SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Staff Report
Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines
Proposed Amended Rule 1100 – Implementation Schedule for NOx Facilities

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EXECUTIVE SUMMARY

The Regional Clean Air Incentives Market (RECLAIM) program was adopted in October 1993 under Regulation XX. RECLAIM is a market-based emissions trading program designed to reduce NOx and SOx emissions and includes facilities with NOx or SOx emissions greater than 4 tons per year. The 2016 Final Air Quality Management Plan (2016 AQMP) included Control Measure CMB-05: Further NOx Reductions from RECLAIM Assessment (CMB-05) to ensure the NOx RECLAIM program was achieving equivalency with command-and-control rules that are implementing Best Available Retrofit Control Technology (BARCT) and to generate further NOx emission reductions at RECLAIM facilities. The adoption resolution for the 2016 AQMP directed staff to achieve five tons per day of NOx emission reductions as soon as feasible but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring BARCT as soon as practicable. On July 26, 2017 the Governor approved California State Assembly Bill 617, which required air districts to develop, by January 1, 2019, an expedited schedule for the implementation of BARCT no later than December 31, 2023 for industrial facilities that are in the State greenhouse gas cap-and-trade program with priority given to older higher polluting sources that need to install BARCT.

As facilities transition out of NOx RECLAIM, a command-and-control rule that includes NOx emission standards that reflect BARCT will be needed for all equipment categories. Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (PAR 1110.2) is a command-and-control rule for RECLAIM facilities with internal combustion engines. Proposed Amended Rule 1110.2 will remove exemptions previously allowed under the NOx RECLAIM program pertaining to internal combustion engines with a rating greater than 50 brake horsepower. As a result, engines at existing RECLAIM facilities will be required to comply with the NOx emission standards under Proposed Amended Rule 1110.2, and with existing monitoring, reporting, and recordkeeping requirements. PAR 1100 is also being amended to include the compliance schedule for equipment at RECLAIM facilities that will be subject to PAR 1110.2.

Of the facilities in RECLAIM, twenty-one will be affected by PAR 1110.2 and seventy-six engines will become subject to the NOx requirements in the rule. Currently, 21 engines meet an emission limit of 11 ppmvd[1] required by PAR 1110.2. Because engines in RECLAIM are already required to comply with the VOC and CO requirements in Rule 1110.2, no further requirements are proposed for these pollutants. Eight engines are portable engines and will be subject to the state's Air Toxic Control Measure (ATCM). For the remaining 47 engines that will be required to meet the NOx emission limits under PAR 1110.2, the overall rule cost-effectiveness is approximately \$33,800 per ton of NOx reduced. As a result of PAR 1110.2, NOx emissions are expected to decrease by approximately 0.29 tons per day.

In addition, PAR 1110.2 is being amended to remove obsolete provisions, to add provisions for linear generators and for cranes operated on offshore facilities, to update provisions for monitoring, reporting, and recordkeeping, and to provide clarifications to rule applicability and implementation. Other revisions include the addition of specific averaging options to demonstrate

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis.

compliance to emission limits and the harmonization of the rule with Rules 219 and 222 for remote radio transmission towers.

The rule development process has been a public one. Six Working Group meetings and one Public Workshop have been held. Multiple stakeholders including affected facilities, the public, other government agencies, and interdepartmental staff have provided input into the process. Although PAR 1110.2 is adding provisions for linear generators, this technology is new to the South Coast AQMD. How this technology impacts air emissions will be determined through future assessments.

CHAPTER 1: BACKGROUND

BACKGROUND

REGULATORY HISTORY

AFFECTED FACILITIES AND EQUIPMENT

PUBLIC PROCESS

BACKGROUND

In October 1993, Regulation XX- RECLAIM was adopted. The purpose of the RECLAIM program was to provide industry with a flexible, market-based approach to reduce NOx and SOx emissions. Participants were initially allocated RECLAIM Trading Credits (RTCs) based on emissions from their highest production level from 1989 to 1992. With the adoption of RECLAIM, engines that had been regulated under Rule 1110.2 were exempt from NOx emission standards.

Over time, the allocation of RTCs was gradually reduced requiring businesses to either install new emissions controls, replace older equipment, or purchase unused RTCs from other sources. In response to concerns regarding actual emission reductions and implementation of BARCT under RECLAIM, Control Measure CMB-05 of the 2016 AQMP committed to an assessment of the RECLAIM program in order to achieve further NOx emission reductions of five tons per day, including actions to transition the program and ensure future equivalency to command-and-control regulations. During the adoption of the 2016 AQMP, the resolution directed staff to modify Control Measure CMB-05 to achieve the five tons per day NOx emission reduction as soon as feasible but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring BARCT-level controls as soon as practicable.

In addition, on July 26, 2017, Governor Brown signed AB 617 which addressed non-vehicular air pollution. AB 617 was companion legislation to AB 398 which extended California's cap-and-trade program for reducing greenhouse gas emissions from stationary sources. RECLAIM facilities that are part of the cap-and-trade program are now also subject to the requirements of AB 617. AB 617 requires an expedited schedule for implementing BARCT for cap-and-trade facilities. Under AB 617, the State's air districts were to develop a schedule by January 1, 2019 for the implementation of BARCT no later than December 31, 2023. The highest priority would be given to older, higher polluting units that would need to install retrofit controls.

The October 5, 2018 amendment to Rule 2001 established procedures for facilities to opt out of RECLAIM before receiving an initial determination notification, provided the equipment at the facility met specified criteria. Facilities that satisfied the requirements to opt out would have then received an initial determination notification and would have become subject to Rule 2002. However, this opt-out option was superseded and rescinded.

Staff has been in discussions with the United States Environmental Protection Agency (USEPA) on all elements of transitioning RECLAIM sources to a command-and-control regulatory structure to ensure that the rules relating to the transition would be approved into the State Implementation Plan (SIP). However, the USEPA had expressed concern over facilities exiting RECLAIM before all command-and-control and New Source Review (NSR) requirements had been adopted to clearly demonstrate equivalency to the replaced program. The USEPA has since recommended keeping facilities in RECLAIM until all the rules associated with the transition have been adopted and approved into the SIP.

In consideration of USEPA's recommendation, staff removed the opt-out provisions in Rule 2001 and now prohibits facilities from exiting the RECLAIM program. Until facilities exit RECLAIM, they will continue to be subject to all RECLAIM requirements including Rule 2005 – New Source

Review for RECLAIM, for permitting of new or modified NOx sources that undergo emission increases. In addition, these facilities will also be required to comply with all the requirements in adopted and amended command-and-control rules that apply to RECLAIM facilities, including the implementation schedules and NOx limitations. Staff will continue to work with USEPA on NSR for former RECLAIM facilities as well as on all the relevant command-and-control rules for the RECLAIM transition.

As facilities transition out of NOx RECLAIM, a command-and-control rule that includes NOx emission standards that reflect BARCT will be needed for all equipment categories. Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (PAR 1110.2) is a command-and-control "landing" rule for RECLAIM facilities with internal combustion engines. Proposed Amended Rule 1110.2 will remove exemptions previously allowed for the NOx RECLAIM facilities pertaining to internal combustion engines with a rating greater than 50 brake horsepower. Engines at existing RECLAIM facilities will be required to comply with the NOx emission standards under Proposed Amended Rule 1110.2 and with existing monitoring, reporting, and recordkeeping requirements contained in PAR 1110.2. PAR 1110.2 will also add clarification to its applicability to engines operated at remote radio transmission towers.

With the transition of the RECLAIM program to a command-and-control regulatory structure, internal combustion engines that were once exempt would now be subject to Rule 1110.2. As part of the transition from RECLAIM to a command-and-control structure, staff conducted an analysis to determine if Rule 1110.2 reflects current BARCT and to provide an implementation timeframe for achieving BARCT compliance limits for certain RECLAIM internal combustion engines.

REGULATORY HISTORY

The following provides a regulatory history of Rule 1110.2 and associated actions affecting internal combustion engines.

- In October 1984, Rule 1110.1 was adopted, which regulated emissions from internal combustion engines. Rule 1110.1 required reductions of NOx and carbon monoxide (CO) emissions from gaseous-fueled internal combustion engines rated greater than 50 bhp. This rule was the precursor to Rule 1110.2.

- In August 1990, the Board adopted Rule 1110.2, which required additional reductions for NOx and also volatile organic compounds (VOC) from stationary, non-emergency gaseous- and liquid-fueled internal combustion engines.

- In October 1993, Regulation XX was adopted, which established the RECLAIM program. Engines at RECLAIM facilities were exempted from Rule 1110.2 for NOx.

- In June 2005, Rule 1110.2 was amended to comply with California Senate Bill (SB) 700, which eliminated a statewide agricultural operations exemption. It required that BARCT be applied to previously-exempted agricultural engines.

- In February 2008, Rule 1110.2 was amended, lowering NOx, VOC, and CO emission limits for stationary, non-emergency engines. It also established lower emission standards for new, non-emergency electrical generation engines. The amendment also increased monitoring requirements to include more frequent emissions testing and the development of Inspection and Monitoring (I&M) plans. The amendment affected 859 engines at 405 facilities.

- In July 2010, Rule 1110.2 was amended to provide an exemption from the emissions requirements for engines operated by the County of Riverside for the purpose of public safety communication at one remote location.

- In September 2012, Rule 1110.2 was amended to establish biogas engine emissions limits equivalent to those for natural gas engines. The amendment included an accompanying technology assessment for biogas engine control technology.

- In May 2013, Rules 219 and 222 were amended to exempt engines powering remote radio transmission towers from permitting requirements. The exemption applied to any compression-ignited reciprocating internal combustion engine used exclusively for electrical generation at remote two-way radio transmission towers where no utility, electricity, or natural gas is available within ½ mile radius, has a manufacturer's rating of 100 bhp or less, and is fired exclusively on diesel #2 fuel, compressed natural gas, or liquefied petroleum gas.

- In December 2015, Rule 1110.2 was amended to extend the compliance deadline for biogas engines by one year. The amendment also addressed concerns raised by USEPA related to SIP approval issues contained in the rule language regarding excess emissions from startup, shutdown, and malfunction.

- In June 2016, Rule 1110.2 was amended to extend the compliance deadline for one landfill gas facility due to economic concerns related to its power purchase agreement. The facility is required to retire its engines subject to the rule by October 1, 2022.

AFFECTED FACILITIES AND EQUIPMENT

RECLAIM Facilities and Associated Engines

Out of the 254 facilities currently in the NOx RECLAIM program, approximately 21 facilities were identified as facilities with engines subject to PAR 1110.2. Appendix B contains a list of RECLAIM facilities that operate engines affected by PAR 1110.2.

As part of the RECLAIM transition, several source-specific rules are also being adopted and amended. In addition, several new industry-specific rules are being developed. In such cases, facilities that are affected by these industry-specific rules may have non-emergency, internal combustion engines that are excluded from Rule 1110.2 (e.g., engines operated at electricity generating facilities and in refineries).

Rule 222-RT Engines

In May 2013, Rules 219 and 222 were amended to allow engines that provide power to remote radio transmission towers and that meet specific criteria to be exempt from permitting. At the time of the rule adoption, these engines were also to be exempted from the emission limits in Rule 1110.2 because these engines were considered essential for public safety operations. However, only the exemption from permitting was implemented and there was no corresponding explicit exemption from the emission levels written into Rule 1110.2. To harmonize Rules 219, 222, and 1110.2, staff recommends that Rule 1110.2 be updated to explicitly exempt engines registered under Rule 222-RT from emission requirements. The facilities impacted are not RECLAIM sources.

Biogas Engines

In the 2012 rule amendment, several provisions were added related to the operation of engines fueled by biogas. Stakeholders have expressed confusion on the interpretation and implementation of these provisions. In PAR 1110.2, staff is revising the biogas provisions to update and clarify the intended requirements. The clarifications center on averaging provisions for emissions compliance and on monitoring requirements. Currently, there are 8 facilities that are biogas facilities (e.g., operate engines fueled by digester gas or landfill gas) with 23 biogas engines that operate with continuous emissions monitoring systems (CEMS).

PUBLIC PROCESS

The development of PAR 1110.2 was conducted through a public process. Five Working Group meetings were held on: June 28, 2018, September 27, 2018, February 6, 2019, April 24, 2019 and May 30, 2019. Working Group meetings included staff and representatives from affected businesses, environmental groups, public agencies, consultants, and other interested parties. The purpose of the Working Group meetings is to discuss details of proposed amendments and to listen to concerns and issues with the objective to build consensus and resolve key issues.

In addition, one Public Workshop was held on July 31, 2019. The purpose of the Public Workshop was to present the preliminary staff report and proposed rule language to the general public and to stakeholders. Concurrently with the Public Workshop, a California Environmental Quality Act (CEQA) scoping meeting was held.

Based on additional concerns expressed by stakeholders, a sixth Working Group meeting was held on August 20, 2019.

