

Organic Liquid Storage Tanks – Rule Development Project Scope

Summary

This rule development project will address reactive organic gasses (ROG) emissions from organic liquid storage tanks and associated toxic air contaminants (TACs) as well. Staff estimates that preliminary best available retrofit control technology (BARCT) levels may result in emission reductions of ROG and TACs from organic liquid tank storage. Staff recommends considering amending Regulation 8, Rule 5: Storage of Organic Liquids to specifically address ROG and TACs emissions from external floating roof tanks storing organic liquids.

Background

The BAAQMD has regulated emissions from tanks storing organic liquids for nearly 50 years, first under former Regulation 3, which was adopted in 1967, and later under Regulation 8, Rule 5: Storage of Organic Liquids. Rule 8-5 was originally adopted in 1978 and has been amended several times. By 1993, this rule included most of the control strategies found in the current rule, including gap standards for floating roof rim seals, pressure vacuum valve setpoint requirements for fixed roof tanks, closure requirements for tank roof fittings and tank degassing requirements. Amendments in 2006 improved the rule primarily in the area of non-routine operations, such as tank degassing and cleaning.

Storage vessels containing organic liquids can be found in many industries, including 1) petroleum producing and refining, 2) petrochemical and chemical manufacturing, 3) bulk storage and transfer operations, and 4) other industries consuming or producing organic liquids. Organic liquids in the petroleum industry, usually called petroleum liquids, generally are mixtures of hydrocarbons having dissimilar true vapor pressures (for example, gasoline and crude oil). Organic liquids in the chemical industry, usually called volatile organic liquids, are composed of pure chemicals or mixtures of chemicals with similar true vapor pressures (for example, benzene or a mixture of isopropyl and butyl alcohols).

Six basic tank designs are used for organic liquid storage vessels: fixed roof (vertical and horizontal), external floating roof, domed external (or covered) floating roof, internal floating roof, variable vapor space, and pressure tanks (low and high).

Reactive Organic Gasses (ROG)

Regulatory Context and Preliminary BARCT Level

Emissions from organic liquids in storage occur because of evaporative loss of the liquid during its storage and as a result of changes in the liquid level. The emission sources vary with tank design, as does the relative contribution of each type of emission source. Emissions from fixed roof tanks are a result of evaporative losses during storage (known as breathing losses or

standing storage losses) and evaporative losses during filling and emptying operations (known as working losses). External and internal floating roof tanks are emission sources because of evaporative losses that occur during standing storage and withdrawal of liquid from the tank. Standing storage losses are a result of evaporative losses through rim seals, deck fittings, and/or deck seams

Tanks regulated under Air District Rule 8-5 are used for bulk storage of organic liquids or liquid mixtures containing organic compounds. Such tanks are typically found at petroleum refineries and chemical plants, as well as gasoline bulk plants and terminals. Underground gasoline storage tanks located at gasoline stations are regulated under Air District Regulation 8, Rule 7: Gasoline Dispensing Facilities and are not addressed in Rule 8-5.

Federal tank regulations include 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC. Each of these federal requirements (new source performance standard (NSPS) in 40 CFR 60, and Maximum Achievable Control Technology (MACT) standards in 40 CFR 63) require certain storage vessel provisions in terms of control, monitoring, and recordkeeping.

South Coast Air Quality Management District (SCAQMD) maintains their tank regulations in Regulation 1178. The rule applies to all aboveground storage tanks that have capacity equal to or greater than 75,000 liters (19,815 gallons), are used to store organic liquids with a true vapor pressure greater than five millimeters of mercury (mm Hg) (0.1 psi) absolute under actual storage conditions, and are located at any petroleum facility that emits more than 40,000 pounds (20 tons) per year of VOC in any emission inventory year starting with the emission inventory year 2000. Domed roof requirements are included. Several exemptions are allowed in the rule. The most important exemptions are 1) exempt crude oil tanks from doming requirements, 2) facilities with an emission cap equal to or less than 20 tons per year are exempt from the rule requirements, and 3) tanks with true vapor pressure limits less than 3 psia shall be exempt from doming requirements.

Air District External Floating Roof Tank BACT

Best available control technology (BACT) for external floating roof storage tanks containing organic liquids is found in the Air District BACT Workbook 167.1.2 dated 9/2011. A vapor recovery system (VRU) with an overall system efficiency of at least 98 percent appears to be technologically feasible and cost effective. BACT achieved in practice is an Air District approved roof with liquid mounted primary seal and zero gap secondary seal, all meeting design criteria of Reg 8, Rule 5. Also prescribed in the evaluation are no ungasketed roof penetrations, no slotted pipe guide pole unless equipped with a float and wiper seals, and no adjustable roof legs unless fitted with vapor seal boots or equivalent. Typical technology implemented is a thermal incinerator, carbon adsorber, refrigerated condenser, or an Air District approved equivalent. Achieved in practice is an Air District approved roof and seal design.

Additionally, a dome is required for tanks that meet 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 material with a vapor pressure equal to or greater than 3 pounds per square

inch absolute (psia) (except for crude oil tanks that are permitted to contain more than 97 percent by volume crude oil).

Potential Emission Reductions and Impacts

Emissions generated from organic liquid storage tanks for AB-617 identified sources in the Air District (2016) are nearly 840 tons a year from approximately 100 tanks. Table 1 below shows AB- 617 identified floating roof (non-crude), coned roof (non-crude) and crude tank storage.

Table 1. Organic Liquid Storage Tank Emissions AB-617 BARCT Emission Summary

Tank Type	Number of AB-617 Tanks	2016 ¹ Emissions (TPY)
Floating Roof	30	400
Coned Roof	47	300
Other	9	40
Crude	14	100
Total	100	840

Note – External floating roof vs internal floating roof not identified

¹ 2016 emissions referenced in Air District data files. Emission factors vary from AP-42, 7.1 to Tanks 4.09D emission calculations.

Additional tanks are identified in the AB-617 analysis but ROG emissions were less than 10 pounds per day (1.82 TPY). Crude units identified above include both coned and floating roof tank types. Tanks associated with refineries comprise over 95 percent of the Phase I AB-617 organic liquid storage tanks identified above.

Potential ROG emission reductions may be found by installing domes on external floating roof tanks and capturing vented emissions from internal floating roof tanks or coned roof tanks and removing ROG emissions through a vapor recovery unit (VRU) flowing back to the tank(s) or vapor recovery unit to a thermal incinerator. Domed roofs on external floating roofs without capture will reduce ROG by limiting wind effects. Tables 2, 3, and 4 below describe the potential emission reductions, cost effectiveness, and incremental cost effectiveness from floating roof tanks.

Table 2. Organic Liquid Storage Tank AB-617 VRU BARCT Summary

Current Emissions Floating Roof (TPY)	400
Potential Emission Reductions (TPY)	50
Preliminary BARCT Level/controls	Vapor Recovery Unit (98%)
Incremental	See below
Total Capital Cost -VRU	\$275,000
Total Annual Cost	\$50,000
Cost-Effectiveness (\$/ton)	\$6,250

Table 3. Organic Liquid Storage Tank AB-617 Dome + VRU BARCT Summary

Current Emissions Floating Roof (TPY)	400
Potential Emission Reductions (TPY)	100
Preliminary BARCT Level/controls	EFR w/Dome + Vapor Recovery Unit (98%)
Incremental	See below
Total Capital Cost – Dome + VRU	\$850,000
Total Annual Cost	\$150,000
Cost-Effectiveness (\$/ton)	\$15,000

Table 4. Organic Liquid Storage Tank AB-617 Dome + VRU + Incinerator BARCT Summary

Current Emissions Floating Roof (TPY)	400
Potential Emission Reductions (TPY)	150
Preliminary BARCT Level/controls	EFR w/Dome + VRU (98%) + incinerator
Total Capital Cost: Dome + VRU+ incinerator	\$1,200,000
Total Annual Cost	\$250,000
Cost-Effectiveness (\$/ton)	\$25,000

Dome installation on an external floating roof tank costs is approximately \$40.00 per square foot with a construction cost of \$50,000. Using an average tank size of 135-foot diameter (based on Valero refinery gasoline tanks) dome capital costs, including installation, will be nearly \$625,000. Annualized cost will be approximately \$75,000.

Vapor recovery units (VRU) have capital costs of approximately \$225,000 per single tank. There will be cost savings by tying in multiple tanks with an associated increase in compressor size. Incinerators will add another \$350,000 in capital costs per tank with an associated cost savings combining several tanks into one VRU header prior to incineration. Fuel cost for incineration may be a factor.

In lieu of converting fixed roof tanks to internal floating roof tanks, the operator may choose to vent the vapor losses from these fixed roof tanks to a vapor control system or a vapor recovery system. An existing vapor control or vapor recovery system on site may be able to carry the additional load. In this scenario, the cost effectiveness of this control option is negligible. The cost effectiveness however could vary significantly with each individual scenario depending on the location of the tanks, the size of the existing compressors, and the types of vapor control or vapor recovery system the facility would choose to use.

Further Considerations

Staff recommends working with stakeholders to collect tank design data and emission information associated with the organic liquid storage tanks at AB-617 identified facilities. Staff will form an

OLST (Organic Liquid Storage Tank) Working Group that includes representatives of affected facilities, environmental organizations, and manufacturers of domed roofs to discuss relevant control technologies for storage tanks. In parallel, staff will perform site visits of the affected facilities to assess actual operating conditions. Staff will need to estimate current emissions and potential reductions in concert with the Air District emission inventory group using the U.S. Environmental Protection Agency (EPA) TANKs version 4.09 D program. The Air District emission inventory group and engineering group use the EPA tanks program to estimate ROG emission from storage tanks. Staff will conduct OLST Working Group meetings, a Public Workshop, and numerous individual site visits and meetings with stakeholders.

Nitrogen Oxides (NO_x)

There could be a slight increase in NO_x emissions due to possible ROG vapor recovery system combustion; however, no additional rulemaking for NO_x will be considered at this time.

Particulate Matter (PM)

There could be a slight increase in PM emissions due to possible ROG vapor recovery system combustion; however, no additional rulemaking for PM will be considered at this time.

Sulfur Dioxide (SO₂)

There could be a slight increase in SO₂ emissions due to possible ROG vapor recovery system combustion; however, no additional rulemaking for SO₂ will be considered at this time.

