAER determination for equipment not found in Part B of the BACT Guidelines is done according to the process outlined in Chapter 1.

GENERAL

Part B is divided into three sections. Section I - SCAQMD LAER/BACT Determinations, contains information on LAER/BACT determinations contained in permits issued by SCAQMD, with permit limits based on achieved in practice technology. Section II - Non-AQMD LAER/BACT Determinations, lists LAER/BACT determinations contained in other air pollution control agencies' permits or BACT Guidelines, with permit limits based on achieved in practice technology. Section III - Other Technologies, consists of information on technologies which have been achieved in practice but are not reflected in a permit limit, and information on emerging technologies or emission limits which have not yet been achieved in practice (i.e., do not qualify as LAER). All three sections are subdivided based on the attached Index-List of Equipment Categories. Within each category, the LAER/BACT determinations will be listed in order of stringency.

Each listing includes the following information, in addition to other information detailing the description and operation of the equipment-subdivided into the following six sections:

1.1 Basic Equipment¹⁶

This provides information on the type, model, style, manufacturer, function, and cost of the basic equipment. It also lists applicable SCAQMD Regulation XI rules. Cost data are generally obtained from the SCAQMD application forms, manufacturer or owner/operator, and are not verified.

1.2 Basic Equipment Rating/Size

This identifies the size, dimensions, capacity, or rating of the basic equipment. It also provides additional information such as fuel type for combustion equipment, weight of parts cleaned per load for degreasers, and the number and size of blowers for spray booths.

1.3 Company Information

This identifies the contact person and owner/operator of the equipment, along with telephone numbers.

¹⁶ Basic equipment is the process or equipment, which emits the air contaminant for which BACT is being determined.

2.1 Permit Information

This identifies the permitting agency and the name and telephone number of the agency's contact person. It also provides information on Permits to Construct/Operate. The SCAQMD is always the issuing agency for LAER determinations listed in Section I.

2.2 Emission Information

This identifies the actual permit limits and LAER/BACT requirements set forth by the issuing agency for the equipment being evaluated. It provides technical, performance, and cost data on the control technology used to achieve the permit limit and the LAER/BACT requirements.

2.3 Comment

This provides additional information relevant to basic equipment and control technology assessment, or further explains or clarifies the LAER/BACT determination.

The above ~~six sections~~ information will enable permit applicants to assess the applicability of each LAER/BACT determination to their particular equipment.

The LAER requirements usually found in ~~section 5A~~ of the LAER Determination listings are in the form of:

- 2.1** an emission limit;
- 2.2** a control technology;
- 2.3** equipment requirements; or
- 2.4** a combination of the last two.

If the requirement is an emission limit, the applicant may choose any control technology to achieve the emission limit. The SCAQMD prefers to set an emission limit as LAER because it allows an applicant the most flexibility in reducing emissions. If control technology and/or equipment requirements are the only specified LAER, then either emissions from the equipment are difficult to measure or it was not possible to specify an emission limit that applies to all equipment within the category. Where possible, an emission limit or control efficiency condition will be specified on the permit along with the control technology or equipment requirements to ensure that the equipment is properly operated with the lowest emissions achievable.

HOW TO DETERMINE LAER

The Part B LAER determinations are only examples of LAER determinations for equipment that have been issued permits or that have been demonstrated in practice. As described in Chapter 1, LAER is determined on a case-by-case basis. To find out what LAER is likely to be for a particular equipment, the applicant should review the Part B LAER determinations found at the SCAQMD website www.aqmd.gov/home/permits/bact ~~http://www.aqmd.gov/bact~~. The CAPCOA Clearinghouse maintained by the California Air Resources Board and the USEPA RACT/BACT/LAER Clearinghouse should also be reviewed. These compendiums contain information from other districts, local agencies, and states that may not be included in the SCAQMD BACT Guidelines. Finally, the SCAQMD permitting staff may be contacted to discuss LAER prior to submitting a permit application.

CHAPTER 2 - HOW TO USE PART B OF THE BACT GUIDELINES

As described in Chapter 1, the permit applicant should bring to the attention of the SCAQMD permitting engineer any special permitting considerations that may affect the LAER determination.

PART B - LAER/BACT DETERMINATIONS FOR MAJOR POLLUTING FACILITIES

Part B of the BACT Guidelines is maintained on the SCAQMD Internet website at
<http://www.aqmd.gov/home/permits/bact/guidelines> ~~http://www.aqmd.gov/bact.~~

PART C - POLICY AND PROCEDURES FOR NON-MAJOR POLLUTING FACILITIES

Chapter 1 - How Is MSBACT Determined for Minor Polluting Facilities?

This chapter explains the definitions of BACT for non-major polluting facilities (minor source BACT or MSBACT) found in SCAQMD rules and state law and how they are interpreted. It also explains the criteria used for initializing the Part D MSBACT Guidelines and the process for updating the MSBACT Guidelines.

INITIALIZATION OF PART D OF THE MSBACT GUIDELINES

Part D of the MSBACT Guidelines specifies the MSBACT requirements for all of the commonly permitted categories of equipment. (See Chapter 2 for a full explanation of Part D).

~~The initial~~The initial listings in Part D of the MSBACT Guidelines reflected the current BACT determinations at the time for sources at non-major polluting facilities as of April 2000. ~~This~~ ~~These~~ initialization ~~does~~ ~~did~~ not represent new requirements but rather memorializes memorialized current BACT determinations and emission levels at that time. This initialization ~~is~~ was necessary to benchmark the transition from federal LAER to MSBACT for non-major polluting facilities. The control technologies and emission levels identified ~~initially~~ will apply applied to any non-major source subject to NSR until the Guideline ~~is~~ was updated or ~~becomes~~ became out of date. The dates listed on the BACT determinations in Part D refer to the date of adoption of the determination. The dates listed do not grandfather the equipment from complying with any new requirements or limits that are implemented after the approval of a BACT determination¹⁷.

CRITERIA FOR NEW MSBACT AND UPDATING PART D

MSBACT requirements are determined for each source category based on the definition of MSBACT. In essence, MSBACT is the most stringent emission limit or control technology that is:

- found in a state implementation plan (SIP), or
- achieved in practice (AIP), or
- is technologically feasible and cost effective.

For practical purposes, nearly all SCAQMD MSBACT determinations will be based on AIP BACT because it is generally more stringent than MSBACT based on SIP, and because state law contains some constraints on SCAQMD from using the third approach. For minor polluting facilities, MSBACT will also take economic feasibility into account.

Based on Governing Board policy, MSBACT also includes a requirement for the use of clean fuels.

Terms such as "achieved in practice" and "technologically feasible" (including technology transfer) have not been defined in the rule, so one of the purposes of this

¹⁷ SCAQMD Rule 1303(a)(3)

section is to explain the criteria SCAQMD permitting staff uses to make a MSBACT determination.

MSBACT Based on a SIP

The most stringent emission limit found in an approved state implementation plan (SIP) might be the basis for MSBACT. This means that the most stringent emission limit adopted by any state as a rule, regulation or permit¹⁸ and approved by USEPA is eligible as a MSBACT requirement. This does not include future emission limits that have not yet been implemented.

Achieved in Practice MSBACT

MSBACT may also be based on the most stringent control technology or emission limit that has been achieved in practice (AIP) for a category or class of source. AIP control technology may be in operation in the United States or any other part of the world. SCAQMD permitting engineers will review the following sources to determine what is the most stringent AIP MSBACT:

- LAER/BACT determinations in Part B of the BACT Guidelines
- CAPCOA BACT Clearinghouse
- USEPA RACT/BACT/LAER Clearinghouse
- Other districts' and states' BACT Guidelines
- Permits to operate issued by SCAQMD or other agencies
- Any other source for which the requirements of AIP can be demonstrated

Achieved in Practice Criteria

A control technology or emission limit found in any of the references above may be considered as AIP if it meets all of the following criteria:

Commercial Availability:

At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guaranty must be available with the purchase of the control technology, as well as parts and service.

Reliability:

The control technology must have been installed and operated reliably for at least twelve months on a comparable commercial operation. If the operator did not require the basic equipment to operate continuously, such as only eight hours per day and 5 days per week, then the control technology must have operated whenever the basic equipment was in operation during the twelve months.

Effectiveness:

The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then

¹⁸ Some states incorporate individual permits into their SIP as case-by-case Reasonably Available Control Technology requirements.

those modes must be identified. The verification shall be based on a District-approved performance test or tests, when possible, or other performance data.

Cost Effectiveness:

The control technology or emission rate must be cost effective for a substantial number of sources within the class or category. Cost effectiveness criteria are described in detail in a later section. Cost criteria are not applicable to an individual permit but rather to a class or category of source.

Technology Transfer

MSBACT is based on what is AIP for a category or class of source. However, technology transfer must also be considered across source categories, in view of the other AIP criteria. There are two types of potentially transferable control technologies: 1) exhaust stream controls, and 2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, process similarity governs the technology.

Requirements of Health & Safety Code Section 40440.11

Senate Bill 456 (Kelley) was chartered into state law in 1995 and became effective in 1996. H&SC Section 40440.11 specifies the criteria and process that must be followed by the SCAQMD to establish new MSBACT limits for source categories listed in the MSBACT Guidelines. In general, the provisions require:

- ☐ Considering only control options or emission limits to be applied to the basic production or process equipment;
- ☐ Evaluating cost to control secondary pollutants;
- ☐ Determining the control technology is commercially available;
- ☐ Determining the control technology has been demonstrated for at least one year on a comparable commercial operation;
- ☐ Calculating total and incremental cost-effectiveness;
- ☐ Determining that the incremental cost-effectiveness is less than SCAQMD's established cost-effectiveness criteria;
- ☐ Putting BACT Guideline revisions on a regular meeting agenda of the SCAQMD Governing Board;
- ☐ Holding a Board public hearing prior to revising maximum incremental cost-effectiveness values;
- ☐ Keeping a BACT determination made for a particular application unchanged for at least one year from the application deemed complete date; and
- ☐ Considering a longer period for a major capital project (> \$10,000,000)

After consultation with the affected industry, the CARB, and the U.S. EPA, and considerable legal review and analysis, staff concluded that the process specified in SB 456 to update the BACT Guidelines should be interpreted to apply only if the SCAQMD proposes to make BACT more stringent than LAER or where LAER is inapplicable (e.g. in establishing minor source BACT). Staff intends to incorporate

the spirit and intent of the SB 456 provisions into the MSBACT update process, as explained below, because non-major polluting facilities are no longer subject to federal LAER-, according to Regulation XIII. Therefore, MSBACT may consider cost as specified herein.

COST EFFECTIVENESS METHODOLOGY

Cost effectiveness is measured in terms of control costs (dollars) per air emissions reduced (tons). If the cost per ton of emissions reduced is less than the maximum required cost effectiveness, then the control method is considered to be cost effective. This section also discusses the updated maximum cost effectiveness values, and those costs, which can be included in the cost effectiveness evaluation.

There are two types of cost effectiveness: average and incremental. Average cost effectiveness considers the difference in cost and emissions between a proposed MSBACT and an uncontrolled case. On the other hand, incremental cost effectiveness looks at the difference in cost and emissions between the proposed MSBACT and alternative control options.

Applicants may also conduct a cost effectiveness evaluation to support their case for the special permit considerations discussed in Chapter 2.

Discounted Cash Flow Method

The discounted cash flow method (DCF) is used in the MSBACT Guidelines. This is also the method used in SCAQMD the 1999 Air Quality Management Plan. The DCF method calculates the present value of the control costs over the life of the equipment by adding the capital cost to the present value of all annual costs and other periodic costs over the life of the equipment. A real interest rate¹⁹ of four percent, and a 10-year equipment life is used. The cost effectiveness is determined by dividing the total present value of the control costs by the total emission reductions in tons over the same 10-year equipment life.

Maximum Cost Effectiveness Values

The MSBACT maximum cost effectiveness values, shown in Table 45, are based on a DCF analysis with a 4% real interest rate.

Table 45: Maximum Cost Effectiveness Criteria ~~(Second Quarter 2003)~~^{1*}2nd Quarter 2016)

Pollutant	Average (Maximum \$ per Ton)	Incremental (Maximum \$ per Ton)
ROG	<u>28,370,460</u> 20,200	<u>85,400,380</u> 60,600
NOx	<u>26,820,910</u> 19,100	<u>80,320,590</u> 57,200
SOx	<u>14,180,230</u> 10,100	<u>42,550,690</u> 30,300

¹⁹ The real interest rate is the difference between market interest rates and inflation, which typically remains constant at four percent.

^{1*} The real interest rate is the difference between market interest rates and inflation, which typically remains constant at four percent.

Pollutant	Average (Maximum \$ per Ton)	Incremental (Maximum \$ per Ton)
PM ₁₀	6,324,045.00	18,828,013.400
CO	560,400	1,620,150

The cost criteria are based on those adopted by the SCAQMD Governing Board in the 1995 BACT Guidelines, adjusted to first-second quarter 2016-2003-dollars using the Marshall and Swift Equipment Cost Index. Cost effectiveness analyses should use these figures adjusted to the latest Marshall and Swift Equipment Cost Index. Contact the BACT Team for current figures, which is published monthly in Chemical Engineering.

Top-Down Cost Methodology

The SCAQMD uses the top-down approach for evaluating BACT and cost effectiveness. This means that the best control method, with the highest emission reduction, is first analyzed. If it is not cost effective, then the second-best control method is evaluated for cost effectiveness. The process continues until a control method is found to be cost-effective. This process provides a mechanism for all practical and potential control technologies to be evaluated. As part of the permitting process, the applicant is responsible for preparing the BACT analysis, and submitting it to the District for review and approval.

The top-down process consists of five steps:

1. Identify all control technologies

Identify all possible air pollution control options for the emissions unit. In addition to add-on control, control options may include production process methods and techniques. Innovative, transferable technologies, and LAER technologies should also be identified.

2. Eliminate technically infeasible options

The technologies identified in Step 1 should be evaluated for technical feasibility. Elimination of any of the technologies identified in Step 1 should be well-documented and based on physical, chemical and engineering principles.

3. Rank remaining control technologies

Based on overall control effectiveness, all remaining technically feasible control options should be ranked for the pollutants under review. A list should be generated for each pollutant subject to the BACT analysis. This list should include control efficiencies, emission rates, emission reductions, environmental impacts and energy impacts. Environmental impacts may include multimedia impacts and the impacts of the control option on toxic emissions.

4. Evaluation

Evaluate the most effective controls and document the results. For each option, the applicant is responsible for objectively discussing each of the beneficial and adverse impacts. Typically, the analysis should focus on the direct impacts. Calculations for

both incremental and average cost effectiveness should be completed during this step. The MSBACT option must be cost effective for both analyses. In the event that the top option from Step 4 is ruled out after the impacts and cost effectiveness are evaluated, the decision and reasoning should be fully documented. The next most stringent alternative from Step 4, should then be evaluated.

5. Select BACT

The most effective control option not eliminated in Step 4 is proposed as BACT for the pollutant and permit unit and presented to the District for review and approval.

~~The SCAQMD uses the top-down approach for evaluating cost effectiveness. This means that the best control method, with the highest emission reduction, is first analyzed. If it is not cost effective, then the second best control method is evaluated for cost effectiveness. The process continues until a control method is found to be cost effective.~~

~~AQMD staff will calculate both incremental and average cost effectiveness. The new MSBACT must be cost effective based on both analyses.~~

Costs to Include in a Cost Effectiveness Analysis

Cost effectiveness evaluations consider both capital and operating costs. Capital cost includes not only the price of the equipment, but the cost for shipping, engineering and installation. Operating or annual costs include expenditures associated with utilities, labor and replacement costs. Finally, costs are reduced if any of the materials or energy created by the process result in cost savings. These cost items are shown in Table 56. Methodologies for determining these values are given in documents prepared by USEPA through their Office of Air Quality Planning and Standards (QAQPS-EPA Air Pollution Control Cost Manual, 4th-Sixth Edition, 2002, USEPA 450/452/3B-9002-006-001 and Supplements).

The cost of land will not be considered because 1) add-on control equipment usually takes up very little space, 2) add-on control equipment does not usually require the purchase of additional land, and 3) land is non-depreciable and has value at the end of the project. In addition, the cost of controlling secondary emissions and cross-media pollutants caused by the primary MSBACT requirement should be included in any required cost effectiveness evaluation of the primary MSBACT requirement.

Table 56: Cost Factors

<u>Total Capital Investment</u>	
<u>Purchased Equipment Cost</u> Control Device Ancillary (including duct work) Instrumentation Taxes Freight	<u>Indirect Installation Costs</u> Engineering Construction and Field Expenses Start-Up Performance Tests Contingencies
<u>Direct Installation Cost</u> Foundations and Supports Handling and Erection Electrical Piping Insulation Painting	
<u>Total Annual Cost</u>	
<u>Direct Costs</u> Raw Materials Utilities - Electricity - Fuel - Steam - Water - Compressed Air Waste Treatment/Disposal Labor - Operating - Supervisory - Maintenance Maintenance Materials Replacement Parts	<u>Indirect Costs</u> Overhead Property Taxes Insurance Administrative Charges <u>Recovery Credits</u> Materials Energy

CLEAN FUEL GUIDELINES REQUIREMENTS

In January 1988, the SCAQMD Governing Board adopted a Clean Fuels Policy that included a requirement to use clean fuels as part of BACT. A clean fuel is one that produces air emissions equivalent to or lower than natural gas for NO_x, SO_x, ROG, and fine respirable particulate matter (PM₁₀). Besides natural gas, other clean fuels are ~~methanol, liquid petroleum gas (LPG), and hydrogen and electricity. Industrial electrification (e.g., replacement of I.C. Engines, etc.) is~~ Utilization of zero and near-zero emission technologies are also integrated into the Clean Fuels Policy. The burning of landfill, digester, refinery and other by-product gases is not subject to the

clean fuels requirement as they are considered industry. However, the combustion of these fuels must comply with other SCAQMD rules, including the sulfur content of the fuel.

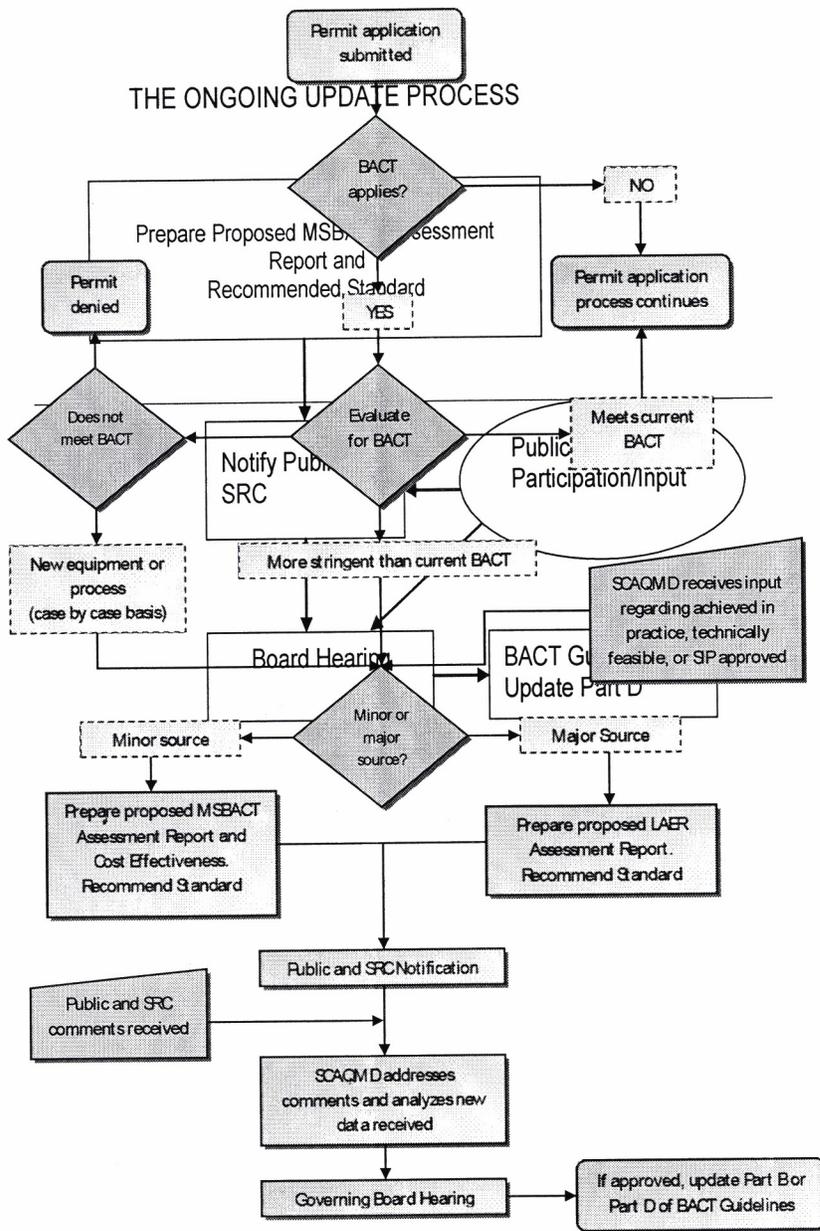
The requirement of a clean fuel is based on engineering feasibility. Engineering feasibility considers the availability of a clean fuel and safety concerns associated with that fuel. Some state and local safety requirements limit the types of fuel, which can be used for emergency standby purposes. Some fire departments or fire marshals do not allow the storage of LPG near occupied buildings. Fire officials have, in some cases, vetoed the use of methanol in hospitals. If special handling or safety considerations preclude the use of the clean fuel, the SCAQMD has allowed the use of fuel oil as a standby fuel in boilers and heaters, fire suppressant pump engines and for emergency standby generators. The use of these fuels must meet the requirements of SCAQMD rules limiting NO_x and sulfur emissions. In addition, the Clean Fuel requirements for MSBACT are subject to the provisions of California Health and Safety Code Section 40440.11.

BACT UPDATE PROCESS

As technology advances, the SCAQMD's MSBACT Part D Guidelines will be updated. Updates will include revisions to the guidelines for existing equipment categories, as well as new guidelines for new categories.

The MSBACT Guidelines will be revised based on the criteria outlined in the previous sections. Once a more stringent emission limit or control technology has been reviewed by staff and is determined to meet the criteria for MSBACT, it will be reviewed through a public process. The process is shown schematically in Figure 2. The public will be notified and the BACT Scientific Review Committee (SRC) will have an opportunity to comment. Following the public process and comment period, the guidelines will be presented to the Governing Board for approval at a public hearing, prior to updates of the MSBACT Guidelines, Part D.

Figure 2: The Ongoing BACT Update Process



Chapter 2 - How to Use Part D of the MSBACT Guidelines

This chapter explains the MSBACT information found in Part D - MSBACT Guidelines. The Guidelines in Part D should be used to determine MSBACT for non-major polluting facilities. For a listing of equipment, refer to the Part D Table of Contents. Determination of MSBACT for equipment not found in Part D of the MSBACT Guidelines is also explained.

GENERAL

Part D includes MSBACT Guidelines for more than 100 categories of equipment commonly processed by SCAQMD. Some guidelines are further subdivided by equipment size, rating, type or the material used, as appropriate.

The MSBACT requirements are in the form of:

- 1) an emission limit;
- 2) a control technology;
- 3) equipment requirements; or
- 4) a combination of the last two.

If the requirement is an emission limit, the applicant may choose any control technology to achieve the emission limit. The SCAQMD prefers to set an emission limit as MSBACT because it allows an applicant the most flexibility in reducing emissions.

If a control technology and/or equipment requirements are the only specified MSBACT, then either emissions from the equipment are difficult to measure or it was not possible to specify an emission limit that applies to all equipment within the category. Where possible, an emission limit or control efficiency condition will be specified in the permit along with the control technology or equipment requirements to ensure that the equipment is properly operated with the lowest emissions achievable. An applicant may still propose to use other ways to achieve the same or better emission reduction than the specified MSBACT.

MSBACT is the control technology or emission limit given in Part D for the basic equipment or process being evaluated, unless the guideline is out of date, or there are special permitting conditions, or the equipment is not identified in Part D. In those cases, the procedures described in the following sections will be used to determine MSBACT. Applicants or other interested parties are encouraged to contact the SCAQMD permitting staff if there are any questions about MSBACT.

SPECIAL PERMITTING CONSIDERATIONS

Although the most stringent, AIP BACT for a source category will most likely be the required MSBACT, SCAQMD staff may consider special technical

circumstances that apply to the proposed equipment which may allow deviation from that MSBACT. The permit applicant should bring any pertinent facts to the attention of the SCAQMD permitting engineer for consideration.

Case-Specific Situations

SCAQMD staff may consider unusual equipment-specific and site-specific characteristics of the proposed project that would warrant a reconsideration of the MSBACT requirement for new equipment.

Technical infeasibility of the control technology:

—A particular control technology may not be required as MSBACT if the applicant demonstrates that it is not technically feasible to install and operate it to meet a specific MSBACT emission limitation in a specific permitting situation.

Operating schedule and project length:

If the equipment will operate much fewer hours per year than what is typical, or for a much shorter project length, it can affect what is considered "AIP".

Availability of fuel or electricity:

Some MSBACT determinations may not be feasible if a project will be located in an area where natural gas or electricity is not available.

Process requirements:

Some MSBACT determinations specify a particular type of process equipment. SCAQMD staff may consider requirements of the proposed process equipment that would make the MSBACT determination not technically feasible.

Equivalency

The permit applicant may propose alternative means to achieve the same emission reduction as required by BACT. For example, if BACT requires a certain emission limit or control efficiency to be achieved, the applicant may choose any control technology, process modification, or combination thereof that can meet the same emission limit or control efficiency.

Super Clean-Compliant Materials

SCAQMD will accept the use of super clean-compliant materials in lieu of an add-on control device controlling volatile organic compound (VOC) emissions from coating operations. For example at this time, if a permit applicant uses only surface coatings that meet the super compliant material definition in SCAQMD Rule 109 contain less than 5% VOC by weight, it may qualify as VOC MSBACT. This policy does not preclude any other MSBACT requirement for other contaminants.

Equipment Modifications

As a general rule, it is more difficult to retrofit existing equipment with MSBACT as a result of NSR modification when compared to a new source. The equipment being modified may not be compatible with some past MSBACT

determinations that specify a particular process type. There may also be space restrictions that prevent installation of some add-on control technology.

Other Considerations

Although multiple process and control options may be available during the MSBACT determination process, considerations should be made for options that reduce the formation of air contaminants from the process, as well as ensuring that emissions are properly handled. In addition to evaluating the efficiency of the control stage, these additional considerations are needed to ensure that the system is capable of reducing or eliminating emissions from the facility on a consistent basis during the operational life of the equipment. Measures listed in this section for MSBACT are subject to the requirements of California Health and Safety Code Section 40440.11.

Pollution Prevention

The Pollution Prevention Act of 1990 (42 U.S.C. §§13101-13109) established a national policy that pollution should be prevented or reduced at the source whenever feasible. In many cases, air pollution control is a process that evaluates contaminants at the exhaust of the system. Pollution prevention is the reduction or elimination of waste at the source by the modification of the production process. Pollution prevention measures may consist of the use of alternate or reformulated materials, a modification of technology or equipment, or improvement of energy efficiency changes that result in an emissions reduction. These measures should be considered as part of the MSBACT determination process if the measures will result in the elimination or reduction of emissions, but are not required to include projects which are considered to fundamentally redefine the source. New and different emissions created by a process or material change will also need to be considered as part of the MSBACT determination process, in contrast to the overall emissions reductions from the implementation of pollution prevention measures. U.S. EPA policy defined pollution prevention as source reduction and other practices that reduce or eliminate the creation of pollutants through increased efficiency in the use of raw materials, energy, water, or other resources, and protection of natural resources by conservation²⁰. U.S. EPA further specifies that pollution prevention does not include recycling (except in-process recycling), energy recovery, treatment or disposal. For purposes of these BACT Guidelines, and to be consistent with federal definitions, source reduction and pollution prevention shall may include, but not be limited to, consideration of the feasibility of:

- ☐ equipment or technology modifications,
- ☐ process or procedure modifications,
- ☐ reformulation or redesign of products,
- ☐ substitution of raw materials, or
- ☐ improvements in housekeeping, maintenance or inventory control.

²⁰ U.S. EPA Pollution Prevention Law and Policies (www.epa.gov/p2/pollution-prevention-law-and-policies#define)

that reduce the amount of air contaminants entering any waste stream or otherwise released into the environment, including fugitive emissions.

Monitoring and Testing

In order to ensure that MSBACT determinations continue to meet their initial emission and efficiency standards, periodic or continuous parameter monitoring and testing requirements may be implemented required during the permitting process. Equipment and processes may experience some change over time, due to aging or operational methods of the equipment, which may affect emission rates or control efficiencies. In addition to other rule requirements, additional monitoring and testing requirements may need to focus on aspects directly related to the MSBACT determination, and may be made enforceable by permit conditions. Monitoring and testing requirements should be specific to characterize operating conditions (e.g. temperatures, pressures, flows, production rates) and measurement techniques when MSBACT is established to ensure clarity and consistency with the standard.

Capture Efficiency

An integral part of controlling air pollutants emitted from a process with add-on air pollution control equipment is capturing those emissions and directing them to the air pollution control device. Emissions which are designed to be collected by an exhaust system but are vented uncontrolled into the atmosphere can have a much greater impact than controlled emissions. When applicable, the evaluation of a process and its associated control equipment should address the qualification and quantification of capture efficiency. By addressing capture efficiency during MSBACT determinations, a standard can be established to evaluate the capture efficiency of other systems, as well as ensure that the capture efficiency is maintained consistently over time.

If applicable, MSBACT determinations may include the percentage capture efficiency and the methods and measurements (e.g. EPA Method 204, capture velocity measurements, design using ACGIH's Industrial Ventilation, static pressures) used to determine and verify it. For various circumstances, several SCAQMD rules (see Table 5, Part A, Chapter 1) already require an assessment of collection efficiency of an emission control system following EPA Method 204, EPA's "Guidelines for Determining Capture Efficiency", SCAQMD's "Protocol for Determination of Volatile Organic Compounds (VOC) Capture Efficiency," or other methods approved by the Executive Officer, and are appropriate to include as BACT requirements. The capture efficiency for any MSBACT Determination shall be no less stringent than any applicable rule requirement. Other considerations that may affect capture, such as cross-drafts, thermal drafts and the volume of combustion products, should also be addressed during this process.

MSBACT Determinations Should the Guidelines Become Out of Date

Should the MSBACT Guideline Part D become out of date with state BACT requirements or permits issued for similar equipment in other parts of the state,

staff will evaluate permits consistent with the definition of BACT considering technical and economic criteria as required by Rule 1303 (a) and Health & Safety Code Section 40405. The technical and economic factors to be considered are those identified in Chapter 1.

BACT APPLICATION CUT-OFF DATES

These guidelines apply to all non-major polluting facility applications deemed complete subsequent to SCAQMD Governing Board adoption of the Regulation XIII amendments in 2000.

Applications for a Registration Permit for equipment issued a valid Certified Equipment Permit (CEP), which is valid for one year, will only be required to comply with MSBACT as determined at the time the CEP was issued. However, SCAQMD staff will reevaluate the MSBACT requirements for the CEP upon annual renewal of the CEP by the equipment manufacturer.

PART D - BACT GUIDELINES FOR NON-MAJOR POLLUTING FACILITIES

Part D of the BACT Guidelines is published as a separate document.

PART E – POLICY AND PROCEDURES
FOR FACILITIES SUBJECT TO
PREVENTION OF SIGNIFICANT
DETERIORATION FOR GREENHOUSE
GASES

Chapter 1 - GHG BACT

This chapter explains the requirements of greenhouse gases (GHG) BACT regulations according to EPA, describes the Top-Down Process, shows how to calculate GHG emissions and explains the Prevention of Significant Deterioration (PSD) Applicability for GHGs for new sources as well as modified sources. Currently, the Tailoring Rule is undergoing a revision to address the U.S. Supreme Court decision in *Utility Air Regulatory Group v. Environmental Protection Agency*, 134 S. Ct. 2427 (2014)²¹. The guidance in this chapter is applicable to the EPA requirements in place as of the date of these guidelines, and takes into consideration the U.S. Supreme Court decision in *Utility Air Regulatory Group v. Environmental Protection Agency*, 134 S. Ct. 2427 (2014)²², as well as SCAQMD Rule 1714.

BACKGROUND

EPA has found that GHG, made up of up of six combined compounds, constitute air pollution that endanger public health and welfare. EPA's adopted requirements for GHG under 40 CFR 52.21 Tailoring Rule was issued in May 2010, which were revised in October 2015, to establishing a way to permit GHG emissions under PSD and Title V. Through this rule, permitting focused on the major industrial sources, which emit nearly 70 percent of the greenhouse gas pollution from stationary sources. At this time, smaller businesses and sources are not be subject to these requirements.

The requirements of this rule apply only to GHG as defined by EPA as a total group of six GHG which are: carbon dioxide (CO₂), nitrous oxide (N₂O), methane (CH₄), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF₆). All other attainment air contaminants, as defined in SCAQMD Rule 1702 subdivision (a), shall be regulated for the purpose of PSD. PSD is not applicable to air contaminants designated as nonattainment status.

PERMITTING GUIDANCE FOR GHG

EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" provides the basic information that permit writers and applicants need to address GHG emissions in permits. Although this guidance was issued prior to the revision of 40 CFR 52.21 in 2015, there are parts still applicable to the current requirements. The applicable parts of the guidance document are summarized in these Guidelines. The guidance:

- ²¹ applies long-standing PSD and Title V permitting requirements and processes to GHG;
- ²² reiterates that BACT determinations will continue to be a state, and project specific decision;

²¹ The UARG v. EPA decision limited the scope originally envisioned by the Tailoring Rule, and now only "anyway sources" are subject to GHG BACT.

²² The UARG v. EPA decision limited the scope originally envisioned by the Tailoring Rule, and now only "anyway sources" are subject to GHG BACT. On October 3, 2016, EPA proposed revising 40 CFR 52.21 to establish a Significant Emissions Rate for GHGs at the same threshold of 75,000 ton per year CO₂e as Step 1 of the Tailoring Rule for "anyway" sources.

- § 81.1 does not prescribe GHG BACT for any source type;
- § 81.1 emphasizes the importance of BACT options that improve energy efficiency;
- § 81.1 points out that Carbon Capture and Sequestration (CCS) is a promising technology in the early stage of demonstration and commercialization (it should be identified as an available control measure in the first step of BACT, it is currently an expensive technology and unlikely to be selected as BACT in most cases);
- ~~clarifies that EPA does not intend to require GHG to be addressed in permits issued before January 2, 2011 that do not become effective until after this date;~~
- § 81.1 notes that biomass could be considered BACT after taking into account environmental, energy, and economic considerations and state and federal policies that promote biomass for energy-independence and environmental reasons. In its memorandum²³ dated November 19, 2014, EPA states that it is still assessing and monitoring biogenic feedstocks and will provide further guidance. Further updates can be found at EPA's webpage "CO2 Emissions Associated with Biomass Use at Stationary Sources."
- § 81.1 provides flow charts and examples that illustrate the key points of the traditional five-step process for determining BACT for GHG; and
- § 81.1 identifies technical resources related to GHG emissions and controls.

FEDERAL PSD APPLICABILITY FOR GHG

~~Beginning January 2, 2011, GHG are regulated as a NSR contaminant. GHG BACT applies when a new or modified facility is subject to PSD requirements for GHG. The first step for PSD applicability determination for new or modified sources is listed in the Tables 7 and 8 below that address the Tailoring Rule requirements in 40 CFR 52.21. A second step for PSD applicability is contemporaneous netting. For detailed guidance on this topic, EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) should be referenced, but should be used in accordance with EPA's clarifying documents regarding the U.S. Supreme Court decision in *Utility Air Regulatory Group v. Environmental Protection Agency*²⁴ and the current requirements under 40 CFR 52.21.~~

In determining PSD applicability, a differentiation between GHG CO₂e and mass basis must be made. GHG mass basis is simply the sum of all six GHG compound mass emissions. However, to obtain GHG CO₂e, the mass emissions of each individual GHG compound must be multiplied by its 100-year Global Warming Potential (GWP). The individual GHG CO₂e are then summed to obtain the total CO₂e for the source. Current GWP factors should be obtained from EPA's website when performing these calculations.

²³ EPA Memo: "Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources, (2014 November 9)"

²⁴ EPA Memo: Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision, (2014, July 24)

Table 7
GHG PSD Applicability for New Sources

PSD applies to GHG if:
1. <u>The source is otherwise subject to PSD for another regulated NSR pollutant, AND</u>
2. <u>The source has a GHG PTE \geq 75,000 tons per year (TPY) CO₂e;</u>

Table 8
GHG PSD Applicability for Modified Sources

PSD applies to GHG if:
1. <u>The modification is otherwise subject to PSD for another regulated NSR pollutant, AND</u>
2. <u>The modification results in a GHG emissions increase or a net emissions increase:</u>
a. <u>PTE \geq 75,000 TPY CO₂e, AND</u>
b. <u>> zero TPY mass basis</u>

Contemporaneous Netting

Contemporaneous netting is the process of considering all of the creditable emission increases and decreases that have occurred during the period beginning five years before the proposed construction of the modification through the date that the emission increase from the modification occurs. When calculating the net emissions increase in Table 8 above for PSD applicability, it must include all emission increases and decreases during this period.

SCAQMD PSD APPLICABILITY FOR GHG

SCAQMD adopted Rule 1714 in 2010 to implement the PSD GHG requirements set forth by 40 CFR 52.21. SCAQMD Rule 1714 incorporates the provisions of 40 CFR 52.21 by reference, excluding the sections listed under SCAQMD Rule 1714 (c)(1). SCAQMD PSD applicability should be determined following the applicable sections of the Code of Federal Regulation identified in the rule.

TOP-DOWN BACT PROCESS

EPA recommends that permitting authorities continue to use the EPA's five-step "Top-Down" BACT process to determine BACT for GHG (U.S. EPA, 2011)²⁵. While this section summarizes the steps in the process, further details for each of the steps can be referenced in EPA's guidance document.

BACT Step 1 – Identify All Available Control Options

The first step in the top-down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation.

Permit applicants and permitting authorities should identify all "available" GHG control options that have the potential for practical application to the source under consideration.

The application of BACT to GHG does not affect the discretion of a permitting authority to exclude options that would fundamentally redefine a proposed source. GHG control technologies are likely to vary based on the type of facility, processes involved, and GHG being addressed. EPA has emphasized the importance of energy efficiency improvements. ~~The first category of energy efficiency improvement options includes technologies or processes that maximize the efficiency of the individual emissions unit. The second category of energy efficiency improvements includes the options that could reduce emissions from a new greenfield facility by improving utilization of thermal energy and electricity that is generated and used on-site.~~

For the purposes of a BACT analysis for GHG, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO₂-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO₂ streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).

BACT Step 2 – Eliminate Technically Infeasible Options

Under the second step of the top-down BACT analysis, a potentially applicable control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. EPA generally considers a technology to be technically feasible if it has been successfully operated on the same type of source under review, or is available and applicable to the source under review.

Assuming CCS has been included in Step 1 of the top-down BACT process for such sources, it now must be evaluated for technical feasibility in Step 2. CCS is composed of three main components: CO₂ capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for anyeach of these three main components from what has already

²⁵ U.S. EPA (2011). PSD and Title V Permitting Guidance for Greenhouse Gases

been applied to a differing source type. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (e.g., space for CO₂ capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options).

BACT Step 3 – Ranking of Controls

After the list of all available controls is winnowed down to a list of the technically feasible control technologies in Step 2, Step 3 of the top-down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated NSR pollutant under review. The most effective control alternative (i.e., the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness. The ranking of control options in Step 3 determines where to start the top-down BACT selection process in Step 4.

The options considered in a BACT analysis for GHG emissions will likely include, but not necessarily be limited to, control options that result in energy efficiency measures to achieve the lowest possible emission level. Where plant-wide measures to reduce emissions are being considered as GHG control techniques, the concept of overall control effectiveness will need to be refined to ensure the suite of measures with the lowest net emissions from the facility is the top-ranked measure. Ranking control options based on their net output-based emissions ensures that the thermal efficiency of the control option, as well as the power demand of that control measure, is fully considered when comparing options in Step 3 of the BACT analysis. Finally, to best reflect the impact on the environment, the ranking of control options should be based on the total CO₂e rather than total mass or, mass for the individual GHG.

BACT Step 4 – Economic, Energy, and Environmental Impacts

Under Step 4 of the top-down BACT analysis, permitting authorities must consider the economic, energy, and environmental impacts arising from each option remaining under consideration. Accordingly, after all available and technically feasible control options have been ranked in terms of control effectiveness (BACT Step 3), the permitting authority should consider any specific energy, environmental, and economic impacts identified with those technologies to either confirm that the top control alternative is appropriate or determine it to be inappropriate.

There are compelling public health and welfare reasons for BACT to require all GHG reductions that are achievable, considering economic impacts and the other listed statutory factors. As a key step in the process of making GHG a regulated pollutant, EPA has considered scientific literature on impacts of GHG emissions and has made a final determination that emissions of six GHG endanger both the public health and the public welfare of current and future

generations. Potential impacts that may be considered in this step based on the EPA's January 2010 Endangerment Finding²⁶ are detailed in EPA's guidance document. Among the public health impacts and risks that EPA cited are anticipated increases in ambient ozone and serious ozone-related health effects, increased likelihood of heat waves affecting mortality and morbidity, risk of increased intensity of hurricanes and floods, and increased severity of coastal storm events due to rising sea levels. With respect to public welfare, EPA cited numerous and far ranging risks to food production and agriculture, forestry, water resources, sea level rise and coastal areas, energy, infrastructure, and settlements, and ecosystems and wildlife. The potentially serious adverse impacts of extreme events such as wildfires, flooding, drought and extreme weather conditions also supported EPA's finding.

When conducting a BACT analysis for GHG, the environmental impact analysis should continue to concentrate on impacts other than the direct impacts due to emissions of the regulated pollutant in question. Where GHG control strategies affect emissions of other regulated pollutants, applicants and permitting authorities should consider the potential trade-offs of selecting particular GHG control strategies.

BACT Step 5 – Selecting BACT

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit. For energy-producing sources, one way to incorporate the energy efficiency of a process unit into the BACT analysis is to compare control effectiveness in BACT Step 3 based on output-based emissions of each of the control options. Establishing an output-based BACT emissions limit, or a combination of output- and input-based limits, wherever feasible and appropriate to ensure that BACT is complied with at all levels of operation should be considered.

GHG CONTROL MEASURES WHITE PAPERS

EPA has a series of technical "white papers" that summarize readily available information on control techniques and measures to reduce GHG emissions from specific industrial sectors. These papers provide basic technical information which may be useful in a BACT analysis, but they do not define BACT for each sector. The industrial sectors covered include:

-  Electric Generating Units (PDF) (48pp, 805k)
EPA Contact: Christian Fellner (919-541-4003 or fellner.christian@epa.gov)
-  Large Industrial/Commercial/Institutional Boilers (PDF) (39pp, 337k)
EPA Contact: Jim Eddinger (919-541-5426 or edding.jim@epa.gov)
-  Pulp and Paper (PDF) (62pp, 421k)
EPA Contact: Bill Schrock (919-541-5032 or schrock.bill@epa.gov)

²⁶ <https://www3.epa.gov/climatechange/endangerment/>

-  Cement (PDF) (48pp, 220k)
EPA Contact: [Keith Barnett \(919-541-5605 or barnett.keith@epa.gov\)](mailto:barnett.keith@epa.gov)
-  Iron and Steel Industry (PDF) (78pp, 620k)
EPA Contact: [Donna Lee Jones \(919-541-5251 or jones.donnalee@epa.gov\)](mailto:jones.donnalee@epa.gov)
-  Refineries (PDF) (42pp, 707k)
EPA Contact: [Brenda Shine \(919-541-3608 or shine.brenda@epa.gov\)](mailto:shine.brenda@epa.gov)
-  Nitric Acid Plants (PDF) (31pp, 544k)
EPA Contact: [Nathan Topham \(919-541-0483 or topham.nathan@epa.gov\)](mailto:topham.nathan@epa.gov)
-  Landfills (PDF) (28pp, 250k)
EPA Contact: [Hillary Ward \(919-541-3154 or ward.hillary@epa.gov\)](mailto:ward.hillary@epa.gov)

**PART F – BACT DETERMINATIONS FOR
FACILITIES SUBJECT TO PREVENTION
OF SIGNIFICANT DETERIORATION FOR
GREENHOUSE GASES**

(This section is currently under development)

LIST OF ABBREVIATIONS

AIP	Achieved in Practice
APCD	Air Pollution Control District Air Pollution Control District
AQMD	South Coast Air Quality Management District
AQMP	Air Quality Management Plan
BACT	Best available control technology
BRC	BACT Review Committee, <u>SCAQMD</u>
CAA	Clean Air Act
CAPCOA	California Air Pollution Control Officers Association
CARB	California Air Resources Board
CCS	Carbon Capture and Sequestration
CEP	Certified Equipment Permit
CFC	Chlorofluorocarbons
CFR	Code of Federal Regulations
CO	Carbon monoxide
CO₂	Carbon dioxide
CO₂e	Carbon dioxide equivalent
DCF	Discounted Cash Flow Method
DEO	Deputy Executive Officer
GHG	Greenhouse Gas(es)
GWP	Global Warming Potential
H&SC	Health and Safety Code, California State
LAER	Lowest achievable emission rate
LPG	Liquefied petroleum gas
MDAB	Mojave Desert Air Basin
MICR	Maximum Individual Cancer Risk
MSBACT	Minor Source BACT
NO ₂	Nitrogen dioxide
NO _x	Oxides of nitrogen
NSR	New Source Review
ODC	Ozone depleting compounds
Pb	Lead
PM ₁₀	Particulate matter less than 10 microns in diameter
PM_{2.5}	Particulate matter less than 2.5 microns in diameter
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACT	Reasonably available control technology
RECLAIM	Regional Clean Air Incentives Market
ROG	Reactive organic gas
RTC	RECLAIM trading credit
SCAQMD	South Coast Air Quality Management District
SIP	State Implementation Plan
SOCAB	South Coast Air Basin

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline**

Source Category

Source:	IC Engine – Compression Ignition, Stationary Prime; non-Agricultural	Revision:	6
Class:	> 50 BHP Output	Document #:	96.1.4
		Date:	04/13/2009

REVISED 6/11/15

John - before I print many of these, is this the information you need?

*Thanks
Bill
6/12/17*

Determination

Pollutant	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. 50% reduction of current tier ^{a,b} standard for POC. 2. Current tier ^{a,b} standard for POC at applicable horsepower rating.	1. Catalytic oxidation combined with current POC certified engine. ^{a,b} 2. Current POC certified engine. ^{a,b}
NOx	1. 85% reduction of current tier ^{a,b} standard for NOx. 2. Current tier ^{a,b} standard for NOx at applicable horsepower rating.	1. Selective catalytic reduction (SCR) + current NOx certified engine. ^{a,b} 2. Current NOx certified engine. ^{a,b}
SO ₂	1. n/s 2. Fuel sulfur content not to exceed 0.0015% (wt) or 15 ppm.	1. n/s 2. CARB Diesel Fuel (Ultra Low Sulfur Diesel).
CO	1. 50% reduction of current tier ^{a,b} standard for CO. 2. 2.75 g/bhp-hr [319 ppmvd @ 15% O ₂] ^d	1. Catalytic oxidation combined with current CO certified engine. ^{a,b} 2. Any engine demonstrated or certified to meet 2.75 g/bhp-hr.
PM ₁₀	1. n/s 2. 0.01 g/bhp-hr or equiv ^c technology. ^c 3. TBACT: 0.01 g/bhp-hr or equivalent ^c technology. ^c	1. n/s 2. Any engine/technology verified or certified to achieve 0.01 g/bhp-hr. ^c 3. (See 2., above) ^c
NPOC	1. n/s 2. n/s	1. n/s 2. n/s

References

- a. Current tier standard: The current CARB or EPA off-road tier standard for the pollutant of concern within the appropriate horsepower range. Where NMHC + NOx is listed (with no individual standards for NOx or NMHC) as the standard, the portions may be considered 95% NOx and 5% NMHC. For the purposes of determining BACT NMHC = POC. Any engine which has been certified or demonstrated to meet the current year tier standard may be considered a current certified engine for that pollutant.
- b. An engine which does not meet the current EPA or CARB off-road tier standard may represent BACT2, providing 1) the engine met the most stringent EPA Tier Standard in effect prior to the Tier change for that horsepower rating, and 2) the permit application is submitted within 6 months of the effective date of the Tier change. [Source: California Health & Safety Code Section 93116.3(b)(7)]
- c. Compliance with 0.01 g/bhp-hr may be demonstrated by use of *Alternative Compliance Demonstration*, specified in California Health & Safety Code Section 93115.13(f) [Stationary CI Engine ATCM].
- d. Previous BACT determination dated 01/11/02.
- e. Specified because not all BAAQMD-defined stationary engines are subject to the Stationary ATCM.

Overview of Off-Road Compression Ignition Engine Certification Standards in g/bhp-hr (g/kW-hr)¹

Engine HP (KW)	Tier 1 ₂					Tier 2				Tier 3				Tier 4					
	HC	NOx	CO	PM	Years	NMHC + NOx	CO	PM	Years	NMHC + NOx	CO	PM	Years	NMHC + NOx	NMHC	NOx ₃	CO	PM	Years
50 <75 (37<56)		6.9 (9.2)			1998 - 2003	5.6 (7.5)	3.7 (5.0)	0.30 (0.40)	2004 - 2007	3.5 (4.7)	3.7 (5.0)	0.22 (0.30)	2008 - 2012	3.5 (4.7)			3.7 (5.0)	0.02 (0.03)	2013+
75<100 (56<75)		6.9 (9.2)			1998 - 2003	5.6 (7.5)	3.7 (5.0)	0.30 (0.40)	2004 - 2007	3.5 (4.7)	3.7 (5.0)	0.30 (0.40)	2008 - 2011	3.5 (4.7)	0.14 (0.19)	0.30-2.5 (0.40-3.4)	3.7 (5.0)	0.01 (0.02)	2012 - 2013
															0.14 (0.19)	0.30 (0.40)	3.7 (5.0)	0.01 (0.02)	2014+
100<175 (75<130)		6.9 (9.2)			1997 - 2002	4.9 (6.6)	3.7 (5.0)	0.22 (0.30)	2003 - 2006	3.0 (4.0)	3.7 (5.0)	0.22 (0.30)	2007 - 2011	3.0 (4.0)	0.14 (0.19)	0.30-2.5 (0.40-3.4)	3.7 (5.0)	0.01 (0.02)	2012 - 2013
															0.14 (0.19)	0.30 (0.40)	3.7 (5.0)	0.01 (0.02)	2014+
175<300 (130<225)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	1996 - 2002	4.9 (6.6)	2.6 (3.5)	0.15 (0.20)	2003 - 2005	3.0 (4.0)	2.6 (3.5)	0.15 (0.20)	2006 - 2010	3.0 (4.0)	0.14 (0.19)	0.30-1.5 (0.40-2.0)	2.6 (3.5)	0.01 (0.02)	2011 - 2013
															0.14 (0.19)	0.30 (0.40)	2.6 (3.5)	0.01 (0.02)	2014+
300<600 (225<450)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	1996 - 2000	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2001 - 2005	3.0 (4.0)	2.6 (3.5)	0.15 (0.20)	2006 - 2010	3.0 (4.0)	0.14 (0.19)	0.30-1.5 (0.40-2.0)	2.6 (3.5)	0.01 (0.02)	2011 - 2013
															0.14 (0.19)	0.30 (0.40)	2.6 (3.5)	0.01 (0.02)	2014+
600<750 (450<560)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	1996 - 2001	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2002 - 2005	3.0 (4.0)	2.6 (3.5)	0.15 (0.20)	2006 - 2010	3.0 (4.0)	0.14 (0.19)	0.30-1.5 (0.40-2.0)	2.6 (3.5)	0.01 (0.02)	2011 - 2013
															0.14 (0.19)	0.30 (0.40)	2.6 (3.5)	0.01 (0.02)	2014+
≥750 (≥560)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	2000 - 2005	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2006 - 2010						0.30 (0.40)	2.6 (3.5)	2.6 (3.5)	0.075 (0.10)	2011 - 2014
															0.14 (0.19)	2.6 (3.5)	2.6 (3.5)	0.03 (0.04)	2015+
>750≤1200 ⁴ (560≤900) Gen. Only	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	2000 - 2005	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2006 - 2010						0.30 (0.40)	2.6 (3.5)	2.6 (3.5)	0.075 (0.10)	2011 - 2014
															0.14 (0.19)	0.50 (0.67)	2.6 (3.5)	0.02 (0.03)	2015+
>1200 ⁴ (>900) Gen. Only	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	2000 - 2005	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2006 - 2010						0.30 (0.40)	0.50 (0.67)	2.6 (3.5)	0.075 (0.10)	2011 - 2014
															0.14 (0.19)	0.5 (0.67)	2.6 (3.5)	0.02 (0.03)	2015+

1 This table is intended as an overview. For California Exhaust Emission Standards and Test Procedures -Off-Road Compression-Ignition Engines, consult title 13, California Code of Regulations, section 2423. For federal Nonroad Compression Ignition Engine Certification Standards, consult title 40, United States Code of Federal Regulations, Chapter 1, Part 89, subpart B and Part 1039, Subpart B.

2 Engine manufacturers have several options for complying with NOx during the transitional implementation years of Tier 4, including a "phase-in--phase-out" or alternative NOx level approach.

San Joaquin Valley APCD

Back

Best Available Control Technology (BACT) Guideline 1.8.2 D

Emissions Unit: Refinery Process Heater, Refinery Fuel Gas and/or Natural Gas
Equipment Rating: 641 and 215 MM Btu/hr

Facility: Big West of California LLC
References: S-33-407-0 and '411-0

Location: Bakersfield
Date of Determination: 9/1/2006

Pollutant BACT

CO 10 ppmv @ 3% O₂ (SCR and burner tuning)
 NO_x 5 ppmv at 3% O₂, (15 minute average) (Low NO_x burners and SCR)
 PM₁₀ Treated refinery gas and/or natural gas with no more than 100 ppmv total reduced sulfur (3-hour rolling average)
 SO_x Treated refinery gas and/or natural gas with no more than 100 ppmv total reduced sulfur (3-hour rolling average)
 VOC Good combustion practices

BACT Status	Comment
Achieved in Practice	VOC, NO _x , SO _x and CO
Technologically Feasible BACT	PM ₁₀

Best Available Control Technology (BACT) Guideline 1.8.2 C

Emissions Unit: Process Heater - Refinery
Equipment Rating: All
Facility: Equilon Enterprise
References: ATC #: Withdrawn Project #: S-990010
Location: Bakersfield
Date of Determination: 1/4/2001

Pollutant BACT

CO BACT NOT TRIGGERED

Pollutant	BACT
NOx	BACT NOT TRIGGERED
PM10	BACT NOT TRIGGERED
SOx	Natural gas or treated refinery gas @ 0.0621 grains H2S/dscf (100 ppmv H2S)
VOC	BACT NOT TRIGGERED

BACT Status

Comment

Achieved in Practice

Best Available Control Technology (BACT) Guideline 1.8.2 B

Emissions Unit:	Process Heater - Refinery	Equipment Rating:	= or > 50.0 MMBtu/hr
Facility:	n/a	References:	District Proactive BACT Determination
Location:	n/a	Date of Determination:	6/30/1999

Pollutant	BACT
CO	BACT NOT TRIGGERED
NOx	9.0 ppmvd @ 3% O ₂ (0.0108 lb/MMBtu) SCR
PM10	BACT NOT TRIGGERED
SOx	BACT NOT TRIGGERED
VOC	BACT NOT TRIGGERED

BACT Status

Comment

Achieved in Practice

Best Available Control Technology (BACT) Guideline 1.8.2 A

Emissions Unit:	Process Heater - Refinery	Equipment Rating:	92 MMBtu/hr
Facility:	Equilon Enterprises LLC	References:	ATC #: S-33-17-7 Project #: S-981236

BACT Clearinghouse (Searchable)

INSTRUCTIONS: To filter, enter a search term in "Search Description" and press return, or select a "Main Category" and/or "Sub Category".

Search Description	Main Category	Sub Category
	All	All

#	Description
1.1.1	<u>Boiler: < or = 20.0 MMBtu/hr, Natural Gas or Propane Fired *RESCINDED*</u> (10/26/2009)
1.1.2	<u>Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings. *RESCINDED*</u> (10/26/2009)
1.1.3	<u>Boiler - > 20.0 MMBtu/hr, Natural gas fired, with highly variable loads or high turndown ratios. *RESCINDED*</u> (10/26/2009)
1.1.4	<u>Digester Gas Fired Boiler *RESCINDED*</u> (10/26/2009)
1.1.5	<u>Boiler-Dual Fuel for Facilities Requiring Liquid Backup Fuel *RESCINDED*</u> (10/26/2009)
1.1.6	<u>Boiler - Fired with a High-Ammonia Fuel *RESCINDED*</u> (10/26/2009)
1.1.7	<u>Limited Use Boiler - Natural Gas Fired, < 9 Billion Btu/yr *RESCINDED*</u> (10/26/2009)
1.1.8	<u>Biomass-fired Boiler - Grate Systems *RESCINDED*</u> (10/26/2009)
1.2.1	<u>Oilfield Steam Generator (> or =20 MMBtu/hr) (3/24/2014)</u>
1.2.2	<u>Steam Generator - >20.0 MMBtu/Hr Vertically Oriented w/Counterflow Heat Transfer *RESCINDED*</u> (10/26/2009)
1.2.3	<u>Oilfield Steam Generator/TEOR Gas Incinerator **RESCINDED - part of 5/04 update to guideline 1.2.1** (5/1/2004)</u>
1.3.1	<u>Fluidized-Bed Combustor => 272 MMBtu/hr, Cogeneration Operation, Fired with Delayed Petroleum Coke (DPC) (8/27/2005)</u>
1.3.2	<u>Fluidized Bubbling Bed Combustor (biomass-fired) *RESCINDED*</u> (3/12/2012)
1.4.1	<u>Waste Gas Flare - 15.3 MMBtu/hr, Serving a Tank Vapor Control System *RESCINDED*</u> (11/7/2016)
1.4.2	<u>Waste Gas Flare - Incinerating Produced Gas *RESCINDED*</u> (11/7/2016)
1.4.3	<u>Landfill Gas Vapor Collection System *RESCINDED*</u> (11/7/2016)
1.4.4	<u>Digester Gas-Fired Flare *RESCINDED*</u> (11/7/2016)
1.4.5	<u>Oilfield Waste Gas Incinerator *RESCINDED*</u> (11/7/2016)



This web site has BACT for San Joaquin Valley APCP. I can not print them. You will have to open the site, pick the equipment, and read the info.

If you do find a way to print the individual results, let me know & I'll go back to print the applicable ones

**San Joaquin Valley
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Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

Main Category: 1.0 External Combustion

BACT Code	Boilers	NOx	VOC
1.1.1.a	Boiler: < or = 20.0 MMBtu/hr, Natural Gas or Propane Fired (> 30 Billion Btu/year)	15 ppmvd @ 3% O2(0.018 lb/MMBtu)	Natural gas with LPG backup or propane fired
1.1.1.b	Boiler: < or = 20.0 MMBtu/hr, Natural Gas or Propane Fired (< 30 Billion Btu/year)	20.0 ppmvd @ 3% O2 (0.024 lb/MMBtu)	Natural gas with LPG backup or propane fired
1.1.2	Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu)	Natural gas fuel with LPG backup
1.1.3	Boiler - > 20.0 MMBtu/hr, Natural gas fired, with highly variable loads or high turndown ratios	15.0 ppmvd @ 3% O2 (0.018 lb/MMBtu)	Natural Gas Fired with LPG as a backup fuel
1.1.4	Digester Gas Fired Boiler - < 5 MMBtu/hr	Natural Gas as supplemental fuel	Natural Gas as supplemental fuel
1.1.5	Boiler-Dual Fuel for Facilities Requiring Liquid Backup Fuel	15 ppmvd @ 3% O2 for the primary fuel	Natural gas as primary fuel with low sulfur #2 fuel oil (0.05% S by weight or less) as backup fuel gaseous fuel
1.1.6	Boiler - Fired with a High-Ammonia Fuel		
1.1.7	Limited Use Boiler - > 20.0 MMBtu/hr, Natural Gas Fired, < 9 billion Btu/year	30.0 ppmvd @ 3% O2 (0.036 lb/MMBtu)	Natural gas fuel with LPG backup

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Main Category: 1.0 External Combustion

BACT Code	Steam Generators	NOx	VOC
1.2.1	Steam Generator (> or = 5 MMBtu/hr, Oil Field)	14 ppmvd @ 3% O ₂	Gaseous fuel
1.2.2.a	Steam Generator - >20.0 MMBtu/Hr Vertically Oriented w/Counterflow Heat Transfer (> 30 Billion Btu/year)	15 ppmvd @ 3% O ₂ (0.018 lb/MMBtu)	Natural Gas or LPG
1.2.2.b	Steam Generator - >20.0 MMBtu/Hr Vertically Oriented w/Counterflow Heat Transfer (< 30 Billion Btu/year)	30.0 ppmvd @ 3% O ₂ (0.036 lb/MMBtu)	Natural Gas or LPG

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Main Category: 1.0 External Combustion

BACT Code	Fluidized-bed Combustors	NOx	VOC
1.3.1	Fluidized-Bed Combustor => 272 MMBtu/hr, Cogeneration Operation, Fired with Delayed Petroleum Coke (DPC)	28 ppmvd (as NO2 corrected to 3% O2), ammonia injection (less than 30 ppmvd ammonia slip) and natural gas and fuel oil as auxiliary fuel)	0.008 lb/MMBtu, natural gas and fuel oil as auxiliary fuel
1.3.2	Fluidized Bubbling Bed Combustor (biomass-fired)	0.10 lb/MMBtu, ammonia injection and natural gas auxiliary fuel	0.02 lb/MMBtu, natural gas auxiliary fuel

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Main Category: 1.0 External Combustion

BACT Code	Flares	NOx	VOC
1.4.1	Waste Gas Flare - 15.3 MMBtu/hr, Serving a Tank Vapor Control System	Steam-assisted or air-assisted when steam unavailable	Steam-assisted or air-assisted when steam unavailable
1.4.2	Waste Gas Flare - Incinerating Produced Gas	Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable	Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable
1.4.3	Landfill Gas Vapor Collection System	0.06 lb-NOx/MMBtu	Flare with a control efficiency of (= or >) 98% or a controlled VOC (measured as methane) of (= or <) 20 ppmv @ 3% O ₂
1.4.4	Digester Gas-Fired Flare	enclosed flare and NOx emissions <= 0.06 lb/MMBtu	enclosed flare and VOC emissions =< 0.068 lb/MMBtu
1.4.5	Oilfield Waste Gas Incinerator	Natural gas auxiliary fuel	Natural gas auxiliary fuel
1.4.7	Waste Gas Flare - Oilfield Well Drilling and Testing Operation, < 50 MMscf/day	N/A	Elevated Flare with propane fueled pilot light
1.4.8	Refinery Flare	Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases.	Engineered flare designed with a VOC destruction efficiency of ≥ 98%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system non-emergency releases.

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Main Category: 1.0 External Combustion

BACT Code	Furnaces	NOx	VOC
1.5.1	Fiberglass Production Furnace, Natural gas fired	Natural gas firing, electric heat boost, Low excess air (< 5%), and use of cullet > 15% annually	Natural gas firing and use of cullet (scrap glass) > 15% annually
1.5.2	Flat Glass Production Float Furnace, Natural Gas Fired	Tier 1 limit in Rule 4354 specific to furnace	gaseous fuel
1.5.4	Metal Melting Crucible/Furnace	Natural gas	Natural gas
1.5.5	Glass Bottle Label Curing Lehr - < 10 MMBtu/hr, Natural Gas Fired	Natural Gas or LPG Fuel	Natural Gas or LPG Fuel
1.5.6	Natural Gas-Fired Metal Heating Furnace	30 ppmv NOx @ 3% O2 at the final stack	30 ppmv NOx @ 3% O2 at the final stack
1.5.7	Glass Furnace Forehearth	natural gas/propane-fired and good combustion practices	natural gas/propane-fired and good combustion practices
1.5.8	Container Glass Production - Container Glass Distributor	Natural gas-fired container glass distributor with good combustion practices, using LPG backup fuel, and NOx emissions of 0.10 lb/MMBtu	Natural gas with LPG backup
1.5.9	Container Glass Production - Furnace	NOx emissions of < or = 1.5 lb/ton of glass pulled	VOC emissions of < or = 0.2 lb/ton of glass pulled
1.5.10	Container Glass Production - Container Glass Lehr	60 ppmv NOx @ 3% O2 or 0.073 lb-NOx/MMBtu	Natural gas with LPG backup

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Main Category: 1.0 External Combustion

BACT Code	Food & Ag Products Ovens, etc.	NOx	VOC
1.6.1.a	Tomato Roaster	Operation of burner within manufacturer's specification to minimize Nox emissions	Gaseous fuel
1.6.1.b	Vegetable Roasting Operation	Use of natural gas fuel and operating the burner within manufacturer's specification to minimize NOx emissions	Gaseous fuel
1.6.2	Oven - Tortilla, <= 5 MMBtu/hr	natural gas fired with optional LPG as backup fuel	natural gas fired with optional LPG as backup fuel
1.6.4	Oven - Snack Food	Natural gas and LPG as backup fuel	Natural gas and LPG as backup fuel
1.6.7	Pistachio Roasting Operation	Natural gas fuel	Natural gas fuel
1.6.8	Pistachio Nut Dryer	0.083 lb/MMBtu and natural gas fuel	Natural gas fuel
1.6.11	Dryer - Milk Spray, > or = 20 MMBtu/hr	Low NOx burner fired on natural gas with LPG as backup fuel	Natural gas with LPG as backup fuel
1.6.14	Dehydrator Tunnel - Fruit, Natural Gas Fired	< 0.16 lb/MMBtu	Natural Gas or Propane-Fired Burner
1.6.15	Dryer - Milk Spray, < 20 MMBtu/hr	20 ppmv @ 3% O2	Natural gas or propane
1.6.16	Dryer - Seed Processing, < 20 MMBtu/hr	20 ppmv	Natural gas with LPG backup
1.6.17	Food Preparation Oven, <800 degrees Fahrenheit, = or < 3.7 MMBtu/hr	20 - 30 ppmv @ 3% O2	Natural gas with LPG backup
1.6.19	Meat Smokehouse - Natural Gas-Fired, < or = 2 MMBtu/hr	Natural gas-fired oven/smokehouse with a natural gas-fired smoke generator	Natural gas-fired oven/smokehouse with a natural gas-fired smoke generator
1.6.20	Feather Meal Processing Rotary Dryer - Natural Gas Fired, High Ammonia Environment	Natural gas fired with LPG as a backup fuel	Natural gas fired with LPG as a backup fuel
1.6.21	Flake Cereal Dryer - < 20 MMBtu/hr, Conveyor-fed	30 ppmv @ 3% O2	Natural gas fuel
1.6.22	Wood Drying Kiln	natural gas	natural gas fuel
1.6.23	Pistachio, Almond, and Walnut Dryers (<10 MMBtu/hr and <2,160 hr/yr)	0.06 lb/MMBtu	Natural gas with LPG as backup fuel

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BACT Code	Food & Ag Products Ovens, etc.	NOx	VOC
1.6.24	Commercial Bakery Oven	30 ppmvd @ 3% O2 equivalent to 0.036 lb/MMBtu	VOC capture and 95% control efficiency
1.6.25	Blood Drying Operation	no determination	95% overall capture and control efficiency
1.6.27	Direct-Fired Conveyorized Hotdog Cooking Oven	70.0 ppmvd @ 3% O2 (0.085 lb/MMBtu)	Natural gas fuel

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Main Category: 1.0 External Combustion

BACT Code	Industrial Ovens	NOx	VOC
1.7.1	Oven - Polyethylene Curing, = or < 20 MMBtu/hr	Natural Gas or Propane Fuel	Natural Gas or Propane Fuel
1.7.2	Oven - Plastisol curing/fusing, = or < 2.5 MMBtu/hr	Natural gas fuel used in the fusing oven	Plastisol with 2% VOC by weight and natural gas fuel used in the fusing oven
1.7.3	Oven - Parts Cleaning, Burnoff or Burnout	Natural Gas Fuel	99% by weight control

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Main Category: 1.0 External Combustion

BACT Code	Petroleum Product Combustion Devices	NOx	VOC
1.8.1	Process Heater - Refinery, = or < 50.0 MMBtu/hr	30.0 ppmvd @ 3% O ₂ (0.036 lb/MMBtu)	good combustion practices
1.8.2	Process Heater - Refinery, > 50 MMBtu/hr	9.0 ppmvd @ 3% O ₂ (0.0108 lb/MMBtu)	Good combustion practices
1.8.3.a	Gas Dehydration - Glycol Reboiler (=> 5 MM scf/year)	Natural gas fired burner	collection and control
1.8.3.b	Gas Dehydration - Glycol Reboiler (< 5 MM scf/year)	Natural gas fired burner	no determination
1.8.4	Heater Treater < 20 MMBtu/hr, Natural Gas Fired	15 ppmv @ 3% O ₂	gaseous fuel and good combustion practices
1.8.5	Process Heater (non-refinery, < or = 20 MMBtu/hr)	12 ppmv @ 3% O ₂	natural gas with LPG backup or propane fired

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Main Category: 1.0 External Combustion

BACT Code	Misc. Combustion Devices	NOx	VOC
1.9.3	Crematory - Natural Gas Fired	natural gas fuel	natural gas fuel and a secondary combustion chamber (afterburner) => 1600 degrees F
1.9.4	Dryer - Natural Gas Fired, Solvent-Laden Towels, = or < 950 lb towels/day	0.061 lb NOx /MMBtu	Natural gas
1.9.5	Gas Absorption Chiller - Natural Gas Fired,< 20 MMBtu/hr	0.036 lb NOx /MMBtu	Natural gas fuel
1.9.6	Asphalt-Surface-Repair Heater, Propane Fired, < 20 MMBtu/hr	0.15 lb NOx /MMBtu	Gaseous fuel
1.9.7	Auxiliary Burner System, Dryer, Natural Gas Fired,< 20 MMBtu/hr	no determination	Natural gas fuel
1.9.8	Municipal-waste Incinerator - < 750 lb waste/hr feed rate	Natural gas fuel	Multichamber incinerator with afterburner, Starved Air Design (> 1500 degrees Fahrenheit afterburner)
1.9.9	Molded Paper Products Dryer - Natural Gas Fired,< 20 MMBtu/hr	80 ppmv @ 3% O2	Natural gas fuel
1.9.10	Mineral Products Spray Dryer - Natural Gas Fired,< or = 20 MMBtu/hr	20 ppmv NOx @ 3% O2	Natural gas fuel
1.9.12	Transportable Diesel-Fired Nitrogen Vaporizer	diesel fuel achieving 155 ppmv @ 3% O2	0.2 lb/100 gal
1.9.13	Blood Meal Processing Ring Dryer Burner	Natural gas fired with LPG as a backup fuel	Natural gas fired with LPG as a backup fuel
1.9.14	Natural Gas Fired Dryer with High Turndown Ratio	= < 8.9 ppmvd @ 19% O2 (0.1 lb/MMBtu)	Natural gas with LPG backup
1.9.15	Jet Aircraft Fire Training Facility	Use of Natural Gas or LPG/Propane Fuel	Use of Natural Gas or LPG/Propane Fuel

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Main Category: 2.0 Remediation and Waste Disposal

BACT Code	Soil Remediation	NOx	VOC
2.1.1	Soil Remediation Operation - Thermal Oxidizer	N/A	95% or greater control efficiency
2.1.2	Soil Remediation Operation - I.C. Engine	LPG auxiliary fuel and 3 - way catalytic converter	95% control efficiency
2.1.3	Soil Remediation Operation - Carbon Adsorption	N/A	95% control efficiency
2.1.4	Extracted Soil Remediation using Steam Stripping/Flushing and 4-Stage Carbon Adsorption, > or = 40 tons/hr	N/A	95% Control efficiency
2.1.6	Soil Remediation Operation - Boiler, = or < 4.2 MMBtu/hr	0.036 lb/MMBtu (30 ppmv) when gas firing and 0.048 lb/MMBtu (40 ppmv) when firing diesel backup fuel	95% control efficiency
2.1.7	Soil Remediation Operation - Thermal Soil Desorber	Low NOx burner and natural gas/LPG firing	95% control efficiency

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Main Category: 2.0 Remediation and Waste Disposal

BACT Code	Waste Disposal	NOx	VOC
2.2.1	Non-hazardous Wastewater Receiving, Treatment, and Impoundment	N/A	Bays used to settle out solids and to skim oil from waste water. Recovered oil pumped to storage tank venting to carbon canisters or drums. Treated wastewater discharged to impoundments for evaporation.
2.2.2	Landfill - VOC-Contaminated Soil	N/A	Daily clean-fill cover (minimum one inch of compacted, District approved soil) onto the exposed VOC contaminated soil.

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Main Category: 3.0 Internal Combustion Engines

BACT Code	Emergency IC Engines	NOx	VOC
3.1.1	Emergency Diesel IC Engine, <175 hp	Certified emissions of 6.9 g/bhp-hr or less	Positive crankcase ventilation
3.1.2	Emergency Diesel I.C. Engine (= or > 175 hp and < 400 hp)	Certified NOx emissions of 6.9 g/bhp-hr or less.	Positive crankcase ventilation
3.1.3	Emergency Diesel I.C. Engine = or > 400 hp	Certified emissions of 6.9 g/bhp-hr or less	Positive crankcase ventilation
3.1.4	Emergency Diesel I.C. Engine Driving a Fire Pump	Certified NOx emissions of 6.9 g/bhp-hr or less	Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]
3.1.5	Emergency Gas Fired I.C. Engine - < 132 hp, Rich Burn	natural gas fuel	Positive crankcase ventilation (PCV)
3.1.6	Emergency Gas Fired I.C. Engine > or = 132 hp, Rich Burn	Natural gas, LPG or propane as fuel	Positive Crankcase Ventilation(PCV), and natural gas, LPG, or propane as fuel
3.1.8	Emergency Gas-Fired IC Engine - > or = 250 hp, Lean Burn	1.5 g/bhp-hr	1.0 g/bhp-hr

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Main Category: 3.0 Internal Combustion Engines

BACT Code	Limited/Special Use Engines	NOx	VOC
3.2.1	Diesel I.C. Engine - > 449 hp, used for testing of crankcase emission controls	NOx emissions of 7.2 grams/hp-hr or less OR Turbocharger with intercooler or aftercooler and timing retarded 4° relative to standard timing	PCV or 90% crankcase control device
3.2.2	Limited Use (1,000 hr/yr max) Diesel-Fired IC Engine - Located at a Stationary Source, non-emergency, non-Transportable, and not used to drive an electrical generator	6.9 grams/bhp-hr	Catalytic filter; thermal oxidizer, or equal
3.2.4	Transportable and Multi-location Diesel I.C. Engine	Certified NOx emissions of 6.9g/bhp-hr or less	Positive Crankcase Ventilation (PCV) or Crankcase Control Device that is at least 90% efficient
3.2.5	Diesel I.C. Engine - Used for starting a Gas Turbine	Certified NOx emissions of 6.9g/bhp-hr or less	Positive Crankcase Ventilation (PCV) or Crankcase Control Device that is at least 90% efficient
3.2.7	Diesel-Fired IC Engine - Low Use (= or < 1,000 hr/yr max)	Certified NOx emissions of 6.9g/bhp-hr or less.	Positive crankcase ventilation(PCV).
3.2.8	Limited Life (1,000 hr total max life) Diesel-Fired IC Engine - < 600 bhp, and Not Used to Drive an Electrical Generator	Certified NOx emissions of 7.2 g/bhp-hr or less OR Turbocharger with intercooler or aftercooler and timing retarded 4 deg relative to standard timing OR Turbocharger with intercooler or aftercooler and injection timing not to be greater than 16 deg BTDC (this option may be used if it is consistent with District policy GEAR 16-1, "Determination of Injection Timing Retard for Diesel IC Engines", dated 08/14/96)	Positive crankcase ventilation(PCV)

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Main Category: 3.0 Internal Combustion Engines

BACT Code	Fulltime IC Engines	NOx	VOC
3.3.1	Diesel Fired IC Engine - < 600 hp, Transportable Metal Contaminated Soil Processing Operation	NOx emissions of 7.2 g/hp-hr or less	Positive crankcase ventilation or 90% crankcase control device(PCV)
3.3.12	Fossil Fuel Fired IC Engine > 50 hp	9 ppmvd @ 15% O2, 0.15 g/bhp-hr, or 0.5 lb/MW/hr	25 ppmvd @ 15% O2, 0.15 g/bhp-hr, or 0.5 lb/MW-hr
3.3.13	Waste Gas Fired IC Engine - > 50 hp	50 ppmvd @ 15% O2, 0.6 g/bhp-hr, or 1.9 lb/MW-	130 ppmvd @ 15% O2, 0.6 g/bhp/hr, or 1.9 lb/MW-hr
3.3.14	Full-time Rich-burn IC Engine, Syngas-fueled	9 ppmvd at 15% O2	25 ppmvd at 15% O2

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Main Category: 3.0 Internal Combustion Engines

BACT Code	Gas Turbines	NOx	VOC
3.4.1	Gas Turbine - = or > 47 MMBtu/hr, Variable Load, Without Heat Recovery	8 ppmvd @ 15% O ₂ (Steady State) and 12 ppmv @ 15% O ₂ (Transitional State)	0.007 lb/MMBtu
3.4.2	Gas Turbine - = or > 50 MW, Uniform Load, with Heat Recovery	2.5 ppmv dry @ 15% O ₂ (1-hr average, excluding startup and shutdown)	2.0 ppmv @ 15% O ₂
3.4.3	Gas Turbine with Heat Recovery (= > 3 MW and = < 10 MW)	2.5 ppmv @ 15% O ₂ , based on a three-hour	2.0 ppmv @ 15% O ₂ , based on a three-hour average
3.4.4	Limited Use (< 877 hours per year) Gas Fired Turbine = or < 26 MW, without Heat Recovery	25 ppmvd @ 15% O ₂	PUC quality natural gas with fuel oil #2 as backup.
3.4.6	Gas Turbine - > 10 MW and < 50 MW, Uniform Load, with Heat Recovery	2.5 ppmvd @ 15% O ₂ , based on a three-hour rolling average	2.0 ppmvd @ 15% O ₂
3.4.7	Gas Turbine - = or > 50 MW, Uniform Load, without Heat Recovery	5.0 ppmvd @ 15% O ₂ , based on a three-hour average	2.0 ppmvd @ 15% O ₂ , based on a three-hour average
3.4.8	Gas Turbine - < 50 MW, Uniform Load, Without Heat Recovery	5.0 ppmvd @ 15% O ₂ , based on a three-hour average	2.0 ppmvd @ 15% O ₂ , based on a three-hour average
3.4.9	Gas Turbine - < 3 MW, Uniform Load, With or Without Heat Recovery	9.0 ppmvd @ 15% O ₂ , based on a three-hour average	5.0 ppmvd @ 15% O ₂ , based on a three-hour average
3.4.10	Oxy-Fuel Combustor Powering a Steam Turbine, Power Output < 3 MW, without Heat Recovery, Uniform and Variable Load, Research Facility	5.3 ppmvd @ 15% O ₂ , equivalent to 0.3 lb/MW-hr	5.0 ppmv @ 15% O ₂ , equivalent to 0.1 lb/MW-hr

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Dry Cleaners	NOx	VOC
4.1.2	Petroleum Solvent Dry Cleaning	N/A	dry-to-dry machine vented to vapor control device

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Motor Vehicle Coating	NOx	VOC
4.2.1	Automotive Spray Painting Operation, < 5.0 MMBtu/hr	Natural gas or LPG fired burner	HVLP spray guns, coatings, cleaning materials, and solvents compliant with District Rule 4612
4.2.2	Group II Vehicles Spray Painting Operation - Vehicles requiring a Color Match	N/A	Use coatings with a VOC content of 3.5 lb/gal (less water and exempt compounds) or less, and Pretreatment Wash Primers with a VOC content of 6.0 lb/gal (less water and exempt compounds) or less, HVLP (or equivalent) spray equipment, and using an enclosed spray gun cleaning system
4.2.3	Mobile Equipment Coating Operation - Multiple Location, <= 20,000 lb-VOC/year	N/A	Coatings and cleaning materials, and solvents compliant with District Rule 4612, HVLP spray gun
4.2.4	Trailer Coating Operation	N/A	Using topcoats with a low VOC content (2.8 lb/gal less water and exempt compounds) and pretreatment wash primers with a low VOC content (6.0 lb/gal less water and exempt compounds)
4.2.5	Limited Aircraft Coating Operation - Maintenance and Refinishing of Metal Parts on Aircraft, < 20 Gallons/day.	N/A	Use of Coating compliant with Rule 4605, HVLP application equipment, and an enclosed gun cleaner, or equal.
4.2.6	Aerospace Parts Coating Operation	N/A	The use of an enclosed gun cleaner and coatings with a VOC content (less water and exempt compounds) lower than the following: Primers < 6.4 lb VOC/gal Topcoats < 5.2 lb VOC/gal
4.2.7	Aerospace and Metal Parts Coating Operating - Solid Film Lubricant for computer, medical specialty, and aerospace metal parts and products	N/A	Solvent-based solid film lubricant coating with a VOC content of 6.44 lb/gal (less water and exempt compounds), or lower.

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Motor Vehicle Coating	NOx	VOC
4.2.8	Recreational Marine Vessel (Pleasure Craft) Coating	N/A	Use of materials with VOC contents (less water and exempt compounds) as indicated, or lower: - antifouling coatings: aluminum substrate: 440 g/l, - other substrates: 330 g/l, - high gloss coatings: 340 g/l - extreme high gloss coatings: 490 g/l - pretreatment wash primers: 420 g/l - primers: 340 g/l - all other coatings: 340 g/l
4.2.10	Motor Vehicle Chassis Coating Operation -Electrodeposition with a Curing Oven.	N/A	95 % control system serving coating tank and curing oven

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Metal Parts and Products Coating	NOx	VOC
4.3.1	Metal Parts and Products Coating - Air Dried (excluding specialty coating as defined in Rule 4603)	N/A	Coatings with a VOC content of 2.8 lb/gal or less; HVLP (or equivalent) spray equipment; and an enclosed spray gun cleaning system
4.3.2	Metal Parts and Products Coating - Heat Dried	N/A	HVLP guns, the use of an enclosed gun cleaner & coatings compliant with District Rule 4603
4.3.3	Metal Product Coating - Metal Rod Dip Coating, Air-Dried, = or > 150 gallons/month coating	N/A	Dip coating with low VOC content of 3.5 lb/gallon (less water and exempt compounds), Dip tank covered when not in use
4.3.5	Metal Parts and Products Coating Operations (using specialty coatings as defined by Rule 4603)	N/A	Using coatings with a VOC content of 3.5 lb/gal (less water and exempt compounds) or less, using HVLP spray equipment (or other application methods listed in Rule 4603), and using an enclosed spray gun cleaning system
4.3.6	Metal Products Coating - Shipping/Storage Containers	N/A	Coating with a VOC content of 2.8 lb/gal (less water and exempt compounds) or less; HVLP (or equivalent) spray equipment
4.3.7	Powder Coating Operation = or >1.5 MMBtu/hr	Natural gas fired fusing oven	Low-VOC Coating (< 1.5% VOC by weight) and Natural gas fired fusing oven
4.3.8	Metal Product Coating - Large Steel Structures, < 64 lbVOC/day, Outdoor Coating Operation	N/A	Use of coatings with a VOC content (less water and exempt compounds) as indicated, or lower: - for General Coating: 2.5 lb/gal, - for General Coating, when the ambient temperature is at or below 60 F: 2.8 lb/gal, and - for Specialty Coatings - Extreme Performance or High-Gloss 3.5 lb/gal and use of an HVLP spray gun or equivalent application method.
4.3.9	Metal Product Coating - Large Steel Structures, = or < 64 lb VOC/day, Indoor Operation	N/A	Coating with a low VOC content (2.5 lb/gal less water and exempt compounds) and HVLP spray gun or equivalent application method.