Staff also has had numerous meetings with stakeholders and has conducted multiple site visits as part of this rulemaking process. In addition, staff has had discussions with compliance staff from the USEPA related to the amendments proposed for Rule 1110.2.

CHAPTER 2: BARCT ASSESSMENT

INTRODUCTION
BARCT ANALYSIS APPROACH

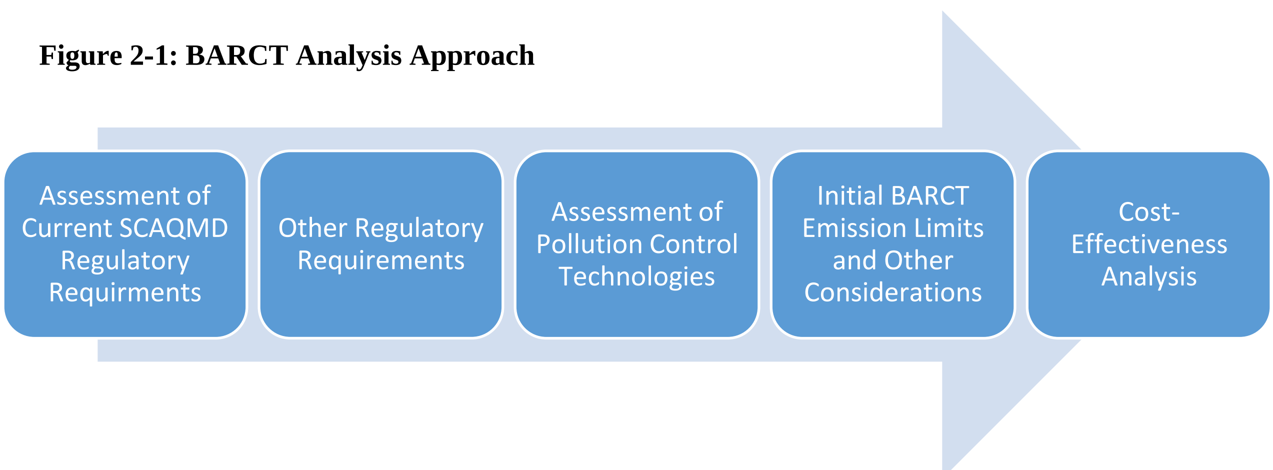
INTRODUCTION

Staff conducted an assessment of the NOx emission limit under Rule 1110.2 to ensure it is still representative of BARCT for engines. BARCT analyses are periodically performed for equipment categories to assess technological changes that may reflect a lower emission limit. The 2008 amendments to Rule 1110.2 represent the most recent BARCT analysis for engines. Under California Health and Safety Code § 40406, BARCT is defined as:

> "… an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."

The BARCT assessment for this rule development consisted of a multi-step analysis. The first three steps represent the technology assessment where staff first conducts a review of current South Coast AQMD regulatory requirements, staff then surveys other air districts and agencies outside of the South Coast AQMD's jurisdiction to identify emission limits that exist for similar equipment, and in the third step, staff identifies and assesses pollution control technologies to determine what degree of reduction could be achievable for the affected sources. Based on the collected information, initial BARCT emission limits were then established. Once the initial BARCT emission limits are determined, a cost-effectiveness analysis is conducted.

Figure 2-1: BARCT Analysis Approach



BARCT ANALYSIS APPROACH

Assessment of Current South Coast AQMD Regulatory Requirements

In the first step of the BARCT analysis, staff reviewed South Coast AQMD rules that affect engines operating within its jurisdiction: Rule 1470 and Rule 1110.2. Each rule was evaluated based on their respective regulatory effect on emission of NOx, VOC, and CO.

<u>South Coast AQMD Rule 1470</u>

Rule 1470 is a toxics rule designed to reduce diesel particulate emissions, which is a carcinogen. Rule 1470 applies to stationary, diesel-fueled engines owned or operated with a rated brake horsepower greater than 50 bhp with limited exceptions and regulates particular matter (PM) emissions from diesel engines. Within Rule 1470, any reference to NOx, VOC, and CO for prime engines is referred to Rule 1110.2.

- Rule 1470 states that all new stationary prime diesel-fueled compression-ignition engines (> 50 bhp) shall meet the applicable emission standards specified in Rule 1110.2.

- Rule 1470 states that owners or operators that choose to meet the diesel PM limits with emission control strategies that are not verified through the Verification Procedure shall meet the applicable HC, NOx, NMHC+NOx, and CO emission standards specified in South Coast AQMD Rule 1110.2 – Emissions From Gaseous and Liquid-Fueled Engines.

Although engines in the RECLAIM program were exempt from the requirements of Rule 1110.2, compliance to Rule 1470 is still mandatory for PM emissions to address diesel PM. For specific NOx limits, Rule 1470 defers to Rule 1110.2. Rule 1470 primarily applies to emergency engines that operate under the Rule 1110.2 exemption of 200 hours per year. Emergency engines operated at RECLAIM facilities that are subject to Rule 1470 are not proposed to be subject to PAR 1110.2.

<u>South Coast AQMD Rule 1110.2</u>

Rule 1110.2 applies to engines with a rated brake horsepower greater than 50 bhp. The rule separates engines into two sub-categories: stationary or portable.

For existing stationary prime engines, the NOx, VOC, and CO emission limits are listed in Table 2-1. The rule does not distinguish by engine type (e.g., whether the engine is two-cycle, four-cycle, lean-burn, or rich-burn). The limits have been in effect for gaseous- and liquid-fueled engines since July 1, 2011 and for biogas engines since January 1, 2017.

Table 2-1: Rule 1110.2 Emissions

Emission Limits for Stationary Prime Engines (ppmvd)	
NOx[1]	11
VOC[2]	30
CO[1]	250

[1] Corrected to 15% O_2 on a dry basis
[2] Measured as carbon, corrected to 15% O_2 on a dry basis, averaged over 15 minutes

For new non-emergency engines driving electrical generators, the emission limits differ from those for existing stationary prime engines. The emission limits were established during the 2008 rule amendment and modeled in part from CARB's approach for distributed generation (DG) equipment that does not require local district permits. The CARB standards were based on the emissions from large new central generating stations (e.g., electricity generating facilities or utility power plants) equipped with best available control technology (BACT). Rule 1110.2 differs slightly from the CARB standards for VOC and CO which are set at .02 lb/MW-hr and 0.10 lb/MW-hr, respectively in that Rule 1110.2 contains slightly higher emission limits.

At the time of rule adoption in 2008, staff originally had proposed emission standards that, as of January 1, 2007, CARB already enforced for distributed generation equipment that do not require local district permits. However, the Engine Manufacturers Association commented that by increasing the proposed limits, in lbs/MW-hr, from 0.10 to 0.20 for CO and from 0.02 to 0.10 for VOC, some advanced engines may be able to comply. The revised limits were considered to still achieve the same NOx reductions as the original proposal, and for an electrical generator without heat recovery, the revised limits would still achieve an 89% reduction of CO and a 77% reduction of VOC, compared to the current BACT limits for typical new engines.[1]

Table 2-2 lists the emission limits for all new, non-emergency engines driving electrical-generators. These limits are for new installations and do not apply to retrofits.

Table 2-2: Comparison of Emission Limits

Limits for New Electrical Generation Devices (lbs/MW-hr)		
	South Coast AQMD	CARB
NOx[1]	0.07	0.07
VOC[2]	0.10	0.02
CO[1]	0.20	0.10

[1] Corrected to 15% O_2 on a dry basis, averaged over 15 minutes
[2] Calculated using a ratio of 16.04 lbs of VOC per lb-mole of carbon

For portable prime engines, Rule 1110.2 refers to state regulations for emissions limitations (State Air Toxics Control Measure).

Other Regulatory Requirements

Staff compared emission limits for similar equipment in other air districts (contained in Table 2-3). Equipment categories varied, but the most stringent emission limit relevant to stationary prime engines was selected for comparison. Based on staff's review, the South Coast AQMD has the lowest NOx limits for stationary internal combustion engines of 11 ppmvd (corrected to 15% O2 on a dry basis), relative to other air districts. In addition, the South Coast AQMD has the lowest emission standards for CO and VOC relative to other air districts.

Within California, staff reviewed regulations in the following air districts (listed alphabetically):

[1] Information taken from The Final Staff Report for Proposed Amended Rule 1110.2, December 2007.

- Antelope Valley
- Bay Area
- Mojave Desert
- Santa Barbara
- San Diego
- San Joaquin Valley
- San Luis Obispo
- Ventura County

Outside California, staff reviewed regulations in the following air districts (listed alphabetically):

- New Jersey
- New York
- Pennsylvania
- Texas

Table 2-3: Lowest NOx Emission Limits in Other Jurisdictions

Jurisdiction	Type of Engine	Limit (ppmvd[1])
Antelope Valley AQMD	General, spark-ignited	36
Bay Area AQMD	Fossil-derived fuel, rich-burn	25
Mojave Desert APCD	Non-agriculture, rich-burn, spark-ignited engines	50
Santa Barbara APCD	Rich-burn, noncyclically-loaded spark ignition engines	50
San Diego APCD	Gaseous fuel or gasoline, rich-burn	25
San Joaquin Valley APCD	Non-exempted ICEs	11
San Luis Obispo APCD	Spark-ignited, rich-burn	50
Ventura County APCD	General, rich-burn	25
New Jersey	Non-exempted ICEs	70
New York	Natural gas, >200 hp	116
Pennsylvania	Rich-burn, natural gas	155
Texas (Dallas-Fort Worth Area)	Non-exempted ICEs	39

[1] ppmvd corrected to 15% oxygen, dry basis

Assessment of Pollution Control Technologies

Current air pollution control technology for internal combustion engines can be divided into two commercially available systems: Non-Selective Catalytic Reduction (NSCR) and Selective Catalytic Reduction (SCR).

NSCR

NSCR is a commercially available air pollution control system used to reduce emissions from rich-burn, stationary engines. The system has been commercially available for many years from different sources and is considered cost effective to install. It uses a precious metal catalyst base to reduce NOx to nitrogen, to oxidize CO to carbon dioxide (CO_2), and to convert VOCs to CO_2 and water. Catalyst efficiency relies on good air-to-fuel ratio (A/F) control. Most systems control the A/F ratio using exhaust oxygen measurement, along with air/fuel ratio controllers. Removal efficiencies for a 3-way catalyst are greater than 90 percent for NOx, greater than 80 percent for CO, and greater than 50 percent for VOC. Greater efficiencies, below 10 parts per million NOx, are possible through use of an improved catalyst containing a greater concentration of active catalyst materials, use of a larger catalyst to increase residence time, or through use of a more precise air/fuel ratio controller.

As part of this evaluative process, staff solicited and received information from catalyst vendors related to the installation and/or retrofitting of NSCR systems for various engine sizes. This data was used to calculate cost-effectiveness in achieving proposed emission limits for these type of engines.

SCR

SCR is another commercially available air pollution control system used to reduce NOx emissions from diesel or other lean-burn, stationary engines. SCR technology injects ammonia into an engine's exhaust. The exhaust is then passed through a fixed catalyst bed where NOx reacts with the ammonia and is converted into nitrogen. If CO and VOCs are also to be controlled, then an oxidation catalyst is added to the exhaust stream typically upstream of the SCR. Catalyst efficiency relies on good dispersion and mixing. Typical conversion efficiencies for SCR systems range between 90 – 95% for NOx.

As part of this evaluative process, staff solicited and received information related to the installation and/or retrofitting of SCR systems. In addition, data from previous rulemaking efforts was reviewed and considered. This data was used to calculate cost-effectiveness in achieving proposed emission limits for these type of engines.

Other Technology Options

Staff reviewed two alternative technologies to NSCR and SCR. The first alternative that was considered was developed by a company called Tecogen. Tecogen has a patented, 3-step emissions control system that can be retrofitted onto an existing engine. The technology is currently applied only on select rich-burn natural gas fueled engines. Compared to a standard NSCR system, the

Tecogen product is designed to provide an operator with a wider air-to-fuel ratio control window by utilizing its dual catalyst system.

Within the South Coast AQMD's jurisdiction, several engines equipped with the Tecogen system have been recently permitted. The initial testing results indicate that these engines meet Rule 1110.2 NOx and CO limits. At this time, however, the technology has been installed on mostly smaller engines under 1,000 brake horsepower and it has not been demonstrated whether this technology can be applied to a wider range of engines, especially larger engines. This technology is capable of achieving the lower emission standard for non-emergency electrical generators. In addition, operators have expressed that when employed for compliance with the 11 ppm NOx limit, it offers a larger and safer compliance margin than in utilizing only a single catalyst. Staff will continue to monitor and evaluate future installations.