Petroleum Wastewater Treating – Rule Development Project Scope

Summary

This rule development project would address reactive organic compounds (ROG) emissions from petroleum wastewater treating operations. Staff estimates that preliminary best available retrofit control technology (BARCT) levels could result in emission reductions of ROGs based on individual refinery wastewater treatment processes. The Air District has addressed ROG emissions from petroleum wastewater treatment facilities (Rule 8-8 Wastewater Collection and Separation Systems) in previous rule developments. Staff recommends reviewing each of the five Bay Area refineries for any opportunities for reduction of wastewater ROG's. This review may include on-site air emissions testing which will require refinery cooperation. Any recommended and implemented controls in addition to current regulatory requirements are also likely to remove hazardous air pollutant (HAP) components.

Background

All refineries employ some form of waste water treatment, so water effluents can safely be returned to the environment or reused in the refinery. The design of waste water treatment plants is complicated by the diversity of refinery pollutants, including oil, phenols, sulfides, dissolved solids, and toxic chemicals. Although the treatment processes employed by refineries vary greatly, they generally include drain systems, neutralizers, oil/water separators, settling chambers, clarifiers, dissolved air flotation systems, coagulators, aerated lagoons, and activated sludge ponds.

Drain systems consist of individual process drains, where oily water from various sources is collected, and junction boxes, which receive the oily water from multiple drains. Oil-water separators (OWS) generally represent the first step in the treatment of refinery wastewater. The separation and removal of the oil from the water are accomplished through density differences that cause oil to rise to the top and enable it to be skimmed off. Air flotation usually follows the oil-water separator and is used to remove remaining oil and solids by introducing air bubbles into the wastewater by mechanical means. The factors influencing emissions from these systems are wastewater composition, equipment design, and climatic factors.

Reactive Organic Gases (ROG)

Regulatory Context and Potential Future BARCT Options

The purpose of an amended rule would be to reduce ROG emissions from petroleum wastewater treatment operations located in the Air District. The main components of atmospheric emissions from waste water treatment plants are fugitive ROGs and dissolved gases that evaporate from the surfaces of waste water residing in open process drains, separators, and ponds. Treatment processes that involve extensive contact of wastewater and

air, such as aeration ponds and dissolved air flotation, have an even greater potential for atmospheric emissions.

The control of waste water treatment plant emissions involves covering systems where emission generation is greatest (such as oil/water separators and settling basins) and removing dissolved gases from water streams with sour water strippers before contact with the atmosphere. These control techniques potentially can achieve greater than 90 percent reduction of waste water system emissions.

Emission Estimates

Current emission estimates attributed to refinery wastewater operations are enigmatic. Some refiners report wastewater ROG emission in total, while others split it out between OWS's and fugitive emission estimates. Still other refiners report no discernable wastewater component of ROG emissions. Including the caveats mentioned above, a reasonable estimate of ROG annual emissions is 300-600 tons per year attributable to refinery wastewater treatment systems. Additional emissions inventory review and refinery emission reporting methodology, factors used, and calculations will need to be reviewed prior to rule development.

BACT

Recent best available control technology determinations (BACT) from the United States Environmental Protection Agency (EPA) RBLC¹ database, for refinery waste water systems, includes the requirement that process wastewater effluent treatment utilize a covered system. All lift stations, manholes, junction boxes, conveyances, and any other wastewater facilities should be covered, and all emissions routed to a vapor combustor with a guaranteed destruction removal efficiency (DRE) of 99 percent for control. Additionally, BACT includes a general requirement of good control practices.

The Air District lists a BACT determination of an OWS system greater than 250 gallons a minute. The determination includes a recommendation of a vapor tight fixed cover vented to vapor recovery system with combined collection and destruction/removal efficiency (DRE) of greater than 95 percent.

Regulations

Current Air District Rule 8-8: Wastewater Collection and Separation Systems requires oil/water separators to be covered.

Additionally, Rule 8-18: Equipment Leaks also requires refining operations to test for potential equipment leaks related to wastewater operations.

Federal applicable requirements include 40 CFR Part 60, Subpart QQQ; and 40 CFR Part 61, Subpart FF. Subpart QQQ focuses on the control of air emissions from process drains, junction boxes, and oily water separators. Subpart FF pertains to benzene waste operations

¹ RBLC-RACT/BACT/LAER/Clearinghouse
Petroleum Wastewater Treating
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NESHAPS² (BWON). 40 CFR 63 subpart CC (MACT³ 1) targets miscellaneous wastewater process vents.

Further Considerations and Emission Measurements

Refineries generate a large amount of wastewater that has both process and non-process origins. Depending on the type of crude oil, composition of condensate and treatment processes, the characteristics of refinery wastewater vary according to a complex pattern that is very refinery specific. Therefore, there is no singular approach to handling and treating refinery wastewater.

Indeed, to reduce ROG further will require emissions testing protocols and individual refinery cooperation with the Air District measurements staff. Aeration ponds can be a large area source of ROG emissions in a petroleum wastewater process. Control strategies for this type of source are unknown.

Additional coordination with the Air District Measurements and Meteorology Division and Engineering Division staffs will be required to determine individual refinery specific measurement data, coordinate emission factor development across refineries and review emission estimation techniques and methodologies. The previous Air District study of refinery wastewater in 2006 will be reviewed and referenced in this this analysis. Staff recommends additional development and research prior to development of the concept paper.

Sulfur Dioxide (SO₂)

Sulfur dioxide is not a significant source of emissions from petroleum refinery wastewater treatment processes. Therefore, rulemaking for SO₂ emissions is not anticipated at this time.

Nitrogen Oxides (NO_x)

Nitrogen oxides are not a significant component of petroleum refinery wastewater process emissions. Therefore, rulemaking for NO_x emissions is not anticipated at this time.

Particulate Matter (PM)

Particulate matter emissions are not a significant component of petroleum refinery wastewater process emissions. Therefore, rulemaking for PM emissions is not anticipated at this time.

² National Emissions Standards for Hazardous Air Pollutants

³ Maximum Achievable Control Technology

Portland Cement Manufacturing – Rule Development Project Scope

Summary

This rule development project would address emissions from Portland cement manufacturing operations. Staff estimates that preliminary best available retrofit control technology (BARCT) levels may result in potential emission reductions of particulate matter (PM) and sulfur dioxide (SO₂). Preliminary evaluations of potential BARCT controls for emissions of oxides of nitrogen (NO_x) and reactive organic gases (ROG) were also conducted, but rulemakings for these pollutants are not anticipated at this time.

Background

Portland cement is used as a component of concrete, which can be used in a variety of construction projects. The Portland cement manufacturing process involves the mining of limestone, crushing and blending of the limestone with other raw materials (such as clay, sand, and alumina), calcining of the mixture in a cement kiln to produce clinker, and the subsequent cooling, grinding, and mixing of the clinker with gypsum and additional limestone to produce cement. Cement kiln operations can generate substantial PM, NO_x, and SO₂ emissions from the combustion of fuel and the heating and calcining of feed materials. PM emissions also arise from other aspects of material handling, including crushing, mixing, storage, and clinker cooling. One Portland cement manufacturing facility operates within the San Francisco Bay Area.

Particulate Matter

Regulatory Context and Preliminary BARCT Level

Federal rules that address emissions from Portland cement manufacturing include New Source Performance Standards (NSPS) Subpart F and National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart LLL. The NSPS and NESHAP subparts include multiple PM emission limits for new and existing cement kilns. The Air District adopted Regulation 9, Rule 13 (Rule 9-13): Nitrogen Oxides, Particulate Matter, and Toxic Air Contaminants from Portland Cement Manufacturing in 2012 (with subsequent amendments in 2016), which contains the following PM emission limits: 0.04 pounds of filterable PM per ton (lb/ton) clinker from cement kilns and 0.04 lb/ton clinker from clinker coolers. Staff's review of existing best available control technology (BACT) guidelines and recent determinations indicates that PM emission levels of 0.01 grains of filterable PM per dry standard cubic foot (gr/dscf) and 0.02 lb/ton clinker have been achieved at cement kilns.

The existing regulatory limits, guidelines, and determinations described above are based on methods for monitoring and measuring filterable particulate matter only. Recent advancements in the understanding and quantification of condensable particulate matter formation indicate that cement kilns may emit substantial amounts of condensable PM in addition to filterable PM.

Therefore, Staff believes that the PM limits in BAAQMD Rule 9-13 adopted in 2012 may not reflect current BARCT levels for addressing total (filterable and condensable) PM. Staff believes that substantial reductions of the condensable PM emissions are achievable, however research of potential control options for cement kilns is ongoing, and a preliminary BARCT level is still under development. Controls may involve reduction of SO₂, ammonia (NH₃), or other condensable components and precursors. Note that further discussions on SO₂ controls and BARCT levels are included in the SO₂ section of this scope. Staff believes that SO₂ emission reductions would also be an integral part of reducing these condensable PM emissions, and anticipates that these SO₂ and PM control efforts would be considered and developed in concert.

Potential Emission Reductions and Impacts

Because a preliminary BARCT emission level has not yet been identified, estimates of potential emission reductions and control costs are not currently available. Staff estimates that cement manufacturing emits approximately 600 tons per year of total PM, and the potential for substantial emission reductions should be further evaluated.

Further Considerations

Additional testing and study of the cement kiln are likely necessary to properly characterize condensable PM emissions. Potential control options, as well as their efficacy, feasibility, and cost-effectiveness, would depend heavily on this evaluation. Efforts towards development and/or implementation of cement kiln SO₂ BARCT controls should also be considered in any future study and evaluation of cement kiln condensable PM emissions.

SO₂

Regulatory Context and Preliminary BARCT Level

Federal NSPS Subpart F includes an emissions limit of 0.4 lb SO₂ per ton clinker on a 30-day rolling average basis; however, this limit only applies to cement kilns constructed, reconstructed, or modified after June 16, 2008. Air District Rule 9-13 addresses Portland cement manufacturing emissions, but does not include limits on SO₂ emissions.

Staff's review of existing BACT guidelines and recent determinations indicate that performance levels of 0.16 to 1.0 lb SO₂ per ton clinker have been achieved at cement kilns. Typical controls include judicious selection and use of raw materials, dry scrubbing, and dry sorbent injection. Based on staff's review, Staff is proposing a preliminary BARCT level of 1.0 lb SO₂ per ton clinker.

