

Organic Liquid Storage Tanks – Rule Development Project Scope

Summary

This rule development project would address emissions of reactive organic gases (ROG) from organic liquid storage tanks. Staff estimates that preliminary best available retrofit control technology (BARCT) levels may result in ROG emission reductions, as well as reductions of associated toxic air contaminant (TAC) emissions from organic liquid tank storage. Staff recommends considering amending Regulation 8, Rule 5: Storage of Organic Liquids to specifically address these ROG and TAC emissions from external floating roof tanks storing organic liquids. Rulemaking for emissions of oxides of nitrogen (NO_x), sulfur dioxide (SO₂), and particulate matter (PM) is not anticipated at this time.

Background

The Air District 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 petroleum producing and refining, petrochemical and chemical manufacturing, bulk storage and transfer operations, and 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).

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.

Existing Applicable Regulations

Tanks used for bulk storage of organic liquids or liquid mixtures containing organic compounds are regulated under Air District Rule 8-5. 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 new source performance standards (NSPS) in 40 CFR 60 Subpart Kb, and Maximum Achievable Control Technology (MACT) standards in 40 CFR 63 Subpart CC. Each of these federal requirements 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 with capacities greater than or equal to 75,000 liters (19,815 gallons) that 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 volatile organic compounds (VOC) in any emission inventory year, starting with the emission inventory year 2000. The rule also includes requirements for domed roofs. Several exemptions are also listed in the rule, the most notable of which include: 1) exemption from doming requirements for crude oil tanks, 2) exemption of facilities with an emission cap equal to or less than 20 tons per year, and 3) exemption from doming requirements for tanks with true vapor pressure limits less than 3 psia.

Review of BACT and Potential Controls

Best Available Control Technology (BACT) for external floating roof storage tanks containing organic liquids is found in the Air District BACT Guideline 167.1.2 dated September 2011. This BACT guideline includes information on two categories of BACT: 1) "technologically feasible and cost effective" and 2) "achieved in practice". The first category of BACT is a more stringent level of control, and generally refers to advanced control devices or techniques. The guideline indicates that a vapor recovery system (VRU) with an overall system efficiency of at least 98 percent would constitute BACT that is "technologically feasible and cost effective". Typical technology implemented for this BACT level includes a thermal incinerator, carbon adsorber, refrigerated condenser, or an Air District-approved equivalent.

The guideline indicates that the BACT level "achieved in practice" is an Air District-approved roof with liquid mounted primary seal and zero gap secondary seal, all meeting the design

criteria of Rule 8-5. The tank system must have 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). Additionally, a dome is required for tanks that meet the following criteria: 1) capacity greater than or equal to 19,815 gallons, 2) located at a facility with greater than 20 tons per year of 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 crude oil by volume).

Potential Emission Reductions and Impacts

Emissions generated from organic liquid storage tanks for AB 617 identified sources in the Air District are nearly 840 tons per 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. AB 617 Organic Liquid Storage Tank Emission Summary

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

¹ Floating roof tanks include both external floating roof and internal floating roof. Further distinction between these two types has not yet been identified.

² 2016 emissions referenced in Air District data files. Emission factors vary from AP-42, 7.1 to Tanks 4.09D emission calculations.

Crude units identified above include both coned and floating roof tank types. Tanks associated with refineries comprise over 95 percent of the AB 617 organic liquid storage tanks identified above. Additional tanks were identified in the AB 617 analysis but excluded from further BARCT analysis, as ROG emissions for each of these tanks were less than 10 pounds per day (1.8 TPY).

Potential ROG emission reductions may be achieved by installing domes on external floating roof tanks, and by capturing vented emissions from internal floating roof or coned roof tanks and removing ROG emissions through a vapor recovery unit (VRU) flowing back to the tank(s) or 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 and cost effectiveness from these different control options at floating roof tanks. Note that each of the estimates for total capital cost and total annual costs below are based on approximately 10 tanks with Rule 8-5 applicability as external floating roof tanks (EFRTs).