The second alternative was developed by a company called EtaGen. EtaGen has designed and constructed a linear generator. The linear generator produces electricity unlike a traditional combustion engine. In this design, magnets are driven through copper coils to produce electricity. However, this type of engine is similar to a compression-ignited engine where a mix of gas undergoes a compression phase and products of combustion are generated. One feature that distinguishes this engine from traditional engines is that combustion reaction takes place at lower temperatures. At lower temperatures, engine thermal efficiency is expected to be higher, but at lower temperatures, the exhaust gas temperature will be lower compared to traditional engines. At lower exhaust temperatures, destruction of any residual VOCs through exhaust controls such as an oxidation catalyst system may be negatively impacted. This type of engine is expected to produce lower NOx and CO emissions approaching Distributed Generation (DG) levels, but VOC emission concentrations levels may be higher than current DG limits. At this time, no linear generator system has been installed or in operation within the South Coast AQMD jurisdiction. One application for a permit to construct has been filed and is under evaluation by permitting staff.

BARCT Emission Limits and Other Considerations

The 2008 Rule 1110.2 amendment established a NOx emission limit of 11 ppmvd @ 15% O_2 for non-RECLAIM engines effective July 1, 2011 except for engines fueled by landfill or digester gas (biogas). Subsequently, engines fueled by landfill or digester gas (biogas) were required to meet this limit by July 1, 2017.

Currently, the NSCR and SCR are commercially available and cost-effective to establish a NOx emission limit of 11 ppmvd @ 15% O_2. NSCR systems can be used for rich-burn engines and SCR systems can be used for lean-burn engines. As part of its analysis of non-RECLAIM engines operating within the South Coast AQMD's jurisdiction, staff reviewed available source test data for stationary, non-emergency engines and found that existing engines are complying with a NOx emission limit of 11 ppmvd @ 15% O_2.

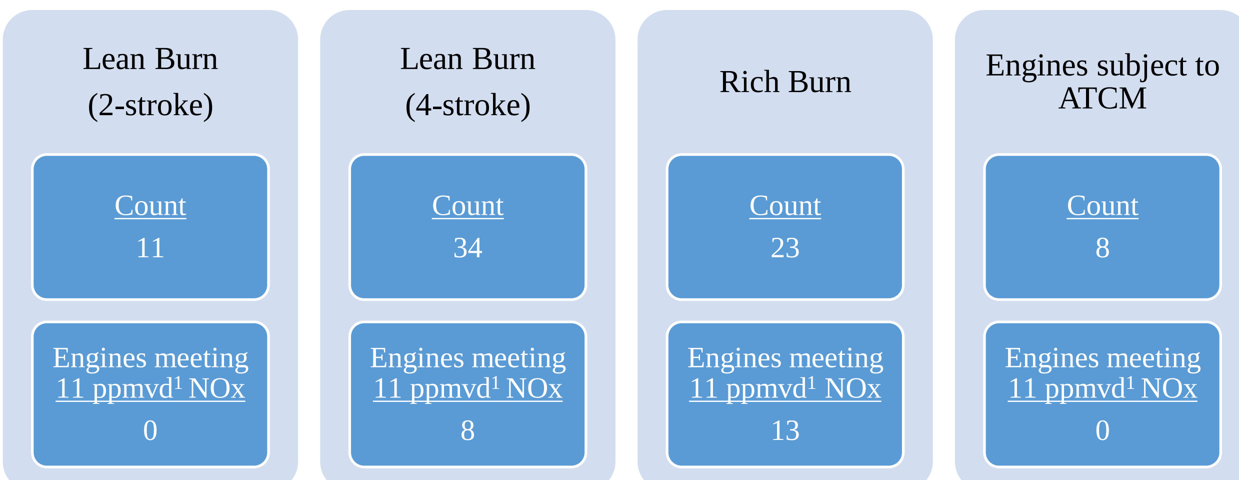
Engine Categories

Seventy-six engines that are currently in the RECLAIM program would be subject to Rule 1110.2. As part of the BARCT analysis, engines were subdivided into four categories based on the unique characteristics of each type of engine and the associated emissions controls available to each category:

- Lean-Burn, 2 stroke
- Lean-Burn, 4 stroke
- Rich-Burn
- Portable Engines, subject to the ATCM

Figure 2-2 lists the number of RECLAIM engines by type and by the number of engines that meet the current emission limit of 11 ppmvd[1] NOx. Engines subject to the State ATCM will not be affected due to PAR 1110.2. These engines have been identified as portable diesel engines subject to Rule 1110.2 (d)(2)(B). Currently, Rule 1110.2 (d)(2)(B) defers emission limits to the State ATCM for any portable diesel engines. In general, these engines either will be phased out or will be operated as low-use engines under 200 hours or less in a calendar year, per the provisions of the ATCM.

Figure 2-2: RECLAIM Engines by Type



[1] Parts per million by volume, corrected to 15% oxygen on a dry basis

CHAPTER 3: PROPOSED AMENDMENTS TO RULE 1110.2

INTRODUCTION

PROPOSED AMENDMENTS TO RULE 1110.2

PROPOSED AMENDMENTS TO RULE 1100

INTRODUCTION

PAR 1110.2 is a landing rule for facilities in RECLAIM that establishes NOx emission limit for engines over 50 bhp. The purpose of the proposed amendments is to remove the exemption for RECLAIM facilities to help with the transition of facilities in the RECLAIM program to a command-and-control regulatory structure. Through this rulemaking process, staff conducted a BARCT analysis of the NOx emission limit, consistent with AB 617. In addition, the proposed amended rule has a number of additional revisions to address various issues raised by stakeholders. Proposed revisions to Rule 1110.2 include the removal of obsolete provisions, the inclusion of specific averaging options, updating reporting and recordkeeping requirements, the harmonization of remote radio transmission tower exemptions with existing rules, the clarification of CEMS provisions for biogas engines, and the addition of requirements for offshore crane engines. Proposed revisions to Rule 1100 introduces an implementation schedule for facilities exiting RECLAIM and provides additional time and consideration for compressor gas lean-burn engines to meet the emission concentration limits in Rule 1110.2.

PROPOSED AMENDMENTS TO RULE 1110.2

Definitions – Subdivision (c)

Subdivision (c) was revised to reflect the transition of equipment from the RECLAIM program to a command-and-control regulatory structure. Staff included definitions to differentiate between a FORMER RECLAIM FACILITY, NON-RECLAIM FACILITY, and RECLAIM FACILITY. In addition, staff included a definition for COMPRESSOR GAS LEAN-BURN ENGINE, and ESSENTIAL PUBLIC SERVICE to clarify use within the rule.

- COMPRESSOR GAS LEAN-BURN ENGINE means a stationary gaseous-fueled two-stroke or four-stroke lean-burn engine used to compress natural gas or pipeline quality natural gas for delivery through a pipeline or into storage.

- ESSENTIAL PUBLIC SERVICE means any facility or operator as defined in Rule 1302.

- FORMER RECLAIM FACILITY means a facility, or any of its successors, that was in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX, that has received a final determination notification, and is no longer in the RECLAIM program.

- NON-RECLAIM FACILITY means a facility, or any of its successors, that was not in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX.

- RECLAIM FACILITY means a facility, or any of its successors, that was in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX.

Modification of RECLAIM Language

The existing language in the clauses and subclauses listed below were changed from "subject to Regulation XX (RECLAIM)" to "at RECLAIM or former RECLAIM facilities". The purpose of the change was to reflect that the provisions will apply to facilities that are in RECLAIM and to these facilities after they transition out of RECLAIM as they transition from the RECLAIM program to a command-and-control regulatory structure:

- (f)(1)(D)(ii)(II)
- (f)(1)(D)(ii)(III)

Clarification of Rule Language in Subparagraph (d)(1)(B)

In the current version of Rule 1110.2, subparagraph (d)(1)(B) contained three undesignated clauses listed after Table II that included provisions pertaining to Pre-2010 emission limits that were for low-use engines, alternative CO and VOC limits, and engines operating with non-pipeline quality natural gas.

To provide additional clarity, the first section of emission limits in Table II has been labeled as "Low-Use Engines" as those limits are for low-use engines. In addition, the section of Table II where the concentration limits "effective July 1, 2010" has been removed as these limits are obsolete and have been superseded by concentration limits "effective July 1, 2011.

Subparagraph (d)(1)(B) has been restructured to contain individual clauses specific to meeting the emission requirements of Table II, including provisions for averaging and alternative averaging times, low-use engines, and alternative emission limits. The following discussion provides an overview of each clause that has been revised or has been inserted under subparagraph (d)(1)(B).

❖ (d)(1)(B)(i) – No changes are suggested to this existing clause except to note that other subclauses may be applicable.

❖ (d)(1)(B)(ii) – The language was revised for grammatical agreement to the subparagraph. In addition, staff recognizes that there are special operational situations which may result in alternative emission concentrations limits as approved by the Executive Officer. The footnotes to the Tables I, II, III-A, III-B, and IV that list emission limits have been revised to not specify the averaging over 15 minutes. This clause states that unless otherwise provided in another section of the rule, concentration limits listed in either Tables II, Table III-A or III-B or technologically achievable case-by-case VOC or CO emission concentration limits approved by the Executive Officer will be averaged over 15 minutes. Clauses (d)(1)(B)(iii) through (d)(1)(B)(v), however, allow for alternate averaging times for unique situations. Under this clause the operator shall:

  - Comply with the applicable emission concentration limits listed in either Table II or Table III-A or B, or alternate emission concentration limits approved by the Executive Officer, averaged over 15 minutes or other averaging time period allowed by clauses (d)(1)(B)(iii) through (d)(1)(B)(v).

- (d)(1)(B)(iii) – This is an existing provision that allowed the operator of an engine that uses non-pipeline natural gas that demonstrates that due to the varying heat value of the gas, a longer averaging time is necessary. The language was revised for grammatical agreement to the subparagraph. The use of a fixed-interval averaging time was inserted for clarification. The revised provision, however, does allow for use of a longer averaging period if an engine is subject to an existing permit condition allowing for an averaging time greater than six hours. Staff has identified one engine in RECLAIM that currently contains a permit limit of 24 hours, and there is no proposed change to that existing requirement. Under this clause, the operator shall:

  - Use an averaging time approved by the Executive Officer for an engine that uses non-pipeline quality natural gas that has demonstrated that due to the varying heating value of the gas a longer averaging time was necessary. The fixed-interval averaging time shall not exceed six hours for any of the concentration limits of Table II, unless an engine is subject to an existing permit condition allowing for an averaging time greater than six hours. Non-pipeline quality natural gas is a gas that does not meet the gas specifications of the local gas utility and is not supplied to the local gas utility.

  The following two clauses address the use of longer averaging times and specify the use of a fixed-interval, or a "block" averaging approach. Unlike a rolling average, the operator that averages over a fixed-interval is required to collect and average data over a fixed amount of time. For example, if an operator of an engine is using a six-hour fixed-interval averaging option, then the operator would collect data from 12:01 am to 6:00 am and average over this time period to demonstrate compliance with a given emission limit. The next subsequent intervals would then be taken from 6:01 am to 12:00 pm, from 12:01 pm to 6:00 pm, and 6:01 pm to 12:00 am, and so forth, and the data would then be averaged over these discrete and fixed intervals. Stakeholders have raised several concerns with using a fixed-interval system to determine compliance:

  - The first concern is regarding which data interval or frequency should data be collected. If an operator is using a CEMS unit to monitor the emissions from an engine, Rule 218.1 (b)(1)(E), the Data Acquisition System (DAS) for the CEMS shall acquire data from monitored parameters at least once every minute and all valid data points shall be used to determine compliance with applicable limit(s). Rules 218 and 218.1 contain the requirements and specifications for the operation of CEMS.

  - The second concern is regarding the situation where an operator is using a 6-hour interval with the averaging starting at 12:01 am, but starts an engine at 3:00 am. Does the averaging start at 3:00 am? In this example, even if not all data is recorded during the 6-hour block, the average is taken from only the data that has been collected from 12:01 am to 6:00 am. Staff believes that as long as there is at least one valid data point in the block, an operator can use it for that fixed-interval. Rule 218.1 provides guidance for reporting values when any data points fall below 10 percent or exceed 95 percent of the full span range.

- Another concern is regarding if a non-operation period of the engine can be counted in the averaging. Valid data should be produced, pursuant to Rules 218 and 218.1. In general, periods of non-operation should not be counted towards the averaging provision because these periods can artificially bias any valid readings downward. However, staff is working on proposed amendments to Rules 218 and 218.1 that would contain requirements for these types of situations for all CEMS installations outside of RECLAIM that would correspond to requirements currently contained in the Code of Federal Regulations for CEMS installations (40 CFR Part 60 and Part 75).

- The last concern is regarding if an operator has to source test an engine, how can compliance be determined for a six-hour averaging period if the test does not last that long. In this situation, the source test protocol or RATA and associated averaging requirements would be followed.

