SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT

DRAFT STAFF REPORT

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Proposed Amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters – Phase 3)
Proposed Amendments to Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr)

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I. SUMMARY

A. Reasons for Rule Development and Implementation

The U.S. Environmental Protection Agency (EPA) periodically reviews and establishes health-based air quality standards for ozone, particulates, and other pollutants. Although the San Joaquin Valley's (Valley) air quality is steadily improving, the Valley experiences unique and significant difficulties in achieving these increasingly stringent standards. The Valley's challenges in meeting national ambient air quality standards are unmatched in the nation due to the region's unique geography, meteorology and topography. In response to the latest federal mandates and to improve quality of life for Valley residents, the District has developed and implemented multiple generations of rules on various sources of air pollution. Valley businesses are currently subject to the most stringent air quality regulations in the nation. Since 1992, the District has adopted nearly 650 rules to implement an aggressive on-going control strategy to reduce emissions in the Valley, resulting in air quality benefits throughout the Valley. Similarly, the California Air Resources Board (CARB) has adopted stringent regulations for mobile sources. Together, these efforts represent the nation's toughest air pollution emissions controls and have greatly contributed to reduced ozone and particulate matter concentrations in the Valley.

Due to the significant investments made by Valley businesses and residents and stringent regulatory programs established by the District and CARB, the Valley's ozone and PM2.5 (particulate matter that is 2.5 microns or less in diameter) emissions are at historically low levels, and air quality over the past few years has continued to set new clean air records. Despite the significant progress under these regulations, greatly aided by the efforts of Valley businesses and residents, many air quality challenges remain, including attainment of the federal air quality standards for PM2.5 that are addressed in the District's recently adopted *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards* (*2018 PM2.5 Plan*).

The *2018 PM2.5 Plan* contains a comprehensive set of local and state measures that build on existing measures to further reduce air pollution from stationary, area, and mobile sources throughout the Valley. Attaining the multiple federal PM2.5 standards by the mandated deadlines is not possible without significant additional reductions in directly emitted PM2.5 and PM2.5 precursors like NOx (oxides of nitrogen).

The *2018 PM2.5 Plan* includes a suite of innovative regulatory and incentive-based measures, supported by robust public education and outreach efforts to reduce emissions of PM2.5 in the Valley. One of the measures included in the plan is to amend District Rule 4306 (Boilers, Steam Generators, and Process Heaters - Phase 3) and Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr) as a necessary cost-effective measure for further reducing NOx emissions and bringing the Valley into attainment with federal PM2.5 standards within the mandated federal deadlines.

Based on a comprehensive technical analysis, in-depth review of local, state, and federal regulations, and a robust public process, District staff are proposing several modifications to Rules 4306 and 4320 to reduce emissions from boilers, process heaters, and steam generators in the San Joaquin Valley. The proposed Rule 4306 and Rule 4320 go above and beyond federal standards of Reasonably Available Control Technology (RACT), Best Available Retrofit Control Technology (BARCT), and Most Stringent Measures (MSM). This rule amendment project is proposed to satisfy the commitments in the District's *2018 PM2.5 Plan*. The proposed amendments to Rule 4306 and Rule 4320 will seek to obtain as much reduction of NOx from boilers, steam generators, and process heaters as expeditiously practicable and technologically and economically feasible.

B. PM2.5 Health Impacts and Benefits of Implementing NOx Control Measures

The health risks of PM2.5 have been linked to a variety of health issues, including aggravated asthma, increased respiratory symptoms (irritation of the airways, coughing, difficulty breathing), decreased lung function in children, development of chronic bronchitis, irregular heartbeat, non-fatal heart attacks, increased respiratory and cardiovascular hospitalizations, lung cancer, and premature death. CARB explains that even short-term exposure of less than 24 hours can cause for premature mortality, increased hospital admissions for heart or lung causes, acute and chronic bronchitis, asthma attacks, emergency room visits, respiratory symptoms, and restricted activity days.[1] Children, older adults, and individuals with heart or lung diseases are the most likely to be affected by PM2.5.

PM2.5 emissions are characterized by a unique combination of direct and secondarily formed constituents. As NOx emissions are a key precursor to the formation of ammonium nitrate, which is a large portion of total PM2.5 during the peak winter season, continuing to assess the feasibility of achieving additional NOx reductions across the Valley is beneficial for continuing to improve PM2.5 throughout the region. PM2.5 is a major health risk because it can be inhaled more deeply into the gas exchange tissues of the lungs, where it can be absorbed into the bloodstream and carried to other parts of the body. Due to these significant health risks, as discussed earlier in this report, EPA establishes health based ambient air quality standards for PM2.5. The District develops attainment plans and implements control measures to lower the amount of PM2.5 throughout the San Joaquin Valley, with the goal of attaining the federal standards.

Within the *2018 Plan for the PM2.5 Standard* the District committed to attain the federal standards for PM2.5, including the 24-hour standard of 35 $\mu g/m^3$ by the end of 2024, and the annual standard of 12 $\mu g/m^3$ by the end of 2025. Since 1992, the District has adopted nearly 650 rules to implement an aggressive on-going control strategy to reduce emissions in the Valley. District rules and regulations reduce particulate matter and NOx emissions, and contribute to the Valley's progress toward attainment of health-based ambient air quality standards.

New regulatory and incentive-based measures proposed by both the District and CARB, combined with existing measures achieving new emissions reductions will achieve the emissions reductions necessary to attain each health-based federal PM2.5 standard as expeditiously as practicable, and will improve public health as emissions reductions and associated health benefits are realized. The proposed amendments will achieve additional reductions in NOx emissions as requirements are implemented by affected sources and new technologies are installed.

C. Description of the Project

The District's Governing Board adopted Rule 4306 on September 18, 2003, and last amended this rule on October 16, 2008. Rule 4320 was adopted on October 16, 2008. The rules apply to any gaseous fuel or liquid fuel fired boilers, steam generators, and process heaters with a rated heat input greater than 5 million Btu/hour. Facilities with units subject to this control measure represent a wide range of industries, including but not limited to electrical utilities, cogeneration, oil and gas production, petroleum refining,

[1] "Inhalable Particulate Matter and Health (PM2.5 and PM10)." *California Air Resources Board*, 2020, ww2.arb.ca.gov/resources/inhalable-particulate-matter-and-health.

manufacturing and industrial, food and agricultural processing, and service and commercial facilities.