Table 2. AB 617 Organic Liquid Storage Tanks BARCT Summary – Dome

Current Emissions, Floating Roof Tanks (tpy)	400
Potential Emission Reductions (tpy)	75
Preliminary BARCT Level	EFRT Dome with 75% Evaporation/Wind Effect Reduction
Controls Required	EFRT Dome
Total Capital Cost	\$6,250,000
Total Annual Cost	\$750,000
Cost-Effectiveness (\$/ton)	\$10,000

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

Current Emissions, Floating Roof Tanks (tpy)	400
Potential Emission Reductions (tpy)	100
Preliminary BARCT Level	EFRT Dome + 98% Efficiency Vapor Recovery Unit
Controls Required	EFRT Dome + 98% Efficiency Vapor Recovery Unit
Total Capital Cost	\$8,500,000
Total Annual Cost	\$1,500,000
Cost-Effectiveness (\$/ton)	\$15,000

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

Current Emissions, Floating Roof Tanks (tpy)	400
Potential Emission Reductions (tpy)	125
Preliminary BARCT Level	EFRT Dome + 98% Efficiency Vapor Recovery Unit + Incinerator
Controls Required	EFRT Dome + 98% Efficiency Vapor Recovery Unit + Incinerator
Total Capital Cost	\$12,000,000
Total Annual Cost	\$2,500,000
Cost-Effectiveness (\$/ton)	\$20,000

Dome installation on an external floating roof tank cost estimates assume a dome cost of approximately \$40 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) would be approximately \$625,000 per tank. Total annualized cost would be approximately \$75,000 per tank. Additional considerations would need to be made for tank age, earthquake structural supports, and fire suppression on certain tanks.

Vapor recovery units (VRU) capital costs are estimated to be approximately \$225,000 per single tank. There would likely be cost savings for VRU systems that are applied to multiple tanks with an associated increase in compressor size. Incinerators are estimated to require an additional

\$350,000 in capital costs per tank, with potential cost savings for systems combining several tanks into one VRU header prior to incineration. Additional fuel costs for incineration may also need to be considered and evaluated further.

In lieu of converting fixed roof tanks to internal floating roof tanks, operators may instead choose to vent the vapor losses from these fixed roof tanks to a vapor control system or a vapor recovery system for ROG control. Facilities with an existing vapor control or vapor recovery system on site may be able to accommodate the additional vapor recovery load without installation of additional systems or capacity. In this scenario, the costs of implementing this control option would be anticipated to be minor. However, the cost and cost effectiveness 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 additional tank design data and emission information associated with the organic liquid storage tanks at AB 617 identified facilities. Staff recommends forming an OLST (Organic Liquid Storage Tank) Working Group that may include representatives of affected facilities, environmental organizations, and manufacturers of domed roofs to discuss relevant control technologies for storage tanks. In parallel, staff may also perform site visits of the affected facilities to assess actual operating conditions. Additional refinements to estimates of current emissions and potential reductions would be needed to appropriately evaluate BARCT control options. This further study and refinement may involve additional estimation of ROG emissions through site visits, testing, monitoring, or assessment of emission estimation protocols and programs, such as the United States Environmental Protection Agency (EPA) TANKS version 4.09D program. Staff would also seek input through OLST Working Group meetings, public workshops, and numerous individual site visits and meetings with stakeholders.

SO₂

Organic liquid storage tanks do not typically generate substantial SO₂ emissions that would require additional controls. Therefore, further BARCT evaluation and rulemaking are not anticipated at this time. 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.

NO_x

Organic liquid storage tanks do not typically generate substantial NO_x emissions that would require additional controls. Therefore, further BARCT evaluation and rulemaking are not anticipated at this time. 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

Organic liquid storage tanks do not typically generate substantial PM emissions that would require additional controls. Therefore, further BARCT evaluation and rulemaking are not anticipated at this time. 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.

Petroleum Wastewater Treating – Rule Development Project Scope

Summary

This rule development project would address emissions of reactive organic gases (ROG) from petroleum wastewater treating operations. Staff estimates that preliminary best available retrofit control technology (BARCT) levels could result in potential ROG emission reductions. The Air District has addressed ROG emissions from petroleum wastewater treatment facilities in previous rule developments (Rule 8-8 Wastewater Collection and Separation Systems), but staff recommends reviewing each of the five Bay Area refineries for additional opportunities for reduction of wastewater ROG. This review may include on-site air emissions testing, which will require refinery cooperation. Any recommended and implemented ROG controls in addition to current regulatory requirements are also anticipated to reduce toxic air contaminant (TAC) emissions. Rulemaking for emissions of oxides of nitrogen (NO_x), sulfur dioxide (SO₂), and particulate matter (PM) is not anticipated at this time.