Clause (d)(1)(b)(iv) provides for one hour averaging and clause (d)(1)(B)(v) provides for three hour averaging:

❖ (d)(1)(B)(iv) – Stakeholders have requested for a longer allowance for the averaging time for units equipped with CEMS to increase from 15 minutes to one hour. Stakeholders feel that 15 minutes is too short of an interval to allow for operational transient emissions. In particular, one facility operator has followed the practice of shutting down an engine when that engine has approached an exceedance of an emission limit averaged over 15 minutes. The operator claimed that if they had been able to average emissions over a one hour period, fluctuations associated with load demand changes could be better controlled and responded to. In addition, with each new start-up, some uncontrolled emissions would be emitted. Staff reviewed CEMS data from the facility and determined that if a one hour averaging provision had been allowed, the operator would not have had to shut down an engine. As a result, there would be an emissions benefit by not shutting down an engine and then starting back up relative to transient emissions affecting the 15-minute average. The analysis for this continuous data is presented in Appendix E.

  Under RECLAIM, the averaging time for engines with CEMS consisted of a one-hour averaging time over four 15 minute quadrants. Other combustion rules, Rules 1134 for turbines, Rule 1135 for electrical generating facilities, and Rule 1146 for boilers and heaters allow a one-hour averaging period, similar to RECLAIM. PAR 1110.2 has been modified to allow a fixed-interval averaging approach for one hour averaging that can be utilized for engines with CEMS. For example if an operator of an engine in this situation is using a 1-hour fixed-interval averaging option, then the operator would collect data from 12:01 am to 1:00 am and average over this time period to demonstrate compliance with a given emission limit. The next subsequent intervals would then be taken from 1:01 am to 2:00 am, from 2:01 am to 3:00 am, and 3:01 am to 4:00 am, and so forth and the data would then be averaged over these discrete and fixed one-hour intervals. Under this clause, the operator shall:

  - Use a fixed-interval averaging time of one hour for engines equipped with a continuous emissions monitoring system (CEMS), to demonstrate compliance with the emission concentration limits of Table II or Table III-B.

- (d)(1)(B)(v) – This new clause addresses concerns raised by an affected stakeholder for the operation of their compressor gas lean-burn engines. Their engines are fueled with natural gas and are used for natural gas compression and pipeline transportation. Due to challenges associated with design and operation of these engines, the engines are more prone to emissions fluctuations to load demand changes. Staff recognizes these issues and provides an option for the operator to average emissions over a three-hour period for these engines that are equipped with an SCR and a CEMS. Staff also recommends a fixed-interval averaging approach. For example, if an operator of engine under this clause is using a 3-hour fixed-interval average, the operator would collect data from 12:01 am to 3:00 am and average over this time period to demonstrate compliance with a given emission limit. The next subsequent intervals would then be taken from 3:01 am to 6:00 am, from 6:01 am to 9:00 am, and 9:01 am to 12:00 pm, and so forth, and the data would then be averaged over these discrete and fixed three hour intervals. Under this clause, the operator shall:

    - Use a fixed-interval averaging time of three hours for compressor gas lean-burn engines equipped with selective catalytic reduction pollution control equipment and a CEMS, to demonstrate compliance with the NOx emission concentration limit of Table II.

- (d)(1)(B)(vi) – This is an existing provision that was not designated as a clause that provides a low use exemption for engines that operate fewer than 500 hours per year or use less than 1 x 10^9 Btus per year (higher heating value) of fuel. If an engine meets the criteria for low-use, then the limits for emissions in Table II effective before July 1, 2011 would apply. This clarification addresses concerns brought to the attention of staff. This low use exemption was read by some to mean that if an engine operated less than 500 hours or used less than 1 x 10^9 Btus per year (higher heating value) of fuel, then the engine was exempt from all emission limits. This is not the correct interpretation. To add clarity, Table II states for "Low-Use Engines" to clarify that engines that are below the annual hourly usage or heating value, the engines are subject to the limits for low-use engines. For example, a non-biogas engine that is rated less than 500 bhp and is operated less than 500 hours per year or uses less 1 x 10^9 Btus per year (higher heating value) of fuel would be subject to the following emission limits: 45 ppmvd[1] NOx, 250 ppmvd[2] VOC, and 2000 ppmvd[1] CO.

- (d)(1)(B)(vii) – This is also an existing provision that was not designated in a clause that provides alternative CO and VOC emissions limits that were approved by the Executive Officer in lieu of the concentration limits in Table II effective on and after July 1, 2011. This provision applies to two-stroke engines equipped with an oxidation catalyst and insulated exhaust ducts and catalyst housing that demonstrates that the CO and VOC limits in Table II were not achievable. The case-by-case limits shall not exceed 250 ppmvd VOC and 2000 ppmvd CO. There is no proposed change to this provision.

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis.
[2] Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

- (d)(1)(B)(viii) – This is a new clause being added to the rule. Staff reviewed concerns raised regarding the intermittent use of diesel-fueled engines used to power cranes located on offshore platforms. Recently, a facility installed new, Tier-4 final engines to replace older, higher-polluting engines. Although a source test was completed on two of the engines indicating compliance to the current NOx emission limits of 11 ppmvd, staff questioned whether the test represents actual operation. As such, staff is working with the facility to establish a technologically achievable NOx limit not to exceed 45 ppmvd. The technological achievable NOx limit was selected as a backstop limit based on the pre-July 1, 2010 limit for engines rated less than 500 bhp. However, an alternative emission limit above 45 ppmvd may be approved by the Executive Officer based on approved source test results.

Ammonia Emission Limits for New Engine Installation with SCRs

Staff initially proposed including an ammonia slip concentration limit for engines that install post-combustion emission controls, such as SCR. Currently when engines are permitted with post-combustion controls such as SCR or an SCR is added to a new engine, a BACT ammonia concentration limit of 5 ppmvd is specified in the permit. Staff decided to remove the ammonia concentration limit from PAR 1110.2 as this is a Regulation XIII – New Source Review BACT issue that has and will continue to be addressed during permitting of new engines with SCR and existing engines with new SCR systems. Provisions for monitoring ammonia have also been removed from PAR 1110.2 since monitoring requirements will also be addressed during permitting. If an existing SCR is replaced with a new SCR, the existing ammonia slip requirements can be retained provided there is no emissions increase of ammonia as a result of the modification.

Averaging Time Provisions for Biogas Engines (d)(1)(I)

The 2012 amendments to Rule 1110.2 established emission limits for biogas engines that would correspond to those for natural gas engines. Due to the unique nature of this type of biogas fuel (e.g., lower heating value and contaminant loading), provisions that would allow a longer averaging time were included. The current language contained in subparagraph (d)(1)(I) states that provided the operator of a retrofitted biogas engine can demonstrate through CEMS that NOx emissions are achieving levels of at least 10% below the 11 ppmvd NOx concentration limit (e.g., at or below 9.9 ppmvd for NOx) over a 4-month time period, the use of longer averaging is allowed. This provision would also apply for CO (e.g., at or below 225 ppmvd for CO) if it is also selected for averaging, although CO CEMS is not required for lean burn engines. Once the ability to use a longer averaging time is established, an operator could use a monthly fixed interval averaging time for the first four months of operation and up to a 24-hour fixed averaging time thereafter.

A review of these requirements gave rise to a need for additional clarity, specifically regarding the longer averaging time period that had been allowed immediately upon startup (e.g., before the first four months have elapsed), and how the ongoing requirement would be demonstrated and enforced. Stakeholders also commented on the 24-hour averaging and the need for a longer averaging time. As a result, staff proposes an averaging time for biogas engines equipped with CEMS over a 48-hour fixed interval of time. In exchange for the longer averaging time of 48 hours, the engine would be required to meet a concentration limit of 9.9 ppm for NOx and 225 ppmvd

CO (if CO is selected for averaging). If the owner or operator elects to use the longer averaging time, the emission limits and averaging time must be included in the permit to operate for the engine. Subparagraph (d)(1)(I) would now read:

- An operator of a biogas engine with a CEMS shall either meet:
  - (i) The NOx and CO limits of Table III-B, averaged pursuant to the specified averaging provisions in subparagraph (d)(1)(B); or

  - (ii) Meet the concentration limits at or below 9.9 ppmvd for NOx and 225 ppmvd for CO (if CO is selected for averaging), each corrected to 15%O2 and averaged over a 48-hour fixed interval, with the concentration limits and averaging time specified as a condition in the engine's permit to operate.

Qualitatively, if a facility uses the 48-hour averaging provision, then the expected benefit in emissions reductions would be 10% of what was previously emitted.

The existing provisions for determining compliance contained in clauses (d)(1)(I)(i) through (iv) are proposed to be removed and replaced with this 48-hour option. In the monitoring, testing, recordkeeping, and reporting section of Rule 1110.2, existing clause (f)(1)(A)(iii) clearly specifies that all CEMS under Rule 1110.2 are required to comply with all applicable requirements of Rule 218 and 218.1.

In addition, there are specific requirements for biogas averaging in the existing rule language that does not allow the averaging of data when the engine is not in operation or during periods of quality control, such as calibration. This provision is proposed to be kept in the rule and it is anticipated that subsequent amendments to Rules 218 and 218.1 would contain requirements for these types of situations for all CEMS installations outside of RECLAIM. These anticipated amendments would correspond to requirements currently contained in the Code of Federal Regulations for CEMS installations (40 CFR Part 60 and Part 75). Clause (d)(1)(I)(ii)(A) is added to keep the provision in the rule until such time that Rules 218 and 218.1 are amended. This provision states:

- Until Rules 218 and 218.1 are amended after [*Date of Amendment*], an operator shall not average data during one-minute periods in which the underlying equipment is not operated or when the CEMS is undergoing zero or calibration checks, cylinder gas audits, or routine maintenance in accordance with the provisions in Rules 218 and 218.1.

Addition of Concentration Limits for New Electrical Generation Devices (d)(1)(L)

Staff was approached by a manufacturer of electrical generating devices using linear generator technology with a request to provide concentration limits in addition to the listed emission standards for new electrical generating devices as currently expressed as pounds of NOx per Megawatt-Hour. Staff has updated Table IV, which contains the requirements for new electrical generators to reflect the conversion from a mass-based emission standard to a concentration limit.

The following calculation was used in the conversion from a mass-based emission to a concentration limit:

Step 1: Convert lbs/MW-hr to g/bhp-hr

lbs → grams	Multiply by 453.6
MW → bhp	Multiply by 1341

Pollutant	lbs/MW-hr	g/bhp-hr
NOx	0.07	0.0237
CO	0.2	0.0676
VOC	0.1	0.0338

Step 2: Convert g/bhp-hr to ppmvd

1 lb → grams	(A)	453.6	g
bhp → BTU/hr	(B)	2545	Btu/hp-hr
thermal efficiency	(C)	0.4	
O2	(D)	15	%
molar volume	(E)	385	@68 F and 1 atm
Molecular Weight of Constituents	(W_i)	46	NOx
		28	CO
		16	VOC
F factor	(F)	8710	natural gas

Equation 1: $Ci = M_i/A \times C/B \times E/(W_i \times F) \times (20.9 - D)/20.9 \times 10^{12}$

C_i = Concentration of constituent
M_i = Emissions in g/bhp-hr

NOx Value (g/bhp-hr)	0.0237
Convert NOx (ppmvd)	2.225
CO Value (g/bhp-hr)	0.0676
Convert CO (ppmvd)	10.446
VOC Value (g/bhp-hr)	0.0338
Convert VOC (ppmvd)	9.140

In the conversion from lbs/MW-hr to ppmvd, staff assumed a 40% thermal efficiency value for an engine in this operation. This value may differ due to varying thermal efficiency ratings. The basis for using a 40% thermal efficiency value was derived in part from information contained in a patent filing by the manufacturer. An expected thermal efficiency for a regular combustion engine is about 30%. In comparison, a linear generator has an expected increase in thermal efficiency to about 50%. However, to meet potential VOC requirements in the future, this overall efficiency increase may not be realized in practice. Therefore, an average between 30% and 50% was used. For this rule development, 40% was used as the thermal efficiency value for this technology.

In determining the equivalent emission limits, staff did not include any credit for recovered energy. The final determination of these values included a 10% rounding margin. Based on this evaluation, staff has added concentration limits to Table IV as listed in Table 3-1.

Table 3-1: New Rule 1110.2 Table IV Concentration Limits

Pollutant	Emission Standard (lbs/MW-hr)[1]	Concentration Limit[3] (ppmvd)[4]
NOx	0.070	2.5
CO	0.20	12
VOC	0. 10[2]	10

1 The averaging time of the emission standard for VOC is the sampling time required by the test method.

2 Mass emissions of VOC shall be calculated using a ratio of 16.04 pounds of VOC per lb-mole of carbon.

3 Concentration limit is calculated using a 40% engine efficiency and no applied thermal credit.

4 Parts per million by volume, corrected to 15% oxygen on a dry basis.

At this time, a size limit has not been proposed. The manufacturer of this linear generator technology has informed staff that due to the inherent low temperature of the exhaust, the oxidation catalyst used to reduce VOC emissions cannot reach temperatures to completely oxidize VOC emissions, particularly propane compounds, to meet a VOC concentration limit of 10 ppmvd. The manufacturer has expressed that it is working towards a solution to lower the VOC emissions.