Proposed amendments would amend Rule 4306 and Rule 4320 to satisfy commitments in the *2018 PM2.5 Plan*. The proposed amendments to Rule 4306 and 4320 include lowering NOx emissions limits for multiple classes and categories of units subject to these rules, clarifying definitions, and updating test methods. The limits proposed require the installation of ultra-low NOx burners or the most advanced add-on control equipment, including Selective Catalytic Reduction (SCR). An evaluation was also conducted as to the feasibility of requiring alternative technologies, including electric and solar technologies. Through the implementation of the proposed Rule 4306 amendments, an estimated 16.4% reduction of NOx emissions will be achieved in 2024, with an additional 2.6% reduction of NOx emissions in 2030. Based on the emissions inventory used for the *2018 PM2.5 Plan*, this will result in 0.19 tons per day (tpd) of NOx emission reductions in 2024, and an additional 0.03 tpd of NOx emission reductions in 2030. Proposed amendments to Rule 4320 will achieve an additional 46% (0.45 tpd) of NOx emission reductions from this source category in 2024, although District staff are not proposing these reductions for SIP-credit at this time.

D. Rule Development Process

As part of the rule development process, District staff conducted public workshops to present and discuss proposed amendments to Rule 4306 and Rule 4320. District staff conducted public workshops in December 2019, July 2020, September 2020, and October 2020. In addition to the workshops, numerous meetings were held with stakeholders to discuss their individual issues and suggestions. Updates were also presented throughout the rulemaking process at multiple public meetings of the Citizens Advisory Committee, Environmental Justice Advisory Group, and the District Governing Board.

At the workshops, District staff presented the objectives of the proposed rulemaking project and provided the draft rules. District staff solicited information from affected source operators, consultants, vendors and manufacturers of control technologies, and trade associations on the technological feasibility and compliance cost information that would be useful in developing amendments to Rule 4306 and Rule 4320. The comments received from the public, affected sources, interested parties, CARB, and EPA, during the public workshop process were incorporated into the draft rules as appropriate.

Pursuant to state law, the District is required to perform a socioeconomic impact analysis prior to adoption, amendment, or repeal of a rule that has significant air quality benefits or that will strengthen emission limitations. As part of the District's socioeconomic analysis process, the District hired a socioeconomic consultant to prepare a socioeconomic impact report. The results of the socioeconomic analysis are included in this report (Appendix D).

The proposed rule amendments, final draft staff report with appendices, and final draft socioeconomic analysis report will be published prior to a public hearing to consider the adoption of rule amendments to Rule 4306 and Rule 4320 by the District Governing Board. The public hearing is scheduled on December 17, 2020.

II. BOILERS, STEAM GENERATORS, AND PROCESS HEATERS GREATER THAN 5 MMBTU/HR IN THE SAN JOAQUIN VALLEY

NOx emissions from sources subject to Rules 4306 and 4320 total 1.35 tons per day in 2020. These emissions account for 5% of all NOx emissions from stationary sources in the District. NOx emission from these sources have already been reduced by 96% from previous rule amendments.

There are over 1,200 units in the District subject to Rules 4306 and 4320. Fire tube boilers, water tube boilers, steam generators, and process heaters are used at a wide range of facilities throughout the San Joaquin Valley, including:

- Food and agricultural product processing operations
- Oil and Gas Production facilities
- Petroleum Refineries
- Manufacture and industrial facilities
- Ethanol Production facilities
- Hospitals
- Schools, Universities
- Livestock husbandry operations (dairies, cattle feedlots, etc.)

The current inventory of boilers, steam generators, and process heaters currently located in the San Joaquin Valley is shown in the table below. This table shows the inventory broken out depending on the size and type of unit in categories further defined in the current version of Rule 4320.

Table 1: Current Inventory of Units in the Valley

Rule 4320 Category	# Units
Group A. Units 5-20 MMBtu/hr except for Categories C-G Units	302
Group B. Units >20 MMBtu/hr except for Categories C-G Units	230
Group C.1 Oilfield Steam Generators 5-20 MMBtu/hr	8
Group C.2 Oilfield Steam Generators >20 MMBtu/hr	410
Group C.3 Oilfield Steam Generators firing on less than 50% PUC quality gas	142
Group D.1 Refinery Boiler 5-40 MMBtu/hr	2
Group D.2 Refinery Boilers ≥40 MMBtu/hr to ≥110 MMBtu/hr	3

Rule 4320 Category	# Units
Group D.3 Refinery Boilers >110 MMBtu/hr	1
Group D.4 Refinery Process Heaters 5-40 MMBtu/hr	42
Group D.5 Refinery Process Heaters ≥40 MMBtu/hr	9
Group D.6 Refinery Process Heaters >110 MMBtu/hr	1
Group E. Units with an annual heat input 1.8-30 billion Btu/yr	65
Total	**1,215**

Specific considerations for each of these types of units have been taken into account throughout this rulemaking, and are further discussed in the “Proposed Amendments” section of this staff report, and in Appendix C.

III. EMISSION CONTROL TECHNOLOGIES

Over the years, the District has adopted numerous generations of rules and rule amendments for units greater than 5 MMBtu/hr that have significantly reduced NOx and PM emissions from this source category. As part of these regulatory efforts, hundreds of boilers in the Valley have been equipped with the best available NOx and PM control technologies. Even though significant effort has already been made to reduce emissions from this source category, the possibility of further reducing emissions from units greater than 5 MMBtu/hr is evaluated in the following discussion.

The two primary methods of controlling NOx emissions from boilers, steam generators, and process heaters are either to change the combustion parameters (i.e., combustion modification) to reduce NOx formation, or to treat the NOx formed before it is emitted into the atmosphere with the use of selective catalytic reduction. The District also evaluated the potential for reducing NOx with electrification, and solar powered oil field steam generators as well as direct PM controls.

Combustion Modification

Combustion modification systems are designed to reduce thermal NOx formation by changing the flame characteristics to reduce peak flame temperature. Combustion controls include low excess air operation, staged combustion, overfire air ports, biased firing, and placing selected burners out-of-service.