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Metal Parts and Products Coating	NOx	VOC
4.3.10	Metal Products Coating - Sheet Metal for Can Manufacturing, Major Source for VOC	20 ppmv @ 3% O2	VOC capture and thermal incineration
4.3.11	Metal Products Coating - Touch-up, 6.2 lb VOC/day	N/A	Coating with 1.9 lb VOC/gal (less water and exempt compounds), HVLP gun
4.3.12	Metal Products Coating - High Gloss, Air-Dried, = or < 30 lb/day Facility-wide VOC coating emissions	N/A	HVLP spray guns, coatings compliant with Rule 4603 and enclosed paint gun cleaners
4.3.13	Metal Products Coating - Metal Frames and Exterior Wooden Wall Panels for Modular Buildings	N/A	Metal frames: use of Rule 4603 compliant coatings Exterior wooden wallpanels: use of Rule 4606 compliant coatings (This control is Achieved in Practice only for facilities subject to Rule 4603/4606)
4.3.14	Side Seam Stripe Spray Coating Operation for 3-Piece Metal Can Manufacturing at a Facility-wide Can Manufacturing Rate of >= 180,000 Can/hr	N/A	VOC capture and control system at the side seam stripe coater with a fume hood (71% capture efficiency) and the curing tunnel exhaust stack all vented to a thermal or catalytic oxidizer (70% overall control efficiency).
4.3.15	Dip Coating of Steel Joists	N/A	Use of coatings with a maximum VOC content of 3.32 lb/gal for coatings with a viscosity, as applied, of less than or equal to 45.6 centistokes at 78 F and an average dry-film thickness of less than or equal to 2.0 mils, or 2.8 lb/gal for coatings with a viscosity, as applied, of more than 45.6 centistokes at 78 For an average dry-film thickness of greater than 2.0 mils with no additional control
4.3.17	"Bright Dip" Aluminum Surface Finishing Operation	97% capture and 70% control	N/A

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Wood Parts and Products Coating	NOx	VOC
4.4.1	Wood Products Coating Operation - Non-Continuous Batch Coating	N/A	Utilizing HVLP or equivalent application equipment and using coatings compliant with District Rule 4606
4.4.2	Wood Products Coating Operation - Continuously-fed Booth, = or < 5000 square feet material coated/day	N/A	Rule 4606 compliant coatings and application equipment
4.4.3	Wood Products Coating Operation - Custom Replica Furniture, < or = 400 lb VOC/day	N/A	Use of coating(s) with a VOC content (less water and exempt compounds) as indicated, or lower: - For Sanding Sealers and Clear Topcoats: 5.7 lb/gal - For High-solids Stain and Pigmented Coatings: 5.0 lb/gal and use of HVLP application equipment, or equivalent method, and a enclosed spray gun cleaner if using a VOC containing solvent.
4.4.4	Wood Products Coating Operation - Exterior Wooden Wall Panels for Modular Buildings	N/A	Utilizing HVLP application equipment or other application methods listed in District Rule 4606 and using coatings compliant with District Rule 4606 (only for those facilities subject to Rule 4606)

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Misc. Coating	NOx	VOC
4.5.1	Paper Roll-Coating - Heatset	N/A	Use of coatings/inks with a VOC content compliant with Rule 4607 (Graphic Arts)[This control is achieved-in-practice only for facilities subject to District Rule 4607]
4.5.3	Coating Operation - Fiberglass Utility Poles, = or > 90 lb/day of VOC emissions	N/A	Low VOC coatings - 10% VOC by wt, HVLP application equipment, enclosed equipment cleanup or water based detergent
4.5.4	Plastic Parts and Products Coating	N/A	The use of HVLP spray guns, an enclosed gun cleaner, and low-VOC coatings (2.8 lb VOC/gal, as applied, less water and exempt solvents)
4.5.5	Coating Operation - Small Concrete Products	N/A	Use of material(s) with a VOC content (less water and exempt compounds) as indicated, or lower: - For Glossy finish: 2.8 lb/gal - For Matte Finish: 1.7 lb/gal - For Waterproofing Sealer: 3.3 lb/gal and use of HVLP application equipment, or equivalent
4.5.6	Coating Operation - Clay-based, Cat Litter, Heat Dried	N/A	Use of low VOC coating (0.69lb/gal (less water and exempt compounds) or less)
4.5.8	Weatherproofing Coating Application (Electronic Components)	N/A	Dip coating and the use of weather proofing coatings with VOC contents of 6.9 lb/gal or less (as applied, less water and exempt compounds)
4.5.9	Vinyl Window and Patio Door Assembly Glazing Table	N/A	utilize glazing material with VOC content, excluding water and exempt compounds, equal to or less than 15 g/l (0.125 lb/gal)

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Fuel Dispensing	NOx	VOC
4.6.1	Motor Vehicle Gasoline Storage and Dispensing Operation	N/A	CARB certified Phase I and Phase II vapor recovery systems
4.6.3	Motor Vehicle Gasoline Storage and Dispensing Operation - Bulk plants with Diesel fuel switch loading	N/A	CARB certified 95% effective Vapor Recovery
4.6.4	Non-Motor Vehicle Fuel Storage and Dispensing Operation	N/A	CARB certified Phase I Vapor Recovery System
4.6.5	Aviation Fuel Dispensing Facility	N/A	CARB certified Phase I vapor recovery system

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Printing & Graphic Arts	NOx	VOC
4.7.1	Offset Lithographic Printing - Publication Printing, High-end Graphics, Heatset using with a Drying Oven	Natural gas fuel used in the drying oven	Using low VOC fountain solutions and inks compliant with District Rule 4607 (Graphic Arts) (This control is achieved in practice only for facilities subject to Rule 4607.)
4.7.2	Offset Lithographic Printing - Non-heat set Press	N/A	Using materials with the following VOC contents: less than 5% VOC by weight for inks (less water and exempt compounds) and less than 6% by volume for fountain solutions; for high end graphics, less than 30% VOC by weight for inks (less water and exempt compounds) and less than 8% by volume for fountain solutions
4.7.3	Flexographic Printer/Gluer - Corrugated Box	N/A	The use of inks with VOC content not exceeding 0.3 lb/gal (less water and exempts solvents) and the use of adhesives not exceeding 0.06 lb/gal (less water and exempt solvents)
4.7.4	Flexographic Printer - Corrugated Boxes, High-End Graphics and Metallic Inks for Porous Substrates	natural gas fuel	The use of inks with a VOC content not exceeding 1.1 lb/gal (less water & exempt compounds) for high-end graphics and use of inks with a VOC content not exceeding 2.5 lb/gal (less water & exempt compounds) for metallic inks
4.7.5	Flexographic printing - Heatset inks on low-porosityglossy paper and plastic film	N/A	Inks with a VOC content of = or < 2.5 lb/gal (less water and exempt compounds)
4.7.6	Screen Printer with natural gas-fired dryer	N/A	Use of inks with a VOC content compliant with Rule 4607 (Graphic Arts) [This control is achieved in practice only for facilities subject to District Rule 4607]
4.7.7	Screen Print - Ultraviolet (UV) Coating with Curing Lamp(s)	N/A	UV curing unit using inks with a VOC content not to exceed 3% by weight (less water and exempt compounds).

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Printing & Graphic Arts	NOx	VOC
4.7.9	Flexographic Printer - High-end graphics printing on Clay coated Paper, = or < 23 tons VOC/year	N/A	Using materials with a VOC content, less water and exempt compounds, as indicated, or lower <ul style="list-style-type: none"> • for metallic inks: 3.3 lb/gal • for non-metallic inks: 1.0 lb/gal • varnish: 0.63 lb/gal and practicing evaporation minimization methods, which include keeping all solvents and solvent-laden cloths/papers, not in active use, in closed containers.
4.7.10	Printing Plate Manufacturing	N/A	Use of processor solvents with a VOC content, less water and exempt compounds, of 7.3 lb/gal, or lower, and Practicing evaporation minimization methods, which include keeping all solvents and solvent-laden cloths/papers, not in active use, in closed containers.
4.7.11	Rotogravure Printing Operation	N/A	Inks with a VOC content of < 2.5 lb/gal (Less water and exempt compounds)
4.7.12	Flexographic Printing - High-end graphics, Heat-set Inks, on High-Porosity Material	N/A	Use of coating(s) with a VOC content (less water and exempt compounds) as indicated, or lower: - Fluorescent Inks: 2.5 lb/gal. - Thermal Inks: 0.3 lb/gal. - Other Inks: 2.4 lb/gal.
4.7.13	Glass and Plastic Bottle Printing – Heat-dried	N/A	Using materials with a VOC content, less water and exempt compounds, as indicated, or lower <ul style="list-style-type: none"> • High-end graphics, screen printing: 3.3 lb/gal • High-end graphics, non-screen printing: 2.5 lb/gal • Non-high-end graphics: 3% by weight (UV-cured inks). And practicing evaporation minimization methods, which include keeping all solvents and solvent-laden cloths/papers, not in active use, in closed containers.

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Printing & Graphic Arts	NOx	VOC
4.7.14	Flexographic UV Printing - High End Printing of Labels, Tags, and Forms**	N/A	Use of coating with a VOC content (less water and exempt compounds) as indicated, or lower: • For UV-cured Coatings: 1% VOC by Weight, and evaporative minimization methods, which include keeping all solvents and solvent-laden cloths/papers, not in active use, in close containers.
4.7.15	Flexographic Printing - Corrugated boxes, Low-endgraphics printing, = or < 50.4 lb VOC/day	N/A	Use of coating with a VOC content (less water and exempt compounds) as indicated, or lower: - 0.3 lb/gal and evaporative minimization methods, which include keeping all solvents and solvent-laden cloths/papers, not in active use, in closed containers.
4.7.16	Rotogravure Printing Operation Low Porosity Substrate - High End Graphics	N/A	inks, coatings, and adhesives with a VOC content of <= 30% (less water and exempt compounds)

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Resin, Fiberglass & Plastic Products	NOx	VOC
4.8.1	Polyester Resin Products - Fiberglass Boat Manufacturing = < 120 gal resin/day	N/A	Low VOC resin (< or = 35% by wt), airless spray gun or hand layup or equivalent, non-VOC containing cleanup solvents
4.8.5	Polyester Resin Products - Chop Spray, Spray, and Hand Lay-Up, < or = 600 gallons resin/day	N/A	Low-VOC resin compliant with District Rule 4684
4.8.7	Fiberglass Products Manufacturing - Fiberglass Mat Dryer and Curing Oven	Natural gas with LPG as a secondary fuel.	98% control efficiency
4.8.8	Polyester Resin Application - Boat & Marine Vessel Repair Operations (Pleasure Crafts Only)	N/A	use of specialty resins and gel coats containing no more than 48% monomer by weight.
4.8.9	Fiberglass Products Manufacturing - Fiberglass Mat Forming	N/A	Low VOC Resin (containing less than 0.25% formaldehyde and less than 0.45% methanol) and White water (containing less than 0.1% VOC).
4.8.10	Expandable Polystyrene (EPS) Molding Operation - Pre-expander unit, = or < 20 Tons/day	N/A	Capture and Thermal Oxidation
4.8.12	Expanded Polystyrene (EPS) Products - Reclaim Extrusion Line	N/A	95% control efficiency
4.8.13	Polyethylene Foam Extrusion Operation	N/A	95% control efficiency
4.8.14	Expanded Polystyrene Products - Fluff Storage Silo, = or < 18 tons of foam/day	N/A	90% capture and 95% destruction efficiency
4.8.15	Existing Polystyrene Foam Sheet Extrusion Operation - Using VOC Blowing Agents to Produce Food Service Products.	N/A	95% destruction efficiency
4.8.17	Polyethylene Products Manufacturing - Rotational Molding	N/A	Mold Release Agents with VOC content not exceeding 6.5 lb/gal (less water and exempt compounds).

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Resin, Fiberglass & Plastic Products	NOx	VOC
4.8.18	Expanded Polystyrene Foam Products - Vertical Water-quenched extruder; Food-grade products.	N/A	Total emissions of 0.94lb VOC/100 lb of raw material processed.
4.8.19	Fiberglass-reinforced Composite Products – Pultruded, heat set resin products.	N/A	Use of polyester resins with 35% monomer by weight, or less, and Use of epoxy-based resins with 1% VOC by weight, or less, and Use of a covered, resin-product cooling bath.
4.8.20	Phenolic Urethane Products - No-Bake Mold Manufacturing	N/A	VOC content of the binder not to exceed 0.07 lb VOC/lb of binder.
4.8.21	Corrosion-Resistant Polyester Resin Application - Metal Products, < 75 gallons/day	N/A	Use of corrosion-resistant resin containing no more than 48% monomer by weight, mechanical non-atomizing resin application, enclosed gun cleaner
4.8.22	Polyisocyanurate Free Rise and Restrained Rise Lines	N/A	90% capture and 95% control of manufacturing emissions
4.8.23	Finished Product Storage Area	N/A	uncontrolled
4.8.24	Fiberglass Mold Manufacturing (Tooling) Operation	N/A	non-atomizing application for polyester resins, gel coat application equipment compliant with District Rule 4684, and tooling resins ad gel coats with a monomer content not exceeding 48%

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Adhesives	NOx	VOC
4.9.1	Adhesives Application Operation - Tire Retreading	N/A	Use of adhesives with a VOC content of 5.2 lb/gal (less water and exempt compounds) or less
4.9.2	Adhesive Application Operation - Rubber Parts and Products, Brush Applied	N/A	Using adhesives with a VOC content of 7.0 lb/gal or less (less water and exempt compounds)
4.9.3	Adhesive Application Process - Foam Products	N/A	Adhesives with a VOC content of = or < 1.0lb/gallon (less water and exempt compounds)
4.9.4	Adhesive Application Process - Non-Porous Materials, Specialty Contact Adhesives, Spray Application	N/A	Using adhesives with a VOC content of 540 grams/liter or less (less water and exempt compounds) until July 1, 2000. Using adhesives with a VOC content of 400 grams/liter or less (less water and exempt compounds) after July 1, 2000.
4.9.5	Adhesive Application Process - Wooden case manufacturing	N/A	Use of adhesives with a VOC content compliant with Rule 4653(Adhesives) [This is achieved in practice only for those facilities subject to District Rule 4653.]
4.9.6	Paper Carton Manufacturing - Printing and Adhesive Application	N/A	Adhesive with a VOC content of = or < 5.7 lb/gal (excluding water and exempt compounds) and Inks with a VOC content of = or < 2.5 lb/gal (excluding water and exempt compounds)
4.9.7	Corrugated PVC Sheet Products - Special Contact Adhesive, Roller Applied	N/A	PVC welding adhesive compliant with District Rule 4653
4.9.8	Adhesive Application Process - Wooden Door Assembly, Roller applied	N/A	Use of an adhesive with a VOC content of 5.0grams/liter (less water and exempt compounds), or less.
4.9.9	Adhesive Application Process - Vinyl Door and Window Assembly, Non-Spray Applied	N/A	Use of adhesive with VOC content of 3.0 g/l (less water and exempt compounds), or less for automated adhesive application and assembly processes 2) Use of adhesive with VOC content of 76.5 g/l (less water and exempt compounds), or less for manually applied adhesive operations when assembling custom window assemblies

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Adhesives	NOx	VOC
4.9.10	Adhesive Application for Multi-Wall Packaging Manufacturing	N/A	Adhesives with a VOC content of ≤ 0.2 lb/gal (excluding water and exempt compounds) for the adhesion of plastic film to porous material adhesives with a VOC content of ≤ 0.13 lb/gal (excluding water and exempt compounds) for the adhesion of porous materials
4.9.11	Adhesive Application Operation - Bonding of Fiberglass Boat Hulls and Decks, Non-Atomizing Application	N/A	Use of adhesives with VOC content of 80 grams/liter or less (less water and exempt compounds)

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Cleaning & Degreasing	NOx	VOC
4.10.2	Cold cleaner/degreaser - Metal Products, Batch Loaded, = or < 1 gal/day solvent usage	N/A	Drainage to Minimize Carryout Emissions, high freeboard ratio
4.10.3	Parts Cleaner - Rubber Parts and Products	N/A	Use of solvents with VOC content (less water and exempt compounds) as indicated, or lower: - for Natural Rubber: 6.3 lb/gal, - for Nitrile, SBR, or chlorobutyl Rubber: 6.71 lb/gal, - for Neoprene Rubber: 7.25 lb/gal and evaporative minimization methods, which include - use of controlled flow dispensers (e.g. squeeze bottles) and - keeping all cloth/papers and solvent, which are not in active use, stored in closed containers.
4.10.5	Medical Grade Silicon Products - Wipe Cleaning Operation	N/A	Use of solvents with VOC content (less water and exempt compounds) of 7.2 lb/gal, or lower, and evaporative minimization methods, which include - use of controlled flow dispensers (e.g. squeeze bottles) and - keeping all cloth/papers and solvent, which are not in active use, stored in closed containers.
4.10.6	Metal Parts, Open-top, Powder Coating Stripping Tank	N/A	Use of solvent with a VOC Content (less water and exempt compounds) of 0.75 lb/gal, or less.
4.10.7	Metal Parts and Products Cleaning - Open-top, Heated, Vapor Degreaser	N/A	95% control (Open top degreaser w/refrigerated freeboard chiller, part movement < 2.2 ft/sec, and holding parts in degreaser until dry, or equal)

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Misc. Manufacturing	NOx	VOC
4.11.3	Cardboard Box Laminator	N/A	use of water-based adhesive with a VOC content (less water and exempt compounds) of 0.021 lb/gal or less
4.11.4	Organic Liquid Storage Tanks - Non-petroleum and non-petrochemical facilities, = or < 19,800 gallons capacity	N/A	Pressure/vacuum valve set within 10% of the maximum allowable tank working pressure.
4.11.6	Railcar Unloading - Transfer of Non-petroleum Organic Liquids into Delivery Vehicles	N/A	Bottom loading with vapor recovery system
4.11.7	Solvent-Laden Towel Cleaning - Counting Station, < 950 lb towels/day	N/A	Evaporative loss minimization (Store solvent-laden towels in closed containers).
4.11.10	Circuit Board Manufacturing – Flux Application for Wave Soldering Machine	N/A	Use of flux material(s) with a VOC content of 6.3 lb/gal(less water and exempt compounds), or lower.
4.11.11	Fructose Reclamation System - Process Vent	N/A	Proper operation and maintenance of the reclamation system as recommended by the equipment manufacturer(s)

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Main Category: 4.0 Evaporative Loss Sources

BACT Code	Chemical Processing	NOx	VOC
4.12.1	Chemical Plants - Valves & Connectors	N/A	Leak defined as a reading of methane, in excess of 100ppmv above background when measured at a distance of one(1) cm from the potential source and an Inspection and Maintenance Program pursuant to District Rule 4451
4.12.2	Chemical Plants Pump and Compressor Seals	N/A	Leak defined as a reading of methane, in excess of 500ppmv above background when measured at a distance of one(1) cm from the potential source and an Inspection and Maintenance Program pursuant to District Rule 4452
4.12.4	Ethanol Fermentation Process Tanks Including: Fermentation Tanks and Beerwell Storage Tanks	N/A	99.5% VOC emissions control efficiency (fermentation wet scrubber vented to a CO12 recovery plant with a condenser and a high pressure scrubber; or equivalent)
4.12.5	Emission Units (Excluding Wet Cake Dryer) Involved in the Ethanol Distillation and Wet Cake Process	N/A	95% VOC emissions control efficiency
4.12.6	Ethanol Manufacturing Facility Distillers Dried Grains with Solubles (DDGS) Dryer	33 ppmv NOx @ 3% O2 (0.04 lb-NOx/MMBtu)	98% by weight capture and control

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Main Category: 5.0 Food and Agriculture Industry

BACT Code	Nut & Grain Processing	NOx	VOC
5.2.6	Feed Mill - High Moisture Grain Pelletizing & Drying Operation	64.2 ppmv @ 3% O ₂ (0.077lb/MMBtu/hr) Natural gas burner	Natural Gas fuel
5.2.8	Propylene Oxide Fumigation - Fumigation Chamber	N/A	98% Control Efficiency
5.2.10	Wet Corn Mill - High Moisture Gluten Dryer	N/A	VOC capture and control with carbon adsorption or biofiltration system

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Main Category: 5.0 Food and Agriculture Industry

BACT Code	Cotton & Fiber Processing	NOx	VOC
5.3.2	Cotton Gin - Natural Gas-Fired Dryer, = or < 8 MMBtu/hr Burner	Natural gas/LPG burner(0.1 lb/MMBtu)	Natural gas/LPG fuel

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Main Category: 5.0 Food and Agriculture Industry

BACT Code	Fruit, Vegetable, Seed Processing, & Equipment	NOx	VOC
5.4.12	Perishable Commodity Methyl Bromide Fumigation Chamber	N/A	minimize use of fumigant (i.e. use no more than product specifications recommend); and air-tight fumigation chamber
5.4.13	Wine Storage Tank	N/A	Insulation or Equivalent, Pressure Vacuum Relief Valve (PVRV) set within 10% of the maximum allowable working pressure of the tank; "gas-tight" tank operation; and continuous storage temperature not exceeding 75 degrees F, achieved within 60 days of completion of fermentation
5.4.14	Wine Fermentation Tank	N/A	Temperature-Controlled Open Top Tank with Maximum Average Fermentation Temperature of 95 deg F

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Main Category: 5.0 Food and Agriculture Industry

BACT Code	Snack Food Processing	NOx	VOC
5.5.4	Polishing Operation	N/A	95% overall control

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Main Category: 5.0 Food and Agriculture Industry

BACT Code	Misc. Processes & Equip	NOx	VOC
5.6.1	Yeast Fermenter	N/A	Process controls limiting ethanol formation 75% - 90% control efficiency
5.6.2	Animal Feed Supplement Manufacturing - Palm Oil & Calcium Oxide Process	N/A	70% control efficiency
5.6.3	Animal Feed Supplements - Steam-Heated Molasses Cooker	N/A	95% control efficiency
5.6.4	Bakery Waste Products Dryer	no determination	thermal/catalytic incineration
5.6.5	Broiler House	N/A	19% control

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Main Category: 6.0 Mineral and Biomass Products

BACT Code	Sand & Gravel Operations	NOx	VOC
6.1.3	Sand Dryer - Fluidized Bed	Natural gas fuel with LPG backup	Natural gas fuel with LPG backup
6.1.5	Rotary Aggregate Dryer - Remote Location Where Commercial Natural Gas is Not Available, (< or =) 15 tons aggregate/hr or (< or =) 22.7 MMBtu/hr burner	LPG fuel	LPG fuel

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Main Category: 6.0 Mineral and Biomass Products

BACT Code	Portland Concrete	NOx	VOC
6.2.5	Portland Concrete Products Processing – Roof Tile Coating, Continuous Feed Booth	N/A	Use of coating(s) with a VOC content of 0.8lb/gal (less water and exempt compounds), or lower
6.2.7	Concrete Roofing Trim Tile Mold Releasing Oil Application Operation	N/A	use of mold releasing oils with a VOC content not exceeding 0.08 lb VOC/gal (less water and exempt compounds)

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Main Category: 6.0 Mineral and Biomass Products

BACT Code	Asphaltic Concrete	NOx	VOC
6.3.1	Asphaltic Concrete - Drum Mix Plant, = or > 2,000 ton/day or = or > 75.6 MMBtu/hr burner	0.088 lb/MMBtu Low-NOx burner and either natural gas or LPG as the primary fuel.	Natural gas or LPG as a primary fuel; and enclosed hot mix silos and loadout operation vented to the rotary-dryer burner.
6.3.2	Asphalt Treating Unit	N/A	98% by weight control efficiency
6.3.3	Asphaltic Concrete Plant - Batch Mix, = or > 75 MMBtu/hr and = or > 2,000 tons/day of Asphaltic Concrete	Natural gas or LPG fuel with a low Nox burner	Natural gas or LPG fired burner
6.3.5	Asphalt Roofing Shingle Mfg. - Process Heater, = or > 8 MMBtu/hr	30 ppmv @ 3% O ₂ , Natural gas with LPG as backup fuel	Natural gas with LPG as backup fuel
6.3.6	Asphalt Roofing Product Mfg. - Coating Operation, >100 tons/day	N/A	80% capture and control
6.3.7	Asphalt-Based Roofing Products - Mixer	N/A	Operating practices to minimize fugitive VOC emissions (shut off blower when not charging mixer and close hatch when not adding materials)

**San Joaquin Valley
Unified Air Pollution Control District**

Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

Main Category: 6.0 Mineral and Biomass Products

BACT Code	Composting & Biomass	NOx	VOC
6.4.7	Co-Composting with Biosolids	N/A	ACTIVE PHASE negatively aerated static piles with engineered, under pile, grid aeration system vent to control device with => 80% control efficiency

**San Joaquin Valley
Unified Air Pollution Control District**

Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

Main Category: 7.0 Petroleum/Gas Industry

BACT Code	Petroleum Production	NOx	VOC
7.1.1	Thermally Enhanced Oil Recovery - Steam Drive Oil Wells	N/A	Vapor control system and inspection and maintenance program with either a) Non-condensables balanced casing vent system tied into tank vapor control system or b) Non-condensables incinerated at steam generator, incinerator, or equal
7.1.2	Thermally Enhanced Oil Recovery - Small Producer, Cyclic Injected Steam Enhanced Oil Well Pilot Test, < or = 10 Cyclic Wells, < or = 180 days of Total Operation	N/A	Closed casing vents and inspection and maintenance of stuffing boxes and polish rods
7.1.3	Petroleum Production - Small Producers, Cyclic Wells, < or = 4 Cyclic Wells	N/A	uncontrolled
7.1.6	Petroleum Production - Sand Removal Basin for Heavy Crude Oil	N/A	sunscreen tarp
7.1.7	Sludge Dewatering, Various Locations	N/A	gas-tight (as defined in Rule 4623) sludge tanks and processing equipment, vented to VOC control system served by carbon adsorption (at least two carbon canisters in series)
7.1.8	Petroleum Production - Mobile Degassing Operation for StorageTank with low H2S content, using an I.C. Engine as a control device	three way catalyst	three way catalyst
7.1.9	Petroleum Production - Mobile Degassing Operation for StorageTank with low H2S content, using a Thermal Oxidizer as a control device	N/A	VOC reduced by at least 98% by weight
7.1.10	Loading Rack/Switch Loading	natural gas or LPG fired pilot and air assist	bottom loading with dry break couplers and vapor collection vented to a thermal incinerator or flare with destruction efficiency => 99%
7.1.13	Petroleum Storage Tank and Pipeline De-Gassing - Mobile Operation	N/A	98% by weight control

**San Joaquin Valley
Unified Air Pollution Control District**

Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

Main Category: 7.0 Petroleum/Gas Industry

BACT Code	Petroleum Production	NOx	VOC
7.1.14	Light Crude Oil Unloading Rack	N/A	use of dry-break couplers or equivalent on unloading lines with an average disconnect loss of no greater than 10 ml liquid per disconnect, and fugitive components subject to Rules 4409 or 4455 as applicable
7.1.15	Biodiesel/Glycerol Production Operation	N/A	100% capture and 98% control

**San Joaquin Valley
Unified Air Pollution Control District**

Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

Main Category: 7.0 Petroleum/Gas Industry

BACT Code	Petroleum Refining	NOx	VOC
7.2.2	Petroleum Refining - Valves & Connectors	N/A	Leak defined as a reading of methane, in excess of 100 ppmv above background when measured at a distance of one(1) cm from the potential source and an Inspection and Maintenance Program pursuant to District Rule 4451
7.2.3	Petroleum Refining - Pump and Compressor Seals	N/A	Leak defined as a reading of methane, in excess of 500ppmv above background when measured at a distance of one(1) cm from the potential source and an Inspection and Maintenance Program pursuant to District Rule 4452
7.2.4	Petroleum Refineries and Chemical Plants - Swivel Joints Handling Volatile Organic Compounds, > 20,000 gallons/day throughput	N/A	Inspection and Maintenance program consistent with District Rule 4451 (amended 12/17/92)- 2,300 ppmv, fugitive emission rate
7.2.7	Natural Gas Processing Plant - Valves, Connectors, and Compressor and Pump Seals (Subject to Rule 4403) < or = 100 Million SCF/Day	N/A	Leak defined as a dripping rate of more than three (3) drops per minute of liquid containing VOC or as a reading of methane, in excess of 10,000 ppmv above background when measured per EPA Method 21, for all components, and an Inspection and Maintenance Program pursuant to District Rule 4409
7.2.8	Catalyst Regeneration - Fluid Catalytic Cracking Unit	20 ppmv @ 0% O2 (365 day rolling average) and 40 ppmv @ 0% O2 (7 day rolling average). During startup/shutdown events, operator must comply with a District approved set of workplace practices.	Good combustion practices

**San Joaquin Valley
Unified Air Pollution Control District**

Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

Main Category: 7.0 Petroleum/Gas Industry

BACT Code	Storage Tanks	NOx	VOC
7.3.1	Petroleum and Petrochemical Production - Fixed Roof OrganicLiquid Storage or Processing Tank, < 5,000 bbl Tank capacity **	N/A	PV-vent set to within 10% of maximum allowable pressure
7.3.2	Petroleum and Petrochemical Production - Fixed Roof OrganicLiquid Storage or Processing Tank, = or > 5,000 bbl Tank capacity **	N/A	99% Control efficiency
7.3.3	Petroleum and Petrochemical Production - Floating Roof Organic Liquid Storage or Processing Tank, = or > 471 bbl Tank capacity, = or > 0.5 psia TVP	N/A	95% control

**San Joaquin Valley
Unified Air Pollution Control District**

Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

Main Category: 8.0 Miscellaneous Sources

BACT Code	Specialty Sources and Operations	NOx	VOC
8.3.3	Standby LPG Fuel Supply System - = or > 30 MMBtu/hr	0.068 lb/MMBtu	99.9% Control efficiency
8.3.5	Satellite thruster testing operation	Chemical packed scrubber serving nitrogen tetroxide transfer operation	N/A
8.3.12	Helicopter Engine Test Cell	Use of JP-8 fuel and good combustion practices.	Use of JP-8 fuel and good combustion practices.
8.3.17	Sulfur Powder Manufacturing (<= 4 MMBtu/hr Gas Generator)	50 ppmv @ 11% O2 natural gas-fired inert gas pneumatic conveyance system	natural gas fuel
8.3.20	On-line Chemical Vapor Deposition Process	N/A	Use of thermal oxidizer



A HEALTHY BREATHING ENVIRONMENT FOR EVERY BAY AREA RESIDENT

District (/) / Permits (/permits)
 Permitting Manuals (/permits/permitting-manuals)
 BACT/TBACT Workbook

BACT / TBACT Workbook

View the BACT/TBACT Workbook, a resource for guiding permit applicants and Air District staff through one step of the New Source Review permitting process.

The Air District's Best Available Control Technology and Best Available Control Technology for Toxics Workbook (PDF) is designed to provide guidance on the BACT (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation-definition-of-bact-tbact.pdf?la=en) (83 Kb PDF, 2 pgs, revised 06/09/15) and TBACT (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation/definition-of-bact-tbact.pdf?la=en) requirements for commonly permitted sources subject to New Source Review in the Bay Area. Each source subject to these requirements is analyzed on a "case by case" basis to determine compliance with these requirements and not all cases are covered by the guidance.

This workbook serves as a guide for permit applicants, Air District engineers, and others interested in understanding emissions limits, control devices, and techniques needed to meet the BACT (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation/definition-of-bact-tbact.pdf?la=en) (83 Kb PDF, 2 pgs, revised 06/09/15) New Source Review Rule (/rules-and-compliance/current-rules) and TBACT (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation-definition-of-bact-tbact.pdf?la=en) New Source Review of Toxic Air Contaminants Rule (/rules-and-compliance/current-rules).

Section 1: BACT/TBACT Policy and Implementation

Introduction (</~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation/introduction.pdf?la=en>)  (88 PDF, 3 pgs, revised 06/09/15)

Definition of BACT and TBACT (</~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation/definition-bact-tbact.pdf?la=en>)  (83 Kb PDF, 2 pgs, revised 06/09/15)

Policy and Implementation Procedure (</~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation/policy-and-implementation-procedure.pdf?la=en>)  (115 Kb PDF, 6 pgs, revised 06/09/15)

User's Guide to BACT/TBACT Workbook (</~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation/user-guide.pdf?la=en>)  (84 Kb PDF, 2 pgs, revised 06/09/15)

Figure 1: Using the Workbook: Step A (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation/figure_01.pdf?la=en)  (86 Kb PDF, 1 pg, revised 06/09/15)

Figure 2: Using the Workbook: Step B (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation/figure_02.pdf?la=en)  (91 Kb PDF, 1 pg, revised 06/09/15)

Section 2: Combustion Sources

Boilers, Commercial, Industrial, Institutional

Boiler, Rental: On-site < 6 consecutive months (</~/media/files/engineering/bact-tbact-workshop/combustion/17-1-1.pdf?la=en>)  (94 Kb PDF, 1 pg, revised 06/11/15)

Boiler: 5 to <33.5 MMBtu/hr (</~/media/files/engineering/bact-tbact-workshop/combustion/17-1-1.pdf?la=en>)  (19 Kb PDF, 2 pgs, revised 06/11/15)

Boiler: ≥ 33.5 to <50 MMBtu/hr (</~/media/files/engineering/bact-tbact-workshop/combustion/17-2-1.pdf?la=en>)  (19 Kb PDF, 2 pgs, revised 06/11/15)

Boiler: ≥ 50 MMBtu/hr (</~/media/files/engineering/bact-tbact-workshop/combustion/17-3-1.pdf?la=en>)  (21 Kb PDF, 2 pgs, revised 11/15)

Boiler, CO - Refinery (</~/media/files/engineering/bact-tbact-workshop/combustion/17-4-1.pdf?la=en>)  (95 Kb PDF, 1 pg, revised 11/15)

Boiler or Water Heater - Landfill or Digester Gas Fired (</~/media/files/engineering/bact-tbact-workshop/combustion/17-5-1.pdf?la=en>)  (95 Kb PDF, 1 pg, revised 05/24/16)

Boiler - Municipal Refuse Fired (</~/media/files/engineering/bact-tbact-workshop/combustion/17-8-1.pdf?la=en>)  (94 Kb PDF, 1 pg, revised 06/11/15)

Boiler - Wood Fired (</~/media/files/engineering/bact-tbact-workshop/combustion/17-9-1.pdf?la=en>)  (94 Kb PDF, 1 pg, revised 11/15)

Internal Combustion Engines

2. Engine - Compression Ignition, Prime > 50 hp (</~/media/files/engineering/bact-tbact-workshop/combustion>

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Water Treating - Oil/Water Separator</i>	Revision:	<i>1</i>
		Document #:	<i>177.1.1</i>
Class:	<i><250 Gallons/min</i>	Date:	<i>10/04/91</i>

Determination

POLLUTANT	BACT		TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice		
POC	1. <i>Vapor-tight fixed cover and vented to vapor recovery system w/ combined collection and destruction/recovery efficiency of >95%^a</i> 2. <i>Vapor-tight fixed cover totally enclosing the separator tank liquid contents^a</i>		1. <i>BAAQMD Approved Design and Operation^a</i> 2. <i>BAAQMD Approved Design and Operation^a</i>
NO _x	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>
SO ₂	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>
CO	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>
PM ₁₀	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>
NPOC	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>

References

<i>a. BAAQMD</i>

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source: <i>Water Treating - Oil/Water Separator</i>	Revision: <i>1</i>
	Document #: <i>177.2.1</i>
Class: <i>≥250 Gallons/min</i>	Date: <i>10/04/91</i>

Determination

POLLUTANT	BACT	TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	
POC	1. <i>n/d</i> 2. <i>Vapor-tight fixed cover and vented to vapor recovery system w/ combined collection and destruction/recovery efficiency of ≥95%^a</i>	1. <i>n/d</i> 2. <i>BAAQMD Approved Design and Operation^a</i>
NOx	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
SO ₂	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
CO	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
PM ₁₀	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
NPOC	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>

References

a. BAAQMD

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Water Treating - Sour Water Stripping</i>	Revision:	<i>1</i>
Class:	<i>All</i>	Document #:	<i>178.1</i>
		Date:	<i>01/10/92</i>

Determination

POLLUTANT	BACT	TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	
POC	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
NO _x	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
SO ₂	1. <i>n/d</i> 2. <i>Steam strip, condense, and vent to sulfur recovery unit, w/ overall removal/recovery ≥95% of the H₂S from the process water stream^b</i>	1. <i>n/d</i> 2. <i>BAAQMD Approved Design and Operation^b</i>
CO	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
PM ₁₀	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
NPOC	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>

References

b. BAAQMD A #5258

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source: <i>Flare - Refinery</i>	Revision: <i>2</i>
	Document #: <i>82.1</i>
Class: <i>All</i>	Date: <i>06/30/95</i>

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	<p>1. <i>Ground level flare, enclosed, steam- or air-assisted, w/ staged combustion; POC destruction efficiency $\geq 98.5\%$ (≥ 0.6 sec. retention time at $\geq 1400^{\circ}\text{F}$); use of natural gas or LPG as pilot fuel. Flare to be operated only during periods of emergency plant upset or breakdown; routine venting of process gases to be routed to fuel gas recovery system^{b,T}</i></p> <p>2. <i>Elevated flare, steam- or air-assisted, w/staged combustion; POC destruction efficiency $\geq 98\%$; use of natural gas or LPG as pilot fuel. Flare to be operated only during periods of emergency plant upset or breakdown; routine venting of process gases to be routed to fuel gas recovery system^{a,b,T}</i></p>	<p>1. <i>BAAQMD Approved Design and Operation^{a,T}</i></p> <p>2. <i>BAAQMD Approved Design and Operation^{a,T}</i></p>
NOx	<p>1. <i>n/d</i></p> <p>2. <i>Staged combustion as for POC above^{a,T}</i></p>	<p>1. <i>n/d</i></p> <p>2. <i>BAAQMD Approved Design and Operation^a</i></p>
SO ₂	<p>1. <i>n/d</i></p> <p>2. <i>n/d</i></p>	<p>1. <i>n/d</i></p> <p>2. <i>n/d</i></p>
CO	<p>1. <i>n/d</i></p> <p>2. <i>Same as for POC above^a</i></p>	<p>1. <i>n/d</i></p> <p>2. <i>BAAQMD Approved Design and Operation^a</i></p>
PM ₁₀	<p>1. <i>n/d</i></p> <p>2. <i>Same as for POC above^{a,T}</i></p>	<p>1. <i>n/d</i></p> <p>2. <i>BAAQMD Approved Design and Operation^{a,T}</i></p>
NPOC	<p>1. <i>n/a</i></p>	<p>1. <i>n/a</i></p>

2. n/a

2. n/a

References

a. BAAQMD

b. CARB/CAPCOA Clearinghouse

T. TBACT

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source: <i>Flanges</i>	Revision: <i>3</i>
	Document #: <i>78.1</i>
Class: <i>All</i>	Date: <i>01/18/06</i>

Determination

POLLUTANT	BACT	TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	
POC	1. <i>n/d</i> 2. <i>100 ppm expressed as methane measured using EPA Reference Method 21^{a,T}</i>	1. <i>n/d</i> 2. <i>Graphitic Gaskets and BAAQMD Approved Inspection and Maintenance^{a,T}</i>
NO _x	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
SO ₂	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
CO	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
PM ₁₀	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
NPOC	1. <i>n/d</i> 2. <i>100 ppm expressed as methane measured using EPA Reference Method 21^{a,T}</i>	1. <i>n/d</i> 2. <i>Graphitic Gaskets and BAAQMD Approved Inspection and Maintenance^{a,T}</i>

References

a. BAAQMD
T. TBACT

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Pressure Relief Valves, Emergency</i>	Revision:	<i>4</i>
		Document #:	<i>135.1</i>
Class:	<i>All</i>	Date:	<i>06/30/95</i>

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. <i>Rupture disk w/ vent to fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency $\geq 98\%$^{a,T}</i> 2. <i>Vent to fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency $\geq 98\%$^{a,T}</i>	1. <i>BAAQMD Approved Design and Operation^{a,T}</i> 2. <i>BAAQMD Approved Design and Operation^{a,T}</i>
NOx	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
SO ₂	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
CO	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
PM ₁₀	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
NPOC	1. <i>Rupture disk w/ vent to carbon adsorption system or vapor recovery system with a capture/recovery efficiency $\geq 90\%$^{a,T}</i> 2. <i>Vent to carbon adsorption system or vapor recovery system with a capture/recovery efficiency $\geq 90\%$^{a,T}</i>	1. <i>BAAQMD Approved Design and Operation^{a,T}</i> 2. <i>BAAQMD Approved Design and Operation^{a,T}</i>

References

a. BAAQMD
T. TBACT

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source: <i>Process Valves</i>	Revision: <i>3</i>
	Document #: <i>136.1</i>
Class: <i>All</i>	Date: <i>01/18/06</i>

Determination

POLLUTANT	BACT	TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	
POC	1. <i>n/d</i> 2. <i>100 ppm expressed as methane measured using EPA Reference Method 21^{a,T}</i>	1. <i>n/d</i> 2. <i>Bellows Valves; Diaphragm Valves; Quarter Turn Valves; Live Loaded Valves; or Other Low-Emission Valves; Each w/BAAQMD Approved Inspection and Maintenance^{a,T}</i>
NO _x	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
SO ₂	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
CO	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
PM ₁₀	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
NPOC	1. <i>n/d</i> 2. <i>100 ppm expressed as methane measured using EPA Reference Method 21^{a,T}</i>	1. <i>n/d</i> 2. <i>Bellows Valves; Diaphragm Valves; Quarter Turn Valves; Live Loaded Valves; or Other Low-Emission Valves; Each w/BAAQMD Approved Inspection and Maintenance^{a,T}</i>

References

a. BAAQMD
T. TBACT

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source: <i>Pumps</i>	Revision: <i>4</i>
	Document #: <i>137.1</i>
Class: <i>All</i>	Date: <i>01/18/06</i>

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. 100 ppm expressed as methane measured using EPA Reference Method 21 ^{a,T} 2. 500 ppm expressed as methane measured using EPA Reference Method 21 ^{a,T}	1. Double Mechanical Seals w/ Barrier Fluid; Magnetically Coupled Pumps; Canned Pumps; Magnetic Fluid Sealing Technology; or Gas Seal System Vented to Thermal Oxidizer or Other BAAQMD Approved Control Device; all w/BAAQMD Approved Quarterly Inspection and Maintenance Program ^{a,b,T} 2. Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program ^{a,b,T}
NOx	1. n/a 2. n/a	1. n/a 2. n/a
SO ₂	1. n/a 2. n/a	1. n/a 2. n/a
CO	1. n/a 2. n/a	1. n/a 2. n/a
PM ₁₀	1. n/a 2. n/a	1. n/a 2. n/a
NPOC	1. 100 ppm expressed as methane measured using EPA Reference Method 21 ^{a,T} 2. 500 ppm expressed as methane measured using EPA Reference Method 21 ^{a,T}	1. Double Mechanical Seals w/ Barrier Fluid; Magnetically Coupled Pumps; Canned Pumps; or Magnetic Fluid Sealing Technology; all w/ BAAQMD Approved Quarterly Inspection and Maintenance Program ^{a,b,T} 2. Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program ^{a,b,T}

References

a. BAAQMD

b. EPA NSPS: 40 CFR 60 Subpart GGG (Petroleum Refineries) and 40 CFR 60 Subpart VV (Chemical Plants)

T. TBACT

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source: <i>Compressors</i>	Revision: <i>4</i>
	Document #: <i>48B.1</i>
Class: <i>All</i>	Date: <i>01/18/06</i>

Determination

POLLUTANT	BACT		TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective	2. Achieved in Practice	
POC	1. 100 ppm expressed as methane measured using EPA Reference Method 21 ^{a,T}		1. Double Mechanical Seals w/ Barrier Fluid; or Gas Seal System Vented to a Thermal Oxidizer or Other BAAQMD Approved Control Device; all w/ BAAQMD Approved Quarterly Inspection and Maintenance Program ^{a,b,T}
	2. 500 ppm expressed as methane measured using EPA Reference Method 21 ^{a,T}		2. Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program ^{a,b,T}
NO _x	1. n/a		1. n/a
	2. n/a		2. n/a
SO ₂	1. n/a		1. n/a
	2. n/a		2. n/a
CO	1. n/a		1. n/a
	2. n/a		2. n/a
PM ₁₀	1. n/a		1. n/a
	2. n/a		2. n/a
NPOC	1. 100 ppm expressed as methane measured using EPA Reference Method 21 ^{a,T}		1. Double Mechanical Seals w/ Barrier Fluid; or Gas Seal System Vented to BAAQMD Approved Control Device; all w/ BAAQMD Approved Quarterly Inspection and Maintenance Program ^{a,b,T}
	2. 500 ppm expressed as methane measured using EPA Reference Method 21 ^{a,T}		2. Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program ^{a,b,T}

References

- a. BAAQMD
- b. EPA NSPS: 40 CFR 60 Subpart GGG (Petroleum Refineries) and 40 CFR 60 Subpart VV (Chemical Plants)
- T. TBACT

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Sulfur Recovery Plant</i>	Revision:	<i>1</i>
		Document #:	<i>169.1</i>
Class:	<i>All</i>	Date:	<i>01/10/92</i>

Determination

POLLUTANT	BACT		TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice		
POC	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>
NO _x	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>
SO ₂	1. <i>Sulfur recovery unit w/ >95% conversion, two tail gas treating units (one standby) to treat gas to <10 ppm H₂S, and standby incinerator^b</i> 2. <i>Sulfur recovery unit w/ >95% conversion, tail gas treating unit to treat gas to <10 ppm H₂S, and standby incinerator^b</i>		1. <i>BAAQMD Approved Design and Operation^b</i> 2. <i>BAAQMD Approved Design and Operation^b</i>
CO	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>
PM ₁₀	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>
NPOC	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>

References

b. BAAQMD A #5258

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Storage tank - External Floating Roof, Organic Liquids</i>	Revision:	2
		Document #:	167.1.2
Class:	<i>All</i>	Date:	09/19/2011

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	<p>1. Vapor recovery system w/ an overall system efficiency $\geq 98\%$^{a,T}</p> <p>2. BAAQMD Approved roof w/ liquid mounted primary seal and zero gap secondary seal, all meeting design criteria of Reg. 8, Rule 5. Also, no ungasketed roof penetrations, no slotted pipe guide pole unless equipped with float and wiper seals, and no adjustable roof legs unless fitted w/ vapor seal boots or equivalent^{a,T}</p> <p>Additionally, a dome is required for tanks that meet all of the following: 1) capacity greater than or equal to 19,815 gallons 2) located at a facility with greater than 20 tpy VOC emissions since the year 2000 and 3) storing a material with a vapor pressure equal to or greater than 3 psia (except for crude oil tanks that are permitted to contain more than 97% by volume crude oil).^b</p>	<p>1. Thermal Incinerator; or Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent^{a,T}</p> <p>2. BAAQMD Approved Roof and Seal Design^{a,T}</p>
NOx	<p>1. n/a</p> <p>2. n/a</p>	<p>1. n/a</p> <p>2. n/a</p>
SO ₂	<p>1. n/a</p> <p>2. n/a</p>	<p>1. n/a</p> <p>2. n/a</p>
CO	<p>1. n/a</p> <p>2. n/a</p>	<p>1. n/a</p> <p>2. n/a</p>
PM ₁₀	<p>1. n/a</p> <p>2. n/a</p>	<p>1. n/a</p> <p>2. n/a</p>
NPOC	<p>1. Vapor recovery system w/ an overall system efficiency $\geq 98\%$^{a,T}</p> <p>2. Same as for POC above</p>	<p>1. Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent^{a,T}</p> <p>2. BAAQMD Approved Roof and Seal Design^{a,T}</p>

References

- a. BAAQMD
T. TBACT
b. BAAQMD Application 22722, SCAQMD Regulation 1178 (1/1/04)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	Storage Tank - Fixed Roof, Organic Liquids	Revision:	2
Class:	<20,000 Gallons	Document #:	167.2.1
		Date:	03/03/95

Determination

POLLUTANT	BACT		TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice		
POC	1. n/d 2. Vapor recovery system w/ an overall system efficiency $\geq 95\%$ ^{a,T}	1. n/d 2. Vapor Balance; or Carbon Adsorber; or Refrigerated Condenser; or Incinerator; or BAAQMD approved equivalent ^{a,T}	
NO _x	1. n/a 2. n/a	1. n/a 2. n/a	
SO ₂	1. n/a 2. n/a	1. n/a 2. n/a	
CO	1. n/a 2. n/a	1. n/a 2. n/a	
PM ₁₀	1. n/a 2. n/a	1. n/a 2. n/a	
NPOC	1. n/d 2. Vapor recovery system w/ an overall system efficiency $\geq 95\%$ ^{a,T}	1. n/d 2. Vapor Balance; or Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent ^{a,T}	

References

a. BAAQMD
T. TBACT

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	Storage Tank - Fixed Roof, Organic Liquids	Revision:	2
		Document #:	167.3.1
Class:	>20,000 Gallons	Date:	03/03/95

Determination

POLLUTANT	BACT		TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice		
POC	1. n/d 2. Vapor recovery system w/ an overall system efficiency $\geq 98\%$ ^{a,T}	1. n/d 2. Thermal Incinerator; or Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent ^{a,T}	
NO _x	1. n/a 2. n/a	1. n/a 2. n/a	
SO ₂	1. n/a 2. n/a	1. n/a 2. n/a	
CO	1. n/a 2. n/a	1. n/a 2. n/a	
PM ₁₀	1. n/a 2. n/a	1. n/a 2. n/a	
NPOC	1. n/d 2. Vapor recovery system w/ an overall system efficiency $\geq 98\%$ ^{a,T}	1. n/d 2. Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent ^{a,T}	

References

^a. BAAQMD
^T. TBACT

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Storage Tank - Internal Floating Roof, Organic Liquids</i>	Revision:	2
Class:	All	Document #:	167.4.1
		Date:	03/03/95

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. Vapor recovery system w/ an overall system efficiency $\geq 98\%$ ^{a,T} 2. BAAQMD Approved roof w/ liquid mounted primary seal and zero gap secondary seal, all meeting design criteria of Reg. 8, Rule 5. Also, no ungasketed roof penetrations, no slotted pipe guide pole unless equipped with float and wiper seals, and no adjustable roof legs unless fitted w/ vapor seal boots or equivalent ^{a,T}	1. Thermal Incinerator; or Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent ^{a,T} 2. BAAQMD Approved Roof and Seal Design ^{a,T}
NO _x	1. n/a 2. n/a	1. n/a 2. n/a
SO ₂	1. n/a 2. n/a	1. n/a 2. n/a
CO	1. n/a 2. n/a	1. n/a 2. n/a
PM ₁₀	1. n/a 2. n/a	1. n/a 2. n/a
NPOC	1. Vapor recovery system w/ an overall system efficiency $\geq 98\%$ ^{a,T} 2. Same as for POC above	1. Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent ^{a,T} 2. BAAQMD Approved Roof and Seal Design ^{a,T}

References

a. BAAQMD
T. TBACT

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Degreaser - Cold Solvent Cleaner</i>	Revision:	<i>2</i>
		Document #:	<i>54.1</i>
Class:	<i>All</i>	Date:	<i>03/10/95</i>

Determination

POLLUTANT	BACT		TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective	2. Achieved in Practice	
POC	1. <i>Compliance w/ BAAQMD Reg. 8, Rule 16 for all solvents, and equipped with cover, freeboard ratio ≥ 1, and either: a) water layer (1 inch); or b) covering while in use^{a,b,T}</i>	2. <i>Compliance w/ BAAQMD Reg. 8, Rule 16 for all solvents, and equipped with cover and freeboard ratio ≥ 0.75^{a,b,T}</i>	1. <i>BAAQMD Approved Design and Operation^{b,T}</i> 2. <i>BAAQMD Approved Design and Operation^{b,T}</i>
NO _x	1. <i>n/a</i>	2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
SO ₂	1. <i>n/a</i>	2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
CO	1. <i>n/a</i>	2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
PM ₁₀	1. <i>n/a</i>	2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
NPOC	1. <i>Same as for POC above</i>	2. <i>Same as for POC above</i>	1. <i>Same as for POC above</i> 2. <i>Same as for POC above</i>

References

<i>a. BAAQMD</i>
<i>b. MACT Standard</i>
<i>c. TBACT</i>

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline**

Source Category

Source:	Boiler	Revision:	4
		Document #:	17.1.1
Class:	5 MMBtu/hr to < 33.5 MMBtu/hr Heat Input	Date:	08/04/10

Determination

Pollutant	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. n/d 2. n/s	1. n/d 2. Good Combustion Practice ^a
NO_x	1. n/d 2. n/d	1. Low NO _x Burners + Flue Gas Recirculation + Selective Catalytic Reduction ^a 2. Low NO _x Burners + Flue Gas Recirculation ^a
SO₂	1. Natural Gas or Treated Refinery Gas Fuel w/ ≤.50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur ^a 2. Natural Gas or Treated Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur ^a	1. Fuel Selection ^{Error! Reference source not found.} 2. Fuel Selection ^{Error! Reference source not found.}
CO	1. 50 ppmv @ 3% O ₂ Dry ^{a,e} 2. 50 ppmv @ 3% O ₂ Dry, for Firetube Boilers ^f 100 ppmv @ 3% O ₂ Dry, for Watertube Boilers ^{a,e}	1. Good Combustion Practice ^a 2. Good Combustion Practice ^a
PM₁₀	1. n/d 2. Natural Gas or Treated Refinery Gas Fuel ^a	1. n/d 2. Fuel Selection ^a
NPOC	1. n/a 2. n/a	1. n/a 2. n/a

References

- a. BAAQMD
- d. NO_x determination by BAAQMD source Test method ST-13A or B (average of three 30-minute sampling runs), or BAAQMD approved equivalent.
- e. CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs), or BAAQMD approved equivalent.
- f. CO 100 ppmv allowance for firetube boilers meeting the 20 ppmv NO_x standard.

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline**

Source Category

Source:	Boiler	Revision:	4
		Document #:	17.2.1
Class:	≥33.5 MMBtu/hr to <50 MMBtu/hr Heat Input	Date:	08/04/10

Determination

Pollutant	BACT		TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice		
POC	1. n/d 2. n/s	1. n/d 2. Good Combustion Practice ^a	
NO_x	1. n/d 2. n/d	1. Low NO _x Burners + Flue Gas Recirculation + Selective Catalytic Reduction ^a 2. Low NO _x Burners + Flue Gas Recirculation ^a	
SO₂	1. Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur ^a 2. Natural Gas or Treated Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur ^a	1. Fuel Selection ^a 2. Fuel Selection ^a	
CO	1. n/d 2. 100 ppmv @ 3% O ₂ Dry ^{a,d}	1. n/d 2. Good Combustion Practice ^a	
PM₁₀	1. n/d 2. Natural Gas or Treated Refinery Gas Fuel ^a	1. n/d 2. Fuel Selection ^a	
NPOC	1. n/a 2. n/a	1. n/a 2. n/a	

References

- a. BAAQMD
- c. NO_x determination by BAAQMD Source Test Method ST-13A or B (average of three 30-minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.
- d. CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs); or Continuous Emission Monitor (3-hour average), or BAAQMD approved equivalent.

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline**

Source Category

Source:	Boiler	Revision:	5
		Document #:	17.3.1
Class:	≥ 50 MMBtu/hr Heat Input	Date:	08/04/10

Determination

Pollutant	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. n/d 2. n/s	1. n/d ^f 2. Good Combustion Practice ^a
NO_x	1. n/d ^{b, c, d} 2. n.d ^{a, c, d}	1. Selective Catalytic Reduction (SCR) + Low NO _x Burners (LNB) + Flue Gas Recirculation (FGR) ^{b, c, d} 2. Ultra Low NO _x Burners (ULNB) + FGR ^{a, c, d}
SO₂	1. Natural Gas or Treated Refinery Gas Fuel w/ <.50 ppmv Hydrogen Sulfide and <100 ppmv Total Reduced Sulfur ^{a, c} 2. Natural Gas or Treated Refinery Gas Fuel w/ <100 ppmv Total Reduced Sulfur ^{a, c}	1. Fuel Selection ^{a, c} 2. Fuel Selection ^{a, c}
CO	1. 10 ppmv @ 3% O ₂ Dry ^f 2. 50 ppmv @ 3% O ₂ Dry ^{a, c, e}	1. Oxidation Catalyst ^f 2. Good Combustion Practice in Conjunction with SCR System or Ultra Low NO _x Burners and FGR ^{a, c, e}
PM₁₀	1. n/d 2. Natural Gas or Treated Refinery Gas Fuel ^{a, c}	1. n/d 2. Fuel Selection ^{a, c}
NPOC	1. n/a 2. n/a	1. n/a 2. n/a

References

- a. BAAQMD
- b. SCAQMD. Cost effectiveness evaluations shall be based on emissions from firing primary fuels but not emergency backup fuels.
- c. BACT limits apply to all fuels except for emergency backup fuel oil used during natural gas curtailment. For emergency backup fuel oil:
BACT(1) for NO_x and CO (achieved using LNB+FGR+SCR and GCP) is 25 ppmvd NO_x @3%O₂, 100 ppmvd CO @3%O₂, and 5 ppmvd NH₃ @ 3%O₂
BACT(2) for NO_x and CO (achieved using ULNB+FGR and GCP) is 40 ppmvd NO_x @3%O₂ and 100 ppmvd CO @#%O₂
BACT(2) for SO₂ and PM₁₀ is the use of low sulfur fuel with < 0.05 wt% S
BACT(2) for POC is GCP
- d. NO_x determination by Continuous Emission Monitor (3-hr average), or BAAQMD approved equivalent.
- e. CO determination by Continuous Emission Monitor (3-hr average), or BAAQMD approved equivalent.
- f. The BACT(1) CO limit does not apply to boilers smaller than 250 MMBTU/hr unless an oxidation catalyst is found to be cost effective for TBACT or POC Control.

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline**

Source Category

Source:	IC Engine – Compression Ignition, Stationary Prime; non-Agricultural	Revision:	6
		Document #:	96.1.4
Class:	> 50 BHP Output	Date:	04/13/2009

Determination

Pollutant	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	<ol style="list-style-type: none"> 50% reduction of current tier^{a,b} standard for POC. Current tier^{a,b} standard for POC at applicable horsepower rating. 	<ol style="list-style-type: none"> Catalytic oxidation combined with current POC certified engine.^{a,b} Current POC certified engine.^{a,b}
NOx	<ol style="list-style-type: none"> 85% reduction of current tier^{a,b} standard for NOx. Current tier^{a,b} standard for NOx at applicable horsepower rating. 	<ol style="list-style-type: none"> Selective catalytic reduction (SCR) + current NOx certified engine.^{a,b} Current NOx certified engine.^{a,b}
SO₂	<ol style="list-style-type: none"> n/s Fuel sulfur content not to exceed 0.0015% (wt) or 15 ppm. 	<ol style="list-style-type: none"> n/s CARB Diesel Fuel (Ultra Low Sulfur Diesel).
CO	<ol style="list-style-type: none"> 50% reduction of current tier^{a,b} standard for CO. 2.75 g/bhp-hr [319 ppmvd @ 15% O₂]^d 	<ol style="list-style-type: none"> Catalytic oxidation combined with current CO certified engine.^{a,b} Any engine demonstrated or certified to meet 2.75 g/bhp-hr.
PM₁₀	<ol style="list-style-type: none"> n/s 0.01 g/bhp-hr or equiv^e technology.^e TBACT: 0.01 g/bhp-hr or equivalent^e technology.^e 	<ol style="list-style-type: none"> n/s Any engine/technology verified or certified to achieve 0.01 g/bhp-hr.^e (See 2., above)^e
NPOC	<ol style="list-style-type: none"> n/s n/s 	<ol style="list-style-type: none"> n/s n/s

References

- Current tier standard:** The current CARB or EPA off-road tier standard for the pollutant of concern within the appropriate horsepower range. Where NMHC + NOx is listed (with no individual standards for NOx or NMHC) as the standard, the portions may be considered 95% NOx and 5% NMHC. For the purposes of determining BACT NMHC = POC. Any engine which has been certified or demonstrated to meet the current year tier standard may be considered a current certified engine for that pollutant.
- An engine which does not meet the current EPA or CARB off-road tier standard may represent BACT2, providing 1) the engine met the most stringent EPA Tier Standard in effect prior to the Tier change for that horsepower rating, and 2) the permit application is submitted within 6 months of the effective date of the Tier change. [Source: California Health & Safety Code Section 93116.3(b)(7)]
- Compliance with 0.01 g/bhp-hr may be demonstrated by use of *Alternative Compliance Demonstration*, specified in California Health & Safety Code Section 93115.13(f) [Stationary CI Engine ATCM].
- Previous BACT determination dated 01/11/02.
- Specified because not all BAAQMD-defined stationary engines are subject to the Stationary ATCM.

Overview of Off-Road Compression Ignition Engine Certification Standards in g/bhp-hr (g/kW-hr)¹

Engine HP (KW)	Tier 1 ₂					Tier 2				Tier 3				Tier 4					
	HC	NOx	CO	PM	Years	NMHC + NOx	CO	PM	Years	NMHC + NOx	CO	PM	Years	NMHC + NOx	NMHC	NOx ₂	CO	PM	Years
50 <75 (37<56)		6.9 (9.2)			1998 - 2003	5.6 (7.5)	3.7 (5.0)	0.30 (0.40)	2004 - 2007	3.5 (4.7)	3.7 (5.0)	0.22 (0.30)	2008 - 2012	3.5 (4.7)			3.7 (5.0)	0.02 (0.03)	2013+
75<100 (56<75)		6.9 (9.2)			1998 - 2003	5.6 (7.5)	3.7 (5.0)	0.30 (0.40)	2004 - 2007	3.5 (4.7)	3.7 (5.0)	0.30 (0.40)	2008 - 2011	3.5 (4.7)	0.14 (0.19)	0.30-2.5 (0.40-3.4)	3.7 (5.0)	0.01 (0.02)	2012 - 2013
															0.14 (0.19)	0.30 (0.40)	3.7 (5.0)	0.01 (0.02)	2014+
100<175 (75<130)		6.9 (9.2)			1997 - 2002	4.9 (6.6)	3.7 (5.0)	0.22 (0.30)	2003 - 2006	3.0 (4.0)	3.7 (5.0)	0.22 (0.30)	2007 - 2011	3.0 (4.0)	0.14 (0.19)	0.30-2.5 (0.40-3.4)	3.7 (5.0)	0.01 (0.02)	2012 - 2013
															0.14 (0.19)	0.30 (0.40)	3.7 (5.0)	0.01 (0.02)	2014+
175<300 (>130<225)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	1996 - 2002	4.9 (6.6)	2.6 (3.5)	0.15 (0.20)	2003 - 2005	3.0 (4.0)	2.6 (3.5)	0.15 (0.20)	2006 - 2010	3.0 (4.0)	0.14 (0.19)	0.30-1.5 (0.40-2.0)	2.6 (3.5)	0.01 (0.02)	2011 - 2013
															0.14 (0.19)	0.30 (0.40)	2.6 (3.5)	0.01 (0.02)	2014+
300<600 (225<450)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	1996 - 2000	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2001 - 2005	3.0 (4.0)	2.6 (3.5)	0.15 (0.20)	2006 - 2010	3.0 (4.0)	0.14 (0.19)	0.30-1.5 (0.40-2.0)	2.6 (3.5)	0.01 (0.02)	2011 - 2013
															0.14 (0.19)	0.30 (0.40)	2.6 (3.5)	0.01 (0.02)	2014+
600<750 (450<560)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	1996 - 2001	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2002 - 2005	3.0 (4.0)	2.6 (3.5)	0.15 (0.20)	2006 - 2010	3.0 (4.0)	0.14 (0.19)	0.30-1.5 (0.40-2.0)	2.6 (3.5)	0.01 (0.02)	2011 - 2013
															0.14 (0.19)	0.30 (0.40)	2.6 (3.5)	0.01 (0.02)	2014+
≥750 (≥560)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	2000 - 2005	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2006 - 2010						0.30 (0.40)	2.6 (3.5)	2.6 (3.5)	0.075 (0.10)	2011 - 2014
															0.14 (0.19)	2.6 (3.5)	2.6 (3.5)	0.03 (0.04)	2015+
>750≤1200 ⁴ (560≤900) Gen. Only	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	2000 - 2005	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2006 - 2010						0.30 (0.40)	2.6 (3.5)	2.6 (3.5)	0.075 (0.10)	2011 - 2014
															0.14 (0.19)	0.50 (0.67)	2.6 (3.5)	0.02 (0.03)	2015+
>1200 ⁴ (>900) Gen. Only	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.40 (0.54)	2000 - 2005	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2006 - 2010						0.30 (0.40)	0.50 (0.67)	2.6 (3.5)	0.075 (0.10)	2011 - 2014
															0.14 (0.19)	0.5 (0.67)	2.6 (3.5)	0.02 (0.03)	2015+

- 1 This table is intended as an overview. For California Exhaust Emission Standards and Test Procedures -Off-Road Compression-Ignition Engines, consult title 13, California Code of Regulations, section 2423. For federal Nonroad Compression Ignition Engine Certification Standards, consult title 40, United States Code of Federal Regulations, Chapter 1, Part 89, subpart B and Part 1039, Subpart B.
- 2 Engine manufacturers have several options for complying with NOx during the transitional implementation years of Tier 4, including a "phase-in-phase-out" or alternative NOx level approach.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	IC Engine-Compression Ignition: Stationary Emergency, non- Agricultural, non-direct drive fire pump	Revision:	7
		Document #:	96.1.3
Class:	≥ 50 BHP Output	Date:	12/22/2010

Determination

Pollutant	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice 3. TBACT	TYPICAL TECHNOLOGY
POC (NMHC)	1. n/s ^c 2. CARB ATCM standard ^a for POC at applicable horsepower rating (see attached Table 1).	1. n/s ^c 2. Any engine certified or verified to achieve the applicable standard. ^a
NO_x	1. n/s ^c 2. CARB ATCM standard ^a for NO _x at applicable horsepower rating (see attached Table 1).	1. n/s ^c 2. Any engine certified or verified to achieve the applicable standard. ^a
SO₂	1. n/s ^c 2. Fuel sulfur content not to exceed 0.0015% (wt) or 15 ppm (wt).	1. n/s ^c 2. CARB Diesel Fuel (Ultra Low Sulfur Diesel)
CO	1. n/s ^c 2. CARB ATCM standard ^a for CO at the applicable horsepower rating (see attached Table 1).	1. n/s ^c 2. Any engine certified or verified to achieve the applicable standard. ^a
PM₁₀	1. n/s ^c 2. 0.15 g/bhp-hr 3. 0.15 g/bhp-hr	1. n/s ^c 2. Any engine or technology demonstrated, certified or verified to achieve the applicable standard. 3. Any engine or technology demonstrated, certified or verified to achieve the applicable standard.
NPOC	1. n/s 2. n/s	1. n/s 2. n/s

References

- a. ATCM standard (listed below): Where NMHC + NOx is listed (with no individual standards for NOx or NMHC) as the standard, the portions may be considered 95% NOx and 5% NMHC. For the purposes of determining BACT NMHC = POC. Any engine which has been certified or demonstrated to meet the current year tier standard may be considered compliant with the certified emission standard for that pollutant.
- b. Deleted (no longer applies).
- c. Cost effectiveness analysis must be based on lesser of 50 hr/yr or non-emergency operation as limited by District health risk screen analysis.

Table 1: BACT 2 Emission Limits based on CARB ATCM

Emissions Standards for Stationary Emergency Standby Diesel-Fueled CI Engines \geq50 BHP g/Kw-hr (g/bhp-hr)			
Maximum Engine Power	PM	NMHC+NOx	CO
37 \leq KW < 56 (50 \leq HP < 75)	0.20 (0.15)	4.7 (3.5)	5.0 (3.7)
56 \leq KW < 75 (75 \leq HP < 100)	0.20 (0.15)	4.7 (3.5)	5.0 (3.7)
75 \leq KW < 130 (100 \leq HP < 175)	0.20 (0.15)	4.0 (3.0)	5.0 (3.7)
130 \leq KW < 225 (175 \leq HP < 300)	0.20 (0.15)	4.0 (3.0)	3.5 (2.6)
225 \leq KW < 450 (300 \leq HP < 600)	0.20 (0.15)	4.0 (3.0)	3.5 (2.6)
450 \leq KW \leq 560 (600 \leq HP \leq 750)	0.20 (0.15)	4.0 (3.0)	3.5 (2.6)
KW > 560 (HP > 750)	0.20 (0.15)	6.4 (4.8)	3.5 (2.6)

Source Category

Source:	<i>IC Engine – Spark Ignition, Natural Gas Fired Rich Burn Engine</i>	Revision:	<i>1</i>
		Document #:	<i>96.3.2</i>
Class:	<i>>= 50 HP</i>	Date:	<i>5/7/03</i>

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. <i>0.069 g/bhp-hr^a (12 ppmvd @ 15% oxygen)</i> 2. <i>0.15 g/bhp-hr^b (25 ppmvd @ 15% oxygen)</i>	1. <i>3-way catalyst + air/fuel ratio controller^a</i> 2. <i>NSCR, 3-way catalyst^b</i>
NO _x	1. <i>0.071 g/bhp-hr^a (4 ppmvd @ 15% oxygen)</i> 2. <i>0.15 g/bhp-hr^b (9 ppmvd @ 15% oxygen)</i>	1. <i>3-way catalyst + air/fuel ratio controller^a</i> 2. <i>NSCR, 3-way catalyst^b</i>
SO ₂	1. <i>n/d</i> 2. <i>n/s</i>	1. <i>n/d</i> 2. <i>natural gas^b</i>
CO	1. <i>n/d</i> 2. <i>0.60 g/bhp-hr^b (56 ppmvd @ 15% oxygen)</i>	1. <i>n/d</i> 2. <i>3-way catalyst^b</i>
PM ₁₀	1. <i>n/d</i> 2. <i>n/s</i>	1. <i>n/d</i> 2. <i>natural gas^b</i>
NPOC	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>

References

- | |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <p><i>a. San Joaquin Valley Air Pollution Control District (SJVUAPCD): Aera Energy Oilfield</i></p> <p><i>b. CARB "Guidance for the Permitting of Electrical Generation Technologies", September 2001</i></p> |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|

Source Category

Source:	<i>IC Engine – Spark Ignition, Natural Gas Fired Lean Burn Engine</i>	Revision:	<i>1</i>
		Document #:	<i>96.3.3</i>
Class:	<i>>= 50 HP</i>	Date:	<i>5/7/03</i>

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. <i>n/d</i> 2. <i>0.15 g/bhp-hr^b (32 ppmvd @ 15% oxygen)</i>	1. <i>n/d</i> 2. <i>oxidation catalyst^b</i>
NO _x	1. <i>0.07 g/bhp-hr^a (6 ppmvd @ 15% oxygen)</i> 2. <i>0.15 g/bhp-hr^b (12 ppmvd @ 15% oxygen)</i>	1. <i>SCR^a</i> 2. <i>SCR^b</i>
SO ₂	1. <i>n/d</i> 2. <i>n/s</i>	1. <i>n/d</i> 2. <i>natural gas^b</i>
CO	1. <i>0.10 g/bhp-hr^a (12 ppmvd @ 15% oxygen)</i> 2. <i>0.60 g/bhp-hr^b (74 ppmvd @ 15% oxygen)</i>	1. <i>oxidation catalyst^a</i> 2. <i>oxidation catalyst^b</i>
PM ₁₀	1. <i>n/d</i> 2. <i>n/s</i>	1. <i>n/d</i> 2. <i>natural gas^b</i>
NPOC	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>

References

- a. Tehama County Air Pollution Control District: *NEO California Power, LLC – Red Bluff, California (ammonia slip limited to 10 ppmvd @ 15% oxygen)*
 b. CARB “Guidance for the Permitting of Electrical Generation Technologies”, September 2001

Source Category

Source:	IC Engine – Spark Ignition, Natural Gas Fired Emergency Engine	Revision:	1
		Document #:	96.3.4
Class:	>= 50 HP	Date:	5/7/03

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. <i>n/d</i> 2. <i>1.0 g/bhp-hr^a</i>	1. <i>n/d</i> 2. <i>lean burn technology^a</i>
NO _x	1. <i>n/d</i> 2. <i>1.0 g/bhp-hr^a</i>	1. <i>n/d</i> 2. <i>lean burn technology^a</i>
SO ₂	1. <i>n/a</i> 2. <i>n/s</i>	1. <i>n/a</i> 2. <i>natural gas^a</i>
CO	1. <i>n/d</i> 2. <i>2.75 g/bhp-hr^a</i>	1. <i>n/d</i> 2. <i>lean burn technology^a</i>
PM ₁₀	1. <i>n/d</i> 2. <i>n/s</i>	1. <i>n/d</i> 2. <i>natural gas^a</i>
NPOC	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>

References

a. 1993 BACT 2 levels for IC Engine-Spark Ignition, Nat. Gas >_ 250 HP (3/19/93) without the need for post-combustion controls (not considered to be cost effective for emergency only applications).

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline**

Source Category

Source:	<i>Heater - Refinery Process, Natural or Induced Draft</i>	Revision:	3
		Document #:	94.1.1
Class:	<i>5 MMBtu/hr to <50 MMBtu/hr Heat Input</i>	Date:	08/12/94

Determination

POLLUTANT	BACT		TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice		
POC	1. n/d 2. n/s		1. n/d 2. Good Combustion Practice ^a
NO _x	1. 10 ppmv @ 3% O ₂ Dry ^{a,b,c,e} 2. 25 ppmv @ 3% O ₂ Dry ^{a,b,e}		1. Selective Catalytic Reduction (SCR) + Low NO _x Burners ^{a,b,c} 2. Low NO _x Burners; or Low NO _x Burners + Selective Non-Catalytic Reduction (SNCR) ^{a,d}
SO ₂	1. Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur ^a 2. Natural Gas or Treated Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur ^a		1. Fuel Selection ^a 2. Fuel Selection ^a
CO	1. n/d 2. 50 ppmv @ 3% O ₂ Dry ^{a,f}		1. n/d 2. Good Combustion Practice ^a
PM ₁₀	1. n/d 2. Natural Gas or Treated Refinery Gas Fuel ^{a,b}		1. n/d 2. Fuel Selection ^{a,b}
NPOC	1. n/a 2. n/a		1. n/a 2. n/a

References

- a. BAAQMD
- b. BAAQMD A #30783
- c. BAAQMD A #3318
- d. BAAQMD A #8407
- e. NO_x determination by BAAQMD Source Test Method ST-13A or B (average of three 30-minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.

f. CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Heater - Refinery Process, Forced Draft</i>	Revision:	<i>3</i>
		Document #:	<i>94.2.1</i>
Class:	<i>5 MMBtu/hr to <50 MMBtu/hr Heat Input</i>	Date:	<i>08/12/94</i>

Determination

POLLUTANT	BACT	TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	
POC	1. <i>n/d</i> 2. <i>n/s</i>	1. <i>n/d</i> 2. <i>Good Combustion Practice^a</i>
NO _x	1. <i>10 ppmv @ 3% O₂ Dry^{a,b,c,e}</i> 2. <i>20 ppmv @ 3% O₂ Dry^{a,b,e}</i>	1. <i>Selective Catalytic Reduction (SCR) + Low NO_x Burners^{a,b,c}</i> 2. <i>Low NO_x Burners; + Flue Gas Recirculation; or Low NO_x Burners + Selective Non-Catalytic Reduction (SNCR); or Selective Catalytic Reduction(SCR)^{a,d}</i>
SO ₂	1. <i>Natural Gas or Treated Refinery Gas Fuel w/ <50 ppmv Hydrogen Sulfide and <100 ppmv Total Reduced Sulfur^a</i> 2. <i>Natural Gas or Treated Refinery Gas Fuel w/ <100 ppmv Total Reduced Sulfur^a</i>	1. <i>Fuel Selection^a</i> 2. <i>Fuel Selection^a</i>
CO	1. <i>n/d</i> 2. <i>50 ppmv @ 3% O₂ Dry^{a,f}</i>	1. <i>n/d</i> 2. <i>Good Combustion Practice^a</i>
PM ₁₀	1. <i>n/d</i> 2. <i>Natural Gas or Treated Refinery Gas Fuel^{a,b}</i>	1. <i>n/d</i> 2. <i>Fuel Selection^{a,b}</i>
NPOC	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>

References

- a. BAAQMD*
- b. BAAQMD A #30783*
- c. BAAQMD A #3318*
- d. BAAQMD A #8407*

e. NO_x determination by BAAQMD Source Test Method ST-13A or B (average of three 30-minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.

f. CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	Heater - Refinery Process	Revision:	4
		Document #:	94.3.1
Class:	≥50 MMBtu/hr Heat Input	Date:	1/14/08

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. n/d 2. n/s	1. n/d 2. Good Combustion Practice ^a
NO_x	1. n/d 2. 5 ppmv @ 3% O ₂ Dry ^{c,d,e}	1. n/d 2. Selective Catalytic Reduction (SCR) + Low NO _x Burners ^{c,d}
SO₂	1. Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur ^a 2. Natural Gas or Treated Refinery Gas Fuel w/ <100 ppmv Total Reduced Sulfur ^a	1. Fuel Selection ^a 2. Fuel Selection ^a
CO	1. n/d 2. 10 ppmv @ 3% O ₂ Dry ^{c,d,f}	1. n/d 2. Good Combustion Practice in Conjunction w/ Selective Catalytic Reduction (SCR) System ^{c,d}
PM₁₀	1. n/d 2. Natural Gas or Treated Refinery Gas Fuel ^{a,b}	1. n/d 2. Fuel Selection ^{a,b}
NPOC	1. n/a 2. n/a	1. n/a 2. n/a

References

- a. BAAQMD A #8407
- b. BAAQMD A #30783
- c. ARB BACT Clearinghouse, based on several South Coast AQMD projects. Recommend ammonia slip limit of 10 ppmv at 3% O₂.
- d. Authority to Construct issued for BAAQMD applications 13424 & 13678 for CononcoPhillips Clean Fuels Expansion Project. For 85 MM BTU/hr furnace, the CO limit only applies at firing rates greater than 30 MM BTU/hr.
- e. NO_x determination by Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.
- f. CO determination by Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Liquid Transfer & Handling - Tank Truck & Rail Car Bulk Loading</i>	Revision:	2
		Document #:	109.1
Class:	<i>All (except Gasoline Bulk Terminals)</i>	Date:	06/28/00

Determination

POLLUTANT	BACT	TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	
POC	1. <i>n/d</i> 2. <i>Submerged pipe fill and vapor collection system vented to a thermal incinerator w/ a destruction efficiency $\geq 98.5\%$^b</i>	1. <i>n/d</i> 2. <i>BAAQMD Approved Design and Operation^b</i>
NOx	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
SO ₂	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
CO	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
PM ₁₀	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
NPOC	1. <i>n/d</i> 2. <i>Submerged pipe fill and vapor recovery system w/ an overall system efficiency $\geq 95\%$^b</i>	1. <i>n/d</i> 2. <i>Refrigerated Condenser; or Carbon Adsorber; or BAAQMD Approved Equivalent^b</i>

References

b. BAAQMD

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Liquid Transfer & Handling - Tank Truck & Rail Car Bulk Loading</i>	Revision:	<i>1</i>
		Document #:	<i>109.2</i>
Class:	<i>Gasoline Bulk Terminals</i>	Date:	<i>06/28/00</i>

Determination

POLLUTANT	BACT	
	1. Technologically Feasible/ Cost Effective	2. Achieved in Practice
POC	1. <i>n/d</i> 2. <i>0.02 pounds/1000 gallons loaded^{a,b}</i>	1. <i>n/d</i> 2. <i>Submerged Loading with Vapor Collection System vented to a Thermal Oxidizer, Carbon Adsorber with vapor tank, or BAAQMD Approved Equivalent^{a,b}</i>
NOx	1. <i>n/a</i> 2. <i>0.10 pounds/1000 gallons loaded^{a,b}</i>	1. <i>n/a</i> 2. <i>Low-NOx combustion system^{a,b}</i>
SO ₂	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
CO	1. <i>n/a</i> 2. <i>0.05 lb CO/1000 gallons loaded^{a,b}</i>	1. <i>n/a</i> 2. <i>Good Combustion Practice^{a,b}</i>
PM ₁₀	1. <i>n/a</i> 2. <i>n/a</i>	1. <i>n/a</i> 2. <i>n/a</i>
NPOC	1. <i>n/d</i> 2. <i>0.02 pounds/1000 gallons loaded^{a,b}</i>	1. <i>n/d</i> 2. <i>Submerged Loading with Vapor Collection System vented to a Carbon Adsorber with vapor tank, or BAAQMD Approved Equivalent^{a,b}</i>

References

- a. BAAQMD Application #100.
b. BAAQMD Interoffice memorandum dated 6/9/2000 from B. Young to Bill deBoisblanc, Director of Permit Services, titled "BACT Revision for Gasoline Bulk Terminals".