Although VOC emissions from these engines at this time may be higher than the proposed limits, there are, however, several beneficial aspects with linear generators: low NOx emissions at start up and no ammonia emissions associated with an SCR. With linear generators, the NOx concentration limit of 2.5 ppmvd can be achieved at start up with no after-controls such as an SCR. As a result, there is no need for ammonia injection that would result in increased ammonia slip or

PM emissions, and the exhaust would achieve immediate compliance with NOx concentration limits. In other combustion technologies where an SCR is used to achieve lower NOx emission limits, start-up emissions are uncontrolled until the SCR catalyst can reach temperatures to control NOx emissions, which can take generally 20 to 30 minutes.

PAR 1110.2 includes a provision that allows engines that can achieve NOx concentration limits at start-up with no ammonia emissions from an SCR to meet an interim VOC concentration limit of 25 ppmvd, until January 1, 2024. Any new installation after this date would be required to meet the lower VOC emission limit of 10 ppmvd in Table IV. Additionally, PAR 1110.2 includes a cap on the number of units that can be installed meeting the alternative VOC concentration limit of 25 ppmvd to ensure that the emissions from such engines would not exceed the VOC significance threshold under CEQA. Staff recommends a total VOC emission cap not to exceed 45 lbs per day of VOC. The South Coast AQMD Air Quality Significance Threshold for VOC emissions due to operation is set at 55 lbs per day.[1] By setting a cap of 45 lbs per day of VOC allows for differences in generator size and operational hours while staying under the significance threshold.

The tracking of installations would be based on the number of applications submitted during the interim period. Engines that meet the limits in Table IV, would not be counted towards the number of units under the cap of the alternative VOC emission limit totaling less than 45 lbs of VOC per day. After January 1, 2024, all linear generators will be subject to the same emissions and monitoring requirements as other electrical generating engines. The provision that would directly apply to equipment using this technology [clause (d)(1)(L)(vii)] would read:

- For owners and operators of engines with no ammonia emissions from selective catalytic reduction pollution control equipment and where NOx emissions meet the limits of Table IV at start-up, an alternative VOC concentration limit of 25 ppmvd may be used in lieu of the VOC concentration limit in Table IV for any new unit up to maximum of 45 lbs of VOC emission per day of combined installation from [*Date of Rule Amendment*] that is installed before January 1, 2024. Any new installation on or after January 1, 2024 shall comply with the VOC concentration limit in Table IV.

Clause (d)(1)(L)(viii) is added to specify that either the emission standard or the concentration limit listed in Table IV is used. Application of this provision should be listed on the permit to operate. The provision states:

- The limits established by Table IV for a pollutant shall be specified in the permit to operate as either an emission standard given in lbs/MW-hr or for engines with no ammonia emissions from selective catalytic control equipment and where NOx emissions meet the concentration limits of Table IV during startup, as a concentration limit given in ppmvd.

Staff is limiting the option of an emissions concentration limit to linear generators where this technology can meet the emission targets upon start-up without an SCR. In addition, staff is concerned that extending a concentration-based limit to non-linear technologies may result in

[1] http://www.aqmd.gov/docs/default-source/ceqa/handbook/scaqmd-air-quality-significance-thresholds.pdf

higher emissions. It is expected that non-linear generator technologies have lower thermal efficiencies which would allow for higher mass based emission levels for a set concentration value.

Averaging Time for Electrical Generation Engines

Several stakeholders that represent facilities that operate these electrical generators, as well as original equipment manufacturers and emission control vendors have expressed the need for a one-hour averaging period for electrical generators. Consistent with the averaging period allowed for other engines in PAR 1110.2, staff is proposing to allow the same proposed option as non-electrical generators that is contained in proposed clause (d)(1)(B)(iv). A one-hour averaging time is more consistent with averaging times allowed for other electrical generating equipment allowed under Rule 1135 for equipment at electrical generating facilities. New clause (d)(1)(L)(vi) would read:

- For engines driving electrical generators and operating with a CEMS, a fixed-interval averaging time of one hour shall be used to demonstrate compliance with the NOx and CO emission concentration requirements of Table IV.

Monitoring Requirement Changes (e)(3)(C)

Under the RECLAIM program, engines categorized as large NOx sources are not required to be equipped with a continuous emission monitoring system (CEMS). Per Rule 2012 - Requirements for Monitoring, Reporting, and Recordkeeping for NOx Emissions, large NOx sources include any internal combustion engine with rated brake horsepower greater than or equal to 1,000 bhp and operating 2,190 hours per year or less, or greater than or equal to 200 bhp but less than 1,000 bhp and operating more than 2,190 hours per year.

Under Rule 1110.2, however, there is no separate designation of a RECLAIM large source. Under Rule 1110.2, CEMS is required for engines of 1,000 bhp and greater and operating more than two million bhp-hr per calendar year. A NOx and CO CEMS is required to be installed, operated and maintained in calibration to demonstrate compliance with the emission limits of the rule. In addition, for facilities with multiple engines that are individually greater than 500 bhp but less than 1000 bhp and have a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16 x 10^9 Btus per year (higher heating value), an operator is required to install, operate and maintain a CEMS to demonstrate compliance of those engines with the applicable NO_x and CO emission limits.

However, the following engines are not counted toward the combined rating or required to have a CEMS under the current rule:

- engines rated at less than 500 bhp;
- standby engines that are limited by permit conditions to only operate when other primary engines are not operable;
- engines that are limited by permit conditions to operate less than 1,000 hours per year or a fuel usage of less than 8 x 10^9 Btus per year (higher heating value of all fuels used);

- engines that are used primarily to fuel public natural gas transit vehicles and that are required by a permit condition to be irreversibly removed from service by December 31, 2014;
- engines required to have a CEMS by another provision in the rule
- if permit conditions limit the simultaneous use of the engines at the same location in a manner to limit the combined rating of all engines in simultaneous operation to less than 1500 bhp.

For those engines at RECLAIM and former RECLAIM facilities, subparagraph (e)(3)(C) has been added to provide a compliance schedule for CEMS installation once a facility exits from RECLAIM and becomes a former RECLAIM facility. This subdivision is necessary since there are several engines that are in RECLAIM that were not required to have a CEMS installed, but per PAR 1110.2, would now require installation of CEMS. For example, an engine that is classified as a large RECLAIM source without CEMS and is rated greater than 1,000 bhp, PAR 1110.2 would require CEMS upon exiting RECLAIM. In addition, engines that are greater than 500 bhp but less than 1,000 bhp and operate in close proximity to each other with an aggregate rating greater than 1,500 bhp would also require a CEMS outside of RECLAIM. Subparagraph (e)(3)(C) would state:

- The operator of any stationary engine that is located at a RECLAIM or former RECLAIM facility that is required to modify an existing CEMS or install a CEMS on an existing engine that is subject to paragraph (f)(1) shall comply with the compliance schedule in Table VII such that the operator shall submit to the Executive Officer applications for a new or modified CEMS within 90 days of becoming a former RECLAIM facility.

The intent of subparagraph (e)(3)(C) is to provide an operator of a former RECLAIM facility with a timeline to install CEMS engines that would now require one. Staff considers 90 days of becoming a former RECLAIM facility to submit to the Executive Officer an application for a new or modified CEMS a reasonable amount of time.

Once the application is initially approved, then the following actions would be required, per the existing requirements listed in Table 3-2

Table 3-2: Rule 1110.2 Table VII

Action Required	Applicable Compliance Date for
• Complete installation and commence CEMS operation, calibration, and reporting requirements	• Within 180 days of initial approval
• Complete certification tests	• Within 90 days of installation
• Submit certification reports to Executive Officer	• Within 45 days after tests are completed
• Obtain final approval of CEMS	• Within 1 year of initial approval

For purposes of clarification, a day is considered on a calendar day basis.

Clause (e)(3)(C)(i) was added to provide relief to facilities that opt to retrofit existing engines with new emission controls or decide to install new engines. For example, if an engine is retrofitted before it exits RECLAIM, CEMS would be required at the time of retrofitting. However, if an engine has exited from RECLAIM and the compliance deadline is some other date in the future, CEMS would not be required to be installed until the engine is retrofitted or when the engine is replaced. This clause states:

- For engines at a RECLAIM or former RECLAIM facility, installation of a CEMS is required concurrently with the installation of retrofit control technologies or new engine replacements to meet the requirements of paragraph (d)(1).

For RECLAIM or former RECLAIM facilities, paragraph (e)(10) of Rule 1110.2 provides the reference to the implementation schedule proposed per Rule 1100. Specifically, for RECLAIM or former RECLAIM facilities:

- The owner or operator of a RECLAIM or former RECLAIM facility with any unit(s) subject to subdivision (d) shall meet the applicable NOx emission limit in Table II in accordance with the schedule specified in Rule 1100 – Implementation Schedule for NOx Facilities.

Threshold for CEMS Requirement at an Essential Public Service (f)(1)(A)

During the rulemaking process, a stakeholder that operates a biogas-fueled engine rated at 1175 bhp requested a provision similar to the provision allowed for CEMS for threshold for the aggregate horsepower provision. Currently under Rule 1110.2 (f)(1)(A)(ii)(VI), the aggregate horsepower CEMS requirement is not applied to public agencies provided that additional diagnostic monitoring is conducted. In response to this request, staff has included the following clauses:

❖ (f)(1)(A)(ix) – In lieu of clause (f)(1)(A)(i), an Essential Public Service or a contractor for an Essential Public Service that is operating a biogas engine of 1000 bhp and greater and less than 1200 bhp, may alternatively comply with the Inspection and Monitoring Plan requirements of subparagraph (f)(1)(D), provided the operator conducts diagnostic emission checks at least weekly or every 150 operating hours, whichever occurs later.

❖ (f)(1)(A)(x) – If an Essential Public Service or a contractor for an Essential Public Service that has elected to comply with the Inspection and Monitoring Plan provisions pursuant to clause (f)(1)(A)(ix) for biogas engines is found to exceed an applicable NOx or CO limit by a source test required by subparagraph (f)(1)(C) or South Coast AQMD test using a portable analyzer on three or more occasions in any 12-month period, the operator shall comply with the CEMS requirements of clause (f)(1)(A)(i) for such biogas engine in accordance with the compliance schedule of Table VII and submit a CEMS application to the Executive Officer within six months of the third exceedance.

If the facility chooses to remove its CEMS and utilize weekly monitoring with a portable analyzer, the facility would be required to reinstall and recertify a CEMS if there are a number of emissions exceedances per clause (f)(1)(A)(x). What is considered an occasion is a separate instance where a limit is exceeded during a compliance check with a portable analyzer. If an operator determines that a limit has been exceeded, the operator is expected to take any and all necessary steps to remedy the situation. In the course of taking corrective action, if the operator performs additional tests with a portable analyzer and has a high value, this is not considered a separate occasion that counts against the cap. However, additional checks may substantiate the amount of time of non-compliance and may be used to determine the scope of any resulting enforcement action.

Clarified Language Regarding Source Testing Deadlines (f)(1)(C)(i)

Currently, Rule 1110.2 requires source tests once every two years (or once every three years if the engine is below a low use hourly threshold pursuant to clause (f)(1)(C)(i). The proposed rule language clarifies when the source tests must be conducted:

- …at least once every two years from the date of the previous source test, no later than the last day of the calendar month that the test is due…

This ensures that the interval between source tests does not become excessive, while allowing for flexibility up to and including the calendar month for scheduling and re-scheduling a source test. For example, if an engine has been source tested on May 21, 2018 and is on a two-year schedule, then the next source test would be due no later than May 31, 2020. However, if an engine is source tested before May 2020, then the source testing month would be reset to that month. Continuing with this example, if the engine was source tested early on April 1, 2020, then the next source test would be due no later than April 30, 2022.

In addition, if an engine has not been operated prior to the date of a source test, the rule is amended to provide flexibility for when the source test would be required once an engine is operated again. Previously, the rule allowed that if an engine had not been operated within three months of the date a source test is required, then a source test would be required once an engine resumes operation for a period of seven consecutive days or 15 cumulative days of operation. If an engine is shut down prior to the due date of a source test, the source test would then be due seven consecutive days or fifteen cumulative days after resumed operation.

To clarify this issue, the proposed rule language states:

- If the engine has not been operated before the date a source test is due, the source test shall be conducted by the end of seven consecutive days or 15 cumulative days of resumed operation.

Relative Accuracy Testing Inclusion (f)(1)(C)(ii)

An update to the source testing requirement listed in clause (f)(1)(C)(ii) has been added to allow relative accuracy tests to satisfy this requirement for those pollutants monitored by CEMS. This condition mirrors what already exists for clause (f)(1)(C)(i). RATA testing can be used in lieu of source testing and would be required for all loads of the equipment operation.