Potential Emission Reductions and Impacts

Based on staff's proposed preliminary BARCT level and understanding of current performance of the potentially affected sources, Staff estimates a potential emission reduction of 698 tons per year of SO₂. The facility currently operates a lime injection system for control of HCl emissions, but staff anticipates that additional lime injection capacity would be required to meet the preliminary BARCT level. The capital cost of the current lime injection system was \$700,000, with operating costs of \$1.3 million per year. EPA cost estimates for lime injection systems at

cement kilns indicate that the capital cost for an appropriately sized system would be less than \$500,000. Based on the costs of the facility's current lime injection system and EPA cost estimates of dry lime injection systems for SO₂ control, staff conservatively estimates capital costs of the additional control system to be approximately \$1.4 million dollars. Total annualized cost of the additional control (including amortized capital and operating costs) is estimated to be \$1.45 million dollars per year, resulting in a cost-effectiveness of approximately \$2,100 per ton of SO₂.

Table 1. Portland Cement Manufacturing SO₂ BARCT Summary

Current Emissions (tpy)	1,298
Potential Emission Reductions (tpy)	698
Preliminary BARCT Level	1.0 lb SO ₂ per ton clinker
Controls Required	Hydrated lime injection
Total Capital Cost	\$1,400,000
Total Annual Cost	\$1,450,000
Cost-Effectiveness (\$/ton)	\$2,100

Further Considerations

Sulfur dioxide emissions from the cement kiln are highly dependent on the sulfur content of the fuel and raw material being processed. Therefore, the efficacy of a lime injection system for SO₂ control and achievable limit may or may not be comparable from one cement manufacturing plant to another. Further refinements to the evaluation of cost-effectiveness and technological feasibility are also needed.

NOx

Regulatory Context and Preliminary BARCT Level

Federal NSPS Subpart F includes an emission limit of 1.5 lb NOx per ton clinker on a 30-day rolling average basis; however, this limit only applies to cement kilns constructed, reconstructed, or modified after June 16, 2008. Air District Rule 9-13 addresses Portland cement manufacturing emissions, and contains an emission limit of 2.3 lb NOx per ton clinker on a 30-operating day rolling average.

Staff believes that the NOx limits in Rule 9-13 adopted in 2012 reflect BARCT for NOx, and further BARCT evaluation and rulemaking is not anticipated at this time.

ROG

Regulatory Context and Preliminary BARCT Level

The federal rules that address emissions from Portland cement manufacturing (NSPS Subpart F and NESHAP Subpart LLL), do not contain limits on ROG, although NESHAP Subpart LLL does include limits to control total hydrocarbon emissions. Air District Rule 9-13 does not contain a ROG emissions limit for Portland cement manufacturing, but contains an emission limit of 24 ppmv (dry at 7 percent O₂) for total hydrocarbon.

The cement kiln does not generate substantial ROG emissions (approximately 1.3 tons per year), and staff believes that BARCT controls to further reduce these emissions are not likely to be cost-effective. Therefore, further BARCT evaluation and rulemaking are not anticipated at this time.

Fluidized Catalytic Crackers and CO Boilers – Rule Development Project Scope

Summary

This rule development project would address emissions from fluidized catalytic cracking units (FCCU) and carbon monoxide (CO) boilers at petroleum refineries. Staff estimates that preliminary best available retrofit control technology (BARCT) levels may result in potential emission reductions of particulate matter (PM) and sulfur dioxide (SO₂). Preliminary evaluations of potential BARCT controls for emissions of oxides of nitrogen (NO_x) and reactive organic gases (ROG) were also conducted, but rulemakings for these pollutants are not anticipated at this time.

Background

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. FCCUs use a powdered catalyst to promote the hydrocarbon cracking process, and this catalyst becomes coated with carbonaceous material (coke) during its exposure to the hydrocarbon feedstock. Each FCCU includes a reaction vessel where the catalyst and feedstock are mixed, as well as a catalyst regenerator where coke is burned off the surface of the catalyst to restore its activity so that it can be re-used. Catalyst regenerators may be designed to burn the coke completely to carbon dioxide (CO₂) (full burn) or to only partially burn the coke to a mixture of CO and CO₂ (partial burn). Because the flue gas from these partial burn regenerators have high levels of CO, the flue gas is vented to a CO boiler where the CO is further combusted to CO₂. FCCUs and associated CO boilers can generate substantial PM, NO_x, and SO₂ emissions.

Four of the five refineries in the San Francisco Bay Area operate FCCUs: Chevron Richmond, Shell Martinez, Andeavor Martinez, and Valero Benicia. Shell Martinez operates a partial burn regenerator and three CO boilers. Valero Benicia also operates a partial burn regenerator and two CO boilers, which are abated by a wet gas scrubber. Andeavor Martinez operates one CO boiler that processes flue gas from its FCCU regenerator. Andeavor's regenerator operates in full burn mode, but does operate in partial burn mode for limited periods under unusual circumstances. Chevron Richmond operates a full burn FCCU and does not have CO boilers.

Particulate Matter

Regulatory Context and Preliminary BARCT Level

Federal rules that address emissions from FCCUs and CO boilers include New Source Performance Standards (NSPS) Subparts J and Ja, and National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart UUU. NSPS Subpart J contains a PM emission limit of 1.0 kilograms of filterable PM per megagram (kg/Mg) (2.0 lb/ton) of coke burnoff in the catalyst regenerator and an opacity limit of 30 percent. NSPS Subpart Ja has a PM emission

limit of 1.0 g/kg of coke burnoff for FCCUs reconstructed or modified after May 14, 2007, and a limit of 0.5 g/kg of coke burnoff for FCCUs newly constructed after May 14, 2007. NESHAP Subpart UUU includes various PM emission limit options for compliance. Air District Regulation 6, Rule 1: Particulate Matter – General Requirements contains an opacity limit of 20% for all sources, including FCCUs and CO boilers.

These existing federal and Air District limits are based on methods for monitoring and measuring filterable particulate matter only. Recent advancements in the understanding and quantification of condensable particulate matter formation indicate that FCCUs and CO boilers may emit substantial amounts of condensable PM in addition to filterable PM. The Air District adopted Regulation 6, Rule 5: Particulate Emissions from Refinery Fluidized Catalytic Cracking Units (Rule 6-5) in 2015 to reduce condensable PM emissions through reduction of ammonia injection. Ammonia is injected in FCCU flue gas to suppress NO_x formation and improve the efficacy of electrostatic precipitators (ESP) for filterable PM abatement, but unreacted ammonia may be present in the exhaust stream (ammonia slip) and contribute to condensable PM formation. Rule 6-5 requires FCCUs to meet ammonia slip limits or conduct optimization of ammonia injection.

Implementation of BAAQMD Rule 6-5 is ongoing, with optimization testing having occurred through 2016 and 2017. Testing indicates that reduction of ammonia injection has the potential to substantially reduce condensable PM emissions. However, because ammonia injection is used as a component of abatement systems for filterable PM, injection rate reductions may be limited by compliance issues with filterable PM and opacity operating limits. Staff believes that substantial reductions of the condensable PM emissions are achievable, however evaluation of control options is ongoing, and a preliminary BARCT level is still under development. Control options may involve further optimization and reduction of condensable components and precursors (such as ammonia and SO₂) or operation of a wet gas scrubber. Staff may also consider additional amendments or adjustments to the existing filterable PM and opacity limits to better harmonize with new condensable PM rule development efforts and focus on potentially large reductions in total PM.

Potential Emission Reductions and Impacts

Because a preliminary BARCT emission level has not yet been identified, estimates of potential emission reductions and control costs are not currently available. Staff estimates that FCCUs and CO boilers emit approximately 480 tons per year of total PM, and the potential for substantial emission reductions should be further evaluated.

Further Considerations

Additional testing and study of the FCCUs and CO boilers are likely necessary to properly characterize condensable PM emissions. Potential control options, as well as their efficacy, feasibility, and cost-effectiveness, would depend on this further study and evaluation. Potential controls involving wet gas scrubbing would also need to be evaluated for other potential environmental impacts, as wet gas scrubbers may require substantial water usage.

SO₂

Regulatory Context and Preliminary BARCT Level

Federal NSPS Subpart J contains SO₂ emission limits of 9.8 kg/Mg (20 lb/ton) of coke burnoff, and 50 parts per million by volume (ppmv) SO₂ for an FCCU with an add-on control device. NSPS Subpart Ja contains SO₂ emission limits of 50 ppmv SO₂ on a seven-day rolling average basis and 25 ppmv SO₂ on a 365-day rolling average basis for FCCUs constructed, reconstructed, or modified after May 14, 2007. The Air District adopted Regulation 6, Rule 5: Particulate Emissions from Refinery Fluidized Catalytic Cracking Units in 2015 to reduce condensable PM emissions. Rule 6-5 does not currently contain SO₂ emission limits, but the role of SO₂ as a PM precursor was recognized during the adoption of Rule 6-5, with the intent of addressing SO₂ in future rule amendments.

Staff's review of existing best available control technology (BACT) guidelines and recent determinations indicates that emission limits of 50 ppmv SO₂ on a seven-day rolling average basis and 25 ppmv SO₂ on a 365-day rolling average basis (equivalent to NSPS Subpart Ja standards for newly constructed, reconstructed, and modified units) have been applied and achieved at FCCUs and CO boilers. Typical controls include SO₂-reducing catalyst additives or wet gas scrubbers. Based on staff's review, staff is proposing a preliminary BARCT level of 50 ppmv SO₂ on a seven-day rolling average basis and 25 ppmv SO₂ on a 365-day rolling average basis.

Potential Emission Reductions and Impacts

Three of the four refineries operating FCCUs currently have permit limits equivalent to staff's proposed preliminary SO₂ BARCT level, and no further emission reductions or additional controls would be anticipated. One refinery does not currently meet the preliminary BARCT level for FCCUs and CO boilers, and would potentially require installation of a wet gas scrubber or optimized use of SO₂-reducing catalyst additives. The facility operates a partial burn FCCU and currently utilizes an SO₂-reducing catalyst additive, however recent advances have been made in the performance and efficacy of catalyst additives, specifically for partial burn operating modes. Staff believes there is potential to reduce SO₂ emissions through optimization of these newer catalyst additives and/or use of wet gas scrubbing.

Based on staff's preliminary BARCT level and understanding of current performance of the potentially affected sources, Staff estimates a potential emission reduction of 567 tons per year of SO₂. Optimized use of a partial burn catalyst additive or installation of a wet gas scrubber would be needed to achieve the preliminary BARCT level. Optimized use of the catalyst additive would result in costs for the additive and optimization testing. For this preliminary evaluation, costs of wet gas scrubbing were considered, as this control technology would likely have higher total costs compared to other control options. Based on vendor cost estimates for a wet gas scrubber of appropriate capacity, capital cost of the system is estimated at \$60 million dollars, with the annualized cost of the control system (including amortized capital and operating costs) estimated at approximately \$11 million dollars per year. This would result in a cost-effectiveness of approximately \$20,000 per ton of SO₂.