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	<i>Boiler, CO - Refinery</i>	Revision:	<i>2</i>
		Document #:	<i>17.4.1</i>
Class:	<i>All</i>	Date:	<i>04/21/93</i>

Determination

POLLUTANT	BACT		TYPICAL TECHNOLOGY
	1. Technologically Feasible/ Cost Effective	2. Achieved in Practice	
POC	1. <i>n/d</i> 2. <i>n/s</i>		1. <i>n/d</i> 2. <i>Minimum Furnace Gas bypassing + Good Combustion Practice^{c,d}</i>
NO _x	1. <i>n/s</i> 2. <i>80 ppm @ 3% O₂, Dry^a</i>		1. <i>Selective Catalytic Reduction (SCR) + Flue Gas Recirculation + Technologies listed below^c</i> 2. <i>Low NO_x Burners + Reduced Air Preheat + Natural Gas or Treated Refinery Gas as Supplemental Fuel^{c,d}</i>
SO ₂	1. <i>Natural gas or Treated Refinery Gas Fuel w/ ≤50 ppm as hydrogen Sulfide as Supplemental Fuel^{c,d}</i> 2. <i>Natural gas or Treated Refinery Gas Fuel w/ ≤100 PPM as hydrogen Sulfide as Supplemental Fuel^{c,d}</i>		1. <i>Fuel Selection^{a,d}</i> 2. <i>Fuel Selection^{a,d}</i>
CO	1. <i>n/d</i> 2. <i>100 ppm @ 3% O₂, Dry^c</i>		1. <i>n/d</i> 2. <i>Minimum Furnace Gas Bypassing + Good Combustion Practice^{a,d}</i>
PM ₁₀	1. <i>n/d</i> 2. <i>n/s</i>		1. <i>n/d</i> 2. <i>Electrostatic Precipitator^a</i>
NPOC	1. <i>n/a</i> 2. <i>n/a</i>		1. <i>n/a</i> 2. <i>n/a</i>

References

- a. SOHIO Refinery, Toledo, Ohio*
- c. BAAQMD*
- d. See also Catalyst Regeneration - Fluidized Catalytic Cracking Unit*

BACT Clearinghouse Database Lookup Results

8 Match(s) for Code 48.B

Compressors

Project Name & Description	A/C Issue Date & ARB File No.	Pollutant
<p><u>Torch Operating Company</u> Nuevo - Platform 'B'</p> <p>Rotary sliding-vane type gas compressor driven by rotating shaft into 1740 scfm compressor and used to move gas from oilfield to onshore processing facility</p> <p><u>(Detailed Information)</u></p>	<p>9/4/94 (P/O no. 9111)</p> <p><u>A350-844-98</u></p> <p>District Contact: Steve Sterner <u>Santa Barbara County</u> <u>APCD</u> (805) 961-8886 sterners@sbcapcd.org</p>	<p>VOC/HC <u>(Detailed Control Information)</u> A-C Compressor Company Double Bellows-type Mechanical Sealing System with barrier fluid pressurized to 10 psig for rotary sliding-vane type gas compressor</p> <p>100 ppmv THC as methane per Method 21</p> <p>-----</p>
<p><u>Mobil Exploration and Producing U.S., Inc.</u> Lost Hills Two Lease Compressor Station</p> <p>280 bhp Ajax model no. DPC 280 lean-burn, natural gas-fired IC engine dring compressor unit and having LPG backup fuel</p> <p><u>(Detailed Information)</u></p>	<p>7/2/96</p> <p>(A/C no. S-1512-458-0)</p> <p><u>A330-724-96</u></p> <p>District Contact: George Heinen <u>San Joaquin Valley Unified</u> <u>Air Pollution Control District</u> (559) 230-5909</p>	<p>NOx <u>(Detailed Control Information)</u> Air/fuel ratio controller and Ajax CleanBurn Combustion Technology</p> <p>1.5 g/bhp-hr 22.32 lbm/day</p> <p>-----</p> <p>PM</p>

		<p><u>(Detailed Control Information)</u> Natural gas/LPG firing, air/fuel ratio controller, and Ajax CleanBurn Combustion Technology</p> <p>0.18 g/bhp-hr 2.19 lbm/day</p> <p>-----</p> <p>VOC/HC <u>(Detailed Control Information)</u> Air/fuel ratio controller and Ajax CleanBurn Combustion Technology with weekly monitoring</p> <p>1.5 g/bhp-hr 22.32 lbm/day</p> <p>-----</p>
<p><u>Exxon</u> (Platform Heritage)</p> <p>18.75 MMscfd gas compressor skid unit</p> <p><u>(Detailed Information)</u></p>	<p>12/18/96</p> <p>(A/C no. 9634)</p> <p><u>A350-715-96</u></p> <p>District Contact: Ray McCaffrey <u>Santa Barbara Co. APCD</u> (805) 961-8826</p>	<p>VOC/HC <u>(Detailed Control Information)</u> or <u>(Performance Information)</u> Flanges w/ graphitic gaskets rated at 150% of actual process temp. and pres.; seals and relief valves routed to vapor recovery system or flare; repair timelines; fugitive I&M program</p>

		<p>100 ppm; 100% control for relief valves and compressor seals -----</p>
<p><u>Exxon</u> (Platform Harmony)</p> <p>18.75 MMscfd gas compressor skid unit</p> <p><u>(Detailed Information)</u></p>	<p>12/18/96</p> <p>(A/C no. 9640)</p> <p><u>A350-714-96</u></p> <p>District Contact: Ray McCaffrey <u>Santa Barbara Co. APCD</u> (805) 961-8826</p>	<p>VOC/HC <u>(Detailed Control Information)</u> or <u>(Performance Information)</u></p> <p>Flanges w/ graphitic gaskets rated at 150% of actual process temp. and pres.; seals and relief valves routed to vapor recovery system or flare; repair timelines; fugitive I&M program</p> <p>100 ppm; 100% control for relief valves and compressor seals -----</p>
<p><u>Texaco Exploration and Production, Inc.</u></p> <p>15 hp Ingersoll-Rand type 30 gas compressor for fixed roof storage tank vapor recovery system</p> <p><u>(Detailed Information)</u></p>	<p>6/2/92</p> <p>(A/C no. 4003956A)</p> <p><u>A330-548-92</u></p> <p>District Contact: Tom Goff <u>San Joaquin Valley Unified APCD</u> (805) 862-5200</p>	<p>VOC/HC <u>(Detailed Control Information)</u></p> <p>Crankcase breather vented to compressor suction inlet with vacuum gauge</p> <p>No limit (Expected control efficiency of 99%) -----</p>
<p><u>Kern Oil Refining Company</u> (Refining Waste Gas Recovery)</p>	<p>3/19/84</p>	<p>VOC/HC <u>(Detailed Control</u></p>

<p>720,000 scf/day vapor compressor, valves, and flanges</p> <p><u>(Detailed Information)</u></p>	<p>(A/C # 2018008A, 2018046A, 2018012B, and 2018062)</p> <p><u>A350-038-84</u></p> <p>District Contact: Tom Paxson <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p><u>Information)</u> Inspection of maintenance to minimize fugitive emissions</p> <p>65% control efficiency</p> <p>-----</p>
<p><u>TOSCO H2 Plant Compressors</u></p> <p>Three 3500 hp each Worthington compressor seals</p> <p><u>(Detailed Information)</u></p>	<p>9/17/82</p> <p>(A/C # 28790)</p> <p><u>A350-018-82</u></p> <p>District Contact: Jim Karas <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> TOSCO mechanical seals vented to a flare</p> <p>No limit</p> <p>-----</p>
<p><u>Cheveron USA Lube Oil Project</u></p> <p>Nine 20 to 1000 hp VOC gas compressors</p> <p><u>(Detailed Information)</u></p>	<p>4/8/82</p> <p>(A/C # 27797)</p> <p><u>A350-011-82</u></p> <p>District Contact: Ellen Linder <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Mechanical seals vented to a flare or vapor recovery system</p> <p>99% control efficiency</p> <p>-----</p>

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BACT Clearinghouse Database Lookup Results

Displaying 68 of 68 Match(s) for Bay Area AQMD

Project Name & Description	A/C Issue Date & ARB File No.	Pollutant
<p><u>Pacific Refinery Modification</u></p> <p>2.75 MMBtu/hr refinery hydrogen reformer furnace, H-4011</p> <p><u>(Detailed Information)</u></p>	<p>9/28/83</p> <p>(A/C # 29180)</p> <p><u>A310-022-80</u></p> <p>District Contact: Leonard Clayton <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NO_x</p> <p><u>(Detailed Control Information)</u></p> <p>Ammonia injection and selective catalytic reduction unit</p> <p>20 ppm @ 3% O₂ 85% control efficiency</p> <p>-----</p>
<p><u>Pacific Refinery Modifications</u></p> <p>Refinery fuel gas system</p> <p><u>(Detailed Information)</u></p>	<p>9/28/83</p> <p>(A/C # 29180)</p> <p><u>A350-021-83</u></p> <p>District Contact: Leonard Clayton <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>SO_x</p> <p><u>(Detailed Control Information)</u></p> <p>Diglycolamine absorbing system for H₂S removal</p> <p>50 ppm H₂S in fuel gas</p> <p>-----</p>
<p><u>TOSCO H₂ Plant Compressors</u></p> <p>Three 3500 hp each Worthington compressor seals</p> <p><u>(Detailed Information)</u></p>	<p>9/17/82</p> <p>(A/C # 28790)</p> <p><u>A350-018-82</u></p> <p>District Contact: Jim Karas <u>Bay Area AQMD</u></p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>TOSCO mechanical seals vented to a flare</p> <p>No limit</p> <p>-----</p>

	(415) 771-6000	
<p><u>Paul Masson Vineyards Cogeneration</u></p> <p>1200 rpm, 526 hp natural gas-fired Waukesha model F2900G reciprocating engine, 300 KW</p> <p><u>(Detailed Information)</u></p>	<p>3/27/81</p> <p>(A/C # 27796)</p> <p><u>A330-016-81</u></p> <p>District Contact: Doug Wolf <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NOx <u>(Detailed Control Information)</u> Emissions Control Systems, Inc. TDRVEX supported model 43N catalytic converter</p> <p>30 ppm</p> <p>-----</p>
<p><u>Stecher - Travng - Schmidt</u></p> <p>Varnisher drying oven, dry-sys, on varnisher 261</p> <p><u>(Detailed Information)</u></p>	<p>10/8/82</p> <p>(A/C #28246)</p> <p><u>A340-015-82</u></p> <p>District Contact: Ellen Linder <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Hirt model FLX-7M fume incinerator</p> <p>90 % overall control efficiency 97% (in-out of incinerator)</p> <p>-----</p>
<p><u>FMC Corp - San Jose Ordnance</u></p> <p>Binks paint spray booth</p> <p><u>(Detailed Information)</u></p>	<p>6/22/82</p> <p>(A/C # 28310)</p> <p><u>A340-012-82</u></p> <p>District Contact: Brain Bateman <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Binks airless-electrostatic spring of 40% solid paint, spraying by automated robots, and in-line heaters to reduce paint viscosity</p> <p>190 lbs/day</p> <p>-----</p>
<p><u>Chevron USA Lube Oil Project</u></p>	<p>4/8/82</p> <p>(A/C # 27797)</p>	<p>VOC/HC <u>(Detailed Control Information)</u></p>

<p>Nine 20 to 1000 hp VOC gas compressors</p> <p><u>(Detailed Information)</u></p>	<p><u>A350-011-82</u></p> <p>District Contact: Ellen Linder <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>Mechanical seals vented to a flare or vapor recovery system</p> <p>99% control efficiency</p> <p>-----</p>
<p><u>Exxon Co. USA - Benicia</u></p> <p>Refinery Process Furnace</p> <p><u>(Detailed Information)</u></p>	<p>12/10/80</p> <p>(A/C # 27599)</p> <p><u>A310-010-80</u></p> <p>District Contact: Leonard Clayton <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NO_x</p> <p><u>(Detailed Control Information)</u></p> <p>Low-NO_x burners and thermal de-NO_x</p> <p>40 ppmvd @ 3% O₂</p> <p>70% control efficiency</p> <p>-----</p>
<p><u>Chevron FCC Precipitator</u></p> <p>61000 bpd fluid catalytic cracking unit</p> <p><u>(Detailed Information)</u></p>	<p>10/6/81</p> <p>(A/C # 27803)</p> <p><u>A350-009-82</u></p> <p>District Contact: John Swanson <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>Two parallel electrostatic precipitator units</p> <p>10 lb/hr</p> <p>94% control efficiency</p> <p>-----</p>
<p><u>H.S. Crocker Co. Printing</u></p> <p>6 COLDR 64" Printing Press</p> <p><u>(Detailed Information)</u></p>	<p>3/21/83</p> <p>(A/C # 28709)</p> <p><u>A340-008-83</u></p> <p>District Contact: Mohamad Mdazed <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>Limit on VOC content of inks</p> <p>2.5 lb VOC/day</p> <p>-----</p>

<p><u>Gazette Press Printing</u></p> <p>Two 12950 cfm Tec Printing System drying ovens</p> <p><u>(Detailed Information)</u></p>	<p>12/20/82</p> <p>(A/C # 28925)</p> <p><u>A340-007-82</u></p> <p>District Contact: Mohamad Mdazed <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Katec, TVA-812 fume incinerator</p> <p>95% control efficiency</p> <p>-----</p>
<p><u>American Metal Decorating Co.</u></p> <p>Paint coating line for metal parts</p> <p><u>(Detailed Information)</u></p>	<p>3/7/80</p> <p>(A/C # 27361)</p> <p><u>A340-006-80</u></p> <p>District Contact: John Phillips <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> CE Air Preheater Cor-Pak fume incinerator</p> <p>87% control efficiency</p> <p>-----</p>
<p><u>Louisiana-Pacific Boiler</u></p> <p>Babcock & Wilcox 4.77 MMBtu/hr waste wood-fired boiler</p> <p><u>(Detailed Information)</u></p>	<p>10/23/80</p> <p>(A/C # 27440)</p> <p><u>A310-005-80</u></p> <p>District Contact: Lew Potter <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>PM <u>(Detailed Control Information)</u> Zurn multiple cyclone, MTSA-240-11.5 & a United McGill electrostatic precipitator, 4-350-2</p> <p>99.7% control efficiency 0.017 gr/scf 17 lb/hr</p> <p>-----</p>
<p><u>Time Oil Co. (Loading Rack)</u></p> <p>One million gallons per day gasoline bulk loading rack</p> <p><u>(Detailed Information)</u></p>	<p>12/23/80</p> <p>(A/C # 27611)</p> <p><u>A350-004-82</u></p>	<p>VOC/HC <u>(Detailed Control Information)</u> McGill activated carbon adsorption system with two</p>

	<p>District Contact: Dave Dixon <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>beds. Automatically timed desorption cycle</p> <p>98.6% control efficiency</p> <p>-----</p>
<p><u>TOSCO Corp. Hydrotreating Unit</u></p> <p>5 hp or larger centerifugal pump seals</p> <p><u>(Detailed Information)</u></p>	<p>2/19/82</p> <p>(A/C # 27769)</p> <p><u>A350-003-82</u></p> <p>District Contact: Jim Karas <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u></p> <p>Double mechanical seals with a oil seal</p> <p>500 ppm</p> <p>-----</p>
<p><u>Crown-Zellerbach Cogeneration</u></p> <p>32 MW gas turbine generator (has a duct fired steam generator)</p> <p><u>(Detailed Information)</u></p>	<p>3/1/82</p> <p>(A/C # 28179)</p> <p><u>A330-002-82</u></p> <p>District Contact: Doug Wolf <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NOx <u>(Detailed Control Information)</u></p> <p>Steam/water injection and lo-NOx burners</p> <p>No limit</p> <p>-----</p>
<p><u>Chevron Lube Oil Project</u></p> <p>Four refinery process furnaces manifolded to common exhaust stack F-7, F-8, F-9, F-10</p> <p><u>(Detailed Information)</u></p>	<p>4/8/82</p> <p>(A/C # 27797)</p> <p><u>A310-002-82)</u></p> <p>District Contact: John Sawnsen <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NOx <u>(Detailed Control Information)</u></p> <p>One selective catalytic reduction unit for four furnaces and lo-NOx burners</p> <p>No limit</p> <p>-----</p>

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BACT Clearinghouse Database Lookup Results

4 Match(s) for Code 94.2

Heaters - Refinery, > 18 MMBtu/hr through < 86.2 MMBtu/hr heat input

Project Name & Description	A/C Issue Date & ARB File No.	Pollutant
<p><u>CENCO Refining Company</u></p> <p>50 MMBtu/hr Tulsa Heaters Inc. natural gas-fired horizontal cabin coker charge heater for a delayed coking unit at the refinery</p> <p><u>(Detailed Information)</u></p>	<p>n.d.</p> <p>(A/C # 352869)</p> <p><u>A350-987-00</u></p> <p>District Contact: Emmaunel E. Ruiviar <u>South Coast AQMD</u> (909) 396-2509 eruiviar@aqmd.gov</p>	<p>NOx <u>(Detailed Control Information)</u> John Zink low-NOx burners, Technip USA selective catalytic reduction with ammonia injection of the flue gas</p> <p>7 ppmvd @ 3% O2, 1-hr average</p> <p>-----</p> <p>CO <u>(Detailed Control Information)</u> John Zink low-NOx burners</p> <p>10 ppmvd @ 3% O2, 1-hr average</p> <p>-----</p> <p>Other Pollutant <u>(Detailed Control Information)</u> No control</p> <p>5 ppmvd @ 3% O2,</p>

		1-hr average -----
<p><u>San Joaquin Refining Company, Inc.</u></p> <p>Refinery process heaters rated between 8.4 and 47.1 MMBtu/hr</p> <p><u>(Detailed Information)</u></p>	<p>3/22/96</p> <p>(A/C no. S-36-51-1)</p> <p><u>A310-681-96</u></p> <p>District Contact: George Heinen <u>San Joaquin Valley Unified APCD</u> (559) 230-5909</p>	<p>NOx <u>(Detailed Control Information)</u> Natural gas and/or LPG firing with low-NOx burners and internal flue-gas recirculation</p> <p>30 ppmvd at 3% oxygen (Equivalent to 0.036 lbm/MMBtu)</p> <p>-----</p> <p>PM <u>(Detailed Control Information)</u> Natural gas and/or LPG firing</p> <p>0.137 lbm/MMBtu</p> <p>-----</p> <p>VOC/HC <u>(Detailed Control Information)</u> Natural gas and /or LPG firing</p> <p>0.004 lbm/MMBtu</p> <p>-----</p>
<p><u>Fletcher Oil and Refining Company</u></p> <p>65 MMBtu/hr vacuum heater heating gas oil before vacuum distillation; unit is fired on refinery gas</p> <p><u>(Detailed Information)</u></p>	<p>7/3/91</p> <p>(App. no. 170819)</p> <p><u>A350-613-94</u></p> <p>District Contact: Sawsan Andrawis <u>South Coast AQMD</u></p>	<p>NOx <u>(Detailed Control Information)</u> Joy Technology selective catalytic reduction unit</p> <p>12 ppm</p> <p>-----</p>

	(919) 396-2607 sandrawis@aqmd.gov	
<p><u>Chevron Lube Oil Project</u></p> <p>Four refinery process furnaces manifolded to common exhaust stack F-7, F-8, F-9, F-10</p> <p><u>(Detailed Information)</u></p>	<p>4/8/82</p> <p>(A/C # 27797)</p> <p><u>A310-002-82)</u></p> <p>District Contact: John Sawnsen <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NO_x</p> <p><u>(Detailed Control Information)</u></p> <p>One selective catalytic reduction unit for four furnaces and lo-NO_x burners</p> <p>No limit</p> <p>-----</p>

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BACT Clearinghouse Database Lookup Results

3 Match(s) for Code 169

Sulfur Recovery Plant

Project Name & Description	A/C Issue Date & ARB File No.	Pollutant
<p><u>Pacific Offshore Pipeline Co.</u></p> <p>Sulfur recovery unit at oil-field natural gas processing plant with 60 MMscfd gas output to sulfur recovery unit at 2.67 hydrogen sulfide</p> <p><u>(Detailed Information)</u></p>	<p>2/4/97</p> <p>(A/C no. 9047)</p> <p><u>A350-745-97</u></p> <p>District Contact: Steve Sterner <u>Santa Barbara Co. APCD</u> (805) 961-8886 sterners@sbcapcd.org</p>	<p>SO_x <u>(Detailed Control Information)</u> Three-stage conversion process of hydrogen sulfide in acid gas from a sulfinol amine system to elemental sulfur</p> <p>99.9% H₂S removal by mass across the sulfur recovery unit 100 ppmv residual H₂S Stretford tail gas prior to incineration</p> <p>-----</p>
<p><u>Texaco Refining and Marketing - Bakersfield</u></p> <p>Three-stage Claus sulfur recovery unit with a capacity of 90 long tons/day liquid sulfur at a refinery</p> <p><u>(Detailed Information)</u></p>	<p>4/18/91</p> <p>(A/C no. 200T245)</p> <p><u>A350-477-91</u></p> <p>District Contact: Tom Goff <u>Kern Co. APCD</u> (now the San Joaquin Valley Unified APCD)</p>	<p>SO_x <u>(Detailed Control Information)</u> Amine-based, tail-gas treating unit</p> <p>10 ppmvd (Expected control efficiency of 99.9%)</p> <p>-----</p>

	(805) 862-5200	
<p><u>Chevron-Gaviota</u></p> <p>Four 7.5 MMscf/day sulfur recovery units</p> <p><u>(Detailed Information)</u></p>	<p>2/6/86</p> <p>(A/C no. 5704)</p> <p><u>A350-126-86</u></p> <p>District Contact: Bill Master <u>Santa Barbara Co. APCD</u> (805) 961-8800</p>	<p>NO_x <u>(Detailed Control Information)</u> Pipeline quality gas in tail-gas incinerator; proper burner operation</p> <p>200 ppmvd at 3% oxygen 15.2 lbm/hr total</p> <p>-----</p> <p>SO_x <u>(Detailed Control Information)</u> Recycle selection process combined with tail-gas incinerator and caustic scrubber</p> <p>90 ppmvd at 3% oxygen 99.9% control</p> <p>-----</p> <p>PM <u>(Detailed Control Information)</u> Use of pipeline quality gas in tail-gas incinerator; caustic scrubber with mist eliminator</p> <p>3.66 lbm/hr total 80% control</p> <p>-----</p> <p>VOC/HC <u>(Detailed Control Information)</u> Pipeline quality gas</p>

		<p>in tail-gas incinerator; proper burner operation</p> <p>3.64 lbm/hr total -----</p> <p>CO <u>(Detailed Control Information)</u> Pipeline quality gas in tail-gas incinerator; proper burner operation</p> <p>6.16 lbm/hr total -----</p>
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5 Match(s) for Code 82

Flares - Refinery

Project Name & Description	A/C Issue Date & ARB File No.	Pollutant
<p><u>California Department of Corrections, Corcoran II Facility</u></p> <p>(1) standby LPG fuel supply system, (3) 30,000 gal storage tanks, vaporizer, air blender and a flare that operates during natural gas interruptions or calibration</p> <p><u>(Detailed Information)</u></p>	<p>3/7/97</p> <p>(A/C no. C-214-22-0)</p> <p><u>A350-805-97</u></p> <p>District Contact: George Heinen <u>San Joaquin Valley Unified APCD</u> (559) 230-5909</p>	<p>VOC/HC <u>(Detailed Control Information)</u> No Control</p> <p>13.16 lbm/1,000 gal -----</p>
<p><u>Fortune Petroleum Co.</u></p> <p>4.395 MMBtu/hr produced gas flare</p> <p><u>(Detailed Information)</u></p>	<p>5/29/92</p> <p>(A/C no. 4278001)</p> <p><u>A350-550-92</u></p> <p>District Contact: Tom Goff <u>San Joaquin Valley Unified APCD</u> (805) 862-5200</p>	<p>NO_x <u>(Detailed Control Information)</u> Burner management</p> <p>No limit -----</p> <p>SO_x <u>(Detailed Control Information)</u> Low sulfur gas of less than 0.2 gr/100 dscf</p> <p>No limit -----</p> <p>PM <u>(Detailed Control Information)</u></p>

		<p>Smokeless combustion using air assist</p> <p>No limit</p> <p>-----</p> <p>VOC/HC (Detailed Control Information) Burner management</p> <p>No limit</p> <p>-----</p> <p>CO (Detailed Control Information) Burner management</p> <p>No limit</p> <p>-----</p>
<p><u>Union Oil Co.</u> (Lompoc Dehydration)</p> <p>Flare limited to a maximum purge and pilot gas flow of 45 scf/hr</p> <p>(Detailed Information)</p>	<p>6/20/86</p> <p>(A/C no. 6708)</p> <p><u>A350-331-89</u></p> <p>District Contact: Bill Master <u>Santa Barbara Co. APCD</u> (805) 961-8800</p>	<p>NO_x (Detailed Control Information) Proper burner management; use of pipeline-quality fuel as pilot fuel</p> <p>No limit</p> <p>-----</p> <p>VOC/HC (Detailed Control Information) Proper burner management; use of pipeline-quality gas as pilot fuel</p> <p>No limit</p> <p>-----</p>
<p><u>Gaviota Terminal Co.</u></p>	<p>5/13/87</p>	<p>NO_x</p>

<p>Backup flare preceded by a vapor control system on a 100,000 bbl/day tanker loading system at a gas and oil marine terminal</p> <p><u>(Detailed Information)</u></p>	<p>(A/C no. 6408)</p> <p><u>A350-328-89</u></p> <p>District Contact: Sanjib Mukherji <u>Santa Barbara Co. APCD</u> (805) 961-8800</p>	<p><u>(Detailed Control Information)</u></p> <p>Proper burner management and use of pipeline-quality natural gas</p> <p>6.92 lbm/hr</p> <p>-----</p>
<p><u>Chevron-Gaviota</u></p> <p>Flare</p> <p><u>(Detailed Information)</u></p>	<p>2/6/86</p> <p>(A/C no. 5704)</p> <p><u>A350-130-86</u></p> <p>District Contact: Bill Master <u>Santa Barbara Co. APCD</u> (805) 961-8800</p>	<p>NO_x <u>(Detailed Control Information)</u></p> <p>Proper burner management and monitoring; gas-fired pilots; emissions equiv. of thermal oxidizer</p> <p>0.05 lbm/hr</p> <p>-----</p> <p>SO_x <u>(Detailed Control Information)</u></p> <p>Gas-fired pilots; pilot fuel with 4 ppmv H₂S max.</p> <p>0.02 lbm/hr</p> <p>-----</p> <p>PM <u>(Detailed Control Information)</u></p> <p>Gas-fired pilots; steam injection for smokeless operation</p> <p>0.02 lbm/hr</p> <p>-----</p> <p>VOC/HC <u>(Detailed Control Information)</u></p>

		<p>Proper burner management and monitoring; gas-fired pilots</p> <p>0.13 lbm/hr</p> <p>-----</p> <p>CO <u>(Detailed Control Information)</u> Gas-fired pilots; proper burner management and monitoring</p> <p>0.02 lbm/hr</p> <p>-----</p>
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referenced table see table

Displaying 50 of 68 Match(s) for Bay Area AQMD

Project Name & Description	A/C Issue Date & ARB File No.	Pollutant
<p><u>U.S.S. Posco Industries</u></p> <p>95.7 MMBtu/hr Mitsubishi - Custom Kawasaki annealing furnace</p> <p><u>(Detailed Information)</u></p>	<p>12/14/87</p> <p>(A/C no. 32211)</p> <p><u>A310-881-99</u></p> <p>District Contact: Don Van Buren <u>Bay Area AQMD</u> (415) 749-4746 dvanburen@baaqmd.gov</p>	<p>NOx</p> <p><u>(Detailed Control Information)</u></p> <p>Mitsubishi Selective Catalytic Reduction unit</p> <p>50 lb/day</p> <p>-----</p>
<p><u>Genxon Power Systems LLC</u></p> <p>1550 KW natural gas-fired Kawasaki MIA-13A combustion gas turbine equipped with a gearbox connected to a 1500 KW generator.</p> <p><u>(Detailed Information)</u></p>	<p>7/7/98</p> <p>(A/C no. 18547)</p> <p><u>A330-878-99</u></p> <p>District Contact: Greg Solomon <u>Bay Area AQMD</u> (415) 749-4715 gsolomonm@baaqmd.gov</p>	<p>NOx</p> <p><u>(Detailed Control Information)</u></p> <p>or <u>(Performance Information)</u></p> <p>Catalytica Combustion Systems, Inc Xonon catalytic combustor</p> <p>5 ppmvd @ 15% O2, average over 3 hours</p> <p>-----</p> <p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>or <u>(Performance Information)</u></p> <p>Catalytica Combustion Systems, Inc Xonon catalytic</p>

		<p>combustor</p> <p>10 ppmvd @ 15% O2, average over 3 hours</p> <p>-----</p> <p>CO <u>(Detailed Control Information)</u> or <u>(Performance Information)</u> Catalytica Combustion Systems, Inc Xonon catalytic combustor</p> <p>5 ppmvd @ 15% O2, average over 3 hours</p> <p>-----</p>
<p><u>Crockett Cogeneration (C&H Sugar)</u></p> <p>1780 MMBtu/hr G E model PG7221(FA), i.e., Frame 7FA, with heat recovery steam generator having low NOx duct burners with a total rated capacity of 349 MMBtu/hr producing 240 MW (combined cycle and cogeneration).</p> <p><u>(Detailed Information)</u></p>	<p>10/5/93</p> <p>(A/C no. S-201)</p> <p><u>A330-859-98</u></p> <p>District Contact: Carol Allen <u>Bay Area AQMD</u> (415) 749-4702 callen@baaqmd.gov</p>	<p>NOx <u>(Detailed Control Information)</u> or <u>(Performance Information)</u> Dry low-NOx combustors and a Mitsubishi Heavy Industries America selective catalytic reduction</p> <p>5 ppmvd @ 15% O2</p> <p>-----</p> <p>VOC/HC <u>(Detailed Control Information)</u> or <u>(Performance Information)</u> Engelhard oxidation catalyst</p> <p>352.6 lbm/day (Approximately 50%)</p>

		<p>control)</p> <p>-----</p> <p>CO <u>(Detailed Control Information)</u> or <u>(Performance Information)</u> Engelhard oxidation catalyst</p> <p>5.9 ppmvd @ 15% O2 (Approximately 90% control)</p> <p>-----</p>
<p><u>Shell Martinez Refining Company</u></p> <p>Refinery fuel gas system for various combustion sources (furnaces, boilers, CO boilers)</p> <p><u>(Detailed Information)</u></p>	<p>7/28/98</p> <p>(A/C no. 18185)</p> <p><u>A350-856-98</u></p> <p>District Contact: Greg Stone <u>Bay Area AQMD</u> (415) 749-4745 gstone@baaqmd.gov</p>	<p>SO_x <u>(Detailed Control Information)</u> H2S and total reduced sulfur (TRS) in refinery fuel gas system reduced by Diethanolamine (DEA) absorder, Claus Sulfur Plant, and SCOT unit.</p> <p>24 hr average H2S content limit of 50 ppm Annual average TRS limit of 70 ppm</p> <p>-----</p>
<p><u>Performance Information</u></p>		
<p><u>Siliconix, Inc.</u></p> <p>Photoresist applicators</p> <p><u>(Detailed Information)</u></p>	<p>2/18/93</p> <p>(App. no. 9321)</p> <p><u>A410-627-94</u></p> <p>District Contact: Karen Dzienkowski</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Munters Zeol model IZS-D1900-TH abatement system with two zeolite rotor concentration in</p>

	<p><u>Bay Area AQMD</u> (415) 749-5141 kdzienkowski@baaqmd.gov</p>	<p>series followed by 500,000 Btu/hr thermal oxidizer</p> <p>No limit (Control level equivalent to 98.5% destruction)</p> <p>-----</p>
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Performance Information

<p><u>Granite Construction Company</u></p> <p>150 MMBtu/hr BMG model 45R30P asphalt drum mixer fired on fuel oil no. 2. This is a portable unit to be operated at remote sites where electricity or natural gas may not be available.</p> <p>(Detailed Information)</p>	<p>5/14/91</p> <p>(A/C no. 5841)</p> <p><u>A390-626-94</u></p> <p>District Contact: R. Ted Hull <u>Bay Area AQMD</u> (415) 749-4919</p>	<p>NOx (Detailed Control Information) Low-NOx burners</p> <p>145 lbm/day for plant and IC engine (Initial source test indicated emissions of 165 ppmvd at 3% oxygen from drum mixer.)</p> <p>-----</p>
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Performance Information

<p><u>Criterion Catalyst Co.</u></p> <p>Micro-Pulverizer Model 60 ACM catalyst grinder with rated input of 2000 lbm/hr and storage silos (inlet PM is 95% PM10)</p> <p>(Detailed Information)</p>	<p>11/4/92</p> <p>(A/C no. 9450)</p> <p><u>A410-584-93</u></p> <p>District Contact: Thu Bui <u>Bay Area AQMD</u> (415) 749-5119 tbui@baaqmd.gov</p>	<p>PM (Detailed Control Information) or (Performance Information) Four Micro-Pulsaire baghouses with 3000 acfm flow rates</p> <p>0.006 gr./dscf</p> <p>-----</p>
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<p><u>West Coast Lithographers, Inc.</u></p> <p>Komori Lithrone sheet-feed lithographic printing presses with integral dryers</p>	<p>10/15/92</p> <p>(A/C no. 8582)</p> <p><u>A340-583-93</u></p>	<p>VOC/HC (Detailed Control Information) Kerosene-like oil-based inks, no</p>
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<p><u>(Detailed Information)</u></p>	<p>District Contact: Thu Bui <u>Bay Area AQMD</u> (415) 749-5119 tbui@baaqmd.gov</p>	<p>more than 10% by vol. VOC fountain solution, and no more than 30% by vol. VOC clean-up solvents (or 7.71 lbm/gal VOC and VOC vapor pressure less than 25 mm Hg)</p> <p>No limit</p> <p>-----</p>
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Performance Information

<p><u>Everett Graphics Co.</u></p> <p>Heidelberg model 1025-LE color lithographic press with an output capacity of 13,000 sheets/hr</p> <p><u>(Detailed Information)</u></p>	<p>7/30/92</p> <p>(A/C no. 7765)</p> <p><u>A340-582-93</u></p> <p>District Contact: Weyman Lee <u>Bay Area AQMD</u> (415) 749-4708 wlee@baaqmd.gov</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Soy-based inks with no more than 8.5% VOC by wt., fountain solutions with no more than 4% VOC by wt., clean-up solvent with no more than 4 lbm VOC/gal, clear coat with no VOC</p> <p>No limit</p> <p>-----</p>
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Performance Information

<p><u>Napa Sanitation District</u></p> <p>913 hp Waukesha model 5900GL IC engine fired on digester gas with supplementary natural gas</p> <p><u>(Detailed Information)</u></p>	<p>3/26/93</p> <p>(A/C no. 9006)</p> <p><u>A330-579-93</u></p> <p>District Contact: Ted Hull <u>Bay Area AQMD</u> (415) 749-4919</p>	<p>NOx <u>(Detailed Control Information)</u> Lean-burn combustion control</p> <p>1.25 g/bhp-hr</p> <p>-----</p> <p>SOx <u>(Detailed Control Information)</u></p>
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		<p><u>Information</u> Addition of iron salts to the digester sludge to reduce H₂S concentrations of digester gas to less than 300 ppmv</p> <p>0.30 g/bhp-hr</p> <p>-----</p>
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Performance Information

<p><u>Aratex Services, Inc.</u></p> <p>33.5 gas-fired Cleaver Brooks model CB200- 800-150 firetube boiler rated at 800 hp output with distillate oil emergency backup fuel</p> <p><u>(Detailed Information)</u></p>	<p>2/3/93</p> <p>(A/C no. 9840)</p> <p><u>A310-578-93</u></p> <p>District Contact: Karen Dzienkowski Bay Area AQMD (415) 749-5141 kdzienkowski@baaqmd.gov</p>	<p>NO_x <u>(Detailed Control Information)</u> or <u>(Performance Information)</u> Cleaver Brooks low NO_x burners and flue-gas recirculation</p> <p>25 ppmvd at 3% oxygen</p> <p>-----</p>
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<p><u>Lucas Film, Ltd</u></p> <p>Lipsner Smith Co. model no. CF-3000-MKV film cleaning system using 180 gal of methyl cloroform per year and processing 8000 feet of film per gallon of solvent</p> <p><u>(Detailed Information)</u></p>	<p>4/29/93</p> <p>(A/C no. 9942)</p> <p><u>A340-577-93</u></p> <p>District Contact: Craig Ullery Bay Area AQMD (415) 749-4718 cullery@baaqmd.gov</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Enclosed film cleaning system with refrigerated chiller operating at no more than 35 F</p> <p>2000 lbm/yr (Estimated control efficiency of 90%)</p> <p>-----</p>
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Performance Information

<p><u>Mark West Quarry</u></p>	<p>4/2/93</p>	<p>PM <u>(Detailed Control</u></p>
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<p>45 ton/hr secondary cone crusher and mineral screeners (addition to existing aggregate crushing operation)</p> <p><u>(Detailed Information)</u></p>	<p>(A/C no. 10641)</p> <p><u>A390-576-93</u></p> <p>District Contact: Ted Hull <u>Bay Area AQMD</u> (415) 749-4919</p>	<p><u>Information)</u></p> <p>Enclosures, curtains, and high 50 micron water mist foggers</p> <p>Visible emission opacity of Ringleman 0.5</p> <p>-----</p>
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Performance Information

<p><u>Conner Peripherals</u></p> <p>38-gallon dip coat/luber</p> <p><u>(Detailed Information)</u></p>	<p>4/29/92</p> <p>(A/C no. 8564)</p> <p><u>A420-541-92</u></p> <p>District Contact: Carol Lee <u>Bay Area AQMD</u> (415) 749-4689 clee@baaqmd.gov</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>Sub-zero chiller at 10 degrees F and finned coils</p> <p>No limit</p> <p>-----</p>
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Performance Information

<p><u>GSS Array Technology, Inc.</u></p> <p>204 gallon Detrex PCBBD-18B51-2ER-W conveyORIZED solvent cleaner (Conditioned to terminate operation 3.5 years after issuance of authority to construct)</p> <p><u>(Detailed Information)</u></p>	<p>5/19/92</p> <p>(A/C no. 8312)</p> <p><u>A340-540-92</u></p> <p>District Contact: Barry Young <u>Bay Area AQMD</u> (415) 749-4721 byoung@baaqmd.gov</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>Secondary refrigerated freeboard chillers, freeboard tunnel extensions, metal baffles, and freeboard ratio of at least 1.0</p> <p>No limit</p> <p>-----</p>
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Performance Information

<p><u>Airco Coating Technology</u></p>	<p>4/28/92</p>	<p>VOC/HC</p> <p><u>(Detailed Control</u></p>
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<p>Custom wipe cleaning operation with 100 gal/yr maximum solvent usage</p> <p><u>(Detailed Information)</u></p>	<p>(A/C no. 8650)</p> <p><u>A340-539-92</u></p> <p>District Contact: Alex Saschin <u>Bay Area AQMD</u> (415) 749-4713</p>	<p><u>Information)</u></p> <p>Solvent to be stored in closed containers</p> <p>No limit</p> <p>-----</p>
<p><u>Performance Information</u></p>		
<p><u>Wickland Oil Company MTBE tank farm</u></p> <p>Thirteen fixed roof storage tanks with 10,000 bbl/hr throughput</p> <p><u>(Detailed Information)</u></p>	<p>7/19/91</p> <p>(A/C no. 6719)</p> <p><u>A350-538-92</u></p> <p>District Contact: Greg Solomon <u>Bay Area AQMD</u> (415) 749-4715 gsolomon@baaqd.gov</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>John Zink carbon adsorption/absorption system</p> <p>1 lbm/1000 bbl (Expected control efficiency of greater than 99%)</p> <p>-----</p>
<p><u>Performance Information</u></p>		
<p><u>Midwestern Pipeline Services</u></p> <p>Pipe coating, including spraybooth and 7.5 MMBtu/hr oven-fired on natural gas; coatings applied to inside of 40"X40' sections of steel pipe</p> <p><u>(Detailed Information)</u></p>	<p>4/16/91</p> <p>(A/C no. 5948)</p> <p><u>A340-537-92</u></p> <p>District Contact: Greg Solomon <u>Bay Area AQMD</u> (415) 749-4715 gsolomon@baaqd.gov</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>or <u>(Performance Information)</u></p> <p>5000 cfm B&G Automated Systems afterburner from spray operation and oven</p> <p>98.5% destruction efficiency</p> <p>-----</p>
<p><u>The Dot Printer</u></p> <p>Flexographic Printing Presses</p>	<p>3/27/92</p> <p>(A/C no. 7571)</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p>

<p><u>(Detailed Information)</u></p>	<p><u>A340-536-92</u></p> <p>District Contact: Alex Saschin <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>Low VOC inks (< 1.5 lbm/gal), and low VOC fountain solution (<13% VOC)</p> <p>No limit</p> <p>-----</p>
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Performance Information

<p><u>Huntway Refining Company, asphalt oxidation plant</u></p> <p>28 ton/hr asphalt oxidation still and seven asphalt storage tanks, six having 85,000 gal capacity and one with 50,000 gal capacity with volatiles routed to control unit</p> <p><u>(Detailed Information)</u></p>	<p>4/3/92</p> <p>(A/C no. 7311)</p> <p><u>A350-535-92</u></p> <p>District Contact: Dharam Singh <u>Bay Area AQMD</u> (415)749-4714 dsign@baaqmd.gov</p>	<p>PM <u>(Detailed Control Information)</u> 4.1 MMBtu/hr gas-fired asphalt heater-cum- thermal oxidizer ducting 5000 cfm</p> <p>0.08932 lbm/ton</p> <p>-----</p> <p>VOC/HC <u>(Detailed Control Information)</u> 4.1 MMBtu/hr gas-fired asphalt heater-cumthermal oxidizer ducting 5000 cfm</p> <p>98% control efficiency 0.0023 lbm/ton</p> <p>-----</p>
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Performance Information

<p><u>Consolidated Publications</u></p> <p>Hantscho two-web lithographic printing press with 5 MMBtu/hr natural-gas, two-web drying oven and having an output capacity 38,000 impressions/hr</p>	<p>1/22/92</p> <p>(A/C no. 7920)</p> <p><u>A340-534-92</u></p> <p>District Contact: Julian Elliot</p>	<p>VOC/HC <u>(Detailed Control Information)</u> TEC Systems Phoenix 2000 1.5 MMBtu/hr thermal oxidizer operating at 1100i F; Less than</p>
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<p><u>(Detailed Information)</u></p>	<p><u>Bay Area AQMD</u> (415) 749-4705 jelliot@baaqmd.gov</p>	<p>12% VOC fountain solution; Less than 10 mm Hg cleanup solvents at 20 degrees C</p> <p>95% POC destruction efficiency by thermal oxidizer</p> <p>-----</p>
<p><u>Performance Information</u></p>		
<p><u>National Semiconductor</u></p> <p>Semiconductor fabrication area with photo-resist maskant and developer operations</p> <p><u>(Detailed Information)</u></p>	<p>4/10/92</p> <p>(A/C no. 7129)</p> <p><u>A410-533-92</u></p> <p>District Contact: Craig Ullery <u>Bay Area AQMD</u> (415) 749-4718 cullery@baaqmd.gov</p>	<p>VOC/HC <u>(Detailed Control Information)</u> or <u>(Performance Information)</u> REECO Fume incinerator</p> <p>10 ppmv 0.985</p> <p>-----</p>
<p><u>Unocal Chemicals Division, Oakland Distribution Facility</u></p> <p>Soil vapor extraction system with two 1267 scfm New York Blower Co. vacuum extraction blowers</p> <p><u>(Detailed Information)</u></p>	<p>4/1/92</p> <p>(A/C no. 8447)</p> <p><u>A430-532-92</u></p> <p>District Contact: Ted Hull <u>Bay Area AQMD</u> (415) 749-4919</p>	<p>VOC/HC <u>(Detailed Control Information)</u> ARI Model CT-1000-SAB-G-50TE catalytic oxidation unit</p> <p>97% control efficiency</p> <p>-----</p>
<p><u>Performance Information</u></p>		
<p><u>Solectron Corporation</u></p> <p>Relocation of wave solder systems with foam fluxers having 3.35 gal flux capacity and a net solvent usage of 6000</p>	<p>4/2/92</p> <p>(App. no. 8337)</p> <p><u>A410-531-92</u></p>	<p>VOC/HC <u>(Detailed Control Information)</u> Calgon Vapor Pac-10 carbon absorption unit</p>

<p>gal/yr</p> <p><u>(Detailed Information)</u></p>	<p>District Contact: Carol Allen <u>Bay Area AQMD</u> (415) 749-4702 callen@baaqmd.gov</p>	<p>10 ppmv at 10,000 cfm 90% control efficiency -----</p>
<p><u>Performance Information</u></p>		
<p><u>Western Steel & Tinplate, Inc.</u></p> <p>6000 sheet/hr sheetmetal coating lines and 5 MMBtu/hr natural gas ovens</p> <p><u>(Detailed Information)</u></p>	<p>4/10/89</p> <p>(App. no. 1931)</p> <p><u>A340-341-89</u></p> <p>District Contact: Alex Saschin <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Direct-flame afterburner</p> <p>90% capture efficiency with 98.5 percent afterburner control efficiency -----</p>
<p><u>International Paper</u></p> <p>7000 sheet/hr lithographic single-sheet printing press</p> <p><u>(Detailed Information)</u></p>	<p>3/23/89</p> <p>(A/C no. 1338)</p> <p><u>A340-340-89</u></p> <p>District Contact: Doug Hall <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Low-solvent inks with no more than 10% VOC by volume; chilled fountain solution (no more than 45 degrees F)</p> <p>15.7 tons/yr -----</p>
<p><u>Westinghouse Electric Corporation</u></p> <p>380 MMBtu/hr gas-fired steam generator producing 300,000 lbm steam/hr</p> <p><u>(Detailed Information)</u></p>	<p>8/17/88</p> <p>(A/C no. 883)</p> <p><u>A310-297-88</u></p> <p>District Contact: Hari Doss <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NO_x <u>(Detailed Control Information)</u> Low-NO_x burners, flue gas recirculation, and SCR</p> <p>12 ppmvd at 3% oxygen -----</p>

<p><u>GWF Power Systems</u></p> <p>202 MMBtu/hr circulating fluidized bed combustor producing 19 MW and fired on petroleum coke, bituminous coal, or distillate fuel oil</p> <p><u>(Detailed Information)</u></p>	<p>2/11/88</p> <p>(A/C nos. 31130, thru 31133, and 30686)</p> <p><u>A310-278-88</u></p> <p>District Contract: Sandra Lopez <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NO_x <u>(Detailed Control Information)</u> Ammonia injection</p> <p>50 ppmvd at 3% oxygen 0.074 lbm/MMBtu 360 lbm/day</p> <p>-----</p> <p>SO_x <u>(Detailed Control Information)</u> Sorbent injection system & 0.05% S content for fuel oil</p> <p>54 ppmvd at 3% oxygen 0.109 lbm/MMBtu 528 lbm/day</p> <p>-----</p> <p>PM <u>(Detailed Control Information)</u> Baghouse</p> <p>0.005 gr/dscf</p> <p>-----</p>
<p><u>Chevron USA, Inc.</u></p> <p>Two 531 MMBtu/hr Brown Boveri Type 8 gas turbines with 250 MMBtu/hr duct burners producing 99 MW total (cogeneration)</p> <p><u>(Detailed Information)</u></p>	<p>9/4/87</p> <p>(A/C no. 30331)</p> <p><u>A330-277-88</u></p> <p>District Contact: Ellen Linder <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NO_x <u>(Detailed Control Information)</u> Steam injection and selective catalytic reduction</p> <p>10 ppmvd at 15% oxygen</p> <p>-----</p>
<p><u>Naval Station</u> Treasure Island</p>	<p>12/19/86</p>	<p>NO_x <u>(Detailed Control</u></p>

<p>Two 50 MMBtu/hr Cleaver Brooks steam boilers fired on natural gas</p> <p><u>(Detailed Information)</u></p>	<p>(A/C no. 30543)</p> <p><u>A310-167-87</u></p> <p>District Contact: Bob Nishimura <u>Bay Area AQMD</u> (415) 771-6000</p>	<p><u>Information)</u></p> <p>Flue gas recirculation and low-NOx burners</p> <p>40 ppmvd at 3% oxygen 0.05 lbm/MMBtu</p> <p>-----</p>
<p><u>City of Santa Clara</u></p> <p>29.4 MW General Electric Frame 5 gas turbine (simple-cycle peaking unit)</p> <p><u>(Detailed Information)</u></p>	<p>1/5/87</p> <p>(A/C no. 31527)</p> <p><u>A330-166-87</u></p> <p>District Contact: Ellen Linder <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NOx</p> <p><u>(Detailed Control Information)</u></p> <p>Water injection</p> <p>42 ppmvd at 15% oxygen</p> <p>-----</p>
<p><u>SF Southeast Treatment Plant</u></p> <p>7300 hp reciprocating engine fired on sewage sludge gas (cogeneration)</p> <p><u>(Detailed Information)</u></p>	<p>5/86</p> <p>(A/C no. 30456)</p> <p><u>A330-150-86</u></p> <p>District Contact: Steve Hill <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NOx</p> <p><u>(Detailed Control Information)</u></p> <p>Clean-burn engine</p> <p>2.0 g/bhp-hr</p> <p>-----</p>
<p><u>Diamond A Ranch Quarry</u></p> <p>350 ton/hr asphaltic concrete plant</p> <p><u>(Detailed Information)</u></p>	<p>6/2/86</p> <p>(A/C no. 30724)</p> <p><u>A390-144-86</u></p> <p>District Contact: Greg Stone <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>PM</p> <p><u>(Detailed Control Information)</u></p> <p>Venturi scrubber</p> <p>0.02 gr/dscf 99.7% control</p> <p>-----</p>
<p><u>Diamond A Ranch Quarry</u></p>	<p>6/2/86</p>	<p>PM</p> <p><u>(Detailed Control</u></p>

<p>300 ton/hr concrete batch plant</p> <p><u>(Detailed Information)</u></p>	<p>(A/C no. 30724)</p> <p><u>A390-143-86</u></p> <p>District Contact: Greg Stone <u>Bay Area AQMD</u> (415) 771-6000</p>	<p><u>Information)</u></p> <p>Water spray and fabric filter</p> <p>99% control 10% opacity</p> <p>-----</p>
<p><u>Diamond A Ranch Quarry</u> (Oliver de Silva)</p> <p>300 ton/hr rock crushing plant</p> <p><u>(Detailed Information)</u></p>	<p>6/2/86</p> <p>(A/C no. 30724)</p> <p><u>A390-142-86</u></p> <p>District Contact: Greg Stone <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>PM</p> <p><u>(Detailed Control Information)</u></p> <p>Water spray and baghouse</p> <p>0.02 gr/decf 99.7% control 10% opacity</p> <p>-----</p>
<p><u>Wickland Oil</u></p> <p>Marine loading with capacity of 10,000 barrels per day</p> <p><u>(Detailed Information)</u></p>	<p>6/86</p> <p>(A/C no. 30472)</p> <p><u>A340-141-86</u></p> <p>District Contact: Steve Hill <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>No controls</p> <p>-----</p>
<p><u>Scientific Games</u></p> <p>Rotogravure press</p> <p><u>(Detailed Information)</u></p>	<p>4/5/85</p> <p>(A/C no. 31248)</p> <p><u>A340-140-86</u></p> <p>District Contact: Ellen Linder <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>Incinerator</p> <p>96% control</p> <p>-----</p>
<p><u>Union Cogeneration</u></p>	<p>1/17/86</p>	<p>NOx</p> <p><u>(Detailed Control</u></p>

<p>Three Westinghouse C191 gas turbines each with 175 MMBtu/hr duct burners and producing 16.5 MWe per turbine</p> <p><u>(Detailed Information)</u></p>	<p>(A/C no. 30810)</p> <p><u>A330-114-86</u></p> <p>District Contact: Steve Hill <u>Bay Area AQMD</u> (415) 771-6000</p>	<p><u>Information)</u> Water injection and selective catalytic reduction</p> <p>25 ppmvd at 15% oxygen</p> <p>-----</p> <p>VOC/HC <u>(Detailed Control Information)</u> Oxidation catalyst</p> <p>8 lbm/hr (equal to 7%)</p> <p>-----</p> <p>CO <u>(Detailed Control Information)</u> Oxidation catalyst</p> <p>39 lbm/hr (equal to 80%)</p> <p>-----</p>
<p><u>Tri-Cities Resource Recovery</u></p> <p>Waste to energy, MSW</p> <p><u>(Detailed Information)</u></p>	<p>12/3/85</p> <p>(A/C no. 29795)</p> <p><u>A320-113-86</u></p> <p>District Contact: B. Bateman <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>NO_x <u>(Detailed Control Information)</u> Flue gas recirculation, combustion modification</p> <p>200 ppmv at 12% CO₂</p> <p>-----</p> <p>SO_x <u>(Detailed Control Information)</u> Dry scrubber</p> <p>30 ppmv at 12% CO₂</p> <p>-----</p>

		<p>PM <u>(Detailed Control Information)</u> Dry scrubber, baghouse</p> <p>0.01 gr/dscf</p> <p>-----</p> <p>VOC/HC <u>(Detailed Control Information)</u> Combustion modification</p> <p>50 ppmv at 12% CO2</p> <p>-----</p> <p>CO <u>(Detailed Control Information)</u> Combustion modification</p> <p>100 ppmv at 12% CO2</p> <p>-----</p>
<p><u>Crown Cork & Seal Co., Inc.</u></p> <p>Aluminum can manufacturing</p> <p><u>(Detailed Information)</u></p>	<p>12/31/85</p> <p>(A/C no. 30862)</p> <p><u>A340-112-86</u></p> <p>District Contact: Judy Cutino <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Incineration</p> <p>95% control</p> <p>-----</p>
<p><u>Stecher-Traung-Schmidt</u></p> <p>Lithographic color printing press</p> <p><u>(Detailed Information)</u></p>	<p>11/5/85</p> <p>(A/C no. 30733)</p> <p><u>A340-111-86</u></p>	<p>VOC/HC <u>(Detailed Control Information)</u> Low VOC solutions, refrigeration and alcohol reclaim, low</p>

	<p>District Contact: Ellen Linder <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC ink 15% VOC content -----</p>
<p><u>Container Corp. of America</u> Two rotogravure print lines (Detailed Information)</p>	<p>1/2/86 (A/C no. 30834) <u>A340-110-86</u> District Contact: Joe Slamovich <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC (Detailed Control Information) Low solvent coatings 73.6 tpy, 2.5% VOC content -----</p>
<p><u>Genstar Gas Recovery Systems</u> Two 2650 hp Cooper-Superior lean burn IC engines fired on landfill gas (Detailed Information)</p>	<p>12/2/85 (A/C no. 30970) <u>A330-109-86</u> District Contact: Craig Ullery <u>Bay Area AQMD</u> (415) 771-6000 cullery@baaqmd.gov</p>	<p>NOx (Detailed Control Information) Stratified charge combustion 1.5 g/hp-hr -----</p>
<p><u>Genstar Gas Recovery Systems</u> Two 1100 hp Cooper-Superior lean burn IC engines fired on landfill gas (Detailed Information)</p>	<p>8/29/85 (A/C no. 30893) <u>A330-108-86</u> District Contact: Craig Ullery <u>Bay Area AQMD</u> (415) 771-6000 cullery@baaqmd.gov</p>	<p>NOx (Detailed Control Information) Stratified charge combustion 1.5 g/hp-hr -----</p>
<p><u>Eimac/Varian Fab Center</u> Detrex VS-8DOE vapor degreaser using 1,1,1</p>	<p>7/12/85 (A/C # 30832)</p>	<p>VOC/HC (Detailed Control Information) Use of freeboard</p>

<p>trichloroethane <u>(Detailed Information)</u></p>	<p><u>A340-083-85</u> District Contact: Craig Ullery <u>Bay Area AQMD</u> (415) 771-6000 cullery@aqmd.gov</p>	<p>chiller (above cooling coils) to provide blanket of cool air to reduce emission of TCE 33% control efficiency -----</p>
<p><u>Continental Can Company</u> 2-piece aluminum can lines <u>(Detailed Information)</u></p>	<p>3/15/85 (A/C # 30129) <u>A340-074-85</u> District Contact: Judy Cutino <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Direct flame afterburner controlling pin ovens, inside bake oven and fugitive emissions from spray machines 26 tons/yr 95% control efficiency (afterburner) -----</p>
<p><u>Pacific Lighting Energy Systems</u> 2650 hp Cooper model 165GTA superior landfill gas-fired clean burn IC engine <u>(Detailed Information)</u></p>	<p>3/1/85 (A/C # 30336) <u>A/C # 330-075-85</u> District Contact: Craig Ullery <u>Bay Area AQMD</u> (415) 771-6000 cullery@baaqmd.gov</p>	<p>NOx <u>(Detailed Control Information)</u> Cooper pre-chamber ignition lean burn or stratified charged turbo-charged engine 1.5g/hp-hr -----</p>
<p><u>PG&E - Los Medanos Comprssor</u> 4130 hp Cooper Energy Systems natural gas-fired clean burn engine <u>(Detailed Information)</u></p>	<p>1/8/81 (A/C # 27512) <u>A330-053-84</u> District Contact: Bob Nishimura</p>	

	<u>Bay Area AQMD</u> (415) 771-6000	
<p><u>IBM Cogeneration Project</u></p> <p>49 MW United Technology Twin Pack gas turbine and 14.4 MW steam turbine generator system</p> <p><u>(Detailed Information)</u></p>	<p>12/21/84</p> <p>(A/C # 30066)</p> <p><u>A330-052-84</u></p> <p>District Contact: Victor Reyes <u>Bay Area AQMD</u> (415) 711-6000</p>	<p>NO_x <u>(Detailed Control Information)</u> Water injection and selective catalytic reduction</p> <p>25 ppm @ 15% O₂</p> <p>-----</p> <p>CO <u>(Detailed Control Information)</u> Johnson Matthey CO catalyst</p> <p>550 lb/day</p> <p>-----</p>
<p><u>General Motors - Toyota Joint Venture</u></p> <p>Automobile undercoating spray booth</p> <p><u>(Detailed Information)</u></p>	<p>2/22/84</p> <p>(A/C # 29614)</p> <p><u>A410-051-84</u></p> <p>District Contact: Jim Tomich <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> High solids coating, airless spray, incineration</p> <p>35% control efficiency</p> <p>-----</p>

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Project Name & Description	A/C Issue Date & ARB File No.	Pollutant
<p><u>Blackwell Land Company, Inc.</u></p> <p>2,500 lbm/hr Pistachio Finishing Operation including a needle separator with fines discharge airleg</p> <p><u>(Detailed Information)</u></p>	<p>12/26/84</p> <p>(A/C # 3004006)</p> <p><u>A370-061-85</u></p> <p>District Contact: Tom Paxson <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>PM</p> <p><u>(Detailed Control Information)</u></p> <p>RL Enterprises high efficiency cyclone discharging to two sock filters in parallel</p> <p>0.63 lbm/hr</p> <p>-----</p>
<p><u>HOPCO</u></p> <p>Crude oil storage tank</p> <p><u>(Detailed Information)</u></p>	<p>12/4/84</p> <p>(A/C # 4099105 to 4099124)</p> <p><u>A350-60-84</u></p> <p>District Contact: Tom Paxon <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>Vapor collection and incineration</p> <p>99-6% control efficiency</p> <p>-----</p>
<p><u>HOPCO</u></p> <p>62.5 MMBtu/hr Thermotics crude oil production steam generators</p> <p><u>(Detailed Information)</u></p>	<p>12/4/84</p> <p>(A/C # 4099002 to 4099013)</p> <p><u>A310-059-84</u></p> <p>District Contact:</p>	<p>SO_x</p> <p><u>(Detailed Control Information)</u></p> <p>Wet scrubber</p> <p>97% destruction efficiency</p>

	<p>Tom Paxson <u>Kern County APCD</u> (Now the San Joaquin Valley Unified APCD) (805) 861-3682</p>	<p>2.1 lbm/hr ----- PM <u>(Detailed Control Information)</u> Wet scrubber 70% destruction efficiency 1.7 lbm/hr -----</p>
<p><u>Chevron USA, Inc. (Add 2 Tanks to Battery)</u> Two 5000 and 2000 bbl cone roof tanks <u>(Detailed Information)</u></p>	<p>11/21/84 (A/C # 4008407B) <u>A350-058-84</u> District Contact: Tom Paxson <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Engersol Rand vapor recovery to gas plant intake by a compressor 15.1 lbm/day -----</p>
<p><u>Pacific Energy Resources, Inc.</u> 2650 hp Cooper Energy Service Superior model 16 SGTA land-fill gas-fired clean burn internal combustion engine <u>(Detailed Information)</u></p>	<p>11/14/84 (A/C # 0083001) <u>A330-057-84</u> District Contact: Tuan Ngo <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>NOx <u>(Detailed Control Information)</u> Clean burn operating mode: two combustion chambers: pre-ignition chamber, fuel rich and main combustion chamber 8.25 lb/hr 1.5 g/bhp-hr -----</p>
<p><u>Frito-Lay Corn Chip Line # 2</u> 2,500 lbm/hr Frito-Lay corn chip fryer</p>	<p>11/9/84 (A/C # 3082013)</p>	<p>PM <u>(Detailed Control Information)</u> Mist entainment</p>

<p><u>(Detailed Information)</u></p>	<p><u>A370-055-84</u></p> <p>District Contact: Tom Paxson <u>San Joaquin Valley Unified</u> <u>APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>separator</p> <p>0.5 lb/hr</p> <p>-----</p>
<p><u>Frito-Lay Cogeneration</u></p> <p>53 MMBtu/hr Allison/Coen gas-fired turbine engine with dual fuel-fired 40 MMBtu/hr duct burner serving boiler</p> <p><u>(Detailed Information)</u></p>	<p>11/9/84</p> <p>(A/C # 3082014)</p> <p><u>A330-054-84</u></p> <p>District Contact: Tom Paxson</p> <p><u>San Joaquin Valley APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>NOx <u>(Detailed Control Information)</u> Allison/Coen water/steam injection</p> <p>13.7 lbm/hr turbine and duct burner</p> <p>-----</p> <p>SOx <u>(Detailed Control Information)</u> Low sulfur fuel (natural gas) with 0.25% S fuel oil as standby for duct burner only during N.G. curtailment</p> <p>0.03 lbm/hr (turbine) 10.1 lbm/hr (duct burner(oil))</p> <p>-----</p> <p>PM <u>(Detailed Control Information)</u> Complete combustion with low sulfur fuels, gaseous fuel except during curtailment</p> <p>0.83 lbm/hr</p> <p>-----</p>

<p><u>Moblie Oil</u></p> <p>Two well vent vapor control systems</p> <p><u>(Detailed Information)</u></p>	<p>9/1/84</p> <p>(A/C # 4011216 and 4011217)</p> <p><u>A350-046-84</u></p> <p>District Contact: Tom Paxon <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>VOC/HC <u>(Detailed Control Information)</u> McGill Inc. incinerate well head non-condensable gases for HC control</p> <p>99% control efficiency</p> <p>-----</p>
<p><u>Kern Pistachio Coop.</u></p> <p>Pistachio precleaning/ hulling /drying</p> <p><u>(Detailed Information)</u></p>	<p>7/25/84</p> <p>(A/C # 3068002A)</p> <p><u>A370-045-84</u></p> <p>District Contact: Tuan Ngo <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>PM <u>(Detailed Control Information)</u> High frequency cyclones and fabric collector</p> <p>0.24 gr/scf (cyclone) 0.0084 gr/scf (fabric collector)</p> <p>-----</p>
<p><u>Mineral Spirits Internal Floating Roof Tank</u></p> <p>3,300 bbl interal floating roof tank</p> <p><u>(Detailed Information)</u></p>	<p>6/18/84</p> <p>(A/C # 2018063)</p> <p><u>A350-044-84</u></p> <p>District Contact: Tom Paxon <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Altech Industries Co. single-seal internal floating roof with no-gap seal retained by 10 pound force or greater</p> <p>98% control efficiency</p> <p>-----</p>
<p><u>Gabriel Power Co.</u></p> <p>Biomass Burner</p>	<p>8/18/84</p> <p>(A/C # 40102610101-144)</p>	<p>SOx <u>(Detailed Control Information)</u> Red Crown baghouse</p>

<p><u>(Detailed Information)</u></p>	<p><u>A320-043-84</u></p> <p>District Contact: George Heinen <u>San Joaquin Valley Unified</u> <u>APCD</u> (599) 230-5909 george.heinen@valleyair.org</p>	<p>and scrubber</p> <p>0.0247 lb/meg btu input</p> <p>-----</p>
<p><u>Shell California Production, Inc. (North Belnidye Dehy Facility)</u></p> <p>3,000 bbl/day crude oil dehydration and storage with truck loading rack</p> <p><u>(Detailed Information)</u></p>	<p>5/25/84</p> <p>(A/C # 4012304A)</p> <p><u>A350-42-84</u></p> <p>District Contact: Tom Paxon <u>San Joaquin Valley Unified</u> <u>APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>VOC/HC <u>(Detailed Control Information)</u></p> <p>Vapor control system connedted to process, storage and truck loading equipment</p> <p>177.2 lbm/day</p> <p>-----</p>
<p><u>Shell California Production Inc. - Kern Ridge</u></p> <p>168 hp Waukesha natural-gas fired compressor engine</p> <p><u>(Detailed Information)</u></p>	<p>5/29/84</p> <p>(A/C # 2028022 and 2028023)</p> <p><u>A330-041-84</u></p> <p>District Contact: Tuan Ngo <u>San Joaquin Valley Unified</u> <u>APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>NOx <u>(Detailed Control Information)</u></p> <p>Riley-Beaird maxium MCSR rich burn catalytic converter</p> <p>1.09 gm/bhp-hr</p> <p>-----</p>
<p><u>Getty Oil - Lost Hills Cogeneration</u></p> <p>5000 hp Renske gas turbine followed by waste heat recovery steam generator for TEOR operation</p> <p><u>(Detailed Information)</u></p>	<p>5/9/84(A/C # 4003571-573)</p> <p><u>A330-40-84</u></p> <p>District Contact: George Heinen <u>San Joaquin Valley Unified</u> <u>APCD</u> (former Kern County APCD) (559) 230-5909</p>	<p>NOx <u>(Detailed Control Information)</u></p> <p>Water injection of 0.8:1 water to fuel gas (by weight) ratio</p> <p>7.6 lb/hr</p> <p>-----</p>

	<p>george.heinen@valleyair.org</p>	
<p><u>Kern Oil Refining Company</u> <u>(Refining Waste Gas Recovery)</u></p> <p>720,000 scf/day vapor compressor, valves, and flanges</p> <p><u>(Detailed Information)</u></p>	<p>3/19/84</p> <p>(A/C # 2018008A, 2018046A, 2018012B, and 2018062)</p> <p><u>A350-038-84</u></p> <p>District Contact: Tom Paxson <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Inspection of maintenance to minimize fugitive emissions</p> <p>65% control efficiency</p> <p>-----</p>
<p><u>Cannery - Stanislaus Food</u></p> <p>125,000 lb/hr Ward-Schmid Nebraska model NS-G-101 steam boiler</p> <p><u>(Detailed Information)</u></p>	<p>3/8/84</p> <p>(A/C # 3-019-04)</p> <p><u>A310-037-84</u></p> <p>District Contact: Mark Boese <u>San Joaquin Valley Unified APCD</u> (Stanislaus County APCD)</p> <p>(209) 571-6908</p>	<p>NOx <u>(Detailed Control Information)</u> Oxygen trim control, Hague International MJ-900-D burner with flue gas recirculation and staged combustion</p> <p>65 ppm @ 3% O2</p> <p>-----</p>
<p><u>University Cogeneration LTD - 1983</u></p> <p>8563 KW Solar Mars natural gas-fired turbine with water injection and waste heat unfired boiler</p> <p><u>(Detailed Information)</u></p>	<p>3/21/84</p> <p>(A/C # 4133001)</p> <p><u>A330-036-84</u></p> <p>District Contact: Tom Paxson <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>NOx <u>(Detailed Control Information)</u> Water injection, 0.9/1.0 w/f</p> <p>714 lb/day</p> <p>-----</p>

<p><u>Salyer Grain & Milling Company</u></p> <p>800 bales/day Lummus 5-158 Saw cotton gin</p> <p><u>(Detailed Information)</u></p>	<p>7/20/83</p> <p>(A/C # 8323)</p> <p><u>A370-034-83</u></p> <p>District Contact: George Heinen <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (599) 230-5909 george.heinen@valleyair.com</p>	<p>PM</p> <p><u>(Detailed Control Information)</u></p> <p>Lummus Industries, Inc. 1D-3D cyclones vented to dual rotary drum filtration units</p> <p>17 lb/hr</p> <p>-----</p>
<p><u>Tankage change of service and vapor control system modification</u></p> <p>Rerun charge and heavy naptha storage tanks</p> <p><u>(Detailed Information)</u></p>	<p>1/4/84</p> <p>(A/C # 218009C, 059-61)</p> <p><u>A350-032-84</u></p> <p>District Contact: Tom Paxson <u>San Joaquin Valley Unfied APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>Incineration of vapors in existing refinery fuel gas system</p> <p>95% control efficiency</p> <p>-----</p>
<p><u>Angus Petrotech</u></p> <p>62.5 MMBtu/hr oil-filled steam generator w/scrubber & "low NOx" burner</p> <p><u>(Detailed Information)</u></p>	<p>11/29/83</p> <p>(A/C # 4132002-004)</p> <p><u>A310-23-83</u></p> <p>District Contact: Tom Paxson <u>Kern County APCD</u> (Now the San Joaquin Valley Unified APCD) (805) 861-3682</p>	<p>SOx</p> <p><u>(Detailed Control Information)</u></p> <p>Diglycolamine absorbing system for hydrogen sulfide removal</p> <p>95% control efficiency 61.4 lb/day</p> <p>-----</p>
<p><u>Warren Petroleum (Natural Gas Processing Orern)</u></p>	<p>10/19/83</p> <p>(A/C # 2023008, 2023009,</p>	<p>NOx</p> <p><u>(Detailed Control Information)</u></p>

<p>2133 hp Waukesha natural gas-fired internal combustion engine</p> <p><u>(Detailed Information)</u></p>	<p>and 2023016)</p> <p><u>A330-020-83</u></p> <p>District Contact: Tuan Ngo <u>San Joaquin Valley Unified APCD</u> (former Kern County APCD) (805) 861-3682</p>	<p>Johnson Metthey, Inc. JMI "rich burn" catalytic converter</p> <p>1.5 gr/bhp-hr</p> <p>-----</p>
<p><u>Snack Foods Plant</u></p> <p>72 MMBtu/hr fuel oil or natural gas-fired process boiler; 507 gal/hr fuel oil or 72,000 scf/hr for natural gas</p> <p><u>(Detailed Information)</u></p>	<p>11/11/83</p> <p>(A/C # 3082001)</p> <p><u>A310-014-83</u></p> <p>District Contact: Tom Paxson <u>Kern County APCD</u> (Now the San Joaquin Valley Unified APCD) (805) 861-3682</p>	<p>NO_x <u>(Detailed Control Information)</u> Low NO_x burners & low sulfur fuel oil (.25% by weight) to be used only during periods of gaseous fuel unavailability</p> <p>75 ppmv @ 3% O₂ 6.8 lbm/hr</p> <p>-----</p> <p>SO_x <u>(Detailed Control Information)</u> Low sulfur fuel oil (.25% by weight) to be used only during periods of gaseous fuel unavailability</p> <p>18.2 lbm/hr</p> <p>-----</p> <p>PM <u>(Detailed Control Information)</u> Low sulfur fuel oil (0.25% by weight) to be used only during periods of gaseous fuel unavailability</p>

		1 lb/hr -----
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BACT Clearinghouse Database Lookup Results

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tab for refineries

Miscellaneous

Project Name & Description	A/C Issue Date & ARB File No.	Pollutant
<p><u>Cannery - Stanislaus Food</u></p> <p>125,000 lb/hr Ward-Schmid Nebraska model NS-G-101 steam boiler</p> <p><u>(Detailed Information)</u></p>	<p>3/8/84</p> <p>(A/C # 3-019-04)</p> <p><u>A310-037-84</u></p> <p>District Contact: Mark Boese <u>San Joaquin Valley Unified APCD</u> (Stanislaus County APCD)</p> <p>(209) 571-6908</p>	<p>NOx</p> <p><u>(Detailed Control Information)</u></p> <p>Oxygen trim control, Hague International MJ-900-D burner with flue gas recirculation and staged combustion</p> <p>65 ppm @ 3% O2</p> <p>-----</p>
<p><u>Ultrasystems-Blue Lake</u></p> <p>162 MMBtu/hr wood-waste fueled steam/electric generation plant with cascade type fuel dryer</p> <p><u>(Detailed Information)</u></p>	<p>1/12/84</p> <p>A/C # HAC-129)</p> <p><u>A320-029-84</u></p> <p>District Contact: Chuck Sassenrath <u>North Coast Unified AQMD</u> (707) 443-3093 ncuaqmd@northcoast.com</p>	<p>PM</p> <p><u>(Detailed Control Information)</u></p> <p>Multiclones and granular bed electro-scrubber for particulate//furnace combustion design for CO, NOx, and HC</p> <p>0.045 lb/MMBtu</p> <p>-----</p>
<p><u>Aeroject Strategic Propulsion</u></p> <p>Chemical Process</p>	<p>4/1/83</p> <p>(A/C # 7542)</p>	<p>VOC/HC</p> <p><u>(Detailed Control Information)</u></p> <p>VIC regenerative</p>

<u>(Detailed Information)</u>	<p><u>A430-028-83</u></p> <p>District Contact: Robert Knight <u>Sacramento Metropolitan</u> <u>AQMD</u> (916) 874-4800</p>	<p>carbon adsorber</p> <p>45 lb/day</p> <p>-----</p>
<p><u>American Lignite Cogeneration</u></p> <p>240 MMBtu/hr Recirculating fluid bed combustion boiler with baghouse</p> <p><u>(Detailed Information)</u></p>	<p>12/21/83</p> <p>(A/C # No A/C)</p> <p><u>A310-025-83</u></p> <p>District Contact: Earl Withycombe <u>Amador County APCD</u> (209) 274-2407</p>	<p>NO_x <u>(Detailed Control</u> <u>Information)</u> Low bed temp, staged combustion</p> <p>61.40 lbm/hr 247.97 tons/yr</p> <p>-----</p> <p>SO_x <u>(Detailed Control</u> <u>Information)</u> Limestone injection into fluid bed</p> <p>65.34 lbm/hr 262.43 tons/yr</p> <p>-----</p> <p>PM <u>(Detailed Control</u> <u>Information)</u> Multiclone/Baghouse</p> <p>7.88 lbm/hr 31.77 tons/yr</p> <p>-----</p>
<p><u>Hayfork Cogeneration Project</u></p> <p>236 MMBtu/hr wood waste-fired steam/electric generation plant</p> <p><u>(Detailed Information)</u></p>	<p>12/14/83</p> <p>(A/C # TAC-012)</p> <p><u>A320-024-83</u></p> <p>District Contact: Chuck Sassenrath</p>	<p>NO_x <u>(Detailed Control</u> <u>Information)</u> Furnace combustion design</p> <p>0.15 lb/MMBtu</p> <p>-----</p>

	<p>(707) 443-3093 ncuaqmd@northcoast.com</p>	<p>SO_x <u>(Detailed Control Information)</u> Furnace combustion modification 0.35 lb/MMBtu ----- PM <u>(Detailed Control Information)</u> Multiclones and ESP 0.04 lb/MMBtu ----- VOC/HC <u>(Detailed Control Information)</u> Furnace combustion design 0.07 lb/MMBtu -----</p>
<p><u>Pacific Refinery Modification</u> 2.75 MMBtu/hr refinery hydrogen reformer furnace, H-4011 <u>(Detailed Information)</u></p>	<p>9/28/83 (A/C # 29180) <u>A310-022-80</u> District Contact: Leonard Clayton Bay Area AQMD (415) 771-6000</p>	<p>NO_x <u>(Detailed Control Information)</u> Ammonia injection and selective catalytic reduction unit 20 ppm @ 3% O₂ 85% control efficiency -----</p>
<p><u>Pacific Refinery Modifications</u> Refinery fuel gas system <u>(Detailed Information)</u></p>	<p>9/28/83 (A/C # 29180) <u>A350-021-83</u></p>	<p>SO_x <u>(Detailed Control Information)</u> Diglycolamine absorbing system for H₂S removal</p>

	District Contact: Leonard Clayton Bay Area AQMD (415) 771-6000	50 ppm H2S in fuel gas -----
<u>Stecher - Travng - Schmidt</u> Varnisher drying oven, dry-sys, on varnisher 261 (Detailed Information)	10/8/82 (A/C #28246) <u>A340-015-82</u> District Contact: Ellen Linder Bay Area AQMD (415) 771-6000	VOC/HC (Detailed Control Information) Hirt model FLX-7M fume incinerator 90 % overall control efficiency 97% (in-out of incinerator) -----
<u>Mr. Spa's, Inc.</u> Gel coat & polyester resin application- manufacture of fiberglass spas (Detailed Information)	9/8/83 (A/C # 1240-1) <u>A340-013-83</u> District Contact Keith Doval Ventura County APCD (805) 654-2664	VOC/HC (Detailed Control Information) Increase styrene content in gel coat (to 41%)//Use of filler material in resin//vapor suppressant agents in resin 63% reduction -----
<u>Exxon Co. USA - Benicia</u> Refinery Process Furnace (Detailed Information)	12/10/80 (A/C # 27599) <u>A310-010-80</u> District Contact: Leonard Clayton Bay Area AQMD (415) 771-6000	NOx (Detailed Control Information) Low-Nox burners and thermal de-NOx 40 ppmvd @ 3% O2 70% control efficiency -----
<u>H.S. Crocker Co. Printing</u>	3/21/83	VOC/HC (Detailed Control

<p>6 COLDR 64" Printing Press <u>(Detailed Information)</u></p>	<p>(A/C # 28709) <u>A340-008-83</u> District Contact: Mohamad Mdazed <u>Bay Area AQMD</u> (415) 771-6000</p>	<p><u>Information)</u> Limit on VOC centent of inks 2.5 lb VOC/day -----</p>
<p><u>Gazette Press Printing</u> Two 12950 cfm Tec Printing System drying ovens <u>(Detailed Information)</u></p>	<p>12/20/82 (A/C # 28925) <u>A340-007-82</u> District Contact: Mohamad Mdazed <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> Katec, TVA-812 fume incinerator 95% control efficiency -----</p>
<p><u>American Metal Decorating Co.</u> Paint coating line for metal parts <u>(Detailed Information)</u></p>	<p>3/7/80 (A/C # 27361) <u>A340-006-80</u> District Contact: John Phillips <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> CE Air Preheater Cor-Pak fume incinerator 87% control efficiency -----</p>
<p><u>Time Oil Co. (Loading Rack)</u> One million gallons per day gasoline bulk loading rack <u>(Detailed Information)</u></p>	<p>12/23/80 (A/C # 27611) <u>A350-004-82</u> District Contact: Dave Dixon <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u> McGill activated carbon adsorption system with two beds. Automatically timed desorption cycle 98.6% control efficiency -----</p>

<p><u>TOSCO Corp. Hydrotreating Unit</u></p> <p>5 hp or larger centerifugal pump seals</p> <p><u>(Detailed Information)</u></p>	<p>2/19/82</p> <p>(A/C # 27769)</p> <p><u>A350-003-82</u></p> <p>District Contact: Jim Karas <u>Bay Area AQMD</u> (415) 771-6000</p>	<p>VOC/HC <u>(Detailed Control Information)</u></p> <p>Double mechanical seals with a oil seal</p> <p>500 ppm</p> <p>-----</p>
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[Click here to return the CAPCOA BACT Search Page](#)

2003

APPENDIX H

**BAAQMD REFINERIES PROPOSED CARFG2 MODIFICATIONS
WITH BACT DETERMINATIONS**

CHEVRON'S PROPOSED CARFG2 OPERATIONAL PHASE EMISSIONS SOURCES WITH BACT DETERMINATIONS

New Sources

S-4355 DIB/ Butamer Plant
 S-4356 Tertiary Amyl Methly Ether (TAME)
 Plant
 S-3205 Tank, Methanol
 S-3206 Tank, Whole Alkylate
 S-3207 Tank, FCC Heavy GASoline
 S-3208 Sphere, Butane
 S-3209 Sphere, Propane
 S-3210 Sphere, Isopropane

Modified Sources

S-4291 Alkylation Plant
 S-4357 C4 Treating Plant
 S-6053 Alky/TAME Cooling Water Tower Bay
 S-6016 FCC Flare
 S-6019 Alky/Poly Flare
 S-4285 Fluid Catalytic Cracker Unit (FCCU)
 S-4353 #3 Naptha Hydrotreater
 S-4032 #3 Naptha Hydrotreater, F101
 S-4033 #3 Naptha Hydrotreater, F102
 S-4346 Gas Recovery Unit
 S-4348 H₂ Recovery Plant
 S-4282 Aromatics Saturation Plant

Best Available Control Technology (BACT) – Regulation 2-2-301 states that BACT must be applied to sources emitting POC, NPOC, NO_x, SO_x, TSP, PM10, or CO in excess of 5 pounds per highest day or 365 pounds per year. The following are the units triggering this Regulation and their methods of compliance with BACT unless otherwise noted.

Flanges

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All flanges	All new flanges inspected quarterly. Leaks of POC defined as 100ppmv.	Use graphite-based gaskets or equivalents for this level of POC control.

Valves

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All valves	Valves inspected quarterly. Leaks of POC defined as greater than 100ppmv.	Use bellows valves, lived loaded valves, graphitic packing, or equivalent. All other valves will utilize upgraded packing for this level of POC control.

Pumps

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All pumps	Pumps inspected quarterly. Leaks of POC defined as greater than 500ppmv.	Use double mechanical seals and barrier fluid or equivalent. Will use double mechanical seals with heavy liquid barrier fluid and/or Chevron's seal vapor recovery system at all light liquid service pumps for this level of POC control.

Compressors

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All compressors	Compressors inspected quarterly. Leaks of POC defined as greater than 500ppm.	Use double mechanical seals and barrier fluid or equivalent. Use wet enclosed seals and/or Chevron's seal vapor recovery system for this level of POC control.

Relief Valves

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All relief valves	All pressure relief valves will be vented to a flare gas recovery system, furnace, or flare for POC control.	

Process Drains

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All process drains	Use p-trap or equivalent method. All new process units will have new process drains with p-traps installed for POC control.	

Alkylation Plant

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above with exception of sulfuric acid services.

Sulfuric acid degrades graphitic packing and gaskets, therefore, use Teflon gaskets for flanges and Teflon/graphitic based packing for valves.

Deisobutanizer/ Butamer Plant

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above.

C4 Treating Plant

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above.

TAME Plant

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above.

Hydrogen Recovery Plant

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above.

Aromatics Saturation Unit

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above. Valves which are 2 inches or less and are on process streams with greater than 2 wt% benzene shall wherever feasible (but no less than 95% of these valves) be Bellows-sealed valves or District approved technology. Fugitive sources with greater than 10 wt% benzene shall be inspected monthly.

Alkylation/ TAME Cooling Water Tower Bay

For particulate control, will equip S-6053 Cooling Tower with a high efficiency drift eliminator to reduce drift loss. BACT for POC emissions from this source consists of good operating practice and minimizing POC leaks from process equipment into the cooling water system.

Flare

BACT is not triggered because incremental increase in emissions from S-6016 and S-6019 are less than 1 pound per day.

Storage Tanks

All non-LPG tanks equipped with external floating roof tanks. Design criteria will meet but not be limited to dual seals with zero gap secondary seal. All roof penetrations are gasketed, adjustable roof legs fitted with vapor seal boots, and with no slots above liquid level on guide poles. Guide poles with organic liquid inside will have a float fitted with wiper seals.

FCCU Gasoline Hydrotreater

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above.

FCC Unit

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
POC		Will comply with all BACT conditions as stated in tables above for POC control. Compliance shall be based on annual source tests that demonstrate Chevron will not exceed 6.1 tons POC emissions per year.
NOx		24hr operating day avg: 220ppmv NOx, 3% O ₂ , dry Rolling 30 day avg: 180ppmv NOx, 3% O ₂ , dry Calendar year avg: 150ppmv NOx, 3% O ₂ , dry
SOx		24 hr day avg: 330ppmv SO ₂ , 3% O ₂ , dry
CO		Rolling 30 day avg: 67ppmv CO, 3% O ₂ , dry Calendar year avg: 50ppmv CO, 3% O ₂ , dry
PM10		Compliance shall be based on source tests that demonstrate Chevron will not exceed 21 lb/hr average of 4 source tests per calendar year.

**SHELL'S PROPOSED CARFG2 OPERATIONAL PHASE EMISSIONS SOURCES
WITH BACT DETERMINATIONS**

UNIT DESCRIPTION

A-4002 Delayed Coking Unit SCR
A-4005 Delayed Coking Unit Coke Barn
Particulate Fabric Filter
A-4006 Delayed Coking Unit Railcar Loading
Particulate Fabric Filter
A-4161 Hydrogen Plant – 3 SCR
A-4180 Sulfur Recovery Unit #4 SCOT Unit
A-4181 Sulfur Recovery Unit #4 Tailgas
Thermal Oxidizer
A-4190 Boiler 6 Selective Catalytic Reduction
A-4191 Boiler 6 Catalytic Oxidation
A-4192 Boiler 6 Selective Catalytic Reduction
A-4193 Boiler 6 Catalytic Oxidation
A-4201 Flare Gas Recovery System
S-4001 Delayed Coker Unit
S-4002 Delayed Coker Unit – Furnace No. 1
S-4003 Delayed Coker Unit – Furnace No. 2
S-4004 Delayed Coker Unit – Furnace No. 3
S-4005 Delayed Coker Unit – Coke Handling
S-4010 Coker Gasoline Splitter Column
S-4020 Distillate Hydrotreater
S-4021 DHT Recycle Gas Heater
S-4022 DHT Fractionator Reboiler Heater
S-4023 DHT Heater SCR
S-4030 Cracked Gasoline Bottoming Column
S-4031 Cracked Gasoline Bottoming Column
Reboiler Heater
S-4040 Distillate Saturation Unit – 2
S-4041 Distillate Saturation Unit – 2
Feed Heater
S-4042 Distillate Saturation Unit – 2
Reboiler Heater

NEW TANKS

S-4301 Spent Sulfuric Acid Tank; abated by
A-33, Flare Gas Recovery System
S-4307 MDEA Make-up Tank
S-4308 DEA Tank #2
S-4309 DEA Tank #1
S-4310 Sour Water Tank
S-4311 Perchloroethylene Tank (pressurized)
S-4312 Perchloroethylene Tank (pressurized)
S-4319 Recovered Oil Tank; abated by
A-56, Vapor Recovery
S-4321 DCU Feed Tank
S-4325 Isom Feed Tank
S-4329 Pentane Tank (pressurized); abated by
A-4330, Pentane Vapor Recompression
S-4330 Pentane Tank (pressurized); abated by
A-4330, Pentane Vapor Recompression
S-4333 Dimate Tank
S-4334 Alkylate Tank; by A-25, Vapor Recover

UNIT DESCRIPTION

S-4050 Light Cracked Gasoline Treater
S-4080 C5/C6 Isomerization Unit
S-4090 Alkylation Unit
S-4100 Light Cracked Gasoline Hydrotreater
S-4101 LGHT Feed Heater
S-4130 Catalytic Reformate Bottoming Column
S-4140 Heavy Cracked Gasoline Hydrotreater
S-4141 HGHT Feed Heater
S-4150 Butane Isomerization Unit
S-4160 Hydrogen Plant – 3
S-4161 Hydrogen Plant – 3 SMR Furnace
S-4170 Lube Hydrotreater – 2
S-4171 Lube Hydrotreater (LHT-2) Feed Heater
S-4180 Sulfur Recovery Unit #4
S-4182 Sour Water Stripper
S-4183 Sour Water Stripper
S-4190 Boiler 6 Gas Turbine #1
S-4191 Boiler 6 Supplmt Steam
Generator #1
S-4192 Boiler 6 Gas Turbine #2
S-4193 Boiler 6 Supplemental Steam
Generator #2
S-4201 Flare
S-4210 Cooling Tower
S-4211 Maintenance Drop Out Vessel
S-4212 Maintenance Drop Out Vessel
S-4338 Pentane Loading Facility
S-4347 Sulfur Pit
S-4350 Process Wastewater Tank
S-4356 Process Wastewater Tank

S-4335 Crude Oil Tank #1
S-4336 Crude Oil Tank #2
S-4346 Sulfuric Acid Tank
S-4349 Pentane Tank (pressurized); abated by
A-4330, Pentane Vapor Recompression
S-4351 Process Wastewater Tank; abated by
A-56, Vapor Recovery
S-4350 Olefin Storage (pressurized)
S-4354 Crude Oil Tank #3
S-4355 Crude Oil Tank #4
S-4356 Process Wastewater Tank; abated by A-
56, Vapor Recovery

EXISTING TANKS

S-1129 Gaso Interim Tank (Tank 1129)
S-1130 Gaso Interim Tank (Tank 1130)
S-1131 Gaso Interim Tank (Tank 1131)

The following is a breakdown of BACT determinations:

Furnaces

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All furnaces with a design firing rate greater than or equal to 50 MMBTU/hr	10ppmv corrected to 3% O ₂ , avg. over 3 hrs	Use combination of low NO _x burners & selective catalytic reduction (SCR) for this level of NO _x control.
All natural draft furnaces with a design firing rate less than 50 MMBTU/hr	25ppmv corrected to 3% O ₂ , avg. over 3 hrs	Use low NO _x burners for this level of NO _x control.
All forced draft furnaces with a design firing rate less than 50 MMBTU/hr	20ppmv corrected to 3% O ₂ , avg. over 3 hrs	Use combination of low NO _x burners and/or flue gas recirculation for this level of NO _x control.
All furnaces, except hydrogen plant furnace (S-4161)	Combustion of refinery fuel gas or other gaseous fuel that does not exceed 50ppmv H ₂ S, avg. over 24 hrs	Use fuel gas amine treating system for this level of SO ₂ control.
All furnaces, except S-4161	50ppm at 3% O ₂ , averaged over 8 hrs	Use an air to fuel ratio controller on each furnace for this level of CO control.
Hydrogen plant furnace S-4161	Combustion of refinery fuel gas and pressure swing absorber (PSA) gas. Refinery fuel gas will not exceed 50ppmv H ₂ S, avg. over 24 hrs. Total reduced sulfur in the refinery fuel gas will not exceed 100ppm, annual avg. The PSA gas will not exceed 3.6ppm H ₂ S avg. over 24 hrs. For SO ₂ control.	
Hydrogen plant furnace S-4161	Due to its large firing rate, limit of 25ppm at 3% O ₂ , averaged over 8hrs	

Gas Turbines & Cogeneration plant

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Cogeneration Plant	5ppmv corrected to 15% , avg. over 3 hrs	Use steam injection & SCR for this level of NO _x control.
Gas Turbines	Combustion of refinery fuel gas that does not exceed 50ppmv H ₂ S, avg. over 24 hrs	Use fuel gas amine treating system for this level of SO ₂ control.
Gas Turbines	Limit of 6.5ppm at 15% O ₂ , avg over 8hrs or 90% overall reduction on a mass basis	Use non-selective catalytic oxidizer for this level of CO control.
Gas Turbine	Precursor Organic Compounds (POC) emissions	Use non-selective catalytic oxidizer for POC control.

Flares

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Flare	Steam assisted ground level flare with staged combustion. Pilots will be fueled with natural gas or LPG. The flare will be operated only during period of emergency upset or breakdown. Routine venting of process gases will go to the flare gas recovery system. For SO ₂ , CO, and PM control.	
Flare	Steam assisted ground level flare with staged combustion. The hydrocarbon destruction efficiency will be at least 98.5% on a mass basis. Pilots will be fueled with natural gas or equivalent. The flare will be operated only during period of emergency upset or breakdown. Routine venting of process gases will go to the flare gas recovery system. For POC control.	

Sulfur Recovery System

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Sulfur Recovery System #4 (SRU)	Exhaust from feed to tailgas incinerator will be limited to contain no more than 100ppm total reduced sulfur at 0% O ₂ . SO ₂ and H ₂ S emissions from the tailgas oxidizer will not exceed 50 and 2.5ppm at 0% O ₂ . The sulfur pit will be enclosed and vented to the tailgas oxidizer. Sour H ₂ O strippers will remove 95% wt of the H ₂ S and NH ₃ from the sour H ₂ O stream. The SRU and SCOT will achieve at least a 99.9% wt conversion of to elemental H ₂ S sulfur.	Use SCOT (Shell Claus Offgas Treatment) unit and a tailgas thermal oxidizer for this level of SO ₂ control.
SRU #4	CO limit of 100ppm in the exhaust from the Thermal Oxidizer.	Meet limit by using good combustion practices.

Pumps

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Pumps in light liquid hydrocarbon service	Pumps inspected quarterly. Leaks of POC defined as greater than 500ppm.	Use double mechanical seals with a barrier fluid. The barrier fluid shall be either: 1) vented to a control device with a 95% efficiency; or 2) at a higher pressure than the process stream pressure.

Compressors

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Compressors in hydrocarbon service	Pumps inspected quarterly. Leaks of POC defined as greater than 500ppm.	Use double mechanical seals with a barrier fluid. The barrier fluid shall be either: 1) vented to a control device with a 95% efficiency; or 2) at a higher pressure than the process stream pressure.

Valves

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Valves in gaseous, light liquid, or toxic services	Valves inspected quarterly. Leaks of POC defined as greater than 100ppm.	Valves will be bellows sealed, lived loaded, graphitic packed, Teflon packed, or equivalent. Control valves will be live loaded with graphite packing and polished stems.

Flanges

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All flanges	Equipped with graphitic or Teflon gaskets, or equivalent for POC control.	

Pressure Relief Valves

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All pressure relief valves in hydrocarbon service	All pressure relief valves will be vented to the flare gas recovery system for POC control.	

Tanks

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Pressurized Tanks (6)	Vapor recompression or operate under a minimum pressure of 15 psig for POC control.	
New Storage Tanks (4)	Use existing vapor recovery systems for POC control.	
Remaining Tanks	Use external floating roof tanks. External floating roof tanks will have zero-gap secondary seals and with the exception of adjustable roof legs, the lowest emitting roof fittings, including: no ungasketed roof penetrations, and no slotted guide poles. Adjustable roof legs will be controlled by vapor seal boots. For POC control.	

Wastewater

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Maintenance Drop Out vessels	Enclosure and venting to the flare gas recovery system for POC control.	

Cooling Tower

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Cooling Tower	Installation of a hydrocarbon monitor to enhance the detection of hydrocarbon leaks to the cooling water system for POC control.	

Railcar Loading (Pentane)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Pentane railcar loading operation	Use existing LPG flare (S-1470) for POC control.	

Coke Handling

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Coke handling operations	1) Coke moisture content of at least 8% wt; 2) water suppression at the crusher and coke barn piles; 3) an enclosed conveying system; 4) an enclosed coke barn controlled by a particulate filter; 5) a shrouded railcar loading operation controlled by a particulate filter; and 6) a vehicle wash-off area inside of the coke barn.	