Recordkeeping Revisions (f)(1)(E) and (f)(2)

Under RECLAIM Rule 2012, stationary and portable engines that are designated as a process unit on the facility permit are allowed to maintain a quarterly operating log. An engine is designated as a process unit if it is rated greater than or equal to 200 bhp but less than 1,000 bhp and operating 2,190 hours per year or less; or greater than 50 bhp but less than 200 bhp. Once the facility exits the RECLAIM program, however, the facility shall comply with subparagraph (f)(1)(E) or paragraph (f)(2) which requires a monthly engine operating log for stationary and portable engines, respectively, instead of a quarterly log. Each of these provisions have been modified to reflect this change:

- Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit until such time that the facility becomes a former RECLAIM facility. The facility shall maintain a monthly engine log starting in the month that it has become a former RECLAIM facility.

Harmonize with Rule 219 and Rule 222 (i)(1)(H)

In May 2013, Rules 219 and 222 were amended such that engines powering remote radio transmission towers meeting specific criteria were exempt from permitting. The criteria included any engine used exclusively for electrical generation at remote two-way radio transmission towers where no utility, electricity, or natural gas is available within a ½ mile radius, has a manufacturer's rating of 100 bhp or less, and is fired exclusively on diesel #2, compressed natural gas, or liquefied petroleum gas.

Staff determined that not only were these engines to be exempted from permitting, but these engines were to be exempted from Rule 1110.2 emission requirements as well. The engines were considered to provide an essential public service and due to their unique locations required this exemption to be extended to this engine category. Subparagraph (i)(1)(H) has been modified to remove reference to the engines operated at Santa Rosa Peak. Subparagraph (i)(1)(M) has been added to harmonize Rules 1110.2, 219, and 222. Subparagraph (i)(1)(M) states that the emission requirement provisions of subdivision (d) shall not apply to:

- An engine used exclusively for electrical generation at remote two-way radio transmission towers where no utility, electricity, or natural gas is available within a ½ mile radius, has a manufacturer's rating of 100 bhp or less, and is fired exclusively on diesel #2, compressed natural gas, or liquefied petroleum gas.

Although subparagraph (i)(1)(H) removes reference to engines operated at Santa Rosa peak, the engines at Santa Rosa peak have been determined to meet the requirements of subparagraph (i)(1)(M). Staff performed a site visit and confirmed applicability.

Other Exemptions

- ❖ Rule 1110.2 (i)(1)(J) has been updated to include within this exemption the tuning of the engine and emission control equipment. The Executive Officer may approve up to two hours for tuning of engine and emission control equipment. Some stakeholders have indicated that additional tuning leads to cleaner operating engines.

- ❖ Rule 1110.2 (i)(1)(K) has been updated to include the installation of catalytic control equipment. As more operators opt to install this type of equipment, stakeholders requested specific inclusion of this provision to have adequate time to make adjustments after significant equipment changes.

- ❖ Rule 1110.2 (i)(1)(N) has been added as an exemption to the emissions requirements of the rule for any engine that is subject to an industry-specific rule. As part of the RECLAIM transition, several new industry-specific rules are being developed. In such cases, facilities that are affected by these industry-specific rules may have non-emergency, internal combustion engines that are excluded from certain Rule 1110.2 requirements (e.g., engines operated at electricity generating facilities and in refineries). Subparagraph (i)(1)(N) will state that the emission requirements in Rule 1110.2 shall not apply to:

    - Any engine at a RECLAM or former RECLAIM facility that is subject to a NOx emission limit in a different rule for an industry-specific category defined in Rule 1100 – Implementation Schedule for NOx facilities.

- ❖ Rule 1110.2 (i)(3) has been added as an exemption to units located at landfills and publicly owned treatment works (POTW) that are subject to a NOx emission limit in a Regulation XI rule adopted or amended after [*Date of Amendment*]. Staff is working on two proposed rules for combustion equipment located at either landfills or publicly owned treatment works and the possibility of including requirements for engines in these two proposed rules. This provision is a placeholder in the event that NOx, CO, and VOC emissions are addressed in these two proposed rules.

Flexibility Added to I&M Plans

Stakeholders have requested consideration on how compliance to the conditions contained in Attachment I can be demonstrated. For example, the manufacturer of linear generators has proposed using parametric monitoring as a substitute to using portable analyzers. In response to this request, staff has proposed an option that would allow owner or operators to make their case to the Executive Officer. The standard for compliance is the portable analyzer, but staff recognizes that as technology advances, diagnostic innovations may provide alternative methods to accomplish similar goals.

PROPOSED AMENDMENTS TO RULE 1100

Rule 1100 – Implementation Schedule for NOx Facilities establishes the implementation for Regulation XI rules for RECLAIM and former RECLAIM facilities. Rule 1100 was created to address the implementation schedule for RECLAIM facilities that are subject to Regulation XI particularly for those rules where the compliance date for the non-RECLAIM facilities has past and the NOx emission limits are fully implemented. Proposed Amended Rule 1100 (PAR 1100) establishes the implementation schedule for PAR 1110.2 for RECLAIM and former RECLAIM facilities. PAR 1100 includes engines regulated under PAR 1110.2 in its applicability for owners or operators of RECLAIM or former RECLAIM facilities.

Definitions – Subdivision (c)

PAR1100 includes new definitions that pertain to equipment covered under PAR 1110.2 (COMPRESSOR GAS LEAN-BURN ENGINE, ENGINE, LEAN-BURN ENGINE, LOCATION, PORTABLE ENGINE, RULE 1110.2 UNIT, and STATIONARY ENGINE.

- COMPRESSOR GAS LEAN-BURN ENGINE is a stationary gaseous-fueled two-stroke or four-stroke lean-burn engine used to compress natural gas or pipeline quality natural gas for delivery through a pipeline or into storage as defined in Rule 1110.2.

- ENGINE is any spark- or compression-ignited internal combustion engine, including engines used for control of VOCs, but not including engines used for self-propulsion as defined in Rule 1110.2.

- LEAN-BURN ENGINE is an engine that operates with high levels of excess air and an exhaust oxygen concentration of greater than 4 percent as defined in Rule 1110.2.

- LOCATION means any single site at a building, structure, facility, or installation. For the purposes of this definition, a site is a space occupied or to be occupied by an engine. For engines which are brought to a facility to perform maintenance on equipment at its permanent or ordinary location, each maintenance site shall be a separate location.

- PORTABLE ENGINE is an engine that, by itself or in or on a piece of equipment, is designed to be and capable of being carried or moved from one location to another. Indications of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting. The operator must demonstrate the necessity of the engine being periodically moved from one location to another because of the nature of the operation as defined in Rule 1110.2.

  An engine is not portable if:

  (A) The engine or its replacement remains or will reside at the same location for more than 12 consecutive months. Any engine, such as a back-up or stand-by engine, that replaces an engine at a location and is intended to perform the same function as the engine being replaced, will be included in calculating the consecutive time period. In that case, the cumulative time of both engines, including the time between the removal of the original engine and installation of the replacement engine, will be counted towards the consecutive time period; or

(B) the engine remains or will reside at a location for less than 12 consecutive months where such a period represents the full length of normal annual source operations such as a seasonal source; or

(C) The engine is removed from one location for a period and then it or its equivalent is returned to the same location thereby circumventing the portable engine residence time requirements.

The period during which the engine is maintained at a designated storage facility shall be excluded from the residency time determination.

- RULE 1110.2 UNIT means any stationary and portable engine over 50 rated brake horsepower (bhp) subject to Rule 1110.2.

- STATIONARY ENGINE is an engine which is either attached to a foundation or if not so attached, does not meet the definition of a portable or non-road engine and is not a motor vehicle as defined in Section 415 of the California Vehicle Code as defined in Rule 1110.2.

Rule 1110.2 Implementation Schedule

Subdivision (d) of PAR 1100 contains the implementation schedule for engines at RECLAIM and former RECLAIM facilities. The final compliance date for most stationary engines at RECLAIM and former RECLAIM facilities to meet the emission limits listed in Rule 1110.2 paragraph (d)(1) will be December 31, 2023, consistent with the implementation deadline of AB 617.

Portable diesel engines greater than or equal to 50 brake horsepower shall comply with the tier phase-out schedule of the California Air Resources Board Airborne Toxic Control Measure. The tier phase-out schedule is provided below in Table 3-3.

Table 3-3: Tier Phase-Out Schedule

Engine Certification	Engines rated 50 to 750 bhp		Engines rated > 750 bhp
	Large Fleet	Small Fleet	
Tier 1	1/1/2020	1/1/2020	1/1/2022
Tier 2 built prior to 1/1/2009	1/1/2022	1/1/2023	1/1/2025
Tier 2 built on or after 1/1/2009	Not Applicable	Not Applicable	1/1/2027
Tier 3 built prior to 1/1/2009	1/1/2025	1/1/2027	Not Applicable
Tier 3 built on or after 1/1/2009	1/1/2025	1/1/2027	Not Applicable
Tier 1,2, and 3 flexibility engines	December 31 of the year 17 years after the date of manufacture		

Upon rule adoption, an owner or operator of RECLAIM or former-RECLAIM facility with a portable spark-ignited engine shall meet the compliance schedule of the Large Spark Ignition Engine Fleet Requirements, Article 2, Chapter 15, Division 3, Title 13 of the California Code of Regulations.

Compressor Gas Lean-Burn Gas Engines

There is one RECLAIM facility stakeholder that is currently using compressor gas lean-burn engines. This stakeholder has commented that these engines are unique in their application and has requested additional consideration in establishing the emission limits and the compliance schedule. PAR 1100 includes three alternative implementation schedules for compressor gas lean-burn engines for: (1) existing engines that are being retrofitted to meet the emission limits; (2) replacement of compressor gas lean-burn engines at a facility; and (3) engines that are being replaced with equipment regulated under another Regulation XI rule.

- Alternative Compliance Schedule Retrofitting Compressor Gas Lean-Burn Engines

PAR 1100 paragraph (d)(5) includes an alternative compliance approach for owner or operators that are retrofitting compressor gas lean-burn engines to meet the emission limits in paragraph (d)(1) of PAR 1110.2. Owner or operators that elect to use this alternative compliance approach must submit a permit application for each compressor gas lean-burn engine by July 1, 2021 if the engine does not meet the NOx concentration specified in PAR 1110.2. No later than 24 months after the issuance of the permit to construct, the compressor gas lean-burn engine shall comply with the NOx concentration limits in Table II of PAR 1110.2. Until the NOx concentration is met, the owner or operator shall provide quarterly reports of monitoring and source test data, applicable engine parameters, and actions taken towards achieving compliance with the NOx limit. The quarterly reports provide data for the South Coast AQMD staff to assess the emission levels that are being achieved the types of corrective actions, if any, that the operator is implemented to achieve the NOx concentration limits.

A time extension may be requested for up to an additional 24 months, provided a compliance plan is submitted no later than 22 months after the permit to construct is issued. The request for the time extension must provide the reason for the time extension and all quarterly report data since the startup of the retrofitted equipment. If the compliance plan is approved, the engine shall meet a NOx concentration limit not to exceed 45 ppm, corrected to 15% oxygen on a dry basis, averaged over a 3 hour fixed interval until the time specified by the Executive Officer. The engine shall also be required to meet the VOC concentration limits of Rule 1110.2, including any previously approved alternate limits. It is expected that efforts be continued to attempt to meet the 11 ppm NOx limit of Rule 1110.2 during this time period.

At the end of the extension period, the owner or operator may notify the Executive Officer that the emission limits in PAR 1110.2 paragraph (d)(1) cannot be achieved. These requirements are contained in PAR 1100 paragraph (d)(6), which require a revision to the compliance plan submitted previously to obtain the time extension. The owner or operator shall submit the past two years of monitoring data, operation logs, and detailed increments of progress including measures taken to meet the emission limits. The Executive Officer shall review the information and either require that the NOx emissions limit in paragraph (d)(1) be met or establish technologically achievable case-by-case emission limits. The owner or operator shall either meet the case-by-case emission limits within 30 days or replace the compressor gas lean-burn engine within one year.

During this period, the engine shall continue to comply with the interim NOx limit in Rule 1100 (d)(5)(C)(i).

If any extension is approved, the owner or operator shall pay the South Coast AQMD a mitigation fee equal to $100,000, with the time period starting after the second year from the issuance of the permit to construct because the engines that would be operating during any granted extension period will be emitting higher levels of emissions than the limits allowed for in the rule. The mitigation fee will be used to fund studies and projects to reduce criteria pollutants and toxic air contaminant emissions. The amount for the mitigation fee is expected to be approximately the amount that the facility would have had to pay to go through the variance process, including excess emissions fees, notification fees, and other procedural fees.