Table 1. FCCUs and CO Boilers SO₂ BARCT Summary

Current Emissions (tpy)	1,044
Potential Emission Reductions (tpy)	567
Preliminary BARCT Level	50 ppmv SO ₂ , 7-day rolling average 25 ppmv SO ₂ , 365-day rolling average
Controls Required	Optimized SO ₂ -reducing catalyst additive; Wet gas scrubber
Total Capital Cost	\$60,000,000 (wet gas scrubber)
Total Annual Cost	\$11,160,000 (wet gas scrubber)
Cost-Effectiveness (\$/ton)	\$20,000 (wet gas scrubber)

Further Considerations

Optimization of partial burn SO₂-reducing catalyst additives may or may not be able to achieve preliminary BARCT levels. Therefore, emission reductions and cost-effectiveness from this control option are not known at this point. Further refinements to the evaluation of cost-effectiveness and technological feasibility for both additive optimization and wet gas scrubbing are also needed.

NO_x

Regulatory Context and Preliminary BARCT Level

Federal NSPS Subpart Ja includes an emission limit of 80 ppmv NO_x for newly constructed, reconstructed, or modified FCCUs. The Air District adopted amendments to Regulation 9, Rule 10: Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries (Rule 9-10) in 2013, which contains NO_x limits for non-partial burn CO boilers (150 ppmv on an operating day average, and 45 ppmv on a calendar year average) and partial burn CO boilers (125 ppmv on an operating day average, and 85 ppmv on a calendar year average). Staff's review of existing BACT guidelines and recent determinations indicates that NO_x emission levels of 20 ppmv NO_x on a 365-day rolling average basis have been achieved at some FCCUs with selective catalytic reduction (SCR) systems and/or low temperature oxidation (LoTOx) controls.

Staff believes that the NO_x limits in Rule 9-10 adopted in 2013 reflect BARCT for NO_x emissions from FCCUs with CO boilers, and further BARCT evaluation and rulemaking is not anticipated at this time. The FCCU at the Chevron Richmond Refinery does not have a CO boiler, and is therefore not subject to Rule 9-10 NO_x limits. However, this FCCU is subject to facility permit limits of 20 ppmv NO_x on a 365-day rolling average basis and 40 ppmvd NO_x on a seven-day rolling average basis, which are comparable to the BACT levels reviewed. Staff believes that these limits reflect BARCT for NO_x emissions from FCCUs, and further BARCT evaluation and rulemaking are not anticipated at this time.

ROG

Regulatory Context and Preliminary BARCT Level

Federal rules NSPS Subparts J and Ja and NESHAP Subpart UUU for FCCUs and CO boilers do not address ROG emissions, although NESHAP Subpart UUU does include limits on total organic hydrocarbon and organic hazardous air pollutant emissions.

Staff's review of existing BACT guidelines and recent determinations indicate that BACT for ROG is typically good combustion practice. Good combustion practices are generally required for complete combustion and control of CO emissions, and staff believes that these sources currently implement these practices. Therefore, further BARCT evaluation and rulemaking are not anticipated at this time.

Refinery Heavy Liquid Leaks – Rule Development Project Scope

Summary

This rule development project addresses reactive organic gas (ROG) emissions and associated toxic air contaminants (TAC) from petroleum refineries, chemical plants, bulk terminals and bulk plants, and other facilities that store, transport and use organic liquids. Amendments to Regulation 8, Rule 18: Equipment Leaks (Rule 8-18) in December 2015 addressed equipment that service heavy liquids at these sources, but those amendments have not yet been fully implemented due to litigation regarding uncertainty of heavy liquid fugitive emissions. Air District staff is coordinating with each of the five Bay Area refineries to conduct Heavy Liquid Leak Studies. These studies are designed to determine appropriate emission factors for heavy liquid leaks. The results of these studies are expected by Fall 2018. Staff recommends using results of the Heavy Liquid Leak Study to amend Rule 8-18, and address the current issues with the 2015 amendments.

Background

Oil refineries, chemical plants, bulk plants, bulk terminals, and other facilities that store, transport, and use volatile organic liquids may occasionally have leaks wherever there is a connection between two pieces of equipment, and lose some organic material as fugitive emissions. Valves, pumps, and compressors can also leak organic material. Rule 8-18 requires such facilities to maintain a leak detection and repair (LDAR) program.

The purpose of the LDAR program is to ensure that all equipment is inspected regularly and, if a leak is found to exceed the leak threshold, the equipment must be repaired, replaced, or placed on a limited list of non-repairable equipment. Component leaks commonly occur at the joints or connections between sections of piping, at valves, at pumps or from barrier fluid contained between seals, and at leaking pressure relief devices (PRDs).

Rule 8-18 was amended in December 2015 to extend the requirements of the LDAR program to include equipment in hydrocarbon heavy liquid service.¹ Inclusion of heavy liquids is costly because equipment in heavy liquid service expands the LDAR program by approximately one-third more equipment than is currently being monitored. Completion of the heavy liquid leak study mentioned above has been problematic, because some heavy hydrocarbon liquids are condensing and coating the leak detection sensors. These equipment problems have prevented the ability to obtain all the data needed. Study participants are re-configuring the study approach, and anticipate having useful data by the Fall of 2018.

¹ Heavy hydrocarbon liquids defined as having an initial boiling point greater than 302°F.

Reactive Organic Gases

Regulatory Context and Preliminary BARCT Level

The Air District originally adopted Rule 8-18 in 1980 and has amended it in 1992, 2004 and 2015. In addition, some minor changes were made to the rule in 1998 and 2002. The original intent of the rule was to control fugitive organic gas leaks from valves and connectors at refineries, chemical plants, bulk plants, and bulk terminals. Rule amendments adopted in 1992 significantly lowered the allowable leak concentration limits to the lowest levels in the country and required more effective inspection and repair programs to reduce emissions and promote self-compliance. The 1992 amendments reduced emissions by an estimated 1.2 tons per day (tpd).

The allowable leak standard is 500 parts per million volume (ppmv) for pumps, compressors, and PRDs.² For valves and other equipment, the allowable leak standard is 100 ppmv. Leaks are detected using a portable combustible gas indicator.

The U.S. Environmental Protection Agency (EPA) standards in 40 CFR parts 60 and 63 include LDAR provisions for monitoring and repairing equipment in heavy liquid service and do not rely on instrument monitoring, but instead rely on “visual, audible, olfactory, or any other detection method.” The concern with visual, audible and olfactory monitoring is that it only identifies large leaks (typically 10,000 ppm or more). Instrument monitoring can identify much smaller leaks (in the 100 – 500 ppm range).

Potential Emission Reductions and Impacts

The 2015 emissions inventory estimates fugitive hydrocarbon leaks from the five refineries in the Bay Area at 1172 tons per year ROG based on emission factors that will be used during the completion of the heavy liquid leak study mentioned above. Actual emissions, and potential emission reductions will be quantified based on the results of the heavy liquid leak study.

Table 1. Refinery Equipment Leaks – Heavy Liquids ROG BARCT Summary

Current Emissions – Heavy Liquids (tpy)	1,172 - total 458 - based on estimated emissions factors
Potential Emission Reductions (tpy)	uncertain
Preliminary BARCT Level	TBD
Controls Required	LDAR for heavy liquid equipment
Total Capital Cost	5 refineries - \$250,000
Total Annual Cost	\$4,700,000
Cost-Effectiveness (\$/ton)	uncertain

² PRDs are also subject to the requirements of Air District Regulation 8, Rule 28, *Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants*.

Further Considerations

Rule 8-18 will require amendments based on litigation settlement agreements, including results of heavy liquid leak study. Results of the study will also inform health risk analyses required by Rule 11-18.

PM

Heavy liquid leak LDAR program will control heavy liquids that become aerosols, and any toxic air contaminants that may be in the composition of the heavy liquid.

NO_x

Heavy liquid leaks do not generate NO_x emissions.

SO_x

Heavy liquid leaks do not generate SO_x emissions.

Internal Combustion (Reciprocating) Engines - Rule Development Project Scope

Summary

This rule development project addresses reactive organic gases (ROG) emissions from internal combustion (IC) reciprocating engines. Staff estimates that preliminary BARCT levels may result in a significant emission reduction percentage of ROG. Amendments to Regulation 9, Rule 8 (Rule 9-8) in July 2007 addressed emissions of oxides of nitrogen (NO_x) and carbon monoxide (CO) from stationary internal combustion engines; however, neither the amendments nor the rule address ROG. Staff recommends amending Rule 9-8 or creating a new rule in the Regulation 8 series to address ROG.

Background

IC engines generate power through an explosive combustion of an air/fuel mixture in an enclosed chamber. IC engines range in size from relatively small engines (less than 50 brake horsepower (bhp)) to extremely large engines (thousands of bhp) and are used primarily to generate electricity, operate pumps and compressors, and power water pumps for irrigation. There are two primary types of IC engines: compression-ignition (CI) and spark-ignition engines. All IC engines operate under one of three modes: rich burn (excess fuel), stoichiometric (a chemical balance between fuel and oxygen), or lean burn (excess air). Generally, uncontrolled engines that run rich emit higher levels of ROG and CO, and lower levels of NO_x and particulate matter (PM); while uncontrolled engines that run lean emit less ROG and CO, and emit higher NO_x and PM.

Compression-Ignition Engines: CI engines run lean (excess air) using diesel fuel or other longer-chained hydrocarbons, including fuel oil, distillate oil, or jet fuel. CI engines operate by compressing air, which increases the temperature of the air. A diesel engine uses this property to ignite the air-fuel mixture and power the engine. The larger fraction of stationary IC engines in the Air District are CI engines, of which, diesel-fueled engines are the vast majority.

Spark-Ignition Engines: Another category of internal combustion engine is the spark-ignition engine. This term is normally used to refer to internal combustion engines where the air-fuel mixture is ignited with a spark. This type of engine contrasts with CI engines, where the heat from compression alone ignites the mixture. Most spark-ignited engines burn fuels such as natural gas, propane, or waste gas (digester and landfill gases). Natural gas fired spark-ignited engines are the second largest category of stationary IC engines in the Bay Area. These engines operate as either rich-burn (excess fuel) or lean-burn (excess air).

Reactive Organic Gases (ROG)

Regulatory Context and Preliminary BARCT Level

The pollutants commonly classified as ROG can encompass a wide spectrum of volatile organic compounds that are photoreactive in the atmosphere. ROG's emitted from anthropogenic sources pose direct and indirect hazards to both the atmospheric environment and human health due to their contribution to the formation of photochemical smog and potential toxicity including carcinogenicity.