**PACIFIC'S PROPOSED CARFG2 OPERATIONAL PHASE EMISSIONS
SOURCES WITH BACT DETERMINATIONS**

Unit Description

A-109 Catalytic Converter abating S-270
A-110 SCR system abating S-271
~~A-111 Catalytic Converter abating S-271~~

Unit Description

S-257 Diesel Hydrotreater
S-258 Feed Heater 7-H-101
~~S-259 Feed Heater 7-H-102~~

A-270 SCR system abating S-270
A-275 SCR system abating S-275
A-276 Offgas Scrubber
A-278 SCR system abating S-278
A-279 SCR system abating S-279
A-281 North Vapor Recovery System abating
S-281 & S-282
A-283 South Vapor Recovery System abating
S-283, S-285, S-286, S-287, & S-288
A-368 Electrostatic Precipitator abating S-268
A-378 Oxidizing Catalysts abating S-278
A-379 Catalytic Converter abating S-279
A-468 Wet Gas Scrubber abating S-268
S-250 Crude / Vacuum Unit
S-252 Unifiner Heater 2-H-102
S-253 Unifiner Reboiler 2-H-102
S-254 Fluid Catalytic Cracking Unit
S-255 Feed Heater 3-H-201
S-256 Alkylation Unit

S-273 Isomerization Unit
S-274 Gas Oil Hydrotreater
S-275 Feed Heater 19-H-101
S-276 Sulfuric Acid Regeneration Plant
S-277 Sulfuric Acid Combustor Furnace
S-278 Gas Turbine 79-T-101
S-279 Gas Turbine 79-T-102
S-281 Crude Storage Tank 80-TK-101A
S-282 Crude Storage Tank 80-TK-101B
S-283 Naptha Storage Tank 80-TK-102
S-285 FCCU Feed Tank 82-TK-101A
S-286 FCCU Feed Tank 82-TK-101B
S-287 Diesel Hydrotreater Feed Tank
82-TK-102A
S-288 Diesel Hydrotreater Feed Tank
82-TK-102B
S-296 Cooling Tower
S-79 Unifiner/ Platformer

Crude/ Vacuum Unit (S-250)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All Flanges	All new flanges inspected monthly. Leaks of POC defined as 100ppmv.	Use flanges with graphite-based gaskets or equivalent.
Valves (general)	Valves inspected monthly. Leaks defined as greater than 100ppmv.	Use bellows valves, live-loaded valves, graphite-based packing, or equivalent.
New valves in light liquid & gas service 2" and <	Valves inspected monthly. Leaks defined as greater than 100ppmv.	Use bellows valves.
All other valves	Valves inspected monthly. Leaks defined as greater than 100ppmv.	Use upgraded packing for all other valves.
Pumps	Pumps inspected monthly. Leaks defined as 100ppmv or greater.	Use double mechanical seals with heavy liquid barrier fluid, or canned or mag drive pumps.
Compressors	Compressors inspected monthly. Leaks defined as 100ppmv.	Use double mechanical seals and barrier fluid or equivalent.
Relief Valves	Recovery system, furnace or flare must have recovery/destruction efficiency of at least 98%.	Use rupture disks and vent to a fuel gas recovery system, furnace or flare.

Process drains	BACT must achieve approximately 80% control.	Use of p-trap or equivalent method.
Sample connections	N/A	Consists of closed loop sampling systems with an inert purge gas and venting to a control device. Septum sealed jars used for sampling.

Naptha Hydrotreater (S-252 & S-253; heater rated capacity of 24.55 & 23.25 MMBtu/hr)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
NO _x	Emissions limit of 10ppm NO _x corrected to 3% O ₂ , dry.	Use low NO _x burners and SCR (A-252) on S-252 & S-253. Will abate approx. 90% of NO _x .
POC	BACT is not determined	Good combustion practices and efficient operation for POC control.
SO ₂	Gas used will not have H ₂ S level greater than 50ppm.	Use natural gas or treated refinery gas fuel for this level of SO ₂ control.
PM	BACT 1 is not determined. BACT 2 is triggered.	BACT 2 specifies the use of natural gas or treated refinery fuel gas for PM control.

Isomerization Unit (S-273)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
POC	Unit emits only fugitive POC.	BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above.

Diesel Hydrotreater (S-257)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
POC	Unit emits only fugitive POC.	BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above.

Diesel Hydrotreater (S-258 & S-259; heater rated capacity of 28.57 & 32.47 MMBtu/hr)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
NO _x	Emissions limit of 10ppm NO _x corrected to 3% O ₂ , dry.	Use low NO _x burners and SCR (A-258) on S-258 & S-259. Will abate approx. 90% of NO _x .
POC	BACT is not determined	Good combustion practices and efficient operation for POC control.
SO ₂	Gas used will not have H ₂ S level greater than 50ppm.	Use natural gas or treated refinery gas fuel for this level of SO ₂ control.
PM	BACT 1 is not determined. BACT 2 is triggered.	BACT 2 specifies the use of natural gas or treated refinery fuel gas for PM control.

Gas Oil Hydrotreater (S-274)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
POC	Unit emits only fugitive POC.	BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above.

Gas Oil Hydrotreater (S-275; heater rated capacity of 59.2 MMBtu/hr)

Application	Condition	BACT
NO _x	Emissions limit of 10ppm NO _x corrected to 3% O ₂ , dry.	Use low NO _x burners and SCR (A-275) on S-275. Will abate approx. 90% of NO _x .
POC	BACT is not determined	Good combustion practices and efficient operation for POC control.
SO ₂	Gas used will not have H ₂ S level greater than 50ppm.	Use natural gas or treated refinery gas fuel for this level of SO ₂ control.
PM	BACT 1 is not determined. BACT 2 is triggered.	BACT 2 specifies the use of natural gas or treated refinery fuel gas for PM control.

Hydrogen Plant (S-269)

Application	Condition	BACT
POC	Unit emits only fugitive POC.	BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above.

Hydrogen Plants (S-270, S-271, S-272; heater rated capacity of 125 MMBtu/hr)

Application	Condition	BACT
NO _x	BACT 1 is not determined. BACT 2 is an emissions limit of 10ppm NO _x corrected to 3% O ₂ , dry.	Use low NO _x burners and SCR (A-270, A-110, A-112, respectively) on S-270, S-271, S-272. Will abate approx. 90% of NO _x .
POC	BACT is not determined. POC emissions limited to no more than 6.4 lb/day / heater	Use oxidizing catalysts for all three heaters for this level of POC control.
SO ₂	Gas used will not have H ₂ S level greater than 50ppm.	Use natural gas or treated refinery gas fuel for this level of SO ₂ control.
PM	BACT 1 is not determined. BACT 2 is triggered.	BACT 2 specifies the use of natural gas or treated refinery fuel gas for PM control.

Fluidized Catalytic Cracking Unit (S-254 & S-266)

Application	Condition	BACT
POC	Unit emits only fugitive POC.	BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above.

Fluidized Catalytic Cracking Unit (S-255; heater rated capacity of 24 MMBtu/hr)

Application	Condition	BACT
NO _x	Emissions limit of 10ppm NO _x corrected to 3% O ₂ , dry.	Use low NO _x burners and SCR (A-255) on S-275. Will abate approx. 90% of NO _x .
POC	BACT is not determined	Good combustion practices and efficient operation for POC control.
SO ₂	Gas used will not have H ₂ S level greater than 50ppm.	Use natural gas or treated refinery gas fuel for this level of SO ₂ control.
PM	BACT 1 is not determined. BACT 2 is triggered.	BACT 2 specifies the use of natural gas or treated refinery fuel gas for PM control.

Fluidized Catalytic Cracking Unit (S-268; heater rated capacity of 35.9 MMBtu/hr)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
NO _x	BACT 1 not specified. Emissions limit of 10ppm NO _x corrected to 3% O ₂ , dry.	Use SCR, flue gas recirculation, low-NO _x burners and reduced-air preheat. Use low NO _x burners and SCR (A-268) on S-268.
POC	BACT is not determined	Good combustion practices and efficient operation for POC control.
SO ₂	Gas used will not have H ₂ S level greater than 50ppm.	Use natural gas or treated refinery gas fuel for this level of SO ₂ control. S-268 will be equipped with a wet gas scrubber (A-468) that removes SO ₂ from the flue gas. The controlled SO ₂ level in the flue gas is estimated to be 10ppm corrected to 3% O ₂ .
PM	BACT 1 is not determined. BACT 2 is triggered.	BACT 2 specifies the use of an electrostatic precipitator (ESP). S-268 will be equipped with an ESP (A-368).

Alkylation Unit (S-256)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
POC	Unit emits only fugitive POC.	BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above.

Sulfuric Acid Regeneration Plant (S-276)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
POC	Unit emits only fugitive POC.	BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above.
NO _x & SO _x	Will remove over 94% of the NO _x & SO _x from the plant.	S-276 will be equipped with a "Trimer" tail gas scrubber (A-276) for SO ₂ and NO _x control.

Storage Tanks – Internal Floating Roof (S-281, S-282, S-283, S-287, S-288)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
POC	Vapor recovery system overall efficiency of at least 95%. Satisfies BACT 1 (technologically feasible/cost effective).	Internal floating roof tanks hooked up to one of two vapor recovery systems (A-281 & A-283), each leading to an incinerator. Tanks are also equipped with a nitrogen padding control system to maintain tank pressure.

Storage Tanks – Fixed Roof (S-285, S-286)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
POC	Vapor recovery system overall efficiency of at least 95%. Satisfies BACT 2 (achieved in practice). BACT 1 not determined.	Fixed roof tanks equipped with a nitrogen padding control system and steam coils. Tanks are hooked up to the A-283 vapor recovery system.

Cogeneration Plants (S-278, S-279; heater rated capacity of 193.5 MMBtu/hr)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
NO _x	Emissions limit of 5ppm NO _x corrected to 15% O ₂ , dry.	Use steam injection and SCR (A-278 & A-279) on S-278 & S-279 for this level of NO _x control.
POC	Abatement of at least 50%.	Both turbines will be equipped with oxidation catalysts (A-378 & A-379) which will achieve approximately 90% reduction.
SO ₂ & PM ₁₀	50ppm H ₂ S maximum, 29ppm avg.	Use natural gas as primary fuel, and refinery fuel gas and butane as supplemental fuels.

Cooling Tower (S-296)

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
POC		Good operating practice and minimizing POC leaks from process equipment into the cooling water system.
PM		Equip cooling tower with drift eliminator to reduce drift loss to 0.01%.

EXXON'S PROPOSED CARFG2 OPERATIONAL PHASE EMISSIONS SOURCES WITH BACT DETERMINATIONS

New Sources

S-1020	Heartcut Tower
S-1021	Heartcut Saturation Unit
S-1022	Catalytic T ₉₀ Reformer
S-1023	Catalytic Naptha T ₉₀ Reformer
S-1024	Light Catalytic Naptha Hydrofiner
S-1025	C5/C6 Splitter
S-220	Hot Oil Furnace
S-227	Pentane (C5) Fixed Storage Tank
S-228	C5 Fixed Storage Tank
S-229	C5 Fixed Storage Tank
S-230	Hot Oil Fixed Storage Tank
S-231	Aqueous Ammonia Fixed Roof Storage Tank

Modified Sources

S-1003	Hydrocracking Unit
S-1007	Alkylation Unit
S-1011	Heavy Catalytic Naptha Hydrotreater
S-1014	Virgin Light End Unit
S-151	Waste Water Treatment Plant
S-21	Hydrogen Furnace F-301
S-22	Hydrogen Furnace F-351

Furnaces

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All furnaces with a design firing rate greater than or equal to 50 MMBTU/hr (S-220)	10ppmv corrected to 3% O ₂ , avg. over 3 hrs	Use a combination of low NOx burners and selective catalytic reduction (SCR) for this level of NOx control.
Hydrogen furnaces (S-21 & S-22)	Due to a field test in Jan 1992 not triggering BACT for NOx, a BARCT NOx level of 28ppmv is being proposed. ('92 test of furnace determined uncontrolled NOx level of 99.5ppm at 3% O ₂)	Use a combination of low NOx burners and/or thermal deNOx to meet a 35ppm NOx level.
All furnaces (S-21, S-22, S-220)	Combustion of refinery fuel gas and/or LPG/pentane gases with a total reduced sulfur concentration not to exceed 65 ppmv, annualized 24hr avg based on BACT cost effectiveness discussion*. Daily limit for these furnaces not to exceed H ₂ S concentration of 100ppmv, avg. over 24hrs	Based on BACT #1 level being non-cost effective, BACT #2 is to modify the existing MEA scrubbing system to enhance scrubbing capabilities for the removal of H ₂ S** and this level of SO ₂ control.
All furnaces (S-21, S-22, S-220)	28ppmv at 3% O ₂ , avg. over 8hrs	Best combustion practices as guaranteed by John Zink burner manufacturer for this level of CO control.

* Note: There is no annualized state average. SO₂ BACT determination discussion and explanation from Exxon BAAQMD A/C dated 12/2/93, Application #10392 ppg 9-11

** BACT#2 level determination discussion and explanation from Application #10392 as mentioned above.

Pumps

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Pumps in light liquid hydrocarbon service	Pumps inspected in accordance with Regulation 8, Rule 25. Leaks of POC defined as greater than 500ppm.	Use double mechanical seals with a barrier fluid. The barrier fluid shall be either: 1) vented to a control device with at least 99.5% efficiency; or 2) held at a higher pressure than the process stream pressure for this level of POC control.

Compressors

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
Compressors in hydrocarbon service	Compressors inspected quarterly. Leaks of POC defined as greater than 500ppm.	Use "wet" dual mechanical seals with a heavy liquid barrier fluid or dual gas mechanical seals buffered with inert gases. All reciprocating compressors shall be vented to at least a 99.5% efficient control device for this level of POC control.

Valves

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All hydrocarbon valves	Accessible valves inspected quarterly and inaccessible valves inspected annually. Leaks of POC defined as greater than 100ppm.	Valves will be lived loaded, bellows, graphitic packed, Teflon packed, or equivalent. All hydrocarbon control valves will be live loaded with graphite packing and polished stems or equivalent for this level of POC control.

Flanges

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All flanges	Leaks of POC defined as greater than 500ppm.	Equipped with graphitic gaskets, except in services that are not compatible with graphitic material for this level of POC control.

Pressure Relief Valves

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
All pressure relief valves in hydrocarbon service	All pressure relief valves will be vented to the flaring system or fuel gas recovery system for POC control.	

Tanks

<u>Application</u>	<u>Condition</u>	<u>BACT</u>
New pentane storage tanks (S-227, S-228, S-229)	At least 99.5% control	Use existing vapor recovery systems (A-46, A-47, A-48, A-49). Prior to venting to units A-46 through A-49, these storage tanks will have an auto refrigeration vapor recovery system for this level of POC control.

CARB

Attachment C

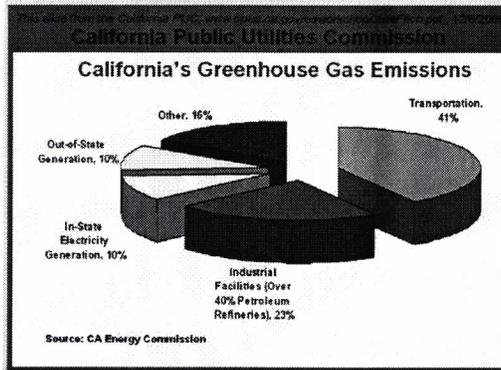
Oil Refinery Sector Recommendations

Summary: **Reduce California Refinery GHG & Other Emissions, Reduce Product Demand**

	DIRECT GHG REDUCTION METHODS	BENEFITS & BARRIERS
<p>1. Require Oil Refineries to become more efficient</p> <p><i>→NO TRADING: Reductions generated through cleaning up oil refineries are necessary for local, regional, and global public health</i></p>	<ul style="list-style-type: none"> • Energy Efficiency Audit for every refinery →require BACT first for biggest sources Up front BACT for already-known big energy users (don't wait to finish audits) for Hydrogen Plants, Hydrotreaters, Hydrocrackers, Cracking, Coking, including Boilers & Heaters. [Many have grandfathered exemptions from modernized emission standards.] • Cogeneration from Waste Heat, audit efficiency & indirect impacts, require BACT • Remove all Methane Exemptions in smog regulations for refineries and all sources • No dumping and burning of "waste" gases: Flare BACT/LAER (beyond BAAQMD & SCAQMD requirements) -- Apply Shell Martinez BACT model – far lower flaring than other refineries, Pressure Relief Devices: Ban venting to atmosphere • Set goal for reduction in Refinery Emissions & Product Demand (e.g. 25% by 2020) 	<ul style="list-style-type: none"> • Local pollution down, Jobs Up • Direct Controls avoid pollution trading pitfalls (failure to address local health impacts, creating toxic hotspots by trading for clean-up elsewhere, major accounting errors due to poor baselines lack of monitoring, toxic co-pollutant inequalities, lack of public input) • Refiner cost up in short term, probably mid term savings
<p>2. Stop refinery expansions & the switch to dirty crude oil</p>	<ul style="list-style-type: none"> • Crude Oil carbon input standard to stop the switch to dirtier crude oils in the state • No new fossil fueled Hydrogen Plants, Hydrocrackers, Cokers, etc. associated with switch to high carbon, dirty crude, and refinery expansions • Carbon tax & windfall profit taxes to fund clean alternative energy and jobs transition • Low Carbon Fuel Standard must have full cradle-to-grave analysis of heavy crude impact on gas & diesel carbon content & must not undermine refinery regulation. LCFS must be designed not to hide high-carbon gasoline by adding corn ethanol to make the total seem lower carbon (while avoiding full cradle-to-grave ethanol carbon analysis, & smog & water pollution impacts analysis.) 	<ul style="list-style-type: none"> • Local criteria & toxics go down • Increase in sustainable jobs when done with demand reduction -- need for green jobs transition & worker protections while reducing demand for fossil fuels, but jobs are also created in 1, 3, and 4 • Higher crude oil cost, but no need for high cost of adding new energy-intensive hydrogen, coking, etc.
<p>3. Switch refinery grid electricity use to clean energy</p>	<ul style="list-style-type: none"> • Refineries are current large users of fossil fuel grid electricity & should be required to switch to clean alternative energy electricity, frequently buildable on refinery land 	<ul style="list-style-type: none"> • Local pollution down & Jobs go up (alternatives create more jobs) • Refiner costs up
<p>4. Reduce demand for California Oil Refinery Products</p>	<p>CARS -- Fund urban core transit systems equitably for EJ, transit system rebuilding and conservation, CAFÉ standards, plug-in hybrids, alternative fuels</p> <p>POWER PLANTS -- Alternatives, efficiency, low carbon inputs</p> <p>TRUCKS & SHIPPING – Efficiency, electrification ALL SOURCES – CARBON TAX</p>	<ul style="list-style-type: none"> • Many savings, solve smog • Cleaner cars -- Political barriers • Public transit - high initial costs • Shipping costs • More and different jobs from public transit, and alternatives

Background on CBE Oil Refinery Recommendations for AB32 Scoping Plan

“Refineries are the largest energy using industry in California and the most energy intensive industry in the United States. . . . After Texas and Louisiana, California has the largest petroleum refining industry in the country.”¹ Oil Refineries are not only a major source of Greenhouse Gases (GHGs) but also the largest point sources of smog precursors. The California Energy Commission found “California ranks 1st in the U.S. in gasoline consumption and 2nd in jet fuel consumption.”² The California Public Utilities Commission found that industrial facilities in California represent about 23% of California’s greenhouse gases, and that about 40% of this comes from refineries. This means that oil refineries cause about 10% of the state’s total GHG emissions:



Focus on direct refinery emissions alone fundamentally understates the impact of oil refining on climate. Refineries make the transportation fuels, which when used as directed, cause an additional 40% of GHGs, they make a major portion of the fossil fuels used to generate electricity (another 20% of GHGs in California), as well as agricultural chemicals. **Efficiency and Best Available Control Technology at oil refineries are essential in reducing local and global pollution from refineries now, but we must also reduce the demand for the inherently polluting refinery fossil fuel products with a planned transition.**

Currently California is going in the wrong direction by building into the oil refinery infrastructure much more energy-intensive refining processes (such as large fossil-fueled hydrogen plants for making more gasoline and diesel, more cokers, more cracking, etc.) to allow the switch to energy intensive high-carbon, high-sulfur crude oil. The state needs to stop this trend and set standards implementing readily available controls, and must identify a specific goal to reduce oil refinery fossil fuel production by a date certain. Cleaning up this inherently polluting industry represents a challenge but it is also a major opportunity to clean up local smog and toxics while making a major reduction in Greenhouse Gas (GHG) emissions.

Key Elements in Reducing GHGs, Smog Precursors, and Toxics from Oil Refineries

1. Require Refinery Energy Efficiency and BACT (Best Available Control Technology)
2. Stop refinery expansions and their switch to dirtier crude oil
3. Switch oil refinery electricity use off the grid to clean alternative electricity
4. Reduce demand for California oil refinery products

¹ Profile of the Petroleum Refining Industry in California, California Industries of the Future Program, Lawrence Berkeley The Lawrence Berkeley National Laboratory, LBNL-55450, page iii., *Ernst Worrell and Christina Galitsky*, Environmental Energy Technologies Division, March 2004, <http://ies.lbl.gov/iespubs/55450.pdf>

² <http://www.energy.ca.gov/oil/index.html>

1. Require Refinery Efficiency and Best Available Control Technology (BACT)

- Energy Efficiency Audits for each refinery → require BACT for largest polluters first
- BACT for Hydrogen Plants, Distillation, Cracking, Coking, Hydrotreaters, Boilers & Heaters
- Cogeneration from Waste Heat
- No dumping of “waste gases” (through venting or flaring)

Energy Efficiency Audits and BACT for known large energy users

Oil refineries’ huge emissions stem from combustion of fossil fuels, evaporation through leaks, and direct dumping to atmosphere. These emissions include practices that use energy (and many practices which waste energy) causing GHG and other emissions that impact public health. At the same time these processes are the single largest stationary source of smog precursors. Refineries emit large amounts of chemicals known to harm breathing, known carcinogens, etc. Progress towards reducing criteria emissions at refineries through smog regulation has slowed. In order to make the necessary progress both on drastically reducing GHGs and local smog and toxic pollution, readily available methods should be applied to rigorously audit and identify the biggest energy users within each refinery and to set stringent standards.

Energy efficiency audits for each refinery in California can identify uneven practices between refineries, such as use of old, inefficient equipment, new intensive energy users, but also best practices that should be more widespread. For example, many refineries have decades-old equipment exempt from current standards (such as large and very old boilers); some refineries have more routine dumping to atmosphere through flaring, Pressure Relief Devices, uncontrolled blowdown systems, and vessel depressurization; and many refineries are in the process of building large fossil-fueled hydrogen plants.

Furthermore, audits on individual refineries that have been carried out in the past have frequently been kept private from the public, and refineries are likely to fight to keep such information out of public scrutiny. The California Air Resources Board (ARB) should both begin by setting standards for known large energy users, but should also carry out its own audits for every refinery in the state and publish the results, since this energy use is an inherent cause of emissions.

While audits to rigorously evaluate each refinery should be required, Best Available Control Technology (BACT) should also be put in place as soon as possible for known large energy users. This should not wait for completion of refinery audits, because it is crucial for greenhouse gas emissions reductions to make expeditious progress.

An audit on the overall oil refining industry in California by the Lawrence Berkeley National Laboratory³ summarized the largest energy users as follows:

³ Ibid, page 31

Table 4. Estimated energy consumption of petroleum refineries in California (2001).

Process	Capacity b/cd	Fuel TBtu	Steam TBtu	Electr. GWh	Final TBtu	Primary TBtu
Desalter	1978132	0	0	32	0	0
CDU	1978132	46	27	322	83	84
VDU	1156155	18	20	132	44	45
Thermal Cracking	381468	11	-2	546	10	13
FCC	650588	12	0	787	15	18
Hydrocracker	476334	21	11	1794	42	49
Reforming	409173	33	6	390	42	43
Hydrotreater	1576697	35	22	1282	67	72
Deasphalting	47767	2	0	30	2	2
Alkylates	150944	2	14	226	20	21
Aromatics	1433	0	0	1	0	0
Asphalt	73354	5	0	62	5	5
Isomers	81682	12	5	52	19	19
Lubes	30953	11	0	161	12	13
Hydrogen	6417226	94	0	313	95	96
Sulfur	4037	0	-12	16	-15	-15
Other	0	13	7	950	25	29
Total	0	315	98	7094	467	496

Resorting the above processes in descending order of primary energy use and grouping similar processes together, identifies the largest process unit totals for the refining industry, aggregated, in California. The top five categories include Hydrogen Plants, Distillation Units, Cracking Units, Hydrotreaters, and Reforming, which make up about 85% of the total. The report also found: "Hydrocracking and hydrogen production are growing energy consumers in the refining industry."

Process	Final TBtu
Hydrogen	96
Distillation Units	129
CDU (Crude Distillation Unit)	84
VDU (Vacuum Distillation Unit)	45
Cracking Units:	80
Hydrocracker	49
FCC	18
Thermal Cracking	13
Other Large Units:	115
Hydrotreater	72
Reforming	43
Remaining Units:	74
Other	29
Alkylates	21
Isomers	19
Lubes	13
Asphalt	5
Deasphalting	2
Desalter	0
Aromatics	0
Sulfur	-15

This list forms a preliminary order of priority for beginning immediately to set energy efficiency requirements for the top units within refineries. (Coking may be included under thermal cracking, or may be a large hidden energy user.) However, overall audits for individual oil refineries in California should also be carried out to identify problem areas where individual refineries perform poorly compared to other refinery averages.

Fossil-fueled refinery hydrogen plants represent huge sources of GHG emissions, and these sources are expanding drastically in the state (and nationally) in order to process higher carbon, higher sulfur inputs (dirty crude oil) at refineries. We provided the following partial list of refinery hydrogen plants during testimony to the state in 2007 during a public hearing on GHG controls. Although only partial and probably underestimated, it showed almost 6 million metric tons per year CO2 refinery emissions from hydrogen plants alone, and these are only the new or relatively new plants. To put this in perspective, CARB included about 30 million metric tons per year of GHGs, and the CEC estimated closer to 40 million metric tons per year for the total from refineries in the state. Thus the GHGs from just this partial list of only one process within refineries represents an added 15-20% in GHGs. More refineries are planning and building new fossil fueled hydrogen plants and increased plant capacity throughout the state. Without addressing such major increases in refinery GHGs in the state, we will not be able to make progress in reducing GHG emissions. The information below should be updated and evaluated for all refineries:

Examples of CA Refinery Hydrogen Plant Expansions since 1999 (not comprehensive) (million standard cubic feet)	Approximate CO2 Emissions Increases for these sources (metric tons per year)
2007 ConocoPhillips Rodeo --120 MMscf	at least 1,250,000
2007 Chevron Richmond -- 100 MMscf	at least 900,000
2007 Valero Benicia – unknown MMscf	≈ 860,000 **
2003 Chevron El Segundo -- 90MMscf	≈ 940,000*
1999 Air Products Wilmington for area refineries -- 96 MMscf	≈ 1,000,000*
1996 Air Products for Ultramar, Wilmington --83 MMscf	≈ 860,000*
493 MMscf (million standard cubic feet)	≈ at least 5.8 million metric tons per year

* CO2 emissions not yet available, estimated based on plant hydrogen capacity and assumption that emissions are approximately proportional to ConocoPhillips CO2 from Final EIR. This may underestimate emissions. For example, Chevron may be oversizing hydrogen plant for exporting, and not including these CO2 emissions in total. ConocoPhillips may be as well.

** Planned Valero Benicia facility's size is currently unknown – used the smallest size above as approximation

Refinery Boilers and Heaters are major sources of the energy use within refinery processing units that should be a first priority for requiring BACT. There is a wide variation in the efficiency and emissions of Boilers and Heaters at refineries in California. Many boilers and heaters in California refineries are extremely old and have “grandfathered” permitting requirements exempting them from meeting more modernized NOx emissions standards. If refineries were required to meet strong NOx standards across the board, they would also have reduced CO2 emissions because these units are so inefficient. Furthermore, if BACT standards for heaters and boilers were required, further major

reductions could be achieved. Boilers and heaters are such large sources because they fuel the refining process and operate continuously, not intermittently.

Cogeneration to capture refinery waste heat

Oil refineries are a large source of cogeneration in the state, but there is still a great additional potential for capturing waste heat and other waste at oil refineries in order to increase efficiency.

5.10 Power Generation

The petroleum refining industry is one of the largest users of cogeneration or Combined Heat and Power production (CHP) in the country. **The petroleum refining industry is also identified as one of the industries with the largest potential for increased application of CHP. We estimate installed CHP capacity in Californian refineries at at least 1400 MWe.**⁴

Cogeneration has the potential to capture waste energy and increase refinery efficiency, but since it introduces complex interactions with electric Power Plants, care is needed in evaluating the relative efficiency of refinery cogeneration compared to other sources, as well as any environmental impacts associated with cogeneration at refineries. The key is to capture waste energy without introducing new sources of combustion at the refinery or otherwise increasing environmental impacts. BACT standards must be in place.

Reducing the need at refineries for grid electricity can increase reliability of electric power available to the refinery, which reduces risk of power outages causing emergency refinery shutdowns. Power plant outages and emergency shutdowns at refineries have caused major flaring, resulting in GHG emissions and major local impacts from hydrocarbon, SOx emissions, and very large plumes of black smoke (particulate matter). These impacts were exacerbated when several refineries shutdown simultaneously in the South Coast region, with neighbors reporting respiratory impacts and sickness for days following one event.

The South Coast Air Quality Management District (SCAQMD) presented the following table during a flare working group meeting in 2006. This table showed which refineries in the South Coast had high, medium, and low risk of power outage and increased risk of flaring. It also listed quantities of fossil-fuel based grid electricity used by these oil refineries.⁵

⁴Ibid, page 45, Units MWe are electrical megawatts, as opposed to thermal megawatts

⁵ South Coast Air Quality Management District, Rule 1118 Working Group Meeting, October 26, 2006

REFINERIES AND ROTATING POWER OUTAGE RISKS*

Company	Location	Operating Crude Oil Atm Dist Capacity (MBPSD)	Electric Utility Service Area	Estimated Electricity Demand (MW)	Cogen Capacity (MW)	Number of Cogen Units	Cogen vs Demand - Cogen Coverage (%)
HIGH RISK							
ExxonMobil	Torrance	160	SCE	94	42	1	44.8%
Conoco-Phillips	Carson	137	SCE	26	0	0	N/A
MODERATE RISK							
Chevron	El Segundo	273	SCE	108	138	2	127.8%
Shell	Wilmington	100	SCE	58	60	2	103.4%
LOW RISK							
BP	Carson	260	SCE	82	331	1	403.5%
Ultramar	Wilmington	79	LADWP	37	0	0	N/A
Conoco-Phillips	Wilmington	0	LADWP	47	59	1	124.5%
UNDEFINED RISK							
Paramount	Paramount	48					

<http://www.scaqmd.gov/airquality/stan/pwk/airqa/airqaform1.htm#1>

In this presentation, SCAQMD concluded that: “Commercial power usage increased 67% from 79,691 megawatt-hours in 1990 to 117,573 megawatt-hours in 2004.” This indicates that not only are refineries responsible for more fossil fuel emissions (from power plants), but also that they are becoming more vulnerable to power outages. (Also see additional comments on flaring later in this comment letter.)

Remove all methane exemptions from smog regulations

As an Early Action Measure under AB32, CBE proposed the removal of methane exemptions in smog regulations, which are currently allowed by Air Quality agencies throughout the state (and also throughout the nation). While the ARB did not accept removing the exemptions as an Early Action Measure, staff did recommend in the Final Report that removing the exemptions was feasible and should be considered as part of the Scoping Plan process under AB32.

The definition of VOCs (Volatile Organic Compounds) in smog precursor control regulations exempts methane in most cases. The following examples of regulations in different regions in the state include the SCAQMD, the BAAQMD, and the SJVAPD.

SCAQMD:⁶

VOLATILE ORGANIC COMPOUND (VOC) is any volatile compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, ammonium carbonate, and exempt compounds.

ORGANIC MATERIAL means a chemical compound of carbon excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides, metallic carbonates and ammonium carbonate.

BAAQMD:⁷

1-233 Organic Compound: Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate.

SJVUAPCD:⁸

⁶ SCAQMD Regulation 1, General Provisions, Rule 102, Definition of Terms (Amended Dec 3, 2004)

⁷ BAAQMD Regulation 1 General Provisions and Definitions (Adopted March 17, 1982)

3.53 **Volatile Organic Compound (VOC):** any compound containing at least one (1) atom of carbon **except for the following exempt compounds:**

- **Methane** (Many other compounds which are non-smog precursors are also listed as exempt.)

The methane exemption can no longer be justified for oil refineries, other stationary sources, or any pollution source in the state. Methane is not only a highly potent greenhouse gas (23 times more potent than CO₂), it is also a key smog precursor (for ground-level ozone), and its reduction is highly effective in reducing smog. A Harvard study, *Linking ozone pollution and climate change: The case for controlling methane*⁹ found:

“Methane (CH₄) emission controls are found to be a powerful lever for reducing both global warming and air pollution via decreases in background tropospheric ozone (O₃)”

This study was summarized as follows in *Environmental Science and Technology*¹⁰:

“Aggressive efforts to improve urban air quality could be undermined by rising levels of methane, a compound more closely linked to global warming than air pollution. Using a global model of tropospheric chemistry, researchers at Harvard University, Argonne National Laboratory, and the U.S. EPA determined that higher methane levels could increase ozone background levels worldwide, lead to a greater frequency of days with high ozone levels in the summer, and produce a longer “season of ozone pollution days.”

“It is already known that methane is a major source of worldwide tropospheric ozone background concentrations, and this study supports that finding. However, the surprise is that a 50% reduction in anthropogenic methane in their scenario is as effective as a 50% drop in anthropogenic NO_x concentrations at lowering summer afternoon ozone levels over the United States.” (page 452A)

NOAA (National Oceanic and Atmospheric Administration) also found:¹¹

**Linking climate and air pollution:
Methane emission controls yield a double dividend**

An important area of research at GFDL is investigating the contribution of methane to surface ozone pollution, and quantifying the potential benefits to air quality and climate from controls on methane emissions. **Methane is both a greenhouse gas and an important contributor to background levels of ozone. Tropospheric ozone, a significant greenhouse gas and the primary constituent of photochemical smog, provides an obvious link between air quality and climate.**

There is no longer any reason for exempting this pollutant from smog regulations. Excluding accounting of methane from smog precursor emissions also makes VOC controls look less cost-effective than they actually are in reducing smog.

To begin to quantify methane as identified in regional air quality plans in criteria pollutant emissions categories, an excerpt of California's 2002 statewide criteria inventory summary table from ARB is excerpted below. This table includes organic compound emissions in both TOG (Total Organic Gases) and VOCs (Volatile Organic Compounds). The year 2002 was chosen because it is the latest year that included both TOG and VOCs. Later inventory years did not provide TOG, but just VOCs.

⁸ SJVUAPCD Rule 1020, Definitions., 6/17/99

⁹ Fiore, et al. 2002. Harvard University. <http://www.agu.org/pubs/crossref/2002/2002GL015601.shtml>

¹⁰ Environmental Science & Technology. December 2002, http://pubs.acs.org/subscribe/journals/esthag-w/2002/oct/science/an_methanelink.html

¹¹ http://www.research.noaa.gov/spotlite/2006/spot_methane.html

2002 Statewide Inventory: Table 2-1 Summary (tons per day)¹²

Division	TOG	ROG
Major Category		
Stationary Sources	2535	538
Fuel Combustion	215	49
Waste Disposal	1447	23
Cleaning And Surface Coatings	344	237
Petroleum Production And Marketing	450	164
Industrial Processes	79	65
Area-Wide Sources	2027	698
Solvent Evaporation	521	463
Miscellaneous Processes	1506	235
Mobile Sources	1530	1406
On-Road Motor Vehicles	1019	938
Other Mobile Sources	511	467
Natural Sources**	106	38
Total Statewide - All Sources	6198	2680

For example, three categories of Stationary Sources listed above (Fuel Combustion, Petroleum Production and Marketing, and Industrial Processes) add up to 744 ton per day (tpd) TOG and 278 tpd VOC, and the difference between these two is 466 tons per day (about 170,000 tons per year). The difference between TOG and VOCs includes exempt organic gases, and in this category, the difference is likely to be made up mostly of methane. If the difference is entirely methane, this is equivalent to almost 4 million US tons per year CO₂Eq just for these categories. (This number is likely underestimated since exempt methane emissions receive less scrutiny.) This category of stationary source methane emissions is a significant source of GHGs, but also a huge source of unregulated smog precursors from only these three categories.

To capture the dual benefit of eliminating or greatly reducing these emissions, the organic compound definitions in the state for all smog regulations need to be modified to remove the exemption for methane. The state should require all regional air quality agencies in California to immediately begin reopening all smog regulations to remove methane exemptions, and to complete this by the most expeditious date. **Furthermore, all new smog regulatory proceedings in the state should be immediately required to include evaluation of removal of methane for each of these regulations.** In the case of such rules that are already in the process of modification, there is no need for any delay evaluating how to remove the methane exemptions. We understand that the state and regional Air Quality Management agencies are now beginning to discuss removing this exemption.

¹² The 2003 California Almanac of Emissions and Air Quality, (page 49), <http://www.arb.ca.gov/aqd/almanac/almanac03/chap203.htm>

No dumping of waste gases through venting or flaring should be allowed

Control Pressure Relief Devices (PRDs) and other venting to atmosphere

While PRDs are necessary for safety to ensure that pressure inside vessels does not get too high, most PRDs do not need to vent to the atmosphere. PRDs can be controlled to vent to refinery gas recovery systems where the gases are recycled as fuel in the refinery.

PRDs are designed to release large volumes of gases within minutes, increasing smog, GHGs, and representing a local health hazard and public nuisance especially because of H2S emissions. Some refineries have most of their PRDs connected to gas recovery systems. Other refineries have half or more PRDs vented to atmosphere. Better practices have been carried out by some refineries, demonstrating their feasibility for all refineries.

The SCAQMD found a large difference in refineries in the number of PRDs designed to vent directly to atmosphere (shown in this excerpt from an SCAQMD presentation).¹³ BP had 592 out of the 770 total of PRDs dumping to atmosphere in the District, far more than the other South Coast refineries. At last count, roughly *half* of Bay Area refiners' PRDs were uncontrolled, although retrofits are distributed unevenly between these refineries as well, as should be expected, since an uncontrolled PRD is antiquated technology.

Atmospheric PRD Inventory

Facility	No. of Atmospheric PRDs (as of 2005)
BP	592
Chevron	49
ConocoPhillips, Carson	15
ConocoPhillips, Wilmington	8
Edgington	14
ExxonMobil	35
Lunday Thagard	9
Shell Equilon	40
Valero	8
TOTAL	770

5

PRD monitoring has historically been very poor. (Many refineries have admitted that they detected PRD releases by sound rather than through actual monitoring!) Because of this, annual inventories of emissions are very incomplete, but new regulations in the Bay Area and South Coast are beginning to improve monitoring. Dumping to the atmosphere should be considered a bad engineering practice and banned, and companies should not be allowed to avoid control through pay-to-pollute schemes allowed in the South Coast. Requiring controls and electronic monitoring will not only reduce GHG emissions but also reduce large episodic emissions of smog precursors and harmful toxics.

¹³ Proposed Amended Rule 1173, Control of VOC Leaks and Releases from Components at Petroleum Facilities and Chemical Plants, Working Group Meeting, March 13, 2007, SCAQMD slideshow

Although PRDs do not vent continually, one PRD can vent over 100 tons of VOCs in one day (even in minutes) including emissions of methane, other VOCs, and H₂S. While these emissions are episodic, the potential to emit is large because there are over a thousand of them at oil refineries in the state. Venting of these devices has been poorly tracked in the past, and emissions very likely underestimated. PRD emissions can cause large spikes in smog precursor emissions on days when they vent; they are a source of direct dumping of methane to the atmosphere. Both for purposes of controlling GHGs and especially to protect public health, these devices should be required to vent to gas recovery systems throughout the state. There is a potential for increased emissions from these sources as refineries ramp up production, and do more intensive refining of heavy crude, increasing the risk of frequent upsets. Requiring all refineries to meet the same BACT standards for PRDs will reduce public health risks, smog precursors, and GHG emissions together.

Evaluate other venting to atmosphere

Refinery energy audits should include not only the refinery's steady state emissions, but should also evaluate:

- Frequency of upsets (which can increase emissions and hazards to neighbors and workers)
- Startup/shutdown and maintenance emissions
- Vessel Depressurization, when some part of gases in vessels are uncontrolled and vent to atmosphere
- Unusual operations (one refinery had uncontrolled blowdown systems with no attached flare, and these dumped directly to atmosphere)
- Tank cleaning that could cause large evaporation on an episodic basis
- Other direct dumping either during emergency conditions or on a regular basis should be identified and prevented
- Best Practices for preventing dumping to atmosphere
- Corrosion and other increased process intensity and decreased process stability impacts of refining lower quality crude and intermediate products

Apply BACT/LAER to Refinery Flares (beyond existing regulations)

Flaring should be limited true emergencies. Planned flaring, and repeated malfunctions that cause flaring from preventable emergencies should trigger enforcement that will prevent flaring from these causes. Flares emit CO₂, methane, other VOCs, sulfur compounds that are known to exacerbate asthma and other breathing impacts, and toxics. While California flare controls have improved substantially due to regulations adopted in the Bay Area and South Coast following strong public pressure, there remain major differences in flaring emissions between different refineries in the state. ARB should require statewide flare standards that meet at least the Shell Martinez BACT/LAER (Best Available Control Technology / Lowest Achievable Emissions Rate) performance standard.

The Shell refinery in Martinez, California has demonstrated sustained and drastically lower emissions compared to other refineries in the state through methods including dedicated backup compressors, a rigorous Flare Minimization Plan, and methodical follow-up after any flaring event through root cause analysis and action to ensure that the cause for each flaring event will not recur. While other refineries in California have prepared Flare Minimization Plans and root cause analysis, they have not been carried out to the degree that Shell has achieved in Martinez, as demonstrated through flare monitoring data.

Flaring levels achieved by Shell in practice should be considered the minimum BACT/LAER for flaring, and further reductions may be achievable. Since Shell has demonstrated in practice much lower flaring levels, these should be required for all refineries in the state. This will further reduce flaring in the Bay Area and the South Coast, and also will capture emissions from the remaining refineries in the state outside these regions. (See Shell's flaring emissions, available at BAAQMD website for current and previous years.¹⁴) In addition, Hydrocarbon Processing has published an account of very low or zero flaring at a refinery in Texas.¹⁵ Performance standards at this facility should also be evaluated to determine whether this facility represents BACT/LAER, and represents an improvement over the Shell Martinez performance.

Flaring is not the largest source of GHGs at oil refineries, but it is a significant source of GHGs and a large source of VOCs and SOx emissions that represent local and regional health risks. Despite the newer flare regulations, flaring emissions in the state have a great potential for increasing. This is because of increased risk of upset due to refinery expansions and more intensive refining to handle dirtier crude oil. Heavier, dirtier, more intensive refining means increasing volumes and concentrations of toxic, corrosive gases such as sulfur compounds in refineries; it means increasing process instability and upsets, and it also means dirtier flaring events.

The expansion of refineries and introduction of heavy, high-sulfur crude oil increases the risk of flaring and the quantities of SOx, VOCs, NOx, CO, PM2.5, and toxic emissions. See CBE report *Flaring Prevention Measures*.¹⁶ This report evaluated in great detail BAAQMD flare data reported by the refineries and Flare Minimization Plans, and found that refinery processes required for heavier crude slates caused more flaring and caused dirtier flaring than other refinery processes. The report found:

Dirty crude refining can increase flare pollution in similar ways. It produces more gases from the expanded catalytic cracking, hydrocracking and coking that make vehicle fuels from the increased volumes of gas oil and heavy ends. This is because of the increased volumes cracked in these processes and because cracking reactions produce gases as well as fuel-sized hydrocarbons. Dirty crude may also produce more gases from distillation. See Figure 4. The bigger gas volumes will have higher concentrations of sulfur and other pollutants. See Table 13. Dirtier processes will flare more, and dirtier, unless more gases are recovered and reused. (page 17)

In addition to being a significant source of GHGs, flaring in the South Coast represented **more than half of the refinery SOx emissions**, making flaring a severe source of emissions of compounds associated with local health impacts including asthma and other respiratory diseases. Statewide

¹⁴ <http://www.baaqmd.gov/enf/flares/>

¹⁵ *Minimize facility flaring, Flares are safety devices that prevent the release of unburned gases to atmosphere*, J. Peterson, Flint Hills Resources, et al, Hydrocarbon Processing,

http://www.johnzink.com/products/flares/pdfs/flare_hydro_proc_june_2007.pdf

¹⁶ *Flaring Prevention Measures*, Communities for a Better Environment (CBE), Greg Karras, April 2007, attached

requirements that flaring meet BACT/LAER performance standards at least as stringent as Shell Martinez will secure further improvements in reducing local SO_x and VOC emissions, reduce GHG emissions, and prevent increases due to expansions and heavy crude introduction.

2. Stop refinery expansions & the switch to dirty crude oil

- No new fossil fueled Hydrogen Plants, cokers, etc.
(only possible without heavy, dirty crude oil inputs)
- Low Carbon Fuel Standard for Refineries
- Limit on heavy, contaminated crude and pre-processed unconventional oil input
- Carbon tax on refineries
- Windfall profit tax to fund clean alternative energy

Heavy crude oil means long hydrocarbon chains which require more cracking and coking, and this high carbon crude oil is typically associated with higher sulfur content. (Also see earlier section on refinery energy use.) This means that refineries switching to heavier crude stocks must build new hydrogen plants, additional cracking capacity to crack the long hydrocarbon chains into gasoline, more coking and bottom of the barrel processing, more hydrotreating to remove sulfur compounds to meet low sulfur gasoline and diesel standards, and more sulfur recovery units. All of these operations require greatly increased energy use by the refineries. (See list page five showing the biggest energy users at refineries, which include these types of units). This much greater energy use means much greater CO₂ emissions. **Unfortunately, we are going strongly in the wrong direction in this state as far as GHG emissions from oil refineries.** The increased sulfur at the refineries also increases the risk to neighbors of upsets that cause asthma attacks and other respiratory impacts.

Given that the state is in the process of adopting a Low Carbon Fuel Standard, this move towards higher carbon inputs to refineries must not be allowed. It is true that lighter crude oils are becoming more expensive, and use of heavy crude oils represents much cheaper inputs. Carrying this to an extreme, use of the heaviest crude oils (Canada Tar Sands) is increasing drastically at U.S. refineries, and refiners also want to introduce this dirty crude source into California. This trend is a clear and present threat to climate protection given that the billions of dollars in proposed refinery equipment tooled for unconventional oil would be locked in place for decades once built.

The state needs to perform a statewide evaluation on the alternatives to use of dirty, high carbon crude oil in the state, including a step-by-step reduction in the demand for refinery products through rigorous fuel efficiency and alternative fuels programs. A windfall profits tax for oil refineries could help fund such a switch, so that instead of expanding refineries and increasing their energy intensity, we develop a detailed planning for reducing their output and impact over time. A few decades ago, an economic analysis for power plants found that they could actually make more money by investing in conservation instead of building more plants. Companies like Dow Chemical and Dupont actually made windfall profits from phasing out ozone depleting chemicals. We need a detailed, comprehensive plan that specifically calls for reducing the need for and the outputs of oil refineries in California. This is achievable through available means, as discussion in a later section of this comment, and can be funded through a carbon tax and windfall profits tax on the oil industry.

The California Low Carbon Fuel Standard requirement in development requires:

“The California Executive Order S-1-07(issued on January 18, 2007), calls for a reduction of at least 10 percent in the carbon intensity of California's transportation fuels by 2020. . . . In response, ARB identified the LCFS as an Early Action Measure with a regulation to be adopted and implemented by 2010.

The LCFS requires a reduction of 10 percent or greater in the average fuel carbon intensity (the “*AFCI*”) [*Average Fuel Carbon Intensity*] of transportation fuels in 2020 compared to the baseline year of 2006, with a phase-in period from 2010 through 2019.”¹⁷

The LCFS needs to be defined and adopted so as to rigorously evaluate the modifications being made to refineries which enable the use of high carbon, heavy crude oil in refineries. It appears from the recently-released partial draft proposal that LCFS will use averages allowing refineries with increasingly heavier crude oil inputs to average carbon intensity and thus underestimate actual carbon intensity. Furthermore facilities with lower carbon intensity inputs appear to be allowed to bank credits if they overcomply. This leads to an inaccurate assessment which makes it appear that the state's refinery fuel products have lower carbon intensity when in reality they are much higher in intensity. Care must also be taken in assessing baselines so as not to build in an inflated baseline assuming high carbon crude oil.

The switch to heavy crude oil is a major contributor to GHGs and increased public health risk as discussed above. Some of the State's own low carbon fuel standards development experts have observed that: “these fuels are physically of lower quality, and exist naturally in less useful form than conventional oil, and thus are likely to have an excess of emissions even in the presence of technological progress.”¹⁸ Stopping this switch should be a major priority of the state to preclude this move toward building high carbon fuels from oil refineries into the state's infrastructure for many decades to come. Much more evaluation will be needed as this regulation develops. Pollution trading should not be allowed as a replacement for actual limits on carbon in the states' fuels.

It also appears that the LCFS may justify increased carbon intensity in oil refinery products (gasoline) by adding corn-based ethanol to gas and averaging the output. If this were to happen, such averaging would not include the full cradle-to-grave accounting of the carbon input caused by trucking heavy corn across the country and other energy use put into corn production. Biofuels plants in the Central Valley are a heavy industry, causing severe local impacts, and increasing smog and water pollution. Furthermore, the introduction of ethanol as an MTBE replacement in gasoline has been estimated to add 20 tons per day in VOC emissions to the South Coast due to permeation through vehicle seals, gaskets and lines, increasing fugitive emissions greatly. The South Coast cannot afford this major increase in smog precursors. Similar high impacts will occur throughout the state. Asthma is already an epidemic in the state, and any LCFS evaluation of introduction of corn ethanol must take into account the true carbon input and the health and environmental impacts. This source must also not

¹⁷ Email notice to listserve on Concept Outline for the California Low Carbon Fuel Standard Regulation, March 20, 2008, from , John Curtis - Manager, Alternative Fuels Section, ARB, <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm>

¹⁸ *Scraping the bottom of the barrel: Greenhouse gas emission consequences of a transition to low-quality and synthetic petroleum resources*, Climate Change (Journal), Brandt and Farrell, Energy and Resources Group, University of California, Berkeley, 2007, Abstract at <http://www.springerlink.com/content/y283j2220jj365g4/> (Full article attached)

be used to justify heavier crude oil at refineries. The LCFS standard is still in development, and care must be taken not to allow these impacts.

3. Switch refinery electricity use to clean energy

Currently oil refineries use significant amounts of electric energy off the grid, from fossil-fueled power plants. Requiring that oil refineries contract with and switch to clean alternative energy sources while not directly reducing emissions at the oil refinery site, would reduce emissions that contribute significantly to Power Plant GHGs, smog precursors, and toxics. The following graph illustrates electrical energy purchases and generation by petroleum refineries from 1988-2001:

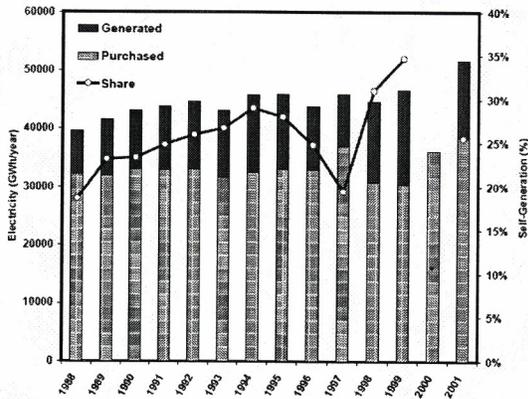


Figure 16. Electricity purchases and generation by petroleum refineries from 1988 till 2001. On the right-hand axis the share of self-generation is expressed as function of total power consumption. Source: U.S. Census, Annual Survey of Manufacturers.

(page 26)

Fossil-fueled grid electrical energy use at oil refineries results in many tons per day of local air pollution and very large GHG emissions which should be required to switch to clean alternative energy.

Oil refineries use substantial amounts of electricity which is generated at power plants by burning fossil fuels. These emissions occur near the power plants, but also cause regional smog and GHGs. Also, when reliability problems bring down the electrical grid, oil refineries shut down, causing upset conditions and huge air emissions near the oil refineries. Such events occurred in the fall of 2005, causing major flaring at several oil refineries in the South Coast region and in the Bay Area in 2002.

Alternative energy sources including wind and solar energy are now readily available and viable alternatives for replacing fossil-fuel electricity generation used at oil refineries. Such alternatives need to be evaluated and required statewide. Refineries frequently have open land where such alternatives can be put in place by the refineries. Refineries are already required to evaluate feasible alternatives

under CEQA (the California Environmental Quality Act), and although we have commented on the feasibility of clean alternative electricity to replace grid electricity for refinery projects (such as the ConocoPhillips Rodeo expansion) refineries have failed to do such clean electricity alternatives analysis in their Environmental Impact Reports. Requirements under CEQA that refineries evaluate and implement feasible clean alternative electricity sources should be enforced statewide, and evaluation and standards set by the state should also be done independently from CEQA.

If the oil refineries in the South Coast example in the table on page eight were to replace either the percentage of electricity not covered by cogeneration capacity (115 megawatts - MW), or to replace all the electrical demand (452 MW) by clean alternative energy regardless of cogeneration capacity at the refineries, electricity not generated through fossil fuels at these facilities would result in many tons per day of emissions reductions calculated below.

Information is available on emissions caused by power plants generated per megawatt hour. For example, PG&E published its 2002 Environmental Report online¹⁹ which provides estimations of air emissions associated with generation of electrical energy. A table from the report is provided below, with air emissions in terms of pounds per megawatt-hour of energy. The two columns at the right are added to calculate daily emissions by power plants generating 115MW or 452MW.

From PG&E 2002 Environmental Report

	Pounds per megawatt-hour of electricity produced	<u>Added Columns, calculating total tons/day using PG&E lbs/MW-hr:</u> Emissions in 24 hours for 115 and 452MW electrical energy needed from fossil-fueled power plant for the South Coast oil refineries	
<i>Emissions Rates</i>	PG&E Corporation*1	115 MW or 2760 MW-hours per day	452MW or 10,848 MW-hours per day
SO2 Fossil-Fuel Units Only	3.2	4.4 tons/day	17.4 tons/day
NOx Fossil-Fuel Units Only	1.3	1.8 tons/day	7.1 tons/day
CO2 Fossil-Fuel Units Only	1,454	>730,000 US tons/year	>2.8 million US tons/year

1. Emissions rates for 2002 * Pounds per megawatt-hour of electricity produced

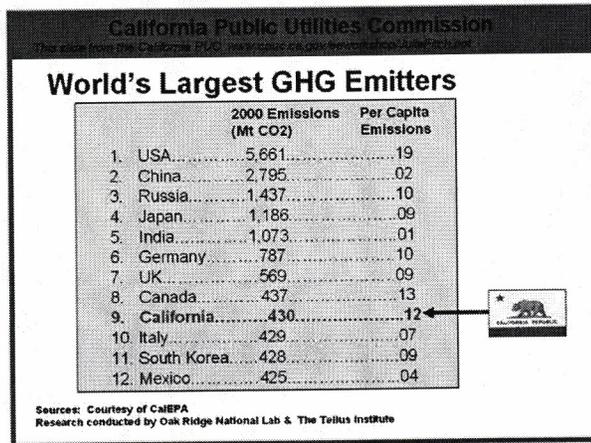
¹⁹ PG&E 2002 Environmental Report, 2002 Performance Results, Air Emissions: NOx, SO2, Mercury, and Greenhouse Gases, available at http://www.pgecorp.com/corp_responsibility/environmental/report/2002/perf_results/02.html

In a 24-hour period, refineries in the South Coast alone use 115 MW of electric energy continuously from fossil-fueled power plants, resulting in 4.4 tons per day of SOx emissions and 1.8 tons per day of NOx emissions, according to the data above. The total electrical energy use in the South Coast basin refineries of 452 MW continuously results in 17.4 tons/day of SOX emissions and 7.1 tons per day of NOx emissions. This calculation assumes that emission rates at the power plants in the state generating this electricity are similar to PG&E's, but national average pollution rates were even higher. Either way, the large air emissions caused by fossil fuel generation at Power Plants due to oil refinery electricity demand is worthy of phaseout requirements by the SCAQMD and other air quality management agencies throughout the state.

These calculations do not include VOC, CO, mercury emissions, methane, and SF6 (sulfur hexafluoride) emissions, also identified by PG&E's report. The emissions probably do not represent peak electricity use, which causes higher emissions. Clearly, refinery electrical energy use is a large source of GHG emissions.

4. Reducing demand over the medium term for California Oil Refinery Products is feasible and should be identified as a specific goal with a deadline under AB32

California emits as much GHG as many countries:



It is no longer possible to pretend that better technology alone at large industrial GHGs emitters like refineries can solve the problem of industrial GHG, smog precursor, and toxic emissions. Direct regulatory controls requiring BACT at refineries and specific plans for reducing the demand for oil refinery products are needed to make real progress. Stopping the disastrous trend to higher carbon inputs and refinery expansion is needed, with a specific plan to reduce oil refinery product demand with deadlines, percent reductions, and a map to get there. The following readily available methods are examples of ways to get big savings in the use of refinery products and to decrease energy use in

general. These methods preclude the need for refinery expansions and reduce demand at oil refineries as they are implemented. These can be included in the AB 32 process:

- **CAFE Standards:**

- If the U.S. increased fuel economy to 45% higher miles per gallon using cost-efficient techniques, we'd save over 50 billion gallons of gasoline/year. (National Academy of Sciences²⁰)
- This is equivalent to saving about 3 1/3 Californias worth of gas use each year (California used about 15 billion gallons per year in 2003).²¹
- Increasing fuel efficiency of cars & trucks by only 3 miles per gallon can save > 1 million barrels of oil / day or five times the amount of Arctic Refuge might produce.²²

- **PLUG IN HYBRIDS:**

- For each mile driven on electricity instead of gasoline, CO2 emissions would be reduced 42% on average in the US (although this advantage could be hurt by coal-generated electric power plants)²³
- Plug-ins encourage development of renewable electricity because of they provide distributed battery storage.
- Running a plug-in would reduce average fuel cost by about half, (based on a price of \$2.77/gallon for gasoline (Sept 2005) and 8 cents per kWh for electricity, (Jan 2006)).

- **CLEAN ELECTRICITY:**

- 80 GigaWatts of CSP could be economically deployed by 2030 (about 200 times today's US capacity) in the Southwest US.²⁴
- "Analysis suggests that 10% of electric grid energy by 2030 could be supplied by PV without creating grid management issues." (Equivalent to 275 GW in the US)²⁵
- Wind capacity in the US was found to be at least 245 GW, but higher amounts are possible if storage is available

- **SHIPPING EFFICIENCY IMPROVEMENTS:**

- Shipping uses about 5% of global oil consumption
- Reducing ship drag due to hull fouling has been found to result in at least 10% reduction in fuel use, which saves both money and reduces GHG and criteria

²⁰ *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards*, National Academy of Sciences, 2002

²¹ *Market Power in California's Gasoline Market*, University of California Energy Institute, Center for the Study of Energy Markets, 2004, page 4, <http://repositories.cdlib.org/cgi/viewcontent.cgi?article=1035&context=upei/csem>

²² According to the Arctic Refuge Defense Campaign, <http://www.arcticrefuge.org/>

²³ *Tackling Climate Change in the U.S.: Potential Carbon Emissions Reductions from Energy Efficiency and Renewable Energy by 2030*, American Solar Energy Society, Charles F. Kutscher, Editor, January 2007, <http://www.ases.org/climatechange/toc/exec-summary.pdf>

²⁴ Ibid.

²⁵ Ibid.

pollutant emissions.²⁶ Shipping in California may represent a larger portion of California's total consumption compared to the global average.

- Electrification of ports through alternative energy to replace the use of high carbon bunker fuel will reduce health risks for neighbors near ports and GHG emissions from the current use of bottom-of-the-barrel bunker fuel.

²⁶ *Fuel Conservation Through Managing Hull Resistance*, Motorship / BIMCO Propulsion Conference, Copenhagen April 26th, 2006, By: Torben Munk, M.Sc., Propulsion Dynamics Inc. (PDI), <http://www.cleanhull.no/doc/PDF%20files/Fuel%20Conservation%20-%20CASPER.pdf>

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Best Available Control Technology (BACT) Guideline 3.4.4

Last Update: 4/5/2001

**Limited Use (< 877 hours per year) Gas Fired Turbine = or < 26 MW,
without Heat Recovery**

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	PUC quality natural gas.	1. 90 % control efficiency (SCONOx, or equal). 2. 71% control efficiency (Oxidation catalyst, or equal)	
NOx	42 ppmvd @ 15% O2 (Water injection system, or equal).	1. 2.5 ppmv NOx @ 15% O2 (SCR, SCONOx, or equal). 2. 15 ppmv @ 15% O2 (Dry low NOx Combustors, or equal). 3. 25 ppmv @ 15% O2 (Dry low NOx Combustors, or equal).	
PM10	Natural gas, air intake filter, and a maximum lube vent exhaust visible emissions of 0% opacity with either • a lube oil coalescer, • a lube vent high efficiency particulate filter , or • a lube vent routed to the turbine or exhaust for oxidation.		

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
SO _x	PUC quality natural gas.		
VOC	PUC quality natural gas with fuel oil #2 as backup.	1. 90 % control efficiency (SCONO _x , or equal). 2. 71% control efficiency (Oxidation catalyst, or equal)	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

This is a Summary Page for this Class of Source. For background information, see Permit Specific BACT Determinations on Details Page.

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Best Available Control Technology (BACT) Guideline 1.4.8

Last Update: 9/1/2006

Refinery Flare

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	<p>Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases.</p>	<p>Engineered flare or enclosed burner with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls, and having demonstrated emissions of NOx of less than 0.068 lb/MM Btu. Flare shall be equipped with a flare gas recovery system for non-emergency releases.</p>	
NOx	<p>Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases.</p>	<p>Engineered flare or enclosed burner with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls, and having demonstrated emissions of NOx of less than 0.068 lb/MM Btu. Flare shall be equipped with a flare gas recovery system for non-emergency releases.</p>	

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
PM10	<p>Engineered flare designed for and operated without visible emissions, except as allowed by 40CFR 60.18(c)(1) and District Rule 4101 and equipped with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.</p>		
SOx	<p>Flare shall be equipped with a flare gas recovery system for non-emergency releases. Pilot and purge gas shall be natural gas, treated refinery gas or LPG.</p>		
VOC	<p>Engineered flare designed with a VOC destruction efficiency of = 98%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District</p>	<p>Enclosed ground level flare or any other engineered flare designed with a VOC destruction efficiency of = 98.5%. Flare design shall include air or steam assisted combustion, staged</p>	

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
	approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.	combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG.	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

This is a Summary Page for this Class of Source. For background information, see Permit Specific BACT Determinations on Details Page.

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Best Available Control Technology (BACT) Guideline 1.8.2 D

Emissions Unit:	Refinery Process Heater, Refinery Fuel Gas and/or Natural Gas	Equipment Rating:	641 and 215 MM Btu/hr
Facility:	Big West of California LLC	References:	S-33-407-0 and '411-0
Location:	Bakersfield	Date of Determination:	9/1/2006
Pollutant	BACT		
CO	10 ppmv @ 3% O2 (SCR and burner tuning)		
NOx	5 ppmv at 3% O2, (15 minute average) (Low NOx burners and SCR)		
PM10	Treated refinery gas and/or natural gas with no more than 100 ppmv total reduced sulfur (3-hour rolling average)		
SOx	Treated refinery gas and/or natural gas with no more than 100 ppmv total reduced sulfur (3-hour rolling average)		
VOC	Good combustion practices		

BACT Status	Comment
Achieved in Practice	VOC, NOx, SOx and CO
Technologically Feasible BACT	PM10

Best Available Control Technology (BACT) Guideline 1.8.2 C

Emissions Unit:	Process Heater - Refinery	Equipment Rating:	All
Facility:	Equilon Enterprise	References:	ATC #: Withdrawn Project #: S-990010
Location:	Bakersfield	Date of Determination:	1/4/2001
Pollutant	BACT		
CO	BACT NOT TRIGGERED		

Pollutant	BACT
NO _x	BACT NOT TRIGGERED
PM ₁₀	BACT NOT TRIGGERED
SO _x	Natural gas or treated refinery gas @ 0.0621 grains H ₂ S/dscf (100 ppmv H ₂ S)
VOC	BACT NOT TRIGGERED

BACT Status

Comment

Achieved in Practice

Best Available Control Technology (BACT) Guideline 1.8.2 B

Emissions Unit:	Process Heater - Refinery	Equipment Rating:	= or > 50.0 MMBtu/hr
Facility:	n/a	References:	District Proactive BACT Determination
Location:	n/a	Date of Determination:	6/30/1999

Pollutant	BACT
------------------	-------------

CO	BACT NOT TRIGGERED
NO _x	9.0 ppmvd @ 3% O ₂ (0.0108 lb/MMBtu) SCR
PM ₁₀	BACT NOT TRIGGERED
SO _x	BACT NOT TRIGGERED
VOC	BACT NOT TRIGGERED

BACT Status

Comment

Achieved in Practice

Best Available Control Technology (BACT) Guideline 1.8.2 A

Emissions Unit:	Process Heater - Refinery	Equipment Rating:	92 MMBtu/hr
Facility:	Equilon Enterprises LLC	References:	ATC #: S-33-17-7 Project #: S-981236

SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT

Final Staff Report: Update to BACT Cost Effectiveness Thresholds

May 14, 2008

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

FINAL STAFF REPORT

Update to Rule 2201 Best Available Control Technology (BACT)

Cost Effectiveness Thresholds

May 14, 2008

Prepared by: Ben Ellenberger, Air Quality Engineer
Leonard Scandura, Supervising Air Quality Engineer

Reviewed by: David Warner, Director of Permit Services
Carlos Garcia, Senior Air Quality Engineer

*I thought
it was interesting
& may be useful
to you*

I. Summary

The current Rule 2201 Best Available Control Technology (BACT) cost effectiveness thresholds were incorporated into the San Joaquin Valley Air Pollution Control District's (SJVAPCD) BACT policy upon formation of the SJVAPCD in 1991. The cost effectiveness thresholds used by the SJVAPCD have not been updated since that time.

In a November 2005 report on their 2003 program review of the SJVAPCD, the California Air Resources Board (CARB) indicated that the SJVAPCD's BACT cost effectiveness thresholds were substantially lower than other Districts with similar or better air quality status and suggested that the cost effectiveness thresholds be increased.

Although SJVAPCD staff has not seen differences in the results of BACT analyses when compared to other air Districts, in our 2006 response to the CARB program review we made a commitment to CARB to form a workgroup of SJVAPCD staff, industry representatives, environmental and community group representatives to investigate CARB's concerns and recommend SJVAPCD action, if appropriate, to the Air Pollution Control Officer.

Members of the workgroup included District staff, industry representatives Daryl Gunderson of Aera Energy, Chris Savage of E & J Gallo, and Roger Isom of California Cotton Ginners and Growers Association; and environmental and community group representatives Sarah Jackson of Earthjustice, Carolina Simunovic of Fresno Metro Ministry, and Caroline Farrell of Center on Race, Poverty and the Environment. CARB and EPA staff were invited to participate in this process; each provided verbal or written comments.

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The proposed updates are the result of the workgroup's collaborative effort, careful discussion, and detailed analysis over several months in 2007. The investigations of this group confirmed overall impressions that there are no significant differences in the results of SJVAPCD's past BACT analyses when compared to other Districts. One conclusion was that the SJVAPCD's cost effectiveness thresholds are not directly comparable to those of other Districts because the method in which the calculated emission reduction is determined is inherently different.

By way of explanation, the SJVAPCD's comparatively low cost effectiveness thresholds are offset by the method in which the SJVAPCD calculates the emission reduction due to installation of technologically feasible control equipment. The SJVAPCD's current methodology calculates the emission reduction due to installing technologically feasible control equipment on equipment available on a nationwide basis. Equipment available on a nationwide basis typically has higher emissions than that allowed by SJVAPCD rules.

As a result, the calculated emission reduction due to installing technologically feasible control equipment is relatively large, making the cost effectiveness of such control equipment relatively low, using the standard cost effectiveness equation:

$$\text{cost effectiveness (\$/ton)} = \frac{\text{annualized cost of tech feasible control (\$/year)}}{\text{calculated emission reduction (ton/year)}}$$

The SJVAPCD's current relatively low cost effectiveness thresholds are appropriate given the typically large emission reductions determined using the SJVAPCD's current emission reduction calculation methodology.

Other Districts with higher cost effectiveness thresholds determine the calculated emission reduction due to installing technologically feasible control equipment on equipment that is in compliance with the District's rules. Such equipment typically has lower emissions than that available on a nationwide basis. In those cases, the calculated emission reduction is low, making the cost effectiveness high. In such cases, higher cost effectiveness thresholds are appropriate.

An examination of the BACT guidelines of the SJVAPCD and other Districts revealed that the SJVAPCD's BACT requirements are as stringent or more stringent than those of other California Districts. As such, the SJVAPCD's current thresholds and emission reduction calculation methodology do not result in less stringent BACT requirements.

To address CARB's concern and to eliminate the appearance of inconsistency when compared to other Districts, the workgroup has generally concluded that the cost effectiveness thresholds and emission reduction calculation methodology should be updated to make the SJVAPCD's cost effectiveness thresholds and emission reduction calculation methodology consistent with that of other Districts.

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These two changes taken together should not have a significant effect on the outcome of the majority of cost effectiveness analyses performed by the SJVAPCD.

II. Current Cost Effectiveness Thresholds And Emission Reduction Calculation Methodology

Rule 2201 section 3.9 defines BACT as the most stringent emission limitation or control technology that is:

- Achieved in practice for such category and class of source,
- Required by an EPA approved State Implementation Plan, i.e. required by a Rule that has been approved by EPA,
- Required by a Federal New Source Performance Standard (NSPS), or
- Is found to be both technologically feasible and cost effective for such class or category of sources or for a specific source.

The Rule 2201 definition of BACT is not proposed to be changed.

Please note that if an emission limit or control technology is achieved in practice for a category and class of source, required by an EPA approved SIP, or is required by a Federal NSPS such control is required regardless of cost. As such, the cost effectiveness analysis process only includes those technologically feasible control technologies that are not achieved in practice for a category and class of source, required by an SIP, or required by an NSPS requirement.

The cost effectiveness thresholds currently used by the SJVAPCD to determine if a technologically feasible control technology is cost effective are as follows:

Pollutant	Cost effectiveness (\$/ton)
NO _x	9,700
CO	300
VOC	5,000
SO _x	3,900
PM ₁₀	5,700

In determining if a technologically feasible control technique is cost effective, the cost effectiveness of a particular control technology is compared to the cost effectiveness thresholds for a given pollutant.

For example, if the cost effectiveness for NO_x control technique A is \$6,000/ton, such a control technique is determined to be cost effective because its cost effectiveness (\$6,000/ton) is less than the SJVAPCD's cost effectiveness threshold (\$9,700/ton). As a result, NO_x control technique A would be required.

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Alternatively, if the cost effectiveness for NO_x control technique B is \$30,000/ton, such a control technique is determined not to be cost effective because its cost effectiveness (\$30,000/ton) is greater than the SJVAPCD's cost effectiveness threshold (\$9,700/ton). As a result, NO_x control technique B would not be required.

Currently, to determine the cost effectiveness of a particular control technique, the annual costs of the control (annualized capital costs plus annual operating costs) are divided by the calculated emission reduction due to that particular control technique. The emissions reduction is calculated as the difference between emissions from equipment available on a nationwide basis and emissions from such equipment equipped with technologically feasible control.

Cost effectiveness (\$/ton) =

$$\frac{\text{Annual cost (\$/year)}}{\text{Emissions (available nationwide) - Emissions (w/ tech feas BACT) (ton/year)}}$$

Emissions from equipment used nationwide can be higher than SJVAPCD prohibitory rules allow for existing equipment. As a result the calculated emission reduction can be overstated, i.e. the calculated emission reduction can be larger than the actual emissions reduced due to installing technologically feasible control on equipment that must otherwise meet SJVAPCD prohibitory rule requirements.

III. Survey of other Districts, CARB, and EPA

The workgroup surveyed the South Coast Air Quality Management District (SCAQMD), Bay Area Air Quality Management District (BAAQMD), Sacramento Metropolitan Air Quality Management District (SMAQMD), Yolo-Solano Air Quality Management District (YSAQMD), San Diego County Air Pollution Control District (SDAPCD), California Air Resources Board (CARB), and the US Environmental Protection Agency (EPA) for the following:

- BACT cost effectiveness thresholds
- Methodology for calculating the "emission reduction" in cost effectiveness analyses

Survey of cost effectiveness thresholds:

Summary of BACT Cost Effectiveness Thresholds (\$/ton)							
	SCAQMD ¹	BAAQMD	SMAQMD	YSAQMD	SDAPCD ²	CARB ²	EPA ²
NO _x	19,100	17,500	24,500	24,500	18,000	N/A	N/A
CO	400	N/A	N/A	300	N/A	N/A	N/A
VOC	20,200	17,500	17,500	17,500	10,200	N/A	N/A
SO _x	10,100	18,300	18,300	3,900	N/A	N/A	N/A
PM ₁₀	4,500	5,300	11,400	5,700	N/A	N/A	N/A

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Notes:

¹The SCAQMD's method of amortizing control equipment costs is now inherently different from the methods used by the other Districts. The SCAQMD method tends to result in lower amortized control equipment costs (and therefore lower cost effectiveness thresholds). Because the SCAQMD amortization method is inherently different than that used by other Districts, it will not be considered further.

²SDPACD does not have thresholds for CO, SOx, and PM10. CARB and EPA do not have defined thresholds for any air contaminant.

The results of the survey indicate that all other Districts have cost effectiveness thresholds much greater than the SJVAPCD for each affected pollutant, except CO.

The average of other District's cost effectiveness thresholds (except SCAQMD) and the % difference from the SJVAPCD's existing levels are as follows:

Average cost effectiveness thresholds (\$/ton)				
NOx	CO	VOC	SOx	PM10
21,100	300	15,700	13,500	7,500
117%	0%	214%	246%	32%

The highest cost effectiveness thresholds of other surveyed Districts and the % difference from the SJVAPCD's existing levels are as follows:

Highest cost effectiveness thresholds (\$/ton)				
NOx	CO	VOC	SOx	PM10
24,500	300	17,500	18,300	11,400
150%	0%	250%	370%	100%

Survey of emission reduction calculation methodology:

District	Emission reduction calculation methodology
SCAQMD	No defined method for determining "emissions without controls" emissions in BACT cost analyses. However, usually use the Prohibitory Rule limits to determine industry standard emissions.
BAAQMD	No defined method for determining "emissions without controls" in BACT cost effectiveness analyses. However, usually use the Prohibitory Rule limits to determine industry standard emissions.
SMAQMD	No defined method for determining "emissions without controls" in BACT cost effectiveness analyses. Case-by-case determination is used.

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District	Emission reduction calculation methodology
YSAQMD	No defined method for determining "emissions without controls" in BACT cost effectiveness analyses. Case-by-case determination is used.
SDAPCD	No defined method for determining "emissions without controls" in BACT cost effectiveness analyses. However, for new and modified equipment that has never triggered BACT, usually use AP-42 to determine "emissions without controls" unless something else makes more sense. For modified equipment that has previously been subjected to BACT, they calculate the emission reductions from the currently permitted emission rate.
CARB	No guidance available
EPA	General guidance is the "emissions without controls" is the realistic upper boundary of uncontrolled emissions, i.e. the highest emitting operation that the facility would use (in the absence of a rule requirement).

When performing a cost effectiveness analysis, most other Districts calculate the emission reduction based on the allowable emissions in District Rules, and not on emissions from equipment available on a nationwide basis.

IV. Options For Revising The SJVAPCD BACT Policy:

Option #1: Do not change current cost thresholds and emission reduction calculation methodology

An examination of the results of SJVAPCD cost effectiveness analyses performed using the SJVAPCD's current thresholds and emission reduction calculation methodology and using other Districts' cost effectiveness thresholds and emission reduction calculation methodology revealed that results are typically similar, i.e. the current method usually results in BACT requirements no more or less stringent than other Districts' BACT requirements. However, continuing to use the current system can result in the impression by oversight agencies and others that the SJVAPCD's BACT requirements are less stringent than those of other Districts.

Additionally, using "nationwide emissions" in cost effectiveness calculations is problematic; the determination of such an emission level is somewhat subjective and such equipment can not typically be operated in the SJVAPCD.

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Option #2: Increase the cost thresholds to the average of the other surveyed Districts and change the methodology used in calculating the emission reduction to that used by most other Districts, i.e. calculate the emission reductions as the difference between emissions required by SJVAPCD rules and emissions with technologically feasible controls.

Some of the Districts surveyed have a similar non-attainment status as the SJVAPCD (SCAQMD, SMAQMD, and YSAQMD) and others have a lesser non-attainment status (BAAQMD and SDAPCD). Districts with better air quality generally have lower cost effectiveness thresholds. As such their cost effectiveness thresholds tend to decrease the average cost effectiveness threshold.

Because of the SJVAPCD's extreme non-attainment status for ozone and non-attainment status for PM_{2.5}, using the average of the other District's cost effectiveness thresholds in the SJVAPCD may not be adequately protective of the SJVAPCD's air quality.

Option #3: Increase the cost thresholds to the highest of the other surveyed Districts and change the methodology used in calculating the emission reduction to that used by most other Districts, i.e. calculate emission reductions as the difference between industry standard emissions (i.e. emissions required by SJVAPCD rules) and emissions with technologically feasible controls.

Option #3 is the recommended approach given the SJVAPCD's extreme non-attainment status. In addition, using SJVAPCD rule limits (or permitted emission limits) as the starting point for calculating emission reductions from installing technologically feasible controls is less subjective and is a better estimate of the actual emission reduction achievable due to installing technologically feasible controls.

V. Proposed Cost Effectiveness Thresholds And Emission Reduction Calculation Methodology

The proposed cost effectiveness thresholds (option #3) to determine if a technologically feasible control technology is cost effective are as follows:

Pollutant	Cost effectiveness (\$/ton)
NO _x	24,500
CO	300
VOC	17,500
SO _x	18,300
PM ₁₀	11,400

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Proposed emission reduction calculation methodology:

Cost effectiveness (\$/ton) =

$$\frac{\text{Annual cost (\$/year)}}{\text{District Standard Emissions - Emissions (w/ tech feas BACT) (ton/year)}}$$

Annual costs are equal to annualized cost of utilizing technologically feasible BACT controls on an emission unit that already meets District standard emissions. Annual costs do not include costs necessary to meet District standard emissions.

For new emission units, District standard emissions are equal to the emissions level allowed by applicable SJVAPCD rule requirements once the compliance date, i.e. the date at which the emission unit must meet a specific emission requirement, for the rule has passed. For rules with a phased compliance schedule, the earliest compliance date which applies to the equipment being analyzed shall be used. The emission limits in the applicable SJVUAPCD prohibitory rule shall be those that the particular emission unit is subject to. Please note that if the applicable rule has both a standard and enhanced compliance option, the emission level and earliest compliance date required by the standard compliance option shall be used.

For existing emission units, District standard emissions are equal to the emissions level allowed by the current PTO.

If there is no SJVAPCD prohibitory rule emission limit that applies to the particular new emission unit or if the existing emission unit does not have permitted emission limits, District standard emissions for the unit are equal to the emissions from similar equipment that is commonly available in the District. In no case shall the emissions used be higher than that allowed by State or Federal requirements. If insufficient information is available to make a determination regarding emissions from common available equipment in the District, District standard emissions will be estimated based on EPA's Compilation of Air Pollutant Emission Factors (AP-42), or other references as determined by the SJVAPCD to be appropriate.



San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT



HEALTHY AIR LIVING™

APR 26 2016

Travis Goddard
All Phase Oilfield Service Inc.
17346 Kranenburg Ave.
Bakersfield, CA 93314

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: S-8760
Project Number: S-1154230

Dear Mr. Goddard:

Enclosed for your review and comment is the District's analysis of All Phase Oilfield Service Inc.'s application for an Authority to Construct for three flares to operate at various locations.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. David Torii of Permit Services at (661) 392-5620.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:dbt

Enclosures

cc: Tung Le, CARB (w/ enclosure) via email

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
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Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: 661-392-5500 FAX: 661-392-5585

IV. Process Description

After drilling, and periodically during their productive lives, oil and gas wells are tested to establish their flow and pressure decline rates. The well test flares will incinerate the gases released from the well during testing.

V. Equipment Listing

S-8730-2-0, '3-0 and '4-0:

3" DIA. X 20 FT. TALL WELL TEST FLARE WITH CONTINUOUS ELECTRIC IGNITION POWERED BY SOLAR/BATTERY, OPERATED AT VARIOUS UNSPECIFIED LOCATIONS, SJVUAPCD

VI. Emission Control Technology Evaluation

A well test flare is an emission control and safety device used to incinerate combustible gases that would otherwise be released during testing of an oil or gas production well. The combustible gases include a significant fraction of VOC along with measurable concentrations of various sulfur compounds such as hydrogen sulfide (H_2S). By incinerating these gases, VOC emissions are reduced by at least 99%, while sulfur compounds are expected to be entirely converted to SO_x .

VII. General Calculations

A. Assumptions

Each Flare:

- Well test gas venting is limited to 1.0 MMscf/day and 288 MMscf/yr (applicant)
- Test gas higher heating value is 1,000 Btu/scf (applicant)
- Test gas sulfur content is 5 gr/100 scf (applicant)
- Pilot gas: propane (applicant)
- Pilot gas flow : 45 scf/hr (applicant)
- The pilot gas combustion emissions are assumed to be negligible
- VOC destruction efficiency is 99%
- No flares will operate together (at the same stationary source)

B. Emission Factors

Flare Emission Factors		
	lb./MMBtu	Source
NO _x	0.068	FYI 83
*SO _x	0.0143	Mass Balance Equation
PM ₁₀	0.008**	FYI 83
CO	0.37	FYI 83
VOC	0.063	FYI 83

$$\frac{5 \text{ gr} \cdot \text{S}}{100 \text{ dscf}} \left(\frac{\text{dscf}}{1,000 \text{ Btu}} \right) \frac{10^6 \text{ Btu}}{\text{MMBtu}} \left(\frac{1 \text{ lb}}{7,000 \text{ gr}} \right) \frac{64 \text{ lb} \cdot \text{SO}_2}{32 \text{ lb} \cdot \text{S}} = 0.0143 \frac{\text{lb} \cdot \text{SO}_2}{\text{MMBtu}}$$

**Note that the applicant has proposed the BACT-compliant PM10 emission factor pursuant to District FYI 83; therefore, visible emissions will be limited to less than Ringelmann ¼ and less than 5% opacity

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since this is a new emissions unit, PE1 = 0 for all pollutants.

2. Post Project Potential to Emit (PE2)

Pollutant	Daily PE2 (Each Flare)		
	EF2 (lb./MMBtu)	Heat Input (MMBtu/day)	Daily Emissions (lb./day)
NO _x	0.068	1000	68.0
SO _x	0.0143	1000	14.3
PM ₁₀	0.008	1000	8.0
CO	0.37	1000	370.0
VOC	0.063	1000	63.0

Pollutant	Annual PE2 (Each Flare)		
	EF2 (lb./MMBtu)	Heat Input (MMBtu/yr.)	Emissions (lb./yr.)
NO _x	0.068	288,000	19,584
SO _x	0.0143	288,000	4,118
PM ₁₀	0.008	288,000	2,304
CO	0.37	288,000	106,560
VOC	0.063	288,000	18,144

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site.

The District's longstanding permitting practice is that oilfield service activities are distinct from oil and gas production operations and are therefore not part of the oil and gas production stationary source they serve.

Furthermore, each well test flare is its own stationary source and no other permitted equipment, including other well test flares, are allowed to operate as part of a well test flare's stationary source. Therefore, these are new facility's (stationary sources); therefore, the SSPE1s are equal to zero.

4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

The District's longstanding permitting practice is that oilfield service activities are distinct from oil and gas production operations and are therefore not part of the oil and gas production stationary source they serve.

Furthermore, each well test flare is its own stationary source and no other permitted equipment, including other well test flares, are allowed to operate as part of a well test flare's stationary source.

SSPE2 (lb/year)					
Permit Unit	NO _x	SO _x	PM ₁₀	CO	VOC
S-8730-2-0	19,584	4,118	2,304	106,560	18,144
SSPE2	19,584	4,118	2,304	106,560	18,144

SSPE2 (lb/year)					
Permit Unit	NO _x	SO _x	PM ₁₀	CO	VOC
S-8730-3-0	19,584	4,118	2,304	106,560	18,144
SSPE2	19,584	4,118	2,304	106,560	18,144

SSPE2 (lb/year)					
Permit Unit	NO _x	SO _x	PM ₁₀	CO	VOC
S-8730-4-0	19,584	4,118	2,304	106,560	18,144
SSPE2	19,584	4,118	2,304	106,560	18,144

5. Major Source Determination

Rule 2201 Major Source Determination:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

As shown in Section VII.C.5 above, the facility is not a Major Source for any pollutant.

Therefore BE=PE1.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification. Additionally, since the facility is not a major source for PM₁₀ (140,000 lb/year), it is not a major source for PM_{2.5} (200,000 lb/year).

VIII. Compliance

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

- a. Any new emissions unit with a potential to emit exceeding two pounds per day,
- b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
- c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
- d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)						
Each Flare	NO _x	SO _x	PM ₁₀	PM _{2.5}	CO	VOC
SSPE1	0	0	0	0	0	0
SSPE2	19,584	4,118	2,304	2,304	106,560	18,144
Major Source Threshold	20,000	140,000	140,000	200,000	200,000	20,000
Major Source?	No	No	No	No	No	No

Note: PM2.5 assumed to be equal to PM10

As seen in the table above, the facility is not an existing Major Source and is not becoming a Major Source as a result of this project.

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO2	VOC	SO2	CO	PM	PM10
Estimated Facility PE before Project Increase	0	0	0	0	0	0
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	n	n	n	n	n	n

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

a. New emissions units – PE > 2 lb/day

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a well drilling and testing operation with PE greater than 2 lb. /day for NO_x, SO_x, CO, and VOC. As discussed in Section VI above, the flare is a VOC control device (not emissions units) and therefore BACT is triggered only for VOC only.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore BACT is not triggered.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 and/or Federal Major Modification. Therefore BACT is not triggered.

2. BACT Guideline

BACT Guideline 1.4.7 covers waste gas flares from oilfield well drilling and testing operations that incinerate less than 50 MMscf/day of waste gas.

3. Top-Down BACT Analysis

As shown by the Top-Down BACT Analysis in Appendix A, BACT is satisfied by the use of an elevated flare with a propane fueled pilot flame.

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO _x	SO _x	PM ₁₀	CO	VOC
SSPE2	19,584	4,118	2,304	106,560	18,144
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

C. Public Notification

1. Applicability

Public noticing is required for:

- a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
- b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
- c. Any project which results in the offset thresholds being surpassed, and/or
- d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.
- e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is not greater than the Major Source threshold for any pollutant. Therefore, public noticing is not required for this project for new Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

b. PE > 100 lb/day

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO _x	68.0	100 lb/day	N
SO _x	14.3	100 lb/day	N
PM ₁₀	8.0	100 lb/day	N
CO	370.0	100 lb/day	Y
VOC	63.0	100 lb/day	N

Therefore, public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO _x	0	19,584	20,000 lb/year	No
SO _x	0	4,118	54,750 lb/year	No
PM ₁₀	0	2,304	29,200 lb/year	No
CO	0	106,560	200,000 lb/year	No
VOC	0	18,144	20,000 lb/year	No

As detailed above, offset thresholds were not surpassed with this project; therefore public noticing is not required for offset purposes.

d. SSIPE > 20,000 lb/year

SSIPE Public Notice Thresholds					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO _x	19,584	0	19,584	20,000 lb/year	No
SO _x	4,118	0	4,118	20,000 lb/year	No
PM ₁₀	2,304	0	2,304	20,000 lb/year	No
CO	106,560	0	106,560	20,000 lb/year	Yes
VOC	18,144	0	18,144	20,000 lb/year	No

As demonstrated above, the SSIPEs for CO is greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating permit, this change is not a Title V significant Modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project for CO emissions in excess of 100 lb/day and 20,000 lb/yr. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions:

Daily and annual amounts of gas flared shall not exceed 1.0 MMscf/day nor 288 MMscf/yr. [District Rules 2201 and 4102]

- Emission rates shall not exceed any of the following: 0.008 lb-PM10/MMBtu, 0.068 lb.-NOx/MMBtu(as NO₂), 0.063 lb.-VOC/MMBtu, or 0.37 lb.-CO/MMBtu. [District Rule 2201]
- Sulfur compound concentration of gas flared shall not exceed 5 gr/100 scf. [District Rule 2201]
- Daily and annual amounts of gas flared shall not exceed 0.144 MMscf/day and 52.56 MMscf/yr. [District rule 2201]

E. Compliance Assurance

1. Source Testing

Pursuant to District Policy APR 1705, source testing is not required to demonstrate compliance with Rule 2201.