- Alternative Compliance Schedule Facility Modernization with Zero-Emission Technologies for Compressor Gas Lean-Burn Engines

PAR 1100 paragraph (d)(7) includes an alternative compliance approach for facilities that elect to replace existing compressor gas lean-burn engines with new engines or other zero-emission technologies. By January 1, 2021 the facility must submit a compliance plan indicating that the engines at a facility will be replaced or removed. On or before July 1, 2022, permit applications must be submitted. Within 36 months of issuance of the permit to construct, the identified engines must be replaced or removed, with at least 20 percent of the total horsepower using a zero-emission technology such as an electric motor or fuel cell technology. A time extension of up to 36 months may be requested. The request shall be approved provided the information required is complete and accurate, all permit applications were submitted by July 1, 2022, and documentation demonstrates that the replacement equipment has been ordered and necessary applications and approvals have been initiated, along with the reasons for any delay with replacement or removal of the existing equipment. Engines to be replaced as part of a modernization plan with equipment subject to another Regulation XI rule shall be shut down no later than six months of commencement of operation of the replacement units to allow sufficient time to confirm reliability of the replacement equipment. The associated permit to operate for the replacement equipment may require the shutdown at shorter time interval if reliability has been demonstrated sooner.

A mitigation fee of $100,000 per facility shall be assessed per year and any portion of a year for any time extension because the engines that would be operating during any granted extension period will be emitting higher levels of emissions than the limits allowed for in the rule. The mitigation fee will be used to fund studies and projects to reduce criteria pollutants and toxic air contaminant emissions. The amount for the mitigation fee is expected to be approximately the amount that the facility would have had to pay to go through the variance process, including excess emissions fees, notification fees, and other procedural fees.

- Compliance Schedule for Engines Replaced by Equipment Regulated Under Another Regulation XI Rule

PAR 1100 subparagraph (d)(4) provides a schedule for engine removal for compressor gas lean-burn engines that will be replaced with equipment subject to another Regulation XI rule such as a turbine that is covered under Rule 1134. This would require a submittal of a retirement plan that would specify when the engines will be replaced and removed from service. Engines that will be replaced will not be required to install a CEMS. However, if such engine is not replaced for any reason, the engine shall meet the emission limits specified in Rule 1110.2 by December 31, 2023 and require the installation of CEMS.

Compliance Schedule for Diesel Engines at Ski Resorts

Additional consideration is also provided for diesel-fired electrical generators at ski resorts in paragraph (d)(9). If any engine operates less than or equal to 500 hours per year or uses less than 1×10^9 Btu per year, it may retain NOx and ammonia limits as well as the monitoring and source testing requirements specified on the South Coast AQMD permit to operate in effect on the date of rule adoption. The low-use provision must be made a condition of the South Coast AQMD permit to operate. If the engine exceeds the annual hours and fuel use requirements, the owner or operator must submit an application to repower or retrofit the engines within six months. The engine must be retired or meet the emission concentration standards in Rule 1110.2 Table II within two years of the exceedance.

Other minor amendments are made for clarification.

CHAPTER 4: IMPACT ASSESSMENTS

INTRODUCTION

EMISSION REDUCTIONS

COST-EFFECTIVENESS

SOCIOECONOMIC ASSESSMENT

CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

COMPARATIVE ANALYSIS

INCREMENTAL COST EFFECTIVENESS

INTRODUCTION

Through the rulemaking process, staff initially identified 98 RECLAIM engines that would potentially subject to PAR 1110.2. Subsequent analysis reduced the number of engines to 76 engines. The reduction in the number of engines came as a result of contact with facilities. Eighteen engines were identified as no longer in operation and removed from service, three engines were identified as engines permitted with the jurisdiction of the South Coast AQMD, but having been shipped out-of-state, and one based on its integration with a connected heater was determined to be regulated by Rule 1146. Of the 76 engines, 14 engines are permitted to meet a NOx emission limit of 11 ppmvd[1]. Staff noted that permits for seven engines listed a NOx limit of 12.3 ppmvd[1]. However, staff determined that the permitted value should have been 11 ppmvd[1], based on State certification levels. The remaining 55 engines are either permitted or operate at an emission level greater than 11 ppmvd[1]. Of the 55 engines that have emissions greater than 11 ppmvd[1], eight are portable engines that would not require changes and will be subject to the State ATCM requirements and 47 are engines that will need changes per the proposed requirements of the rule.

In addition to the working group meetings, staff conducted multiple site visits with stakeholders affected by PAR 1110.2. The purpose of the visits is to evaluate site-specific concerns associated with PAR 1110.2. Staff has also met individually with affected stakeholders.

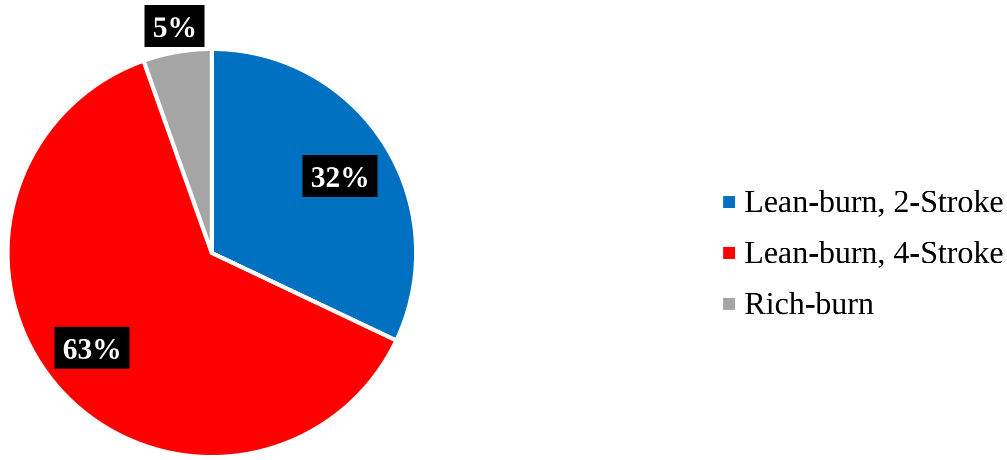
As part of the rule development process, staff sent surveys to both RECLAIM and non-RECLAIM facilities affected by Rule 1110.2. Surveys were sent to 25 RECLAIM facilities that would potentially be covered under Rule 1110.2 and surveys were also sent to 430 non-RECLAIM facilities identified as owning and/or operating prime engines, both portable and stationary. Staff received surveys from 88% of the RECLAIM facilities and 30% of non-RECLAIM facilities. The data collected from the surveys was used to the verify the engine inventory at RECLAIM sites and to ascertain operational characteristics at non-RECLAIM sites, such as the annual hours of operation.

EMISSION REDUCTIONS

RECLAIM emissions from the 2017 compliance year audits were collected for each device. An exception was given for one facility that was not operational during compliance year 2017. For equipment operated at this facility, staff used data from the 2014 Compliance Year audit as a basis, which was the most recent year of normal operation for the facility. The RECLAIM emissions for the 2017 compliance year were selected as the basis for the emission reduction calculations as representative of actual throughput (emissions) and actual reductions achieved by the transition of engines in the RECLAIM program to a command-and-control regulatory structure. In addition, data from the Annual Emissions Reporting (AER) program for the 2017 Compliance Year was reviewed and the information matched the RECLAIM data. The total NOx inventory for the RECLAIM units affected by PAR 1110.2 is estimated to be 0.37 tons per day.

[1] @ 15% O_2 averaged over 15 minutes

Figure 4-1 - Emissions Inventory (0.37 tons per day)



As presented in Figure 4-1, approximately 63% of the 2017 baseline RECLAIM emissions were emitted from lean-burn, 4-stroke engines. Another 32% of the 2017 baseline RECLAIM emissions were emitted from lean-burn, 4-stroke engines, and rich-burn engines accounted for approximately 5% of the emissions. In general, RECLAIM rich-burn engines equipped with NSCR meet the NOx emission limits of Rule 1110.2, are smaller in size, and subsequently have lower total emissions relative to lean-burn engines.

To estimate the emission reductions for Proposed Amended Rule 1110.2, a baseline emission concentration level for each engine was calculated. The estimate used existing emissions limits listed on the engine permits. Where no expressed limit was given (e.g., engines designated as major sources in the RECLAIM program), staff reviewed the engine's permit application file and utilized the engineering basis that was used to process the permit. For some older engines, the engineering basis relied on limits established per Rule 1110.1. For other engines, the engineering basis relied on actual source test results at the time of permitting.

To calculate the NOx emission reductions, the final emission limit was set to 11 ppmvd. Emission reductions were calculated using Equation 4-1. The initial emission factor or concentration level (permitted concentration emission limit) is subtracted by the final emission factor or concentration level (set at 11 ppmvd for NOx). The difference is then multiplied by the throughput (RECLAIM NOx emissions) reported for the 2017 compliance year for each device.

<u>Equation 4-1:</u>

$$\text{Emission Reductions} = (E_{initial} - E_{final}) \times \text{Throughput}$$

Where,

$E_{initial}$ = permitted concentration limit

E_{final} = proposed concentration limit of 11 ppmvd
Throughput = RECLAIM NOx emissions based on 2017 Compliance Year

As presented in Figure 4-2, approximately 59% of the estimated emission reduction is realized from lean-burn, 4-stroke engines. Another 38% of the estimated emission reduction comes from lean-burn, 2-stroke engines. Rich-burn engines account for only approximately 3% of the reductions. As a result of engines transitioning from the RECLAIM program to a command-and-control regulatory structure, NOx emissions are expected to decrease by approximately 0.29 tons per day. For each engine, emission reductions were grouped by engine category. Table 4-1 show the NOx emissions reductions by engine category.

Figure 4-2 - Estimated Emissions Reductions (0.29 tons per day)

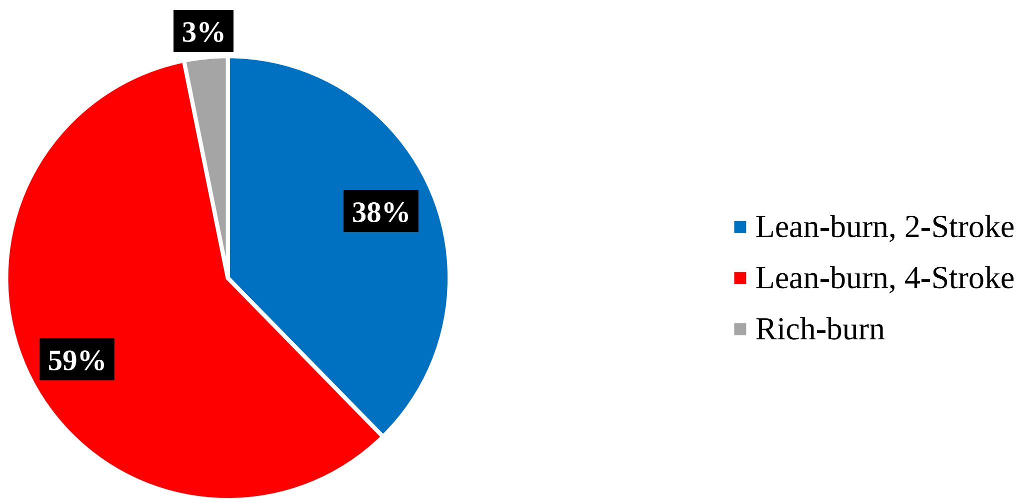


Table 4-1: NOx Emissions Reductions by Engine Category

Category	ton/day
(a) Lean-burn, 2-Stroke	0.109
(b) Lean-burn, 4-Stroke	0.172
(c) Rich-Burn	0.009
Total	0.29

COST-EFFECTIVENESS

Staff conducted a cost-effectiveness analysis for retrofit costs for existing engines. The target pollutant of the analysis is NOx. The RECLAIM program had exempted engines from compliance with the NOx emission limits established under Rule 1110.2. However, limits on other pollutants were not exempted and remained in effect (e.g. VOC and CO). As a result, the proposed amendments will not require VOC or CO reductions.

For this analysis, present worth value (PWV) was calculated for the engines requiring retrofits. Included in the PWV calculation, the total installed cost (TIC) of any proposed modification and the anticipated annual cost were considered. The TIC included the cost for emissions control equipment and associated catalyst. Cost data for equipment and catalyst was collected from vendors and actual stakeholders. The data included costs for several engine sizes. The costs were then fitted into a curve that was used to estimate general cost for potential retrofit applications. In general, a factor of 1.5 times the sum of equipment and catalyst costs was used to estimate the installation costs. However, in one unique case, staff used a factor of 2.5 to estimate installed cost due to the site-specific concerns that may contribute to potential increased installation costs.

In considering Annual Cost, staff included an operations and maintenance factor for an incremental cost associated with additional emissions control equipment of 0.5%. The operations and maintenance cost factor was taken from the EPA's 2016 SCR Cost Manual[1]. In addition, for units that require urea or ammonia injection, the amount of urea or ammonia used whether for new or existing SCRs was calculated from data collected from vendors.

For units that require CEMS due to their transition from the RECLAIM program to Rule 1110.2, equipment and installation costs were based on information supplied by a vendor specializing in CEMS equipment and installation. For engines that have a horsepower rating greater than or equal to 500 hp but less than 1,000 hp and are operating at a facility with an aggregate horsepower rating of 1,500 hp, these engines will be required under Rule 1110.2 to install a CEMS. Sharing of CEMS was not considered as part of this evaluation. Staff evaluated worst-case scenarios for individual CEMS installations, but there can be a cost savings by employing time-shared CEMS for groups of engines. Despite this, facilities based on their operational characteristics, can apply for permit conditions that limit usage and operation (e.g., backup engines or engines that are used sparingly or in rotation). For these engines, CEMS would not be required, per existing requirements in Rule 1110.2 subclause (f)(1)(A)(ii)(III).