Combustion modification is also achieved by different burner designs such as Low NOx Burners (LNB) and Ultra Low NOx Burners (ULNB). ULN and LNBs control fuel air mixing to improve flame structure resulting in less NOx formation through the use of staged air burners, staged fuel burners, pre-mix burners, internal recirculation, and radiant burners. ULNBs can be installed on most units and are capable of achieving NOx emissions as low as 5 ppmv for certain types and sizes of units. Retrofitting a unit with ULNBs has a capital cost of $30,000 to $400,000 depending on the size of the unit. The use of ULNBs can also increase annual costs due decreased thermal efficiency and the need for more electricity.

A combustion control system may be used by itself or in combination with Flue Gas Recirculation (FGR), additional oxygen flow controls, and tuning. FGR recycles a portion of the exhaust stream back into the burner windbox, mixing low oxygen air with combustion air prior to entering the combustion chamber. This technique reduces thermal NOx formation by reducing the peak temperature and by reducing oxygen in the combustion zone. FGR when combined with additional control equipment and tuning can allow an operator to meet a lower NOx limit without replacing burners. The capital cost for a FGR system is $17,000 to $84,000 depending on the size of the unit. FGR also increases annual costs due to the additional electricity needed to run the recirculation fan.

<u>Selective Catalytic Reduction</u>

Selective Catalytic Reduction (SCR) is another way to reduce NOx. NOx is reduced to molecular nitrogen by adding a flue gas treatment system consisting of a catalyst module and a reagent injection system located after the boiler firebox. SCR units operate at a certain temperature range to effectively reduce NOx in the exhaust gas by injecting either ammonia stored in aqueous form, anhydrous form, generated on demand, or released from urea into the post-combustion zone of the boiler. SCR systems are generally paired with LNB.

SCR systems have significant initial capital cost and require large footprints. The installed cost of an SCR system is $230,000 to $750,000 depending on the size of the unit. Some facilities may also require additional construction costs to accommodate the large size of the catalyst. However, the use of an SCR system can result in an annual cost savings as a result of less need for electricity to run FGR fans and decreased fuel use from the increased efficiency of a LNB. The annual cost savings could range from $16,000 to $148,000, depending on the size of the unit, with vendors and some operators noting that the initial capital cost could be recouped in a number of years.

SCR technology is not a common NOx emission control technology for oilfield steam generators. The temperature required for SCR to work (400-800 F) is higher than the temperature that of oilfield steam generator exhaust (~250 F). The steam generators would have to be cut open to retrofit SCR into the convection section of the steam generator to operate the SCR system at the correct temperature. This would cause heat loss, preventing the production of the steam necessary for the oil field operation. Additional feasibility limitations associated with the installation of SCR for oil field steam generators include space limitations within installed infrastructure, and concerns with the storage of anhydrous ammonia in the remotely located, unsecure oil fields where these types of units operate. Due to these factors, SCR is not a feasible control system for use on oil field steam generators at this time.

Electrification of Units

Electric boilers and process heaters are commercially available and generally cost about the same as similarly sized natural gas units. However, the cost to operate a large unit on electricity is much higher than on natural gas. Our analysis has also shown that the electricity generation required to operate units larger than 5 MMBtu/hr would produce more NOx than units operating at the proposed NOx limits in Rule 4306. For example, a 5 MMBtu/hr fire tube boiler would cost nearly seven times as much to operate on electricity compared to natural gas and the NOx emitted from the electric utility grid to operate the unit would be twice as much as a natural gas fired unit operating at 7 ppmv NOx.

Currently, there are no electric steam generators capable of meeting the demands of conventional steam generators. One of the largest electric steam generators available produces 4,882 lb/hr @ 135 pounds per square inch gauge (psig). This steam flow rate is only 1/10 of the rate needed from one conventional steam generator and the pressure rating of 135 psig is far below the needed pressure of 800 – 900 psig.

Furthermore, a typical conventional natural gas-fired steam generator is rated (designed) to burn up to 62.5 million Btu/hr of natural gas and consumes approximately 50 million Btu/hr (i.e. 80% firing rate). This will require, on average, 13.75 MW of electricity to replace one conventional steam generator. Therefore, the electricity needs to replace one conventional steam generator with electric steam generation would be the equivalent electricity demand of over 10,000 homes. To replace conventional steam generators operating in the San Joaquin Valley with electric steam generation would require approximately 5,160 MW, which would be the equivalent electricity demand of 3,800,000 homes. The immense amount of power needed to electrify all steam generators in the District would require significant infrastructure upgrades to California's power grid. Therefore, electric steam generators are not feasible at this time.

Solar Powered Oilfield Steam Generation

Emissions from oilfield steam generators that provide steam to reduce the viscosity of oil in thermally enhanced oil recovery operations have been significantly reduced through decades of increasingly stringent rule requirements. Instead of fuel oil, steam generators today are powered by natural gas or field gas, which are significantly cleaner. To ensure that all potential emission reduction opportunities are evaluated, the District performed a comprehensive review of solar powered steam generators.

In the Valley, two small pilot projects were conducted to demonstrate the feasibility of solar powered steam generation technologies and found that such technologies were not feasible:

Berry Petroleum Company: This company installed a small pilot test facility designed to use solar energy to pre-heat feed water for the existing natural gas fired steam generators. The system consisted of mirrors in a glass greenhouse (supplied by Glasspoint Solar). The mirrors were designed to focus solar energy onto a pipe carrying water to heat the water. The heated water would then be sent to the input of the steam generators. The facility had a designed heat production of 300 kW. This project operated for a short time and was ultimately shut down based on the following shortcomings:

1) Significant heat loss: The heat losses to the water from the pipe runs from the solar installation to the actual steam generator locations were such that the water delivered to the steam generators was ambient or slightly warmer.
2) Excessively large footprint requirement: The footprint of the solar steam generators needed to provide the thermal output of one 85 MMBtu steam generator would be excessively large.
3) Inconsistent steam quality: The inability of the solar steam generators to consistently generate the quality of steam that is needed for injection that is currently supplied by the steam generators.
4) Unreliable power: The solar steam generators would still need to be supplemented by gas fired steam generators at night and during cloudy days.

Chevron: This company installed a pilot solar thermal steam plant near Coalinga, consisting of 7,600 mirrors that would direct solar energy towards a single solar collector tower (supplied by Brightsource Energy). The heat collected in the tower would turn water into steam. The installation had a footprint of 100 acres. This system discontinued operation in 2014. Although information from Chevron on their findings on the performance of this project is unavailable, based on news articles,[2][3] the system was excessively costly. A news article referencing the manufacturer's SEC filings stated the company realized a 40 million dollar loss on the project.