Partially burned hydrocarbons result from poor air-to-fuel mixing or incorrect air-to-fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system. Low cylinder temperature may yield partially burned hydrocarbons due to excessive cooling, or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed.

On June 28, 2011, EPA published a final rule revising New Source Performance Standards (NSPS) 40 CFR 60 Subpart IIII for stationary CI engines. The final rule also revised some definitions and made minor corrections to NSPS Subpart JJJJ for stationary SI Engines. The rule became effective August 29, 2011. In addition, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE) 40 CFR part 63 subpart ZZZZ apply for those area sources and stationary sources exceeding hazardous air pollutants (HAP) applicability thresholds.

The Air District adopted Rule 9-8 in 2007 (effective 2012) addressing NO_x and PM emissions from reciprocating engines located in the Air District. Currently, Rule 9-8 does not consider ROG emissions from reciprocating engines. Reciprocating engine regulations for ROG are currently not addressed in other Air District Rules.

Potential Emission Reductions and Impacts

Current estimated emissions of ROG from reciprocating engines, associated with facilities that participate in the GHG Cap-and-Trade system are approximately 100 tons per year. Potential ROG emission reductions could reach up to 95 percent based on installation and operation of oxidation catalysts. Cost effectiveness determinations will be consistent with recent BARCT determinations.

Table 1. Reciprocating Engine PM BARCT Summary

Current Emissions (tpy)	100
Potential Emission Reductions (tpy)	40
Preliminary BARCT Level	29 ppmvd@15% O ₂
Controls Required	Catalytic Oxidation
Total Capital Cost	\$2.5 million for 6 Recip Engines
Total Annual Cost	\$150,000 per
Cost-Effectiveness (\$/ton)	\$19.3k - \$28.4k Average: \$23.7k

Additionally, ROG good combustion practices should be specified that include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters should be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

Further Considerations

Reciprocating engines located in facilities not participating in the GHG Cap-and-Trade system may be included under new ROG reciprocating engine requirements. This option will be determined during the rule-making process, and may add additional Air District-wide ROG emission reductions.

Post Combustion Controls – Oxidation Catalyst

Post combustion controls generally consist of catalysts that act on the engine exhaust to reduce emissions. This control method is applicable to all engines. For stationary engines, oxidation catalysts have been used primarily on lean-burn engines. Rich-burn engines tend to use three-way catalysts, which combine nonselective catalytic reduction (NSCR) for NO_x control and an oxidation catalyst for control of CO and ROG. The oxidation catalyst has been used on lean-burn engines for nearly 30 years. Oxidation catalysts are used less frequently on stationary engines. In the United States, only about 500 stationary lean-burn engines have been fitted with oxidation catalysts.

An oxidation catalyst promotes oxidation reactions between oxygen, CO, and ROG to produce carbon dioxide and water vapor. These reactions occur when exhaust at the proper temperature and containing sufficient oxygen passes through the catalyst. Depending on the catalyst formulation, an oxidation catalyst may obtain reductions at temperatures as low as 300 or 400 degrees Fahrenheit (°F), although minimum temperatures in the 600 to 700 °F range are generally required to achieve maximum reductions. In the case of rich-burn engines, where the exhaust does not contain enough oxygen to fully oxidize the CO and VOC in the exhaust, air can be injected into the exhaust upstream of the catalyst.

The effectiveness of an oxidation catalyst is a function of the exhaust temperature, oxygen content of the exhaust, amount of active material in the catalyst, exhaust flow rate through the catalyst, and other parameters. Catalysts can be designed to achieve almost any control efficiency desired. Reductions greater than 90 percent for both CO and VOC are typical. Reductions in VOC emissions can vary significantly and are a function of the fuel type and exhaust temperature. Adequate oxygen must be present in the exhaust for the catalyst to operate effectively. In addition, the effectiveness of an oxidation catalyst may be poor if the exhaust temperature is low, which is the case for an engine at idle. Oxidation catalysts, like other catalyst types, can be degraded by masking, thermal sintering, or chemical poisoning by sulfur or metals. If the engine is not in good condition, a complete engine overhaul may be needed to ensure proper catalyst performance. Also note that catalyst will increase back pressure in the exhaust, resulting in a slight reduction in engine efficiency and maximum rated power.

NOx

Essentially all NOx formed in natural gas-fired reciprocating engines occurs through the thermal NOx mechanism. The rate of NOx formation through the thermal NOx mechanism is highly dependent upon the stoichiometric ratio, combustion temperature, and residence time at the combustion temperature. Maximum NOx formation occurs through the thermal NOx mechanism near the stoichiometric air-to-fuel mixture ratio since combustion temperatures are greatest at this air-to-fuel ratio. BAAQMD amended Rule 9-8: NOx and CO from Stationary IC Engines in 2007. Staff believes that the NOx limits in Rule 9-8 adopted in 2007 and effective January 2012 reflect BARCT for NOx, and further BARCT evaluation and rulemaking is not anticipated at the is time.

SOx

Sulfur oxides emissions are a function of only the sulfur content in the fuel rather than any combustion variables. In fact, during the combustion process, essentially all the sulfur in the fuel is oxidized to SO₂. The oxidation of SO₂ gives sulfur trioxide (SO₃), which reacts with water to give sulfuric acid (H₂SO₄), a contributor to acid precipitation. Sulfuric acid reacts with basic substances to give sulfates, which are fine particulates that contribute to PM₁₀ (particulate matter with an aerodynamic diameter of 10 microns or less) and visibility reduction. Since oxides of sulfur (SOx) emissions are directly related to the sulfur content of the fuel, Staff recommends that fuel sulfur standards be applied to specific fuel types in other parts of the BAAQMD Rules.

PM

PM emissions result from carryover of noncombustible trace constituents in the fuel and lubricating oil and from products of incomplete combustion. Emission of PM from natural gas-fired reciprocating engines are generally minimal and comprise fine filterable and condensable PM. Increased PM emissions may result from poor air-to-fuel mixing or maintenance problems. PM emissions were reduced in 2007/2012 through the reduction of NOx emissions in Rule 9-8. PM emission reduction are attributable to the reduction of secondary formation of PM from NOx emissions and no further BARCT evaluation for PM is anticipated at this time.

Fiberglass Manufacturing – Rule Development Project Scope Summary

This rule development project addresses emissions from fiberglass manufacturing. Staff estimates that preliminary BARCT levels may result in significant emission reductions of particulate matter (PM) and potential reductions of oxide of nitrogen (NOx) emissions. Staff recommends considering a new regulation to address PM emissions and additional review is suggested for NOx emissions from fiberglass manufacturing.

Background

Fiberglass manufacturing consists of melting recycled glass, limestone and other minerals, extruding the molten glass into fibers, and coating the fibers with a chemical solution and then forming the fibers into mats that are used for insulation. Emissions of PM come from recycled glass handling, melting the glass in an electric furnace, extruding the fibers, coating of the fibers and forming into mats. NOx emissions come from fuel combustion for heating during the manufacturing process. The Bay Area has only one fiberglass manufacturing facility, Owens Corning, located in Santa Clara and is currently regulated as a Title V facility.

The Owens Corning plant in Santa Clara manufactures wool glass fibers that are used in building insulation materials. Glass fiber manufacturing is the high-temperature conversion of various raw materials (predominantly borosilicates) into a homogenous melt, followed by the fabrication of this melt into glass fibers.

Glass fiber production can be segmented into four phases: 1) Raw Materials Handling, 2) Glass Melting and Refining, 3) Wool Glass Fiber Forming, and 4) Wool Glass Fiber Finishing.

Raw Materials Handling

Glass Batch – The primary component of glass is sand (silica), but the batch may also contain other materials (e.g. sodium sulfate, anhydrous borax, etc.). The bulk supplies are received by rail car and/or truck. Lesser-volume supplies are received in drums, bags, or other packages. From storage, the materials are weighed according to the desired batch formulation and then blended well before their introduction into the melting unit. The weighing, mixing, and charging operations are conducted in either batch or continuous mode.

Binder – The binder is an aqueous solution of a thermosetting resin. Other materials may also be added, e.g. red dye, process oil, urea, etc. The bulk supplies are received by rail car and/or truck. Lesser volume supplies are received in drums, totes, bags, or other packages. From storage some of the materials are pre-mixed into solutions. The binder raw materials, along with the pre-mixed solutions are then metered into a mix tank. The resulting binder is transferred to storage for application in the forming section.

Glass Melting and Refining

In the glass-melting furnace, the raw materials are heated to temperatures that transform them through a sequence of chemical reactions to molten glass. Electric furnaces melt glass by passing an electric current through the fused mass or melt. In operation, mixed raw materials are introduced continuously on top of a bed of molten glass where they slowly melt.

Wool Glass Fiber Forming

During the formation of fibers into a wool fiberglass mat (the process known as “forming” in the industry), glass fibers are made from molten glass by using the rotary spin process: centrifugal force causes the fibers to flow through small holes in the wall of a rapidly rotating cylinder to create fibers that are broken into short lengths by an air stream. A chemical binder is simultaneously sprayed on the fibers as they are created. The binder is a thermosetting resin that holds the glass fibers together. After the glass fibers are created and sprayed with the binder solution, they are collected by gravity and suction air on a perforated conveyor belt in the form of a mat.

Wool Glass Fiber Finishing

The conveyor carries the newly formed mat through a large oven to cure the thermosetting binder and then through a cooling section where ambient air is drawn down through the mat. The cooled mat remains on the conveyor for trimming of the uneven edges. Then, if product specifications require it, a backing is applied with an adhesive, usually laminating asphalt, to form a vapor barrier. The mat is then cut into batts or rolls of the desired dimensions and packaged.

Particulate Matter

Regulatory Context and Preliminary BARCT Level

Federal New Source Performance Standards (NSPS) Title 40 Chapter 60 Subpart CC, apply to PM emissions from glass manufacturing facilities. Additionally, fiberglass manufacturing hazardous materials are regulated by federal 40 CFR Part 63 Subpart NNN, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Wool Fiberglass Manufacturing. This regulation is focused on formaldehyde and methanol emissions.

Particles are formed from glass and other mineral raw material handling, although those emissions are relatively minor and can be controlled by solids handling dust control measures. Significant emissions occur when melting the glass and other raw materials, during forming the glass fibers, and during the cooling and treating of the fibers during formation of fiberglass mats used for insulation. These particles can vary in size from less than one micron (from volatilized glass) and from small particles less than 2.5 microns that can be formed as a by-product of the extrusion of molten glass into fibers.