Background

All refineries employ some form of wastewater treatment so that water effluents can be safely returned to the environment or reused in the refinery. The designs of specific wastewater treatment plants are complex, and are complicated by the diversity of refinery pollutants, including oils, 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.

ROG

Regulatory Context and Preliminary BARCT Level

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 wastewater treatment plants are fugitive ROGs and dissolved gases that evaporate from the surfaces of wastewater 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 wastewater 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 ROG emission estimates associated with refinery wastewater operations may vary widely and may not be consistently characterized between different systems and components. Some facilities report total wastewater ROG emissions for the overall treatment system, while others may delineate between OWS emissions and fugitive emissions. Additionally, other facilities may report no discernable ROG emission contributions from wastewater treatment components and systems. Considering these caveats and limitations, a reasonable estimate of annual ROG emissions attributable to refinery wastewater treatment systems is 300 to 600 tons per year. Additional review and study of current emissions inventories, refinery emission reporting methodology, emission factors, and calculations would be needed to appropriately inform future rule development.

Review of BACT and Potential Controls

Recent best available control technology (BACT) determinations from the United States Environmental Protection Agency (EPA) RBLC¹ database indicate that controls for refinery wastewater systems include requirements for process wastewater effluent treatment to 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 with capacity greater than 250 gallons per minute. The determination includes a recommendation of a vapor tight fixed cover vented to a vapor recovery system with combined collection and destruction/removal efficiency greater than 95 percent.

Existing Applicable Regulations

Current Air District Rule 8-8: Wastewater Collection and Separation Systems requires oil-water separators to be covered. Additionally, Air District Rule 8-18: Equipment Leaks also requires refining operations to test for potential equipment leaks related to wastewater operations.

Applicable federal 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

¹ RACT/BACT/LAER/Clearinghouse
Petroleum Wastewater Treating
BARCT Scope

boxes, and oil-water separators. Subpart FF pertains to benzene waste operations NESHAPs² (BWON). 40 CFR 63 Subpart CC (MACT³ 1) targets miscellaneous wastewater process vents.

Further Considerations

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 can vary widely according to refinery-specific factors. Therefore, there is no singular approach to handling and treating refinery wastewater.

Accordingly, strategies to further reduce ROG emissions will require development and refinement of emissions testing protocols, as well as individual refinery cooperation with the Air District measurements and testing staff. Further evaluation of the potential control options identified, as well as their efficacy, feasibility, and cost-effectiveness, would depend heavily on these additional study and research efforts. In addition to the wastewater treatment system components discussed, aeration ponds can also be a large area source of ROG emissions in the petroleum wastewater treatment process. Control strategies for this type of source are unknown at this time, but would also need to be studied further.

Additional coordination between individual facilities and 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. Previous Air District efforts, including studies of refinery wastewater conducted in 2006, would be reviewed and referenced in developing these further analyses and efforts. Staff recommends additional evaluation and research prior to development of a draft BARCT limit or rule.

SO₂

Petroleum refinery wastewater treatment processes do not typically generate substantial SO₂ emissions that would require additional controls. Therefore, further BARCT evaluation and rulemaking are not anticipated at this time.

NO_x

Petroleum refinery wastewater treatment processes do not typically generate substantial NO_x emissions that would require additional controls. Therefore, further BARCT evaluation and rulemaking are not anticipated at this time.

Particulate Matter

Petroleum refinery wastewater treatment processes do not typically generate substantial PM emissions that would require additional controls. Therefore, further BARCT evaluation and rulemaking are 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). Rulemaking for emissions of oxides of nitrogen (NO_x) and reactive organic gases (ROG) is 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 clinker (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 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 for condensable PM 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 (including filterable and condensable 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, use of low sulfur fuels, dry scrubbing, and dry sorbent injection. Based on this review, staff has identified a preliminary BARCT level of 1.0 lb SO₂ per ton clinker. This preliminary BARCT level is used for staff's evaluation of potential BARCT controls, compliance costs, and emissions reductions, but may change as controls are further evaluated.