Aera Energy: Aera Energy was previously in collaboration with Glasspoint Solar to evaluate the potential installation of a large 770-acre solar steam generation system adjacent to an Aera Energy oil production operation in western Kern County. However,

[2] "Potential For Solar-Assisted EOR in California Oilfield Still Unfulfilled" Natural Gas Intelligence, 2015, https://www.naturalgasintel.com/potential-for-solar-assisted-eor-in-california-oilfield-still-unfulfilled

[3] "BrightSource's solar steam project went way over budget" GigaOm, 2011, https://gigaom.com/2011/10/12/brightsources-solar-steam-project-went-way-over-budget

this project has run into major delays due to financial and technical issues and appears to be completely stalled.[4]

This proposed system would have generated the steam equivalent to approximately 10 gas-fired steam generators. The solar steam generators would still have needed to be supplemented by gas-fired steam generators at night and during cloudy days. Based on discussions with Aera Energy, the project would have relied heavily on solar tax credits, the generation and sale of low carbon fuel standard (LCFS) credits, and the reduction in costs of greenhouse gas allowances for Aera. According to Aera Energy, there was no economic benefit to implementing such technologies. In fact, without the LCFS credits, the cost of steam using this solar technology would be as much as 3 times the current cost. AERA Energy was pursuing this technology to continue its effort in helping lead the industry to cleaner energy. The system proposed would have been primarily funded by the solar steam generation equipment manufacturer and outside investors. Aera Energy would commit to purchasing the steam if successfully built.

The project faced technical challenges, similar to the above pilot projects. Furthermore, the gas-fired steam generators that are required to supplement the system could have faced difficulty meeting current rule limits due to the need to ramp up and down. There has not been a successful large scale implementation of such technologies. The District was working closely with AERA to facilitate this project, and is committed to supporting similar projects in the event that they become feasible in the future.

In summary, solar powered oilfield steam generators are not yet feasible and still face significant technical and economic challenges as outlined below:

- **Costs:** The use of solar steam generation rely on a complex set of funding sources to make the operations economically feasible, including the Federal 30% tax credit, the value of California low-carbon fuel standards credits that may be generated as a result of using solar steam generation to produce oil, and a reduction in the costs for the oil producer of AB32 cap-and-trade credits required for their operations in California. The value of the GHG credits generated varies based on the price of credits on the open market. As the value of the credits is not fixed, the economic viability of a project may change depending on the value of the credits prior to construction and during operation. Even with available credits, the costs continue to be a challenge.

- **Land Availability:** Adequate open land next to the steam injection wells is needed to house the solar collectors. Both the amount of land and the distance of the land to the injection point are important factors. It is estimated that to create the steam needed to replace one steam generator would require at least

[4] "Omani- and Shell-Backed Solar EOR Firm Runs Out of Steam" *Journal of Petroleum Technology*, 2020, https://pubs.spe.org/en/jpt/jpt-article-detail/?art=7057.

60 acres of solar generation. Finding the required amount of land available next to oilfield operations may be difficult. The solar systems have to be close to the steam injection wells. Otherwise, additional solar capacity will need to be developed to account for the heat loss because of travel distance.

- **Variability of Solar Steam Generation Output:** Solar steam generation plants need sunny days to be able to collect enough energy to make steam. During cloudy days and also during the night, the solar equipment would not make enough steam. Oilfield operators will need to supplement the solar operation with natural gas fired steam generators for when the solar equipment is not producing enough steam. On partly cloudy days, the natural gas steam generators would need to cycle on and off depending on the cloud cover. This may cause operational difficulties as the gas fired steam generators are tuned to operate at constant load. A variable load could cause emissions variability and potentially have emissions higher than that allowed in permit limits and/or District prohibitory rules.

Direct PM2.5 Controls

Post-combustion control devices remove pollutants from the flue gases downstream of the unit. These controls are effective at removing PM, SO_2, and NOx. PM post-combustion controls include fabric filters, ceramic filters, electrostatic precipitators (ESPs), and wet scrubbers. SO_2 post-combustion controls include flue gas desulfurization and dry sorbent injection.

ESPs use an electrical charge to separate the particles in the flue gas. The ESP particles in the flue gas are then attracted to an oppositely charged plate or tube and collected to a hopper by vibrating the collection surface. ESPs have been reported to achieve 99 percent PM2.5 removal efficiency. Currently, there are a several produced gas fired steam generators operating in crude oil production facilities that are required by their permits to operate SOx scrubbers and ESPs (to reduce SOx emissions and visible emissions to burning high sulfur produced gas).

Fabric filters and ceramic filters known as a baghouses trap particulates in the flue gas before they exit the stack. Fabric filters are not recommended for units that use oil exclusively. A baghouse downstream of an ESP provides high rates of PM2.5 removal. Baghouses can capture up to 99 percent of filterable particulates and 20% of condensable particulates. Baghouses are not commonly used on units affected by Rule 4306 and Rule 4320.

Flue gas desulfurization typically uses lime or limestone as a sorbent to remove SO_2 from the exhaust gas. The most common flue gas desulfurization technology is wet scrubbers. A wet scrubber operates by introducing the dirty gas stream with a scrubbing liquid, typically water. Particulates are collected in the scrubbing liquid. Wet scrubbers control large particulates (>PM5) by 99% and PM2.5 emissions by approximately 50%.

The majority of boilers (>5 MMBtu/hr) in the Valley combust Public Utilities Commission (PUC) quality natural gas, which contains a very low sulfur content and inherently has low emissions. Few boilers in the Valley use alternative fuels for their combustion processes. Alternative fuels include digester gas, produced gas, and liquid fuel. Units fired on digester gas or produced gas are already required to use inlet gas scrubbers to meet District rule requirements.

Current rule language requires that liquid fuel shall be used only during a PUC-quality natural gas curtailment period provided it contains no more than 15 ppmv sulfur. While the use of liquid fuel is strictly limited, the feasibility of reducing PM emissions through adding PM2.5 limits for boilers and steam generators was explored as part of the District's comprehensive technology evaluation.