Control of small glass particles is very difficult, simply because the particles are so small and can be less than one micron. Best available control technology (BACT) PM levels for these processes are as follows:

- Furnace: 0.25 lb/ton – control from a baghouse
- Forming: 2.57 lb/ton – control from a wet scrubber.

Potential Emission Reductions and Impacts

Potential emissions reductions from the fiberglass manufacturing facility in the Bay Area is 25 tons per year.

A wet scrubber is estimated to cost \$3,200,000 capital, resulting in \$475,000 annual costs including amortization of capital. A baghouse is estimated to cost \$1,600,000 capital, resulting in \$240,000 annual costs including amortization of capital. Cost effectiveness for these control methods averaged \$38,000 per ton of reduced emissions.

Table 1. Fiberglass Manufacturing PM BARCT Summary

Current Emissions (tpy)	131
Potential Emission Reductions (tpy)	25
Preliminary BARCT Level	Furnace: 0.25 lb/ton of fiberglass Forming: 2.57 lb/ton of fiberglass
Controls Required	Furnace: baghouse Forming: wet scrubber / wet electrostatic precipitator
Total Capital Cost	\$6,400,000
Total Annual Cost	\$960,000
Cost-Effectiveness (\$/ton)	\$38,000

Further Considerations

This facility has recently upgraded their fiber coating process, so controls for hazardous air contaminants currently meet BACT requirements.

Nitrogen Oxides (NOx)

Regulatory Context and Preliminary BARCT Level

There are no federal regulations addressing NOx emissions from fiberglass plant manufacturing. BAAQMD Regulation 9, Rule 12 (Rule 9-12): NOx From Glass Melting Furnaces prescribes glass manufacturing plant NOx limits of 5.5 pounds of NOx per ton of glass throughput. Current NOx emission estimates from the Owens Corning facility are approximately 90 percent less than the Rule 9-12 standard.

The Owens Corning manufacturing operation includes two manufacturing lines: the “M” and the “O” lines. Each of the two manufacturing lines consist of glass batch melting, glass fiber and pack forming, curing, and cooling section sources.

The “M” line curing oven is equipped with four oven zones with one burner per zone for a total of four oven zone burners.

BACT listed in the Environmental Protection Agency (EPA) RBLC¹¹ database for glass forming operations include Low NOx Burners (LNB) with flue gas recirculation (FGR) and best operating practices for electric arc furnaces. No specific NOx BACT limits for these control requirements are provided in the database.

The BAAQMD Title V permit includes lb/hr and tons per year (TPY) NO_x limits for the M and O process lines.

Potential Emission Reductions and Impacts

Total NO_x emissions reported in 2016 include emissions from the M and O forming and curing lines and the electric arc furnace and forehearth associated with each line. NO_x emissions reported in 2016 from the M and O forming lines are 8 tons and 13 tons respectively. Electric arc furnace operation includes approximately 14 tons of NO_x of both M and O lines combined.

Electric arc furnace BARCT is considered best operating practices and staff recommends no specific control technology to meet that generic standard. Since there is no BACT specific limits listed for glass manufacturing, a typical LNB standard is approximately 0.1 lb NO_x/MMBtu. Based on 2016 reported data, the M and O lines are operating at about 0.14 lb NO_x/MMBtu.

The application of low NO_x burner technology and retrofit for approximately 36 burners on the combined M and O lines would include a capital cost of approximately \$1.0 million dollars. Annualized costs of LNB implementation would be approximately \$395,000 USD. Based on potential NO_x removed of 30% with installation of LNB, this would equate to greater than \$60,000 per ton of NO_x removed as per Table 2 “Fiberglass Manufacturing BARCT Summary” shown below.

Table 2. Fiberglass Manufacturing BARCT Summary

Current Emissions (tpy)	21
Potential Emission Reductions (tpy)	7
Preliminary BARCT Level	0.1 lb NO _x /MMBTU
Controls Required	LNB/FGR
Total Capital Cost	\$1.0 Million
Total Annual Cost	\$200,000
Cost-Effectiveness (\$/ton)	\$29,000

Further NO_x Considerations

Based on the NO_x analysis above, the cost effectiveness for application of LNB technology appears to be consistent with recent BARCT determinations. However, these furnaces seem to have an unusually high number of burners (18) for total heat input of approximately 45 MM Btu/hr to each furnace, so cost estimates must be further refined.

ROG

Hydrocarbon emissions from fiberglass manufacturing are primarily from the coating of fibers. These emissions are currently controlled from a recent upgrade in the coating section, so likely meet BACT requirements.

SO_x

Fiberglass manufacturing does not generate sulfur oxide (SO_x) emissions.

¹ RACT / BACT / LAER Clearinghouse

Municipal Solid Waste Landfills – Rule Development Project Scope

Summary

This rule development project addresses emissions from municipal waste landfills. Staff estimates that preliminary Best Available Retrofit Control Technology (BARCT) levels may result in significant emission reductions of particulate matter (PM). Reactive organic gases (ROG) emissions may require further refined assessment based on individual landfill operations and consideration given to dovetailing potential future requirements with the proposed 2019 Landfill Methane Rule. Staff recommends considering a new regulation to address landfill PM emissions.

Background

The majority of landfills currently use the “area fill” method, which involves placing waste on a landfill liner, spreading it in layers, and compacting it with heavy equipment. A daily soil cover is spread over the compacted waste to prevent wind-blown trash and to protect the trash from scavengers and vectors. The landfill liners are constructed of soil (i.e., recompacted clay) and synthetics (i.e., high density polyethylene) to provide an impermeable barrier to leachate (i.e., water that has passed through the landfill) and gas migration from the landfill. Once an area of the landfill is completed, it is covered with a “cap” or “final cover” composed of various combinations of clay, synthetics, and soil and cover vegetation to control the incursion of precipitation, the erosion of the cover, and the release of gases and odors from the landfill. Landfills generate particulate matter (PM) emissions from truck traffic bringing municipal solid waste to the landfill, from dumping the waste into the landfill, covering with clean material, from excavating material to use as cover, and bulldozing and compacting both the waste and cover.

Landfills generate landfill gas due to the waste decomposition process. The landfill gas contains methane (CH₄) and carbon dioxide, which are both greenhouse gases (GHG) and small amounts of non-methane organic compounds (NMOC) and sulfur compounds. Many of the NMOCs are reactive organic gases (ROG), and many NMOCs are also toxic air contaminants (TACs) and hazardous air pollutants (HAPs). The definition of ROG does not include methane. Hydrogen sulfide, a TAC, makes up about 95 percent or more of the sulfur compounds in landfill gas. Air District and EPA regulations require that landfill gas from larger landfills be continuously collected and controlled to reduce emissions of NMOCs to the atmosphere. These collection and control requirements also reduce GHG, TAC, and HAP emissions. In accordance with these requirements, most landfills are equipped with a landfill gas collection system and a landfill gas control system. Landfill gas collection systems are perforated pipes that are buried in the refuse at numerous locations. For active collection systems, the perforated pipes are connected to blowers by solid pipes (referred to as laterals and headers). The blowers maintain a vacuum in the buried refuse and draw landfill gas into the perforated pipes. The landfill is also equipped

with a leachate collection system, which collects liquid leachate that is then injected into the landfill gas flare for destruction.

The collected landfill gas is generally used as fuel for power generation (or other useful utilities to operate the landfill) in a reciprocating engine or gas turbine. Combustion destroys most of the methane, NMOCs, TACs, and HAPs that are present in the landfill gas. However, landfill gas combustion also produces secondary emissions comprised of nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO₂), PM, formaldehyde, and acid gases such as hydrogen chloride (HCl) and hydrogen fluoride (HF).

Particulate Matter

Regulatory Context and Preliminary BARCT Level

Landfill emissions limits are typically set by permit limits and permit conditions. The general PM rule, Rule 6-1, establishes an opacity limit for all sources of fugitive dust in the Bay Area, including landfills. New proposed Rule 6-6 (currently in development) will establish trackout limits for landfills. All other PM limits are established through permit conditions.

Potential Emission Reductions and Impacts

Current estimates of PM emissions from four specific landfills that participate in the California Greenhouse Gas Cap-and-Trade Program are estimated to be 199 tons per year. Best available control technology (BACT) emission are 0.016 pound of PM per ton of (lb/ton) waste disposal. Potential emission reductions are estimated to be 144 tons per year. However, more research is needed to confirm that the BACT level of 0.016 lb/ton of waste includes all aspects of waste disposal and cover; excavating, bulldozing and compacting; and associated vehicle and truck traffic related to the waste disposal.

Air District staff assessment of Bay Area landfills is that each landfill has implemented BACT controls reasonably effectively; so significant emission reductions do not appear to be likely. This raises the question of whether the BACT level of 0.016 lb/ton only characterizes emissions from one aspect of the waste disposal process, or excludes vehicle traffic associated with waste disposal.

Cost estimates below are based on construction of windscreens as an additional element of wind erosion control. Existing landfills appear to have all the other BACT control methods in place. Portable windscreens that can be moved to adjust for wind direction and location within the landfill are estimated to cost \$500,000 capital for each facility at 6 source locations, totaling \$3,000,000. Annual costs are estimated at \$100,000 for each source location. Cost effectiveness ranges from \$1,600 to \$15,000 per ton depending on the landfill, with average cost effectiveness estimated to be \$6,600 per ton of PM emission reductions.

Table 1. Landfill PM BARCT Summary

Current Emissions (tpy)	199
Potential Emission Reductions (tpy)	144
Preliminary BARCT Level	0.016 lb/ton waste
Controls Required	Watering, wind erosion control, vehicle speed and route management
Total Capital Cost	6 landfill source locations - \$3,000,000
Total Annual Cost	\$600,000
Cost-Effectiveness (\$/ton)	\$1,600 - \$15,000 Average: \$6,600

Further Considerations

There are approximately 15 active landfills in the Bay Area. Any new rule will apply to all landfills, unless exemptions are created for smaller, “de minimis” sized landfills.

PM emissions from these sources have historically been difficult to quantify, and current estimates may not adequately reflect the actual emissions and the efficacy of existing controls at landfills. Staff intends to further study these sources and evaluate the potential for PM reductions when more refined emissions estimates and comparisons with BACT can be developed.