Potential Emission Reductions and Impacts

Based on staff's identified 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 lime injection and sodium carbonate systems for control of HCl emissions, but staff anticipates that additional lime injection capacity or an additional dry sorbent injection system would be required to meet the preliminary BARCT level

for SO₂. The capital cost of the current lime injection system was \$700,000, with operating costs of \$1.26 million per year.¹ Based on EPA cost estimating methods and assumptions for lime injection systems at cement kilns,² the capital cost of an appropriately sized system for the facility is estimated to be less than \$500,000, with annual operating costs of approximately \$1 million dollars. 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 \$1.47 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	\$1,470,000
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 site-specific analysis of the affected facility would be needed to appropriately evaluate the impact of existing controls on SO₂ emissions and better characterize the efficacy of additional controls. This may involve testing and optimization of additional lime injection, use of different sorbents, and modification of control equipment parameters, as well as further source testing (including speciation of condensable PM). Further refinements to the evaluation of control costs and cost-effectiveness are also needed. Draft and final proposed BARCT limits may change throughout the rule development process as additional testing, research, and evaluation is conducted.

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

¹ BAAQMD, 2012. Staff Report – Regulation 9, Rule 13: Nitrogen Oxides, Particulate Matter, and Toxic Air Contaminants from Portland Cement Manufacturing. July.

² EPA, 2010. Summary of Environmental and Cost Impacts of Final Amendments to Portland Cement NESHAP. August.

manufacturing emissions, and contains an emission limit of 2.3 lb NO_x per ton clinker on a 30-operating day rolling average.

Staff believes that the NO_x limits in Rule 9-13 adopted in 2012 reflect BARCT for NO_x, 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). Rulemaking for emissions of oxides of nitrogen (NO_x) and reactive organic gases (ROG) is 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 is evaluating additional amendments to Rule 6-5 to further reduce ammonia slip following the conclusion of the current ammonia injection optimization process. Enhancements may include modifications to the ammonia optimization requirements and/or ammonia slip limit. Enhanced ammonia slip requirements and limits may require the upgrade or installation of additional ESP capacity to improve filterable PM removal and reduce the need to ammonia injection, or use of alternative flue gas conditioning agents. Results from the current ammonia optimization testing may provide information on the level of controls needed and the achievable ammonia slip levels. 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

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. Estimates of potential emission reductions would also be highly dependent on the efficacy of the current Rule 6-5 implementation process and ammonia optimization. Therefore, emission reductions and cost-effectiveness of these controls may be more appropriately evaluated following the

conclusion of the current Rule 6-5 implementation. Additional baseline testing of current condensable PM emissions should also be conducted as part of this ongoing evaluation.

Costs of additional controls for reducing ammonia slip may vary depending on the types of control options required. Staff reviewed ESP cost data and information from previous analyses from South Coast Air Quality Management District (SCAQMD)¹ and EPA,² and estimated that capital costs of additional ESP capacity or upgrades may range from \$20 million to \$50 million per facility. Implementation of alternative conditioning agents would be anticipated to require lower capital and operating costs compared to ESPs. Further site-specific considerations of current ESP and ammonia injection performance, additional control costs, and space constraints would be needed to appropriately evaluate the potential for achieving substantial condensable PM reductions. As discussed previously, evaluation of potential emission reductions and cost-effectiveness of these additional controls would be more appropriate following the conclusion of the current Rule 6-5 implementation.

Further Considerations

Additional testing and study of the FCCUs and CO boilers are likely necessary to properly characterize condensable PM emissions. This further study would be expected to inform the evaluation of efficacy, feasibility, and cost-effectiveness of various potential control options. Potential controls involving ESP improvements or additional capacity would need to be evaluated for costs and space constraints, and the feasibility of achieving the ammonia slip limit would need to be analyzed on a site-specific basis. 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

¹ SCAQMD, 2003. Final Staff Report – Proposed Rule 1105.1 Reduction of PM10 and Ammonia Emissions from Fluid Catalytic Cracking Units. September 2003.

² EPA, 2008. Regulatory Impact Analysis of the Petroleum Refinery NSPS. April 2008.

achieved at FCCUs and CO boilers. Typical controls include SO₂-reducing catalyst additives or wet gas scrubbers. Based on staff's review, staff has identified 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. This preliminary BARCT level is used for staff's evaluation of potential BARCT controls, compliance costs, and emissions reductions, but may change as controls are further evaluated.

Potential Emission Reductions and Impacts

Three of the four refineries operating FCCUs currently have permit limits equivalent to the 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 be required to install a wet gas scrubber or optimize use of enhanced 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 up to 567 tons per year of SO₂. For this preliminary evaluation, staff estimated potential emission reductions and costs for control options involving enhanced catalyst additive optimization and wet gas scrubbing.