Units firing on natural gas, propane, liquefied petroleum gas, or low sulfur diesel tend to emit very low levels of PM2.5 and SO_2. AP-42 indicates that the uncontrolled total PM (condensable and filterable) is 0.007 pound per million Btu and uncontrolled SO_2 is 0.0006 pound per million Btu for boilers firing on natural gas.

Cost analyses for baghouses, electrostatic precipitators, and wet scrubbers show these technologies are not cost effective options for PM control. For more information on the cost effectiveness analyses of PM controls, refer to Appendix C of this staff report.

IV. CURRENT AND PROPOSED REGULATIONS

A. Existing Rule 4306

The purpose of Rule 4306 is to limit NOx and CO emissions from boilers, steam generators, and process heaters. The rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, and process heater with a rated heat input greater than 5.0 million Btu/hr.

The current rule does not apply to units that are addressed by other District rules. These units include solid fuel fired units, dryers, glass melting furnaces, kilns and smelters, unfired or fired waste heat recovery boilers, and any unit in which the total rated heat input of each burner is less than or equal to 5 million Btu per hour as specified in the operating permit, and in which each burner's products of combustion does not come in contact with the products of combustion of any other burner. The rule also contains certain exemptions such as burning of any fuel other than natural gas during natural gas curtailment for no more than 168 hours. Units subject to the rule must comply with the NOx and CO limits listed in the following table.

Table 2: Existing Rule 4306 Table 1 - Existing NOx and CO Limits

Category	Operated on Gaseous Fuel			Operated on Liquid Fuel	
	NOx Limit		CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
	Standard Option	Enhanced Option			
A. Units with a rated heat input equal to or less than 20.0 MMBtu/hour, except for Categories C, D, E, F, G, H, and I units	15 ppmv or 0.018 lb/MMBtu	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
B. Units with a rated heat input greater than 20.0 MMBtu/hour, except for Categories C, D, E, F, G, H, and I units	9 ppmv or 0.011 lb/MMBtu	6 ppmv or 0.007 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
C. Oilfield Steam Generators	15 ppmv or 0.018 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
D. Refinery units with a rated heat input greater than 5 MMBtu/hr up to 65 MMBtu/hr	30 ppmv or 0.036 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
E. Refinery units with a rated heat input greater than 65 MMBtu/hr up to 110 MMBtu/hr	25 ppmv or 0.031 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
F. Refinery units with a rated heat input greater than 110 MMBtu/hr	5 ppmv or 0.0062 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
G. Load-following units	15 ppmv or 0.018 lb/MMBtu	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
H. Units limited by a Permit to Operate to an annual heat input of 9 billion Btu/year to 30 billion Btu/year	30 ppmv or 0.036 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
I. Units in which the rated heat input of each burner is less than or equal to 5 MMBtu/hr but the total rated heat input of all the burners in a unit is greater than 5 MMBtu/hr, as specified in the Permit to Operate, and in which the products of combustion do not come in contact with the products of combustion of any other burner.	30 ppmv or 0.036 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400

Other provisions contained in the rule include periodic source testing, monitoring, and recordkeeping.

B. Summary of Proposed Amendments to Rule 4306

Based on the comprehensive technology assessment that District staff have conducted for this source category, as well as a thorough review of state, federal, and other air district regulations, District staff are proposing several modifications to Rules 4306 and 4320. Proposed modifications to Rule 4306 include lowering NOx emissions limits for a variety of source categories. Proposed changes are further discussed below.

Section 3.0 – Definitions

The following definitions would be added to the rule to improve clarity and reflect changes to rule requirements:

- Digester Gas: gas derived from the decomposition of organic matter in a digester.
- Fire Tube Boiler: any boiler that passes hot gases from a fire box through one or more tubes running through a sealed container of water. The heat of the gases is transferred through the walls of the tubes by thermal conduction, heating the water and ultimately creating steam or hot water.
- Normal Operation: the period of operating time during which a unit is not in a startup or a shutdown event.
- Replacement Unit: the replacement of a boiler, steam generator, oil field steam generator, or process heater. The retrofit of an existing unit does not qualify as a replacement.
- School: any public or private school used for the purpose of education and instruction of school pupils in Kindergarten through Grade 12, and any college or university which provides postsecondary education and has the authority to confer Associate, Bachelors, or Graduate/Professional level degrees. This does not include any private school in which education and instruction are primarily conducted in private homes.
- Thermal Fluid Heater: a natural gas fired process heater in which a process stream is heated indirectly by a heated fluid other than water.

The definition of load following unit will be removed from the rule because there will not be specific NOx or CO limits for these units. Load following units will need to comply with the proposed NOx limits in the applicable category in Table 2.

Section 5.0 – Requirements

Units subject to the rule must comply with the NOx limits in Table 1 until the NOx limits in Table 2 take effect. Table 2 summarizes the NOx proposed emission limits and the dates for the emission control plans, authorities to construct, and compliance deadlines. The NOx emission limits are in concentrated units of parts per million at dry stack gas conditions and 3% by volume stack gas oxygen.

The proposed NOx limits are based on technical analysis, a thorough public process, and meetings with vendors, manufacturers, and operators. The control technologies necessary to achieve the proposed limits was deemed to be reasonably available, economically feasible, and cost effective.

The proposed Rule 4306 categories have been updated from the previous categories in the rule. Categories were updated to account for differences in technologically achievable and cost-effective limits which may differ between different types and sizes of units. Updated category groupings also establish consistency in the categories included in Rule 4306 as well as Rule 4320. Major changes include:

- Category A was split into 5 sub categories based on type of unit, operating fuel, and location of the unit.
- Category B was split into 3 sub categories based on heat input and the type of unit
- Category C was split into 4 sub categories based on heat input and if the units are fired on less than 50% PUC quality gas
- Category D was split into 6 sub categories with based on size and whether the unit is a boiler or a process heater

Table 2: Tier 2 NOx and CO Limits				
Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G unit				
1. Fire Tube Boilers	7 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
2. Units at Schools or Colleges	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units fired on Digester Gas	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
4. Thermal Fluid Heaters	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
5. All other units	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units				
1. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