Reactive Organic Gases (ROG)

Regulatory Context and Preliminary BARCT Level

ROG Regulatory Context

On May 2, 1984, the Air District adopted Regulation 8, Rule 34: Solid Waste Disposal Sites (Rule 8-34) to control the emissions of methane and other organic compounds in landfill gas. The rule has been amended four times since then to clarify and tighten standards, reduce the need for variances, and improve the flexibility of the rule. The current rule requires landfill operators to collect landfill gas and to process this gas through an emission control system.

Emission control systems are usually enclosed flares, internal combustion engines, or gas turbines. The rule contains operating requirements for the landfill gas collection system, sets minimum methane and organic compound removal efficiencies for emission control systems, and limits the concentration of methane and organic compounds at the landfill surface, collection system components, and control system components.

BARCT

Landfill gas is collected and removed from the buried waste by using a passive or an active collection system. Both systems use vertical wells or horizontal collectors (perforated pipes placed within the buried refuse) connected by pipes to a header pipe. The header pipe is then vented to the emission control system. In the passive collection system, landfill gas pressure is allowed to increase naturally until there is enough gas being generated by decomposing refuse to create a pressure gradient. The increasing pressure in the buried refuse pushes landfill gas

into the collection pipes and on to the emission control system. In an active collection system, blowers are used to create a vacuum within the piping system. Landfill gas is then drawn into the perforated pipes because of the pressure gradient and vented to the emission control system. Active collection systems are considered to be more effective. Rule 8-34 currently requires the use of an active collection system.

There are two types of emission control systems that may be used to control organic emissions in the collected landfill gas: combustion type controls and non-combustion type controls. Combustion type controls include equipment with no energy recovery capabilities (open or closed flares) and equipment that can recover some of the heat produced by burning landfill gas. Some types of energy recovery equipment are boilers, gas turbines, and internal combustion engines. Rule 8-34 does not allow the use of open flares to control landfill gas emissions. Enclosed flares are currently the most prevalent control option in the Bay Area due to their low cost, ease of operation, and reliability. However, some Bay Area landfills are currently using energy recovery equipment to control collected landfill gas. Many landfills are reinvestigating using energy recovery equipment due to recently enacted utility deregulation requirements and tax incentives. These incentives have made energy recovery a more economically viable option. For sites relying mainly on energy recovery equipment to control collected landfill gas, enclosed flares are usually employed as back-up control devices.

All combustion type emission control systems will produce secondary pollutant emissions such as nitrogen oxides, carbon monoxide, sulfur dioxide, and particulate matter with an aerodynamic diameter of ten microns (PM₁₀). Due to the presence of halogenated compounds in the landfill gas, combustion equipment can also produce acid gases (hydrogen chloride, hydrogen fluoride, or hydrogen bromide) as secondary pollutants. Secondary pollutants are limited by other Air District requirements:

- Regulation 2, Rule 2: New Source Review;
- Regulation 9, Rules 1: Sulfur Dioxide;
- Regulation 9, Rule 7: Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, And Process Heaters,
- Regulation 9, Rule 8: Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines,
- Regulation 9, Rule 9: Nitrogen Oxides and Carbon Monoxide from Stationary Gas Turbines; and
- the Air District's Toxic Risk Management Policy;
 - Regulation 2, Rule 5: New Source Review of Toxic Air Contaminants and
 - Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities.

BACT

Recent BACT determinations from the Environmental Protection Agency (EPA) RBLC¹ database include the following requirements for new landfills:

- VOC measured as NMOC in the landfill gas shall be controlled by one or more enclosed flares and each enclosed flare shall have a NMOC control efficiency of 98

percent by weight or more or shall reduce the outlet concentration of NMOC to equal or less than 20 parts per million by volume, dry (ppmvd) as hexane corrected to 3 percent oxygen.

Potential Emission Reductions and Impacts

ROG emission reductions (NMOC) from landfills will be addressed by new Air District Methane landfill rules expected to be promulgated in 2019. Currently, the Air District is performing a methane study and rulemaking strategy for methane reductions from various sources including landfills. It should be noted that NMOC emissions constitute less than one percent of total organic emissions (including methane) from landfills. Staff recommends no additional ROG landfill rulemaking until the Methane Rules are adopted and any new proposed limits and control strategies are evaluated.

Further Considerations

None.

Nitrogen Oxides (NO_x)

NO_x emissions are generated from landfill combustion devices and are addressed in other Air District Rules.

Sulfur Dioxide (SO₂)

SO₂ emissions are generated from landfill combustion devices and are addressed in other Air District Rules.

¹ RBLC – RACT/BACT/LAER clearinghouse

Petroleum Coke Calcining – Rule Development Project Scope

Summary

This rule development project would address oxides of nitrogen (NO_x) emissions from petroleum coke calcining operations. Staff estimates that preliminary BARCT levels could result in significant emission reductions of NO_x; however, NO_x control options for petroleum coke calcining appear limited in practice in the United States. The Air District has not addressed NO_x emissions concerning petroleum coke calcining in previous rule developments. Staff recommends potentially amending Regulation 9, Rule 14: Petroleum Coke Calcining Operations (Rule 9-14), which only address sulfur dioxide (SO₂), to include NO_x emissions if socioeconomic impacts, cost effectiveness, and control technology application can be justified as BARCT. Technologies potentially available for NO_x reduction for this process may not be commercially available nor demonstrated in practice and indubitably may be considered Lowest Achievable Emission Rate (LAER).

Background

Petroleum coke calcining operations in the Bay Area occur only at the Phillips 66 Carbon Plant. It is one of two such facilities in California. The other facility is in Southern California. The Carbon Plant processes green coke from the Phillips 66 San Francisco Refinery to purify it and sell it to industry that is primarily offshore. The facility commenced calcining operations with a single kiln in 1960. A second kiln was added to the facility in 1968. The Carbon Plant sells the majority of its calcined coke to a single company that uses the refined coke to produce titanium dioxide - a photocatalyst that is commonly used to manufacture white pigments that are incorporated into a wide range of applications including skincare, plastics, food coloring as well as paint and coating products.

Phillips 66 Carbon Plant Operations

The Phillips 66 Carbon Plant operates two process trains that include a natural gas kiln burner (approx. 60 million British thermal units (MMBtu/hr) each) with a combined permitted maximum coke throughput of 250 tons per hour. Each train includes a pyroscrubber and baghouse and a separate exhaust stack. Annual production is limited to 262,800 tons of coke produced per train.

Petroleum coke is received from the Phillips 66 refinery coker and stored on site. Coke is conveyed to the coke calciner where it is calcined (heated). This process removes impurities from the coke, including sulfur and volatiles. The hot waste gases from the calciner are sent to the pyroscrubber that removes particulates through a combination of settling and incineration. Sulfur compounds are oxidized to SO₂. The hot waste gases are sent to a heat recovery steam generator to produce steam for the generation of electricity. The cooled waste gases pass through a baghouse and tall stack and are emitted into the atmosphere. The resulting calcined coke is then sold.

Petroleum Coke

Petroleum coke is a carbon by-product that remains from petroleum refining processes. It is a black solid residue that results from the thermal processing of petroleum derived from

feedstocks, tar, pitch, or vacuum tower bottom blends that have been cracked or otherwise processed in a coker to remove low boiling fractions. Coke consists mainly of carbon (90 - 95 percent) and is created by heat-treating the residual oil (more accurately described as tar) to a temperature high enough to polymerize it to form a non-melting solid carbonaceous material.

Coke is used as a feedstock in coke ovens for the steel industry, for heating purposes, for electrode manufacturing, and for the production of chemicals. Coke, as it is removed from the petroleum coking process, is referred to as “green coke.” Green petroleum coke may contain approximately 15 to 20 percent residual hydrocarbon materials. Such hydrocarbons are compounds that do not polymerize in the coke cracking process and cannot be removed from the coke substrate due to process limitations. Thus, green coke is calcined to remove hydrocarbons and other impurities to make it a more marketable product.

Calcining Process

Calcined petroleum coke is manufactured by heating green coke in a rotary kiln to a temperature that ranges between approximately 2,200 – 2,500 degrees Fahrenheit (°F). This roasting process combusts virtually all of the residual hydrocarbons and also removes sulfur compounds and moisture from the coke. The coke’s crystalline structure is refined and thus enhances the coke’s physical properties such as electrical conductivity, density and oxidation characteristics. A rotary kiln is a long, refractory lined cylindrical device that rotates on its own axis and drives off contaminants from the green coke by bringing the contaminants into direct contact with heated gas. As the petroleum coke slides down the rotating kiln it flows counter-current to the rising hot combustion gas produced by burning natural gas.

Nitrogen Oxides (NO_x)

Regulatory Context and Potential Future BARCT Options

The purpose of a new rule would be to reduce NO_x emissions from petroleum coke calciners located in the Air District. NO_x emissions from gas-fired combustion kilns result primarily from oxidation of atmospheric nitrogen during the combustion of natural gas and coke fines. NO_x formation is favored when both high combustion temperatures and high excess oxygen (O₂) levels are present. Thermal NO_x formation increases exponentially as a function of temperature with the rate of formation rising very rapidly at temperatures above about 2,400 °F. NO_x can also be formed if nitrogen is present in the fuel.

When the Phillips 66 petroleum coke calcining plant calcines green coke under fully operational conditions, the total NO_x emissions are approximately 2000 pounds per day; this translated to approximately 350 tons per year in 2015. In previous years, NO_x emissions have exceeded 500 tons per year from the facility.

There are no federal or Air District NO_x requirements applicable to petroleum coke calcining operations.

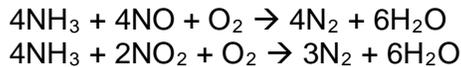
Further Considerations and Potential Control Technologies

NO_x control for petroleum coke calcining operations appears to be unproven and not necessarily commercially available. There are no NO_x best available control technology (BACT) determinations found for the process in the United State Environmental Protection

Agency RBL¹ database. However, South Coast Air Quality Management District (SCAQMD) has published a 2000 BACT guideline for NO_x at 44 ppmvd @ 3 percent O₂. Further research is needed to determine if possible control options have been achieved in practice in SCAQMD or other parts of the US. Some may consider selective catalytic reduction (SCR) and LoTO_x as LAER for this process.

SCR

SCR is a post-combustion control technology that, for combustion unit applications, typically employs ammonia (NH₃) in the presence of a catalyst to convert NO_x to nitrogen and water according to the following overall reactions:



An SCR system typically utilizes an injection grid to evenly disperse the NH₃ into the combustion unit exhaust gas upstream of a catalyst. The function of the catalyst is to lower the activation energy of the NH₃-NO_x reduction reactions. Operating temperature between 500 °F and 800 °F are required of the gas stream at the catalyst bed. NO_x removal rates can exceed 90 percent with a well-designed system.