2. Monitoring

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following condition(s) are listed on the permit to operate:

- Permittee shall maintain accurate daily records indicating flare location, flared gas sulfur content at each location, and daily and annual rates of gas flared; and such records shall be made readily available for District inspection upon request for a minimum of 5 years. [District Rules 2201 and 4311] N

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

An AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to **Appendix B** of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_x, CO, and SO_x. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_x, CO, or SO_x.

The proposed location is in a non-attainment area for the state's PM₁₀ as well as federal and state PM_{2.5} thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM₁₀ and PM_{2.5}.

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII. C. 9. above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 4001 New Source Performance Standards (NSPS)

This rule incorporates by reference the NSPS established in Title 40, Code of Federal Regulations, Part 60 (40 CFR 60) and applies to any source subject to an applicable standard. However, no NSPS applies to these oil well test flares. No further discussion is required.

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

This rule incorporates by reference the NESHAP established in 40 CFR 61 and 63 and applies to any source subject to an applicable standard. However, no NESHAP applies to these oil well test flares. No further discussion is required.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). The applicant has proposed the BACT-compliant PM10 emission factor pursuant to District FYI 83; therefore, visible emissions will be limited to less than Ringelmann ¼ and less than 5% opacity. As long as the flaring system is operating correctly, compliance with this rule is expected.

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source

or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (**Appendix B**), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

RMR Summary			
Categories	Three Well Test Flares (Units 2-0, 3-0, 4-0)	Project Totals	Facility Totals
Prioritization Score	250.0 ¹	250.0 ¹	>1.0
Acute Hazard Index	0.01 ¹	0.01 ¹	0.01 ¹
Chronic Hazard Index	0.00 ¹	0.00 ¹	0.00 ¹
Maximum Individual Cancer Risk	8.51E-07 ¹	8.51E-07 ¹	8.51E-07 ¹
T-BACT Required?	No		
Special Permit Requirements?	Yes		

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot. For natural gas the EPA F-factor (adjusted to 60°F) is 8710 dscf/MMBtu (40 CFR 60 Appendix B).

PM₁₀ Emission Factor: 0.008 lb-PM₁₀/MMBtu
 Percentage of PM as PM₁₀ in Exhaust: 100%
 Exhaust Oxygen (O₂) Concentration: 3%
 Excess Air Correction to F Factor = $\frac{20.9}{(20.9 - 3)} = 1.17$

$$GL = \left(\frac{0.008 \text{ lb-PM}}{\text{MMBtu}} \times \frac{7,000 \text{ grain}}{\text{lb-PM}} \right) / \left(\frac{8,710 \text{ ft}^3}{\text{MMBtu}} \times 1.17 \right)$$

$GL = 0.0055 \text{ grain/dscf} < 0.1 \text{ grain/dscf}$

Rule 4311 Flares

This rule is intended to limit the emissions of NO_x, SO_x, and VOC from the operation of flares. However, pursuant to Section 4.3, except for the record keeping requirement of Section 6.1.4 the requirements of this rule do not apply to any flare located at a stationary source with potential emissions less than 10.0 tons per year of VOC and 10.0 tons per year of NO_x. Section 6.1.4 requires an operator claiming exemption under Section 4.3 to record annual throughput, material usage, or other information necessary to demonstrate compliance with the terms of the exemption. The following condition, previously stated in this evaluation, will ensure compliance with this recordkeeping requirement:

- *Permittee shall maintain accurate daily records of flare location and volume of well test gas flared. [District Rules 2201 and 4311]*

Rule 4801 Sulfur Compounds

Rule 4801 requires that a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO₂), on a dry basis averaged over 15 consecutive minutes.

Emission calculations were calculated using a fuel with a 5 gr/100 dscf sulfur content. Therefore, the maximum SO_x ppmv are calculated to be:

$$\begin{aligned} \text{SO}_x &= (5 \text{ gr}/100 \text{ dscf fuel}) \times (1 \text{ lb.}/7000 \text{ gr S}) \times (1 \text{ mol}/32 \text{ lb. S}) \times (379.5 \text{ dscf S}/1 \text{ mol S}) \times \\ &\quad (1 \text{ dscf fuel}/1000 \text{ Btu}) \times (1 \times 10^6 \text{ Btu}/8710 \text{ dscf}) \times (1 \times 10^6) \\ &= 9.7 \text{ ppmv} < 2,000 \text{ ppmv} \end{aligned}$$

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

The District performed an Engineering Evaluation (this document) for the proposed project and determined that the activity consists of issuing a permit for a piece of transportable equipment to be used at various locations within the District. The District makes the following findings regarding this activity: 1) Issuance of the permit does not have a significant environmental impact. 2) Assessment of potential environmental effects resulting from the use of the transportable equipment on a development project is the responsibility of the Lead Agency approving the specific project, and will be determined on a project specific basis. The District has determined that no additional findings are required.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs S-8730-2-0, '3-0 and '4-0 subject to the permit conditions on the attached draft ATCs in Appendix C.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-8730-2-0	3020-02 H	15.0 MMBtu/hr or greater	\$1080
S-8730-3-0	3020-02 H	15.0 MMBtu/hr or greater	\$1080
S-8730-4-0	3020-02 H	15.0 MMBtu/hr or greater	\$1080

Appendixes

- A: BACT Guideline and BACT Analysis
- B: HRA and AAQA Summary
- C: Draft ATC BACT Analysis

All Phase Oilfield Service Inc.
1154230, S-8730

APPENDIX A
BACT Guideline and BACT Analysis

Best Available Control Technology (BACT) Guideline 1.4.7
Last Update: 8/27/1999

Waste Gas Flare - Oilfield Well Drilling and Testing Operation, < 50 MMscf/day

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
VOC	Elevated Flare with propane fueled pilot light		

BACT Analysis:

The well test flares are covered by BACT Guideline 1.4.7, which covers waste gas flares for oilfield well drilling and testing operations with a maximum flow rate less than 50 MMscf/day.

Step 1 – Identify All Possible Control Technologies:

1. Elevated flare with propane fueled pilot light – Achieved in Practice

Step 2 – Eliminate Technologically Infeasible Options:

All technologies listed in Step 1 are technologically feasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

1. Elevated flare with propane fueled pilot light

Step 4 – Cost Effectiveness Analysis

The applicant has proposed the highest-ranked control option remaining from Step 3. No cost effectiveness analysis is required.

Step 5 – Select BACT

BACT is satisfied by the applicant's proposal to use an elevated flare with a propane fueled pilot light. No further discussion is required.

All Phase Oilfield Service Inc.
1154230, S-8730

APPENDIX B
HRA and AAQA Summary

San Joaquin Valley Air Pollution Control District Risk Management Review

To: David Torii – Permit Services
 From: Cheryl Lawler – Technical Services
 Date: February 24, 2016
 Facility Name: All Phase Oilfield Service Inc.
 Location: Various Unspecified Locations
 Application #(s): S-8730-2-0, 3-0, 4-0
 Project #: S-1154230

A. RMR SUMMARY

RMR Summary			
Categories	Three Well Test Flares (Units 2-0, 3-0, 4-0)	Project Totals	Facility Totals
Prioritization Score	250.0 ¹	250.0 ¹	>1.0
Acute Hazard Index	0.01 ¹	0.01 ¹	0.01 ¹
Chronic Hazard Index	0.00 ¹	0.00 ¹	0.00 ¹
Maximum Individual Cancer Risk	8.51E-07 ¹	8.51E-07 ¹	8.51E-07 ¹
T-BACT Required?	No		
Special Permit Requirements?	Yes		

¹Reported risks are for each individual flare. Each flare constitutes its own stationary source.

Proposed Permit Requirements

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

Units 2-0, 3-0, 4-0

1. The flare shall vent vertically upward. The vertical exhaust flow shall not be impeded any obstruction.

B. RMR REPORT

I. Project Description

Technical Services received a request on February 17, 2016, to perform an Ambient Air Quality Analysis and a Risk Management Review for the installation of three flares for multiple uses including well testing. The flares will be authorized to operate at various unspecified locations. Each flare is also considered to be its own stationary source.

II. Analysis

Toxic emissions for each flare were calculated using 2001 Ventura County Air Pollution Control District emission factors for Natural Gas fired external combustion and from a Refinery Gas composition analysis from the 2005 report, *FINAL REPORT Test of TDA's Direct Oxidation Process for Sulfur Recovery*. Emissions were then input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015), risks from the project were prioritized using the procedures in the 1990 CAPCOA Facility Prioritization Guidelines. The prioritization score for the project was greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required. The AERMOD model was used, with the parameters outlined below and meteorological data for 2010-2014 from Hanford to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters (each flare) ¹ Units 2-0, 3-0, 4-0			
Source Type	Flare	Location Type	Rural
Effective Stack Height (m)	8.92	Closest Receptor (m)	25 ²
Effective Diameter (m)	1.17	Type of Receptor	Residential/ Business
Effective Velocity (m/s)	54.99	Natural Gas/Waste Gas Process Rates (MMscf)	0.042 hr 288 yr
Temperature (°K)	810.93		

¹All parameters are based on the District's Flare Modeling Parameter Estimator for open flares.

²The receptor distance of 25 meters represents the worst case distance that was modeled for this project.

Technical Services also performed modeling for criteria pollutants CO, NO_x, SO_x, and PM₁₀ with the emission rates below:

Unit #	NO _x (Lbs.)		SO _x (Lbs.)		CO (Lbs.)		PM ₁₀ (Lbs.)	
	Day	Yr.	Day	Yr.	Day	Yr.	Day	Yr.
2-0	68	19,584	14.3	4,118	370	106,560	8	2,304
3-0	68	19,584	14.3	4,118	370	106,560	8	2,304
4-0	68	19,584	14.3	4,118	370	106,560	8	2,304

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Three Flares	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO _x	Pass ¹	X	X	X	Pass
SO _x	Pass	Pass	X	Pass	Pass
PM ₁₀	X	X	X	Pass ²	Pass ²
PM _{2.5}	X	X	X	Pass ²	Pass ²

*Results were taken from the attached PSD spreadsheet.

¹The project was compared to the 1-hour NO₂ National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.

²The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

III. Conclusion

The acute and chronic indices are below 1.0, and the cancer risk factor associated with the project is less than 1.0 in a million. In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).

To ensure that human health risks will not exceed District allowable levels; the permit requirements listed on Page 1 of this report must be included for the proposed units.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

All Phase Oilfield Service Inc.
1154230, S-8730

APPENDIX C
Draft ATC

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT
DRAFT

PERMIT NO: S-8730-2-0

LEGAL OWNER OR OPERATOR: ALL PHASE OILFIELD SERVICES
MAILING ADDRESS: 17346 KRANENBURG AVENUE
BAKERSFIELD, CA 93314

LOCATION: VARIOUS LOCATIONS, SJVAPCD

EQUIPMENT DESCRIPTION:
3" DIA. X 20 FT. TALL WELL TEST FLARE WITH CONTINUOUS ELECTRIC IGNITION POWERED BY
SOLAR/BATTERY, OPERATED AT VARIOUS UNSPECIFIED LOCATIONS, SJVUAPCD

CONDITIONS

1. The equipment shall not be located within 1000 ft. of any K-12 school. [CH&SC 42301.6]
2. The flare shall vent vertically upward. The vertical exhaust flow shall not be impeded any obstruction. [District Rule 4102]
3. Flare shall only be used to combust gas released during well testing. [District Rule 2201]
4. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
5. Permittee shall notify the District Compliance Division of each location at which the operation is located in excess of 24 hours. Such notification shall be made no later than 48 hours after starting operation at the location. [District Rule 2201]
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8. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rules 2201 and 4101]
9. Gas line to flare shall be equipped with operational, volumetric flow rate indicator. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

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Seyed Sadredin, Executive Director, APSCO

DRAFT
Arnaud Marjolle, Director of Permit Services

S-8730-2-C, Mar 29 2018 3:04PM - TORID Joint Inspection NOT Required

10. Amounts of gas flared shall not exceed 1.0 MMscf/day nor 288 MMscf/yr. [District Rules 2201 and 4102]
11. Sulfur compound concentration of gas flared shall not exceed 5 gr/100 scf. [District Rules 2201 and 4801]
12. Emission rates shall not exceed any of the following: 0.008 lb-PM10/MMBtu, 0.068 lb-NO_x/MMBtu (as NO₂), 0.063 lb-VOC/MMBtu, or 0.37 lb-CO/MMBtu. [District Rule 2201]
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15. Permittee shall document compliance with well gas sulfur compound concentration limit by performing sulfur content analysis of well gas upon startup at each new location. [District Rule 2201]
16. The following test methods shall be used for well gas sulfur content: ASTM D3246 or double GC for H₂S and mercaptan. [District Rule 1081]
17. Permittee shall maintain accurate daily records indicating flare location, flared gas sulfur content at each location, and daily and annual rates of gas flared; and such records shall be made readily available for District inspection upon request for a minimum of 5 years. [District Rules 2201 and 4311]

DRAFT

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT
DRAFT

PERMIT NO: S-8730-3-0

LEGAL OWNER OR OPERATOR: ALL PHASE OILFIELD SERVICES
MAILING ADDRESS: 17346 KRANENBURG AVENUE
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DRAFT
Arnaud Marjolle, Director of Permit Services

S-8730-3-0; Mar 28 2018 3:04PM - TORID - Joint Inspection NOT Required

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San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT
DRAFT

PERMIT NO: S-8730-4-0

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S-8730-4-0, Mar 29 2016 2:04PM - TORID : Joint Inspection NOT Required

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DRAFT



San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT



NOV 16 2016

Mr. Gregory Pritchett
Chevron USA Inc
PO Box 1392
Bakersfield, CA 93302

Re: Proposed ATC / Certificate of Conformity (Significant Mod)
District Facility # S-1128
Project # 1162368

Dear Mr. Pritchett:

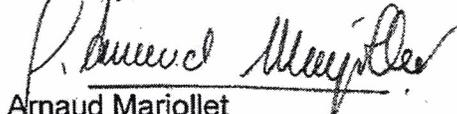
Enclosed for your review is the District's analysis of an application for Authority to Construct for the facility identified above. You requested that a Certificate of Conformity with the procedural requirements of 40 CFR Part 70 be issued with this project. The project authorizes a new tank.

After addressing all comments made during the 30-day public notice and the 45-day EPA comment periods, the District intends to issue the Authority to Construct with a Certificate of Conformity. Please submit your comments within the 30-day public comment period, as specified in the enclosed public notice. Prior to operating with modifications authorized by the Authority to Construct, the facility must submit an application to modify the Title V permit as an administrative amendment, in accordance with District Rule 2520, Section 11.5.

If you have any questions, please contact Mr. Leonard Scandura, Permit Services Manager, at (661) 392-5500.

Thank you for your cooperation in this matter.

Sincerely,


Arnaud Marjollet
Director of Permit Services

Enclosures

cc: Tung Le, CARB (w/enclosure) via email
cc: Gerardo C. Rios, EPA (w/enclosure) via email

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: 661-392-5500 FAX: 661-392-5585

CCR, Title 14, Div 6, Chap 3, Sections 15000-15387: CEQA Guidelines

III. PROJECT LOCATION

The project is located at the 2F (Oil Cleaning Plant (OCP), Midway Sunset Oilfield, CUSA's Western Kern County field heavy oil production stationary source. This location is not located within 1,000 feet of a K-12 school.

IV. PROCESS DESCRIPTION

The proposal is for the installation of a 2,000 barrel drain tank at the 2F oil cleaning plant. The tank will be equipped with a pressure-vacuum (PV) relief vent valve set to within 10% of the maximum allowable working pressure of the tank. The PV-valve will reduce VOC wind induced emissions from the tank vent.

The tank will be equipped with a gas blanketing system which will maintain the tank's vapor space above the upper explosive limit (gas becomes too rich to burn) by the addition of PUC-quality natural gas. Applicant has stated that the PV vent will be set at a pressure higher than expected internal pressure spikes from daily spikes due to temperature changes. The tank is expected to be empty over 90% of the time.

The gas blanket gas exits to atmosphere through the relief valve once enough liquid enters the tank. Once the liquid level is reduced a regulator will allow pressure in the tank to build back up.

A diagram of the gas blanket system is included in **Attachment I**.

V. EQUIPMENT LISTING

ATC Equipment Description:

S-1128-1018-0: 2000 BBL DRAIN TANK WITH NATURAL GAS BLANKETING (2F OCP)

VI. EMISSION CONTROL TECHNOLOGY EVALUATION

The tank will be equipped with a pressure-vacuum (PV) relief vent valve set to within 10% of the maximum allowable working pressure of the tank. The PV-valve will reduce VOC wind induced emissions from the tank vent. The tank will be equipped with a gas blanketing system which will maintain the tank's vapor space above the upper explosive limit by the addition of PUC quality natural gas.

VII. GENERAL CALCULATIONS

A. Assumptions

- The tank operates as a spill prevention container. It will also be used periodically for routine removal of fluids (drains and maintenance).
 - The tank is a potential source of volatile organic compound (VOC) emissions.
 - Maximum throughput = 2,000 bbl/day and 70,000 bbl/yr
 - The tank paint conditions are good, the color is gray and the shade is medium.
 - TVP of oil = 0.5 psia (Applicant)
 - Tank temperature, 200 °F
 - Tank will be equipped with a pump which activates at 5 feet, pumping liquid from the tank to a pipeline. The pump shuts off when the liquid level reaches 4 feet. Therefore, an average height of 4 feet was used to calculate emissions from the tank.
 - For Greenhouse Gas (GHG) Emissions tank emissions are assumed to be 100% methane.
-
- The VOC content of the gas blanket vapors does not exceed 10% by weight (9/9/16 applicant email, **Attachment II**). In accordance with District SSP 2015 policy "Quantifying Fugitive VOC Emissions at Petroleum and SOCOMI Facilities", VOC emissions are not assessed to piping and components handling vapor streams with a VOC content of 10% and therefore fugitive emissions components do not emit VOCs.
 - Fugitive emissions associated with the gas blanket system were neglected in the emissions used for the HRA.

B. Emission Factors

Emissions from the uncontrolled tank with a PV valve were calculated using the District's spreadsheet for crude oil/organic liquids with API gravity < 26 degrees (**Attachment III**).

Greenhouse Gas (GHG) Emissions Calculations

GWP for CH₄ = 21 lb-CO₂e per lb-CH₄
GWP for N₂O = 310 lb-CO₂e per lb-N₂O

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since this is a new emissions units, PE1 = 0 for all criteria pollutants.

2. Post-Project Potential to Emit (PE2)

Post-Project Potential to Emit (PE2)			
Permit Unit	Location	VOC – Daily PE2 (lb/day)	VOC – Annual PE2 (lb/yr)
S-1128-1018-0	2F	103.00	4,588

GHG Emissions

4,588 lb/yr CH₄ x 21 lb-CO₂e per lb-CH₄ x short ton/2000 lb x 0.9072 metric tons/short ton = 43.7 mtons/yr < 230 mtons/yr

Emissions profiles are included in **Attachment IV**.

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the Pre-Project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Facility emissions are already above the Offset and Major Source Thresholds for all pollutants. An estimate* of SSPE1 is provided below.

*SSPE Calculator (7-19-16, PTOs only)

	lb/yr	Tons/yr
NOx	748,121	374
SOx	2,121,476	1,061
PM10	554,561	277
CO	1,379,562	690
VOC	1,601,897	801

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

As shown above, facility emissions are already above the Offset and Major Source Thresholds for all criteria air contaminants.

5. Major Source Determination

Rule 2201 Major Source Determination:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)						
	NO _x	SO _x	PM ₁₀	PM _{2.5}	CO	VOC
SSPE1	748,121	2,121,476	554,561	554,561	1,379,562	1,601,897
SSPE2	748,121 (374 tons)	2,121,476	554,561	554,561	1,379,562	1,606,485
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	Yes	yes	yes	yes	yes	yes

Note: PM2.5 assumed to be equal to PM10

Annual emissions do not include emissions increases from outstanding ATCs

As seen in the table above, the facility is an existing Major Source for NO_x, SO_x, PM10, CO, and VOCs.

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination (tons/yr)						
	NO ₂	VOC	SO ₂	CO	PM	PM ₁₀
Estimated Facility PE before Project Increase (tpy)	374					
PSD Major Source Thresholds (tpy)	250	250	250	250	250	250
PSD Major Source? (Y/N)	y					

As shown above, the facility is an existing major source for PSD for at least one pollutant. Therefore, the facility is an existing major source for PSD.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project, to calculate the QNEC and if applicable, to determine the amount of offsets required.

Since this is a new emissions units, $BE = PE_1 = 0$ for VOC.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

As discussed in Section VII.C.6 above, the facility is an existing Major Source for all criteria air contaminants.

Major Modification Thresholds (Existing Major Source)			
Pollutant	Project PE2 (lb/year)	Threshold (lb/year)	Major Modification
VOC	4,588	50,000	N

The project's PE2 is less than the SB 2588 Major Modification Threshold for VOC.

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

The determination of Federal Major Modification is based on a two-step test. For the first step, only the emission *increases* are counted. Emission decreases may not cancel out the increases for this determination.

For new emissions units, the increase in emissions is equal to the PE2 for each new unit included in this project.

The project's combined total emission increases are compared to the Federal Major Modification Thresholds in the following table.

Federal Major Modification Thresholds for Emission Increases			
Pollutant	Total Emissions Increases (lb/yr)	Thresholds (lb/yr)	Federal Major Modification?
NO _x	0	0	Yes
VOC	4,588	0	Yes
PM ₁₀	0	30,000	No
SO _x	0	80,000	No

Since there is an increase in VOC emissions, this project constitutes a Federal Major Modification and no further analysis is required.

Federal Offset Quantities:

The Federal offset quantity is calculated only for the pollutants for which the project is a Federal Major Modification. The Federal offset quantity is the sum of the annual emission changes for all new and modified emission units in a project calculated as the potential to emit after the modification (PE2) minus the actual emissions (AE) during the baseline period for each emission unit times the applicable federal offset ratio. There are no special calculations performed for units covered by an SLC.

Only pollutants for which the project is a Federal Major Modification have Federal offset quantities. The calculated Federal offset quantity, listed in the table below, is entered into the Major Modification tracking spreadsheet under the heading "Federal Offset Quantity"

NOx		Federal Offset Ratio	1.5
Permit No.	Actual Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
S-1128-1018	0	4,588	4,588
Net Emission Change (lb/year):			4,588
Federal Offset Quantity: (NEC * 1.5)			6,882

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Sulfuric acid mist
- Hydrogen sulfide (H2S)
- Total reduced sulfur (including H2S)
- Reduced sulfur compounds

I. Project Location Relative to Class 1 Area

As demonstrated in the “PSD Major Source Determination” Section above, the facility was determined to be an existing PSD Major Source. Because the project is not located within 10 km (6.2 miles) of a Class 1 area – modeling of the emission increase is not required to determine if the project is subject to the requirements of Rule 2410.

II. Project Emission Increase – Significance Determination

a. Evaluation of Calculated Post-project Potential to Emit for New or Modified Emissions Units vs PSD Significant Emission Increase Thresholds

As a screening tool, the post-project potential to emit from all new and modified units is compared to the PSD significant emission increase thresholds, and if the

total potentials to emit from all new and modified units are below the applicable thresholds, no further PSD analysis is needed.

PSD Significant Emission Increase Determination: Potential to Emit (tons/year)					
	NO2	SO2	CO	PM	PM10
Total PE from New and Modified Units	0	0	0	0	0
PSD Significant Emission Increase Thresholds	40	40	100	25	15
PSD Significant Emission Increase?	N	N	N	N	N

As demonstrated above, because the post-project total potentials to emit from all new and modified emission units are below the PSD significant emission increase thresholds, this project is not subject to the requirements of Rule 2410 and no further discussion is required.

10. Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

$QNEC = PE2 - BE$, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
 PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
 BE = Baseline Emissions (per Rule 2201) for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.6 in the evaluation above, quarterly PE2 and quarterly BE is calculated in the following tables:

QNEC			
Pollutant	PE2	BE	QNEC
NO _x	0	0	0
SO _x	0	0	0
PM ₁₀	0	0	0
CO	0	0	0
VOC	4,588	0	1,147

VIII. COMPLIANCE

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

- a. Any new emissions unit with a potential to emit exceeding two pounds per day,
- b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
- c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
- d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

As seen above, the applicant is proposing to install a new tank with a PE greater than 2 lb/day for VOC. BACT is triggered for VOC since the PE is greater than 2 lb/day.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no existing emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project; therefore BACT is not triggered.

d. SB 288/Federal Major Modification

As discussed above, this project constitutes a Federal Major Modification for VOC; therefore BACT is triggered for VOC Federal Major Modification purposes.

2. BACT Guideline

BACT Guideline 7.3.1 applies to tanks/vessels issued (see **Attachment V**).

3. Top-Down BACT Analysis

Pursuant to the attached Top-Down BACT Analysis (see **Attachment VI**), BACT has been satisfied with the following:

VOC: PV-vent set to within 10% of maximum allowable pressure.

Proposed Rule 2201 BACT Condition:

This tank shall be equipped with a pressure-vacuum (PV) relief valve set to within 10% of the maximum allowable working pressure of the tank, labeled with the operating pressure settings, properly maintained in good operating order in accordance with the manufacturer's instructions, and shall remain in gas-tight condition except when the operating pressure exceeds the valve's set pressure. [District Rule 2201]

Note that the BACT Technologically Feasible requirement of vapor control was not found to be cost effective.

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals or exceeds the offset threshold levels in Table 4-1 or Rule 2201.

The applicant concedes they are over the offset threshold for VOCs. Therefore offsets are triggered for the emissions increases associated with this project approval.

2. Quantity of Offsets Required

As seen above, the SSPE2 is greater than the offset thresholds for VOCs; therefore offset calculations will be required for this project.

The quantity of offsets in pounds per year is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets required (lb/year) = $(\Sigma[PE2 - BE] + ICCE) \times DOR$, for all new or modified emissions units in the project,

Where,

PE2 = Post Project Potential to Emit, (lb/year)

BE = Baseline Emissions, (lb/year)

ICCE = Increase in Cargo Carrier Emissions, (lb/year)

DOR = Distance Offset Ratio, determined pursuant to Section 4.8

BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE)

BE = 0 for this new emissions unit.

The facility is proposing to install a new emissions unit; therefore Baseline Emissions are equal to zero. Also, there are no increases in cargo carrier emissions; therefore offsets can be determined as follows:

Offsets Required (lb/year) = PE2 x DOR

The project is a federal Major modification and therefore the Distance Offset Ration (DOR) is 1.5:1. The required offsets and proposed ERCs are summarized below:

The DOR is 1.5:1 as the project is a Federal Major Modification.

Offsets Required (lb/year) = $4,588 \times 1.5$
= 6,882 lb VOC/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quarterly offsets required (lb/qtr) = $(6,882 \text{ lb VOC/year}) \div (4 \text{ quarters/year})$
= 1,720.5 lb/qtr

Calculating the appropriate quarterly emissions to be offset is as follows:

As shown in the calculation above, the quarterly amount of offsets required for this project, when evenly distributed to each quarter, results in fractional pounds of offsets being required each quarter. Since offsets are required to be withdrawn as whole pounds, the quarterly amounts of offsets need to be adjusted to ensure the quarterly values sum to the total annual amount of offsets required.

To adjust the quarterly amount of offsets required, the fractional amount of offsets required in each quarter will be summed and redistributed to each quarter based on the number of days in each quarter. The redistribution is based on the Quarter 1 having the fewest days and the Quarters 3 and 4 having the most days. The redistribution method is summarized in the following table:

Redistribution of Required Quarterly Offsets (where X is the annual amount of offsets, and $X + 4 = Y.z$)				
Value of z	Quarter 1	Quarter 2	Quarter 3	Quarter 4
.0	Y	Y	Y	Y
.25	Y	Y	Y	Y+1
.5	Y	Y	Y+1	Y+1
.75	Y	Y+1	Y+1	Y+1

Therefore the appropriate quarterly emissions to be offset are as follows:

<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>	<u>Total Annual</u>
1,720	1,720	1,721	1,721	6,882

The following ERCs will be used to offset the emissions increase for the project.

Current Certificate	1Q	2Q	3Q	4Q	Total
S-410-1	5	7	11	15	38
S-3404-1	171	202	232	232	837
S-4004-1	460	466	471	470	1,867
S-4110-1	90	93	83	66	332
S-4549-1	0	182 (42 to Q1)	257 (157 to Q1)	114	553
From S-4549-1 2Q	42				
From S-4549-1 3Q	157				
S-1878-1	230	136	143	82	591
S-1912-1	225	238	250	250	963
S-1983-1	340	438	431	492	1701
Total	1,720	1,762 (1720 +42)	1,878 (1,721+157)	1,721	6,882
Total Offsets/Qtr	1,720	1,720	1,721	1,721	6,882

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

Proposed Rule 2201 (offset) Conditions:

Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter – 1,720 lb, 2nd quarter – 1,720 lb, 3rd quarter – 1,721 lb, and fourth quarter - 1721 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 2/18/16) for the ERC specified below. [District Rule 2201] Y

ERC Certificate Numbers S-410-1, S-3404-1, S-4004-1, S-4110-1, S-4549-1, S-1878-1, S-1912-1, and S-1983-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Y

C. Public Notification

1. Applicability

Public noticing is required for:

- a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
- b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
- c. Any project which results in the offset thresholds being surpassed, and/or
- d. Any project with an SSPE of greater than 20,000 lb/year for any pollutant.
- e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project is a Federal Major Modification. Therefore, public noticing for SB 288 or Federal Major Modification purposes is required.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. As seen in Section VII.C.2 above, this project does not include a new emissions unit which has daily emissions greater than 100 lb/day for any pollutant, therefore public noticing for PE > 100 lb/day purposes is not required.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO _x	>20,000 lb/year	>20,000 lb/year	20,000 lb/year	No
SO _x	>54,750 lb/year	>54,750 lb/year	54,750 lb/year	No
PM ₁₀	>29,200 lb/year	>29,200 lb/year	29,200 lb/year	No
CO	>200,000 lb/year	>200,000 lb/year	200,000 lb/year	No
VOC	>20,000 lb/year	>20,000 lb/year	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO _x	>20,000 lb/year	>20,000 lb/year	0	20,000 lb/year	No
SO _x	>54,750 lb/year	>54,750 lb/year	0	20,000 lb/year	No
PM ₁₀	>29,200 lb/year	>29,200 lb/year	0	20,000 lb/year	No
CO	>200,000 lb/year	>200,000 lb/year	0	20,000 lb/year	No
VOC	>20,000 lb/year	>20,000 lb/year	4,588	20,000 lb/year	No

As demonstrated above, the SSIPEs for all pollutants were less than 20,000 lb/year; therefore public noticing for SSIPE purposes is not required.

e. Title V Significant Permit Modification

As shown in the Discussion of Rule 2520 below, this project constitutes a Title V significant modification. Therefore, public noticing for Title V significant modifications is required for this project.

2. Public Notice Action

As discussed above, public noticing is required for this project. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

The permit DELs will be included as follows.

- *This tank shall only store, place, or hold organic liquid with a true vapor pressure (TVP) of less than 0.5 psia under all storage conditions. [District Rule 4623]*
- *Tank liquid throughput shall not exceed 2,000 barrels per day or 70,000 barrels per year. [District Rule 2201]*
- *VOC emission rate from the tank shall not exceed 103 lb/day or 4,588 lb/year. [District Rule 2201]*

E. Compliance Assurance

1. Source Testing

Pursuant to District Policy APR 1705, source testing is not required to demonstrate compliance with Rule 2201.

2. Monitoring

No monitoring is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. A condition addressing this requirement is included on the S-1128 facility-wide permit.

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

An AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. There are no AAQA standards for VOCs and therefore an AAQA is not required.

G. Compliance Certification

Section 4.15.2 of this Rule requires the owner of a new Major Source or a source undergoing a Title I Modification to demonstrate to the satisfaction of the District that all other Major Sources owned by such person and operating in California are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. As discussed in Section VIII above, this facility is a new major source and this project does constitute a Title I modification; therefore this requirement is applicable. CUSA's compliance certification is included in **Attachment VII.**

H. Alternate Siting Analysis

The current project occurs at an existing facility. The applicant proposes to authorize an organic liquid transfer operation.

Since the project will provide a tank to be used at the same location, the existing site will result in the least possible impact from the project. Alternative sites would involve the relocation and/or construction of various support structures on a much greater scale, and would therefore result in a much greater impact.

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII. C. 9. above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

This facility is subject to this Rule, and has received their Title V Operating Permit. Section 3.29 defines a significant permit modification as a "permit amendment that does not qualify as a minor permit modification or administrative amendment."

The project is Federal Major Modification and therefore is also a Title V Significant Modification. As discussed above, the facility has applied for a Certificate of Conformity (COC); therefore, the facility must apply to modify their Title V permit with an administrative amendment, prior to operating with the proposed modifications. Continued compliance with this rule is expected. The Title V Compliance Certification form is included in **Attachment VIII.**

District Rule 4001 New Source Performance Standards

This rule incorporates the New Source Performance Standards from 40 CFR Part 60. 40 CFR Part 60, Subparts K, Ka, Kb and OOOO could potentially apply to the tanks located at this facility. However, Subparts K, Ka and Kb do not apply to storage vessels less than 10,000 barrels used for petroleum or condensate that is stored, processed and/or treated at a drilling and production facility prior to transfer. Subpart OOOO has no standards for tanks with annual VOC emissions less than 6 tons per year.

Therefore, the requirements of these subparts are not applicable to this project.

District Rule 4101 Visible Emissions

District Rule 4101, Section 5.0, indicates that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour, which is dark or darker than Ringlemann 1 or equivalent to 20% opacity.

As long as the equipment is properly maintained and operated, compliance with visible emissions limits is expected under normal operating conditions.

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants, which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (**Attachment IX**), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

HRA Summary		
Unit	Cancer Risk	T-BACT Required
S-1128-1018-0	0.224 per million	No

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District Rule 4623 Storage of Organic Liquids

This rule applies to any tank with a capacity of 1,100 gallons or greater in which any organic liquid is placed, held or stored.

Per Section 4.4, tanks exclusively receiving and/or storing organic liquids with a TVP less than 0.5 psia are exempt from this rule except for complying with Sections 6.2, 6.3.6, 6.4, and 7.2. This tank will be limited to receiving and/or storing organic liquids with a TVP less than 0.5 psia. The following condition shall be placed on the ATC:

- *{2480} This tank shall only store, place, or hold organic liquid with a true vapor pressure (TVP) of less than 0.5 psia under all storage conditions. [District Rule 4623]*

The tank will not be served by a vapor control system. The applicant has elected to participate in the voluntary tank preventative inspection, maintenance, and tank cleaning program. Tank cleaning will be conducted according to the requirements of Table 6. As the tank is not subject to the requirements of District Rule 4623, the rule reference will be changed to District Rule 2080.

As this tank will not be equipped with a vapor recovery system, TVP and API gravity testing is required. The following conditions will be included on the permit:

- *Permittee shall conduct true vapor pressure (TVP) testing of the organic liquid stored in this tank, or representative tank as provided in District Rule 4623, at least once every 24 months during summer (July-September), and/or whenever there is a change in the source or type of organic liquid stored in this tank in order to maintain exemption from this rule. [District Rule 4623]*
- *{2482} The API gravity of crude oil or petroleum distillate shall be determined by using ASTM Method D 287-92 "Standard Test Method for API Gravity of Crude Petroleum Products (Hydrometer Method)". Sampling for API gravity shall be performed in accordance with ASTM Method D-4057-95 "Standard Practices for Manual Sampling of Petroleum and Petroleum Products". [District Rule 4623]*
- *{2483} For crude oil with an API gravity of 26 degrees or less, the TVP shall be determined using the latest version of the Lawrence Berkeley National Laboratory "Test Method for Vapor Pressure of Reactive Organic Compounds in*

Heavy Crude Oil using Gas Chromatograph", as approved by ARB and EPA.
[District Rule 4623]

- Instead of testing each uncontrolled fixed roof tank, the permittee may conduct a TVP test of the organic liquid stored in a representative tank. [District Rule 4623]
- {2911} The TVP testing shall be conducted at actual storage temperature of the organic liquid in the tank. The permittee shall also conduct API gravity testing. [District Rule 4623]
- The permittee shall keep accurate records of API gravity, true vapor pressure, storage temperature and types of liquids stored. [District Rules 2201 and 4623]
- Permittee shall submit the records of TVP and API gravity testing to the APCO within 45 days after the date of testing. The records shall include the tank identification number, Permit to Operate number, type of stored organic liquid, TVP and API gravity of the organic liquid, test methods used, and a copy of the test results. [District Rule 4623]

Heavy Oil Tank Inspection and Maintenance:

- Operator shall visually inspect tank shell, hatches, seals, seams, cable seals, valves, flanges, connectors, and any other piping components directly affixed to the tank and within five feet of the tank at least once per year for liquid leaks, and with a portable hydrocarbon detection instrument conducted in accordance with EPA Method 21 for gas leaks. Operator shall also visually or ultrasonically inspect as appropriate, the external shells and roofs of uninsulated tanks for structural integrity annually. [District Rule 2080]
- Upon detection of a liquid leak, defined as a leak rate of greater than or equal to 30 drops per minute, operator shall repair the leak within 8 hours. For leaks with a liquid leak rate of between 3 and 30 drops per minute, the leaking component shall be repaired within 24 hours after detection. [District Rule 2080]
- Upon detection of a gas leak, defined as a VOC concentration greater than 10,000 ppmv measured in accordance with EPA Method 21, operator shall take one of the following actions: 1) eliminate the leak within 8 hours of detection; or 2) if the leak cannot be eliminated, then minimize the leak to the lowest possible level within 8 hours after detection by using best management practices, and eliminate the leak within 48 hours after minimization. In no event shall the total time to minimize and eliminate a leak exceed 56 hours after detection. [District Rule 2080]
- Components found to be leaking either liquids or gases shall be immediately affixed with a tag showing the component to be leaking. Operator shall maintain records of the liquid or gas leak detection readings, date/time the leak was

discovered, and date/time the component was repaired to be a leak-free condition. [District Rule 2080]

- Leaking components that have been discovered by the operator that have been tagged and repaired within the timeframes specified in District Rule 4623, Table 3 shall not constitute a violation of this rule. Leaking components as defined by District Rule 4623 discovered by the District staff that were not previously identified and/or tagged by the operator, and/or leaks that were not repaired within the timeframes specified in District Rule 4623, Table 3 shall constitute a violation of this rule. [District Rule 2080]
- If a component type for a given tank is found to leak during an annual inspection, operator shall conduct quarterly inspections of that component type on the tank or tank system for four consecutive quarters. If no components are found to leak after four consecutive quarters, the operator may revert to annual inspections. [District Rule 2080]
- Any component found to be leaking on two consecutive annual inspections is in violation of this rule, even if covered under the voluntary inspection and maintenance program. [District Rule 2080]

Heavy Oil Tank Cleaning:

- Permittee shall notify the APCO in writing at least three (3) days prior to performing tank degassing and interior tank cleaning activities. Written notification shall include the following: 1) the Permit to Operate number and physical location of the tank being degassed, 2) the date and time that tank degassing and cleaning activities will begin, 3) the degassing method, as allowed in the permit, to be used, 4) the method to be used to clean the tank, including any solvents to be used, and 5) the method to be used to dispose of any removed sludge, including methods that will be used to control emissions from the receiving vessel and emissions during transport. [District Rule 4623 or 2080]
- This tank shall not be required to de-gas before commencing cleaning activities. All other applicable requirements shall be complied with before, during, and after tank cleaning activities. [District Rule 4623 or 2080]
- While performing tank cleaning activities, operators may only use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302 degrees F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams of VOC per liter or less. [District Rule 2080]
- Steam cleaning shall only be allowed at locations where wastewater treatment facilities are limited, or during the months of December through March. [District Rule 2080]

Compliance with District Rule 4623 requirements is expected.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

Greenhouse Gas (GHG) Significance Determination

District is a Responsible Agency

Oil and gas operations in Kern County must comply with the *Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting*. In 2015, Kern County revised the Kern County Zoning Ordinance Focused on Oil and Gas Activities (Kern Oil and Gas Zoning Ordinance) in regards to future oil and gas exploration, and drilling and production of hydrocarbon resource projects occurring within Kern County.

Kern County served as lead agency for the revision to their ordinance under the California Environmental Quality Act (CEQA), and prepared an Environmental Impact Report (EIR) that was certified on November 9, 2015. The EIR evaluated and disclosed to the public the environmental impacts associated with the growth of oil and gas exploration in Kern County, and determined that such growth will result in significant GHG impacts in the San Joaquin Valley. As such, the EIR included mitigation measures for GHG.

The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). As a Responsible

Agency, the District is limited to mitigating or avoiding impacts for which it has statutory authority. The District does not have statutory authority for regulating GHGs. The District has determined that the applicant is responsible for implementing GHG mitigation measures imposed in the EIR by the Kern County for the Kern County Zoning Ordinance.

District CEQA Findings

The proposed project is located in Kern County and is thus subject to the *Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting*. The *Kern County Zoning Ordinance* was developed by the Kern County Planning Agency as a comprehensive set of goals, objectives, policies, and standards to guide development, expansion, and operation of oil and gas exploration within Kern County.

In 2015, Kern County revised their *Kern County Zoning Ordinance* in regards to exploration, drilling and production of hydrocarbon resources projects. Kern County served as lead agency for the revision to their ordinance under the California Environmental Quality Act (CEQA), and prepared an Environmental Impact Report (EIR) that was certified on November 9, 2015. The revised Kern County Zoning Ordinance establishes a written process (Conformity Review permit process or Minor Activity permit) by which oil and gas exploration projects involving site-specific operations can be evaluated to determine whether the environmental effects of the operation were covered in the *Kern County Zoning Ordinance* EIR.

For stationary source emissions that are below the offset threshold, i.e. not required to surrender ERCs, and for non-stationary source emissions, Kern County entered into an Oil and Gas Emission Reduction Agreement (Oil and Gas ERA) with the District pursuant to the EIR. Per the Oil and Gas ERA, the applicant shall fully mitigate project emissions that are not required to be offset by District permit rules and regulations. Such mitigation can be achieved through any of the three options: (1) the applicants pay an air quality mitigation fee with each Oil and Gas Conformity Review permit issued by the Kern County, (2) the applicants may develop and propose to implement their own emission reduction projects instead of paying all or part of the mitigation fee, or (3) the applicants will be allowed to enter into an agreement directly with the District (if approved by Kern County) to develop an alternative fee schedule.

Kern County, as the lead agency, is the agency that will enforce the mitigation measures identified the EIR, including the mitigation requirements of the Oil and Gas ERA. As a responsible agency the District complies with CEQA by considering the EIR prepared by the Lead Agency, and by reaching its own conclusion on whether and how to approve the project involved (CCR §15096). The District has reviewed the EIR prepared by Kern County, the Lead Agency for the project, and finds it to be adequate. To reduce project related impacts on air quality, the District evaluates emission controls for the project such as Best

Available Control Technology (BACT) under District Rule 2201 (New and Modified Stationary Source Review). In addition, the District is requiring the applicant to surrender emission reduction credits (ERC) for stationary source emissions above the offset threshold.

Thus, the District concludes that through a combination of project design elements, permit conditions, and the Oil and Gas ERA, the project will be fully mitigated to result in no net increase in emissions. Pursuant to CCR §15096, prior to project approval and issuance of ATCs the District prepared findings.

Indemnification Agreement/Letter of Credit Determination

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The revision to the *Kern County Zoning Ordinance* went through an extensive public process that included a Notice of Preparation, a preparation of an EIR, scoping meetings, and public hearings. The process led to the certification of the final EIR and approval of the revised *Kern County Zoning Ordinance* in November 2015 by the Kern County Board of Supervisors. As mentioned above, the proposed project will be fully mitigated and will result in no net increase in emissions. In addition, the proposed project is not located at a facility of concern; therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Make preliminary decision to issue the requested Authority to Construct subject to the proposed conditions presented in **Attachment X**.

X. Billing Information

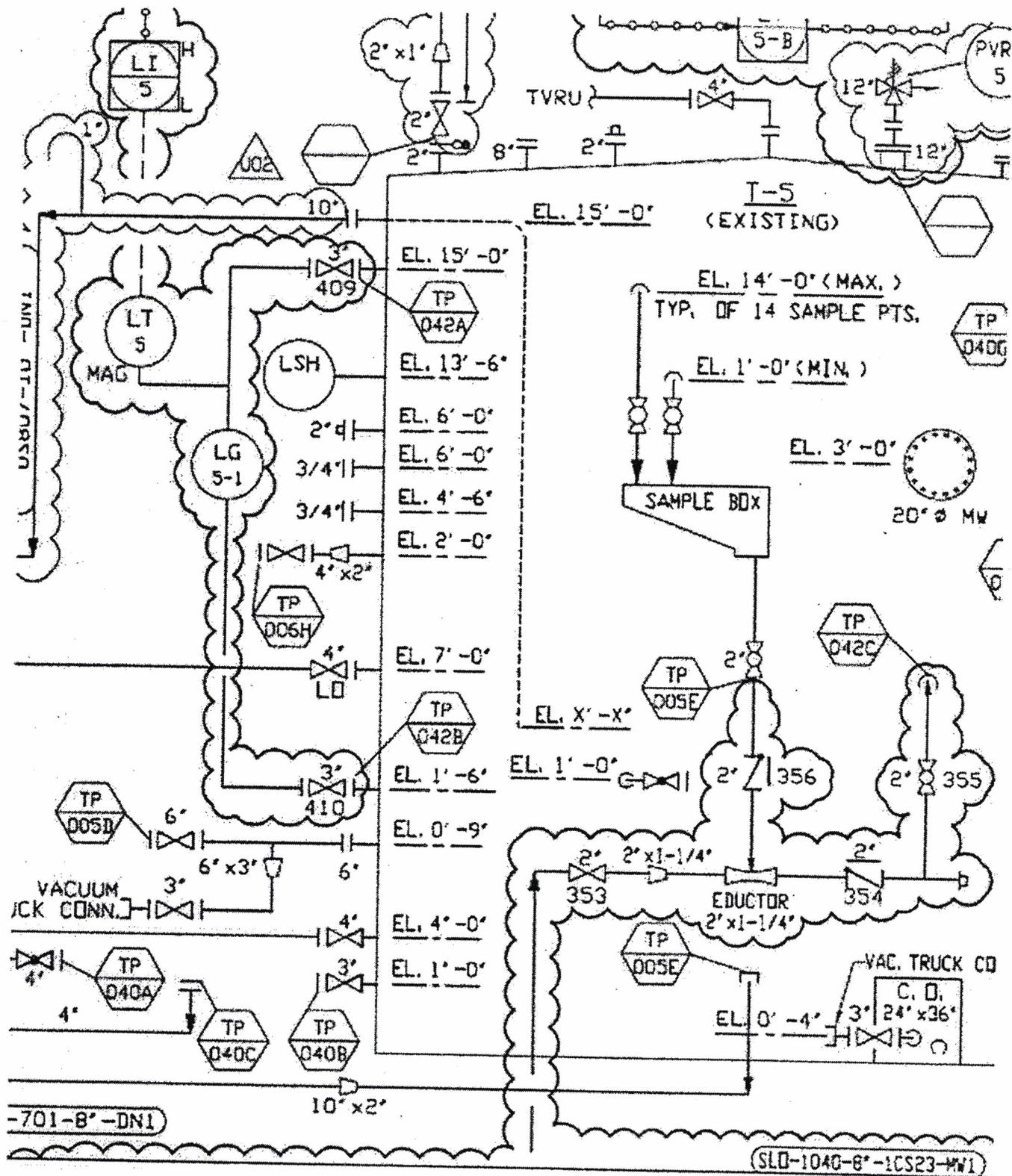
Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-1128-1018-0	3020-05-D	84,000 gallons	\$203.00

Attachments

- I: Process Diagram
- II: Laboratory Analysis
- III: Tank Emissions
- IV: Emissions Profiles
- V: BACT Guideline
- VI: BACT Analysis
- VII: Statewide Compliance Statement
- VIII: Title V Compliance Certification Form
- IX: HRA
- X: Draft ATCs

ATTACHMENT I

Process Diagram



Kris Rickards
 Environmental Engineer/Specialist - Air
 San Joaquin Valley Business Unit

Chevron North America Exploration & Production

ATTACHMENT II
Laboratory Analysis



GENERAL GAS ANALYSIS (C-6 +) (2.3.8)

ELAP Cert.1396-A

Rev 10/08/14

Chevron SATURN Reporting Format

Customer: Chevron Corporation
Address: 26251 Highway 33
 Fellows, CA 93224
Attention: 8o Bravo
Sample Description: Kerto Blend Fuel Gas TF 159, Temp 82°F Pressure 212 psia

Log #: 30598-4
Date Received: 5/2/15
Date Completed: 5/2/15
Report Date: 5/2/15

Constituent	Mole %	Wt %	Lv %
Oxygen/Argon O2 / Ar	0.097	0.174	0.050
Nitrogen N2	0.733	1.138	0.463
Carbon Dioxide CO2	3.938	9.607	3.854
Carbon Monoxide CO	0.000	0.000	0.000
Methane C-1	89.862	79.912	87.374
Ethane C-2	5.135	8.559	7.876
Propane C-3	0.188	0.485	0.314
Iso-Butane C-4	0.015	0.047	0.027
N-Butane C-4	0.016	0.052	0.029
Neo-Pentane C-5	0.000	0.000	0.000
Iso-Pentane C-5	0.003	0.014	0.007
N-Pentane C-5	0.001	0.005	0.003
Hexanes Plus C-6 (+)	0.001	0.006	0.003
Hydrogen H ₂	0.000	0.000	0.000
Hydrogen Sulfide H ₂ S	0.000	0.000	0.000
Total	100.000	100.000	100.000

	DMV	Grains H ₂ S 100 cu.ft.	VOC's	% Water Content	% VOC/THC
(1.2) Hydrogen Sulfide, H ₂ S =	0.00	0.000	(% by Wt. C-3+)	(lb/MM C.F.)	(% by Wt)
(1.2) Total Sulfur, as H ₂ S =	0.00	0.000	0.609	NR	0.288

	Gross BTU		Net BTU	
	dry	wet	dry	wet
(4.8.7.8) *** BTU cu.ft. Ideal =	1,004.72	987.24	906.09	890.32
*** BTU cu.ft. real =	1,007.05	989.53	908.18	892.38
BTU/lb, Ideal =	21,135.57	20,767.82	19,059.38	18,727.75

(Density) Sp. Gr. Ideal =	0.6228	0.6120	** GPM C-2+ =	0.936
(Density) Sp. Gr. Real =	0.6240	0.6132	** GPM C-3+ =	0.955
Density lbm/1000 ft ³ =	47.533	46.706	** GPM C-4+ =	0.972
			** GPM C-5+ =	0.987

C-H-O-N-S	% by Wt.
% Carbon =	69.787
% Hydrogen =	21.916
% Oxygen =	7.159
% Nitrogen =	1.138
% Sulfur =	0.000
Total =	100.000

* F.factor (80°F)	DSCF/MM Btu =	8,548
* F.factor (88°F)	DSCF/MM Btu =	8,678
	Sp.Vol. Cu.Ft./Lb =	21.03
	Av. Mol. Wt. =	18.04

QC CK	Measured	Range
1 Fidelity Ch =	0.00	(0.97-1.11)
2 Cont area Ch =	0.00	(1.3-9.2)E-8
3 Un-Norm Sum =	0.00	(-95-105)

Notes:

- * F.factor = dcsMMBTU (CARB)
- ** GPM = Gallons Per 1000 Ft³
- *** Hexane (+) BTU Calc. using GPA 2281 Constant
- **** VOC's Volatile Organic Constituents
- N.R. = "Not Requested"

Density-Specific Gravity where Air = 1.0000

DSCF = Dry Standard Cubic Feet

% VOC/THC = Wt. % [Volatile fraction / Total Hydrocarbon fraction] X 100

Btu/Lb Net Physical Constants not available in GPA 2145-09 (4.8.8)

References

- 1 ASTM D 9228-10
- 2 ASTM D 1945-03 (10)
- 3 ASTM D 1946-90 (11)
- 4 ASTM D 3588-98 (11)
- 5 ASTM D 1142-85 (12)
- 6 GPA 2172-88
- 7 GPA 2145-09
- 8 GPA 2281-00

QC _____ Date _____

All Calculations Tabulated @ 60°F
 dry, 14.698 psia
 (288.15°K, 101.325 kPa)

Date:

Kurt R. Buckle, BS Laboratory Director Midway Laboratory, Inc.

ATTACHMENT III
Tank Emissions

Tank Input Data	
permit number (S-xxxx-xx-xx)	S-1128-XXXX
facility tank I.D.	TBD
nearest city (1: Bakersfield, 2: Fresno, 3: Stockton)	1
tank ROC vapor pressure (psia)	0.5
liquid bulk storage temperature, T_b (°F)	152
is this a constant-level tank? {yes, no}	no
will flashing losses occur in this tank (only if first-line tank)? {yes, no}	no
breather vent pressure setting range (psi)	0.06
diameter of tank (feet)	30
capacity of tank (bbl)	2,000
conical or dome roof? {c, d}	c
shell height of tank (feet)	8
average liquid height (feet)	4
are the roof and shell the same color? {yes,no}	yes
For roof:	
color (1:Spec Al, 2:Diff Al, 3:Light, 4:Med, 5:Red, 6:White)	4
condition (1: Good, 2: Poor)	1
-----This row only used if shell is different color from roof-----	
-----This row only used if shell is different color from roof-----	4
	1

Liquid Input Data		A	B
maximum daily fluid throughput (bbl)			2000
maximum annual fluid throughput (bbl)			70,000
-----This row only used if flashing losses occur in this tank-----			0
-----This row only used if flashing losses occur in this tank-----			-
molecular weight, M_w (lb/lb-mol)			100

Calculated Values		A	B
daily maximum ambient temperature, T_{ax} (°F)			77.65
daily minimum ambient temperature, T_{an} (°F)			53.15
daily total solar insolation factor, I (Btu/ft ² -day)			1648.9
atmospheric pressure, P_a (psia)			14.47
water vapor pressure at daily maximum liquid surface temperature (T_{lx}), P_{vx} (psia)	128.1		2.1269
water vapor pressure at daily minimum liquid surface temperature (T_{ln}), P_{vn} (psia)	117.4		1.5845
water vapor pressure at average liquid surface temperature (T_{la}), P_{va} (psia)	122.8		1.8408
roof outage, H_{ro} (feet)			0.3125
vapor space volume, V_v (cubic feet)			3048.33
paint factor, α			0.68
vapor density, W_v (lb/cubic foot)			0.0080
daily vapor temperature range, ΔT_v (degrees Rankine)			49.04
vapor space expansion factor, K_e			0.1223

Results		
	lb/year	lb/day
Standing Storage Loss		
Working Loss	1,088	2.98
Flashing Loss	3,500	100.00
Total Uncontrolled Tank VOC Emissions	N/A	N/A
	4,588	103.0

ATTACHMENT IV Emissions Profiles

Permit #: S-1128-1018-0	Last Updated
Facility: CHEVRON USA INC	09/09/2016 EDGEHILR

Equipment Pre-Baselined: NO

	<u>NOX</u>	<u>SOX</u>	<u>PM10</u>	<u>CO</u>	<u>VOC</u>
Potential to Emit (lb/Yr):	0.0	0.0	0.0	0.0	4588.0
Daily Emis. Limit (lb/Day)	0.0	0.0	0.0	0.0	103.0
Quarterly Net Emissions Change (lb/Qtr)					
Q1:	0.0	0.0	0.0	0.0	1147.0
Q2:	0.0	0.0	0.0	0.0	1147.0
Q3:	0.0	0.0	0.0	0.0	1147.0
Q4:	0.0	0.0	0.0	0.0	1147.0
Check if offsets are triggered but exemption applies	N	N	N	N	N
Offset Ratio					1.5
Quarterly Offset Amounts (lb/Qtr)					
Q1:					1720.0
Q2:					1720.0
Q3:					1721.0
Q4:					1721.0

ATTACHMENT V BACT Guideline

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 7.3.1*

Last Update 10/1/2002

**Petroleum and Petrochemical Production - Fixed Roof Organic
Liquid Storage or Processing Tank, < 5,000 bbl Tank capacity ****

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
VOC	PV-vent set to within 10% of maximum allowable pressure	99% control (Waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program; transfer of noncondensable vapors to gas pipeline; reinjection to formation (if appropriate wells are available); or equal).	

** Converted from Determinations 7.1.11 (10/01/02).

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

ATTACHMENT VI BACT Analysis

Top Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

BACT Guideline 7.3.1 lists the controls that are considered potentially applicable to fixed-roof organic liquid storage or processing tank <5,000 bbl tank capacity. The VOC control measures are summarized below.

Technologically Feasible

99% control (waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program; transfer of uncondensed vapors to gas pipeline or reinjection to formation, if appropriate wells are available).

Achieved in Practice

PV relief valve set to within 10% of maximum allowable pressure.

Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 99 % control (waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program; transfer of uncondensed vapors to gas pipeline or reinjection to formation, if appropriate wells are available)
2. PV relief valve set to within 10% of maximum allowable pressure

Step 4 - Cost Effectiveness Analysis

As provided in the attached quote, the capital cost for a vapor control system to address the technologically feasible option is \$1,889,000.

The annualized capital cost is:

$AP = (P) \{[(i) (1 + i)^n] / [(1 + i)^n - 1]\}$, where

AP = Equivalent Annual Capital Cost of Control Equipment

P = Present value of the control equipment, including installation cost
= \$2,300,000

- i = interest rate (use 10% per policy)
- n = equipment life (assume 10 years per policy)

$$AP = (\$2,300,000) \left\{ \frac{[(0.1)(1+0.1)^{10}]}{[(1+0.1)^{10} - 1]} \right\} = \$374,210/\text{year}$$

Excluding annual operation costs, total annual cost of vapor control = \$374,210

For calculation of the amount of VOCs removed from the tank with the vapor control system, 100% control is assumed. The VOCs removed annually are 4,588 lb/yr (2.3 tons/yr)

$$\begin{aligned} \text{Annualized cost} &= \$374,210/\text{yr} / 2.3 \text{ tons/yr} \\ &= \$162,700/\text{ton} \end{aligned}$$

This value exceeds the cost effectiveness threshold for VOCs of \$17,500/ton. Therefore, the vapor control system is not cost effective.

Step 5 - Select BACT

PV relief valve set to within 10% of maximum allowable pressure of the tank.

Client: CHEVRON N.A.
 Project: TANK VAPOR RECOVERY SYSTEM
 Location: TAFT, CA
 Country: USA

FLUOR
 Contract No. A6JG
 06-Oct-16
 Rev. No. 3

ROM Class 1 Estimate for CHEVRON N.A. - TANK VAPOR RECOVERY SYSTEM

(Based on one existing Tank being serviced)

DESCRIPTION	CAPACITY BASIS			TOTAL EQUIP. PRICE	MULTIPLIER: EQUIP to DFC	TOTAL ESTIM. DFC	MULTIPLIER: DFC to TIC	TOTAL ESTIMATED TIC
MECHANICAL EQUIPMENT:								
TANK VAPOR RECOVERY UNIT								
K-2 COMPRESSOR - JA-A65 Single Acting Two Cylinder	25 HP Motor			62,400	x 4.0	329,600	x 1.90	\$626,000
INLET SEPARATOR -	1'0" dia x 5'7" s/s			16,450	x 5.0	77,250	x 1.90	\$147,000
E-K2 GAS COOLER	Duty = 43 MMBTU/HR ???			10,300	x 8.0	82,400	x 1.90	\$157,000
DEMOLITION (if required)					ALLOW	30,000	x 1.90	\$57,000
NEW PIPING (Bulks & Labor)	Lineal Feet	Diam	\$/LF		DFC	DFC Rounded		
etc.	70	4"	375		\$26,250	26,000	x 1.60	\$42,000
	100	2"	315		\$31,500	32,000	x 1.60	\$51,000
	25	1.5"	290		\$7,250	7,000	x 1.60	\$11,000
	25	1"	250		\$6,250	6,000	x 1.60	\$10,000
- Straight Run Pipe, including Pipe, minimal fittings, paint, supports, labor, etc.	500	2"	175		\$87,500	88,000	x 1.60	\$141,000
NEW ELECTRICAL (Bulks & Labor)								
- Electrical Equipment, labor, etc. (Allow)	1	Lot	30,000		\$30,000	30,000	x 1.60	\$48,000
- Electrical Runs, including wire, cable, conduit, terminations, labor, etc.	500	LF	50		\$25,000	25,000	x 1.60	\$40,000
OTHER MISCELLANEOUS BULKS & LABOR Incl. CIVIL, STRUCTURAL, CONTROLS SYSTEMS, Etc. (not covered in Equipment to DFC multipliers above)	ALLOW				\$100,000	100,000	x 1.60	\$160,000
TIE-INS TO EXISTING FACILITIES / SYSTEMS	ALLOW				\$30,000	30,000	x 1.60	\$48,000
SUBTOTAL ALL SCOPE (excluding Contingency)				\$108,150		\$863,250	1.78	\$1,536,000
CONTINGENCY	50.0%							\$769,000
TOTAL ALL SCOPE (Including Contingency)								\$2,307,000
TOTAL ALL SCOPE (Rounded)								\$2,300,000

NOTES:

ATTACHMENT VII
Statewide Compliance Statement



Donald Puckett
General Manager - Operations

San Joaquin Valley SBU
Chevron North America
Exploration and Production
P. O. Box 1392

January 13, 2015

Mr. Seyed Sadredin
San Joaquin Valley Air Pollution Control District
34946 Flyover Court
Bakersfield, CA 93308

RE: Statewide Compliance Certification

Dear Mr. Sadredin:

As required under District Rule 2201, Subsection 4.15.2 and Section 173(a)(3) of the Clean Air Act, 42 U.S.C. Section 7503, Chevron U.S.A. Inc. hereby submits this letter of certification regarding statewide compliance as of this date.

Based on reasonable inquiry and to the best of my knowledge and belief, the major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by Chevron U.S.A. Inc. in the State of California as listed below are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act:

- El Segundo Refinery
- El Segundo Marketing Terminal
- Richmond Refinery
- Banta Marketing Terminal
- Huntington Beach Marketing Terminal
- Montebello Marketing Terminal
- Sacramento Marketing Terminal
- Van Nuys Marketing Terminal
- Cross Valley Carneras Gas Compressor Facility (Kern County)
- Kettleman City Pump Station (Kings County)
- 27G Pump Station (Kern County)

- San Joaquin Valley Business Unit:
 - Fresno County Heavy Oil Source (Coalinga)
 - Fresno County Natural Gas Source (Coalinga)
 - Kern County Central Heavy Oil Source (Kern River)
 - Kern County Western Heavy Oil Source (Midway Sunset & Cymric)
 - Kern County Western Light Oil Source (Midway Sunset, Cymric & Lost Hills)
 - Kern County Western Gas Source (Cymric & Lost Hills)
 - San Ardo (Monterey County)

Mr. Seyed Sadredin
Statewide Compliance Certification
January 13, 2015
Page 2

- San Luis Obispo (San Luis Obispo County)
- Global Power (Joint Venture Facilities):
 - Coalinga Cogeneration Company in Fresno County
 - Kern River Cogeneration Company in Kern County
 - Mid-Set Cogeneration Company in Kern County
 - Salinas River Cogeneration Company in Monterey County
 - Sargent Canyon Cogeneration Company in Monterey County
 - Sycamore Cogeneration Company in Kern County

Please telephone Ashley Dahlstrom at (661) 654-7293 or Dave Bone at (661) 654-7150 if there are questions.

Sincerely,



Donald Puckett
General Manager - Operations

ATTACHMENT VIII
Title V Compliance Certification Form

**San Joaquin Valley
Unified Air Pollution Control District**

TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

I. TYPE OF PERMIT ACTION (Check appropriate box)

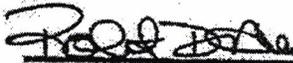
- SIGNIFICANT PERMIT MODIFICATION ADMINISTRATIVE AMENDMENT
 MINOR PERMIT MODIFICATION

COMPANY NAME: CHEVRON U.S.A. INC.	FACILITY ID: S-1128
1. Type of Organization: <input checked="" type="checkbox"/> Corporation <input type="checkbox"/> Sole Ownership <input type="checkbox"/> Government <input type="checkbox"/> Partnership <input type="checkbox"/> Utility	
2. Owner's Name: CHEVRON U.S.A. INC.	
3. Agent to the Owner: N/A	

II. COMPLIANCE CERTIFICATION (Read each statement carefully and initial all circles for confirmation):

- Based on information and belief formed after reasonable inquiry, the equipment identified in this application will continue to comply with the applicable federal requirement(s).
- Based on information and belief formed after reasonable inquiry, the equipment identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.
- Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.
- Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package, including all accompanying reports, and required certifications are true accurate and complete.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:


Signature of Responsible Official

6/2/16
Date

Robert Allen

Name of Responsible Official (please print)

Application for new 2,000 barrel drain tank

Name of Responsible Official (please print)

Operations Supervisor

Title of Responsible Official (please print)

ATTACHMENT IX
HRA

San Joaquin Valley Air Pollution Control District Risk Management Review

To: Richard Edgehill, AQE – Permit Services
 From: Stephanie Pellegrini, AQS – Technical Services
 Date: October 17, 2016
 Facility Name: Chevron USA, Inc
 Location: 2F OCP NW/4 Sec 2, T 11N, R 24W
 Application #(s): S-1128-1018-0
 Project #: S-1162368

A. RMR SUMMARY

RMR Summary			
Categories	Oil Tank (Unit 1018-0)	Project Totals	Facility Totals ¹
Prioritization Score	0.05	0.05	>1.0
Acute Hazard Index	0.10	0.10	0.74
Chronic Hazard Index	0.00	0.00	0.02
Maximum Individual Cancer Risk	2.24E-07	2.24E-07	7.78E-06
T-BACT Required?	No		
Special Permit Requirements?	No		

¹ Facilities S-1128, 1129, 1141, 2592 and 1549 are all considered the same facility. The facility totals in this summary represent the combined score for the facilities.

B. RMR REPORT

I. Project Description

Technical Services received a request on October 5, 2016, to perform a Risk Management Review for a proposed installation of a 200 bbl crude oil storage tank. An Ambient Air Quality Analysis was not required because VOCs are the only emissions for this project.

II. Analysis

Toxic emissions from Oilfield Fugitives were calculated using emission factors derived from 1991 source tests of central valley sites, and input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines. The prioritization score for the facility is greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required. The AERMOD model was used, with the parameters outlined below and

meteorological data for 2004-2008 from Fellows to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 1018-0			
Source Type	Circular Area	Location Type	Rural
Tank Height (m)	2.44	Closest Receptor (m)	550
Tank Diameter (m)	9.14	Type of Receptor	Residential
VOC Emissions (lb/hr)	4.29	VOC Emissions (lb/yr)	4,588

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

IV. Attachments

- A. RMR request from the project engineer
- B. Additional information from the applicant/project engineer
- C. Prioritization score w/ toxic emissions summary
- D. Facility Summary

ATTACHMENT X
Draft ATC

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT
DRAFT

PERMIT NO: S-1128-1018-0

LEGAL OWNER OR OPERATOR: CHEVRON USA INC
MAILING ADDRESS: P O BOX 1392
BAKERSFIELD, CA 93302

LOCATION: HEAVY OIL WESTERN STATIONARY SOURCE
KERN COUNTY

EQUIPMENT DESCRIPTION:
2000 BBL DRAIN TANK WITH NATURAL GAS BLANKETING (2F OCP)

CONDITIONS

1. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit
2. Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
3. Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter - 1,720 lb, 2nd quarter - 1,720 lb, 3rd quarter - 1,721 lb, and fourth quarter - 1,721 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 2/18/16) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit
4. ERC Certificate Numbers S-410-1, S-3404-1, S-4004-1, S-4110-1, S-4549-1, S-1878-1, S-1912-1, and S-1983-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit
5. This tank shall only store, place, or hold organic liquid with a true vapor pressure (TVP) of less than 0.5 psia under all storage conditions. [District Rule 4623] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director, APCO

Arnaud Marjolle, Director of Permit Services

S-1128-1018-0, Sep 9 2016 7:37PM -- EDGEHLR -- Joint Inspection NOT Required

6. Tank liquid throughput shall not exceed 2,000 barrels per day or 70,000 barrels per year. [District Rule 2201] Federally Enforceable Through Title V Permit
7. VOC emission rate from the tank shall not exceed 103.0 lb/day or 4,588 lb/year. [District Rule 2201 and 40 CFR Part 60, Subpart OOOO] Federally Enforceable Through Title V Permit
8. Permittee shall conduct true vapor pressure (TVP) testing of the organic liquid stored in this tank, or representative tank as provided in District Rule 4623, at least once every 24 months during summer (July - September), and/or whenever there is a change in the source or type of organic liquid stored in this tank in order to maintain exemption from the rule. [District Rule 4623] Federally Enforceable Through Title V Permit
9. The API gravity of crude oil or petroleum distillate shall be determined by using ASTM Method D 287 e1 "Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method). Sampling for API gravity shall be performed in accordance with ASTM Method D 4057 "Standard Practices for Manual Sampling of Petroleum and Petroleum Products." [District Rule 4623] Federally Enforceable Through Title V Permit
10. For crude oil with an API gravity of 26 degrees or less, the TVP shall be determined using the latest version of the Lawrence Berkeley National Laboratory "test Method for Vapor pressure of Reactive Organic Compounds in Heavy Crude Oil Using Gas Chromatograph", as approved by ARB and EPA. [District Rule 4623] Federally Enforceable Through Title V Permit
11. Instead of testing each uncontrolled fixed roof tank, the permittee may conduct a TVP test of the organic liquid stored in a representative tank. [District Rule 4623] Federally Enforceable Through Title V Permit
12. The TVP testing shall be conducted at actual storage temperature of the organic liquid in the tank. The permittee shall also conduct an API gravity testing. [District Rule 4623] Federally Enforceable Through Title V Permit
13. This tank shall be equipped with a pressure-vacuum (PV) relief valve set to within 10% of the maximum allowable working pressure of the tank, labeled with the operating pressure settings, properly maintained in good operating order in accordance with the manufacturer's instructions, and shall remain in gas-tight condition except when the operating pressure exceeds the valve's set pressure. [District Rule 4623] Federally Enforceable Through Title V Permit
14. Permittee shall submit the records of TVP and API gravity testing to the APCO within 45 days after the date of testing. The records shall include the tank identification number, Permit to Operate number, type of stored organic liquid, TVP and API gravity of the organic liquid, test methods used, and a copy of the test results. [District Rule 4623] Federally Enforceable Through Title V Permit
15. Operator shall visually inspect tank shell, hatches, seals, seams, cable seals, valves, flanges, connectors, and any other piping components directly affixed to the tank and within five feet of the tank at least once per year for liquid leaks, and with a portable hydrocarbon detection instrument conducted in accordance with EPA Method 21 for gas leaks. Operator shall also visually or ultrasonically inspect as appropriate, the external shells and roofs of uninsulated tanks for structural integrity annually. [District Rule 2080] Federally Enforceable Through Title V Permit
16. Upon detection of a liquid leak, defined as a leak rate of greater than or equal to 30 drops per minute, operator shall repair the leak within 8 hours. For leaks with a liquid leak rate of between 3 and 30 drops per minute, the leaking component shall be repaired within 24 hours after detection. [District Rule 2080] Federally Enforceable Through Title V Permit
17. Upon detection of a gas leak, defined as a VOC concentration of greater than 10,000 ppmv measured in accordance with EPA Method 21, operator shall take on of the following actions: 1) eliminate the leak within 8 hours after detection; or 2) if the leak cannot be eliminated, then minimize the leak to the lowest possible level within 8 hours after detection by using best maintenance practices, and eliminate the leak within 48 hours after minimization. In no event shall the total time to minimize and eliminate a leak exceed 56 hours after detection. [District Rule 2080] Federally Enforceable Through Title V Permit
18. Components found to be leaking either liquids or gases shall be immediately affixed with a tag showing the component to be leaking. Operator shall maintain records of the liquid or gas leak detection readings, date/time the leak was discovered, and date/time the component was repaired to a leak-free condition. [District Rule 2080] Federally Enforceable Through Title V Permit

DRAFT
CONDITIONS CONTINUE ON NEXT PAGE

19. Leaking components that have been discovered by the operator that have been immediately tagged and repaired within the timeframes specified in District Rule 4623, Table 3 shall not constitute a violation of this rule. Leaking components as defined by District Rule 4623 discovered by District staff that were not previously identified and/or tagged by the operator, and/or any leaks that were not repaired within the timeframes specified in District Rule 4623, Table 3 shall constitute a violation of this rule. [District Rule 2080] Federally Enforceable Through Title V Permit
20. If a component type for a given tank is found to leak during an annual inspection, operator shall conduct quarterly inspections of that component type on the tank or tank system for four consecutive quarters. If no components are found to leak after four consecutive quarters, the operator may revert to annual inspections. [District Rule 2080] Federally Enforceable Through Title V Permit
21. Any component found to be leaking on two consecutive annual inspections is in violation of this rule, even if covered under the voluntary inspection and maintenance program. [District Rule 2080] Federally Enforceable Through Title V Permit
22. Permittee shall notify the APCO in writing at least three (3) days prior to performing tank degassing and interior tank cleaning activities. Written notification shall include the following: 1) the Permit to Operate number and physical location of the tank being degassed, 2) the date and time that tank degassing and cleaning activities will begin, 3) the degassing method, as allowed in this permit, to be used, 4) the method to be used to clean the tank, including any solvents to be used, and 5) the method to be used to dispose of any removed sludge, including methods that will be used to control emissions from the receiving vessel and emissions during transport. [District Rule 2080] Federally Enforceable Through Title V Permit
23. This tank shall not be required to de-gas before commencing cleaning activities. All other applicable requirements shall be complied with before, during, and after tank cleaning activities. [District Rule 2080] Federally Enforceable Through Title V Permit
24. While performing tank cleaning activities, operators may only use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302 degrees F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams of VOC per liter or less. [District Rule 2080] Federally Enforceable Through Title V Permit
25. Steam cleaning shall only be allowed at locations where wastewater treatment facilities are limited, or during the months of December through March. [District Rule 2080] Federally Enforceable Through Title V Permit
26. The permittee shall keep accurate records of each organic liquid stored in the tank, including its storage temperature, TVP, and API gravity. [District Rule 4623] Federally Enforceable Through Title V Permit

DRAFT

**REGULATION 6
PARTICULATE MATTER
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**REGULATION 6
PARTICULATE MATTER
RULE 5
PARTICULATE EMISSIONS FROM REFINERY FLUIDIZED CATALYTIC
CRACKING UNITS**

(Adopted December 16, 2015)

6-5-100 GENERAL

6-5-101 Description: This rule limits the emissions of condensable particulate matter emissions from petroleum refinery fluidized catalytic cracking units (FCCUs) as well as emissions of precursors of secondary particulate matter. Regulation 6, Rule 1 addresses filterable particulate emissions from FCCUs. For the purposes of this rule, commingled ammonia, condensable particulate and sulfur dioxide emissions from an FCCU and one or more other sources from a single exhaust point shall all be considered to be FCCU emissions.

6-5-110 EXEMPTIONS

6-5-111 Exemption, Emissions Abated by Wet Scrubber: The emission limits in Section 6-5-301 shall not apply to emissions that are abated by a wet scrubber that is required to be operated by a District permit and that constitutes best available control technology (BACT) for any pollutant.

6-5-112 Limited Exemption, Emissions during Startup or Shutdown Periods: The requirements of Section 6-5-301 shall not apply to emissions during an FCCU startup or shutdown period. FCCU startup and shutdown periods shall be as defined in this rule, unless a different period is specified in a District Permit to Operate for an FCCU, in which case the Permit to Operate shall take precedence. This exemption is also applicable to a non-FCCU source with startup or shutdown provisions specified in a Permit to Operate, if that source is subject to the requirements of Section 6-5-301 because the source emissions are commingled with those of an FCCU at a single exhaust point; the startup or shutdown provisions specified in the Permit to Operate shall be the basis for this exemption. Whenever this exemption applies to any source, it shall apply to all sources with commingled emissions.

6-5-113 Limited Exemption, Installation of Wet Scrubber: The emission limit effective date for ammonia in Section 6-5-301 may be extended to a later date specified in a District Authority to Construct for an existing FCCU to be controlled with a new wet scrubber, but may not be extended by more than 36 months.

6-5-114 Limited Exemption, FCCU without Nitrogen-Based Additives: The emission limit for ammonia in Section 6-5-301 shall not apply to an FCCU where ammonia, urea or any other nitrogen-based additive is not used in a way that contributes to ammonia or condensable particulate FCCU emissions.

6-5-115 Limited Exemption, Ammonia Optimization: The ammonia emission limit in Section 6-5-301 shall not apply to the owner/operator of a refinery that implements an optimization of ammonia and/or urea injection in accordance with Section 6-5-403.

6-5-200 DEFINITIONS

6-5-201 Ammonia Slip: Ammonia slip is the amount of unreacted ammonia emitted to the atmosphere from the FCCU, regardless of the source of the ammonia.

6-5-202 Catalyst Regeneration Unit (CRU): A catalyst regeneration unit regenerates spent FCCU catalyst by burning off the coke that has deposited on the catalyst surface. The resulting CRU flue gas is the primary emission source addressed by this rule.

- 6-5-203 Condensable Particulate Matter:** Liquid droplets that coalesce, or gaseous emissions that condense to form liquid or solid particles. These liquid and/or solid particles are identified as condensable organic or condensable inorganic particulate matter using EPA Test Method 202.
- 6-5-204 Daily Average:** The arithmetic mean of the measured ammonia emissions subject to Section 6-5-301 on any calendar day that the FCCU operates.
- 6-5-205 FCCU Shutdown:** Unless otherwise specified in a District Permit to Operate, FCCU shutdown is a period which begins when fresh feed flow to the FCCU reactor stops and ends when the main blower for catalyst recirculation is shutdown.
- 6-5-206 FCCU Startup:** Unless otherwise specified in a District Permit to Operate, FCCU startup is a period not exceeding 120 hours which begins with the startup of the main blower for introduction of catalyst and ends after fresh feed is introduced to the FCCU reactor, when the process reaches steady state.
- 6-5-207 Fluidized Catalytic Cracking Unit (FCCU):** A fluidized catalytic cracking unit (FCCU) is a processing unit that converts heavy petroleum fractions, typically from crude oil distillation units, into lighter fuel intermediates by using a fine, powdered catalyst to promote a chemical reaction in which the heavy petroleum molecules are broken into smaller molecules. In addition to the cracking reactor, an FCCU includes a catalyst regeneration unit (CRU), ancillary equipment including blowers, and all equipment for controlling air pollutant emissions and recovering heat.
- 6-5-208 Petroleum Refinery:** An establishment that is located on one or more contiguous or adjacent properties that processes crude oil to produce more usable products such as gasoline, diesel fuel, aviation fuel, lubricating oils, asphalt or petrochemical feedstocks. Petroleum refinery processes include separation processes (e.g., atmospheric or vacuum distillation, and light ends recovery), petroleum conversion processes (e.g., cracking, reforming, alkylation, polymerization, isomerization, coking, and visbreaking) petroleum treating processes (e.g., hydrodesulfurization, hydrotreating, chemical sweetening, acid gas removal, and deasphalting), feedstock and product handling (e.g., storage, blending, loading, and unloading), auxiliary facilities (e.g., boilers, waste water treatment, hydrogen production, sulfur recovery plant, cooling towers, blowdown systems, compressor engines, and power plants).
- 6-5-209 Primary Particulate Matter:** Material emitted to the atmosphere as filterable or condensable particulate matter.
- 6-5-210 Secondary Particulate Matter:** Material emitted to the atmosphere in a gaseous form that will not coalesce or condense to a solid or liquid form at atmospheric temperature and pressure, but that may react in the atmosphere into a solid or liquid form. For the purposes of this rule, precursors of Secondary Particulate Matter shall include sulfur dioxide (SO₂) and ammonia.
- 6-5-211 Wet Scrubber:** A device that removes air pollutants from gas streams by contacting the gas stream with a scrubbing liquid.

6-5-300 STANDARDS

6-5-301 Fluidized Catalytic Cracking Unit (FCCU) Emission Limits: The owner/operator of a Petroleum Refinery that includes an FCCU shall not cause emissions to the atmosphere from the FCCU that exceed the limits in Table 1 on or after the indicated effectiveness date:

Pollutant	Emission Limit	Effective Date
Ammonia	10 ppmvd at 3% O ₂ as a daily average	January 1, 2018
Condensable Particulate Matter	[future]	[future]
Sulfur Dioxide (SO ₂)	[future]	[future]

6-5-400 ADMINISTRATIVE REQUIREMENTS

6-5-401 Ammonia Control Plan and Permit Applications: No later than January 1, 2017, the owner/operator of a Petroleum Refinery subject to the ammonia emission limit in Section 6-5-301 shall submit to the APCO a control plan detailing the measures, if any, to be taken in order to meet the requirements of Section 6-5-301, and also applications for all Authorities to Construct necessary for compliance with Section 6-5-301.

6-5-402 Ammonia Monitoring Plan: No later than January 1, 2017, the owner/operator of a Petroleum Refinery that includes an FCCU subject to the ammonia emission limit in Section 6-5-301 shall submit to the APCO a plan for the installation of an ammonia monitoring system to perform monitoring as required by Section 6-5-501. This plan shall identify the proposed monitoring technique, monitoring equipment, installation details and installation schedule.

6-5-403 Ammonia Optimization: As an alternative to compliance with the ammonia emission limit of Section 6-5-301, the owner/operator of a refinery may instead establish an enforceable ammonia emission limit for the FCCU that results in the minimization of total FCCU PM_{2.5} emissions (including all condensable particulate matter), as follows:

403.1 No later than March 1, 2016, the refinery owner/operator shall submit to the APCO an Optimization and Demonstration Protocol for the purpose of establishing the minimum rate of ammonia and/or urea injection necessary to minimize total PM_{2.5} FCCU emissions (including all condensable particulate matter) while complying with all existing permit requirements, excluding permit requirements that are not based on District BACT requirements, on District prohibitory rule limits or on federal consent decrees. The Optimization Protocol shall include the ammonia and/or urea injection rates to be evaluated and the criteria for selecting these rates, and also the criteria for determining the Optimized Ammonia Emissions Concentration that minimizes total FCCU PM_{2.5} emissions.

403.2 Within 60 days, the APCO shall either approve or disapprove the Optimization and Demonstration Protocol.

403.3 The refinery owner/operator shall commence and complete the Optimization and Demonstration Protocol, approved by the APCO, no later than June 30, 2017.

403.4 The refinery owner/operator shall report to the APCO the results of the Optimization and Demonstration Protocol and the proposed Optimized Ammonia Emissions Concentration no later than August 31, 2017. No later than this same date, the refinery owner/operator shall submit a District permit application to 1) establish the Optimized Ammonia Emissions Concentration as an enforceable permit requirement, and to 2) relax any existing permit conditions that are not based on District BACT requirements, on District prohibitory rule limits or on federal consent decrees to the extent necessary to minimize total FCCU PM_{2.5} emissions.

403.5 Disapproval of an Optimization and Demonstration Protocol, or a failure to meet any requirement or deadline in this section shall not constitute a violation of this rule, but shall preclude the applicability of the limited exemption in Section 6-5-115.

6-5-500 MONITORING AND RECORDS

6-5-501 Ammonia Monitoring: The owner/operator of a Petroleum Refinery that includes an FCCU subject to the ammonia emission limit in Section 6-5-301 shall, no later than January 1, 2018, operate one of the following;

501.1 A mass-balance monitoring system that includes all of the following:

- 1.1 Parametric monitors that comply with District Regulation 1, Section 523 to continuously measure the injection or addition rate (pounds per hour) of ammonia, urea or any other nitrogen-based additive into the emission stream, and;
 - 1.2 Continuous emission monitors that comply with District Regulation 1, Section 522 to continuously measure NOx and oxygen concentrations at appropriate locations to allow a calculation of the amount of ammonia and/or urea consumed in NOx-reduction reactions, and therefore the remaining, emitted amount of non-consumed ammonia.
- 501.2 Any other ammonia emission monitoring system approved in writing by the APCO.

6-5-502 Ammonia Records: The owner/operator of a Petroleum Refinery subject to the ammonia emission limit in Section 6-5-301 shall maintain records of the data required to be measured in Section 6-5-501. These records shall be kept for a period of at least five years and shall be made available to the APCO on request.

6-5-600 MANUAL OF PROCEDURES

6-5-601 Compliance Determination: All compliance determinations shall be made in the as-found operating condition. No compliance determinations shall be made during periods subject to the exemption in Section 6-5-112.

6-5-602 Determination of Ammonia and Oxygen: Determination of ammonia shall be by Regulation 1, Section 522 NOx monitors or other APCO approved ammonia monitoring system. Determination of oxygen shall be by Regulation 1, Section 522 oxygen monitor.

**REGULATION 8
ORGANIC COMPOUNDS
RULE 6
ORGANIC LIQUID BULK TERMINALS AND BULK PLANTS**

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**REGULATION 8
ORGANIC COMPOUNDS
RULE 6
ORGANIC LIQUID BULK TERMINALS AND BULK PLANTS**

8-6-100 GENERAL

8-6-101 Description: The purpose of this rule is to limit emissions of organic compounds as defined in Section 8-6-207 from transfer operations at non-gasoline organic liquid bulk terminals and bulk plants. (Amended March 17, 1982; February 2, 1994)

8-6-110 Exemption, Low Vapor Pressure Organic Liquids: Until December 1, 1994, the requirements in this Rule shall not apply to loading or delivery of any organic liquid having a true vapor pressure less than 77.5 mmHg (1.5 psia). After December 1, 1994, the requirements of this Rule shall not apply to loading and delivery of any organic liquid having a true vapor pressure less than 25.8 mmHg (0.5 psia), as determined by the methods specified in Sections 8-6-603 or 604. (Amended February 2, 1994)

8-6-111 Exemption, Low Throughput: The vapor recovery requirements of subsection 8-6-302.1 do not apply when the total annual throughput of organic liquids with at least 77.5 mmHg (1.5 psia) true vapor pressure transferred into delivery vehicles only is less than 2,271 cubic meters (600,000 gallons) on a facility-wide basis. (Amended February 2, 1994)

8-6-112 Deleted February 2, 1994

8-6-113 Deleted February 2, 1994

8-6-114 Exemption, Maintenance and Repair: The requirements of Section 8-6-306 shall not apply to spills resulting from maintenance or repair operations provided proper operating practices are employed to minimize evaporation of organic compounds into the atmosphere.