Optimized use of enhanced partial burn catalyst additive would result in one-time costs for optimization testing, as well as continued costs of the enhanced catalyst additive. Staff conservatively estimates that optimization testing may result in costs up to \$5 million dollars, and costs of continued addition and use of enhanced catalyst additive may be up to \$1 million dollars per year. Note that these current estimates do not account for any cost savings from reduced additive usage that may occur as a result of the optimization. Based on these estimates, the annualized cost of the control strategy (including amortized optimization costs and operating costs) is estimated at approximately \$1.8 million dollars per year. This would result in a cost-effectiveness of approximately \$4,000 per ton of SO₂. Note that further study is needed to determine if this optimization option would achieve the preliminary BARCT level and associated emission reductions.

Capital and operating costs of wet gas scrubbing would likely have higher total costs compared to other control options. Based on staff's review of wet gas scrubber costs from vendor estimates and previous projects and evaluations, capital costs of a wet gas scrubber are estimated at \$135 million dollars, with the annualized cost of the control system (including amortized capital costs and operating costs) estimated at approximately \$27 million dollars per year. This would result in a cost-effectiveness of approximately \$47,000 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	\$5,000,000 (enhanced catalyst additive) to \$135,000,000 (wet gas scrubber)
Total Annual Cost	\$1,800,000 (enhanced catalyst additive) to \$27,000,000 (wet gas scrubber)
Cost-Effectiveness (\$/ton)	\$4,000 (enhanced catalyst additive) to \$47,000 (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, estimates of emission reductions and cost-effectiveness for this control option may change with additional testing, research, and study of these sources and enhanced catalyst additives. Further refinements to the evaluation of cost-effectiveness and technological feasibility for both additive optimization and wet gas scrubbing are also needed.

NOx

Regulatory Context and Preliminary BARCT Level

Federal NSPS Subpart Ja includes an emission limit of 80 ppmv NOx 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 NOx 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 NOx emission levels of 20 ppmv NOx 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 NOx limits in Rule 9-10 adopted in 2013 reflect BARCT for NOx 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 NOx limits. However, this FCCU is subject to facility permit limits of 20 ppmv NOx on a 365-day rolling average basis and 40 ppmvd NOx on a seven-day rolling average basis, which are comparable to the BACT levels reviewed. Staff believes that these limits reflect BARCT for NOx 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 would address emissions of reactive organic gases (ROG) 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 a Heavy Liquid Leak Study. 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. Any recommended and implemented requirements to address ROG emissions from these sources are also anticipated to reduce toxic air contaminant (TAC) emissions. Rulemaking for emissions of oxides of nitrogen (NO_x), sulfur dioxide (SO₂), and particulate matter (PM) is not anticipated at this time.

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. Air District 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, that the equipment is 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

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

proper collection of all the data needed. Study participants are re-configuring the study approach, and anticipate having useful data by the Fall of 2018.

ROG

Regulatory Context and Preliminary BARCT Level

The Air District originally adopted Rule 8-18 in 1980, and has amended the rule 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 these methods only identify 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 that fugitive hydrocarbon leaks from the five refineries in the Bay Area total approximately 1,172 tons per year of ROG based on emission factors at that time. The estimate of 458 tons per year shown below is based on interim emission factors that will be used during the completion of the heavy liquid leak study mentioned above. Refined estimates of actual emissions and potential emission reductions will be quantified based on the results of the heavy liquid leak study.

Table 1. Refinery Heavy Liquid Leaks ROG BARCT Summary

Current Emissions (tpy)	1,172 tpy (458 tpy based on estimated emissions factors)
Potential Emission Reductions (tpy)	Uncertain
Preliminary BARCT Level	TBD
Controls Required	LDAR for heavy liquid equipment
Total Capital Cost	\$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 the heavy liquid leak study. Therefore, estimates of emission reductions and cost-effectiveness for this control and monitoring may change as the heavy liquid leak study progresses. Results of the study are also expected to inform health risk analyses required by Rule 11-18, so further controls based on implementation of Rule 11-18 may also be taken into consideration when evaluating further rulemaking activity.