SCR has been successfully installed at a petroleum coke calcining facility in Germany however additional firing was required to heat the gases back up to 500 °F prior to flow through the SCR catalyst bed, increasing GHG emissions.

LoTO_x

The LoTO_x system injects ozone into the flue gas stream that oxidizes insoluble NO_x to soluble oxidized compounds. LoTO_x is a low temperature system; therefore, it does not require heat input to maintain operational efficiency or to prevent the 'slip' of treatment chemicals, such as ammonia, as is common with SCR and selective non-catalytic reduction (SNCR) systems. Ozone rapidly reacts with insoluble nitric oxide (NO) and nitrogen dioxide (NO₂) molecules to form soluble dinitrogen dioxide (N₂O₂). The species N₂O₂ is highly soluble and will rapidly react with moisture in the gas stream to form nitric acid. The conversion of NO_x into the aqueous phase in the scrubber is rapid and irreversible, allowing nearly complete removal of NO_x. The nitric acid, along with unreacted N₂O₂ and nitrous acid formed by reaction of NO₂ with water, can be easily scrubbed out of the gas stream in a wet scrubber with water or neutralized with a caustic solution. Increased water use in California is of concern. Additional research is required to determine commercial availability for this application.

SO_x

In April 2016, Air District Rule 9-14 was promulgated limiting SO_x emissions from petroleum calcining operations. Additional rulemaking for SO_x emissions from petroleum coke calcining operations are not anticipated at this time.

¹ RACT/BACT/LAER Clearinghouse

ROG

Natural gas fired pyroscubbers control ROG emissions. The main function of a pyroscrubber in petroleum coke calcining process is to oxidize the carbonaceous contents, including hydrocarbon volatiles, of the exhaust gas from the coke calcination kiln. Specific rulemaking for ROG emissions from petroleum coke calcining operations are not anticipated at this time.

Particulate Matter (PM)

Natural gas fired pyroscubbers and baghouses are located on each train to control PM emissions. Current permit requirements include keeping the baghouses in good operating condition, meeting 12-month rolling average PM limits, and incorporating monitoring and recordkeeping as specified per the Title V operating permit conditions. Specific rulemaking for PM emissions from petroleum coke calcining operations are not anticipated at this time.

Cooling Towers – Rule Development Project Scope

Summary

This rule development project addresses emissions from industrial cooling water towers. Staff estimates that preliminary Best Available Retrofit Control Technology (BARCT) levels may result in significant emission reductions of particulate matter (PM). Amendments to Regulation 11, Rule 10 (Rule 11-10) in December 2015 addressed emissions of reactive organic gases (ROG), but that rule will be modified based on litigation and a subsequent Enforcement Agreement and Agreement to Stay Litigation. Staff recommends amending Rule 11-10 to address PM and to address current issues with the 2015 amendments identified in the litigation.

Background

Industrial cooling towers provide cooling to a wide variety of industrial processes. Heat from these processes is transferred into the water through heat exchangers. The water is cooled by evaporation through counter-current flow of cooling water and air in the cooling tower. Since wet cooling towers provide direct contact between the cooling water and the air passing through the tower, some of the liquid water may be entrained in the air stream and be carried out the top of the tower as mist, called "drift." This water mist is an aerosol, and considered a PM emission. However, the mist is primarily water so the primary concern is solids (typically sodium, calcium and magnesium salts) that are contained in the water mist droplet. Solids in cooling water are concentrated by the evaporation, so fresh water is added and a slipstream of cooling tower water is bled from the circulating system to control these solids. When this water mist droplet evaporates, it leaves a residual solid particle.

Heat exchangers can leak occasionally. If the pressure of the process side is higher than the pressure of the cooling water, process fluid can leak into the cooling water. Refinery and petrochemical plant process fluids are typically organic hydrocarbons, and leaks can create ROG emissions. Amendments were made to Rule 11-10 to require regular monitoring of cooling water to catch any potential leaks of hydrocarbon into the cooling water quickly, and minimize ROG emissions.

Particulate Matter

Regulatory Context and Preliminary BARCT Level

Rule 11-10 was initially adopted in 1989, originally addressing use of hexavalent chromium-based water treatment chemicals. Rule 11-10 was amended in December 2015 to address ROG emissions from cooling towers. Federal requirements are outlined in 40 CFR 63, Subpart CC (MACT¹ standard) and 40 CFR 63 Subpart Q (NESHAP²). The MACT standard requirements address potential hydrocarbon leaks, define test methods, and require repair of a

¹ MACT: Maximum Achievable Control Technology

² NESHAP: National Emissions Standard for Hazardous Air Pollutants

leaking exchanger within 45 days if technically feasible. NESHAP requirements address use of hexavalent chromium water treatment chemicals.

PM emissions from cooling towers are not currently being addressed. Water mist from cooling towers is a liquid aerosol, containing water with high total dissolved solids (TDS). When the water evaporates, it leaves a solid particle. Depending on the size of the mist droplet, and the level of solids, these particles may or may not be larger than 10 microns. One study evaluated the particle size distribution of water mist droplets with 3000 parts per million TDS and found roughly 50 percent of the solids are PM with an aerodynamic diameter of ten microns (PM₁₀).³

Current estimates of PM₁₀ emissions from industrial cooling towers range from 0.17 – 6.35 lbs. per million gallons of cooling water circulation. EPA AP-42 emission factor for cooling towers is 0.019 lbs PM₁₀ per thousand gallons⁴ (equal to 19 lbs per million gallons) of cooling water circulation, however the Emission Factor Rating is E, signifying the lowest level of confidence (and cost). Source tests of industrial cooling towers are problematic because they typically don't have uniform discharge vents/stacks required for precise tests.

High efficiency drift eliminators can reduce water mist to less than 0.0005 percent of the cooling water circulation rate. These drift eliminators are estimated to cost \$5.00 per square foot. Cost impacts are estimated based on doubling this cost to \$10.00 per square foot, plus contingency. Cooling towers are designed to accommodate six to eight gallons per minute (gpm) of cooling water circulation per square foot of cooling tower cross sectional area. Cooling water TDS levels also impact the total solids contained in the mist, with higher TDS content leads to larger particles after evaporation. Staff estimates BARCT is 0.125 lb of PM₁₀ per million gallons of cooling water circulation. If the particles are actually only 50 percent PM₁₀, BARCT equals 0.0625 lb of PM₁₀ per million gallons circulation.

Potential Emission Reductions and Impacts

Current estimates of PM₁₀ emissions from cooling towers is 614 tons per year, based on the solids content and estimates of cooling tower mist. Potential emission reductions are 584 tons per year. If only 50 percent of these particles are smaller than 10 microns, the potential emission reductions are reduced to 292 tons per year PM₁₀.

Table 1. Cooling Tower PM₁₀ BARCT Summary

Current Emissions (tpy)	614
Potential Emission Reductions (tpy)	584
Preliminary BARCT Level	0.0005% drift; ~3000 ppm TDS
Controls Required	Hi Efficiency Drift Eliminators TDS control
Total Capital Cost	27 cooling towers - \$1,775,000
Total Annual Cost	\$266,000

³ Calculating Realistic PM10 Emissions from Cooling Towers, Abstract No. 216 Session No. AM-1b, Joel Reisman and Gordon Frisbie, Greystone Environmental Consultants, Inc., 2000

⁴ Chapter 13, Section 4: Wet Cooling Towers, Table 13-4.1.
<https://www3.epa.gov/ttn/chief/ap42/ch13/final/c13s04.pdf>

Cost-Effectiveness (\$/ton)	Lowest at \$200/ton Highest at \$25,500/ton Average: \$455/ton
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Further Considerations

Cooling tower water mist drift is based on typical cooling towers without high efficiency drift eliminators. Three of 27 cooling towers have relatively low PM emissions so further study is needed to fully understand the drift performance of these three cooling towers versus the other 24 cooling towers. PM emissions from these sources have historically been difficult to quantify, and current estimates may not adequately reflect the actual emissions.

The degree to which cooling tower mist creates PM₁₀ and PM with an aerodynamic diameter of 2.5 microns (PM_{2.5}) depends on the size distribution of the of the cooling water mist droplets, and the level of TDS in the cooling water. Larger mist droplets and higher TDS lead to larger particles when the water evaporates. The study cited above indicates PM₁₀ emissions tend to be uniform over a wide range of TDS levels, so further study is needed to understand the need for TDS control and its impact on water use. Staff intends to further study these sources and evaluate the potential for PM reductions when more refined emissions estimates can be developed.

Reactive Organic Gases

Regulatory Context and Preliminary BARCT Level

Rule 11-10 originally addressed use of hexavalent chromium based water treatment chemicals. Rule 11-10 was amended in December 2015 to address ROG emissions from cooling towers. Federal requirements are outlined in 40 CFR 63, Subpart CC (MACT) and 40 CFR 63 Subpart Q (NESHAP). The MACT standard requirements address potential hydrocarbon leaks, define test methods, and require repair of a leaking exchanger within 45 days if technically feasible. NESHAP requirements address use of hexavalent chromium water treatment chemicals.

ROG emissions from cooling towers are currently estimated to be six lbs per million gallons of cooling water circulation, based on the EPA AP-42 emission factor.⁵ MACT standard controls are weekly or monthly monitoring of the cooling water return to monitor for any hydrocarbon leak. If routine monitoring is in place, the EPA AP-42 emission factor is 0.7 lbs per million gallons of cooling water circulation.

Rule 11-10 was amended in December 2015 to require monitoring of cooling water for hydrocarbon leaks, and improve ROG emissions. The requirements in Rule 11-10 have been modified based on litigation and a subsequent Enforcement Agreement and Agreement to Stay Litigation. Staff recommends amending Rule 11-10 codify the modifications documented in the Enforcement Agreement and Agreement to Stay Litigation that address ROG. Routine monitoring based on modified Rule 11-10 has been implemented, so cooling tower emission

⁵ USEPA AP-42 Emission Factors, Chapter 5, Section 1: Petroleum Refineries, Table 5.1-3: Fugitive Emission Factors for Petroleum Refineries

factors and estimated emissions are expected to be much lower. Additional emission reductions are unlikely.

Potential Emission Reductions and Impacts

With Rule 11-10 modifications, no further emission reductions are likely.

Further Considerations

None.

NO_x

Cooling towers do not generate NO_x emissions.

SO_x

Cooling towers do not generate SO_x emissions.