8-6-115 Exemption, Bulk Gasoline Distribution Facilities: Gasoline bulk terminals and bulk plants are not subject to the requirements of this rule. Such facilities are subject to the provisions of Regulation 8, Rules 33 or 39. (Adopted November 30, 1983; Amended February 2, 1994)

8-6-116 Exemption, Small Transportable Containers: The requirements of subsection 8-6-302.2 shall not apply to loading organic liquids into any transportable container with a capacity less than 0.114 cubic meters (30 gallons). (Amended February 2, 1994)

8-6-117 Exemption, Liquefied Organic Gases: The requirements of this rule do not apply to transfer operations involving liquefied organic gases such as liquefied petroleum gas (LPG) and halogenated gases. (Amended February 2, 1994)

8-6-200 DEFINITIONS

8-6-201 Bulk Plant: Until December 1, 1994, any storage and distribution facility that receives organic liquid by pipeline, railcar, and/or delivery vehicle; stores it in stationary tanks; and/or mixes it in blending tanks; and/or loads it into delivery vehicles or transportable containers, for delivery to distributors, marketers or any product end user; and which has an annual throughput of not more than 22,710 cubic meters (6,000,000 gallons). After December 1, 1994, the annual throughput shall include organic liquids of at least 25.8 mmHg (0.5 psia) true vapor pressure. (Amended July 2, 1980; February 2, 1994)

8-6-202 Deleted February 2, 1994

8-6-203 Submerged Fill Pipes: Any discharge pipe, lance, or nozzle which meets either of the following conditions:

203.1 Where the vessel is filled from the top, the end of the discharge pipe or nozzle must be submerged when the liquid level is 15 centimeters (6 inches) from the bottom of the vessel. When the vessel is filled from the top with a

retractable lance, the lance shall remain below the liquid surface during the transfer operation.

203.2 Where the vessel is filled from the side, the discharge pipe or nozzle must be totally submerged when the liquid level is 46 centimeters (18 inches) from the bottom of the vessel.

(Renumbered March 17, 1982; Amended February 2, 1994)

8-6-204 Bulk Terminal: Until December 1, 1994, any storage and distribution facility that receives organic liquid; stores it in stationary tanks; and/or mixes it in blending tanks; and/or loads it into delivery vehicles and transportable containers, for delivery to distributors, marketers or any product end user; and which has an annual throughput of more than 22,710 cubic meters (6,000,000 gallons). After December 1, 1994, the annual throughput shall include organic liquids of at least 25.8 mmHg (0.5 psia) true vapor pressure.

(Renumbered March 17, 1982; Amended February 2, 1994)

8-6-205 True Vapor Pressure: The pressure exerted when an organic liquid is in equilibrium with its own vapor at 25°C (77°F). For liquid mixtures, true vapor pressure is the sum of the equilibrium partial pressures exerted by all organic compounds in the liquid and can be estimated using Raoult's Law as follows:

$$P^* = \sum_{i=1}^n \frac{(w_i)(VP_i) / MW_i}{\frac{W_w}{MW_w} + \sum_{i=1}^n \frac{W_i}{MW_i}}$$

Where:

W_i = Weight of the "i"th organic compound, in grams

W_w = Weight of water, in grams

MW_i = Molecular weight of the "i"th organic compound, in grams/gram-mole

MW_w = Molecular weight of water, in grams/gram-mole

P^* = True vapor pressure of liquid mixture at 25°C, in mmHg

VP_i = Vapor pressure of the "i"th organic compound at 25°C, in mmHg

For organic liquids and organic liquid mixtures to which heat is applied, the true vapor pressure shall be determined at 25°C (77°F) or the actual loading temperature, whichever is higher.

(Renumbered March 17, 1982; Amended February 2, 1994)

8-6-206 Vapor Tight: A leak less than 100 percent of the Lower Explosive Limit on a portable hydrocarbon detector measured at a distance of 1 centimeter from the source.

(Renumbered March 17, 1982; Amended February 2, 1994)

8-6-207 Organic Compound: Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides of carbonates, and ammonium carbonate. (Adopted February 2, 1994)

8-6-208 Loading Equipment: Any combination of loading arms, pumps, flexible hoses, dispensing nozzles, meters, and other piping and valves necessary to fill delivery vehicles or transportable containers with organic liquids. (Adopted February 2, 1994)

8-6-209 Organic Liquid: Any organic compound or mixture of organic compounds that exists in the liquid phase at actual loading conditions. For the purposes of this rule, organic liquids shall not include coatings, adhesives and sealants.

(Adopted February 2, 1994)

8-6-210 Transportable Containers: Any portable enclosed vessel such as a tote tank or cylindrical drum, which contains 550 gallons or less and is used to transport and distribute organic liquids. (Adopted February 2, 1994)

8-6-211 Leak Free: An organic liquid leak not exceeding three drops per minute excluding losses which occur upon disconnecting transfer fittings. Such disconnect losses shall not exceed 10 milliliters (ml) during a bottom loading operation or no more than two milliliters (ml) during a top loading operation, averaged over three disconnects.

Adopted February 2, 1994)

8-6-212 Delivery Vehicle: Any motor truck or truck trailer equipped with a stationary cargo tank having a capacity more than 550 gallons and designed and built for the transportation of organic liquids. (Adopted February 2, 1994)

- 8-6-213 Switch Loading:** For the purpose of this rule, switch loading refers to the transfer of organic liquids into a delivery vehicle cargo tank, which results in displacement of organic vapors remaining from a previous load. (Adopted February 2, 1994)
- 8-6-214 Vapor Loss Control System:** A system for reducing emissions to the atmosphere, consisting of an abatement device and a collection system, which achieves the abatement efficiency or emission limit specified in the applicable standard(s) during the transfer operation and meets the requirements of Regulation 2, Rule 1. (Adopted February 2, 1994)
- 8-6-215 Liquefied Petroleum Gas:** A compressed gas composed of one or more of the following flammable hydrocarbons (propane, n-butane, isobutane, propylene, and butylenes), which is used especially as a fuel or as raw material for chemical synthesis. (Adopted February 2, 1994)
- 8-6-216 Vapor Balance System:** A piping system that is designed to collect organic vapors displaced from organic liquid transfer operations, and to route the collected vapors to the vessel from which the liquid being loaded originated. (Adopted February 2, 1994)
- 8-6-217 Throughput:** The total volume of organic liquid transferred into delivery vehicles and transportable containers. The volume of water in an organic liquid/water mixture shall not be considered part of the facility throughput. (Adopted February 2, 1994)
- 8-6-300 STANDARDS**
- 8-6-301 Bulk Terminal Limitations:** A person shall not transfer or allow the transfer of organic liquids from bulk terminal loading equipment unless a vapor loss control system is properly connected and used. Such transfer operations shall not emit into the atmosphere more than 21 grams of organic compounds per cubic meter (0.17 pounds per 1,000 gallons) of organic liquid loaded. Switch loading shall be subject to this standard. (Amended March 17, 1982; February 2, 1994)
- 8-6-302 Bulk Plant Limitations:** A person shall not load or allow the loading of any organic liquid from bulk plant loading equipment unless the following requirements are satisfied:
- 302.1 Vapor Recovery Requirement: Any emissions displaced while transferring an organic liquid with a true vapor pressure of at least 77.5 mmHg (1.5 psia) into a delivery vehicle shall be controlled by a vapor balance system or a vapor loss control system, which is properly connected and used during loading. Emissions to atmosphere shall not exceed 44 grams of organic compounds per cubic meter (0.35 pounds per 1,000 gallons) of organic liquid loaded.
- 302.2 Submerged Fill Requirement: Except as provided in Section 8-6-116, either a submerged fill pipe, bottom filling, or a vapor loss control system shall be used when transferring an organic liquid into a delivery vehicle or transportable container. When a vapor loss control system is used, emissions to atmosphere shall not exceed 44 grams of organic compound per cubic meter (0.35 pounds per 1000 gallons) of organic compound loaded. (Amended July 2, 1980; February 2, 1984)
- 8-6-303 Deleted February 2, 1994**
- 8-6-304 Deliveries to storage Tanks:** A person shall not transfer or allow the transfer of any organic liquid with a true vapor pressure of at least 77.5 mmHg (1.5 psia) into any bulk terminal or bulk plant storage tank having a capacity between 7.6 and 150 cubic meters, (2,008 and 39,630 gallons) inclusive, unless a vapor balance system or vapor loss control system, has been properly installed on the storage tank and is properly connected during delivery. Emissions to atmosphere shall not exceed 21 grams of organic compounds per cubic meter (0.17 pounds per 1,000 gallons) of organic compound loaded. (Amended February 2, 1994)
- 8-6-305 Delivery Vehicle Requirements:** Any delivery vehicle loaded at a terminal or bulk plant which is subject to the requirements of Sections 8-6-301 or 302.1 shall be equipped to allow proper connection to the vapor balance system or vapor loss

control system required by the section and shall be maintained to be vapor tight, leak free, and in good working order. (Amended February 2, 1994)

8-6-306 Equipment Maintenance: All equipment associated with organic liquid delivery and loading operations shall be maintained to be vapor tight, leak free and in good working order. (Amended February 2, 1994)

8-6-307 Operating Practices: Any organic liquid subject to this Rule shall not be spilled, discarded in sewers, stored in open containers, or handled in any other manner that would result in evaporation to the atmosphere. (Amended February 2, 1994)

8-6-400 ADMINISTRATIVE REQUIREMENTS

8-6-401 Deleted February 2, 1994

8-6-402 Deleted February 2, 1994

8-6-403 Compliance Schedule: Any person who must install or modify equipment to comply with the requirements of Sections 301, 302 or 304 shall comply with the following increments of progress:

403.1 By June 1, 1994 submit a completed application to the APCO for an Authority to Construct.

403.2 After December 1, 1994 be in final compliance. (Adopted February 2, 1994)

8-6-500 MONITORING AND RECORDS

8-6-501 Records: After December 1, 1994, a person whose loading equipment is subject to this rule shall comply with the following requirements:

501.1 A person shall maintain a current record of the true vapor pressure of each organic liquid and organic liquid mixture.

501.2 A person shall maintain monthly records that provide the throughput (gallons) of each organic liquid and organic liquid mixture transferred into delivery vehicles and transportable containers with at least 25.8 mmHg (0.5 psia) true vapor pressure.

501.3 Such records shall be retained for the previous 24-month period and be available to the APCO upon request. (Adopted February 2, 1994)

8-6-502 Portable Hydrocarbon Detector: Any instrument used for the measurement of organic compounds shall meet the specifications and performance criteria, and shall be calibrated in accordance with EPA Reference Method 21 (40CFR60, Appendix A). (Adopted February 2, 1994)

8-6-503 Burden of Proof: The burden of proof of eligibility for exemption from the requirements of this rule is on the applicant. Persons seeking such an exemption shall maintain adequate records and furnish them to the APCO upon request. (Adopted February 2, 1994)

8-6-600 MANUAL OF PROCEDURES

8-6-601 Efficiency and Rate Determination: The means for determining compliance with Sections 8-6-301, 302, and 304 are set forth in the Manual of Procedures, Volume IV, ST-3 or ST-34. (Amended March 17, 1982; February 2, 1994)

8-6-602 Deleted February 2, 1994

8-6-603 Analysis of Samples, True Vapor Pressure: Samples of organic compounds as specified in Section 8-6-110 shall be analyzed for true vapor pressure at 25°C (77°F), as prescribed in the Manual of Procedures, Volume III, Method 28. For organic liquids and organic liquid mixtures to which heat is applied, the true vapor pressure shall be determined at 25°C (77°F) or the actual loading temperature, whichever is higher.

(Adopted March 17, 1982; Amended February 2, 1994)

8-6-604 Determination of Applicability: Any of the following methods may be used to determine if an organic liquid is subject to the requirements of this rule based on its true vapor pressure:

604.1 EPA-450/3-87-026 (Exhibit A-2 in Appendix A or Appendix D), or

- 604.2 Standard reference texts, or
- 604.3 For liquid mixtures, use Raoult's Law of Partial Pressures as defined in Section 8-6-205 or ASTM Method D 2879-83. (Adopted February 2, 1994)

**REGULATION 8
ORGANIC COMPOUNDS
RULE 5
STORAGE OF ORGANIC LIQUIDS**

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- 8-5-114 Deleted May 4, 1988
- 8-5-115 Deleted May 4, 1988
- 8-5-116 Exemption, Gasoline Storage Tanks at Gasoline Dispensing Facilities
- 8-5-117 Limited Exemption, Low Vapor Pressure
- 8-5-118 Limited Exemption, Gas Tight Requirement
- 8-5-119 Limited Exemption, Repair Period

8-5-200 DEFINITIONS

- 8-5-201 Deleted October 18, 2006
- 8-5-202 Storage Tank
- 8-5-203 Deleted November 27, 2002
- 8-5-204 Organic Liquid
- 8-5-205 Gasoline
- 8-5-206 Gas Tight
- 8-5-207 Approved Emission Control System
- 8-5-208 Degassing
- 8-5-209 External Floating Roof Tank
- 8-5-210 Internal Floating Roof Tank
- 8-5-211 True Vapor Pressure
- 8-5-212 Organic Compound
- 8-5-213 Viewport
- 8-5-214 Gauge Float
- 8-5-215 Guidepole
- 8-5-216 Zero Gap Pole Wiper Seal
- 8-5-217 Decommissioning
- 8-5-218 Stock Change
- 8-5-219 Tank Cleaning
- 8-5-220 Temporary Removal From Service
- 8-5-221 Liquid Balancing
- 8-5-222 Pressure Relief Device
- 8-5-223 Pressure Vacuum Valve
- 8-5-224 Connection
- 8-5-225 Good Operating Condition
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8-5-300 STANDARDS

- 8-5-301 Storage Tank Control Requirements
- 8-5-302 Requirements for Submerged Fill Pipes
- 8-5-303 Requirements for Pressure Vacuum Valves
- 8-5-304 Requirements for External Floating Roof Tanks
- 8-5-305 Requirements for Internal Floating Roof Tanks

- 8-5-306 Requirements for Approved Emission Control Systems
- 8-5-307 Requirements for Fixed Roof Tanks, Pressure Tanks and Blanketed Tanks
- 8-5-310 Deleted May 4, 1988
- 8-5-311 Deleted November 27, 2002
- 8-5-312 Deleted January 20, 1993
- 8-5-313 Deleted January 20, 1993
- 8-5-314 Deleted January 20, 1993
- 8-5-320 Floating Roof Tank Fitting Requirements
- 8-5-321 Primary Seal Requirements
- 8-5-322 Secondary Seal Requirements
- 8-5-323 Deleted January 20, 1993
- 8-5-324 Deleted January 20, 1993
- 8-5-325 Deleted January 20, 1993
- 8-5-326 Deleted May 4, 1988
- 8-5-327 Deleted May 4, 1988
- 8-5-328 Tank Degassing Requirements
- 8-5-329 Deleted November 27, 2002
- 8-5-330 Deleted November 27, 2002
- 8-5-331 Tank Cleaning Requirements
- 8-5-332 Sludge Handling Requirements

8-5-400 ADMINISTRATIVE REQUIREMENTS

- 8-5-401 Inspection Requirements for External Floating Roof Tanks
- 8-5-402 Inspection Requirements for Internal Floating Roof Tanks
- 8-5-403 Inspection Requirements for Pressure Relief Devices
- 8-5-404 Inspection, Abatement Efficiency Determination and Source Test Reports
- 8-5-405 Deleted October 18, 2006
- 8-5-410 Deleted May 4, 1988
- 8-5-411 Enhanced Monitoring Program
- 8-5-412 Monitoring of Leaking Pontoons

8-5-500 MONITORING AND RECORDS

- 8-5-501 Records
- 8-5-502 Source Test Requirements
- 8-5-503 Deleted October 18, 2006

8-5-600 MANUAL OF PROCEDURES

- 8-5-601 Analysis of Samples, Reid Vapor Pressure
- 8-5-602 Analysis of Samples, True Vapor Pressure
- 8-5-603 Determination of Abatement Efficiency
- 8-5-604 Determination of Applicability Based on True Vapor Pressure
- 8-5-605 Measurement of Leak Concentrations and Residual Concentrations
- 8-5-606 Analysis of Samples, Tank Cleaning Agents

REGULATION 8
ORGANIC COMPOUNDS
RULE 5
STORAGE OF ORGANIC LIQUIDS

(Adopted January 1, 1978)

8-5-100 GENERAL

8-5-101 Description: The purpose of this rule is to limit emissions of organic compounds from storage tanks.

Note: New storage tanks may also be subject to Regulation 10 and storage tanks located at bulk plants may also be subject to the requirements of Regulation 8, Rule 6 or Rule 33.

(Amended 9/4/85; 5/4/88; 1/20/93; 10/18/06)

8-5-110 Exemptions: This rule does not apply to emissions from the following sources:

110.1 Storage tanks having a capacity of less than 1.0 m³ (264 gal).

110.2 Any storage tank installed prior to January 4, 1967, which is not used for storage of gasoline to be dispensed to internal combustion engine fuel tanks, and is either of a capacity of less than 7.6 m³ (2,008 gal), or an underground tank with an offset fill line.

110.3 Any above ground gasoline tank of 7.6 m³ (2,008 gal) or less capacity installed and in service prior to January 9, 1976, and equipped with a submerged fill pipe.

(Amended 5/4/88; 1/20/93; 11/27/02; 10/18/06)

8-5-111 Limited Exemption, Tank Removal From and Return to Service: The requirements of Sections 8-5-304, 305, 306 and 307 shall not apply to storage tanks during or after tank decommissioning, and shall not apply during temporary removal from service provided that the operator complies with the following requirements:

111.1 The operator shall notify the APCO. This notification shall identify the specific requirement for which an exemption is necessary and explain how the planned or performed activities necessarily prevent compliance with those requirements. The notification requirement may be satisfied in one of the following ways:

1.1 Three days prior to such work being done, written notification is received by the APCO; or

1.2 Telephone notification is made to the APCO prior to such work being done, and written notice is received by the APCO within three days after such work has been done.

111.2 The tank is in compliance with all applicable requirements of this rule at the time the notification in Section 8-5-111.1 is made.

111.3 When the floating roof is resting on the leg supports, the process of filling, emptying, and refilling shall be continuous and shall be accomplished as rapidly as possible.

111.4 Vapor recovery shall be used on tanks so equipped during filling and emptying procedures.

111.5 Emissions shall be minimized during the period of exemption. If the tank interior is to be opened to the atmosphere through an access hatch or manway, as much product as possible shall be drained from the tank, and degassing equipment and an associated abatement device shall be connected and operated, as required by Section 8-5-328, as soon as possible.

111.6 Effective January 1, 2007, if the tank operator discovers that the tank is not in compliance with all applicable requirements of this rule during the exemption period, telephone notification shall be made to the APCO within 24 hours of discovery and a written report that describes the non-compliance and any corrective actions taken shall be submitted within 60 days of discovery. This telephone notification and report are not required for tanks that are subject to deviation reporting requirements in a Major Facility Permit

issued pursuant to Regulation 2, Rule 6. Notification and reporting are not otherwise required when returning a tank to service.

(Amended 1/20/93; 12/15/99; 11/27/02; 10/18/06)

- 8-5-112 Limited Exemption, Preventative Maintenance and Inspection of Tanks in Operation:** The requirements of Sections 8-5-304, 305, 306, 307.2, 307.3 and 328 shall not apply to storage tanks during preventative maintenance of a vapor control device, tank roof, roof fitting or tank seal; during primary seal inspection; or during removal and installation of a secondary seal provided that the operator complies with the following requirements:
- 112.1 The operator shall notify the APCO. This notification shall identify the affected tank and the specific requirement for which an exemption is necessary, shall explain how the planned or performed activities necessarily prevent compliance with those requirements, and shall describe the measures to be taken to minimize emissions. For secondary seal installations, the type of installed seal shall be specified. The notification requirement may be satisfied in one of the following ways:
 - 1.1 Three days prior to such work being done, written notification is received by the APCO; or
 - 1.2 Except for secondary seal replacements, which are subject to Section 8-5-112.1.1, telephone notification is made to the APCO prior to such work being done, and written notice is received by the APCO within three days after such work has been done.
 - 112.2 The tank is in compliance with all applicable requirements of this rule at the time the notification in Section 8-5-112.1 is made.
 - 112.3 Product shall be moved neither in nor out of the storage tank and emissions shall be minimized.
 - 112.4 The time of exemption allowed under this section does not exceed 7 consecutive days.
 - 112.5 Effective January 1, 2007, if the tank operator discovers that the tank is not in compliance with all applicable requirements of this rule during the exemption period, telephone notification shall be made to the APCO within 24 hours of discovery and a written report that describes the non-compliance and any corrective actions taken shall be submitted within 60 days of discovery. This telephone notification and report are not required for tanks that are subject to deviation reporting requirements in a Major Facility Permit issued pursuant to Regulation 2, Rule 6.
 - 112.6 Effective June 1, 2007, the tank operator shall keep the following records for at least 24 months after each use of this exemption:
 - 6.1 The affected tank and the date and duration of the exemption;
 - 6.2 The preventative maintenance, inspection or other activity that was performed;
 - 6.3 The specific standards of this rule for which an exemption was necessary; and
 - 6.4 Actions taken to minimize emissions during the exemption period.
- (Adopted 9/4/85; Amended 5/4/88; 1/20/93; 12/15/99; 11/27/02; 10/18/06)*
- 8-5-113 Deleted May 4, 1988**
- 8-5-114 Deleted May 4, 1988**
- 8-5-115 Deleted May 4, 1988**
- 8-5-116 Exemption, Gasoline Storage Tanks at Gasoline Dispensing Facilities:** The provisions of this rule shall not apply to any gasoline storage tank located at a gasoline dispensing facility subject to the requirements of Regulation 8, Rule 7.
(Adopted 1/20/93; Amended 10/18/06)
- 8-5-117 Limited Exemption, Low Vapor Pressure:** The provisions of this rule, except for Section 8-5-307.3, shall not apply to tanks storing organic liquids with a true vapor pressure of less than or equal to 25.8 mm Hg (0.5 psia) as determined by Sections 8-5-602 or 604.
(Adopted 1/20/93; Amended 11/27/02; 10/18/06)
- 8-5-118 Limited Exemption, Gas Tight Requirement:** The gas tight requirement of Section 8-5-306.2 shall not apply to tanks at facilities that are subject to the requirements of Regulation 8, Rule 18.

(Adopted October 18, 2006)

- 8-5-119 Limited Exemption, Repair Period:** A tank operator who has implemented an Enhanced Monitoring Program pursuant to Section 8-5-411 and who discovers equipment that fails to meet a requirement listed in Section 8-5-119.1 shall not be deemed in violation of that requirement, provided the operator complies with all of the conditions listed in Sections 8-5-119.2 and 119.3. The period of such an exemption shall not exceed the amount of time necessary to meet the requirement in accordance with Section 8-5-119.2.3. An operator shall not be entitled to this exemption for any violation discovered by the APCO during an APCO-initiated inspection.
- 119.1 The exemption is available only for the following requirements:
- 1.1 Section 8-5-303.1 (good operating condition requirement only), 303.2 (gas tight requirement only);
 - 1.2 Sections 8-5-304.4, 304.5, 304.6, 305.5 and 305.6;
 - 1.3 Section 8-5-306.2;
 - 1.4 Sections 8-5-307.1 and 307.3;
 - 1.5 Sections 8-5-320.3, 320.4.2, 320.4.3, 320.5.2 (gaps only), 320.5.3 and 320.6;
 - 1.6 Sections 8-5-321.1, 321.3.1, 321.3.2, 321.3.3, and 321.4;
 - 1.7 Sections 8-5-322.1, 322.2, 322.3, 322.4, and 322.5.
- 119.2 The following conditions shall be met for the exemption to be available:
- 2.1 The tank operator shall have implemented an Enhanced Monitoring Program in accordance with Section 8-5-411;
 - 2.2 The tank operator shall minimize excess emissions resulting from the failure to meet the requirement as soon as possible, but no later than 8 hours after discovery;
 - 2.3 The tank operator shall bring the tank into compliance with the requirement as soon as possible, but no later than 48 hours after discovery;
 - 2.4 The tank operator shall not move material into or out of the tank until the tank is in compliance with all applicable requirements, except to the extent necessary to make repairs.
- 119.3 The tank operator shall submit a report within 60 days of any use of this exemption. The report shall include the following:
- 3.1 the affected tank and the date and duration of the exemption;
 - 3.2 the repair or other activity that was performed;
 - 3.3 the specific requirements of this rule for which an exemption was necessary; and
 - 3.4 actions taken to minimize emissions during the exemption period.

(Adopted October 18, 2006)

8-5-200 DEFINITIONS

8-5-201 Deleted October 18, 2006

8-5-202 Storage Tank: Any container, reservoir, or tank used for the storage of organic liquids, excluding tanks that are permanently affixed to mobile vehicles such as railroad tank cars, tanker trucks or ocean vessels.

(Adopted 9/4/85; Amended 11/27/02; 10/18/06)

8-5-203 Deleted November 27, 2002

8-5-204 Organic Liquid: Any organic compound that exists as a liquid at actual conditions of use or storage.

(Adopted 9/4/85; Amended 1/20/93)

8-5-205 Gasoline: Petroleum distillates used as motor fuel with a Reid vapor pressure greater than 4.0 psia.

(Adopted 9/4/85; Amended 5/4/88)

8-5-206 Gas Tight: A concentration of organic compounds of less than 100 ppm (expressed as methane) above background, for any point or item, except for pressure relief devices; and less than 500 ppm (expressed as methane) above background, for pressure relief devices only.

(Adopted 5/4/88; Amended 1/20/93; 11/27/02; 10/18/06)

- 8-5-207 Approved Emission Control System:** A system for reducing emissions to the atmosphere that consists of a collection system and an abatement device, which is approved in writing by the APCO and achieves the overall abatement efficiency specified in the applicable standards section.
(Adopted 1/20/93; Amended 11/27/02)
- 8-5-208 Degassing:** The process of removing organic gases from a tank.
(Adopted January 20, 1993)
- 8-5-209 External Floating Roof Tank:** An open top tank with a storage vessel cover consisting of a double deck or pontoon single deck that rests upon and is supported by the liquid being contained.
(Adopted 1/20/93; Amended 10/18/06)
- 8-5-210 Internal Floating Roof Tank:** A tank with a floating cover or roof that rests upon or is floated upon the liquid being contained, and that also has a fixed roof on top of the tank shell to shield the floating roof from wind, rain and other elements. An external floating roof tank that has been retrofitted with a geodesic dome or other fixed roof shall be considered to be an internal floating roof tank for the purposes of this rule.
(Adopted 1/20/93; Amended 11/27/02; 10/18/06)
- 8-5-211 True Vapor Pressure:** The vapor pressure of a liquid at storage temperature.
(Adopted 1/20/93; Amended 11/27/02)
- 8-5-212 Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate.
(Adopted January 20, 1993)
- 8-5-213 Viewport:** An accessible opening in the fixed roof of an internal floating roof tank that measures at least 0.75 meters (30 inches) on each side or at least 0.75 meters (30 inches) in diameter.
(Adopted January 20, 1993)
- 8-5-214 Gauge Float:** A device to indicate the level of liquid within a tank. The float rests on the liquid surface inside a well in the tank.
(Adopted December 15, 1999)
- 8-5-215 Guidepole:** An anti-rotation device that is fixed to the top and bottom of a tank, passing through a well in a floating roof. Guidepoles may be solid or be equipped with slots or holes for gauging purposes.
(Adopted December 15, 1999)
- 8-5-216 Zero Gap Pole Wiper Seal:** A seal with no gap exceeding 0.06 inches between the guidepole or gauge well and pole wiper seal.
(Adopted December 15, 1999)
- 8-5-217 Decommissioning:** The removal of all organic liquid and gases from a storage tank with the intent of no longer using the tank for storage of organic liquids or gases.
(Adopted November 27, 2002)
- 8-5-218 Stock Change:** The removal of organic liquids from a tank prior to refilling the tank with a different organic liquid.
(Adopted November 27, 2002)
- 8-5-219 Tank Cleaning:** The process of washing or rinsing the interior of a storage tank, or removing sludge, or rinsing liquid from a storage tank.
(Adopted November 27, 2002)
- 8-5-220 Temporary Removal From Service:** The removal of organic liquid from a storage tank for tank cleaning, stock change, tank repair, roof repair, or removal of contaminated stock, followed by return to service.
(Adopted November 27, 2002)
- 8-5-221 Liquid Balancing:** The process of reducing the vapor pressure of the contents of a tank by adding lower-vapor pressure liquid without breaking tank vacuum, and, for floating roof tanks, without landing the floating roof on its supports.
(Adopted November 27, 2002)
- 8-5-222 Pressure Relief Device:** Any device that is used to relieve either positive or negative pressure upstream of the device, or both.
(Adopted October 18, 2006)
- 8-5-223 Pressure Vacuum Valve:** A type of pressure relief device that is used to control breathing losses from a fixed-roof tank by allowing slight positive or negative pressure variations in a tank while preventing the movement of gas into or out of the tank.
(Adopted October 18, 2006)

8-5-224 Connection: Flanged, screwed, or other joined fittings used to connect any piping or equipment.

(Adopted October 18, 2006)

8-5-225 Good Operating Condition: A tank component or related equipment is in good operating condition when it operates as designed without visible breaks, cracks or other defects that result in organic emissions.

(Adopted October 18, 2006)

8-5-226 Emission Minimization: Emission minimization required in Sections 8-5-119.2.2 means reducing excess emissions caused by violation of a rule standard to the lowest achievable level using best modern practices while maintaining the associated tank in service.

(Adopted October 18, 2006)

8-5-300 STANDARDS

8-5-301 Storage Tanks Control Requirements: A person shall not store organic liquid in any storage tank unless such tank is equipped with a vapor loss control device that is specified by the table below for the tank capacity, or for a higher capacity, and for the true vapor pressure of the tank organic liquid contents, or for a higher true vapor pressure.

Tank Capacity	True Vapor Pressure of Tank Organic Contents		
	>0.5 to ≤1.5 psia	>1.5 to <11 psia	≥ 11 psia
≥1.0 m ³ to ≤37.5 m ³ (≥264 gallons to ≤9,906 gallons)	Submerged fill pipe	Submerged fill pipe (underground tank or aboveground non-gasoline tank), pressure vacuum valve, internal or external floating roof	Pressure tank or approved emission control system
>37.5 m ³ to <75 m ³ (>9,906 gallons to <19,803 gallons)	Submerged fill pipe	Submerged fill pipe (underground tank), pressure vacuum valve, internal or external floating roof	Pressure tank or approved emission control system
≥75 m ³ to <150 m ³ (≥19,803 gallons to <39,626 gallons)	Submerged fill pipe	Internal or external floating roof	Pressure tank or approved emission control system
≥150 m ³ (≥39,626 gallons)	Internal or external floating roof	Internal or external floating roof	Pressure tank or approved emission control system

(Amended, Renumbered 9/4/85; Amended 5/4/88; 1/20/93; 12/15/99; Amended, Renumbered 11/27/02; Amended 10/18/06)

8-5-302 Requirements for Submerged Fill Pipes: A submerged fill pipe required by Section 8-5-301 must meet either of the following requirements:

302.1 Where the tank is filled from the top, the end of the discharge pipe or nozzle must be totally submerged when the liquid level is 15 cm (6 in.) from the bottom of the tank.

302.2 Where the tank is filled from the side, the discharge pipe or nozzle must be totally submerged when the liquid level is 46 cm (18 in.) from the bottom of the tank.

(Adopted 9/4/85; Amended, Renumbered 11/27/02; Amended 10/18/06)

8-5-303 Requirements for Pressure Vacuum Valves: A pressure vacuum valve required by Section 8-5-301 must meet the following requirements:

303.1 The pressure vacuum valve must be set to either at least 90% of the tank's maximum allowable working pressure, or at least 25.8 mm Hg (0.5 psig), and the valve must be in good operating condition.

- 303.2 The pressure vacuum valve sealing mechanism must remain in a gas tight condition except when operating pressure exceeds the valve set pressure, or except when the sealing mechanism is vented to a vapor recovery or disposal system that has an overall abatement efficiency of at least 95% by weight.

(Amended 9/4/85; 5/4/88; 1/20/93; Amended, Renumbered, 11/27/02; Amended 10/18/06)

8-5-304 Requirements for External Floating Roof Tanks: An external floating roof required by Section 8-5-301 must meet the following requirements:

- 304.1 The floating roof fittings must meet the requirements of Section 8-5-320.
- 304.2 The floating roof must be equipped with a primary seal that meets the requirements of Section 8-5-321.
- 304.3 The floating roof must be equipped with a secondary seal that meets the requirements of Section 8-5-322.
- 304.4 The floating roof must rest on the surface of the liquid tank contents and must be in good operating condition. There shall be no liquid tank contents on top of either the primary or secondary seal, or on top of the floating roof (this requirement does not apply to liquid that clings to the inside tank walls as the tank is drained, or to liquid that drips from the tank walls onto the seals).
- 304.5 The tank shell must be in good operating condition with no liquid leakage through the shell.
- 304.6 An external floating roof tank shall not be operated with organic liquid tank contents in any tank pontoon unless the following conditions are met:
- 6.1 Within 48 hours of discovery of organic liquid in a pontoon, all lids or other openings on the affected pontoon shall be sealed and maintained in a gas tight condition; and
- 6.2 The next time the tank is removed from service, repairs shall be made on all pontoon leaks on that tank.

(Amended, Renumbered 9/4/85; Amended 5/4/88; 1/20/93; Amended, Renumbered 11/27/02; Amended 10/18/06)

8-5-305 Requirements for Internal Floating Roof Tanks: An internal floating roof required by Section 8-5-301 must meet the following requirements:

- 305.1 For a tank with seals installed on or before February 1, 1993, the tank must be equipped with one of the following:
- 1.1 A liquid mounted primary seal, mounted in full contact with the liquid in the annular space between the tank shell and floating roof,
- 1.2 A metallic shoe primary seal, or
- 1.3 A vapor mounted primary and a secondary seal
- If sections of seal with a total length equal to or greater than the diameter of the tank are replaced at one time, or if sections of seal with a total cumulative length equal to or greater than 50% of the total seal circumference are replaced over time, then the seal shall be considered to be newly installed and subject to Section 8-5-305.2.
- 305.2 For a tank with seals installed after February 1, 1993, the tank must be equipped with a liquid mounted or metallic shoe primary seal that meets the requirements of Section 8-5-321 and a secondary seal that meets the requirements of Section 8-5-322.
- 305.3 Internal floating roof tanks that are placed into service or de-gassed after February 1, 1993 shall be equipped with at least 3 viewports in the fixed roof of the tank. This requirement shall not apply to external floating roof tanks retrofitted with domes or other fixed roofs after February 1, 1993, as long as the dome consists of translucent panels through which sufficient light passes to allow inspection of the floating roof seal.
- 305.4 The floating roof fittings must meet the requirements of Section 8-5-320.
- 305.5 The floating roof must rest on the surface of the liquid tank contents and must be in good operating condition. There shall be no liquid tank contents on top of either the primary or secondary seal, or on top of the floating roof (this requirement does not apply to liquid that clings to the inside tank walls as the tank is drained, or to liquid that drips from the tank walls onto the seals).

305.6 The tank shell must be in good operating condition with no liquid leakage through the shell.

(Amended, Renumbered 9/4/85; Amended 5/4/88; 1/20/93; Amended, Renumbered 11/27/02; Amended 10/18/06)

8-5-306 Requirements for Approved Emission Control Systems: An Approved Emission Control System required by Section 8-5-301 must meet the following requirements:

- 306.1 It must provide an abatement efficiency of at least 95% by weight, based on a comparison of controlled emissions to those emissions which would occur from a fixed or cone roof tank in the same product service without an approved emission control system, expressed as a percentage. Baseline emissions shall be calculated using the criteria in API Bulletin 2518
- 306.2 It must be gas tight.

(Amended 1/20/93; Amended, Renumbered 11/27/02; Amended 10/18/06)

8-5-307 Requirements for Fixed Roof Tanks, Pressure Tanks and Blanketed Tanks:

- 307.1 Fixed roof tank shells and pressure tank shells must be in good operating condition with no liquid leakage through the shell.
- 307.2 A pressure tank must maintain working pressures sufficient at all times to prevent organic vapor or gas loss to the atmosphere.
- 307.3 The sealing mechanism on pressure relief devices located on pressure tanks and on tanks blanketed with organic gases other than natural gas shall be maintained in a gas tight condition except when operating pressure exceeds the valve set pressure, or except when the sealing mechanism is vented to a vapor recovery or disposal system that has an overall abatement efficiency of at least 95% by weight.

(Adopted 9/4/85; Amended 5/4/88; 1/20/93; Amended, Renumbered 11/27/02; Amended 11/18/06)

8-5-310 Deleted May 4, 1988

8-5-311 Deleted November 27, 2002

8-5-312 Deleted January 20, 1993

8-5-313 Deleted January 20, 1993

8-5-314 Deleted January 20, 1993

8-5-320 Floating Roof Tank Fitting Requirements: The fittings on any floating roof storage tank subject to Section 8-5-304 or 305 shall meet the following conditions:

- 320.1 Deleted November 27, 2002.
- 320.2 All openings through the floating roof, except pressure relief devices, shall provide a projection below the liquid surface to prevent belching of liquid and reduce escaping organic vapors.
- 320.3 All openings through the floating roof, except floating roof legs, shall be equipped with a gasketed cover, seal or lid, which shall meet either of the following requirements, as applicable, except as provided in Sections 8-5-320.4, 320.5 or 320.6.
 - 3.1 The gasketed cover, seal or lid shall have no measurable gap exceeding 0.32 cm (1/8 in.), except when the opening is in use.
 - 3.2 For inaccessible openings on internal floating roof tanks, there shall be no visible gaps as viewed from the fixed roof manway or viewports, except when the opening is in use.
- 320.4 Solid sampling or gauging wells, and similar fixed projections through a floating roof such as an anti-rotational pipe, shall meet the following conditions:
 - 4.1 The well shall provide a projection below the liquid surface.
 - 4.2 The well shall be equipped with a cover, seal or lid, which shall at all times be in a closed position with no gap exceeding 0.32 cm (1/8 in.), except when the well is in use.
 - 4.3 The gap between the well and the roof shall be added to the gaps measured to determine compliance of the secondary seal and in no case shall exceed 1.3 cm (1/2 in.).
- 320.5 Slotted sampling or gauging wells, and similar fixed projections through a floating roof such as an anti-rotational pipe, shall meet the following conditions:
 - 5.1 The well shall provide a projection below the liquid surface.

- 5.2 The well on an external floating roof shall be equipped with the following: a sliding cover, a cover gasket, a pole sleeve, pole wiper and an internal float and float wiper designed to minimize the gap between the float and the well, provided that the gap shall in no case exceed 1.3 cm (1/2 in.), or shall be equipped with a well gasket, a zero gap pole wiper seal and a pole sleeve that projects below the liquid surface.
 - 5.3 The gap between the well and the roof shall be added to the gaps measured to determine compliance of the secondary seal and in no case shall exceed 1.3 cm (1/2 in.).
- 320.6 Any emergency roof drain shall be provided with a slotted membrane fabric cover, or equivalent, that covers at least 90% of the area of the opening.

(Amended 9/4/85; 5/4/88; 1/20/93; 12/15/99; 11/27/02; 10/18/06)

8-5-321

Primary Seal Requirements: A person shall not operate a storage tank equipped with a primary seal subject to the requirements of Section 8-5-304 or 305 unless such tank meets the following conditions:

- 321.1 There shall be no holes, tears, or other openings in the primary seal fabric that allow the emission of organic vapors.
- 321.2 The seal shall be either a metallic shoe or a liquid mounted type, except as provided in Section 8-5-305.1.3.
- 321.3 Metallic-shoe-type seals shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 61 cm (24 in.) for external floating roofs and 18 inches for internal floating roofs above the stored liquid surface. Measurements of the gap between tank shell and seals shall be made around the full circumference of the tank, and measured gaps shall meet the following requirements:
 - 3.1 The geometry of the shoe shall be such that the maximum gap between the shoe and the tank shell is no greater than double the gap allowed by the seal gap criteria for a length of at least 46 cm (18 in.) in the vertical plane above the liquid surface.
 - 3.2 For welded tanks, no gap between the tank shell and the primary seal shall exceed 3.8 cm (1-1/2 in.). No continuous gap greater than 0.32 cm (1/8 in.) shall exceed 10% of the circumference of the tank. The cumulative length of all primary seal gaps exceeding 1.3 cm (1/2 in.) shall be not more than 10% of the circumference, and the cumulative length of all primary seal gaps exceeding 0.32 cm (1/8 in.) shall be not more than 40% of the circumference.
 - 3.3 For riveted tanks, no gap between the tank shell and the primary seal shall exceed 6.4 cm (2-1/2 in.). The cumulative length of all primary seal gaps exceeding 3.8 cm (1-1/2 in.) shall be not more than 10% of the circumference.
- 321.4 For resilient-toroid-seal equipped tanks, no gap between the tank shell and the primary seal shall exceed 1.3 cm (1/2 in.). The cumulative length of all gaps exceeding 0.32 cm (1/8 in.) shall be not more than 5% of the circumference. Measurements of the gap shall be made around the full circumference of the tank.

(Amended 1/20/93; 12/15/99; 11/27/02; 10/18/06)

8-5-322

Secondary Seal Requirements: A person shall not operate a storage tank equipped with a secondary seal subject to the requirements of Sections 8-5-304 or 305, unless such tank meets the following requirements. In determining compliance with seal gap requirements, measurements of the gap between tank shell and seals shall be made around the full circumference of the tank.

- 322.1 There shall be no holes, tears, or other openings in the secondary seal fabric that allow the emission of organic vapors.
- 322.2 The secondary seal shall allow easy insertion of probes up to 3.8 cm (1-1/2 in.) in width in order to measure gaps in the primary seal.
- 322.3 No gap between the tank shell and the secondary seal shall exceed 1.3 cm (1/2 in.). The cumulative length of all secondary seal gaps exceeding 0.32 cm (1/8 in.) shall be not more than 5% of the circumference of the tank.

- 322.4 For riveted tanks, the secondary seal shall consist of at least two sealing surfaces, such that the sealing surfaces prevent the emission of organic compounds around the rivets. Serrated sealing surfaces are allowable if the length of serration does not exceed 15.2 cm (6 in.).
- 322.5 For welded external floating roof tanks with seals installed after September 4, 1985 or welded internal floating roof tanks with seals installed after February 1, 1993, no gap between the tank shell and the secondary seal shall exceed 1.5 mm (0.06 in.). The cumulative length of all secondary seal gaps exceeding 0.5 mm (0.02 in.) shall be not more than 5% of the circumference of the tank excluding gaps less than 5 cm (1.79 in.) from vertical weld seams. If sections of seal with a total length equal to or greater than the diameter of the tank are replaced at one time, or if sections of seal with a total cumulative length equal to or greater than 50% of the total seal circumference are replaced over time, then the seal shall be considered to be newly installed for the purpose of this section.
- 322.6 The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal.

(Amended 1/20/93; 11/27/02; 10/18/06)

8-5-323 Deleted January 20, 1993

8-5-324 Deleted January 20, 1993

8-5-325 Deleted January 20, 1993

8-5-326 Deleted May 4, 1988

8-5-327 Deleted May 4, 1988

8-5-328 Tank Degassing Requirements: A tank operator shall not open the interior vapor space of a tank subject to this rule to the atmosphere through a hatch or manway, except to connect or disconnect degassing equipment or to conduct tank contents or emissions sampling, unless such tank meets the following conditions:

- 328.1 For tanks larger than 75 m³, the emissions of organic compounds resulting from degassing shall be controlled by an abatement device that collects and processes all organic vapors and gases and has an abatement efficiency of at least 90% by weight. The system shall be operated until the concentration of organic compounds in the tank is less than 10,000 ppm expressed as methane. In order to satisfy this requirement, effective June 1, 2007, the residual organic concentration must be measured to be less than 10,000 ppm as methane for at least four consecutive measurements performed at intervals no shorter than 15 minutes each.
- 328.2 For all tanks subject to this rule, tank degassing shall not commence after the District predicts an excess of the Federal or State Ambient Air Quality Standard for ozone for the following day, unless emissions resulting from degassing are controlled as required by Section 8-5-328.1.
- 328.3 Effective June 1, 2007, the tank operator shall provide written notification that is received by the APCO at least 3 days before the start of a degassing operation that is subject to this rule. However, where degassing must be performed on an emergency basis, telephone notification shall be made to the APCO within 8 hours of commencing degassing. This notification shall identify the tanks to be degassed, including their location and the liquid stored in the tanks, the nature of the emergency, and the time and date degassing will commence.

(Adopted 1/20/93; Amended 11/27/02; 10/18/06)

8-5-329 Deleted November 27, 2002

8-5-330 Deleted November 27, 2002

8-5-331 Tank Cleaning Requirements: Effective June 1, 2007, tank interior cleaning agents must meet the following requirements, unless all organic vapors and gases emitted during tank cleaning are collected and processed at an abatement device that has an abatement efficiency of at least 90% by weight.

- 331.1 Agents used to clean tank interiors shall have an initial boiling point greater than 302 degrees F, a true vapor pressure less than 0.5 psia, or a VOC content less than 50 grams per liter.

- 331.2 Except as allowed in Section 8-5-331.3, steam shall not be used to clean tank interiors at facilities that operate wastewater treatment facilities.
- 331.3 Steam may be used to remove scale or film from tank interior surfaces only after routine tank cleaning, including sludge removal, has been completed.

(Adopted October 18, 2006)

8-5-332 Sludge Handling Requirements: Effective June 1, 2007, the operator of a tank shall place sludge removed from that tank directly into a sludge container that meets the following requirements. This section applies to sludge removed from any tank that was subject to the requirements of this rule at any time since it was last put into service.

332.1 The sludge container shall allow no liquid leakage.

332.2 The sludge container shall have no measurable gap exceeding 1.3 cm (1/2 in.) except when the container is being loaded or unloaded, and except during sludge sampling or treatment.

(Adopted October 18, 2006)

8-5-400 ADMINISTRATIVE REQUIREMENTS

8-5-401 Inspection Requirements for External Floating Roof Tanks: Tanks subject to the requirements of Section 8-5-304 shall be inspected by the operator as follows:

401.1 The entire circumference of each primary and secondary seal shall be inspected for compliance with the requirements of Sections 8-5-321 and 8-5-322 twice per calendar year at 4 to 8 month intervals, and 4 times per calendar year at 2 to 4 month intervals for tanks subject to enhanced monitoring pursuant to Section 8-5-411. If a new primary or secondary seal is installed, or if a primary or secondary seal is repaired, both seals shall be inspected at the time of the seal installation or repair. Flexible wiper seals shall be inspected when the outer edge of the seal is curved upward.

401.2 Tank fittings shall be inspected for compliance with the requirements of Section 8-5-320 twice per calendar year at 4 to 8 month intervals, and 4 times per calendar year at 2 to 4 month intervals for tanks subject to enhanced monitoring pursuant to Section 8-5-411.

(Amended 1/20/93; Amended, Renumbered 11/27/02; Amended 10/18/06)

8-5-402 Inspection Requirements for Internal Floating Roof Tanks: Tanks subject to the requirements of Section 8-5-305 shall be inspected by the operator as follows:

402.1 The entire circumference of each primary and secondary seal shall be inspected for compliance with the requirements of Sections 8-5-321 and 8-5-322. The time between inspections shall not exceed 10 years. If a new primary or secondary seal is installed, or if a primary or secondary seal is repaired, both seals shall be inspected at the time of the seal installation or repair. Flexible wiper seals shall be inspected when the outer edge of the seal is curved upward.

402.2 The entire circumference of the outermost seal (secondary seal where so equipped, or primary seal where no secondary seal is required) shall be visually inspected for compliance with the requirements of Sections 8-5-305.1, 8-5-305.2, 8-5-305.3, 8-5-321.1 and 8-5-322.1 twice per calendar year at 4 to 8 month intervals, and 4 times per calendar year at 2 to 4 month intervals for tanks subject to enhanced monitoring pursuant to Section 8-5-411. Flexible wiper seals shall be inspected when the outer edge of the seal is curved upward.

402.3 Tank fittings shall be inspected for compliance with the requirements of Section 8-5-320 twice per calendar year at 4 to 8 month intervals, and 4 times per calendar year at 2 to 4 month intervals for tanks subject to enhanced monitoring pursuant to Section 8-5-411. Standards involving gap measurements shall be checked whenever the tank roof is accessible, but need not be checked more frequently than twice per calendar year, or 4 times per calendar year for tanks subject to enhanced monitoring pursuant to Section 8-5-411.

(Amended 1/20/93; Amended, Renumbered 11/27/02; Amended 10/18/06)

- 8-5-403 Inspection Requirements for Pressure Relief Devices:** Pressure relief devices, including pressure vacuum valves, shall be inspected by the tank operator for compliance with the following requirements twice per calendar year at 4 to 8 month intervals, and 4 times per calendar year at 2 to 4 month intervals for tanks subject to enhanced monitoring pursuant to Section 8-5-411:
 403.1 Pressure vacuum valves: gas tight standards in Section 8-5-303.
 403.2 Effective June 1, 2007, for all pressure relief devices except pressure vacuum valves: gas tight standard in Section 8-5-307.3.
(Adopted 11/27/02; Amended 10/18/06)
- 8-5-404 Inspection, Abatement Efficiency Determination and Source Test Reports:** Within 60 days of any inspection, abatement efficiency determination or source test required by this rule, a report shall be submitted to the APCO that certifies compliance with each individual requirement associated with the inspection, abatement efficiency determination or source test, and that includes data, supported by necessary calculations, to support this certification.
(Amended, Renumbered 9/4/85; Amended 5/4/88; 1/20/93; 11/27/02; 10/18/06)
- 8-5-405 Deleted October 18, 2006**
- 8-5-410 Deleted May 4, 1988**
- 8-5-411 Enhanced Monitoring Program:** The operator of a tank that is subject to this rule may implement an Enhanced Monitoring Program by complying with all of the following:
 411.1 The tank operator shall submit to the APCO a list of all tanks at a facility that are subject to this rule, and the capacity of each tank. At least 25% of these tanks, but no less than 1 tank at each facility, shall be selected by the operator for enhanced monitoring. The selected tanks shall constitute at least 20% of the total tank capacity at the facility that is subject to this rule. Only external floating roof tanks may be selected for enhanced monitoring unless there are not enough to constitute 25% of the total number of tanks. In this case, other tank types may be selected as necessary to constitute the required number. All tanks selected for enhanced monitoring must be subject to Section 8-5-401, 402 or 403.
 411.2 An Enhanced Monitoring Program shall go into effect at a facility after the APCO determines that the criteria in Section 411.1 are satisfied. The specific tanks selected by the operator for enhanced monitoring may be changed at any time by the operator upon written notification to the APCO provided that the criteria in Section 8-5-411.1 continue to be satisfied. An Enhanced Monitoring Program may be discontinued at any time by the operator upon written notification to the APCO.
 411.3 The operator shall perform enhanced monitoring as specified in Sections 8-5-401, 402 and 403.
(Adopted October 18, 2006)
- 8-5-412 Monitoring of Leaking Pontoons:** The operator of a floating roof tank on which a leaking pontoon has been discovered shall inspect the lids and other openings on any leaking pontoon for compliance with the requirements of Section 8-5-304.6.1 once per calendar quarter beginning the quarter after the leaking pontoon is discovered until a repair of the leak is completed.
(Adopted October 18, 2006)
- 8-5-500 MONITORING AND RECORDS**
- 8-5-501 Records:**
 501.1 A person who operates a tank subject to this rule shall keep an accurate record of the type and amount of liquids stored, type of blanket gases used, and the true vapor pressure ranges of such liquids and gases. These records shall be kept for at least 24 months.
 501.2 For internal and external floating roof tanks, a tank operator who replaces all or part of a primary or secondary seal shall keep an accurate record of the length of seal replaced and the date(s) on which replacement occurred. These records shall be kept for at least 10 years.

- 501.3 Unless otherwise specified, the tank operator shall retain all records required by this rule, and shall retain copies of any report, notification or other submittal required by this rule for at least 24 months.
- 501.4 The tank operator shall keep engineering data sheets showing setpoints for pressure vacuum valves installed after June 1, 2007.

(Amended 1/20/93; 11/27/02; 10/18/06)

8-5-502 Source Test Requirements: Any tank operator who uses an Approved Emission Control System or other abatement device to comply with the requirements of this rule shall perform a source test as specified in this section. Source testing, including prior notification of the District, shall be performed in accordance with the Manual of Procedures, Volume IV. This section does not apply to any device that collects all emissions and vents them to a fuel gas collection system for combustion, or to any device that is subject to periodic source testing in accordance with a District permit to operate.

502.1 A tank operator using an Approved Emission Control System or other abatement device to comply with the requirements of Sections 8-5-303.2, 306.1 or 307.3 shall perform a source test on the system verifying operation at the required abatement efficiency at least once in any calendar year in which the system is used to comply with this rule.

502.2 A tank operator using an abatement device to comply with the requirements of Sections 8-5-328.1 or 331 shall:

- 2.1 Demonstrate that a source test on the system verifying operation at the required abatement efficiency was completed within the 12 months prior to the operator's commencement of use and shall maintain a complete copy of the source test report; or
- 2.2 Perform such a source test during the operation in question.

(Adopted 1/20/93; Amended 11/27/02; 10/18/06)

8-5-503 Deleted October 18, 2006

8-5-600 MANUAL OF PROCEDURES

8-5-601 Analysis of Samples, Reid Vapor Pressure: Samples of organic compounds as specified in this rule shall be analyzed for Reid vapor pressure as prescribed in the Manual of Procedures, Volume III, Lab Method 13.

(Amended 9/4/85; 5/4/88; 10/18/06)

8-5-602 Analysis of Samples, True Vapor Pressure: Samples of organic compounds not listed in Table I shall be analyzed for true vapor pressure at the tank storage temperature as prescribed in the Manual of Procedures, Volume III, Lab Method 28.

(Adopted 9/4/85; Amended 5/4/88; 10/18/06)

8-5-603 Determination of Abatement Efficiency: Abatement efficiency of an Approved Emission Control System or other abatement device as specified in Section 8-5-502 shall be determined as prescribed in the Manual of Procedures, Volume IV, ST-7. For Approved Emission Control Systems subject to Section 8-5-306.1 only, baseline emissions shall be determined as specified in Section 8-5-306.1.

(Renumbered 9/4/85; Amended 1/20/93; 11/27/02; 10/18/06)

8-5-604 Determination of Applicability Based on True Vapor Pressure: Table I shall be used to determine if a storage tank is subject to the requirements of this rule. For organic compounds not listed in Table I, refer to Sections 8-5-601 or 602.

(Adopted 9/4/85; Amended 5/4/88; 1/20/93; 10/18/06)

8-5-605 Deleted October 18, 2006

8-5-605 Measurement of Leak Concentrations and Residual Concentrations: Determination of organic compound concentrations shall be conducted as follows:

- 605.1 Any instrument used for the measurement of organic compound concentration shall be a combustible gas indicator that meets the specifications and performance criteria of and has been calibrated in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).
- 605.2 Measurements of organic compound concentration, except as otherwise specified, shall be conducted in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A). Measurements of residual organic concentration required by Section 8-5-328.1 shall be measured with the instrument probe

inlet placed at least 12 inches above the bottom of the tank and above the surface of any sludge material on the bottom of the tank, and at least 12 inches inside the tank measured from the inner surface of the tank wall.

(Adopted 1/20/93; Amended 11/27/02; 10/18/06)

8-5-606 Analysis of Samples, Tank Cleaning Agents

- 606.1 Initial boiling point shall be determined in accordance with ASTM D-1078-93, or by an alternate method approved in writing by the APCO and U.S. EPA.
- 606.2 True vapor pressure shall be determined in accordance with the Manual of Procedures, Volume III, Method 28, or by an alternate method approved in writing by the APCO and U.S. EPA.
- 606.3 VOC content shall be determined in accordance with the Manual of Procedures, Volume III, Method 31, or by an alternate method approved in writing by the APCO and U.S. EPA.

(Adopted October 18, 2006)

TABLE I*

STORAGE TEMPERATURE VERSUS TRUE VAPOR PRESSURE (TVP)

	Density (lb/gal)	Reference Gravity API	IBP °F	Max. Temp. °F Not to Exceed	
				0.5 Psia TVP	1.5 Psia TVP
Crude Oils:*		-	-	-	-
San Joaquin Valley	-	-	390	249	-
Middle Distillates:					
Kerosene	-	42.5	350	195	250
Diesel	-	36.4	372	230	290
Gas Oil	-	26.2	390	249	310
Stove Oil	-	23	421	275	340
Jet Fuels:					
JP-1	-	43.1	330	165	230
JP-3	-	54.7	110	-	25
JP-4	-	51.5	150	20	68
JP-5	-	39.6	355	205	260
JP-7	-	44-50	360	205	260
Fuel Oil:					
No. 1	-	42.5	350	195	250
No. 2	-	36.4	372	230	290
No. 3	-	26.2	390	249	310
No. 4	-	23	421	275	340
No. 5	-	19.9	560	380	465
No. 6	-	16.2	625	450	-
Asphalts:					
60-100 pen.	-	-	-	490	550
120-150 pen.	-	-	-	450	500
200-300 pen.	-	-	-	360	420
Organic Compounds:					
Acetone	6.6	47	133	-	35
Acrylonitrile	6.8	41.8	173	30	62
Benzene	7.4	27.7	176	34	70
Carbon Disulfide	10.6	22.1	116	-	10
Carbon Tetrachloride	13.4	-	170	20	63
Chloroform	12.5	-	142	-	40
Cyclohexane	6.5	49.7	177	30	65
1,2 Dichloroethane	10.5	-	180	35	75
Ethyl Acetate	7.5	23.6	171	38	70
Ethyl Alcohol	6.6	47.0	173	55	85
Isopropyl Alcohol	6.6	47.0	181	62	95
Methyl Alcohol	6.6	47.0	148	30	62
Methyl Ethyl Ketone	6.7	44.3	175	30	70
Toluene	7.3	30	231	75	120
Vinylacetate	7.8	19.6	163	30	65

* True vapor pressure for crude oils should be determined from the specific crude slate.

**REGULATION 8
ORGANIC COMPOUNDS
RULE 8
WASTEWATER COLLECTION AND SEPARATION SYSTEMS**

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**REGULATION 8
ORGANIC COMPOUNDS
RULE 8
WASTEWATER COLLECTION AND SEPARATION SYSTEMS**

(Adopted January 17, 1979)

8-8-100 GENERAL

- 8-8-101 Description:** The purpose of this Rule is to limit the emissions of organic compounds from wastewater collection and separation systems that handle liquid organic compounds from industrial processes.
(Amended 11/1/89; 9/15/04)
- 8-8-110 Exemption, Less Than 760 Liters:** The requirements of Section 8-8-301 shall not apply to any wastewater separator which processes less than 760 liters (200 gals.) per day of wastewater containing organic liquids. This exemption shall not apply to wastewater separators at petroleum refinery complexes after March 1, 1980.
- 8-8-111 Deleted November 1, 1989**
- 8-8-112 Exemption, Wastewater Critical Organic Compound Concentration Or Temperature:** The requirements of Sections 8-8-301, 302, 306, 307, and 308 shall not apply to any wastewater separation system that processes influent wastewater with a temperature of less than 20 degrees C (68 °F) except at petroleum refineries. Wastewater having a concentration of less than 1.0 ppm (volume) critical organic compounds, as defined in Section 8-8-210, dissolved in the water samples, is exempt from the requirements of Sections 8-8-301, 302, 306, 307, 308, 312 and 313. The requirements of Section 8-8-502 must be met.
(Adopted 11/1/89; Amended 9/15/04)
- 8-8-113 Exemption, Secondary Wastewater Treatment Processes And Stormwater Sewer Systems:** The requirements of Sections 8-8-301, 302, 306, and 308 shall not apply to any secondary wastewater treatment processes or stormwater sewer systems, as defined in Sections 8-8-208 and 216, that are used as a wastewater polishing step or for collection of stormwater that is segregated from the process wastewater collection system.
(Adopted 11/1/89; Amended 9/15/04)
- 8-8-114 Exemption, Bypassed Oil-Water Separator or Air Flotation Influent:** The requirements of Sections 8-8-301, 302, and 307 shall not apply for wastewater which bypasses either the oil-water separator or air flotation unit provided that: (1) the requirements of Section 8-8-501 are met; and (2) on that day the District did not predict an excess of the Federal Ambient Air Quality Standard for ozone.
(Adopted November 1, 1989)
- 8-8-115 Exemption, Municipal Wastewater Collection, Separation and Treatment Facilities:** The requirements of Sections 8-8-301, 302, 303, 304, 305, 306, 307, 308, 312, 313 and 314 shall not apply to any publicly owned municipal wastewater treatment facility.
(Adopted 11/1/89; Amended 9/15/04)
- 8-8-116 Limited Exemption, Oil-Water Separation Trenches:** The requirements of Sections 8-8-312, 313 or 314 shall not apply to oil-water separation trenches used as part of maintenance or turnaround activities.
(Adopted September 15, 2004)
- 8-8-200 DEFINITIONS**
- 8-8-201 Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate.
(Amended 11/1/89; 9/15/04)
- 8-8-202 Wastewater (Oil-Water) Separator:** Any device used to separate liquid organic compounds from oil-water waste streams (excluding wastewater separator forebays, air flotation (AF) units, sludge-dewatering units, oil-water separator and /or AF Unit slop oil vessels, and junction boxes).
(Amended November 1, 1989)

- 8-8-203 Wastewater Separator Forebay:** That section of a gravity-type separator which (a) receives the untreated, contaminated wastewater from the preseparator flume, and (b) acts as a header which distributes the influent to the separator channels.
(Amended November 1, 1989)
- 8-8-204 Vapor-tight:** A leak of less than 500 ppm (expressed as methane) above background, measured at the interface of the component in accordance with Section 8-8-603.
(Amended 11/1/89; 9/15/04)
- 8-8-205 Oil-Water Separator Slop Oil:** Floating oil, flocculant sludge, and solids which accumulate in an oil-water separator or air flotation unit.
(Adopted November 1, 1989)
- 8-8-206 Oil-Water Separator Effluent Channel/Pond:** An open channel, trench, pond, or basin which handles wastewater downstream of an oil-water separator that has not been treated by an air flotation unit (usually located between the separator and the air flotation unit).
(Adopted November 1, 1989)
- 8-8-207 Full Contact Fixed Cover:** A stationary separator cover which is always in full contact with the liquid surface of the oil-water separator.
(Adopted November 1, 1989)
- 8-8-208 Secondary Treatment Processes:** Any wastewater treatment process which is downstream of the air flotation unit, any other biological treatment process at a refinery, or any treatment process which is regulated by the EPA National Categorical Pretreatment Standards. These treatment processes are considered to be wastewater polishing steps and include: activated sludge tanks/basins, trickling or sand filters, aerated lagoons, oxidation ponds, rotating biological contactors, and other biological wastewater treatment processes.
(Adopted November 1, 1989)
- 8-8-209 Air Flotation Unit:** Any device, equipment, or apparatus in which wastewater is saturated with air or gas under pressure and removes floating oil, floating emulsified oil, or other floating liquid precursor organic compounds by skimming. Also included in this definition are: induced air flotation units and pre-air flotation unit flocculant sumps, tanks, or basins.
(Adopted November 1, 1989)
- 8-8-210 Critical Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate emitted during separation, processing, transportation or storage of wastewater, and having a carbon number of C-14 or less (excluding phenolic compounds).
(Adopted 11/1/89; Amended 9/15/04)
- 8-8-211 Wastewater:** Any process water which contains oil, emulsified oil, or other organic compounds which is not recycled or otherwise used within a facility.
(Adopted November 1, 1989)
- 8-8-212 Pre-Air Flotation Unit Flocculation Sump, Basin, Chamber, or Tank:** Any facility which pretreats the air flotation unit's influent with chemical coagulants, and/or adjusts the influent's pH.
(Adopted November 1, 1989)
- 8-8-213 Oil-Water Separator Slop Oil Vessel:** Any vessel which, as its sole function, treats or dewater oil-water separator slop oil.
(Adopted November 1, 1989)
- 8-8-214 Oil-Water Separator Effluent:** Any process wastewater downstream of the oil-water separator that has not been treated by an air flotation unit.
(Adopted November 1, 1989)
- 8-8-215 Sludge-dewatering Unit:** Any device which, as its sole function, is used to dewater oil-water separator and air flotation slop oil/sludge.
(Adopted November 1, 1989)
- 8-8-216 Stormwater Sewer System:** A drain and collection system that is designed and operated for the sole purpose of collecting stormwater and is segregated from the wastewater collection system.
(Adopted 11/1/89; Amended 9/15/04)
- 8-8-217 Junction Box:** Any structure where sewer lines meet and one or more wastewater streams are co-mingled.
(Amended September 15, 2004)

- 8-8-218 Sewer Line:** A lateral, trunk line, branch line, ditch, channel, or other conduit used to convey wastewater to downstream oil-water separators.
(Adopted November 1, 1989)
- 8-8-219 Leak Minimization:** Reducing the leak to the lowest achievable level using best modern practices and without shutting down the process the equipment serves.
(Adopted September 15, 2004)
- 8-8-220 Leak Repair:** The tightening, adjustment, or addition of material, or the replacement of the equipment, which reduces leakage to the atmosphere below 500 ppm.
(Adopted September 15, 2004)
- 8-8-221 Lift Stations:** Any structure whose function is to take water from a low point on a gradient and transport it to the treatment system via a pumping mechanism.
(Adopted September 15, 2004)
- 8-8-222 Manholes:** Any service entrance into sewer lines that allows access for inspection and cleaning.
(Adopted September 15, 2004)
- 8-8-223 Oil-Water Separation Trench:** Any grated open topped culvert used to separate debris from oil-water during equipment washing or steaming associated with maintenance or turnaround.
(Adopted September 15, 2004)
- 8-8-224 Petroleum Refinery:** A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411 (1997).
(Adopted September 15, 2004)
- 8-8-225 Process Drains:** Any point in the wastewater collection system where streams from a source or sources enter the collection system. A process drain may be connected to the main process sewer line or to trenches, sumps, or ditches.
(Adopted September 15, 2004)
- 8-8-226 Reaches:** Any segments of sewer pipe that convey wastewater between two manholes or other sewer components such as lift stations or junction boxes.
(Adopted September 15, 2004)
- 8-8-227 Sumps:** Any below-grade structure typically used as a collection point for wastewater from multiple sewer lines prior to pumping or overflow to wastewater treatment.
(Adopted September 15, 2004)
- 8-8-228 Trenches:** Any open-topped culvert used to transport wastewater from the point of process discharge to subsequent wastewater collection system components, such as junction boxes and lift stations.
(Adopted September 15, 2004)
- 8-8-229 Vent Pipes:** Any piping used to ventilate a wastewater collection system component or a wastewater separation system.
(Adopted September 15, 2004)
- 8-8-230 Wastewater Collection System Components:** Any structure or part of structures used to collect and transport wastewater prior to any treatment. These structures are usually located before oil/water separators and may include but are not limited to process drains, sewer lines, trenches, manholes, junction boxes, reaches, sumps and lift stations (including vent pipes).
(Adopted September 15, 2004)
- 8-8-231 Wastewater Separation System:** Any structure used to remove oil from water via a physical process including but not limited to oil-water separators, dissolved air flotation units or dissolved gas flotation units.
(Adopted September 15, 2004)
- 8-8-232 Water Seal or Equivalent Control:** Any seal pot, p-leg trap, or other type of trap filled with a liquid not containing organic compounds in order to create a barrier between the sewer and the atmosphere, or an equivalent physical seal, enclosed piping, pollution prevention measure or abatement device that meets the criteria of Regulation 2, Rule 1.
(Adopted September 15, 2004)
- 8-8-300 STANDARDS**
- 8-8-301 Wastewater Separators Greater than 760 Liters per Day and Smaller than 18.9 Liters per Second:** A person shall not operate any wastewater separator and/or forebay with a design rated or maximum allowable capacity greater than 760 liters

per day and smaller than 18.9 liters per second (oil-water separators and/or forebays between 200 gals per day to 300 gals per min.) unless such wastewater separator and/or forebay is operated within its design rated or maximum allowable capacity and is equipped with one of the following:

- 301.1 A solid, gasketed, fixed cover totally enclosing the separator tank, chamber, or basin (compartment) liquid contents, with all cover openings closed, except when the opening is being used for inspection, maintenance, or wastewater sampling. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps greater than 0.32 cm (0.125 inch) occur in the roof or between the roof and wall; and that the access doors and other openings are closed and gasketed properly; or
- 301.2 A floating pontoon or double-deck vapor-tight type cover. All floating roofs must rest entirely on the liquid surface. The floating roof shall consist of two seals, one above the other, the one below shall be referred to as the primary seal, while the other seal shall be referred to as the secondary seal.
 - 2.1 Oil-Water Separator Liquid-Mounted Primary Seal Gap Criteria: No gap between the separator wall and the liquid-mounted primary seal shall exceed 3.8 cm (1.5 inch). No continuous gap greater than 0.32 cm (0.125 inch) shall exceed 10 percent of the perimeter of the separator. The cumulative length of all primary seal gaps exceeding 1.3 cm (0.5 inch) shall be not more than 10 percent of the perimeter and the cumulative length of all primary seal gaps exceeding 0.32 cm (0.125 inch) shall be not more than 40 percent of the perimeter.
 - 2.2 Oil-Water Separator Secondary And Wiper Seals Gap Criteria: No gap between the separator wall and the secondary and wiper seals shall exceed 1.5 mm (0.06 inch). The cumulative length of all secondary and wiper seals gaps exceeding 0.5 mm (0.02 inch) shall be not more than 5 percent of the perimeter of the separator. The secondary and wiper seals must exert a positive pressure against the separator such that the seal surface in contact with the separator wall does not pull away from the separator wall more than the gaps allowed.
 - 2.3 Primary And Secondary Seal Gap Inspection: The primary seal shall be inspected within 60 calendar days after initial installation of the floating roof and once every 5 years thereafter in accordance with the requirements of Section 8-8-301.2.1. The secondary seal shall be inspected within 60 calendar days after initial installation of the floating roof and once every year thereafter in accordance with the requirements of Section 8-8-301.2.2. The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in Sections 8-8-301.2.1 and 301.2.2; or
- 301.3 An organic compound vapor recovery system with a combined collection and destruction efficiency of at least 95 percent, by weight.
- 301.4 Deleted October 6, 1993

(Amended 11/1/89; 10/6/93; 9/15/04)

8-8-302

Wastewater Separators Larger than or Equal to 18.9 Liters per Second: A person shall not operate any wastewater separator and/or forebay with a rated or maximum allowable capacity larger than or equal to 18.9 liters per second (300 gals per min.) unless such wastewater separator and/or forebay is operated within its design rated or maximum allowable capacity and is equipped with one of the following:

- 302.1 A solid, vapor-tight, full contact fixed cover which totally encloses the separator tank, chamber, or basin (compartment) liquid contents, with all cover openings closed and sealed, except when the opening is being used for inspection, maintenance, or wastewater sampling; or
- 302.2 A floating pontoon or double-deck vapor-tight type cover. All floating roofs must rest on the liquid surface. The floating roof shall consist of two seals,

one above the other, the one below shall be referred to as the primary seal, while the other seal shall be referred to as the secondary seal.

- 2.1 Oil-Water Separator Liquid-Mounted Primary Seal Gap Criteria: No gap between the separator wall and the liquid-mounted primary seal shall exceed 3.8 cm (1.5 inch). No continuous gap greater than 0.32 cm (0.125 inch) shall exceed 10 percent of the perimeter of the separator. The cumulative length of all primary seal gaps exceeding 1.3 cm (0.5 inch) shall be not more than 10 percent of the perimeter and the cumulative length of all primary seal gaps exceeding 0.32 cm (0.125 inch) shall be not more than 40 percent of the perimeter.
 - 2.2 Oil-Water Separator Secondary And Wiper Seals Gap Criteria: No gap between the separator wall and the secondary and wiper seals shall exceed 1.5 mm (0.06 inch). The cumulative length of all secondary and wiper seals gaps exceeding 0.5 mm (0.02 inch) shall be not more than 5 percent of the perimeter of the separator. The secondary and wiper seals must exert a positive pressure against the separator such that the seal surface in contact with the separator wall does not pull away from the separator wall more than the gaps allowed; or
 - 2.3 Primary And Secondary Seal Gap Inspection: The primary seal shall be inspected within 60 calendar days after initial installation of the floating roof and once every 5 years thereafter in accordance with the requirements of Section 8-8-302.2.1. The secondary seal shall be inspected within 60 calendar days after initial installation of the floating roof and once every year thereafter in accordance with the requirements of Section 8-8-302.2.2. The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in Sections 8-8-302.2.1 and 302.2.2.; or
- 302.3 A vapor-tight fixed cover with an organic compound vapor recovery system which has a combined collection and destruction efficiency of at least 95 percent, by weight, inspection and access hatches shall be closed except when the opening is being used for inspection, maintenance, or wastewater sampling, or
- 302.4 A solid, sealed, gasketed, fixed cover which totally encloses the separator tank, chamber, or basin (compartment) liquid contents, with all cover openings closed and sealed, except when the opening is being used for inspection, maintenance, or wastewater sampling. The cover may include a pressure/vacuum valve. The concentration of organic compounds, measured at the interface of the roof seals, fixed cover, access doors, pressure/vacuum valve, and other openings shall not exceed 1,000 ppm (expressed as methane) above background. Roof seals, fixed cover, access doors, and other openings shall be inspected initially and semiannually thereafter to ensure that there are no emission leaks greater than 1,000 ppm. Any emission leak greater than 1,000 ppm must be reported to the APCO and repaired within 15 days.
- 302.5 Deleted October 6, 1993
- 302.6 Roof seals, fixed covers, access doors, and other openings at petroleum refineries shall be inspected initially and semiannually thereafter to ensure that they are vapor tight. A leak in any component that is not vapor tight must be minimized within 24 hours and repaired within 7 days.
(Adopted 1/1/89; Amended 10/6/93; 9/15/04)
- 8-8-303 Gauging and Sampling Devices:** Any compartment or access hatch shall have a vapor tight cover. Any gauging and sampling device in the compartment cover shall be equipped with a vapor tight cover, seal, or lid. The compartment cover and gauging or sampling device cover shall at all times be in a closed position, except when the device is in use for inspection, maintenance, or wastewater sampling.
(Amended, Renumbered November 1, 1989)

8-8-304 Sludge-dewatering Unit: Any sludge-dewatering unit, equipment, machinery, apparatus, or device shall be totally enclosed and vented to a control device which has a minimum combined collection and destruction efficiency of 95 percent by weight; or shall have vapor-tight covers on the unit, conveyer belts, and storage bins or tanks except during inspection, maintenance or when the solids storage bin is in use. Sludge must be maintained in vapor tight containers during storage.

(Adopted 11/1/89; Amended 10/6/93; 9/15/04)

8-8-305 Oil-Water Separator And/Or Air Flotation Unit Slop Oil Vessels: A person shall not store any oil-water separator and/or air flotation unit sludges in an oil-water separator slop oil vessel unless such oil-water separator slop oil vessel is equipped with one of the following:

305.1 A solid, gasketed, fixed cover totally enclosing the vessel liquid contents, with all cover openings closed, except when the opening is being used for inspection, maintenance, or wastewater sampling. The cover may include an atmospheric vent or a pressure/vacuum valve. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps greater than 0.32 cm (0.125 inch) occur in the roof or between the roof and wall; and that the access doors and other openings are closed and gasketed properly; or

305.2 An organic compound vapor recovery system with a combined collection and destruction efficiency of at least 70 percent, by weight.

305.3 Deleted October 6, 1993

(Adopted 11/1/89; Amended 10/6/93; 9/15/04)

8-8-306 Oil-Water Separator Effluent Channel, Pond, Trench, or Basin: A person shall not operate any oil-water separator effluent channel, pond, trench, or basin a design rated or maximum allowable capacity greater than 25.2 liters per second (any oil-water separator effluent channel, pond, trench, or basin greater than 400 gals per min) unless such oil-water separator effluent channel, pond, trench, or basin is operated within its design rated or maximum allowable capacity and is equipped with one of the following:

306.1 A solid, gasketed, fixed cover totally enclosing the oil-water separator effluent channel, pond, trench, or basin (compartment) liquid contents, with all cover openings closed, except when the opening is being used for inspection, maintenance, or wastewater sampling. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps greater than 0.32 cm (0.125 inch) occur in the roof or between the roof and wall; and that the access doors and other openings are closed and gasketed properly; or

306.2 An organic compound vapor recovery system with a combined collection and destruction efficiency of at least 70 percent, by weight.

306.3 Deleted October 6, 1993

(Adopted 11/1/89; Amended 10/6/93; 9/15/04)

8-8-307 Air Flotation Unit: A person shall not operate any air flotation unit and/or pre-air flotation unit flocculation sump, basin, chamber, or tank with a design rated or maximum allowable capacity greater than 25.2 liters per second (air flotation units and/or pre-air flotation unit flocculation sump, basin, chamber, or tank greater than 400 gals per min.) unless such air flotation unit and/or pre-air flotation unit flocculation sump, basin, chamber, or tank is operated within its design rated or maximum allowable capacity and is equipped with one of the following:

307.1 A solid, gasketed, fixed cover totally enclosing the air flotation and pre-air-flotation-unit flocculation tank, chamber, or basin (compartment) liquid contents, with all cover openings closed, except when the opening is being used for inspection, maintenance, or wastewater sampling. The cover may include an atmospheric vent or pressure/vacuum valve. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps greater than 0.32 cm (0.125 inch) occur in the roof or between the roof and wall; and that the access doors and other openings are closed and gasketed properly; or

307.2 An organic compound vapor recovery system with a combined collection and destruction efficiency of at least 70 percent, by weight.

307.3 Deleted October 6, 1993

(Adopted 11/1/89; Amended 10/6/93; 9/15/04)

8-8-308 Junction Box: Any junction box shall be equipped with either a solid, gasketed, fixed cover totally enclosing the junction box or a solid manhole cover. Junction boxes may include openings in the covers and vent pipes if the total open area of the junction box does not exceed 81.3 cm² (12.6 in²) and all vent pipes are at least 3 feet in length.

(Adopted 11/1/89; Amended 10/6/93)

8-8-309 Deleted October 6, 1993

8-8-310 Deleted October 6, 1993

8-8-311 Deleted October 6, 1993

8-8-312 Controlled Wastewater Collection System Components at Petroleum Refineries: Effective January 1, 2006, all controlled wastewater collection system components at petroleum refineries shall be vapor tight except when in use for active inspection, maintenance, repair or sampling. A leak in any controlled wastewater collection system component that is not vapor tight must be minimized within 24 hours and repaired within 7 days.

(Adopted September 15, 2004)

8-8-313 Uncontrolled Wastewater Collection System Components at Petroleum Refineries: Petroleum refineries shall comply with either Section 8-8-313.1 or 313.2 below:

313.1 Each uncontrolled wastewater collection system component must be equipped with a water seal or equivalent control according to the schedule in Section 8-8-403. Any uncontrolled collection system component that is not vapor tight must be minimized. Upon installation of a water seal or equivalent control, the provisions of Section 8-8-312 will apply; **or**

313.2 Effective January 1, 2006 and until January 1, 2007, each uncontrolled wastewater collection system component must be inspected bi-monthly. Effective January 1, 2007, each uncontrolled wastewater system component must be inspected semi-annually. Any uncontrolled wastewater collection system component that is not vapor tight shall be identified, minimized within 24 hours and re-inspected every 30 days. The component may be returned to a semi-annual inspection schedule if it is vapor tight during three consecutive 30-day inspections. Any uncontrolled wastewater collection system component that is not vapor tight during any three inspections in a five-year period must be equipped with a water seal or equivalent control within 30 days after the third inspection. Upon installation of the water seal or equivalent control, the provisions of Section 8-8-312 shall apply. Unless previously identified by the refinery, any wastewater system component discovered by the APCO not to be vapor tight must be minimized within 24 hours and repaired within 7 days.

(Adopted September 15, 2004)

8-8-314 New Wastewater Collection System Components at Petroleum Refineries: Effective January 1, 2005, any new wastewater collection system component at a petroleum refinery shall be equipped with a water seal or equivalent control.

(Adopted September 15, 2004)

8-8-400 ADMINISTRATIVE REQUIREMENTS

8-8-401 Deleted October 6, 1993

8-8-402 Wastewater Inspection and Maintenance Plan at Petroleum Refineries: All petroleum refineries must implement an inspection and maintenance plan that meets all of the following requirements:

402.1 By October 1, 2005, all wastewater collection system components must be identified and the APCO must be provided with lists, diagrams or other information sufficient to locate all components. It shall not be violation of this requirement if the refinery discovers that a component has been omitted from the list, diagram, or other information and submits information to the APCO

regarding the component. Effective October 1, 2005, any wastewater collection system component found by the APCO that was not identified pursuant to the provisions of this section shall constitute a violation.

- 402.2 By October 1, 2005, an initial inspection of all wastewater collection system components must be completed by the refinery. The results of the initial inspection shall be made available to the APCO, but any wastewater collection system component that is not vapor tight shall not trigger the requirements of Section 8-8-313 before the effective date of that Section.
- 402.3 Effective January 1, 2006, for petroleum refineries that elect to comply with Section 8-8-313.2, the plan must provide for the identification and minimization of leaking components and a re-inspection within 30 days of discovery. The plan must also provide for re-inspections every thirty days until the affected component is either controlled or is returned to the inspection schedule in Section 8-8-313.2.
- 402.4 Effective January 1, 2006, each controlled component shall be inspected semi-annually.
- 402.5 Records must be maintained pursuant to Section 8-8-505.

(Adopted September 15, 2004)

8-8-403 Petroleum Refinery Compliance Schedule: Any petroleum refinery electing to comply with Section 8-8-313.1 shall install controls on uncontrolled wastewater collection system components according to the following schedule:

- 403.1 By October 31, 2005, install controls on 25% of wastewater collection system components that were uncontrolled as of January 1, 2005.
- 403.2 By April 30, 2006, install controls on 50% of wastewater collection system components that were uncontrolled as of January 1, 2005.
- 403.3 By October 31, 2006, install controls on 75% of wastewater collection system components that were uncontrolled as of January 1, 2005.
- 403.4 By April 30, 2007, install controls on 100% of wastewater collection system components that were uncontrolled as of January 1, 2005.

(Adopted September 15, 2004)

8-8-404 Uncontrolled Wastewater Collection System Components Election: By November 1, 2004, each petroleum refinery shall choose a compliance option from Section 8-8-313 and notify the APCO in writing indicating which option has been chosen.

(Adopted September 15, 2004)

8-8-500 MONITORING AND RECORDS

8-8-501 API Separator or Air Flotation Bypassed Wastewater Records: Any person who bypasses wastewater past their API Separator or Air Flotation unit shall maintain records on the amount of bypassed wastewater, duration, date, causes for bypasses, and dissolved critical organic compound concentration (volume). These records shall be retained and available for inspection by the APCO for at least 24 months.

(Adopted 11/1/89; Amended 9/15/04)

8-8-502 Wastewater Critical Organic Compound Concentration Or Temperature Records: Any person who exempts their wastewater separator because of either wastewater critical organic compound concentration or temperature shall sample and test the wastewater initially and semiannually thereafter and maintain records on the date, time of test, location, and wastewater temperature and/or critical organic compound concentration (volume). These records shall be retained and available for inspection by the APCO for at least 24 months.

(Adopted 11/1/89; Amended 9/15/04)

8-8-503 Inspection and Repair Records: Records of inspections and repairs as required by Sections 8-8-301, 302, 305, 306 or 307 shall be retained and made available for inspection by the APCO for at least 24 months.

(Adopted October 6, 1993)

8-8-504 Portable Hydrocarbon Detector: Any instrument used for the measurement of organic compounds shall be a gas detector that meets the specifications and performance criteria of and has been calibrated in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).

(Adopted June 15, 1994)

8-8-505 Records for Wastewater Collection System Components at Petroleum Refineries: Any person subject to the requirements of this rule shall:

- 505.1 Maintain records of the type and location of each wastewater collection system component.
- 505.2 Record the date of each wastewater collection system component inspection, and re-inspection and leak concentration measured for each inspection or re-inspection.
- 505.3 Record a description of the minimization or repair efforts on each leaking component that is not vapor tight.
- 505.4 Maintain required records for at least 5 years and make them available to the APCO for inspection at any time.

(Adopted September 15, 2004)

8-8-600 MANUAL OF PROCEDURES

8-8-601 Wastewater Analysis for Critical Organic Compounds: Samples of wastewater as specified in this rule shall be taken at the influent stream for each unit and analyzed for the concentration of dissolved critical organic compounds as prescribed in the Manual of Procedures, Volume III, Lab Method 33.

(Amended 11/1/89; 10/6/93; 9/15/04)

8-8-602 Determination of Emissions: Emissions of organic compounds as specified in Sections 8-8-301.3, 8-8-302.3, 8-8-304, 8-8-305.2, 8-8-306.2, and 8-8-307.2 shall be measured as prescribed by any of the following methods: 1) BAAQMD Manual of Procedures, Volume IV, ST-7, 2) EPA Method 25, or 25A). A source shall be considered in violation if the organic compound emissions measured by any of the referenced test methods exceed the standards of this rule.

(Amended 11/1/89; 10/6/93; 6/15/94; 9/15/04)

8-8-603 Inspection Procedures: For the purposes of Sections 8-8-301, 302, 303, 304 312, 313 and 402, leaks shall be measured using a portable gas detector as prescribed in EPA Reference Method 21 (40 CFR 60, Appendix A).

(Adopted 6/15/94; Amended 9/15/04)

**REGULATION 8
ORGANIC COMPOUNDS
RULE 18
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**REGULATION 8
ORGANIC COMPOUNDS
RULE 18
EQUIPMENT LEAKS**

(Adopted October 1, 1980)

8-18-100 GENERAL

8-18-101 Description: The purpose of this Rule is to limit emissions of total organic compounds from equipment leaks at petroleum refineries, chemical plants, bulk plants and bulk terminals including, but not limited to: valves, connectors, pumps, compressors, pressure relief devices, diaphragms, hatches, sight-glasses, fittings, sampling ports, meters, pipes, and vessels.

(Amended 3/17/82; 3/4/92; 1/7/98; 1/21/04, 9/15/04, 12/16/15)

8-18-110 Exemption, Controlled Seal Systems and Pressure Relief Devices: The provisions of this Rule shall not apply to seal systems and pressure relief devices vented to a vapor recovery or disposal system which reduces the emissions of organic compounds from the equipment by 95% or greater as determined according to Section 8-18-603.

(Amended, Renumbered 1/7/98; Amended 1/21/04)

8-18-111 Exemption, Small Facilities: The provisions of this rule shall not apply to facilities which have less than 100 valves or less than 10 pumps and compressors. Such facilities are subject to the requirements of Regulation 8, Rule 22.