Table 2: Tier 2 NOx and CO Limits				
Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
2. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units with a rated heat input > 75 MMBtu/hour	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
C. Oilfield Steam Generators				
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units with a total rated heat input > 75.0 MMBtu/hr	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
4. Units firing on less than 50%, by volume, PUC quality gas	15 ppmv or 0.018 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
D. Refinery Units				
1. Boilers with a total rated heat input > 5.0 MMBtu/hr and ≤ 40.0 MMBtu/hr	30 ppmv or 0.036 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
	5 ppmv or 0.0061 lb/MMBtu upon replacement of unit			
2. Boilers with a total rated heat input > 40.0 MMBtu/hr and ≤110 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
	5 ppmv or 0.0061 lb/MMBtu upon replacement of unit			
3. Boilers with a total rated heat input >110 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

Table 2: Tier 2 NOx and CO Limits				
Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
4. Process Heaters with a total rated heat input > 5.0 MMBtu/hr and ≤ 40.0 MMBtu/hr	30 ppmv or 0.036 lb/MMBtu 9 ppmv or 0.011 lb/MMBtu upon replacement of unit	400	40 ppmv or 0.052 lb/MMBtu	400
5. Process Heaters with a total rated heat input > 40.0 MMBtu/hr and ≤110 MMBtu/hr	15 ppmv or 0.018 lb/MMBtu 9 ppmv or 0.011 lb/MMBtu upon replacement of unit	400	40 ppmv or 0.052 lb/MMBtu	400
6. Process Heaters with a total rated heat input >110 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
E. Units limited by a Permit to Operate to an annual heat input of 9 billion Btu/year to 30 billion Btu/year	30 ppmv or 0.036 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

The proposed Rule 4306 NOx limit for Category A fire tube boilers is 7 ppmv and 9 ppmv for all other units in this size range (including units at schools, units fired on digester gas, and thermal fluid heaters). District staff are proposing to add fire tube boilers as a new category, as the technology assessment has shown that fire tube boilers are capable of meeting lower limits than water tube boilers or fire tube heaters.

The proposed Rule 4306 NOx limit for Category B units is 7 ppmv for units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour, and 5 ppmv for units with a rated heat input > 75 MMBtu/hour. The remaining units can retrofit to meet the proposed limits by retrofitting with ultra low NOx burners, oxygen flow controls such as flue gas recirculation, and/or SCR.

The proposed Rule 4306 NOx limit for Category C is 9 ppmv and 7 ppmv respectively for natural gas fired oil field steam generators for units with a total rated heat input > 5.0 MMBtu/hr and ≤ 75 MMBtu/hour and for units > 75 MMBtu/hour. The District is proposing to maintain the 15 ppmv NOx limit for oil field steam generators fired on less the 50% PUC quality gas. Units fired on natural gas can meet the proposed NOx limits by retrofitting with ultra-low NOx burners and oxygen flow controls. Oil field steam generators fired on less than 50% PUC quality gas have a more difficult time achieving lower NOx limits due to the impurities in field gas like ammonia that can create additional NOx when combusted.

The proposed Rule 4306 NOx limit for Category D units ≤ 40 MMBtu/hr will be maintained at 30 ppmv, but units will have to meet lower limits of 5 ppmv upon replacement. Proposed NOx limits for units > 40 MMBtu/hr and ≤ 110 MMBtu/hr is 9 ppmv for boilers and 15 ppmv for heaters. These units would also be required to meet lower NOx limits when replaced. For the largest units at refineries, the District proposes to maintain the existing 5 ppmv NOx limit. The proposed Rule 4306 NOx limits for boilers and heaters at petroleum refineries are generally higher than limits for other boilers and heaters due to their design and operating conditions. In addition, refineries use a mix of natural gas and non-PUC quality process gas to fuel their boilers and heaters. Process gas contains differing amounts of impurities, including hydrocarbons, which create additional NOx when combusted. The majority of refinery units are natural draft instead of forced draft and would require oxygen flow controls or SCR to meet lower limits. Due to these considerations, retrofitting these types of units was not shown to be cost-effective. Therefore, the District is proposing to require more stringent limits upon replacement for these types of units.

Section 6.0 – Administrative Requirements

Section 6.4.2 will be removed, as there is no longer a category for load following units. Test methods will be updated to reflect the latest version of test methodology available.

Section 7.0 – Compliance Schedule

Units subject to the rule must comply with Rule 4306 in accordance with the schedule specified in Table 3 and Table 4 (previously Table 2 and Table 3) until the schedule specified in Table 5.

Table 5: Tier 2 - Compliance Schedule			
Category	Emission Control Plan	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G unit			
1a. Fire Tube Units permitted greater than 9 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
1b. Fire Tube Units permitted less than or equal to 9 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029

Table 5: Tier 2 - Compliance Schedule			
Category	Emission Control Plan	Authority to Construct	Compliance Deadline
2. Units at Schools	May 1, 2022	May 1, 2022	December 31, 2023
3. Units fired on Digester Gas	May 1, 2022	May 1, 2022	December 31, 2023
4. Thermal Fluid Heaters	May 1, 2022	May 1, 2022	December 31, 2023
5a. All other units permitted greater than 12 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
5b. All other units permitted less than or equal to 12 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units			
1a. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted greater than 9 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
1b. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted less than or equal to 9 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
2a. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted greater than 9 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
2b. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted less than or equal to 9 ppmv as of 6 months from date of rule amendment	May 11, 2028	May 1, 2028	December 31, 2029
3a. Units with a rated heat input > 75 MMBtu/hour permitted greater than 7 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
3b. Units with a rated heat input > 75 MMBtu/hour permitted less than or equal to 7 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
C. Oilfield Steam Generators			

Table 5: Tier 2 - Compliance Schedule			
Category	Emission Control Plan	Authority to Construct	Compliance Deadline
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
3. Units with a total rated heat input > 75.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
4. Units firing on less than 50%, by volume, PUC quality gas	May 1, 2022	May 1, 2022	December 31, 2023
D. Refinery Units			
1. Boilers with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
2. Boilers with a total rated heat input > 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
3. Heaters with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
4. Heaters with a total rated heat input > 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
E. Units limited by a Permit to Operate to an annual heat input of 9 billion Btu/year to 30 billion Btu/year	May 1, 2022	May 1, 2022	December 31, 2023

The final compliance date for most categories is December 31, 2023. However, the District determined that later compliance dates were appropriate for operations that had invested in lower-emission units due to the high costs of retrofitting those units. The District is proposing to extend the compliance dates for these lower-emitting units to 2029 to allow for the useful life of the unit.