Particulate Matter

Heavy liquid leaks do not typically generate substantial PM emissions that would require additional controls. Heavy liquids that may become aerosols (and any toxic air contaminant components) would be controlled by a heavy liquid leak LDAR program for ROG emissions. Therefore, further BARCT evaluation and rulemaking are not anticipated at this time.

NO_x

Heavy liquid leaks do not typically generate substantial NO_x emissions that would require additional controls. Therefore, further BARCT evaluation and rulemaking are not anticipated at this time.

SO₂

Heavy liquid leaks do not typically generate substantial SO₂ emissions that would require additional controls. Therefore, further BARCT evaluation and rulemaking are not anticipated at this time.

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 therefore may be considered Lowest Achievable Emission Rate (LAER). Rulemaking for emissions of sulfur dioxide (SO₂), reactive organic gases (ROG), and particulate matter (PM) is not anticipated at this time.

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 located 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, and 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, which is a photocatalyst commonly used to manufacture white pigments that are incorporated into a wide range of applications, including skincare products, plastics, food coloring, 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 with a rating of approximately 60 million British thermal units (MMBtu/hr) each, and that have a combined permitted maximum coke throughput of 250 tons per hour. Each train includes a pyroscrubber and baghouse with 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 is stored on-site at the Carbon Plant. 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 to 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 to 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.

NO_x

Regulatory Context and Preliminary BARCT Level

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. Currently, there are no federal or Air District NO_x requirements applicable to petroleum coke calcining operations.

When the Phillips 66 Carbon Plant calcines green coke under fully operational conditions, the total NO_x emissions are approximately 2,000 pounds per day; this translated to approximately 350 tons per year in 2015. In previous years, NO_x emissions from the facility have exceeded 500 tons per year. Staff believes that substantial reductions of NO_x emissions may be achievable, however research of potential control options is ongoing, and a preliminary BARCT

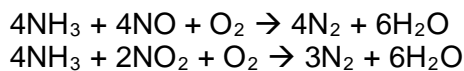
level is still under development. Potential control technologies are discussed in the section below.

Further Considerations

NOx control for petroleum coke calcining operations appears to be unproven and not necessarily commercially available. There were no best available control technology (BACT) determinations for NOx emissions found for the process in the United State Environmental Protection Agency RBLC¹ database. However, South Coast Air Quality Management District (SCAQMD) published a 2000 BACT guideline for NOx at 44 ppmvd at 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. Typical NOx control options include selective catalytic reduction (SCR) and LoTOx, which may be considered by some as a LAER control 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 NOx 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-NOx reduction reactions. Operating temperatures between 500 °F and 800 °F are often required of the gas stream at the catalyst bed. NOx 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.

Additional study of this control option would be required to appropriately evaluate this control strategy and achievable BARCT limits. Further considerations of efficacy, feasibility, and cost-effectiveness would need to be analyzed on a site-specific basis. Draft and final proposed BARCT limits may change throughout the rule development process as additional testing, research, and evaluation is conducted.

LoTOx

In the LoTOx system, ozone is injected into the flue gas stream and oxidizes insoluble NOx to soluble oxidized compounds. LoTOx 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.

¹ RACT/BACT/LAER Clearinghouse

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.

Additional study of this control option would be required to appropriately evaluate this control strategy and achievable BARCT limits. Increased water use associated with the LoTOx system would need to be evaluated, as substantial water consumption may be a concern. Additional research is also required to determine commercial availability for this application. Further considerations of efficacy, feasibility, and cost-effectiveness would need to be analyzed on a site-specific basis. Draft and final proposed BARCT limits may change throughout the rule development process as additional testing, research, and evaluation is conducted.

SO₂

Regulatory Context and Preliminary BARCT Level

In April 2016, Air District Rule 9-14 was promulgated limiting SO₂ emissions from petroleum calcining operations. Staff believes that these limits reflect BARCT for SO₂, and further BARCT evaluation and rulemaking is not anticipated at this time.

ROG

Regulatory Context and Preliminary BARCT Level

Natural gas fired pyroscrubbers 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. Staff believes that this level of control reflects BARCT for ROG at the source, and further BARCT evaluation and rulemaking is not anticipated at this time.

Particulate Matter

Regulatory Context and Preliminary BARCT Level

Natural gas fired pyroscrubbers 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. Staff believes that this level of control reflects BARCT for PM at the source, and further BARCT evaluation and rulemaking is not anticipated at this time.