(Adopted 3/4/92; Amended, Renumbered 1/7/98)

8-18-112 Exemption, Bulk Plant and Terminal Loading Racks: The provisions of this rule shall not apply to those connections at the interface between the loading rack and the vehicle being loaded.

(Adopted 3/4/92; Amended, Renumbered 1/7/98)

8-18-113 Limited Exemption, Initial Boiling Point: Until January 1, 2018, the provisions of Sections 8-18-400 shall not apply to equipment which handle organic liquids having an initial boiling point greater than 302°F.

(Adopted 3/4/92; Amended, Renumbered 1/7/98, Amended 12/16/15)

8-18-114 Limited Exemption, Research and Development: The provisions of Sections 8-18-401, 402 and 502 shall not apply to research and development plants which produce only non-commercial products solely for research and development purposes.

(Adopted 3/4/92; Amended, Renumbered 1/7/98)

8-18-115 Limited Exemption, Storage Tanks: The provisions of this rule shall not apply to appurtenances on storage tanks including pressure relief devices, which are subject to requirements contained in Regulation 8, Rule 5: Storage of Organic Liquids.

(Adopted January 7, 1998)

8-18-116 Limited Exemption, Vacuum Service: The provisions of Sections 8-18-400 and 502 shall not apply to equipment in vacuum service.

(Amended January 7, 1998)

8-18-117 Limited Exemption, Visual Inspection: The provisions of Section 8-18-403 shall not apply to days when a facility is not staffed.

(Amended, Renumbered January 7, 1998)

8-18-118 Deleted January 7, 1998

8-18-119 Limited Exemption, Open-Ended Valve or Line: The provisions of Section 8-18-309 shall not apply to the following:

119.1 Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset.

119.2 Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system.

(Adopted December 16, 2015)

8-18-120 Limited Exemption, Non-repairable Equipment: The provisions of Sections 8-18-306 and 311 shall not apply to equipment added to the non-repairable equipment list prior to December 16, 2015 except that:

- 120.1 The equipment must be counted toward the total number of pieces of equipment allowed by Section 8-18-306.2.
- 120.2 Any connection on the list must be counted as two valves toward the total number of non-repairable valves allowed by Section 8-18-306.2.
- 120.3 Any valve on the list with a leak that cannot be minimized below a concentration of 10,000 parts per million (ppm), expressed as methane, may not remain on the list for more than 45 days after leak discovery unless the mass emission rate has been measured in accordance with Section 8-18-604 and has been determined to be less than 15 pounds per day.
- 120.4 The equipment must be repaired or replaced within five years or at the next scheduled turnaround, whichever date comes first.

(Adopted December 16, 2015)

8-18-200 DEFINITIONS

8-18-201 Background: The ambient concentration of total organic compounds determined at least 3 meters (10 feet) upwind from the equipment to be inspected and not influenced by any specific emission point as indicated by a hydrocarbon analyzer specified by Section 8-18-501.

(Amended March 4, 1992)

8-18-202 Bulk Plants and Terminals: A distribution facility that is subject to Regulation 8, Rule 6, 33 or 39.

(Amended, Renumbered 1/7/98, Amended 12/16/15)

8-18-203 Chemical Plant: Any facility engaged in producing organic or inorganic chemicals and/or manufacturing products by chemical processes, including (1) any facility or operation that has 325 as the first three digits in the North American Industrial Classification Standard (NAICS) code, (2) any facility that manufactures industrial inorganic and organic chemicals; plastic and synthetic resins, synthetic rubber, synthetic and other manmade fibers; drugs; soap, detergents and cleaning preparations; perfumes, cosmetics, and other toilet preparations; paints, varnishes, lacquers, enamels, and allied products; agricultural chemicals; safflower and sunflower oil extracts; and (3) any facility engaged in re-refining.

(Amended, Renumbered 1/7/98; Amended 1/21/04, 12/16/15)

8-18-204 Connection: Flanged, screwed, or other joined fittings used to connect any piping or equipment, including any fitting connecting equipment to piping or other equipment, such as a valve bonnet flange or pump flange

(Amended, Renumbered 1/7/98; Amended 1/21/04, 12/16/15)

8-18-205 Equipment: All components including, but not limited to: valves, connections, pumps, compressors, pressure relief devices, diaphragms, hatches, fittings, sampling ports, pipes, plugs, gauges or sight-glasses.

(Amended, Renumbered 1/7/89, Amended 12/16/15)

8-18-206 Inaccessible Equipment: Any equipment located over 13 feet above the ground when access is required from the ground; or any equipment located over 6.5 feet away from a platform when access is required from a platform.

(Amended, Renumbered January 7, 1998)

8-18-207 Inspection: The determination of the concentration of total organic compounds leaking from equipment using EPA Reference Method 21 as required by Section 8-18-501.

(Amended, Renumbered January 7, 1998)

8-18-208 Leak: The concentration of total organic compounds above background, expressed as methane, as measured in accordance with Section 8-18-602.

(Amended, Renumbered 1/7/98; 1/21/04, Amended 12/16/15)

8-18-209 Leak Minimization: Reducing the leak to the lowest achievable level using best modern practices and without shutting down the process the equipment serves. Leak minimization is the most common method for repair. Leak minimization includes but is not limited to tightening of packing gland nuts, injecting lubricant into lubricated packing, tightening bonnet bolts, tightening flange bolts, or installing plugs or caps into open ended lines or valves. Cleaning, scrubbing, or washing equipment alone is not considered best modern practice.

(Renumbered 3/17/82; Amended 3/4/92, 1/7/98, 12/16/15)

- 8-18-210 Leak Repair:** The tightening, adjustment, addition of material, or the replacement of the equipment using best modern practices, which reduces the leakage to the atmosphere below the applicable standard in Section 8-18-300.
(Renumbered 3/17/82; Amended 3/4/92; 1/7/98, 12/16/15)
- 8-18-211 Liquid Leak:** Dripping of liquid at a rate of greater than 3 drops per minute and a concentration of total organic compounds greater than the applicable leak standard in Section 8-18-300.
(Amended, Renumbered January 7, 1998)
- 8-18-212 Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate.
(Amended, Renumbered January 7, 1998)
- 8-18-213 Petroleum Refinery:** Any facility that processes petroleum products as defined in North American Industrial Classification Standard Number 32411, Petroleum Refining.
(Amended, Renumbered January 7, 1998)
- 8-18-214 Pressure Relief Device:** The automatic pressure-relieving device actuated by the static pressure upstream of the device including, but not limited to, pressure relief valves and rupture disks.
(Amended, Renumbered January 7, 1998)
- 8-18-215 Process Unit:** A manufacturing process which is independent of other processes and is continuous when supplied with a constant feed or raw materials and has sufficient storage facilities for product.
(Amended, Renumbered January 7, 1998)
- 8-18-216 Quarter:** One of the four consecutive 3-month divisions of the calendar year beginning on January 1.
(Amended, Renumbered January 7, 1998)
- 8-18-217 Reinspection:** Any inspection following the minimization or repair of leaking equipment.
(Amended, Renumbered January 7, 1998)
- 8-18-218 Rupture Disc:** The thin metal diaphragm held between flanges.
(Amended, Renumbered January 7, 1998)
- 8-18-219 Total Organic Compounds:** The concentration of organic compounds and methane as indicated by a hydrocarbon analyzer as specified by Section 8-18-501.
(Amended, Renumbered 1/7/98; Amended 1/21/04)
- 8-18-220 Turnaround:** The scheduled shutdown of a process unit for maintenance and repair work.
(Amended, Renumbered January 7, 1998)
- 8-18-221 Valve:** Any device that regulates the flow of process material by means of an external actuator acting to permit or block passage of liquids or gases.
(Amended, Renumbered January 7, 1998)
- 8-18-222 Weephole:** A drain hole in the discharge horn of a pressure relief device.
(Adopted January 7, 1998)
- 8-18-223 Deleted January 7, 1998**
- 8-18-224 Deleted January 7, 1998**
- 8-18-225 Deleted December 16, 2015**
- 8-18-226 Essential Equipment:** Any valve, connection, pressure relief device, pump or compressor that cannot be taken out of service without shutting down the process unit that it serves.
(Adopted December 16, 2015)
- 8-18-227 Open-Ended Valve or Line:** Any valve, except a safety relief valve, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.
(Adopted December 16, 2015)
- 8-18-228 Double Block Bleed System:** Two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.
(Adopted December 16, 2015)
- 8-18-300 STANDARDS**
- 8-18-301 General:** Except for valves, pumps and compressors, connections and pressure relief devices subject to the requirements of Sections 8-18-302, 303, 304, 305 and

306, a person shall not use any equipment that leaks total organic compounds in excess of 100 ppm unless the leak has been discovered by the operator, minimized within 24 hours and repaired within 7 days.

(Amended 7/15/81; 3/17/82; 9/6/89; 3/4/92; 1/7/98)

8-18-302 Valves: Except as provided in Section 8-18-306, a person shall not use any valve that leaks total organic compounds in excess of 100 ppm unless one of the following conditions is met:

302.1 If the leak has been discovered by the operator, minimized within 24 hours and repaired within 7 days; or

302.2 If the leak has been discovered by the APCO, the leak must be repaired within 24 hours.

(Adopted 3/4/92; Amended 1/7/98, 1/21/04, 12/16/15)

8-18-303 Pumps and Compressors: Except as provided in Section 8-18-306, a person shall not use any pump or compressor that leaks total organic compounds in excess of 500 ppm unless one of the following conditions is met:

303.1 If the leak has been discovered by the operator, minimized within 24 hours and repaired within 7 days; or

303.2 If the leak has been discovered by the APCO, the leak must be repaired within 24 hours.

(Adopted 3/4/92; Amended 1/7/98, 1/21/04, 12/16/15)

8-18-304 Connections: Except as provided in Section 8-18-306, a person shall not use any connection that leaks total organic compounds in excess of 100 ppm unless one of the following conditions is met:

304.1 If the leak has been discovered by the operator, minimized within 24 hours and repaired within 7 days; or

304.2 If the leak has been discovered by the APCO, the leak must be repaired within 24 hours.

(Adopted 3/4/92; Amended 1/7/98, 1/21/04, 12/16/15)

8-18-305 Pressure Relief Devices: Except as provided in Section 8-18-306, a person shall not use any pressure relief device that leaks total organic compounds in excess of 500 ppm unless the leak has been discovered by the operator, minimized within 24 hours and repaired within 15 days; or if the leak has been discovered by the APCO, minimized within 24 hours and repaired within 7 days.

(Amended 1/7/98, 12/16/15)

8-18-306 Non-repairable Equipment: Any essential equipment leak that cannot be repaired as required by Section 8-18-302, 303, 304 or 305 may be placed on a non-repairable list provided the operator complies with the following conditions:

306.1 Any essential equipment leak must be less than 10,000 ppm and mass emissions must be determined within 30 days of placing on the non-repairable list. The APCO must be notified no less than 96 hours prior to conducting mass emissions measurements.

306.2 The number of individual pieces of equipment awaiting repair does not exceed that portion of the total population for each equipment type expressed in the table below, rounded to the next higher whole number.

Equipment	Total Number of Non-repairable Equipment Allowed (%)
Valves and Connections as allowed by Section 8-18-306.3	0.15% of total number of valves
Pressure Relief Devices	0.5% of total number of pressure relief devices
Pumps and Compressors	0.5% of total number of pumps and compressors

306.3 A connection can be considered non-repairable equipment pursuant to Section 8-18-306 provided each non-repairable connection is counted as two valves toward the total number of non-repairable valves allowed.

306.4 The essential equipment is repaired or replaced within five years or at the next scheduled turnaround, whichever date comes first.

(Adopted 3/4/92; Amended 1/7/98, 1/21/04, 12/16/15)

8-18-307 Liquid Leak: A person shall not use any equipment that leaks liquid as defined in Section 8-18-211, unless the leak has been discovered by the operator, minimized within 24 hours and repaired within 7 days.

(Adopted 3/4/92; Amended 1/7/98)

8-18-308 Alternate Compliance: The requirements of Sections 8-18-301, 302, 303, 304, 305, 306 and 307 shall not apply to any facility which complies with an alternative emission reduction plan that satisfies all the requirements in Sections 8-18-405 and 406.

(Adopted January 7, 1998)

8-18-309 Open-Ended Valve or Line: Open-ended valves or lines shall be equipped with a cap, blind flange, plug or second valve which shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

309.1 When a double block and bleed system is installed, the second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

309.2 When a double block and bleed system is in use, the bleed valve or line may remain open during operations that require venting the line between the block valves, but shall comply with Sections 8-18-309 and 309.1 at all times.

309.3 When a double block and bleed system is not in use, the open end of the second valve shall not leak greater than 100 ppm.

(Adopted December 16, 2015)

8-18-310 Recurrent Leaks: If a valve, pump, compressor or PRD is found leaking more than 3 consecutive quarters, the inspection frequency shall change from quarterly to monthly pursuant to Section 8-18-407.

(Adopted December 16, 2015)

8-18-311 Mass Emissions: A person shall not use any equipment that emits total organic compounds in excess of five pounds per day except during any repair periods allowed by Sections 8-18-301, 302, 303, 304, and 305.

(Adopted December 16, 2015)

8-18-400 ADMINISTRATIVE REQUIREMENTS

8-18-401 Inspection: Any person subject to this Rule shall comply with the following inspection requirements:

401.1 All equipment that has been opened during a turnaround shall be inspected for leaks within 90 days after start-up is completed following a turnaround.

401.2 Except as provided under Subsection 8-18-401.3, 404, 405, and 406 all valves, pressure relief devices, pumps or compressors subject to this Rule shall be inspected quarterly.

401.3 Inaccessible valves and pressure relief devices subject to this Rule shall be inspected at least once a year unless found leaking pursuant to Subsection 8-18-403.

401.4 Any equipment subject to this Rule may be inspected at any time by the APCO.

401.5 Any equipment found to have a leak in excess of the standard in Section 8-18-300 shall be reinspected within 24 hours after any leak repair or minimization.

401.6 Any connections subject to this rule shall be inspected annually or be part of an APCO and EPA approved connection inspection program.

401.7 Any pressure relief device equipped with a weep hole shall be inspected quarterly at the outlet of the weep hole if the horn outlet is inaccessible.

401.8 Any pressure relief device that releases to the atmosphere shall be inspected within 5 working days after the release event.

401.9 Any essential equipment placed on the non-repairable list shall be inspected at least once per quarter.

401.10 The mass emission rate of any essential equipment placed on the non-repairable list in accordance with Section 8-18-306 shall be determined at least once per calendar year. The APCO shall be notified no less than 96 hours prior to conducting the measurements required by this section.

401.11 The owner/operator shall identify the equipment and/or source of any background reading greater than 50 ppm.

(Amended 12/16/15)

8-18-402 Identification: Any person subject to this Rule shall comply with the following identification requirements:

402.1 All valves, pressure relief devices, pumps and compressors, and, effective January 1, 2017, connectors shall be identified with a unique permanent identification code approved by the APCO. This identification code shall be used to refer to the valve, connector, pressure relief device, pump or compressor location. Records for each valve, connector, pressure relief device, pump or compressor shall refer to this identification code.

402.2 All equipment with a leak in excess of the applicable leak limitation in Section 8-18-300 shall be tagged with a brightly colored weatherproof tag indicating the date the leak was detected.

(Amended 3/4/92, 1/7/98, 12/16/15)

8-18-403 Visual Inspection Schedule: All pumps and compressors shall be visually inspected daily for leaks. If a leak is observed, the concentration shall be determined within 24 hours of discovery pursuant to Section 8-18-602.

(Renumbered 1/7/98; Amended 12/16/15)

8-18-404 Alternative Inspection Schedule: The inspection frequency for valves or pumps may change from quarterly to annually provided all of the conditions in Subsection 404.1 and 404.2 are satisfied.

404.1 The valve or pump has been operated leak free for five consecutive quarters; and

404.2 Records are submitted to the District and approved by the APCO.

404.3 The valve or pump remains leak free pursuant to the Sections 8-18-302 and 303. If a leak is discovered, the inspection frequency will revert back to quarterly.

(Adopted 1/7/98; Amended 12/16/15)

8-18-405 Alternate Emission Reduction Plan: Any person may comply with Section 8-18-308 by developing and submitting an alternate emission reduction plan to the APCO that satisfies all of the following conditions:

405.1 The plan shall contain all information necessary to establish, document, measure progress and verify compliance with an emission reduction level set forth in this rule.

405.2 All emission reductions must be achieved solely from equipment and connections subject to this rule.

405.3 Public notice and a 60-day public comment period shall be provided.

405.4 Following the public comment period, the plan shall be submitted to and approved in writing by the EPA, Region IX prior to the APCO approval of the plan.

405.5 An alternate emission reduction plan must provide for emission reductions equal to or greater than required by the specific limits in this rule.

(Adopted 1/7/98; Amended 11/27/02)

8-18-406 Interim Compliance: A facility is subject to the limits contained in Sections 8-18-301, 302, 303, 304, 305, 306 and 307 until receipt of the written approvals of both the APCO and the EPA of an Alternate Emission Reduction Plan that complies with Section 8-18-405.

(Adopted 1/7/98; Amended 11/27/02)

8-18-407 Recurrent Leak Schedule: For any valve, pump, compressor or pressure relief device found leaking in more than three consecutive quarters, a person subject to this Rule shall comply with the following requirements:

407.1 The inspection frequency shall be changed from quarterly to monthly; and

407.2 Records of each valve, pump, compressor and pressure relief device changed to monthly monitoring shall be submitted to the District each quarter pursuant to Section 8-18-503.1.

407.3 If the valve, pump, compressor or pressure relief device remains leak free for four consecutive months pursuant to Sections 8-18-302, 303 and 305 the inspection frequency will revert back to quarterly upon request and after APCO approval.

8-18-500 MONITORING AND RECORDS

8-18-501 Portable Hydrocarbon Detector: Any instrument used for the measurement of total organic compounds shall be a combustible gas indicator that has been approved by the APCO and meets the specifications and performance criteria of and has been calibrated in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).

(Amended 3/17/82, 9/6/89, 3/4/92, 12/16/15)

8-18-502 Records: Any person subject to the requirements of this rule shall maintain records that provided the following information:

- 502.1 For equipment subject to Section 8-18-402.1, the equipment identification code, equipment type and the location of the equipment.
- 502.2 The date, time, type of repairs and corresponding leak concentrations measured on all inspections and reinspections as specified by Section 8-18-401.
- 502.3 Records shall be maintained for at least 5 years and shall be made available to the APCO for inspection at any time.
- 502.4 Records of all non-repairable equipment subject to the provisions of Section 8-18-306 shall be maintained and contain the equipment identification code, equipment type, equipment location, initial leak concentration measurement and date, quarterly leak concentration measurements and dates, the duration the equipment has been on the non-repairable list, date of any repair attempts made to equipment, mass emission rate determinations, date the determination was made, last process unit turnaround date, total number of non-repairable equipment awaiting repair, and explanation why equipment was deemed essential equipment.
- 502.5 Records of all equipment and/or sources identified as a result of background readings greater than 50 ppm.
- 502.6 Effective January 1, 2018, Piping and Instrumentation Diagrams (P&IDs) with all components in heavy liquid service clearly identified.

(Adopted 3/4/92; Amended 1/7/98, 12/16/15)

8-18-503 Reports: Any person subject to the requirements of this rule shall submit the following information to the District:

- 503.1 Effective July 1, 2016, a report shall be submitted to the APCO quarterly that includes the following information:
 - 3.1.1 The equipment identification code, equipment type, stream service, equipment location, leak concentration measurement and date, leak repair method and concentration measurements of any valves, pumps, compressors and PRDs found leaking in more than 3 consecutive quarters pursuant to Section 8-18-310.
 - 3.1.2 Records of all non-repairable equipment subject to the provisions of Section 8-18-306 shall be submitted to the District quarterly and contain the equipment identification code, equipment type, equipment location, initial leak concentration measurement and date, the duration the equipment has been on the non-repairable list, any repair attempts made to equipment, mass emission rate determination, date the determination was made, last process unit turnaround date, total number of non-repairable equipment awaiting repair and explanation why equipment was deemed essential equipment.
- 503.2 Effective July 1, 2016, a person subject to this rule shall submit to the District an inventory identifying the total numbers of valves, pressure relief devices, pumps and compressors and connections to which this rule applies broken down per unit or other grouping if component is not associated with an individual unit. After review and approval of the initial inventory by the APCO, annual inventory updates shall be submitted to the District every January 1st.

503.4 Inspection records of all equipment opened during a turnaround shall be submitted to the District the first month following completion of the 90-day startup up leak inspections pursuant to Section 8-18-401.1.

503.5 By January 1, 2018, submit records required by Section 8-18-502.6 and annually thereafter for information that has changed since last submittal.

(Adopted 1/21/04; Amended 12/16/15)

8-18-600 MANUAL OF PROCEDURES

8-18-601 Analysis of Samples: Samples of organic compounds as defined in Section 8-18-113 shall be analyzed for Initial Boiling Point as prescribed in ASTM D-1078- 98 or ASTM D-86.

(Adopted 3/17/82; Amended 3/4/92; 1/7/98)

8-18-602 Inspection Procedure: Inspections of equipment shall be conducted as prescribed by EPA Reference Method 21 (40 CFR 60, Appendix A).

(Adopted 9/6/89; Amended 3/4/92; 1/7/98)

8-18-603 Determination of Control Efficiency: The control efficiency as specified by Section 8-18-110 shall be determined by any of the following methods: 1) BAAQMD Manual of Procedures, Volume IV, ST-7, 2) EPA Method 25 or 25A. A source shall be considered in violation if the emissions of organic compounds measured by any of the referenced test methods exceed the standards of this rule.

(Amended, Renumbered 1/7/98; Amended 1/21/04)

8-18-604 Determination of Mass Emissions: The mass emission determination as specified by Section 8-18-306 and Section 8-18-311 shall be made using any of the following methods: 1) EPA Protocol for Equipment Leak Emission Estimates, Chapter 4, Mass Emission Sampling, (EPA-453/R-95-017) November, 1995 or 2) or a mass emission monitoring method determined to be equivalent by the EPA and approved by the APCO.

(Adopted 1/7/98; Amended 1/21/04, 12/16/15)

Utah Retirement Systems

SANDRA L DIXON W58125865

Beneficiaries

Retirement System Beneficiary Confirmation

JORDAN DAVIS 04/23/1975
 Changes to your beneficiary information have been successfully submitted (see details below). A confirmation letter will be mailed to your current address.

Retirement System		
401(k)		
Designation	Beneficiary Name	Birth Date
Primary	JORDY DAVIS 04/23/1975	
Primary	JORDAN DAVIS	04/23/1975

401(k)		
Designation	Beneficiary Name	Birth Date
Primary	JORDY DAVIS	04/23/1975

Before signing, make sure all beneficiary information is correct. You may be asked to provide additional information and/or documentation.

Revoking any previous nominations of beneficiary(ies), I hereby designate the above individual(s) to receive all benefits payable upon my death.

I hereby, represent all information is true and correct. I understand and agree that any false information I provide on this form may, at URS' sole discretion, result in a limitation or termination of my benefits. By signing below I hereby agree to the terms and conditions of URS Board Resolutions and Federal Law.

By typing my name in the indicated fields, I agree to conduct business electronically with URS/PEHP in accordance with the federal Electronic Signatures in Global and National Commerce Act (E-Sign), 15 U.S.C.A. §§ 7001-7031 (Supp. 2001) and Utah's Uniform Electronic Transactions Act (UETA), Utah Code Ann. §§ 46 4-101 to -501 (2000). I understand transactions and/or signatures in records may not be denied legal effect solely because they are conducted, executed, or prepared in electronic form, and that if a law requires a record or signature to be in writing, an electronic record or signature satisfies that requirement.

Signed by SANDRA L DIXON on June 6, 2017 11:56 AM

**REGULATION 8
ORGANIC COMPOUNDS
RULE 53
VACUUM TRUCK OPERATIONS**

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**REGULATION 8
ORGANIC COMPOUNDS
RULE 53
VACUUM TRUCK OPERATIONS**

(Adopted April 18, 2012)

8-53-100 GENERAL

8-53-101 Description: The purpose of this rule is to limit the emissions of organic compounds from the use of vacuum trucks to move materials at petroleum refineries, bulk plants, bulk terminals, marine terminals, and organic liquid pipeline facilities.

8-53-102 Applicability: This rule applies to the following facilities:

- 102.1 Petroleum refineries;
- 102.2 Bulk plants;
- 102.3 Bulk terminals;
- 102.4 Marine terminals;
- 102.5 Organic liquid pipeline facilities.

8-53-103 Exemption, Emergencies: Vacuum trucks responding to spills, equipment failures, and other emergency situations shall be exempt from the requirements of this rule, provided that (1) use of equipment capable of complying with the rule would delay the response, and (2) the delay would pose a risk of significant harm to facility equipment, personnel, the public, or the environment.

8-53-104 Limited Exemption, Positive Displacement Pump or Gravity Feed Loading: A loading event in which gravity or a positive displacement pump is used to move regulated materials into a vacuum truck shall be exempt from the requirements of Sections 8-53-301 and 8-53-501.

8-53-105 Exemption, Secondary Treatment Processes: Vacuum truck activities at secondary treatment processes, as defined in Regulation 8, Rule 8, Section 208, shall be exempt from this rule.

8-53-200 DEFINITIONS

8-53-201 Air Mover: A specialized type of vacuum truck that uses a combination of vacuum and air flow to load a variety of material types into the truck.

8-53-202 Affected Facility: A facility to which this rule applies pursuant to Section 8-53-102.

8-53-203 Aviation Gas: Gasoline suitable for use in piston-driven aircraft.

8-53-204 Background Concentration: The ambient concentration of TOC determined at least 3 meters (10 feet) upwind from the vacuum truck blower exhaust, as determined by a hydrocarbon analyzer pursuant to Section 8-53-501.

8-53-205 Bulk Plant: A distribution facility that is subject to Regulation 8, Rule 39 or to Section 302 of Regulation 8, Rule 6.

8-53-206 Bulk Terminal: A distribution facility that is subject to Regulation 8, Rule 33 or to Section 301 of Regulation 8, Rule 6.

8-53-207 Control Equipment: Equipment used to reduce TOC emissions from vacuum truck operations in order to comply with emission limits set forth in Section 8-53-301 of this rule, including, but not limited to, carbon adsorption systems, internal combustion engines, thermal oxidizers, refrigerated condenser systems, and liquid scrubbers.

8-53-208 Crude Oil: A naturally occurring mixture consisting predominantly of hydrocarbons and/or sulfur, nitrogen and oxygen derivatives of hydrocarbons that is removed from the earth in a liquid state or is capable of being so removed.

8-53-209 Gasoline: Any petroleum-derived, volatile mixture of hydrocarbons suitable for use as a fuel in a spark-ignited, internal combustion engine.

8-53-210 Gasoline Blending Stock: Any organic liquid used as a component of gasoline, including, but not limited to aromatic or alcohol octane boosters and oxygenates, isomerate, reformate, alkylate, straight run gasoline, cat gasoline, pyrolysis gasoline, FCC gasoline and light hydrocrackate.

- 8-53-211 Loading Event:** The loading at a single location within an affected facility of regulated materials into a vacuum truck or other container through a vacuum truck operation. The resumption of loading at the same location after an interruption shall not be considered a separate loading event.
- 8-53-212 Marine Terminal:** Any facility or structure constructed to load or unload organic liquid bulk cargo into or off of marine tank vessels.
- 8-53-213 Naphtha:** A general term for a variety of crude oil fractions in the gasoline boiling range that are used as feeds and products including but not limited to straight run naphtha, coker naphtha, cat cracked naphtha, and hydrocracked naphtha.
- 8-53-214 Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate.
- 8-53-215 Organic Liquid Pipeline Facility:** Any pipeline used to transport petroleum, petroleum products, or petroleum product blending stock, along with any associated breakout stations.
- 8-53-216 Petroleum Refinery:** Any facility that processes petroleum products as defined in North American Industry Classification System code number 32411, Petroleum Refineries.
- 8-53-217 Positive Displacement Pump:** Equipment that, for each cycle of operation, draws in fluid at a constant volume and then forces that exact volume of fluid into a discharge line. For the purposes of this rule, a diaphragm pump is considered to be a positive displacement pump.
- 8-53-218 Regulated Material:** A regulated material is any of the following:
- 218.1 Gasoline, aviation gasoline, gasoline blending stock, naphtha;
 - 218.2 Transmix, slop, or any other hydrocarbon mixture that includes a material listed in Section 8-53-218.1 if
 - 2.1 For a mixture without significant water content, the true vapor pressure of the mixture is greater than 25.8 mmHg (0.5 psia) as determined pursuant to Section 8-53-602, or
 - 2.2 For a mixture with significant water content, the water content is less than 90% as determined pursuant to Section 8-53-603.
- Crude oil is not a regulated material.
- 8-53-219 Slop:** Any mixture of petroleum materials that does not meet product specifications and may not be used or distributed without further processing.
- 8-53-220 Total Organic Compounds (TOC):** Organic compounds and methane.
- 8-53-221 Transmix:** A mixture of hydrocarbons resulting from (1) the sequential transmission of batches of materials through a pipeline and mixing at the interface between different materials, or (2) the collection for re-refining of material that is not loaded, typically because it does not meet a fuel specification or has become contaminated.
- 8-53-222 Vacuum Truck:** Portable equipment with an affixed barrel or tank that relies on the creation of a pressure differential, typically through use of a pump or blower, to pneumatically load materials into the barrel or tank of the equipment.
- 8-53-223 Vacuum Truck Operation:** The movement of regulated material into a vacuum truck or into any other container through use of a vacuum truck. For purposes of this rule, the use of other means, typically gravity feed or an auxiliary pump, to push or pull materials into a vacuum truck shall be considered a vacuum truck operation.
- 8-53-300 STANDARDS**
- 8-53-301 Emission Limit:** Effective April 1, 2013, for any loading event, the owner or operator of a facility subject to this rule shall control emissions to meet the requirements of Section 8-53-301.1 or, as an alternative, the requirements of Section 8-53-301.2.
- 301.1 The TOC concentration does not exceed 500 ppmv, expressed as methane (C1), above background, as measured at the exhaust outlet of a vacuum truck operation or, if an auxiliary control device is used to control emissions from a vacuum truck operation, at the exhaust outlet of the control device unless:
 - 1.1 A second concentration reading taken within 60 seconds fails to confirm the exceedance, or

1.2 A second concentration reading taken within 60 seconds confirms a TOC concentration in excess of 500 ppmv, but the loading event is shut down within 3 minutes after the second reading.

301.2 TOC emissions are controlled with an abatement device with an abatement efficiency of at least 95 percent.

8-53-302 Liquid Leaks: Effective April 1, 2013, for any loading event, the owner or operator of a facility subject to this rule shall not use a vacuum truck or associated equipment that leaks liquid at a rate in excess of three drops per minute unless the leak is discovered by the operator and eliminated within 3 minutes of discovery or unless the loading event is shut down within 3 minutes of the discovery of the leak. This does not apply to disconnect leaks provided procedures for minimizing disconnect leaks are used.

8-53-303 Vapor Leaks: Effective April 1, 2013, for any loading event, the owner or operator of a facility subject to this rule shall not use a vacuum truck or associated abatement device that leaks organic vapor in excess of 500 ppmv, expressed as methane (C₁), above background unless the leak is discovered by the operator and minimized to a concentration below 500 ppmv within 3 minutes after discovery or unless the loading event is shut down within 3 minutes after the discovery of the leak.

8-53-304 Unloading of Regulated Material: Effective April 1, 2013, the owner or operator of a facility subject to this rule shall meet the following requirements for unloading of regulated material from a vacuum truck at the facility where the vacuum truck was loaded:

304.1 Regulated material shall be unloaded into a tank, vessel or sump that meets the control requirements in Regulation 8, Rule 5 or Regulation 8, Rule 8, or

304.2 If regulated material is unloaded into a tank, vessel or sump that does not meet the control requirements of Regulation 8, Rule 5 or Regulation 8, Rule 8, regulated material shall be unloaded using a submerged fill pipe that complies with the submerged fill pipe discharge requirements of Regulation 8, Rule 5, Section 302 and promptly pumped into storage.

8-53-400 ADMINISTRATIVE REQUIREMENTS

8-53-401 Loading Event Schedule Reporting Requirements: Effective April 1, 2013, upon request by the APCO or the designee of the APCO, the owner or operator of an affected facility subject to this rule shall provide a list of scheduled loading events and the following information, if available at the time of request, for each event:

401.1 Loading event start date and time;

401.2 Facility name, plant number (if applicable), and source number (if applicable), tank, pipeline, or reservoir address, and equipment location;

401.3 Vacuum truck company name, owner/operator's name, and telephone number;

401.4 Control equipment company name, control equipment type, operator's name and telephone number if the control equipment is operated by someone other than the vacuum truck owner/operator; and,

401.5 Tank, pipeline, box, container, or reservoir capacity, estimated volume and type of material to be loaded.

The list shall include loading events that are scheduled within thirty (30) days. The list shall be provided to District staff within three (3) working days and may be provided via hard copy or electronically. Changes to loading event schedules shall be reported to District staff no less than 24 hours prior to loading events.

8-53-500 MONITORING AND RECORDS

8-53-501 Emissions Monitoring Requirement: Effective April 1, 2013, the owner or operator of an affected facility using a vacuum truck operation shall monitor and record emissions as follows:

501.1 To demonstrate compliance with Section 8-53-301.1 when controlling TOC emissions from a vacuum truck operation with technology other than a carbon adsorption system, emission concentrations from the control device shall be measured using the method specified in Section 8-53-601 and recorded as follows:

- 1.1 Conduct one measurement for each loading event before the vacuum truck is approximately 20% full. Conduct an additional measurement before the vacuum truck is approximately 60% full. If a vacuum truck is already 20% full prior to a loading event, conduct an initial measurement as soon as possible after the start of the loading event and an additional measurement before the vacuum truck is approximately 60% full. If a vacuum truck is already 60% full prior to a loading event, conduct one measurement as soon as possible after the start of the loading event.
- 1.2 Record the information required by Section 8-53-502.
- 501.2 To demonstrate compliance with Section 8-53-301.1 when controlling TOC emissions from a vacuum truck operation with a carbon adsorption system, emission concentrations from the control device shall be measured using the method specified in Section 8-53-601 and recorded as follows:
 - 2.1 Commence emission measurements within 2 minutes of startup for each loading event. Additional measurements shall be performed approximately every 10 minutes during loading thereafter;
 - 2.2 When a TOC stream is switched to a back-up or replacement carbon vessel, a new TOC emission measurement must occur within 2 minutes of the carbon vessel replacement.
 - 2.3 Record the information required by Section 8-53-502.
- 501.3 To demonstrate compliance with Section 8-53-301.2, the owner or operator of an affected facility shall perform a source test verifying the required abatement efficiency during the vacuum truck operation or, for abatement devices that combust emissions to achieve the required efficiency, the owner or operator may instead show that a source test on the abatement device verifying the required abatement efficiency was completed within the 12 months prior to the commencement of the vacuum truck operation.
- 501.4 An alternative monitoring plan may be submitted and approved by the APCO.
- 501.5 The owner or operator of an affected facility shall retain records and lists required by this Section for two years and shall make them available for inspection by the APCO upon request.

8-53-502 Recordkeeping Requirement: A person subject to this rule shall keep the following records:

- 502.1 Effective April 1, 2013, record the following information for each loading event:
 - 1.1 The date, time of commencement, and duration of the loading event;
 - 1.2 The type and volume of regulated materials loaded;
 - 1.3 Whether loading was by vacuum, positive displacement pump, or gravity;
 - 1.4 Where vacuum truck control equipment or external control equipment is used, record the make and model of the control equipment, the results of the emission measurements required by Section 8-53-501, and the make, model, and serial number of the device used to measure the TOC concentrations;
 - 1.5 Where loading was by positive displacement pump, the make and model of the pump.
- 502.2 Effective April 1, 2013, record the daily volume of crude oil and oil recovered from centrifuging that is loaded into vacuum trucks.
- 502.3 Effective April 1, 2013, keep records if the owner or operator of an affected facility chooses to perform a true vapor pressure analysis or a percent volume analysis to determine whether material loaded is a regulated material pursuant to Section 8-53-218.
- 502.4 The owner or operator of an affected facility shall maintain complete copies of source test reports required by Section 8-53-501.3.
- 502.5 The owner or operator of an affected facility shall retain records required by this Section for two years and shall make them available for inspection by the APCO upon request.

8-53-600 MANUAL OF PROCEDURES

- 8-53-601 Measurement of TOC Concentrations:** Measurements of TOC concentration for determining compliance with the limit set forth in Section 301 of this rule shall be conducted in accordance with USEPA Reference Methods 21 or 25A; or BAAQMD Manual of Procedures, Volume IV, ST-7, Non-methane Organic Carbon Sampling. If USEPA Reference Method 21 is used to determine compliance, the portable analyzer shall use flame ionization detection and shall meet the specifications and performance criteria of, and shall be calibrated in accordance with, EPA Reference Method 21 (40 CFR 60, Appendix A). Noncompliance established by any one of the specified test methods shall constitute a violation of this rule.
- 8-53-602 Analysis of Materials, True Vapor Pressure:** Materials sampled pursuant to Section 8-53-218.2.1, shall be analyzed for true vapor pressure at loading temperature as prescribed in the Manual of Procedures, Volume III, Lab Method 28: Determination of Vapor Pressure of Organic Liquids from Storage Tanks.
- 8-53-603 Analysis of Materials, Percent Water Volume:** Materials sampled pursuant to Section 8-53-218.2.2 shall be analyzed as prescribed in ASTM D96: Test Methods for Water and Sediment in Crude Oil by Centrifuge Method (Field Procedure), ASTM D1796: Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure) or ASTM D6304: Karl Fisher Water in Petroleum Products. Alternatively, percent water volume may be observed and calculated from a mixed, representative sample collected as specified by ASTM D4057: Standard Practice for Manual Sampling of Petroleum and Petroleum Products and allowed to settle in a graduated cylinder.
- 8-53-604 Determination of Abatement Efficiency:** Abatement efficiency of an abatement device shall be determined as specified in the Manual of Procedures, Volume IV, ST-7 or by EPA Method 25 or 25A. Noncompliance established by any one of the specified test methods shall constitute a violation of the rule.

**REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 1
SULFUR DIOXIDE**

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**REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 1
SULFUR DIOXIDE**

9-1-100 GENERAL

9-1-101 Description: This Rule establishes emission limits for sulfur dioxide from all sources including ships, and limits ground level concentrations of sulfur dioxide.

9-1-110 Conditional Exemption, Area Monitoring: The 300 ppm limitation of Section 9-1-302 shall not apply to a person who meets the requirements of subsections 9-1-110.1 and 110.2, provided such person has complied with those requirements prior to January 1, 1980.

110.1 A person shall be subject to the monitoring, records and reporting requirements contained in Regulation 1, including Sections 1-510, 530, 540, 542, 543, and 544.

110.2 A person shall not emit sulfur dioxide in quantities which result in ground level concentrations of sulfur dioxide in excess of the limits specified in Section 9-1-301. This subsection shall not apply to ground level concentrations occurring on the property from which such emission occurs, provided such property, from the emission point to the point where the excess occurs, is physically secured against public access by the person responsible for the emission.
(Amended May 20, 1992)

9-1-200 DEFINITIONS

9-1-201 Deleted May 20, 1992

9-1-202 Deleted May 20, 1992

9-1-203 Deleted May 20, 1992

9-1-204 Start-up: For the purposes of Section 9-1-605, start-up begins at the time the feed stock is introduced into the process and may proceed for a period not to exceed four consecutive hours.
(Amended May 20, 1992)

9-1-205 Fresh Fruit Sulfuring Operation: Any operation where freshly cut fruit is placed in a sulfur house in order to come into contact with sulfur dioxide.

(Adopted February 16, 1983)

9-1-206 Sulfur Removal and Recovery System: A set of process units which remove H₂S from refinery gas streams and the reduced sulfur compounds and ammonia from process water streams. The reduced sulfur compounds are recovered as sodium hydrosulfide (NaSH), elemental sulfur, sulfuric acid, or other sulfate compounds. The sulfurous compounds are recovered as elemental sulfur or as sulfuric acid. The process units consist of a sour water stripper, regenerative gas treatment system, and a sulfur recovery plant, a sulfuric acid plant, or other process units and facilities which achieve removal efficiencies as required by Section 9-1-313.2.

(Adopted July 18, 1990; Amended March 15, 1995)

9-1-207 Sour Water Stripper: A process unit which removes reduced sulfur compounds from process water using a distillation (stripping) process. (Adopted July 18, 1990)

9-1-208 Regenerative Gas Treatment System: A regenerative process system that removes H₂S from refinery gas streams and recovers the H₂S as H₂S or sulfur.

(Adopted July 18, 1990)

9-1-209 Sulfur Recovery Plant: A process unit which processes sulfur and ammonia containing material and produces a final product of elemental sulfur.

(Adopted July 18, 1990)

9-1-210 Sulfuric Acid Plant: A process unit which processes sulfur containing material and produces a final product of sulfuric acid or oleum.

(Adopted July 18, 1990)

- 9-1-211 Shutdown:** For the purposes of Section 9-1-605, shutdown begins at the time the feed stock is discontinued. (Adopted May 20, 1992)
- 9-1-300 STANDARDS**
- 9-1-301 Limitations on Ground Level Concentrations:** A person shall not emit from sources other than ships, sulfur dioxide in quantities which result in ground level concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes or 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. This section shall not apply to ground level concentrations occurring on the property from which such emission occurs, provided such property, from the emission point to the point where the excess occurs, is physically secured against public access by the person responsible for the emission. (Amended May 20, 1992)
- 9-1-302 General Emission Limitation:** A person shall not emit from any source, other than a ship, a gas stream containing sulfur dioxide in excess of 300 ppm (dry). This section shall not apply to the following sources:
- 302.1 Any source which is subject to any of the limitations in Sections 9-1-304 through 9-1-312.
- 302.2 Any source which satisfies the conditions in Sections 9-1-110. (Amended February 16, 1983)
- 9-1-303 Emissions from Ships:** A person shall not emit a gas stream containing sulfur dioxide in excess of 2000 ppm from any ship, except when the ship is entering the port from outside the District. Emissions resulting only from the combustion of liquid fuel with a sulfur content less than or equal to 3.34% by weight shall be considered in compliance with this Section.
- 9-1-304 Fuel Burning (Liquid and Solid Fuels):** A person shall not burn any liquid fuel having a sulfur content in excess of 0.5% by weight, or solid fuel of such sulfur content as would result in the emission of a gas stream containing more than 300 ppm (dry) of sulfur dioxide. This section shall not apply to:
- 304.1 The burning of sulfur, hydrogen sulfide, acid sludge or other compounds used in the manufacture of sulfur compounds;
- 304.2 The use of liquid or solid fuels to propel any motor vehicle, aircraft, missile, boat or ship;
- 304.3 The use of liquid or solid fuels which do not result in the emission of a gas stream containing more than 300 ppm (dry) of sulfur dioxide.
- 9-1-305 Deleted May 20, 1992**
- 9-1-306 Deleted May 20, 1992**
- 9-1-307 Emission Limitations for Sulfur Recovery Plants:** A person shall not emit, from any source in a sulfur recovery plant, effluent process gas containing sulfur dioxide in excess of 250 ppm by volume (dry) calculated at zero percent oxygen. Plants which emit less than 45 kg (100 lbs.) per day of sulfur dioxide shall not be subject to this limitation. (Amended February 16, 1983; May 20, 1992)
- 9-1-308 Deleted May 20, 1992**
- 9-1-309 Emission Limitations for Sulfuric Acid Plants:** A person shall not emit, from any source in a sulfuric acid plant, effluent process gas containing sulfur dioxide in excess of 300 ppm by volume calculated at 12% oxygen. (Amended February 16, 1983; May 20, 1992)
- 9-1-310 Emission Limitations for Fluid Catalytic Cracking Units, Fluid Cokers, and Coke Calcining Kilns:**
- 310.1 A person shall not emit, from any source in a fluid catalytic cracking unit or fluid coker, effluent process gas containing sulfur dioxide in excess of 1,000 ppm by volume.
- 310.2 A person shall not emit, from any coke calcining kiln, effluent process gas containing sulfur dioxide in excess of 400 ppm by volume or in excess of 113 kg (250 pounds) per hour, whichever is more restrictive.
- 310.3 A person subject to subsections 9-1-310.1 or 310.2 shall comply with the requirements in subsections 9-1-110.1 and 110.2.
- 9-1-311 Emission Limitations for Catalyst Manufacturing Plants:**

- 311.1 Deleted May 20, 1992
- 311.2 A person shall not emit, from any source in a catalyst manufacturing plant, effluent process gas containing sulfur dioxide in excess of 22 kg (50 pounds) per hour. (Adopted May 21, 1980; Amended May 20, 1992)

9-1-312 Emission Limitations for Fresh Fruit Sulfuring Operations:

- 312.1 A person shall not operate any fresh apricot sulfuring operation which uses greater than 4.5 kg (10 pounds) of elemental sulfur or 9.0 kg (20 pounds) of gaseous SO₂ per 9.0 metric ton (1 short ton) of fresh apricots.
- 312.2 A person shall not operate any fresh peach sulfuring operation which uses greater than 5.5 kg (12 pounds) of elemental sulfur or 10.9 kg (24 pounds) of gaseous SO₂ per 9.0 metric ton (1 short ton) of fresh peaches.
- 312.3 A person shall not operate any fresh pear sulfuring operation which uses greater than 6.8 kg (15 pounds) of elemental sulfur or 13.6 kg (30 pounds) of gaseous SO₂ per 9.0 metric ton (1 short ton) of fresh pears. (Adopted February 16, 1983; Amended May 20, 1992)

9-1-313 Sulfur Removal Operations at Petroleum Refineries: Effective September 1, 1990, a person shall not operate a petroleum refinery processing more than 20,000 barrels per stream day of crude oil unless one of the following is met:

- 313.1 The sulfur content of the crude oil does not exceed 0.10 percent by weight, or
- 313.2 There is a sulfur removal and recovery system that removes and recovers, on a refinery wide basis, 95% of the H₂S from the refinery fuel gas, that removes and recovers, on a refinery wide basis, 95% of the H₂S from the process water streams, and removes 95% of the ammonia from the process water streams, provided, however, any refinery which removes sulfurous compounds containing sulfur equivalent of 16.5 tons or more of elemental sulfur in any one day shall install a sulfur recovery plant or a sulfuric acid plant.
- 313.3 A binding, legally enforceable agreement or court order exists which mandates the construction of a sulfur removal and recovery system pursuant to a schedule set forth therein; provided, however, that the sulfur removal and recovery system must be constructed by October 1, 1993, unless, in the judgment of the Air Pollution Control Officer, failure to complete construction by that date results from circumstances beyond the reasonable control of the refinery operator in which case the Air Pollution Control Officer may grant a reasonable extension of the October 1, 1993 deadline. The Air Pollution Control Officer may grant such extension, however, only if the refinery operator has made substantial progress in completing construction of its sulfur removal and recovery system by October 1, 1993. (Adopted July 18, 1990; Amended March 15, 1995)

9-1-400 ADMINISTRATIVE REQUIREMENTS

- 9-1-401 Deleted May 20, 1992
- 9-1-402 Deleted May 20, 1992
- 9-1-403 Deleted May 20, 1992
- 9-1-404 Deleted May 20, 1992

9-1-500 MONITORING AND RECORDS

- 9-1-501 **Area Monitoring Requirements:** Upon request of the APCO, a person subject to Section 9-1-301 shall comply with the monitoring, maintenance, records, and reporting requirements of Regulation 1, including Sections 1-510, 1-530, 1-540, 1-542, 1-543 and 1-544.
- 9-1-502 **Emission Monitoring Requirements:** A person subject to Section 9-1-304, 307, 309 or 310 (with the exception of coke calcining kilns), shall comply with the monitoring requirements of 1-520 and 522. (Amended March 17, 1982; May 20, 1992)

- 9-1-503 Fresh Fruit Sulfuring Recordkeeping Requirements:** Any persons subject to Section 9-1-312 of this Rule shall record the daily weight of elemental sulfur burned or gaseous SO₂ used per unit weight of fresh fruit for each sulfuring operation. Records of the weights used shall be kept for the length of the specific fruit season and shall be made available to the APCO upon request. (Adopted February 16, 1983)
- 9-1-600 MANUAL OF PROCEDURES**
- 9-1-601 Sampling and Analysis of Gas Streams:** The method of sampling and analysis of gas streams of sulfur dioxide concentrations is described in the Manual of Procedures, Volume IV, ST-19 A or B. (Amended March 17, 1982)
- 9-1-602 Sulfur Content of Fuels:** The sulfur content of solid and liquid fuels shall be determined as specified in the Manual of Procedures, Volume III, Method 10. (Amended March 17, 1982)
- 9-1-603 Averaging Times:** The averaging times for production determination and emission analysis are specified in the Manual of Procedures, Volume IV. (Amended March 17, 1982)
- 9-1-604 Ground Level Monitoring:** The monitoring requirements for ground level concentrations of sulfur dioxide, including siting procedures and instrument specifications, calibration and maintenance procedures, are described in the Manual of Procedures, Volume VI, Section 1. (Amended March 17, 1982)
- 9-1-605 Emission Monitoring:** The emission monitoring requirements, including instrument placement, specifications, calibration, and maintenance procedures are described in the Manual of Procedures, Volume V. (Amended March 17, 1982).
- 9-1-606 Analysis of Gas Streams for H₂S:** The method for analyzing refinery fuel gas streams for H₂S before and after control shall be as prescribed in the Manual of Procedures, Volume III, LAB 32 or equivalent method approved by the APCO. Adopted July 18, 1990; Amended May 20, 1992)
- 9-1-607 Analysis of Water Streams for H₂S:** The method for analyzing refinery process water streams for H₂S before and after control shall be as prescribed in the Manual of Procedures, Volume III, LAB 32 or equivalent method approved by the APCO. (Adopted July 18, 1990; Amended May 20, 1992)
- 9-1-608 Analysis of Water Streams for NH₃:** The method for analyzing refinery process water streams for NH₃ before and after control shall be as prescribed in the Manual of Procedures, Volume III, LAB 1 or equivalent method approved by the APCO. Adopted July 18, 1990; Amended May 20, 1992)
- 9-1-609 Analysis of Sulfur Content of Crude Oil:** The method for analyzing the sulfur content of the crude oil shall be as prescribed in the Manual of Procedures, Volume III, Method LAB 10 or equivalent method approved by the APCO. (Adopted July 18, 1990; Amended May 20, 1992)

**REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 8
NITROGEN OXIDES AND CARBON MONOXIDE
FROM STATIONARY INTERNAL COMBUSTION ENGINES**

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**REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 8
NITROGEN OXIDES AND CARBON MONOXIDE
FROM STATIONARY INTERNAL COMBUSTION ENGINES**

(Adopted January 20, 1993)

9-8-100 GENERAL

9-8-101 Description: This rule limits the emissions of nitrogen oxides and carbon monoxide from stationary internal combustion engines with an output rated by the manufacturer at more than 50 brake horsepower

(Amended 8/1/01; 7/25/07)

9-8-110 Exemptions: The requirements of Sections 9-8-301 through 305, 501 and 503 shall not apply to the following:

- 110.1 Until January 1, 2012, engines rated by the manufacturer at less than 250 brake horsepower output rating.
- 110.2 Engines rated by the manufacturer at 50 brake horsepower output rating or less. Effective January 1, 2012.
- 110.3 Until January 1, 2012, engines fired exclusively by liquid fuels including, but not limited to, diesel fuel, gasoline, and methanol.
- 110.4 Engines used directly and exclusively for the growing of crops or the raising of animals.
- 110.5 Emergency standby engines.

(Amended 8/1/01; 7/25/07)

9-8-111 Limited Exemption for Low Usage: The requirements of Sections 9-8-301, 302, 303, 304, and 305 shall not apply to the following low use operations provided the requirements of Sections 9-8-502.1 and 9-8-530 are met:

- 111.1 Until January 1, 2012, engines rated at, or below, 1000 brake horsepower that operate less than 200 hours, exclusive of any emergency use, in any 12-consecutive-month period.
- 111.2 Until January 1, 2012, engines rated above 1000 brake horsepower that operate less than 100 hours, exclusive of any emergency use, in any 12-consecutive-month period.
- 111.3 Effective January 1, 2012, engines that operate less than 100 hours, exclusive of any emergency use, in any 12-consecutive-month period

(Amended July 25, 2007)

9-8-112 Registered Portable Equipment: The requirements of this section shall not apply to an internal combustion engine registered as portable pursuant to the Statewide Portable Engine and Equipment Registration Program, Sections 2450-2465, Article 5, Title 13, California Code of Regulations.

(Adopted July 25, 2007)

9-8-200 DEFINITIONS

9-8-201 Gaseous Fuels: For the purposes of this rule, gaseous fuels include, but are not limited to:

- 201.1 Fossil derived fuel gas such as natural gas, methane, ethane, propane, refinery fuel gas, and butane, including gases stored as liquids such as liquified petroleum gas (LPG).
- 201.2 Waste derived fuel gas such as sewage sludge digester gas or landfill gas.

9-8-202 Nitrogen Oxide (NO_x) Emissions: The sum of nitric oxide (NO) and nitrogen dioxide (NO₂) in the engine exhaust, collectively expressed as nitrogen dioxide.

9-8-203 Rated Brake Horsepower: The maximum brake horsepower rating at maximum revolutions per minute (RPM) specified for the engine by the manufacturer or indicated on the engine nameplate.

- 9-8-204 Stationary Internal Combustion Engine (Engine):** Any spark or compression ignited internal combustion engine that is operated, or intended to be operated, at a specific site for more than one year or is attached to a foundation at that site.
- 9-8-205 Rich-Burn Engine:** Any spark or compression ignited internal combustion engine that is designed to be operated with an exhaust stream oxygen concentration of less than 4 percent, by volume. The exhaust gas oxygen content shall be determined from the uncontrolled exhaust stream.
- 9-8-206 Lean-Burn Engine:** Any spark or compression ignited internal combustion engine that is designed to be operated with an exhaust stream oxygen concentration of 4 percent, by volume, or greater. The exhaust gas oxygen content shall be determined from the uncontrolled exhaust stream.
- 9-8-230 Emergency Standby Engine:** Any engine that is exclusively operated:
 230.1 For emergency use; and
 230.2 For reliability-related activities.
(Adopted August 1, 2001)
- 9-8-231 Emergency Use:** The use of an emergency standby or low usage engine during any of the following:
 231.1 In the event of unforeseeable loss of regular natural gas supply;
 231.2 In the event of unforeseeable failure of regular electric power supply;
 231.3 Mitigation or prevention of an imminent flood;
 231.4 Mitigation of or prevention of an imminent overflow of sewage or waste water;
 231.5 Fire or prevention of an imminent fire;
 231.6 Failure or imminent failure of a primary motor or source of power, but only for such time as needed to repair or replace the primary motor or source of power; or
 231.7 Prevention of the imminent release of hazardous material.
(Adopted 8/1/01; Amended 7/25/07)
- 9-8-232 Reliability-related Activities:** Either:
 232.1 Operation of an emergency standby engine to test its ability to perform for an emergency use; or
 232.2 Operation of an emergency standby engine during maintenance of a primary motor.
(Adopted August 1, 2001)
- 9-8-233 Essential Public Service:**
 233.1 A sewage treatment facility, and associated collection system, which is publicly owned and operated;
 233.2 Water treatment and delivery operations;
 233.3 Public transit;
 233.4 Police or fire fighting facility;
 233.5 Airport runway lights; or
 233.6 Hospital or other medical emergency facility.
(Adopted August 1, 2001)
- 9-8-234 Best Available Control Technology (BACT):** As defined in Regulation 2, Rule 2, Section 2-2-206
(Adopted July 25, 2007)
- 9-8-235 Dual Fuel Pilot Compression-Ignited Engine:** Any dual-fueled engine that uses diesel fuel as a pilot ignition source at an annual average ratio of less than 5 parts diesel fuel to 100 parts total fuel on an energy equivalent basis.
(Adopted July 25, 2007)
- 9-8-236 Portable:** Designed for and capable of being carried or moved from one location to another. Indications of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform.
(Adopted July 25, 2007)
- 9-8-237 Unforeseeable:** Not able to be reasonably anticipated and demonstrated by the owner or operator to the satisfaction of the APCO to have been beyond the reasonable control of the owner or operator. The enforcement of a contractual obligation the owner or operator has with a third party or any other party is foreseeable.
(Adopted July 25, 2007)

9-8-300 STANDARDS

9-8-301 Emission Limits - Spark-Ignited Engines Powered by Fossil Derived Fuels: Effective January 1, 1997, a person shall not operate a stationary internal combustion engine fired exclusively on fossil derived fuels, unless the following emission limits are met:

- 301.1 Rich-Burn Engines: Nitrogen oxide (NO_x) emissions shall not exceed 56 ppmv as corrected to 15% oxygen, dry basis. Effective January 1, 2012, nitrogen oxide (NO_x) emissions shall not exceed 25 ppmv as corrected to 15% oxygen, dry basis.
- 301.2 Lean-Burn Engines: Nitrogen oxide (NO_x) emissions shall not exceed 140 ppmv as corrected to 15% oxygen, dry basis. Effective January 1, 2012, nitrogen oxide (NO_x) emissions shall not exceed 65 ppmv as corrected to 15% oxygen, dry basis.
- 301.3 Carbon monoxide (CO) emissions shall not exceed 2000 ppmv as corrected to 15% oxygen, dry basis.

(Amended July 25, 2007)

9-8-302 Emission Limits - Spark-Ignited Engines Powered by Waste Derived Fuels: Effective January 1, 1997, a person shall not operate a spark-ignited stationary internal combustion engine fired on waste derived fuels or any combination of waste- and fossil-derived gaseous fuels and liquid fuels unless the following emission limits are met:

- 302.1 Lean-Burn Engines: Nitrogen oxide (NO_x) emissions shall not exceed 140 ppmv as corrected to 15% oxygen, dry basis. Effective January 1, 2012, nitrogen oxide (NO_x) emissions shall not exceed 70 ppmv as corrected to 15% oxygen, dry basis.
- 302.2 Rich-Burn Engines: Nitrogen oxide (NO_x) emissions shall not exceed 210 ppmv as corrected to 15% oxygen, dry basis. Effective January 1, 2012, nitrogen oxide (NO_x) emissions shall not exceed 70 ppmv as corrected to 15% oxygen, dry basis.
- 302.3 Carbon monoxide (CO) emissions shall not exceed 2000 ppmv as corrected to 15% oxygen, dry basis.

(Amended July 25, 2007)

9-8-303 Emissions Limits – Delayed Compliance, Existing Spark-Ignited Engines, 51 to 250 bhp or Model Year 1996 or Later: In lieu of compliance with Section 9-8-301 or 302, a person may operate a stationary internal combustion, spark-ignited engine until January 1, 2016 provided:

- 303.1 The brake horsepower rating of the engine is between 51 and 250 bhp or the model year of the engine is 1996 or later;
- 303.2 The requirements of Section 9-8-402 are met;
- 303.3 The engine complies with Best Available Control Technology requirements for a stationary internal combustion, spark-ignited engines no later than January 1, 2016.

(Adopted July 25, 2007)

9-8-304 Emission Limits – Compression-Ignited Engines: Effective January 1, 2012, a person shall not operate a stationary internal combustion compression-ignited engine unless one the applicable emission limit in ppmv corrected 15% oxygen, dry basis set forth below for NO_x and CO is met:

	Existing Compression-Ignited Engine (bhp)	Emission Standards (ppmvd)	
		NO _x	CO
304.1	51 to 175	180	440
304.2	Greater than 175	110	310

(Adopted July 25, 2007)

- 9-8-305 Emission Limits – Delayed Compliance, Existing Compression-Ignited Engines, Model Year 1996 or Later:** In lieu of compliance with Section 9-8-304, a person may operate a stationary internal combustion compression-ignited engine of model year 1996 or later provided the requirements of Section 9-8-402 are met and one of the following conditions is met no later than January 1, 2016:
- 305.1 The NO_x and CO emissions shall not exceed Best Available Control Technology limits for a stationary internal combustion, compression-ignited engines, or
 - 305.2 the NO_x emissions shall not exceed 22 ppmv corrected 15% oxygen, dry basis and the CO emissions shall not exceed 310 ppmv corrected 15% oxygen, dry basis.
- (Adopted July 25, 2007)*
- 9-8-306 Requirements for Dual Fuel Pilot Compression-Ignited Engines:** Effective January 1, 2012, compression-ignited engines powered by diesel fuel and waste gas shall comply with spark-ignited waste-derived fuel emission limits in Section 9-8-302, provided the diesel fuel use does not exceed five percent on an energy basis of the total fuel consumption in any calendar year.
- (Adopted July 25, 2007)*
- 9-8-330 Emergency Standby Engines, Hours of Operation:** A person may only operate an emergency standby engine under the following circumstances:
- 330.1 For emergency use for an unlimited number of hours; and
 - 330.2 Until January 1, 2012, for reliability-related activities so long as total hours of operation for this purpose do not exceed 100 hours in a calendar year, or limitations contained in a District permit, whichever is lower.
 - 330.3 Effective January 1, 2012, for reliability-related activities so long as total hours of operation for this purpose do not exceed 50 hours in a calendar year, or limitations contained in a District permit, whichever is lower. Hours of operation for reliability-related activities may exceed these limits only as necessary to comply with testing requirements of National Fire Protection Association (NFPA) 25 – “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” 1998 edition.
- (Adopted 8/1/01; Amended 7/25/07)*
- 9-8-331 Essential Public Service, Hours of Operation:** An essential public service may only operate an emergency standby engine under the following circumstances:
- 331.1 For emergency use for an unlimited number of hours; and
 - 331.2 Until January 1, 2012, for reliability-related activities so long as total hours of operation for this purpose do not exceed 200 hours per calendar year, or limitations contained in a District permit, whichever is lower.
 - 331.3 Effective January 1, 2012, for reliability-related activities so long as total hours of operation for this purpose do not exceed 100 hours in a calendar year, or limitations contained in a District permit, whichever is lower.
- (Adopted 8/1/01; Amended 7/25/07)*
- 9-8-400 ADMINISTRATIVE REQUIREMENTS**
- 9-8-401 Compliance Schedule:** A person subject to the requirements of Section 9-8-301, 302, 303, 304, 305 or 306 shall submit an application for any Authority to Construct, necessary to achieve compliance with such requirements no later than one year prior to the applicable compliance date listed in Section 9-8-301, 302, 303, 304, 305 or 306.
- (Amended July 25, 2007)*
- 9-8-402 Reporting Requirements for Delayed Compliance:** A person opting to comply with one of the delayed compliance options set forth in Section 9-8-303 or 305 shall notify the APCO in writing no later than January 1, 2012 that the owner or operator of a stationary engine has elected to comply with requirements of Section 9-8-303 in lieu of Section 9-8-301 or 302, or to comply with the requirements of Section 9-8-305 in lieu of Section 9-8-304. The report shall include the following information about the engine: source number; plant number, name, contact, phone number, address; and engine make, model, model year, and size.

9-8-500 MONITORING AND RECORDS

9-8-501 Initial Demonstration of Compliance: A person who must modify existing sources or install new control equipment shall conduct a District approved source test, pursuant to Sections 9-8-601 and 602 according to the schedule listed in the following table:

Engines Operated to Comply with Section	Date that the Initial Source Test Must Be Completed	Date that the Initial Source Test Results Must Be Submitted to the District
9-8-301, 302, 304 or 306	March 31, 2012	May 31, 2012
9-8-303 or 305	March 31, 2016	May 31, 2016

(Amended July 25, 2007)

9-8-502 Recordkeeping: Any person who operates any engine subject to Section 9-8-300 shall comply with the following recordkeeping requirements:

- 502.1 Any person who operates any engine that is exempt from the requirements of Section 9-8-301, 302, 303, or 304 by Section 9-8-110 or 111 shall keep records of the number of hours the engine is fired on a monthly basis. Such records shall be retained for a minimum of 24 months from the date of entry and made available to District staff upon request.
- 502.2 Any person who operates a dual fuel pilot compression-ignited engines in accordance to Sections 9-8-306 shall keep records of fuel usage for each type of fuel used for a minimum of 24 months and make them available to the District staff upon request.
- 502.3 Any person who conducts either an initial demonstration of compliance according to Sections 9-8-501 and 9-8-601, 9-8-602, a quarterly demonstration of compliance according to Section 9-8-503, or an annual demonstration of compliance according to Sections 9-8-504 and 9-8-601 shall keep records of the compliance demonstration for a minimum of 24 months from the date of creation and made available to the District staff upon request.
- 502.4 Any person who operates an engine pursuant to Section 9-8-305 shall keep records verifying the certification of that engine for a minimum of 24 months.

(Amended July 25, 2007)

9-8-503 Quarterly Demonstration of Compliance: Any person who must comply with Section 9-8-301, 302, 303, 304, 305, or 306 shall use a portable analyzer to take NOx and CO emission readings to verify compliance with the applicable emission limits in Sections 9-8-301 through 305 at least once during each calendar quarter in which a source test is not performed. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations. NOx emission readings taken pursuant to this section shall be averaged over a consecutive 15-minute period.

(Adopted July 25, 2007)

9-8-530 Emergency Standby and Low Usage Engines, Monitoring and Recordkeeping: Each emergency standby and low usage engine shall be equipped with a non-resettable totalizing meter that measures hours of operation or fuel usage. All records shall be kept for at least two years, and shall be available for inspection by District staff upon request. The operator shall keep a monthly log of usage that shall indicate the following:

- 530.1 Hours of operation (total)
- 530.2 Hours of operation (emergency)
- 530.3 For each emergency, the nature of the emergency condition.

For low usage engines, these provisions become effective on January 1, 2012.

(Adopted 8/1/01; Amended 7/25/07)

9-8-600 MANUAL OF PROCEDURES

9-8-601 Determination of Nitrogen Oxides: The methods by which samples of exhaust gases are collected and analyzed to determine concentrations of nitrogen oxides are set forth in the District's Manual of Procedures, Volume IV, ST-13 A.

(Amended July 25, 2007)

9-8-602 Determination of Carbon Monoxide and Stack Gas Oxygen: The methods by which samples of exhaust gases are collected and analyzed to determine concentrations of carbon monoxide and stack gas oxygen are set forth in the District's Manual of Procedures, Volume IV, ST-6 (carbon monoxide) and ST-14 (oxygen).

**REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 7
NITROGEN OXIDES AND CARBON MONOXIDE FROM INDUSTRIAL,
INSTITUTIONAL AND COMMERCIAL BOILERS, STEAM GENERATORS AND
PROCESS HEATERS**

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REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 7
NITROGEN OXIDES AND CARBON MONOXIDE FROM INDUSTRIAL,
INSTITUTIONAL AND COMMERCIAL BOILERS, STEAM GENERATORS AND
PROCESS HEATERS

(Adopted September 16, 1992)

9-7-100 GENERAL

9-7-101 Description: This rule limits the emissions of nitrogen oxides (NO_x) and carbon monoxide (CO) from industrial, institutional and commercial boilers, steam generators and process heaters.

9-7-110 Exemptions: The requirements of this rule shall not apply to the following:

- 110.1 Boilers, steam generators and process heaters with a rated heat input of 2 million BTU/hour or less, if fired exclusively with natural gas, liquefied petroleum gas (LPG), or any combination thereof;
- 110.2 Boilers, steam generators and process heaters with a rated heat input less than 1 million BTU/hour fired with any fuel;
- 110.3 Boilers, steam generators and process heaters that are used in petroleum refineries;
- 110.4 Boilers used by public electric utilities or qualifying small power production facilities, as defined in Section 228.5 of the Public Utilities Code, to generate electricity;
- 110.5 Waste heat recovery boilers that are used to recover sensible heat from the exhaust of combustion turbines or reciprocating internal combustion engines;
- 110.6 Kilns, ovens, and furnaces used for drying, baking, heat treating, cooking, calcining or vitrifying; or
- 110.7 Process heaters used to heat thermal fluid for radiant comfort heating.

(Amended 7/30/2008; 5/4/2011)

9-7-111 Limited Exemption, Low Fuel Usage - Section 9-7-301: The requirements of Section 9-7-301 shall not apply to the use of any boiler, steam generator, or process heater with an annual heat input less than 90,000 therms during each consecutive 12-month period after July 1, 1993, or that accepts a limiting condition in their operating permit to limit the annual heat input to less than 90,000 therms, provided the requirements of Sections 9-7-304 and 504 are satisfied. This exemption is not valid for a boiler, steam generator, or process heater that is subject to the requirements of Section 9-7-307 after the effective date of the applicable standard in that section.

(Amended 7/30/2008; 5/4/2011)

9-7-112 Limited Exemption, Low Fuel Usage - Section 9-7-307: The requirements of Sections 9-7-301, 307, 311 and 312 shall not apply to the use of any boiler, steam generator or process heater that was first operated prior to January 1, 2012 provided that all of the following conditions are met:

- 112.1 For devices with a rated heat input less than 10 million BTU/hr, the device uses less than 10% of its annual maximum heat capacity in each consecutive 12-month period beginning January 1, 2012 and the requirements of Sections 9-7-309 and 504 are satisfied;
- 112.2 For devices with a rated heat input of 10 million BTU/hr or more, the device uses less than 10% of its annual maximum heat capacity in each consecutive 12-month period beginning January 1, 2012 and the requirements of Section 9-7-504 are satisfied and the device does not exceed a NO_x exhaust concentration of 30 ppmv or a CO exhaust concentration of 400 ppmv, both dry at 3 percent oxygen.

A boiler, steam generator or process heater that uses 10% or more of its annual maximum heat capacity in any consecutive 12-month period after the effective date specified in Section 9-7-112.1 or 112.2, as applicable, shall not thereafter be eligible for this exemption. An operator of a boiler, steam generator or process heater that loses eligibility for this exemption by using more than the specified amount of fuel in

any consecutive 12-month period shall comply with the applicable standards of Section 9-7-307 within 24 months.

- (Adopted 7/30/2008; Amended 5/4/2011)*
- 9-7-113 Limited Exemption, Natural Gas Curtailment and Testing:** The requirements of Section 9-7-307 shall not apply to any boiler, steam generator or process heater while it burns non-gaseous fuel during a natural gas curtailment or during testing to verify readiness for such a curtailment, provided that all of the following conditions are met:
- 113.1 The device does not burn non-gaseous fuel for more than 168 total hours in each consecutive 12-month period, plus 48 hours in each consecutive 12-month period for oil-burn readiness testing or state, federal or local agency-required performance testing,
 - 113.2 The device does not exceed a NOx exhaust concentration of 150 ppmv, dry at 3 percent oxygen, and
 - 113.3 The records specified in Section 9-7-503.3 are maintained.
- (Adopted 7/30/2008; Amended 5/4/2011)*
- 9-7-114 Limited Exemption, Tune-Up:** The emission limits of Section 9-7-307 shall not apply during the tune-up of a boiler, steam generator or process heater required by Section 9-7-313.
- (Adopted 7/30/2008; Amended 5/4/2011)*
- 9-7-115 Limited Exemption, Startup and Shutdown:** The emission limits of Section 9-7-307 shall not apply during startup and shutdown periods provided that all of the following conditions are met:
- 115.1 Each startup and shutdown period shall not exceed two hours, unless otherwise allowed in a District Permit to Operate. In no case shall the startup period exceed 12 hours, or the shutdown period exceed 9 hours.
 - 115.2 All emission control systems shall be in operation and emissions shall be minimized, to the extent possible, during startup and shutdown periods.
- (Adopted July 30, 2008)*
- 9-7-116 Limited Exemption, Compliance Extension for Facilities Subject to Regulation 9, Rule 9:** Boilers, steam generators or process heaters located at the same facility as a turbine that is subject to Regulation 9, Rule 9 and that is modified or replaced to comply with Section 9-9-301.2 of that regulation, shall comply with the requirements of Section 9-7-307 no later than 24 months after the date otherwise specified for compliance in Section 9-7-308.
- (Adopted July 30, 2008)*
- 9-7-117 Limited Exemption, Devices Rated 75 MM BTU/hr or Higher Limited to 9 PPMV NOx:** The emission limits of Section 9-7-307.6 shall not apply to any boiler, steam generator or process heater that is limited to 9 ppmv NOx or less by a District Permit to Operate in effect on or before July 30, 2008 as long as that permit limit remains in effect.
- (Adopted July 30, 2008)*
- 9-7-200 DEFINITIONS**
- 9-7-201 Annual Heat Input:** The total heat input of fuels burned by a combustion source during any consecutive 12-month period, as determined from the higher heating value and cumulative annual usage of each fuel.
- 9-7-202 Annual Maximum Heat Capacity:** The amount of heat input that a device would have if it operated at its rated heat input continuously for 365 consecutive days.
- (Adopted July 30, 2008)*
- 9-7-203 Boiler or Steam Generator:** Any combustion equipment used to produce steam.
- (Renumbered 7/30/2008; Amended 5/4/2011)*
- 9-7-204 British Thermal Unit (BTU):** The amount of heat required to raise the temperature of one pound of water from 59° to 60°F at one atmosphere.
- (Renumbered July 30, 2008)*
- 9-7-205 Digester Gas:** Gas derived from the decomposition of organic matter in a digester.
- (Adopted July 30, 2008)*
- 9-7-206 Digester Gas-Fired Device:** A boiler, steam generator or process heater that fires or co-fires digester gas at least 90% of its operating time, on a calendar year basis.
- (Adopted July 30, 2008)*

- 9-7-207 Gaseous Fuel:** Any fuel that is a gas at 68°F and one atmosphere.
(Adopted July 30, 2008)
- 9-7-208 Heat Input:** The heat of combustion released due to burning a fuel in a source, using the higher heating value of the fuel. This does not include the sensible heat of incoming combustion air.
(Renumbered July 30, 2008)
- 9-7-209 Heat-Input Weighted Average Limit:** For devices using fuels with different NOx limits, the applicable limit is the heat-input weighted average of the limits for each fuel used, which is:

$$\frac{\sum ((\text{heat input for a fuel}) \times (\text{NOx limit for that fuel}))}{(\text{total heat input for all fuels})}$$
for all fuels used, divided by:
(Amended, Renumbered 7/30/2008; Amended 5/4/2011)
- 9-7-210 Higher Heating Value (HHV):** The total heat liberated per mass of fuel burned (BTU per pound), when fuel and dry air at standard conditions undergo complete combustion and all resultant products are brought to their standard states at standard conditions. The HHV is determined as specified in Section 9-7-605.
(Renumbered July 30, 2008)
- 9-7-211 Landfill Gas:** Gas derived from the decomposition of waste in a landfill.
(Adopted July 30, 2008)
- 9-7-212 Landfill Gas-Fired Device:** A boiler, steam generator or process heater that fires or co-fires landfill gas at least 90% of its operating time, on a calendar year basis.
(Adopted July 30, 2008)
- 9-7-213 Load-Following Unit:** A unit that cannot be operated in a base-loaded mode, and that has normal operational load fluctuations and requirements, imposed by fluctuations in the process(es) served by the unit, that exceed the operational response range of a Ultra-Low NOx burner system operating at 9 ppmv NOx, as determined by the District and indicated on the device's permit to operate.
(Adopted July 30, 2008)
- 9-7-214 Natural Gas:** Any mixture of gaseous hydrocarbons containing at least 80 percent methane by volume, as determined according to Standard Method ASTM D1945-64.
(Renumbered July 30, 2008)
- 9-7-215 Natural Gas Curtailment:** A shortage in the supply of pipeline natural gas, due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of natural gas.
(Adopted July 30, 2008)
- 9-7-216 Nitrogen Oxide (NOx) Emissions:** The sum of nitric oxide (NO) and nitrogen dioxide (NO₂) in the flue gas, collectively expressed as nitrogen dioxide.
(Renumbered July 30, 2008)
- 9-7-217 Process Heater:** Any combustion equipment that transfers heat from combustion gases to water or process streams.
(Amended, Renumbered 7/30/2008; Amended 5/4/2011)
- 9-7-218 Rated Heat Input:** The heat input capacity specified on the nameplate of the boiler, steam generator or process heater, or the sum of the capacities on the nameplates of the burners in the boiler, steam generator or process heater, whichever is greater.
(Amended, Renumbered July 30, 2008)
- 9-7-219 Shutdown Period:** The period of time during which a unit is taken from an operational to a non-operational status.
(Adopted July 30, 2008)
- 9-7-220 Startup Period:** The period of time during which a unit is brought from a non-operational status to operating temperature, including the time required for the unit's emission control system to reach full operation.
(Adopted July 30, 2008)
- 9-7-221 Therm:** One hundred thousand (100,000) BTU's.
(Renumbered July 30, 2008)
- 9-7-300 STANDARDS**
- 9-7-301 Interim Emission Limits:** No person shall operate a boiler, steam generator or process heater with a rated heat input greater than or equal to 10 million BTU per hour unless the following emission limits are met:

- 301.1 Nitrogen oxide (NOx) emissions shall not exceed 30 ppmv, dry at 3 percent oxygen when gaseous fuel is used;
- 301.2 Nitrogen oxide (NOx) emissions shall not exceed 40 ppmv, dry at 3 percent oxygen when non-gaseous fuel is used;
- 301.3 Nitrogen oxide (NOx) emissions shall not exceed the heat-input weighted average of the limits in Sections 9-7-301.1 and 301.2 when a combination of gaseous and non-gaseous fuel is used;
- 301.4 Carbon monoxide (CO) emissions shall not exceed 400 ppmv, dry at 3 percent oxygen.

This section shall not apply to any boiler, steam generator or process heater subject to a NOx or CO emission limit in Section 9-7-307.

(Amended July 30, 2008)

9-7-302 Deleted July 30, 2008

9-7-303 Deleted July 30, 2008

9-7-304 Low Fuel Usage Requirements – Section 9-7-301: No person shall operate any boiler, steam generator or process heater under the limited exemption in Section 9-7-111, or with rated heat input less than 10 million BTU per hour with the capability of firing any non-gaseous fuel, without doing at least one of the following:

- 304.1 Operate in a manner that maintains stack-gas oxygen concentrations at less than or equal to 3 percent by volume on a dry basis; or
- 304.2 Perform an inspection and tune-up at least once every 12 months by a technician in accordance with the procedure specified in Section 9-7-604; or
- 304.3 Meet the emission limits specified in Sections 9-7-301.

(Amended 7/30/2008; 5/4/2011)

9-7-305 Deleted July 30, 2008

9-7-306 Deleted July 30, 2008

9-7-307 Final Emission Limits: No person shall operate a boiler, steam generator or process heater with a rated heat input listed in the table below that exceeds the corresponding NOx and CO emission limits on or after the corresponding effective date specified in Section 9-7-308.

Emission Limit	Rated Heat Input (million BTU/hr)	Fuel	NOx Limit (ppmv, dry at 3% oxygen)	CO Limit (ppmv, dry at 3% oxygen)
307.1	>2 to 5	gaseous, except landfill or digester gas	30	400
307.2	>5 to <10		15	400
307.3	10 to <20		15	400
307.4	20 or more, load-following unit		15	400
307.5	20 to <75		9	400
307.6	75 or more		5	400
307.7	1 or more	landfill or digester gas	30	400
307.8	1 or more	non-gaseous	40	400
307.9	1 or more	multiple fuels	heat-input weighted average limit	400

(Adopted 7/30/2008; Amended 5/4/2011)

9-7-308 Compliance Schedule: Boilers, steam generators and process heaters subject to the requirements of Section 9-7-307 shall comply with those requirements in accordance with the schedule in the table below.

Applicable NOx Limit	At least 33% of devices at a single facility	At least 66% of devices at a single facility	100% of devices at a single facility
9-7-307.1 9-7-307.2	Effective Date: January 1, 2013	One year after Effective Date	Two years after Effective Date
9-7-307.3 9-7-307.4 9-7-307.5 9-7-307.6	Effective Date: January 1, 2012	One year after Effective Date	Two years after Effective Date
9-7-307.7 9-7-307.8 9-7-307.9	Effective Date: January 1, 2013 for devices with rated input <10 MM BTU/hr; July 30, 2008 for devices with rated input ≥10 MM BTU/hr	One year after Effective Date	Two years after Effective Date

For the purpose of complying with the required minimum percentages shown in this table, all boilers, steam generators and process heaters at a single facility with rated heat inputs less than 10 MM BTU/hr, including those subject to Section 9-7-112, may be grouped. All other boilers, steam generators and process heaters at a single facility, including those subject to Section 9-7-112, may be grouped, except for those that are subject to Sections 307.7, 307.8 or 307.9 that also have an effective date of July 30, 2008.

308.1 Notwithstanding the indicated minimum percentages, boilers, steam generators and process heaters rated >2 to 5 MM BTU/hr shall have an effective date 10 years after original manufacture date if manufactured prior to January 1, 2011, IF this is later than the normal effective date.

308.2 Notwithstanding the indicated minimum percentages, boilers, steam generators and process heaters rated >5 to <20 MM BTU/hr shall have an effective date 10 years after original manufacture date if manufactured prior to January 1, 2012, IF this is later than the normal effective date.

308.3 Notwithstanding the indicated minimum percentages, boilers, steam generators and process heaters rated 20 MM BTU/hr or higher shall have an effective date 5 years after original manufacture date if manufactured prior to January 1, 2012, IF this is later than the normal effective date.

(Adopted 7/30/2008; Amended 5/4/2011)

9-7-309 Low Fuel Usage Requirements – Section 9-7-307: No person shall operate any boiler, steam generator or process heater under the limited exemption in Section 9-7-112.1 without doing at least one of the following:

309.1 Deleted May 4, 2011

309.2 Perform an inspection and tune-up at least once per calendar year by a technician in accordance with the procedure specified in Section 9-7-604; or

309.3 Meet the applicable emission limits in Section 9-7-307.

(Adopted 7/30/2008; Amended 5/4/2011)

9-7-310 Prohibition of Commerce in Uncertified Devices: Effective January 1, 2012, no person shall sell, offer for sale, or install any boiler, steam generator or process heater subject to Section 9-7-307.1 or 307.2 unless the device is certified to comply with the applicable standards of these sections by the APCO. This certification requirement shall not apply to burner assembly retrofit packages, or to devices installed in accordance with a District Permit to Operate.

(Adopted 7/30/2008; Amended 5/4/2011)

9-7-311 Insulation Requirements: No person shall operate a boiler or steam generator unless the exposed, external surface of the device, including all pipes and ducts heated by the device, does not exceed a temperature of 120°F. This requirement shall not apply to any of the following:

311.1 Any device that meets the definition of a high-temperature water boiler in California Code of Regulations, Title 8.

311.2 Any surface or appurtenance that must remain un-insulated for safety or operational reasons.

311.3 Any surface that has at least one inch of insulation.

- 311.4 Any surface heated by a source other than the boiler or steam generator, including sunlight.
- 311.5 Any exhaust stack surface.

(Adopted 7/30/2008; Amended 5/4/2011)

9-7-312 Stack Gas Temperature Limits: Effective January 1, 2013, no person shall operate a boiler or steam generator with a stack gas temperature (downstream of any economizer) that exceeds the indicated maximum temperature unless the device is certified by the Air-Conditioning, Heating and Refrigeration Institute (AHRI) as having a thermal efficiency of 80% or more:

Heater Design	Maximum Temperature (°F)	
	Gaseous Fuel	Non-Gaseous Fuel
firetube	100°F over saturated steam temperature for steam boiler, 100°F over hot water temperature for hot water boiler OR 250 °F greater than combustion air temperature, whichever is higher	100°F over saturated steam temperature for steam boiler, 100°F over hot water temperature for hot water boiler OR 300 °F greater than combustion air temperature, whichever is higher
watertube	150°F over saturated steam temperature for steam boiler, 150°F over hot water temperature for hot water boiler OR 250 °F greater than combustion air temperature, whichever is higher	150°F over saturated steam temperature for steam boiler, 150°F over hot water temperature for hot water boiler OR 300 °F greater than combustion air temperature, whichever is higher

(Adopted 7/30/2008; Amended 5/4/2011)

9-7-313 Deleted May 4, 2011

9-7-400 ADMINISTRATIVE REQUIREMENTS

9-7-401 Deleted July 30, 2008

9-7-402 Deleted July 30, 2008

9-7-403 Initial Demonstration of Compliance: No person shall operate a boiler, steam generator or process heater that is subject to the requirements of Sections 9-7-307.1 through 307.6, or a boiler, steam generator or process heater with a rated heat input less than 10 MM BTU/hr that is subject to the requirements of Sections 9-7-307.7 through 9-7-307.9 unless compliance with these requirements is verified in accordance with Sections 9-7-601 or 602 within 1 year of the date on which these requirements become effective. However, devices with a rated heat input <10 MM BTU/hr may be tested using a portable analyzer in accordance with Section 9-7-606. This section does not apply to any device required to perform verification testing to establish compliance with applicable requirements of Sections 9-7-307 in accordance with a District Authority to Construct issued on or after January 1, 2013, or to any device that has had a previous source test performed in accordance with Sections 9-7-601 and 602 that verifies compliance with the applicable requirements of Section 9-7-307, or to any device certified in accordance with Section 9-7-310. The requirements of this section may be satisfied by monitoring emissions with a continuous emission monitoring system (CEMS) that meets the requirements of Regulation 1-522.

(Amended 7/30/2008; 5/4/2011)

9-7-404 Registration: Effective January 1, 2011, no person shall operate any boiler, steam generator or process heater with a rated heat input greater than 2 and less than 10 million BTU/hr unless the device is registered with the District. Any person registering a device shall pay the fees specified in Regulation 3. This registration requirement shall not apply to any device for which the operator holds a District Permit to Operate.

(Adopted 7/30/2008; Amended 5/4/2011)

9-7-405 Deleted May 4, 2011

9-7-406 Application for Certification: A manufacturer may submit an application to certify compliance with the requirements of Section 9-7-307.1 or 9.7-307.2 for a boiler, steam generator or process heater model that is subject to these requirements. The application shall be made on forms specified by the APCO. The certification application shall include a demonstration that the boiler, steam generator or process heater model was tested in accordance with Section 9-7-606 and found to comply with the requirements of Sections 9-7-307.1 or 9.7-307.2. A portable analyzer may not be used for this testing. After completing review of the application for certification and source test report, the APCO will approve the certification and include the subject model on the list of certified devices, or will deny the certification.

(Adopted 7/30/08; Amended 5/4/2011)

9-7-407 Deleted May 4, 2011

9-7-408 Designation of Load-Following Units: To be eligible for the load-following emission standard in section 9-7-307, a unit must be designated a load-following unit by the APCO on the unit Permit to Operate. In order to support this designation, the unit operator shall include the following information with an application for an Authority to Construct or an application for a modification to a Permit to Operate, as specified in Regulation 2:

- 408.1 A description of the processes the unit serves and the normal operational load fluctuations and load requirements imposed on the unit, verifying that the unit cannot be operated in a base-loaded mode.
- 408.2 A detailed report on the design and condition of the unit, burner(s), burner controls, and any other subsystem that may affect the ability of the unit to comply with a 9 ppmv NOx limit, including a verification that the unit is free of air leaks, and is operated within normal design parameters, and is otherwise free of significant design defects and physical defects and is operated within reasonable parameters. This report shall verify that the inability of the unit to comply with a 9 ppmv NOx limit is substantially caused by the system load fluctuations and the limitations of state-of-the-art, commercially-available, 9 ppmv burners and burner controls, rather than any other factor.
- 408.3 Technical data such as steam demand charts or other information to support the description and report described above.