C. Existing Rule 4320

The purpose of Rule 4320 is to limit emissions of NOx, CO, SO_2, and PM10 from boilers, steam generators, and process heaters. The rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, and process heater with a rated heat input greater than 5.0 million Btu/hr. Rule 4320 establishes NOx limits separate from Rule 4306 and provides Advanced Emission Reduction Options for rule compliance, whereby an operator may either:

1. Meet the specific NOx emission and the particulate matter control requirements; or

2. Pay an annual emissions fee to the District and meet the particulate matter control requirements

The current rule does not apply to units that are addressed by other District rules. These units include solid fuel fired units, dryers, glass melting furnaces, kilns and smelters, and unfired or fired waste heat recovery boilers that are used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. Currently, units subject to the rule must comply with the NOx and CO limits listed in the following table.

Table 1 NOx Emission Limits

Category	NOx Limit	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to < 20.0 MMBtu/hr, except for Categories C through G units	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	July 1, 2011	July 1, 2012
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	January 1, 2013	January 1, 2014
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units	a) Standard Schedule 7 ppmv or 0.008 lb/MMBtu; or	July 1, 2009	July 1, 2010
	b) Enhanced Schedule 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014
C. Oilfield Steam Generators			
1. Units with a total rated heat input > 5.0 MMBtu/hr to <20.0 MMBtu/hr	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	July 1, 2011	July 1, 2012
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	January 1, 2013	January 1, 2014
2. Units with a total rated heat input >20.0 MMBtu/hr	a) Standard Schedule 7 ppmv or 0.008 lb/MMBtu; or	July 1, 2009	July 1, 2010

Table 1 NOx Emission Limits			
Category	NOx Limit	Authority to Construct	Compliance Deadline
	b) Staged Enhanced Schedule Initial Limit 9 ppmv or 0.011 lb/MMBtu; and	July 1, 2011	July 1, 2012
	Final Limit 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014
3. Units firing on less than 50%, by volume, PUC quality gas.	Staged Enhanced Schedule Initial Limit 12 ppmv or 0.014 lb/MMBtu; and	July 1, 2010	July 1, 2011
	Final Limit 9 ppmv or 0.011 lb/MMBtu	January 1, 2013	January 1, 2014
D. Refinery units			
1. Units with a total rated heat input > 5.0 MMBtu/hr to $\leq$ 20.0 MMBtu/hr	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	July 1, 2011	July 1, 2012
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	January 1, 2013	January 1, 2014
2. Units with a total rated heat input >20.0 MMBtu/hr to $\leq$ 110.0 MMBtu/hr	a) Standard Schedule 6 ppmv or 0.007 lb/MMBtu; or	July 1, 2010	July 1, 2011
	b) Staged Enhanced Schedule Initial Limit 9 ppmv or 0.011 lb/MMBtu; and	July 1, 2011	July 1, 2012

Table 1 NOx Emission Limits

Category	NOx Limit	Authority to Construct	Compliance Deadline
	Final Limit 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014
3. Units with a total rated heat input > 110.0 MMBtu/hr	Standard Schedule 5 ppmv or 0.0062 lb/MMBtu	N/A	June 1, 2007
4. Units firing on less than 50%, by volume, PUC quality gas.	Staged Enhanced Schedule Initial Limit 12 ppmv or 0.014 lb/MMBtu; and	July 1, 2010	July 1, 2011
	Final Limit 9 ppmv or 0.011 lb/MMBtu	January 1, 2013	January 1, 2014
E. Units, from any Category, that were installed prior to January 1, 2009 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/year but ≤ 30 billion Btu/year.	Standard Schedule 9 ppmv or 0.011 lb/MMBtu	Twelve months before the next unit replacement but no later than January 1, 2013.	At the next unit replacement but no later than January 1, 2014

Table 1 NOx Emission Limits

Category	NOx Limit	Authority to Construct	Compliance Deadline
F. Units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas.	Staged Enhanced Schedule Initial Limit 12 ppmv or 0.014 lb/MMBtu; and	July 1, 2010	July 1, 2011
	Final Limit 9 ppmv or 0.011 lb/MMBtu	January 1, 2013	January 1, 2014
G. Units operated by a small producer in which the rated heat input of each burner is less than or equal to 5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 MMBtu/hr and 20 MMBtu/hr, as specified in the Permit to Operate, and in which the products of combustion do not come in contact with the products of combustion of any other burner.	Standard Schedule 9 ppmv or 0.011 lb/MMBtu	Twelve months before the next unit replacement but no later than January 1, 2013.	At the next unit replacement but no later than January 1, 2014

D. Summary of Proposed Amendments to Rule 4320

Proposed modifications to Rule 4320 include lowering NOx emissions limits for a variety of unit classes and categories. Proposed changes are further discussed below.

Section 3.0 – Definitions

The following definitions would be added to the rule to improve clarity and reflect changes to rule requirements:

- Digester Gas: gas derived from the decomposition of organic matter in a digester.
- Fire Tube Boiler: any boiler that passes hot gases from a fire box through one or more tubes running through a sealed container of water. The heat of the gases is transferred through the walls of the tubes by thermal conduction, heating the water and ultimately creating steam or hot water.
- Normal Operation: the period of operating time during which a unit is not in a startup or a shutdown event.
- School: any public or private school used for the purpose of education and instruction of school pupils in Kindergarten through Grade 12, and any college or university which provides postsecondary education and has the authority to confer Associate, Bachelors, or Graduate/Professional level degrees. This does not include any private school in which education and instruction are primarily conducted in private homes.
- Thermal Fluid Heater: a natural gas fired process heater in which a process stream is heated indirectly by a heated fluid other than water.

Section 5.0 – Requirements

Owners with units subject to Rule 4320 may choose to meet the NOx emission requirements, pay an annual emission fee, or comply with the low-use unit provision. These requirements will be maintained in the proposed Rule 4320.

In order to meet the NOx limits, units must be in compliance with the limits and schedules listed in Table 1 until the NOx limits and compliance schedule in Table 2 take effect. Table 2 summarizes the NOx proposed emission limits and the dates for emission control plans, authorities to construct, and compliance deadlines. The NOx emission limits are in concentrated units of parts per million at dry stack gas conditions and 3% by volume stack gas oxygen.