(Adopted July 30, 2008)

9-7-500 MONITORING AND RECORDS

9-7-501 Combinations of Different Fuels: No person shall simultaneously fire combinations of different fuels in a device subject to the requirements of Sections 9-7-301.3 or 307.9 without first installing a non-resettable totalizing fuel meter in each fuel line for each source.

(Amended July 30, 2008)

9-7-502 Deleted July 30, 2008

9-7-503 Records: Any person subject to the requirements of this rule shall keep records of the following:

- 503.1 Documentation verifying tune-ups performed in accordance with Sections 9-7-304.2, or 309.2.
- 503.2 In the event that the limited exemption in Section 9-7-113 is invoked, documentation from the natural gas supplier verifying that natural gas was unavailable due to a natural gas curtailment.
- 503.3 Documentation verifying the hours of equipment testing using non-gaseous fuel, and of total operating hours using non-gaseous fuel during each calendar month.
- 503.4 The results of any testing required by Sections 9-7-403 or 506.
- 503.5 Digester gas-fired and landfill gas-fired devices operating under Section 9-7-307.7 shall maintain records of total operating hours and operating hours firing or co-firing digester or landfill gas.

Such records shall be retained for a minimum of 24 months from date of entry and be made available to District staff upon request.

(Amended 7/30/2008; 5/4/2011)

9-7-504 Low Fuel Usage - Monitoring and Records: Any person who operates a boiler, steam generator or process heater under the limited exemption of Section 9-7-111 or 112 shall comply with the following requirements:

504.1 Operate a non-resettable totalizing meter for each fuel that demonstrates that the source operated at or below the applicable heat input level, or receive APCO approval for using utility service meters, purchase or tank fill records, or any other acceptable methods for measuring the cumulative annual usage of each fuel; and

504.2 Have available for inspection by the APCO annual fuel use data and the Higher Heating Value of each fuel used, for the prior consecutive 12-month period. Records shall be maintained and made accessible to the APCO for a period of 24 months from the date the record is made.

An operator of a boiler, steam generator or process heater who claims eligibility for the limited exemption in Section 9-7-111 or 112, but who fails to maintain records to allow verification of fuel usage shall have the burden of proof to establish eligibility for the limited exemption.

(Amended July 30, 2008)

9-7-505 Original Manufacture Date: Any person who operates a boiler, steam generator or process heater that is subject to a standard in Sections 9-7-307.1 through 307.6 and that elects to use an effective date for this standard that is based on the original manufacture date of the device shall make available the original manufacture date of the device on the original manufacturer's identification or rating plate permanently fixed to the device, or else on a copy of the manufacturer's invoice.

(Adopted July 30, 2008)

9-7-506 Periodic Testing: No person shall operate a boiler, steam generator or process heater subject to an emission limit specified in the table below unless they verify compliance with the limit at the specified intervals. Testing shall be performed in accordance with Sections 9-7-601 and 602. Alternatively, devices may be tested using a portable analyzer in accordance with Section 9-7-606. No person shall operate a device that uses non-gaseous fuel unless they perform testing using non-gaseous fuel to verify compliance with Section 9-7-307.8 or 307.9, in addition to testing to verify compliance with any other applicable standard in Section 9-7-307. This section does not apply to any device required to perform periodic testing in accordance with a District Permit to Operate or to any device that verifies compliance with an emission limit with a continuous emission monitor that meets the requirements of Regulation 1-522.

Emission Limit	Testing Interval
9-7-307.1 9-7-307.2 9-7-307.3	Every calendar year, beginning with the first complete year after the effective date in Section 9-7-308.
9-7-307.4 9-7-307.5 9-7-307.6	Every calendar year, beginning with the first complete year after the effective date in Section 9-7-308.
9-7-307.8 9-7-307.9	Within 60 days of the first use of non-gaseous fuel in any calendar year in which non-gaseous fuel is used. Use of non-gaseous fuel under limited exemption in Section 9-7-113 shall not trigger this requirement.

(Adopted 7/30/2008; Amended 5/4/2011)

9-7-600 MANUAL OF PROCEDURES

9-7-601 Determination of Nitrogen Oxides: The methods by which samples of exhaust gases are collected and analyzed to determine concentrations of nitrogen oxides are set forth in the District Manual of Procedures, Volume IV, ST-13A.

(Amended May 4, 2011)

9-7-602 Determination of Carbon Monoxide and Stack-Gas Oxygen: Compliance with the carbon monoxide emission requirements of Sections 9-7-301 and 307 and the stack-

gas oxygen concentration requirement of Section 9-7-304.1 shall be determined as set forth in the District Manual of Procedures, Volume IV, ST-6 (carbon monoxide) and ST-14 (oxygen).

(Amended July 30, 2008)

9-7-603 Compliance Determination: All emission determinations shall be made in the as-found operating condition, except that no compliance determination shall be established during startup or shutdown.

(Amended July 30, 2008)

9-7-604 Tune-Up Procedures: The tune-up procedure required by Sections 9-7-304.2 and 309.2 shall be performed in accordance with the procedure set forth in the District Manual of Procedures, Volume I, Chapter 5.

(Adopted 9/15/1993; Amended 7/30/2008; 5/4/2011)

9-7-605 Determination of Higher Heating Value: If certification of the Higher Heating Value is not provided by the third-party fuel supplier, it shall be determined by one of the following test methods: (1) ASTM D2015-85 for solid fuels; (2) ASTM D240-87 or ASTM D2382-88 for liquid hydrocarbon fuels; or (3) ASTM D1826-88, or ASTM D1945-81 in conjunction with ASTM D3588-89, for gaseous fuels.

9-7-606 Certification, Initial Demonstration of Compliance and Periodic Test Methods: The test methods specified in the following table may be used to perform an initial demonstration of compliance in accordance with Section 9-7-403, establish equipment certification in accordance with Section 9-7-406, and also to perform periodic monitoring in accordance with Section 9-7-506. Portable analyzers may only be used where explicitly allowed in Sections 9-7-403 and 506. In addition, any other test method approved for this purpose by the Air Pollution Control Officer of the District and by the regional administrator of the United States Environmental Protection Agency may also be used.

Emission Limit or Parameter	Test Method
NOx (ppmv)	1. BAAQMD Manual of Procedures, Volume IV, ST-13 A 2. California Air Resources Board Method 100 3. U.S. EPA Method 7E 4. U.S. EPA Method CTM-030 (if portable analyzer use is allowed)
CO (ppmv)	1. BAAQMD Manual of Procedures, Volume IV, ST-6 2. California Air Resources Board Method 100 3. U.S. EPA Method 10 4. U.S. EPA Method CTM-030 (if portable analyzer use is allowed)
oxygen (%)	1. BAAQMD Manual of Procedures, Volume IV, ST-14 2. California Air Resources Board Method 100 3. U.S. EPA Method 3 or 3A 4. U.S. EPA Method CTM-030 (if portable analyzer use is allowed)

(Adopted May 4, 2011)

ATTACHMENT 1 DELETED MAY 4, 2011

**REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 9
NITROGEN OXIDES FROM STATIONARY
GAS TURBINES**

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**REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 9
NITROGEN OXIDES FROM STATIONARY
GAS TURBINES**

(Adopted May 5, 1993)

- 9-9-100 GENERAL**
- 9-9-101 Description:** The purpose of this Rule is to limit emissions of nitrogen oxides (NO_x) from stationary gas turbines.
- 9-9-110 Exemption, Small Gas Turbines:** This Rule shall not apply to stationary gas turbines with a heat input rating less than 5 MM Btu/hr.
(Amended December 6, 2006)
- 9-9-111 Exemption, General:** The requirements of this Rule shall not apply to:
- 111.1 Testing of aircraft gas turbine engines for flight certification.
 - 111.2 Gas turbines used solely for firefighting and/or flood control.
 - 111.3 Deleted December 6, 2006
- (Amended December 6, 2006)*
- 9-9-112 Limited Exemption, Low Usage:** The requirements of this Rule shall not apply to the operation of gas turbines rated less than 50 MM Btu/hr heat input that operate less than 877 hours in any 12-month period, provided the requirements of Section 9-9-502 are satisfied.
(Amended December 6, 2006)
- 9-9-113 Exemption, Inspection and Maintenance Periods:** The emission limits of Section 9-9-301 shall not apply during inspection and maintenance periods, with the following limitations:
- 113.1 Inspection and maintenance periods shall be limited to a total of 48 hours between May 1 and October 31 in a calendar year.
 - 113.2 For a calendar year in which a boiler inspection required by California Labor Code Section 7682 is not performed, inspection and maintenance periods shall be limited to a total of 144 hours.
 - 113.3 For a calendar year in which a boiler inspection required by California Labor Code Section 7682 is performed, inspection and maintenance periods shall be limited to 144 hours plus additional time required for the boiler inspection, provided, however, that the additional time shall not cause the calendar-year total of all inspection and maintenance periods to exceed 312 hours.
- (Adopted 9/21/94; Amended 12/6/06)*
- 9-9-114 Exemption, Start-up and Shutdown Periods:** The emission limits of Sections 9-9-301 and 302 shall not apply during start-up or shutdown periods.
(Adopted 9/21/94; Amended 12/6/06)
- 9-9-115 Limited Exemption, Minor Inspection and Maintenance Work:** The requirements of Section 9-9-301 shall not apply during periods of inspection and maintenance work on a gas turbine or associated components, not to exceed 4 hours on any day and 48 hours in any 12-month period, that are planned and scheduled at least 24 hours in advance. The operator shall keep records of these planned inspection and maintenance events and make them available to the APCO on request. This exemption shall not apply to low-usage turbines subject to Section 9-9-302. Any annual emissions limit required by permit condition shall include emissions resulting from this minor inspection and maintenance work.
(Adopted December 6, 2006)
- 9-9-116 Limited Exemption, Very Limited Use Turbines:** The emission limits in Section 9-9-302.2 shall not apply to turbines that operate less than 1200 hours between January 1, 2007 and January 1, 2010, and do not operate more than 400 hours during any 12-month period after January 1, 2010, provided the requirements in Section 9-9-502 are met. Turbines that initially qualify for this limited exemption based on the number of hours of operation between January 1, 2007 and January 1, 2010, but operate more than 400 hours per 12-month period after January 1, 2010,

shall continue to comply with the emission limits in 9-9-302.2 subject to the compliance schedule set forth in Section 9-9-405. This limited exemption does not apply to the emission limits in Section 9-9-302.1.

(Adopted December 6, 2006)

- 9-9-120 Interchangeable Emission Reduction Credits:** Until such time as the December 6, 2006 amendments to this rule are approved into the State Implementation Plan by the EPA, the emission limits of Sections 9-9-301.2 and 9-9-302.2 may be complied with by interchangeable emission reduction credits used pursuant to and as limited by the provisions of Regulation 2, Rule 9. An operator must still comply with the emission limits of Sections 9-9-301.1 and 9-9-302.1 without using interchangeable emission reduction credits.

(Adopted December 6, 2006)

9-9-200 DEFINITIONS

- 9-9-201 Commercially Available:** Any control technology or equipment that is offered for a specific make and model of gas turbine by at least one vendor, is guaranteed by the vendor to achieve the emission control performance required by this Rule, has been demonstrated in practice at 3 or more sites, achieves the required emission control performance utilizing similar fuel composition for a regular or full-scale operation within the United States, and demonstrates at least 90% availability.

(Adopted December 6, 2006)

- 9-9-202 Dry Low-NOx Combustion Technology (DLN):** A turbine combustor design that uses multiple staging, air/fuel premixing or other modifications to achieve lower levels of NOx emissions as compared to conventional combustors.

(Adopted December 6, 2006)

- 9-9-203 EFF:** Thermal efficiency.

(Renumbered December 6, 2006)

- 9-9-204 Emergency Use:** Operation during a natural or civil disaster or emergency situation, as requested or ordered by any federal, state or local agency to protect the public, life or property.

(Adopted December 6, 2006)

- 9-9-205 Essential Gas Turbine:** A gas turbine that cannot be taken out of service without shutting down the process unit which it serves.

(Adopted 9/21/94; Amended, Renumbered 12/6/06)

- 9-9-206 Heat Input Rating:** The heat input requirement (based on fuel HHV) of a gas turbine at its International Standards Organization (ISO) 3977 nameplate rated power output at standard conditions of 1 atmosphere, 15° Centigrade, and 60% atmospheric humidity.

(Adopted December 6, 2006)

- 9-9-207 HHV:** The higher heating value of fuel.

(Renumbered 9/21/94; 12/6/06)

- 9-9-208 LHV:** The lower heating value of fuel.

(Renumbered 9/21/94; 12/6/06)

- 9-9-209 Inspection and Maintenance Period:** A period of time during which the heat recovery steam generator associated with an essential gas turbine is taken out of service for inspection or maintenance, and during which gas turbine emissions are vented to a bypass stack rather than through the heat recovery steam generator.

(Adopted 9/21/94; Amended, Renumbered 12/6/06)

- 9-9-210 Natural Gas:** Any mixture of gaseous hydrocarbons containing at least 80 percent methane by volume, as determined according to Standard Method ASTM D1945.

(Adopted 9/21/94; Amended, Renumbered 12/6/06)

- 9-9-211 Nitrogen Oxide (NOx) Emissions:** The sum of nitric oxide and nitrogen dioxide (NO₂) in the flue gas, collectively expressed as nitrogen dioxide.

(Adopted 9/21/94; Renumbered 12/6/06)

- 9-9-212 Non-Gaseous Fuel:** Any fuel which is not a gas at 68° F and one atmosphere.

(Adopted 9/21/94; Renumbered 12/6/06)

- 9-9-213 Power Augmentation:** An increase in the gas turbine shaft output or the decrease in turbine fuel consumption by the addition of energy recovered from exhaust heat.

(Renumbered 9/21/94; 12/6/06)

- 9-9-214 Power Output Rating:** The continuous megawatt (MW) rating or mechanical equivalent by a manufacturer for gas turbine(s) without power augmentation.
(Renumbered 9/21/94; Amended, Renumbered 12/6/06)
- 9-9-215 Refinery Fuel Gas:** A mixture of hydrogen and gaseous hydrocarbons generated by petroleum refinery processes and used by the refinery for on-site combustion in boilers, process heaters, turbines, and other combustion equipment.
(Adopted 9/21/94; Renumbered 12/6/06)
- 9-9-216 Selective Catalytic Reduction (SCR):** A post-combustion NO_x control technique in which a reducing agent (for example: ammonia) is used in a gas-phase reaction with oxides of nitrogen in the presence of a catalyst to convert the oxides of nitrogen into nitrogen and water.
(Renumbered 9/21/94; Amended, Renumbered 12/6/06)
- 9-9-217 Shutdown Period:** A period of time, not to exceed two hours, during which a gas turbine is brought from normal operating power output to inactive status.
(Adopted 9/21/94; Amended, Renumbered 12/6/06)
- 9-9-218 Start-up Period:** A period of time, not to exceed four hours (six hours for cold steam turbine starts at combined cycle facilities), during which a gas turbine is brought from inactive status to normal operating power output.
(Amended 9/21/94; Amended, Renumbered 12/6/06)
- 9-9-219 Stationary Gas Turbine:** Any gas turbine system that is attached to a foundation and is gas and/or liquid fueled with or without power augmentation. Two or more gas turbines powering one shaft shall be treated as one unit.
(Renumbered 9/21/94; Amended, Renumbered 12/6/06)
- 9-9-220 Waste Gas:** A mixture of hydrogen, gaseous hydrocarbons and other diluent gases generated by sewage treatment or landfill biomass and used by the facility for on-site combustion in gas turbines or other combustion equipment.
(Adopted December 6, 2006)
- 9-9-221 Water Injection / Steam Injection Enhancement:** A retrofit design improvement to water or steam injection location, orientation, or turbine combustor or other modifications to achieve lower levels of NO_x emissions as compared to existing water or steam injection design.
(Adopted December 6, 2006)

9-9-300 STANDARDS

9-9-301 Emission Limits, General:

- 301.1 A person shall not operate a stationary gas turbine unless nitrogen oxides (NO_x) emission concentrations, corrected to 15 percent O₂ (dry basis), do not exceed the compliance limits listed below:
- 301.1.1 Gas turbines rated at 0.3 MW to less than 10.0 MW shall not exceed 42 ppmv, except that, for refinery fuel gas firing, the limit shall be 55 ppmv, and for non-gaseous fuel firing during natural gas curtailment or short testing periods, the limit shall be 65 ppmv.
 - 301.1.2 Gas turbines rated at 10.0 MW and over, without SCR, shall not exceed 15 ppmv, except that, for non-gaseous fuel firing during natural gas curtailment or short testing periods, the limit shall be 42 ppmv.
 - 301.1.3 Gas Turbines rated at 10.0 MW and over, with SCR, shall not exceed 9 ppmv, except that, for non-gaseous fuel firing during natural gas curtailment or short testing periods, the limit shall be 25 ppmv.
- 301.2 Effective January 1, 2010, a person shall not operate a stationary gas turbine unless nitrogen oxides (NO_x) emissions, corrected to 15 percent O₂ (dry basis), are less than either of the alternative compliance limits listed below for the turbine heat input rating and type of fuel burned:

Turbine Heat Input Rating	Natural Gas	Refinery Fuel Gas, Waste Gas or LPG	Non-gaseous Fuel
< 5 MM Btu/hr	Exempt	Exempt	Exempt

Turbine Heat Input Rating	Natural Gas	Refinery Fuel Gas, Waste Gas or LPG	Non-gaseous Fuel
5 - 50 MM Btu/hr	2.12 lbs/MW hr or 42 ppmv	2.53 lbs/MW hr or 50 ppmv	3.28 lbs/MW hr or 65 ppmv
> 50 – 150 MM Btu/hr - no retrofit available ^(a)	1.97 lbs/MW hr or 42 ppmv	2.34 lbs/MW hr or 50 ppmv	3.04 lbs/MW hr or 65 ppmv
> 50 – 150 MM Btu/hr - WI/SI enhancement available ^(b)	1.64 lbs/MW hr or 35 ppmv	2.34 lbs/MW hr or 50 ppmv	3.04 lbs/MW hr or 65 ppmv
> 50 – 150 MM Btu/hr - DLN technology available ^(c)	1.17 lbs/MW hr or 25 ppmv	2.34 lbs/MW hr or 50 ppmv	3.04 lbs/MW hr or 65 ppmv
> 150 – 250 MM Btu/hr	0.70 lbs/MW hr or 15 ppmv	0.70 lbs/MW hr or 15 ppmv	1.97 lbs/MW hr or 42 ppmv
> 250 – 500 MM Btu/hr	0.43 lbs/MW hr or 9 ppmv	0.43 lbs/MW hr or 9 ppmv	1.17 lbs/MW hr or 25 ppmv
> 500 MM Btu/hr	0.15 lbs/MW hr or 5 ppmv	0.26 lbs/MW hr or 9 ppmv	0.72 lbs/MW hr or 25 ppmv

(a) The emission limits on this line apply to turbines for which no Water Injection or Steam Injection enhancement or DLN combustion technology is commercially available.

(b) The emission limits on this line apply to turbines for which Water Injection or Steam Injection enhancement is commercially available.

(c) The emission limits on this line apply to turbines for which DLN combustion technology is commercially available and which have not been required to install Water Injection or Steam Injection enhancements to comply with this Section 301.2.

301.3 If a turbine burns a mixture of fuels, the turbine's NOx emission limit shall be the highest of the limits applicable to any of the fuels in the mixture.

301.4 Violation of either of the alternative standards in Section 301.2 applicable to a particular turbine shall create a rebuttable presumption that the turbine is in violation of Section 301.2. The operator of the turbine may rebut the presumption of violation by demonstrating that the turbine is in compliance with the other alternative standard.

(Amended 9/21/94; 12/6/06)

9-9-302 Emission Limits, Low Usage:

302.1 Until January 1, 2010, or other date provided under a compliance schedule pursuant to Section 9-9-402.2, a person may operate a stationary gas turbine for up to 877 hours in any 12-month period (not counting hours of emergency use) without complying with the emission limits Section 9-9-301 as long as nitrogen oxides (NOx) emission concentrations, corrected to 15 percent O₂ (dry basis), do not exceed 42 ppmv when firing with natural gas and 65 ppmv when firing with non-gaseous fuel, and the requirements of Section 9-9-502 are satisfied.

302.2 Effective January 1, 2010, a person may operate a stationary gas turbine rated at 50 MMBtu/hr or greater for up to 877 hours in any 12-month period (not counting hours of emergency use) without complying with the emission limits set forth in Section 9-9-301 as long as nitrogen oxides (NOx) emissions, corrected to 15 percent O₂ (dry basis), are less than either of the of the alternative limits listed below for the turbine's heat input rating and the type of fuel burned, and the requirements of Section 9-9-502 are satisfied:

Turbine Heat Input Rating	Natural Gas	Refinery Fuel Gas, Waste Gas or LPG	Non-gaseous Fuel
< 50 MMBtu/hr	Exempt	Exempt	Exempt
50 – 150 MMBtu/hr (3 – 10 MW)	1.97 lbs/MW hr or 42 ppmv	N/A	3.04 lbs/MW hr or 65 ppmv

Turbine Heat Input Rating	Natural Gas	Refinery Fuel Gas, Waste Gas or LPG	Non-gaseous Fuel
> 150 – 250 MMBtu/hr (10 – 19 MW)	1.97 lbs/MW/hr or 42 ppmv	N/A	3.04 lbs/MW/hr or 65 ppmv
> 250 – 500 MMBtu/hr (19 – 40 MW)	1.17 lbs/MW/hr or 25 ppmv	N/A	1.97 lbs/MW/hr or 42 ppmv
> 500 MMBtu/hr (40+ MW)	0.72 lbs/MW/hr or 25 ppmv	N/A	1.21 lbs/MW/hr or 42 ppmv

302.3 If a turbine burns a mixture of fuels, the turbine's NOx emission limit shall be the highest of the limits applicable to any of the fuels in the mixture.

302.4 Violation of either of the alternative standards in Section 302.2 applicable to a particular turbine shall create a rebuttable presumption that the turbine is in violation of Section 302.2. The operator of the turbine may rebut the presumption of violation by demonstrating that the turbine is in compliance with the other alternative standard.

(Amended 9/21/94; 12/6/06)

9-9-303 Deleted December 6, 2006

9-9-304 Deleted December 6, 2006

9-9-305 Deleted December 6, 2006

9-9-400 ADMINISTRATIVE REQUIREMENTS

9-9-401 **Certification, Efficiency:** If a person who operates a gas turbine subject to the limits of subsections 9-9-301.1.2 or 301.1.3 can demonstrate a thermal efficiency (EFF) greater than 25 percent in accordance with subsections 401.2.1 or 401.2.2, the emissions limit may be adjusted in accordance with Section 9-9-401.1.

$$401.1 \text{ Adjusted Emission Limit} = \frac{\text{Emission Limit} \times \text{EFF}}{25}$$

401.2 EFF (percent efficiency) is the higher of 2.1 or 2.2. An EFF that is less than 25% shall be assigned a value of 25%.

$$2.1 \text{ EFF} = \frac{3412 \times 100\%}{\text{Actual Heat Rate at HHV of Fuel} \times \frac{\text{BTU}}{\text{KW} - \text{HR}}}$$

which is the demonstrated percent efficiency of the gas turbine only as calculated without consideration of any downstream energy recovery (not used for power augmentation) from the actual heat rate, (BTU/KW-HR) or 1.34 (BTU/HP-HR); corrected to the HHV (higher heating value) of the fuel and standard conditions, as measured at peak load for that facility.

or

$$2.2 \text{ EFF} = \text{Manufacturer's Rated Efficiency} * \times \frac{\text{LHV}}{\text{HHV}}$$

*With Air Pollution Equipment at LHV

which is the manufacturer's continuous rated percent efficiency of the gas turbine with air pollution equipment after correction from LHV to HHV of the fuel.

(Amended 9/21/94; 12/6/06)

9-9-402 **Compliance Schedule:**

402.1 A person who must modify existing sources or install new control equipment to meet the requirements of Section 9-9-301.2 or 302.2 shall submit an application for any Authority to Construct for the modification or installation of new control equipment by July 1, 2008, or by the date required pursuant to Section 9-9-404.3.

402.2 Any turbine subject to Sections 9-9-301.2 or 9-9-302.2 shall comply with the applicable emission limits set forth in those sections by January 1, 2010, or by the date required pursuant to Section 9-9-404.3, unless the turbine has not had a scheduled major maintenance outage by January 1, 2010, in which case the turbine shall comply with the applicable emission limits 30 days after the end of the next scheduled major maintenance outage, but in no event later than January 1, 2012.

(Amended December 6, 2006)

9-9-403 Deleted December 6, 2006

9-9-404 Compliance Schedule for Future Commercial Availability of Retrofit Technology: If water injection or steam injection enhancement retrofits or Dry Low NOx combustion technology become commercially available for a specific make and model of turbine after December 31, 2006, subjecting operators of that make and model of turbine to lower NOx emissions limits pursuant to Section 9-9-301.2, affected operators shall comply with Section 9-9-301.2 according to the following schedule.

- 404.1 Upon determining that water injection or steam injection enhancement retrofits or Dry Low NOx combustion technology are commercially available for a specific make and model of turbine, the APCO shall notify all operators of that make and model, in writing, of the commercial availability of the technology.
- 404.2 If any affected operator disagrees that the technology is commercially available for its turbine, as that term is defined in Section 9-9-201, the operator may object to the APCO in writing within 90 days of such notification. Within 30 days after receiving an objection, the APCO may amend the determination of commercial availability for the turbine for which the objection is made. If no objection is made for a particular turbine, or an objection is made and the APCO does not change the determination of commercial availability, the technology shall be deemed commercially available for that turbine. The APCO shall conduct a cost-effectiveness analysis prior to making a final determination of commercial availability.
- 404.3 Any affected operator that must install new equipment or modify its operation in a manner that requires a permit amendment in order to comply with the applicable NOx emissions limit in Section 9-9-301.2 shall (i) submit an application for Authority to Construct to install the new equipment or modify its operation within 18 months of the date of the initial notification from the APCO of the commercial availability, and (ii) comply with the more stringent emission standards associated with the commercially available technology within 36 months of the date of the initial notification, or 30 days after the end of the next scheduled major maintenance outage if no such outage is scheduled within 36 months of the date of the initial notification, but in no event more than 60 months after the date of initial notification.
- 404.4 If an affected operator can comply the applicable NOx emissions limit in Section 9-9-301.2 without having to install new equipment or modify its operation in a manner that requires a permit amendment, the operator shall (i) so inform the APCO in writing within 90 days of the date of the initial notification from the APCO of the commercial availability, and (ii) comply with the more stringent emission standards associated with the commercially available technology within 30 days thereafter.

(Adopted December 6, 2006)

9-9-405 Notification and Compliance Schedule, Very Limited Use Turbines: If a gas turbine exceeds 400 hours of operation in any 12-month period and is not compliant with the emission limits in Section 9-9-302.2, the operator must notify the APCO of that fact and must provide its best estimates for future operation of the turbine. Based on a review of these estimates, if the APCO determines that the turbine will likely continue to be operated at a rate exceeding 400 hours per 12-month period in the future, the APCO will provide written notice of that determination to the operator. If the APCO determines that the turbine will be operated at a rate exceeding 400 hours in the future, the turbine shall comply with the emission limits in Section 9-9-

302.2. If the operator will have to modify existing sources or install new control equipment to meet the emission limits in Section 9-9-302.2, the operator shall submit an application for Authority to Construct the modification or installation of new control equipment within 18 months of such notification, and shall comply with the emission limits in Section 9-9-302.2 within 36 months of such notification, or 30 days after the end of the next scheduled major maintenance outage if no such outage is scheduled within 36 months of the date of the initial notification, but in no event more than 60 months after the date of initial notification. The limited exemption in Section 9-9-115 shall cease to apply if the turbine violates this compliance schedule.

(Adopted December 6, 2006)

- 9-9-406 Other Useful Heat Recovery:** Any operator who wishes to get credit for other useful heat recovery for their gas turbines shall propose a calculation method to determine Po, as used in Section 9-9-605. This calculation method shall be subject to approval by the APCO.

(Adopted December 6, 2006)

9-9-500 MONITORING AND RECORDS

- 9-9-501 Monitoring and Recordkeeping Requirements:** A person who operates any stationary gas turbine with a heat input rating equal to or greater than 150 MMBtu/hr for more than 4000 hours in any 36-month period shall install, operate and maintain in calibration a continuous emissions monitor (CEM), or alternative monitoring system, capable of determining exhaust gas NO_x concentrations. A CEM must meet the requirements of the District Manual of Procedures, Volume V. Any operator choosing to demonstrate compliance with Section 9-9-301.2 or 9-9-302.2 using the output-based NO_x limits expressed in lbs/MW_{hr} must also monitor and record fuel consumption by the gas turbine and any supplemental duct burners, electrical and mechanical output from both combustion and steam turbines, any steam production flow rates and steam enthalpy. Any alternative monitoring system must be approved by the APCO. Such approval will only be granted upon a determination, pursuant to the criteria of 40 CFR Part 75, Subpart E, that the alternative monitoring system provides information with the same precision, reliability, accessibility, and timeliness as that provided by a CEM for the source.

(Amended 9/21/94; 12/6/06)

- 9-9-502 Records, Low Usage:** A person claiming to be exempt from Section 9-9-301 based on the number of hours of turbine operation, or seeking exemption per Sections 9-9-112 or 9-9-116 of this Rule, shall maintain a daily gas turbine operating record that includes the actual start-up and stop time, total hours of operation, and type (liquid or gas) and quantity of fuel used. This information shall be available to District staff upon request for at least two years from the date of entry.

(Amended December 6, 2006)

- 9-9-503 Initial Demonstration of Compliance:** A person who must modify existing sources or install new control equipment shall conduct a District approved source test to demonstrate compliance with 9-9-301.2 or 302.2, and submit the results to the District within two months of initial operation of the new or modified equipment.

(Amended 9/21/94; 12/6/06)

- 9-9-504 Annual Demonstration of Compliance:** The operator of any turbine subject to this Rule that operates more than 400 hours in any 12-month period and is not equipped with a Continuous Emissions Monitor shall conduct a District-approved source test of the turbine at least once per calendar year, and at intervals not to exceed 15 months between tests, and shall submit the test results to the District within two months of the test date. The operator of any turbine that operates 400 hours or less in any 12-month period shall conduct a District-approved source test of the turbine every two calendar years, at a rate not to exceed 25 months.

(Adopted December 6, 2006)

9-9-600 MANUAL OF PROCEDURES

- 9-9-601 Determination of Emissions:** Source tests for determining compliance with the NOx emissions standards of this rule as specified in Sections 9-9-301 and 302 shall be conducted as prescribed in the District Manual of Procedures, Volume IV, ST-13A.
- (Amended 9/21/94; 12/6/06)*
- 9-9-602 Determination of Stack Gas Oxygen:** Oxygen content of the exhaust gas shall be determined by using District Manual of Procedures, Volume IV, ST-14.
- 9-9-603 Continuous Emission Monitoring:** Continuous Emissions Monitoring (CEM) procedures shall be determined using District Manual of Procedures, Volume V. For purposes of determining compliance with the NOx emissions standards of this rule, NOx emissions shall be calculated as the three hour average NOx emissions corrected to 15 percent O₂ (dry basis). Results of source tests conducted as prescribed in the District Manual of Procedures shall be deemed to be representative of three-hour average NOx emissions.
- (Amended December 6, 2006)*
- 9-9-604 Determination of HHV and LHV:** The HHV and LHV shall be determined using 1) ASTM D240-87 or ASTM D2382-88 ASTM D4809 for liquid hydrocarbon fuel; or 2) ASTM 1826-88 or ASTM 1945-81 in conjunction with ASTM D3588-89 for gaseous fuels.
- (Amended December 6, 2006)*
- 9-9-605 Compliance With Output Based NOx Emissions Standards:** For purposes of complying with the emissions standards in Section 9-9-301.2 and 9-9-302.2, emission rates expressed in lbs/MW_{hr} shall be calculated in accordance with the following equations:

$$E = \frac{1.194 \times 10^{-7} * (NOx)_c * Q_{std}}{(Pe)_t + (Pe)_c + Ps + Po}$$

E = hourly NOx emission rate, in lb/MWh

(NOx)_c = Average NOx concentration, in ppmv adjusted to 15% O₂

Q_{std} = stack gas volumetric flow rate, in dry scf/hr

(Pe)_t = electrical or mechanical energy output of the combustion turbine in MW

(Pe)_c = Electrical or mechanical energy output of the steam turbine (if any) in MW

Ps = useful thermal energy of steam production

Po = other useful heat recovery.

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}}$$

Q = measured steam flowrate in lb/hr.

H = enthalpy of the steam at measured temperature and pressure in Btu/lb.

(Adopted December 6, 2006)

REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 10
NITROGEN OXIDES AND CARBON MONOXIDE FROM BOILERS, STEAM
GENERATORS AND PROCESS HEATERS IN PETROLEUM REFINERIES

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REGULATION 9
INORGANIC GASEOUS POLLUTANTS
RULE 10
NITROGEN OXIDES AND CARBON MONOXIDE FROM BOILERS, STEAM
GENERATORS AND PROCESS HEATERS IN PETROLEUM REFINERIES

(Adopted January 5, 1994)

9-10-100 GENERAL

9-10-101 Description: This rule limits the emissions of nitrogen oxides and carbon monoxide from boilers, steam generators, and process heaters, including CO boilers, in petroleum refineries.

(Amended December 15, 2010)

9-10-110 Exemptions: The requirements of this rule shall not apply to the following:

- 110.1 Boilers, steam generators and process heaters with a rated heat input less than 2 million BTU/hour, if fired exclusively with natural gas, liquefied petroleum gas, or any combination thereof.
- 110.2 Boilers, steam generators and process heaters with a rated heat input less than 1 million BTU/hour fired with any fuel.
- 110.3 Waste heat recovery boilers that are used to recover sensible heat from the exhaust of combustion turbines or reciprocating internal combustion engines.
- 110.4 Boilers, steam generators and process heaters processing hydrogen sulfide process flue gas in sulfur recovery plants and their tail-gas treating units, or sulfuric acid manufacturing plants.
- 110.5 Boilers, steam generators and process heaters fired on non-gaseous fuel when natural gas is unavailable for use.
- 110.6 Boilers, steam generators and process heaters, including CO boilers, that receive an Authority to Construct subject to BACT requirements for NOx on or after January 5, 1994.

(Amended December 15, 2010)

9-10-111 Limited Exemption, Small Units: The requirements of Sections 9-10-301, 303, 305 and 308 shall not apply to the use of any small units, provided the requirements of Section 9-10-306 are satisfied.

(Amended 7/17/02; 12/15/10; 10/16/13)

9-10-112 Limited Exemption, Low Fuel Usage: The requirements of Sections 9-10-301, 303, 305 and 308 shall not apply to the use of any boiler, steam generator or process heater that has an annual heat input less than 90,000 therms during each consecutive 12-month period or that accepts a condition in its Permit to Operate limiting the annual heat input to less than 90,000 therms, provided the requirements for small units in Section 9-10-306 are satisfied and a fuel-flow meter as described in Section 9-10-502.2 is maintained and operated.

(Amended 7/17/02; 12/15/10; 10/16/13)

9-10-113 Limited Exemption, Alternate NOx Compliance Plan: The requirements of Section 9-10-301 shall not apply to the use of any boiler, steam generator or process heater at a refinery subject to Section 9-10-308.

(Adopted October 16, 2013)

9-10-200 DEFINITIONS

9-10-201 Deleted December 15, 2010

9-10-202 Boiler or Steam Generator: Any combustion equipment used to produce steam or heat water.

9-10-203 British Thermal Unit (BTU): The amount of heat required to raise the temperature of one pound of water from 59° F to 60° F at one atmosphere.

9-10-204 CO Boiler: A CO boiler is any boiler or furnace that processes the off-gases from a catalytic cracking unit (CCU) regenerator or a coker burner. A partial-burn CO boiler

normally processes off-gases from a CCU regenerator that is operated in a partial-burn mode such that the off-gases normally have a CO concentration exceeding 2% by volume.

(Amended December 15, 2010)

- 9-10-205 Deleted December 15, 2010**
- 9-10-206 Heat-Input:** The heat of combustion released due to burning a fuel in a source, using higher heating value of the fuel. This does not include the sensible heat of incoming combustion air. In the case of carbon monoxide boilers, the heat input includes the sensible heat of regenerator off-gases and the heat of combustion of the incoming carbon monoxide and of the auxiliary fuel.
- 9-10-207 Higher Heating Value (HHV):** The total heat liberated per mass of fuel burned (BTU per pound) when fuel and dry air at standard conditions undergo complete combustion and all resultant products are brought to their standard states at standard conditions per Section 9-10-604.
- 9-10-208 Natural Gas:** Any mixture of gaseous hydrocarbons containing at least 80 percent methane by volume, as determined according to Standard Method ASTM D1945-64.
- 9-10-209 Nitrogen Oxides (NOx):** The sum of nitric oxide (NO) and nitrogen dioxide (NO₂) in the flue gas, collectively expressed as nitrogen dioxide.
- 9-10-210 Non-Gaseous Fuel:** Any fuel that is not a gas at 68° F and one atmosphere.
(Amended December 15, 2010)
- 9-10-211 Operating Day:** 24 hours from midnight to midnight.
- 9-10-212 Out of Service:** The period of time during which a unit is in an inactive state following shutdown.
- 9-10-213 Petroleum Refinery:** Any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.
- 9-10-214 Process Heater:** Any combustion equipment that transfers heat from combustion gases to water or process streams.
- 9-10-215 Rated Heat Input:** The heat input capacity specified on the nameplate of the combustion source. If the combustion source has been physically modified and/or operated in such a manner that its maximum heat input is different from the heat input capacity specified on the nameplate, then the modified maximum heat input per Section 9-10-503 shall be considered as the rated heat input.
- 9-10-216 Refinery-wide Emission Rate:** The ratio of the total mass of discharge into the atmosphere of nitrogen oxides, in pounds, to the sum of the actual heat input, in million BTU, calculated over a twenty-four (24) hour operating day.
(Amended December 15, 2010)
- 9-10-217 Small Unit:** Any refinery boiler, steam generator or process heater with a rated heat input less than 10 million BTU/hour.
(Amended December 15, 2010)
- 9-10-218 Startup or Shutdown:** Startup is that period of time, not to exceed twelve (12) hours unless specifically extended by a Permit to Operate, during which a unit is brought up to its normal operating temperature from a cold start, initially at zero fuel flow, by following a prescribed series of separate steps or operations. Shutdown is that period of time, not to exceed nine (9) hours unless specifically extended by a Permit to Operate, during which a unit is taken out of service from a normal operating mode to an inactive status following a prescribed series of separate steps or operations.
(Amended 12/15/10; 10/16/13)
- 9-10-219 Therm:** One hundred thousand (100,000) BTUs.
- 9-10-220 Deleted December 15, 2010**
- 9-10-221 Best Available Control Technology (BACT):** As defined in Regulation 2, Rule 2.
(Adopted December 15, 2010)
- 9-10-222 Curtailed Operation:** Operation of a boiler, steam generator or process heater at no more than 30% of its rated heat input.
(Adopted December 15, 2010)

9-10-300 STANDARDS

9-10-301 Refinery-wide NOx Emission Limit: A person shall not exceed a refinery-wide emission rate from boilers, steam generators and process heaters, excluding CO boilers, of 0.033 pounds NOx per million BTU of heat input, based on an operating day average. Boilers, steam generators and process heaters that are test-fired on non-gaseous fuel, that are undergoing startup or shutdown, that are temporarily out of service, or that are in curtailed operation shall be included in the refinery-wide emission rate as follows:

- 301.1 Deleted December 15, 2010
- 301.2 Deleted December 15, 2010
- 301.3 **Units Test-Fired On Non-Gaseous Fuel:** For the purposes of determining compliance with the emission limit of Section 9-10-301, the emission contribution of each boiler, steam generator or process heater that is fired on non-gaseous fuel for equipment testing shall be taken as the operating day average of NOx emissions at the average heat input over the previous thirty (30) day period. Equipment testing shall not exceed a total of forty-eight (48) hours during any calendar year for any one unit.
- 301.4 **Units in Start-up or Shutdown or in Curtailed Operation:** For the purposes of determining compliance with the emission limit of Section 9-10-301, the emission contribution of each boiler, steam generator or process heater that is undergoing startup or shutdown, or that is in Curtailed Operation shall be one of the following:
 - 4.1 The operating day average NOx emissions (either from a continuous emission monitoring system (CEMS) or from an equivalent parametric monitoring system developed in accordance with a Permit to Operate and Section 9-10-502.1), and the operating day heat input.
 - 4.2 The operating day average NOx emissions (either from a CEMS or from an equivalent parametric monitoring system developed in accordance with a Permit to Operate and Section 9-10-502.1), and the operating day heat input averaged over the previous thirty (30) day period or, subject to the approval of the APCO, an alternate 30-day period representative of normal operation.
- 301.5 **Units Temporarily Out of Service:** For the purposes of determining compliance with the emission limit of Section 9-10-301, the emission contribution of each boiler, steam generator or process heater that is temporarily out of service shall be the operating day average NOx emissions (either from a continuous emission monitoring system (CEMS) or from an equivalent parametric monitoring system developed in accordance with a Permit to Operate and Section 9-10-502.1), and the operating day heat input, averaged over the previous thirty (30) day period or, subject to the approval of the APCO, an alternate 30-day period representative of normal operation.

(Amended 12/15/10; 10/16/13)

9-10-302 Deleted July 17, 2002

9-10-303 Federal Refinery-wide and CO Boiler NOx Emission Limits: A person shall not exceed a refinery-wide emission rate from boilers, steam generators or process heaters, excluding CO boilers, of 0.20 pounds NOx per million BTU of heat input, based on an operating day average.

- 303.1 Except during startup and shutdown, a person shall not operate a CO boiler unless the emissions of nitrogen oxides (NOx) do not exceed 300 ppmv, dry at 3% oxygen, based on an operating day average.

(Amended 7/17/02; 12/15/10)

9-10-304 Interim NOx Emission Limit For CO Boilers: Until Section 9-10-307 is effective, and except during startup and shutdown, a person shall not operate a CO boiler unless at least one of the following is met:

- 304.1 Emissions of nitrogen oxides (NOx) do not exceed 150 ppmv, dry at 3% oxygen, based on an operating day average; or

304.2 Emissions of nitrogen oxides (NOx) are controlled by an emission control system with a NOx control efficiency of at least 50 percent by weight.

(Amended December 15, 2010)

9-10-305 CO Emission Limit: Except during start-up, shutdown or curtailed operation, a person shall not operate a boiler, steam generator or process heater, including CO boilers, unless carbon monoxide emissions of 400 ppmv, dry at 3% oxygen, based on an operating day average, are not exceeded.

(Amended December 15, 2010)

9-10-306 Small Unit Requirements: A person shall not operate a small unit unless at least one of the following is met:

306.1 Operate in a manner that maintains stack-gas oxygen concentrations at less than or equal to 3 percent by volume on a dry basis; or

306.2 Tune at least once every twelve (12) months, or within two weeks of unit startup if not operated in the last twelve (12) months, by a technician in accordance with the procedure specified in Section 9-10-605; or

306.3 Meet the applicable emission limits in Sections 9-10-301, 303 and 305.

(Amended December 15, 2010)

9-10-307 Final NOx Emission Limits For CO Boilers: Effective January 1, 2015, and except during start-up or shutdown, a person shall not operate a CO boiler unless it meets the applicable NOx emission limits in Sections 9-10-307.1 and 307.2.

307.1 A person shall not operate a non-partial-burn CO boiler, unless the following NOx limits are not exceeded:

Averaging Period	NOx (ppmv, dry at 3% O ₂)
1.1 Operating day	150
1.2 Calendar year (excluding periods when the CO boiler does not process CCU regenerator offgas)	45

307.2 A person shall not operate a partial-burn CO boiler, unless the following NOx limits are not exceeded:

Averaging Period	NOx (ppmv, dry at 3% O ₂)
2.1 Operating day	125
2.2 Calendar year	85

(Adopted 12/15/10; Amended 10/16/13)

9-10-308 Alternate NOx Compliance Plan: A person at a refinery with an Alternate NOx Compliance Plan that has been approved in accordance with Section 9-10-405, shall not exceed the refinery-wide daily NOx limit from boilers, steam generators and process heaters, excluding CO boilers, as specified in the Plan. The boilers, steam generators and process heaters that are covered by the Alternate NOx Compliance Plan shall be referred to as devices in this Section.

308.1 A daily NOx limit shall apply to all devices at a refinery with an approved Alternate NOx Compliance Plan. The limit shall be the sum of the baseline NOx daily emissions for each device, expressed in pounds of NOx. The baseline NOx daily emissions for each device shall be the average of the daily emissions on any ten (10) different days during the 3-year period immediately preceding the date of the application for an Alternate Compliance Plan, on which the refinery operator was in compliance with Section 9-10-301. The same 10 days shall be used for all devices at a refinery. The APCO may consider allowing 10 days within a different time period, if the APCO finds that a different period allows the selection of operating days that better represent maximum daily emission levels for these devices.

1.1 At any refinery that used Interchangeable Emission Reduction Credits (IERC) to comply with Section 9-10-301 on any of the 10 baseline days, the average difference between actual operating

emissions, in pounds NOx/day, and the emissions that would meet the 0.033 pounds NOx/million BTU NOx limit in Section 9-10-301 shall be calculated for the 10 days used to develop the daily NOx limit, and the daily NOx limit shall be reduced by this difference. NOx Emission Reduction Credits (ERC) generated in accordance with Regulation 2, Rule 2 may be surrendered on a one-time basis at a 1.15 to 1 ratio to make up all or part of the difference, and the daily NOx emissions limit will be adjusted accordingly.

- 1.2 At any refinery with an Authority to Construct application submitted before the date of approval of an Alternate Compliance Plan described in Section 9-10-405, if the actions permitted in the Authority to Construct would reduce the number of devices subject to Section 9-10-301 and require additional NOx emissions reductions to comply with Section 9-10-301, the daily NOx emissions limit shall be reduced by the amount of reductions required. NOx ERC generated in accordance with Regulation 2, Rule 2 may be surrendered on a one-time basis at a 1.15 to 1 ratio to offset all or part of the NOx emissions reductions required, and the daily NOx emissions limit will be adjusted accordingly.
- 308.2 A person operating under a daily NOx limit shall determine compliance with that limit on a daily basis.
- 308.3 For any device for which baseline NOx emissions have been permanently reduced, a permit application may be submitted to modify the baseline daily NOx emissions for that device.
- 308.4 The daily NOx limit shall be reduced when a device is no longer subject to this rule. The amount of reduction shall be equal to the baseline NOx daily emissions for that device.

(Adopted October 16, 2013)

9-10-400 ADMINISTRATIVE REQUIREMENTS

9-10-401 Deleted December 15, 2010

9-10-402 Deleted December 15, 2010

9-10-403 Deleted December 15, 2010

9-10-404 Final Control and Monitoring Plan: A person subject to Section 9-10-307 shall comply with the following increments of progress:

- 404.1 No later than twenty-four (24) months prior to the effective date of Section 9-10-307, submit to the APCO a control plan detailing the proposed measures, if any, to be taken in order to meet the requirements of Section 9-10-307, as well as proposed measures, if any, to be taken to continue to meet the requirements of Section 9-10-301.
- 404.2 No later than eighteen (18) months prior to the effective date of Section 9-10-307, submit applications for all Authorities to Construct required for compliance with Section 9-10-307.
- 404.3 No later than 30 days after the effective date of Section 9-10-307, perform testing for nitrogen oxide and carbon monoxide emissions at each CO boiler subject to Section 9-10-307 at the rated heat input or as near thereto as practicable. This requirement may be satisfied by monitoring nitrogen oxide and carbon monoxide emissions with a continuous emission monitoring system (CEMS).

(Adopted December 15, 2010)

9-10-405 Application for an Alternate NOx Compliance Plan: An application for an Alternate NOx Compliance Plan may be submitted by a person who operates a refinery where a boiler, steam generator or process heater is subject to Section 9-10-301. The Alternate NOx Compliance Plan shall apply to all boilers, steam generators and process heaters that are subject to the NOx limit in Section 9-10-301 at the time the Alternate NOx Compliance Plan is approved, and only to these boilers, steam generators and process heaters. The application shall be submitted and processed

in accordance with Regulation 2, Rule 1. The fees for the application shall be as specified in Regulation 3 for an alternate compliance plan. The application shall include the following information, which shall be included in the Permit to Operate for the boiler, steam generator or process heater:

- 405.1 The proposed effective date of the Alternate NOx Compliance Plan.
- 405.2 A list of the boilers, steam generators and process heaters that will be subject to a daily NOx limit, as specified in Section 9-10-308, and for each:
 - 2.1 The baseline NOx daily emissions determined in accordance with Section 9-10-308.1, including the data used to establish the baseline NOx daily emissions and the source(s) of the data. To the extent possible, the baseline NOx daily emissions shall be based on CEMS data.
 - 2.2 One or two substitute emission factors to be used in the absence of CEMS data and determined from representative source test data measured in accordance with District Manual of Procedures, Volume IV, ST-13A (nitrogen oxides) and ST-14 (oxygen), including the source test report.
 - 2.3 The amount of the required reductions to the daily NOx limit described in Sections 9-10-308.1.1 and 308.1.2 and any proposed mitigation to these reductions.
- 405.3 The amount of any ERC use allowed by Sections 9-10-308.1.1 and 308.1.2 shall be calculated as follows: (average difference between actual operating emissions, in pounds NOx/day, and the pounds NOx emissions/day that would meet the 0.033 pounds NOx/million BTU NOx limit in Section 9-10-301 for the 10 days used to develop the baseline NOx emissions)(365 days/year)(1.15) = NOx ERC surrendered. Any ERC use shall be surrendered before the application for the Alternate NOx Compliance Plan is considered complete. If an Authority to Construct that meets the conditions described in Section 9-10-308.1.2 is cancelled, any ERC surrendered shall be returned to the applicant.

(Adopted October 16, 2013)

9-10-406 Determination of Compliance: Compliance with the daily limit in Section 9-10-301 or 308 shall be determined by CEMS data and, for those boilers, steam generators and process heaters subject to parametric monitoring, the emission factor established according to Section 9-10-502.1.2 and the heat input rate as measured for each boiler, steam generator and process heater.

(Adopted October 16, 2013)

9-10-407 Boiler, Steam Generator and Process Heater Status Report: Any person who operates a boiler, steam generator or process heater that is subject to Section 9-10-301 or 308 shall, no later than April 16, 2014, submit information on the make, model and emission rates for all burners in each boiler, steam generator or process heater. Information shall be submitted in a format as specified by the APCO. The information shall be updated no later than 30 days after any non-identical burner change or replacement.

(Adopted October 16, 2013)

9-10-500 MONITORING AND RECORDS

9-10-501 Deleted December 15, 2010

9-10-502 Monitoring: A person subject to Sections 9-10-301, 303, 304, 305, 307 or 308 shall maintain in good working order, and operate the following equipment:

502.1 An in-stack nitrogen oxide (NOx), carbon monoxide (CO), and oxygen (O₂) continuous emission monitoring system (CEMS), or equivalent parametric monitoring system as specified in a Permit to Operate. The CEMS shall meet the requirements of the District Manual of Procedures, Volume V, Continuous Emission Monitoring, Policy and Procedures.

1.1 No later than April 16, 2014, a person who operates boilers, steam generators or process heaters that are subject to Section 9-10-301 or 308 shall submit a monitoring plan to the APCO for the installation

of NOx CEMS on these boilers, steam generators or process heaters such that no less than 95% of the NOx emissions, by weight, subject to either 9-10-301 or 308 is monitored with a NOx CEMS. The monitoring plan shall consider the actual NOx emission contribution from each boiler, steam generator or process heater subject to Section 9-10-301 or 308 during the most recent calendar year for which complete data are available at the time of the submittal of the monitoring plan. No later than October 16, 2014, the APCO shall approve each submitted monitoring plan, or else shall specify additional NOx CEMS that must be installed, and notify the affected refinery. The date of plan approval or notification shall serve as the "date of notification" specified in the District Manual of Procedures (MOP), Volume V, Continuous Emission Monitoring, Policy and Procedures. The installation of CEMS shall then be in accordance with the schedule and other provisions of MOP, Volume V, except that the completion of installation in Section 4.3 of Volume V shall be within 12 months of submittal of the Intent to Purchase.

1.2 Any person who operates a boiler, steam generator or process heater that uses a parametric monitoring system to monitor compliance with Section 9-10-301 or 308 shall estimate the NOx emission contribution of the boiler, steam generator or process heater based on one or two NOx emission factors (expressed as lb NOx / MM BTU) and on actual fuel input for all operating conditions, except as allowed by Section 9-10-301.3, 301.4 or 301.5. The emission factor shall be based on one or more District-approved source tests and included in a Permit to Operate. The operator shall conduct periodic monitoring of boilers, steam generators and process heaters that use a parametric monitoring system as follows:

2.1 Boilers, steam generators and process heaters rated less than 25 MM BTU/hr shall have one source test per consecutive 12 month period. The time interval between source tests shall not exceed 16 months. A boiler, steam generator or process heater that is out of service need not be placed into service for the purposes of conducting a source test. Notwithstanding the time limits specified above, a source test for a boiler, steam generator or process heater that is out of service may be delayed until it returns to service.

2.2 Boilers, steam generators and process heaters rated 25 MM BTU/hr or more shall have two source tests per consecutive 12 month period. The time interval between source tests shall be no less than 5 months and no more than 8 months. Notwithstanding the time limits specified above, a source test for a boiler, steam generator or process heater that is out of service may be delayed until it returns to service.

If a source test measures an emission factor higher than the emission factor in the Permit to Operate, then the higher emission factor shall become the new emission factor for determining compliance with Section 9-10-301 and 308. An operator may re-test at operating conditions substantially similar to those during the original test and appeal the change in emission factor to the APCO within 60 days. An operator may submit source test data with a permit application to establish a lower emission factor for a device that has been altered in a way that reduces the emission rate. The APCO may require that a source test be performed at a specific operating condition if the APCO determines that such a condition is a representative operating condition that has not been previously tested. Source test results shall be submitted to the APCO within 60 days of any test.

502.2 A fuel-flow meter in each fuel line for each boiler, steam generator and process heater, including each CO boiler.

(Amended 7/17/02; 12/15/10; 10/16/13)

9-10-503 Modified Maximum Heat Input: Any unit that has been physically modified such that its maximum heat input is different than the heat input specified on the nameplate shall demonstrate to the APCO the maximum heat input while operating the source at maximum capacity.

9-10-504 Records: The owner/operator of a source subject to this rule shall keep the following records, in a form suitable for inspection for a period of at least five (5) years. Such records shall be retained for a minimum of sixty (60) months from date of entry and made available to the APCO upon request. These records shall include, but are not limited to the following:

504.1 For all sources subject to the requirements of Sections 9-10-301, 303, 304, 305, 307, 308 or 404.3:

1.1 The continuous emission monitoring system (CEMS) measurements for NO_x and CO (ppmv corrected to 3% oxygen) and O₂ (percent by volume on a dry basis) or equivalent parametric monitoring system parameters; and hourly (lb/hour) and daily (lb/day) NO_x emissions for each source. Measurements shall be submitted in a digital format that can be readily imported into standard database tools as specified by the APCO. The APCO shall provide a reasonable amount of time to implement any required changes in data format.

1.2 The type, heat input (BTU/hr and BTU/day), and higher heating value of each fuel burned, and the injection rate for any reactant chemicals used by the emission control system(s) on a daily basis.

1.3 The date, time, and duration of any startup, shutdown or malfunction in the operation of any unit, emission control equipment or emission monitoring equipment.

1.4 The results of performance testing, evaluations, calibrations, checks, adjustments, and maintenance of any CEMS required by this rule.

1.5 A list of all sources subject to the NO_x refinery-wide emission rate limits in Sections 9-10-301 and 303.

1.6 Total NO_x emissions and total heat input for all sources listed in Section 9-10-504.1.5, on a daily basis.

1.7 The date, time and duration of all start-up and shutdown periods.

1.8 The results of source tests required by Section 9-10-404.3.

504.2 For all sources subject to Section 9-10-306.2, records of annual tune-ups.

(Amended 7/17/02; 12/15/10; 10/16/13)

9-10-505 Reporting Requirements: A person subject to the requirements of Sections 9-10-301, 303, 304, 305, 306, 307 or 308 shall meet the following reporting requirements:

505.1 Report to the APCO any violation of Section 9-10-301, 303, 304, 305, 306, 307 or 308 in accordance with the requirements of Regulation 1-522 for continuous emission monitoring systems (CEMS) and Regulation 1-523 for parametric monitoring systems.

505.2 Submit a written report for each calendar quarter to the APCO. The report shall be due on the 30th day following the end of the calendar quarter and shall include:

2.1 A summary of the data obtained from the CEMS or equivalent parametric monitoring system and the fuel meters installed pursuant to Section 9-10-502; and

2.2 The date, time, duration, and magnitude of emissions in excess of the appropriate standards; the nature and cause of the excess (if known); the corrective actions taken; and the preventive measure adopted.

505.3 A person subject to the requirements of Section 9-10-308 shall submit to the APCO a permit application to amend the Alternate NO_x Compliance Plan whenever Section 9-10-308.4 is triggered. The application shall be submitted within 30 days of the event that triggers Section 9-10-308.4.

(Amended 7/17/02; 12/15/10; 10/16/13)

9-10-600 MANUAL OF PROCEDURES

- 9-10-601 Determination of Nitrogen Oxides:** Compliance with the nitrogen oxide emission requirements of Sections 9-10-301, 303, 304, 307 and 308 shall be determined by a continuous emission monitoring system (CEMS) that meets the requirements of Regulation 1-522, or by an equivalent parametric monitoring system that is authorized in a Permit to Operate and that meets the requirements of Regulation 1-523. CEMS operation and compliance with Section 9-10-404.3 shall be verified by source test as set forth in the District Manual of Procedures, Volume IV, ST-13A (nitrogen oxides) and ST-14 (oxygen).
- 9-10-602 Determination of Carbon Monoxide and Stack-Gas Oxygen:** *(Amended 7/17/02; 12/15/10; 10/16/13)* Compliance with the carbon monoxide emission requirements of Section 9-10-305 shall be determined by a continuous emission monitoring system (CEMS) that meets the requirements of Regulation 1-522, or by an equivalent parametric monitoring system that is authorized in a Permit to Operate and that meets the requirements of Regulation 1-523. CEMS operation and compliance with Section 9-10-404.3 shall be verified by source test as set forth in the District Manual of Procedures, Volume IV, ST-6 (carbon monoxide) and ST-14 (oxygen).
- 9-10-603 Compliance Determination:** *(Amended 12/15/10; 10/16/13)* All emission determinations shall be made in the as-found operating condition, except during periods of start-up or shutdown.
- 9-10-604 Determination of Higher Heating Value:** *(Amended December 15, 2010)* If certification of the higher heating value is not provided by the third-party fuel supplier, it shall be determined by one of the following test methods: (1) ASTM D2015-85 for solid fuels; (2) ASTM D240-87 or ASTM D2382-88 for liquid hydrocarbon fuels; or (3) ASTM D1826-88 or ASTM D1945-81 in conjunction with ASTM D3588-89 for gaseous fuels.
- 9-10-605 Tune-Up Procedures:** The tuning procedure required by Section 9-10-306.2 shall be performed in accordance with the procedure set forth in the District Manual of Procedures, Volume I, Chapter 5.

**REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 11
FLARE MONITORING AT PETROLEUM REFINERIES**

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**REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 11
FLARE MONITORING AT PETROLEUM REFINERIES**

(Adopted June 4, 2003)

12-11-100 GENERAL

- 12-11-101 Description:** The purpose of this rule is to require monitoring and recording of emission data for flares at petroleum refineries.
- 12-11-110 Exemption, Organic Liquid Storage and Distribution:** The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from organic liquid storage vessels subject to Regulation 8, Rule 5 or exclusively from loading racks subject to Regulation 8 Rules 6, 33, or 39.
- 12-11-111 Exemption, Marine Vessel Loading Terminals:** The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from marine vessel loading terminals subject to Regulation 8, Rule 44.
- 12-11-112 Exemption, Wastewater Treatment Systems:** The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from wastewater treatment systems subject to Regulation 8, Rule 8.
- 12-11-113 Exemption, Pumps:** The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from pump seals subject to Regulation 8, Rule 18. This exemption does not apply when emissions from a pump are routed to a flare header.
- 12-11-114 Limited Exemption, Total Hydrocarbon and Methane Composition Monitoring and Reporting:** The provisions of Sections 12-11-401.2, 401.3, 401.5, 502.2 and 502.3 that require monitoring and reporting of total hydrocarbon and methane composition shall not apply to a flare that exclusively burns flexicoker gas with or without supplemental natural gas, provided that the owner or operator demonstrates by weekly sampling and analysis, verified by the APCO, that the methane content and the non-methane content of the vent gas flared are less than 2 percent and 1 percent by volume, respectively.

12-11-200 DEFINITIONS

- 12-11-201 Flare:** A combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. Flares may be either continuous or intermittent and are not equipped with devices for fuel-air mix control or for temperature control. This term includes both ground and elevated flares.
- 12-11-202 Flare Monitoring System:** All sample systems, transducers, transmitters, data acquisition equipment, data recording equipment, video monitoring equipment, and video recording equipment involved in flare monitoring.
- 12-11-203 Flaring:** A high-temperature combustion process used to burn vent gases.
- 12-11-204 Gas:** The state of matter that has neither independent shape nor volume, but tends to expand indefinitely. For the purposes of this rule, "gas" includes aerosols and the terms "gas" and "gases" are interchangeable.
- 12-11-205 Petroleum Refinery:** A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411, and including any associated sulfur recovery plant.
- 12-11-206 Pilot Gas:** The gas used to maintain the presence of a flame for ignition of vent gases.
- 12-11-207 Purge Gas:** The gas used to prevent air backflow in the flare system when there is no vent gas.

- 12-11-208 Sulfur Recovery Plant:** A process unit that processes sulfur and ammonia containing material and produces a final product of elemental sulfur.
- 12-11-209 Thermal Oxidizer:** An enclosed or partially enclosed combustion device that is used to oxidize combustible gases, that generally comes equipped with controls for combustion chamber temperature and often with controls for air/fuel mixture, and that exhausts all combustion products through a vent, duct, or stack so that emissions can be measured directly.
- 12-11-210 Vent Gas:** Any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

12-11-400 ADMINISTRATIVE REQUIREMENTS

- 12-11-401 Flare Data Reporting Requirements:** The owner or operator of a flare shall submit a monthly report to the APCO on or before 30 days after the end of each month for each flare subject to this rule. Only one report is required for a staged or cascading flare system if all flares in the system serve the same header or headers. The report shall be in an electronic format approved by the APCO. Each monthly report shall include all of the following:
- 401.1 The total volumetric flow of vent gas in standard cubic feet for each day and for the month, and, effective for the first full month after the commencement of the monitoring required by Section 12-11-501, for each hour of the month.
 - 401.2 If vent gas composition is monitored using sampling or integrated sampling, total hydrocarbon content as propane by volume, methane content by volume, and, hydrogen sulfide content by volume, for each sample or integrated sample required by Section 12-11-502. If the content of any additional compound or compounds is determined by the analysis of a sample or integrated sample, the content by volume of each additional compound.
 - 401.3 If vent gas composition is monitored by a continuous analyzer or analyzers pursuant to Section 12-11-502, average total hydrocarbon content as propane by volume, average methane content by volume, and, depending upon the analytical method used pursuant to Section 12-11-601, total reduced sulfur content by volume or hydrogen sulfide content by volume of vent gas flared for each hour of the month. If the content of any additional compound or compounds is determined by the continuous analyzer or analyzers, the average content by volume for each additional compound for each hour of the month.
 - 401.4 If the flow monitor installed pursuant to Section 12-11-501 measures molecular weight, the average molecular weight for each hour of the month.
 - 401.5 For any pilot and purge gas used, the type of gas used, the volumetric flow for each day and for the month, and the means used to determine flow.
 - 401.6 For any 24-hour period during which more than 1 million standard cubic feet of vent gas was flared, a description of the flaring including the cause, time of occurrence and duration, the source or equipment from which the vent gas originated, and any measures taken to reduce or eliminate flaring.
 - 401.7 Flare monitoring system downtime periods, including dates and times.
 - 401.8 The archive of images recorded for the month pursuant to Section 12-11-507.
 - 401.9 For each day and for the month provide calculated methane, non-methane and sulfur dioxide emissions. For the purposes of emission calculations only, a flare control efficiency of 98 percent shall be used for hydrocarbon flares, and a flare control efficiency of 93 percent shall be used for flexi-gas flares or if, based on the composition analysis specified in Section 12-11-502, the calculated lower heating value of the vent gas is less than 300 British Thermal Units/Standard Cubic Foot (BTU/SCF).

12-11-402 Flow Verification Report: Effective twelve months after adoption of this rule and every six months thereafter, the owner or operator of a flare shall submit a flow verification report to the APCO for each flare subject to the rule. The flow verification report shall be included in the corresponding monthly report required by Section 12-11-401. Only one report is required for a staged or cascading flare system if all flares in the system serve the same header or headers. The report shall compare flow as measured by the flow monitoring equipment required by Section 12-11-501 and a flow verification pursuant to Section 12-11-602 for the same period or periods of time. The owner or operator shall demonstrate that the flow verification was performed using good engineering practices. If there are no flaring events as described in Section 12-11-401.6 during the preceding six-month period, a flow verification report is not required for that period.

12-11-500 MONITORING AND RECORDS

12-11-501 Vent Gas Flow Monitoring: Effective 180 days after adoption of this rule, the owner or operator of a petroleum refinery shall not operate a flare unless vent gas to the flare is continuously monitored for volumetric flow by a device that meets the following requirements:

- 501.1 The minimum detectible velocity shall be 0.1 foot per second.
- 501.2 The device shall continuously measure the range of flow rates corresponding to velocities from 0.5 to 275 feet per second in the header in which the device is installed.
- 501.3 The device shall have a manufacturer's specified accuracy of $\pm 5\%$ over the range of 1 to 275 feet per second.
- 501.4 The device shall be installed at a location where measured volumetric flow is representative of flow to the flare or to the flare system in the case of a staged or cascading flare system consisting of more than one flare.
- 501.5 Effective 180 days after adoption of this rule, the owner or operator shall provide access for the APCO to verify proper installation and operation of the flare monitoring system.
- 501.6 Effective 18 months after adoption of this rule, the flow monitoring system shall be maintained to be accurate to within $\pm 20\%$ as demonstrated by the flow verification report specified in Section 12-11-402.

12-11-502 Vent Gas Composition Monitoring: The owner or operator of a petroleum refinery shall not operate a flare unless the following requirements are met:

- 502.1 Requirements applicable to all vent gas composition monitoring:
 - 1.1 Vent gas monitored for composition, whether by sampling, integrated sampling or continuous monitoring, shall be taken from a location at which samples are representative of vent gas composition. If flares share a common header, a sample from the header will be deemed representative of vent gas composition for all flares served by the header.
 - 1.2 Effective 90 days after the adoption of this rule, the monitoring system shall provide access for the APCO to collect vent gas samples to verify the analyses required by Section 12-11-502.
- 502.2 Effective 90 days after adoption of this rule and until the requirements of Section 12-11-502.3 are met, the owner or operator shall monitor vent gas composition through sampling that meets the following requirements:
 - 2.1 For each day on which flaring occurs, one sample shall be taken within 30 minutes of the commencement of flaring.
 - 2.2 Samples may be taken from the flare header or from an alternate location at which samples are representative of vent gas composition.
 - 2.3 Samples shall be analyzed pursuant to Section 12-11-601.
- 502.3 Effective 270 days after adoption of this rule, the owner or operator shall monitor vent gas composition using one of the following four methods:

- 3.1 Sampling that meets the following requirements:
 - a. If the flow rate of vent gas flared in any consecutive 15-minute period continuously exceeds 330 standard cubic feet per minute (SCFM), a sample shall be taken within 15 minutes, except that, for flares exclusively serving sulfur or ammonia plants, a sample shall be taken within 1 hour or composition data representing worst-case conditions shall be provided by the owner or operator and verified by the APCO. The sampling frequency thereafter shall be one sample every three hours and shall continue until the flow rate of vent gas flared in any consecutive 15-minute period is continuously 330 SCFM or less. In no case shall a sample be required more frequently than once every 3 hours.
 - b. Samples shall be analyzed pursuant to Section 12-11-601.
- 3.2 Integrated sampling that meets the following requirements:
 - a. If the flow rate of vent gas flared in any consecutive 15 minute period continuously exceeds 330 standard cubic feet per minute (SCFM), integrated sampling shall begin within 15 minutes and shall continue until the flow rate of vent gas flared in any consecutive 15 minute period is continuously 330 SCFM or less.
 - b. Integrated sampling shall consist of a minimum of one aliquot for each 15-minute period until the sample container is full. If sampling is still required pursuant to Section 12-11-502.3.2a, a new sample container shall be placed in service within one hour after the previous container was filled. A sample container shall not be used for a sampling period that exceeds 24 hours.
 - c. Samples shall be analyzed pursuant to Section 12-11-601.
- 3.3 Continuous analyzers that meet the following requirements:
 - a. The analyzers shall continuously monitor for total hydrocarbon, methane, and, depending upon the analytical method used pursuant to Section 12-11-601, hydrogen sulfide or total reduced sulfur.
 - b. The hydrocarbon analyzer shall have a full-scale range of 100% total hydrocarbon.
 - c. Each analyzer shall be maintained to be accurate to within 20% when compared to any field accuracy tests or to within 5% of full scale.
- 3.4 A continuous analyzer employing gas chromatography that meets the following requirements:
 - a. The gas chromatography system shall monitor for total hydrocarbon, methane, and hydrogen sulfide.
 - b. The gas chromatography system shall be maintained to be accurate to within 5% of full scale.

12-11-503 Pilot Monitoring: Any flare subject to this rule must be equipped and operated with an automatic igniter or a continuous burning pilot, which must be maintained in good working order. If a pilot flame is employed, the flame shall be monitored with a device to detect the presence of the pilot flame. If an electric arc ignition system is employed, the system shall pulse on detection of loss of pilot flame and until the pilot flame is reestablished.

12-11-504 Pilot and Purge Gas Monitoring: The owner or operator of a petroleum refinery shall not operate a flare unless (1) volumetric flows of purge and pilot gases are monitored by flow measuring devices, or (2) other parameters are monitored so that volumetric flows of pilot and purge gas may be calculated based on pilot design and the parameters monitored.

12-11-505 Recordkeeping Requirements: Except as provided in Section 12-11-507, the owner or operator of a flare shall maintain records for all the information required to

be monitored for a period of five years and make such records available to the APCO upon request.

12-11-506 General Monitoring Requirements: Persons responsible for monitoring subject to this rule shall comply with the following:

506.1 Periods of flare monitoring system inoperation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Adequate proof of expeditious repair shall be furnished to the APCO for downtime in excess of fifteen consecutive days. Periods of inoperation of the vent gas flow monitoring required by Section 12-11-501 shall not exceed 30 days per calendar year. Periods of inoperation of vent gas composition monitoring specified in Sections 12-11-502.3.2 (integrated sampling) and 12-11-502.3.4 (gas chromatography) shall not exceed 30 days per calendar year. Effective 450 days after the adoption of this rule, periods of inoperation of the vent gas composition monitoring specified in Section 12-11-502.3.3 (continuous analyzers) shall not exceed 30 days per calendar year per analyzer. Periods of inoperation of video monitoring specified in Section 12-11-507 shall not exceed 30 days per calendar year.

506.2 During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 12-11-502, persons responsible for monitoring shall take samples as required by Section 12-11-502.2.1. During periods of inoperation of flow monitors required by Section 12-11-501, flow shall be calculated using good engineering practices.

506.3 The person(s) responsible for monitors subject to this rule shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure.

506.4 Data Recording System: All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages.

12-11-507 Video Monitoring: For each flare equipped with video monitoring capability as of January 1, 2003, the owner or operator of a flare subject to this rule shall, effective 180 days after adoption of this rule, install and maintain equipment that records a real-time digital image of the flare and flame at a frame rate of no less than 1 frame per minute. The recorded image of the flare shall be of sufficient size, contrast, and resolution to be readily apparent in the overall image or frame. The image shall include an embedded date and time stamp. The equipment shall archive the images for each 24-hour period. Effective 180 days after adoption of this rule, for any flare for which the report required by Section 12-11-401 shows that more than 1 million standard cubic feet of vent gas was flared in any 24-hour period, the owner or operator of the flare shall, within 90 days after the end of the month covered by the report, meet the same requirements as those imposed by this Section for flares with existing video monitoring capability.

12-11-600 MANUAL OF PROCEDURES

12-11-601 Testing, Sampling, and Analytical Methods:

601.1 Samples and integrated samples shall be analyzed using the following test methods, or latest revision, where applicable:

- 1.1 Total hydrocarbon content and methane content of vent gas shall be determined using ASTM Method D1945-96, ASTM Method UOP 539-97, or EPA Method 18.
 - 1.2 Hydrogen sulfide content of vent gas shall be determined using ASTM Method D1945-96 or ASTM Method UOP 539-97.
 - 1.3 Any alternative method to the above methods if approved by the APCO and EPA.
- 601.2 Except as provided in Section 12-11-601.3, if vent gas composition is monitored using continuous analyzers, the analyzers shall employ the following methods, or latest revision, where applicable:
- 2.1 Total hydrocarbon content and methane content of vent gas shall be determined using EPA Method 25A or 25B.
 - 2.2 Total reduced sulfur content of vent gas shall be determined using ASTM Method D4468-85.
 - 2.3 Hydrogen sulfide content shall be determined using ASTM Method D4084-94.
 - 2.4 Any alternative method to the above methods if approved by the APCO and EPA.
- 601.3 If vent gas composition is monitored with a continuous analyzer employing gas chromatography, the following requirements shall be met:
- 3.1 ASTM Method D1945-96 or latest revision, or ASTM Method UOP 539-97 or latest revision shall be used.
 - 3.2 The system shall analyze samples for total hydrocarbon content, methane content, and hydrogen sulfide content.
 - 3.3 The minimum sampling frequency shall be one sample every 30 minutes.
 - 3.4 Any alternative method to the above methods if approved by the APCO and EPA.

12-11-602 Flow Verification Test Methods: For purposes of the semi-annual verification required by Section 12-11-402, vent gas flow shall be determined using one or more of the following methods:

- 602.1 District Manual of Procedures, Volume IV, ST-17 and ST-18;
- 602.2 EPA Methods 1 and 2;
- 602.3 Other flow monitoring devices or process monitors.
- 602.4 Any verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 12-11-501.
- 602.5 Tracer gas dilution or velocity.
- 602.6 Any alternative method approved by the APCO and EPA.

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REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 12
FLARES AT PETROLEUM REFINERIES

(Adopted July 20, 2005)

12-12-100 GENERAL

- 12-12-101 Description:** The purpose of this rule is to reduce emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. Nothing in this rule should be construed to compromise refinery operations and practices with regard to safety.
- 12-12-110 Exemption, Organic Liquid Storage and Distribution:** The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from organic liquid storage vessels subject to Regulation 8, Rule 5 or exclusively from loading racks subject to Regulation 8 Rules 6, 33, or 39.
- 12-12-111 Exemption, Marine Vessel Loading Terminals:** The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from marine vessel loading terminals subject to Regulation 8, Rule 44.
- 12-12-112 Exemption, Wastewater Treatment Systems:** The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from wastewater treatment systems subject to Regulation 8, Rule 8.
- 12-12-113 Exemption, Pumps:** The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from pump seals subject to Regulation 8, Rule 18. This exemption does not apply when emissions from a pump are routed to a flare header.
- 12-12-200 DEFINITIONS:** For the purposes of this rule, the following definitions apply:
- 12-12-201 Emergency:** A condition at a petroleum refinery beyond the reasonable control of the owner or operator requiring immediate corrective action to restore normal and safe operation that is caused by a sudden, infrequent and not reasonably preventable equipment failure, natural disaster, act of war or terrorism or external power curtailment, excluding power curtailment due to an interruptible power service agreement from a utility.
- 12-12-202 Feasible:** Capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social and technological factors.
- 12-12-203 Flare:** A combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. This term includes both ground-level and elevated flares. When used as a verb, the term "flare" means the combustion of vent gas in a flare.
- 12-12-204 Flare Minimization Plan (FMP):** A document intended to meet the requirements of Section 12-12-401.
- 12-12-205 Gas:** The state of matter that has neither independent shape nor volume, but tends to expand indefinitely. Gas includes aerosols and the terms "gas" and "gases" are interchangeable.
- 12-12-206 Petroleum Refinery:** A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411 and including any associated sulfur recovery plant.
- 12-12-207 Prevention Measure:** A component, system, procedure or program that will minimize or eliminate flaring.
- 12-12-208 Reportable Flaring Event:** Any flaring where more than 500,000 standard cubic feet per calendar day of vent gas is flared or where sulfur dioxide (SO₂) emissions are greater than 500 pounds per day. For flares that are operated as a backup,

staged or cascade system, the volume is determined on a cumulative basis; the total volume equals the total of vent gas flared at each flare in the system. For flaring lasting more than one calendar day, each day of flaring constitutes a separate flaring event unless the owner or operator demonstrates to the satisfaction of the APCO that the cause of flaring is the same for two or more consecutive days. A reportable flaring event ends when it can be demonstrated by monitoring required in Section 12-12-501 that the integrity of the water seal has been maintained sufficiently to prevent vent gas to the flare tip. For flares without water seals or water seal monitors as required by Section 12-12-501, a reportable flaring event ends when the rate of flow of vent gas falls below 0.5 feet per second.

(Amended April 5, 2006)

- 12-12-209 Responsible Manager:** An employee of the facility or corporation who possesses sufficient authority to take the actions required for compliance with this rule.
- 12-12-210 Shutdown:** The intentional cessation of a petroleum refining process unit or a unit operation within a petroleum refining process unit due to lack of feedstock or the need to conduct periodic maintenance, replacement of equipment, repair or other operational requirements. A process unit includes subsets and components of the unit operation. Subsets and components includes but are not limited to reactors, heaters, vessels, columns, towers, pumps, compressors, exchangers, accumulators, valves, flanges, sample stations, pipelines or sections of pipelines.
- 12-12-211 Startup:** The setting into operation of a petroleum refining process unit for purposes of production. A process unit includes subsets and components of the unit operation. Subsets and components includes but are not limited to reactors, heaters, vessels, columns, towers, pumps, compressors, exchangers, accumulators, valves, flanges, sample stations, pipelines or sections of pipelines.
- 12-12-212 Thermal Oxidizer:** An enclosed or partially enclosed combustion device, other than a flare, that is used to oxidize combustible gases.
- 12-12-213 Vent Gas:** Any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

12-12-300 STANDARDS

- 12-12-301 Flare Minimization:** Effective November 1, 2006, flaring is prohibited unless it is consistent with an approved FMP and all commitments due under that plan have been met. This standard shall not apply if the APCO determines, based on an analysis conducted in accordance with Section 12-12-406, that the flaring is caused by an emergency and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere.

12-12-400 ADMINISTRATIVE REQUIREMENTS

- 12-12-401 Flare Minimization Plan Requirements:** The owner or operator of a petroleum refinery with one or more flares subject to this rule shall submit to the APCO a FMP in accordance with the schedule in Section 12-12-402. The FMP shall be certified and signed by a Responsible Manager and shall include, but not be limited to:

401.1 Technical Data: A description and technical information for each flare that is capable of receiving gases and the upstream equipment and processes that send gas to the flare including:

- 1.1 A detailed process flow diagram accurately depicting all pipelines, process units, flare gas recovery systems, water seals, surge drums and knock-out pots, compressors and other equipment that vent to each flare. At a minimum, this shall include full and accurate as-built dimensions and design capacities of the flare gas recovery systems, compressors, water seals, surge drums and knockout pots.
- 1.2 Full and accurate descriptions including locations of all associated monitoring and control equipment.

- 401.2 **Reductions Previously Realized:** A description of the equipment, processes and procedures installed or implemented within the last five years to reduce flaring. The description shall specify the year of installation.
- 401.3 **Planned Reductions:** A description of any equipment, processes or procedures the owner or operator plans to install or implement to eliminate or reduce flaring. The description shall specify the scheduled year of installation or implementation.
- 401.4 **Prevention Measures:** A description and evaluation of prevention measures, including a schedule for the expeditious implementation of all feasible prevention measures, to address the following:
 - 4.1 Flaring that has occurred or may reasonably be expected to occur during planned major maintenance activities, including startup and shutdown. The evaluation shall include a review of flaring that has occurred during these activities in the past five years, and shall consider the feasibility of performing these activities without flaring.
 - 4.2 Flaring that may reasonably be expected to occur due to issues of gas quantity and quality. The evaluation shall include an audit of the vent gas recovery capacity of each flare system, the storage capacity available for excess vent gases, and the scrubbing capacity available for vent gases including any limitations associated with scrubbing vent gases for use as a fuel; and shall consider the feasibility of reducing flaring through the recovery, treatment and use of the gas or other means.
 - 4.3 Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation shall consider the adequacy of existing maintenance schedules and protocols for such equipment. For purposes of this Section, a failure is recurrent if it occurs more than twice during any five year period as a result of the same cause as identified in accordance with Section 12-12-406.
- 401.5 Any other information requested by the APCO as necessary to enable determination of compliance with applicable provisions of this rule.

Failure to implement and maintain any equipment, processes, procedures or prevention measures in the FMP is a violation of this section.

12-12-402 Submission of Flare Minimization Plans: On or before August 1, 2006, the owner or operator of a petroleum refinery with one or more flares subject to this rule shall submit a FMP as required by Section 12-12-401. On or before November 1, 2005 and every three months thereafter until a complete FMP is submitted, the owner or operator shall provide a status report detailing progress towards fulfilling the requirements of Section 12-12-401. Upon the submission of each status report, the APCO may require a consultation regarding the development of the plan to ensure that the plan meets the requirements of Section 12-12-401.

12-12-403 Review and Approval of Flare Minimization Plans: The procedure for determining whether the FMP meets the applicable requirements of this regulation is as follows:

- 403.1 **Completeness Determination:** Within 45 days of receipt of the FMP, the APCO will deem the plan complete if he determines that it includes the information required by Section 12-12-401. If the APCO determines that the proposed FMP is not complete, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination and the required corrective action.
- 403.2 **Corrective Action:** Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the proposed FMP within 45 days. If the APCO determines that the owner or operator failed to correct any deficiency identified in the notification, the APCO will disapprove the FMP.
- 403.3 **Public Comment:** The complete FMP (with exception of confidential information) will be made available to the public for 60 days. The APCO will

consider any written comments received during this period prior to approving or disapproving the FMP.

403.4 Final Action: Within 45 days of the close of the public comment period, the APCO will approve the FMP if he determines that the plan meets the requirements of Section 12-12-401, and shall provide written notification to the owner or operator. This period may be extended if necessary to comply with state law. If the APCO determines that the FMP does not meet the requirements of Section 12-12-401, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination. Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the FMP within 45 days. If the APCO determines that the owner or operator failed to correct any deficiency identified in the notification, the APCO will disapprove the FMP.

If the owner or operator submitted a complete FMP in accordance with Section 12-12-402, and the APCO has not disapproved the FMP under this section, the FMP shall be considered an approved FMP for the purposes of Section 12-12-301 until the APCO takes final action under Section 12-12-403.4.

12-12-404 Update of Flare Minimization Plans: The FMP shall be updated as follows:

404.1 No more than 12 months following approval of the original FMP and annually thereafter, the owner or operator of a flare subject to this rule shall review the FMP and revise the plan to incorporate any new prevention measures identified as a result of the analyses prescribed in Sections 12-12-401.4 and 12-12-406. The updates must be approved and signed by a Responsible Manager.

404.2 Prior to installing or modifying any equipment described in Section 12-12-401.1.1 that requires a District permit to operate, the owner or operator shall obtain an approved updated FMP addressing the new or modified equipment.

404.3 Annual FMP updates (with exception of confidential information) shall be made available to the public for 30 days. The APCO shall consider any written comments received during this period prior to approving or disapproving the update.

404.4 Within 45 days of the close of the public comment period, the APCO shall approve the FMP update if he determines that the update meets the requirements of Section 12-12-401, and shall provide written notification to the owner or operator. The previously approved FMP together with the approved update constitutes the approved plan for purposes of Section 12-12-301. This period may be extended if necessary to comply with state law. If the APCO determines that the FMP update does not meet the requirements of Section 12-12-401, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination and the required corrective action. Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the FMP update within 30 days. If the APCO determines that the owner or operator failed to correct the deficiencies identified in the notification, the APCO will disapprove the FMP update. For purposes of Section 12-12-301, disapproval of the update constitutes disapproval of the existing FMP, unless otherwise specified by the APCO.

404.5 If the owner or operator fails to submit a plan update as required by this Section, the APCO shall provide written notification of the lapse. If the owner or operator fails to submit an update within 30 days of receipt of the notification, the existing FMP shall no longer be considered an approved plan for purposes of Section 12-12-301.

(Amended April 5, 2006)

12-12-405 Notification of Flaring: Effective August 20, 2005, the owner or operator of a flare subject to this rule shall notify the APCO as soon as possible, consistent with safe operation of the refinery, if the volume of vent gas flared exceeds 500,000 standard

cubic feet per calendar day. The notification, either by phone, fax or electronically, shall be in a format specified by the APCO and include the flare source name and number, the start date and time, and the end date and time.

12-12-406 Determination and Reporting of Cause: The owner or operator of a flare subject to this rule shall submit a report to the APCO within 60 days following the end of the month in which a reportable flaring event occurs. The report shall include, but is not limited to, the following:

- 406.1** The results of an investigation to determine the primary cause and contributing factors for the flaring event.
- 406.2** Any prevention measures that were considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented.
- 406.3** If appropriate, an explanation of why the flaring is consistent with an approved FMP.
- 406.4** Where applicable, an explanation of why the flaring was an emergency and necessary to prevent an accident, hazard or release of vent gas to the atmosphere or where, due to a regulatory mandate to vent to a flare, it cannot be recovered, treated and used as fuel gas at the refinery.
- 406.5** The volume of vent gas flared, the calculated methane, non-methane hydrocarbon and sulfur dioxide emissions associated with the reportable flaring event.

(Amended April 5, 2006)

12-12-407 Deleted April 5, 2006

12-12-408 Designation of Confidential Information: When submitting the initial FMP, any updated FMP or any other report required by this Rule, the owner or operator shall designate as confidential any information claimed to be exempt from public disclosure under the California Public Records Act, Government Code section 6250 et seq. If a document is submitted that contains information designated confidential in accordance with this Section, the owner or operator shall provide a justification for this designation and shall submit a separate copy of the document with the information designated confidential redacted.

12-12-500 MONITORING AND RECORDS

12-12-501 Water Seal Integrity Monitoring: Effective August 1, 2006, the owner or operator of a flare subject to this rule with a water seal shall continuously monitor and record the water level and pressure of the water seal that services each flare. Any new installation of a water seal shall be subject to this requirement immediately. Records of these measurements shall be retained for one year. Monitoring devices required pursuant to this section shall be subject to the reporting and record keeping requirements of Regulation 1, Section 523: Parametric Monitors.