Table 2: Tier 2 NOx Emission Limits				
Category	NOx Limit	Emission Control Plan	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through E units				
1. Fire Tube Boilers	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Units at Schools	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Units fired on Digester Gas	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Thermal Fluid Heaters	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
5. All other units	5 ppmv or 0.061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through E units				
1. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Units with a rated heat input > 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
C. Oilfield Steam Generators				
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	6 ppmv or 0.0073 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023

3. Units with a total rated heat input > 75.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Units firing on less than 50%, by volume, PUC quality gas	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
D. Refinery units				
1. Boilers with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Boilers with a total rated heat input > 40.0 MMBtu/hr to ≤ 110.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Boilers with a total rated heat input > 110.0 MMBtu/hr	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Process Heaters with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
5. Process Heaters with a total rated heat input > 40.0 MMBtu/hr to ≤ 110.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
6. Process Heaters with a total heat input > 110.0 MMBtu/hr	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
E. Units limited by a Permit to Operate to an annual heat input >1.8 billion Btu/year but < 30 billion Btu/year.	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022.	December 31, 2023

The low level of emissions proposed in Table 2 of Rule 4320 may not be able to be achievable by all units due to space limitations and economic considerations. Most of the affected units have typically had several levels of controls and can only reach the new limits with a Selective Catalytic Reduction (SCR). To offset the higher costs associated with the proposed controls, the District developed the concept of an annual emissions fee, which was included in the previous version of Rule 4320 and is proposed to be maintained in this amendment. Operators have the option of paying an annual emissions fee based on the actual emissions of the unit during the previous calendar year. These fees may then be used by the District to purchase emission reductions at a better cost effectiveness rate than the proposed controls. Payments must continue annually until the unit demonstrated compliance with appropriate limits or are permanently removed from use in the District.

The emissions fee is based on the total emissions from the units that do not comply with the applicable NOx limits, and not the difference between the actual and rule limits. The emissions are calculated using the NOx emission limit in the Permit to Operate, in lb/MMBtu, and the actual annual fuel usage, in MMBtu, for the past year. The total annual fee is calculated by multiplying the total emissions by a fee rate plus an administrative fee. The fee rate is based on the cost of NOx reductions, in dollars per ton, as established pursuant to Sections 7.2 and 7.6 of District Rule 9510 (Indirect Source Review (ISR)), as adopted on December 15, 2005, and amended on December 21, 2017.

Section 6.0 – Administrative Requirements

Test methods will be updated in Section 6.4 to reflect the latest version of test methodology available.

IV. SUPPORTING ANALYSIS

The following analysis implement or reference requirements in the California Health and Safety Code, federal Clean Air Act, and the California Environmental Protection Act.

A. Emissions Inventory and Potential Emission Reductions

The NOx emission reductions achieved from the proposed amendments to the Rule 4306 0.19 tons per day (tpd) in 2024 and 0.03 tpd in 2030, on an annual average basis. Additional NOx emission reductions achieved from the proposed amendments to Rule 4320 are estimated to reduce NOx emissions by an additional 46% (0.45 tpd) on an annual average basis, although District staff are not submitting these emission reductions for SIP credit at this time. Please see Appendix B of this draft staff report for further details.

B. Cost Effectiveness Analysis

The California Health and Safety Code (CH&SC) Section 40920.6(a) requires the District to conduct both an absolute cost effectiveness analysis and an incremental cost effectiveness analysis of available emission control options before adopting each BARCT rule. The purpose of conducting a cost effectiveness analysis is to evaluate the economic reasonableness of the pollution control measure or rule. The analysis also serves as a guideline in developing the control requirements of a rule. Cost effectiveness will depend on the current level of controls, unit size, fuel usage and final emission levels. Details of the cost effectiveness analysis is contained in Appendix C to this report.

C. Socioeconomic Analysis

State law requires the District to analyze the socioeconomic impacts of any proposed rule or rule amendment that significantly affects air quality or strengthens an emission limitation. The socioeconomic analysis has been used to further refine the rule amendments. The final socioeconomic report is attached to this staff report as Appendix D.

D. Rule Consistency Analysis

Pursuant to CH&SC §40727.2, prior to adopting, amending, or repealing a rule or regulation, the District is required to perform a written analysis that identifies and compares the air pollution control elements of the rule or regulation with corresponding elements of existing or proposed District and EPA rules, regulations, and guidelines that apply to the same source category. District staff has concluded that the proposed rules are not in conflict with nor inconsistent with other District rules, nor are the proposed rules in conflict with nor inconsistent with federal policy, rule, or regulations governing the same source category. The analysis is discussed further in Appendix E of this staff report.

E. Environmental Impacts

The District is proposing to amend existing District Rule 4306 and District Rule 4320 (Boilers>5MMBtu/hr). The Purpose of this rule amendment project includes lowering the NOx emission limits for specific classes and categories of units, with the Advanced Emission Reduction Option to allow for advanced technology development and deployment in order to meet commitments made to the *2018 PM2.5 Plan*.

There are no other actions or rule requirements associated with this project. Based on the District's investigation, substantial evidence supports the District's conclusion that the amendments will not cause either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment, and as such is not a "project" as that term is defined under the California Environmental Quality Act (CEQA) Guidelines § 15378. In addition, substantial evidence supports the District's conclusion that, if one assumes the amendment is a "project" under CEQA in spite of our conclusion to the contrary, it will not have any significant adverse effects on the environment.

In addition, the amendments to District Rule 4306 and Rule 4320 is an action taken by a regulatory agency, the San Joaquin Valley Air District, as authorized by state law to assure the maintenance, restoration, enhancement, or protection of air quality in the

San Joaquin Valley where the regulatory process involves procedures for protection of air quality.

California Environmental Quality Act (CEQA) Guidelines §15308 (Actions by Regulatory Agencies for Protection of the Environment), provides a categorical exemption for “actions taken by regulatory agencies, as authorized by state or local ordinance, to assure the maintenance, restoration, enhancement, or protection of the environment where the regulatory process involves procedures for protection of the environment. Construction activities and relaxation of standards allowing environmental degradation are not included in this exemption.” No construction activities or relaxation of standards are included in this project. Therefore, the rule amendment project is exempt from CEQA.

Finally, according to Section 15061 (b)(3) of the CEQA Guidelines, a project is exempt from CEQA if, “(t)he activity is covered by the common sense exemption that CEQA applies only to projects which have the potential for causing a significant effect on the environment. Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA.” As such, for this additional reason, the District finds that the rule amendment project is exempt from CEQA.