In the calculation, staff assumed a uniformed series present worth factor (PWF) at a 4% interest rate and a 25-year equipment life expectancy.

$$PWV = TIC + (PWF \times AC)$$

PWV = present worth value ($)

[1] Reference EPA's 2016 SCR Cost Manual at the following website – https://www3.epa.gov/ttn/ecas/docs/SCRCostManualchapter7thEdition_2016.pdf

TIC = total installed cost ($)
AC = annual cost ($)
PWF = uniform series present worth factor (15.622)

Engines were separated into four categories: (1) lean-burn, two-stroke stationary engines, (2) lean-burn, four-stroke stationary engines, (3) rich-burn stationary engines, and (4) portable engines. Categories were selected based on past experience where technology and unique issues were identified and attributed to each. Although identified as a separate category, for purposes of this analysis, portable engines were not included. Portable engines are already required to comply with the State portable ATCM regulation, so cost effectiveness was not calculated for these engines.

Table 4-2 summarizes the results of the analysis. The overall cost-effectiveness was calculated to be $33,800 per ton of NOx reduced. The cost-effectiveness for the lean-burn sub-categories was calculated to be less than $50,000 per ton of NOx reduced. However, the cost-effectiveness for the rich-burn engine category is calculated to be greater than $50,000 per ton of NOx reduced.

For the rich-burn engine sub-category, the incremental amount of NOx reduced for this engine category is minimal at 3% compared to the other two categories. For rich-burn engines, it is anticipated that these engines will meet the NOx emission limit of 11 ppmvd with either minimal catalyst modifications or tuning of the air-to-fuel ratio controller. In many instances, rich-burn engines will incur costs associated with the installation of a CEMS. Under the RECLAIM program, any engine that had a horsepower rating less than 1,000 bhp did not have to have a CEMS. Under Rule 1110.2, however, an engine with a horsepower rating greater than or equal to 500 bhp and less than 1,000 bhp but that is operating at a facility with an aggregate horsepower rating of 1,500 bhp will be required under Rule 1110.2 to install a CEMS on each engine. The cost of installing CEMS on each engine is much greater compared to the cost of additional catalyst or tuning of the controller. These added monitoring costs are reflected in the resultant cost-effectiveness of $71,400 for this sub-category. If a CEMS is not installed on these engines, then the cost effectiveness for the rich-burn category is calculated to be approximately $19,000 per ton of NOx reduced. Because the effect of the rich-burn category on NOx reduction is not great compared to the other engine categories and if the CEMS requirement is not factored in, the overall cost effectiveness drops only from $33,800 per ton of NOx reduced to $32,200 per ton of NOx reduced.

Table 4-2 – Cost Effectiveness Analysis

Category	$/ton NOx
(a) 2-Stroke, Lean-Burn	28,100
(b) 4-Stroke, Lean-Burn	35,500
(c) Rich-Burn	71,400 *(19,000 without CEMS)*
Total	33,800 *(32,200 without CEMS)*

Although the cost-effectiveness analysis is based on the average cost-effectiveness for all affected equipment staff does assess outlier data to better understand why the cost-effectiveness is substantially higher for certain engines compared to the majority of the equipment category. A review of operational data for these outlier engines indicated that the engines did not operate more than 200 hours in the year. Due to the low engine use and the resulting small amount of emissions, the cost of additional controls leads to higher cost-effectiveness values.

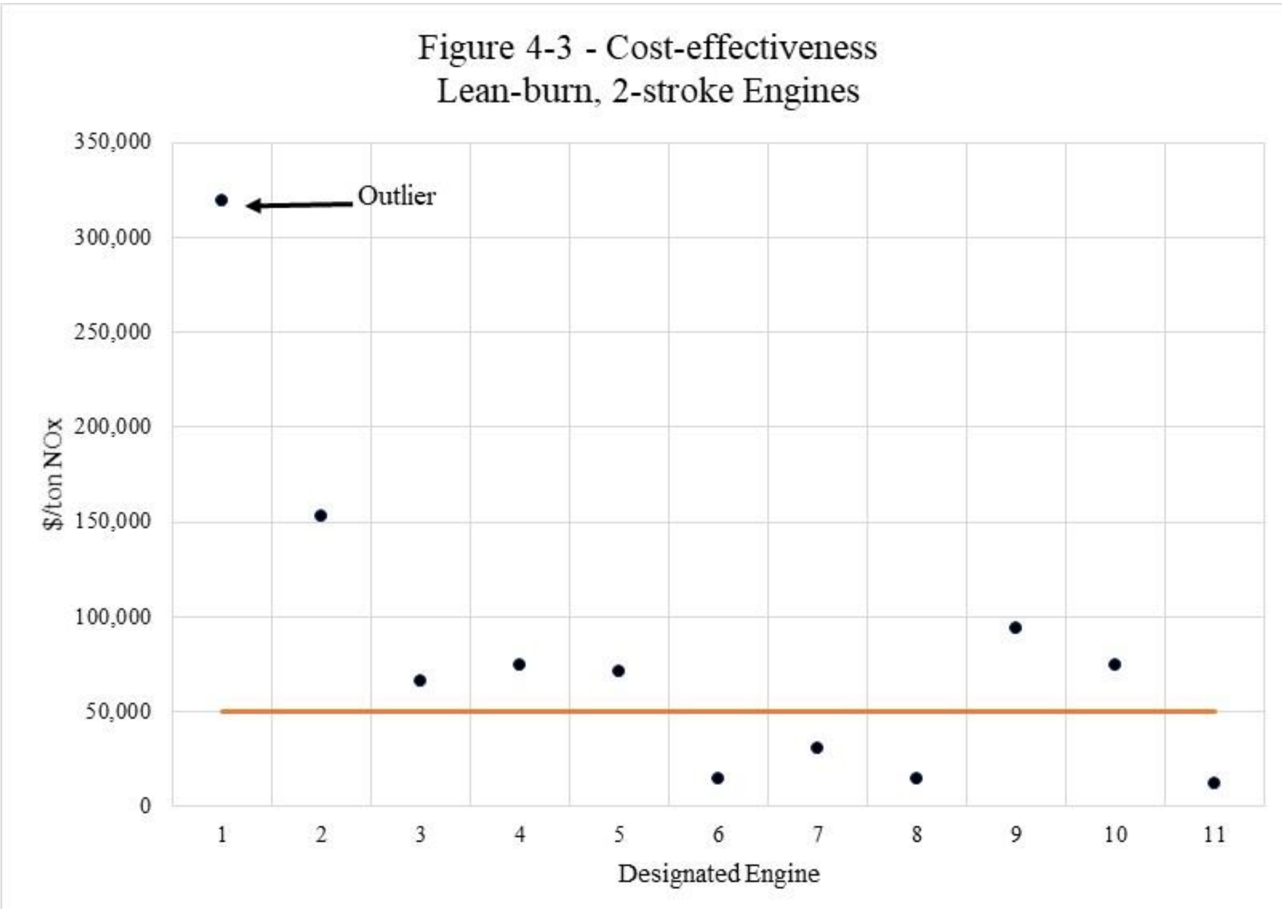


Figure 4-3 presents the distribution of cost-effectiveness for the eleven lean-burn, 2-stroke engines that were evaluated. The straight bar represents a value of $50,000. In this category, an outlier was determined to be a value greater than $213,050 per ton of NOx reduced. Engine No. 1 was identified as an outlier with a calculated value of $362,000 per ton of NOx reduced. Although not considered an outlier, Engine No. 2 also had a high cost-effectiveness. Both are diesel engines, rated at 450 hp and categorized as process units under RECLAIM. Each has a fixed emission factor of 469 lbs/1000 gallon. In 2016 and 2017, both engines operated less than 200 hours each year (one of those engines reported zero operating hours the last two compliance years). For these two engines, the low-use provision contained in Rule 1110.2 (d)(1)(B)(iii) would be applicable, should the facility decide to use it. If these engines exceed 500 hours of operation or use more than 1 x 10^9 British Thermal Units (Btus) per year (higher heating value) of fuel, then the emissions limits listed in Table II would apply.

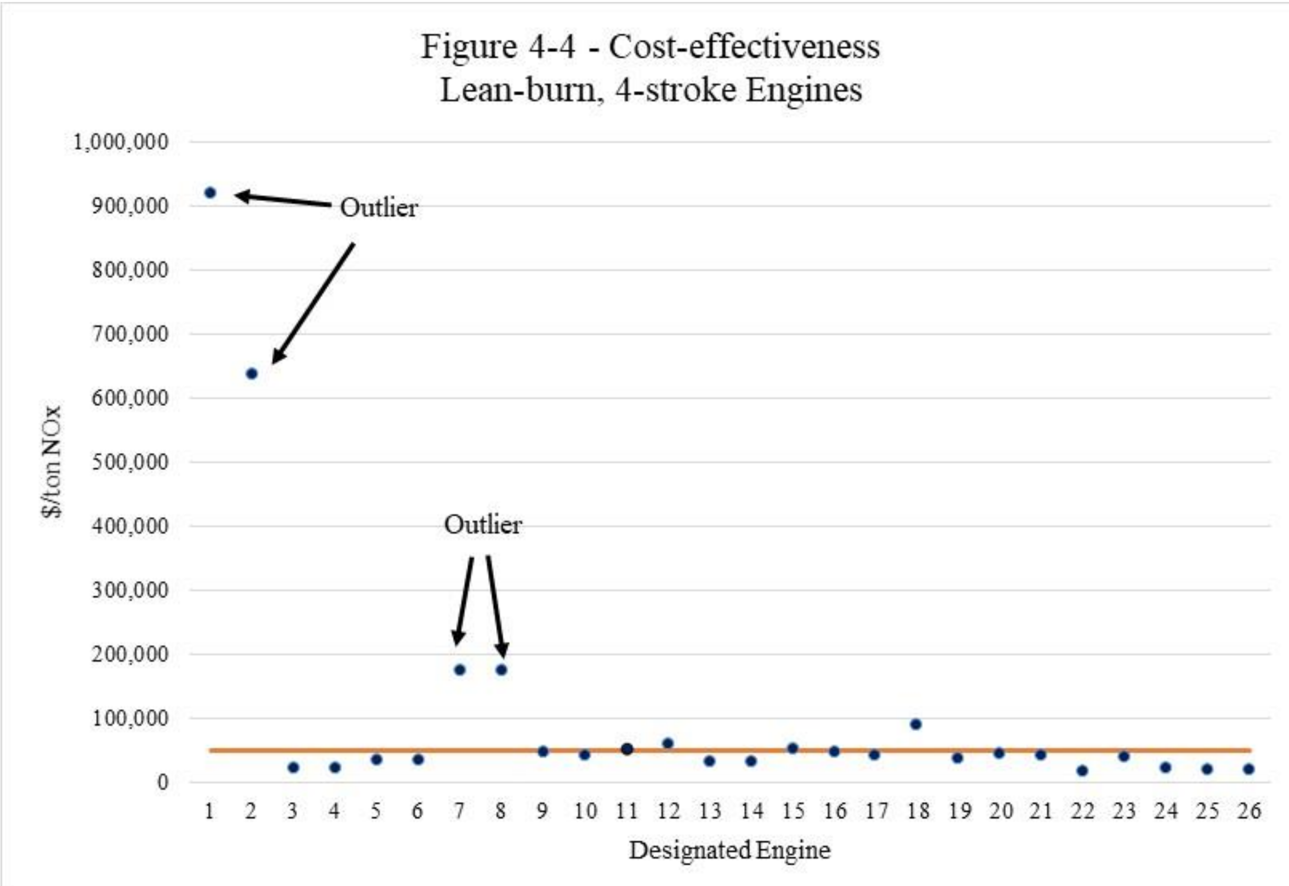


Figure 4-4 presents the distribution of cost-effectiveness for lean-burn, 4-stroke engines. The straight bar represents a value of $50,000. Twenty-six engines were evaluated. In this sub-category, an outlier was determined to be a value greater than $95,288 per ton of NOx reduced. Engine Nos. 1, 2, 7, and 8 were identified as outliers. All four engines are diesel engines rated at 131 hp, 450 hp, 853 hp, and 853 hp, respectively. Engine No.1 was categorized as a process unit under RECLAIM and Engines Nos. 2, 7, and 8 were categorized as RECLAIM large sources. Based on their past reported hours of operation, the low-use provision contained in Rule 1110.2 (d)(1)(B)(iii) would also be applicable, should the facility decide to use. If these engines exceed 500 hours of operation or use more than 1 x 10^9 British Thermal Units (Btus) per year (higher heating value) of fuel, then the emissions limits listed in Table II would apply.

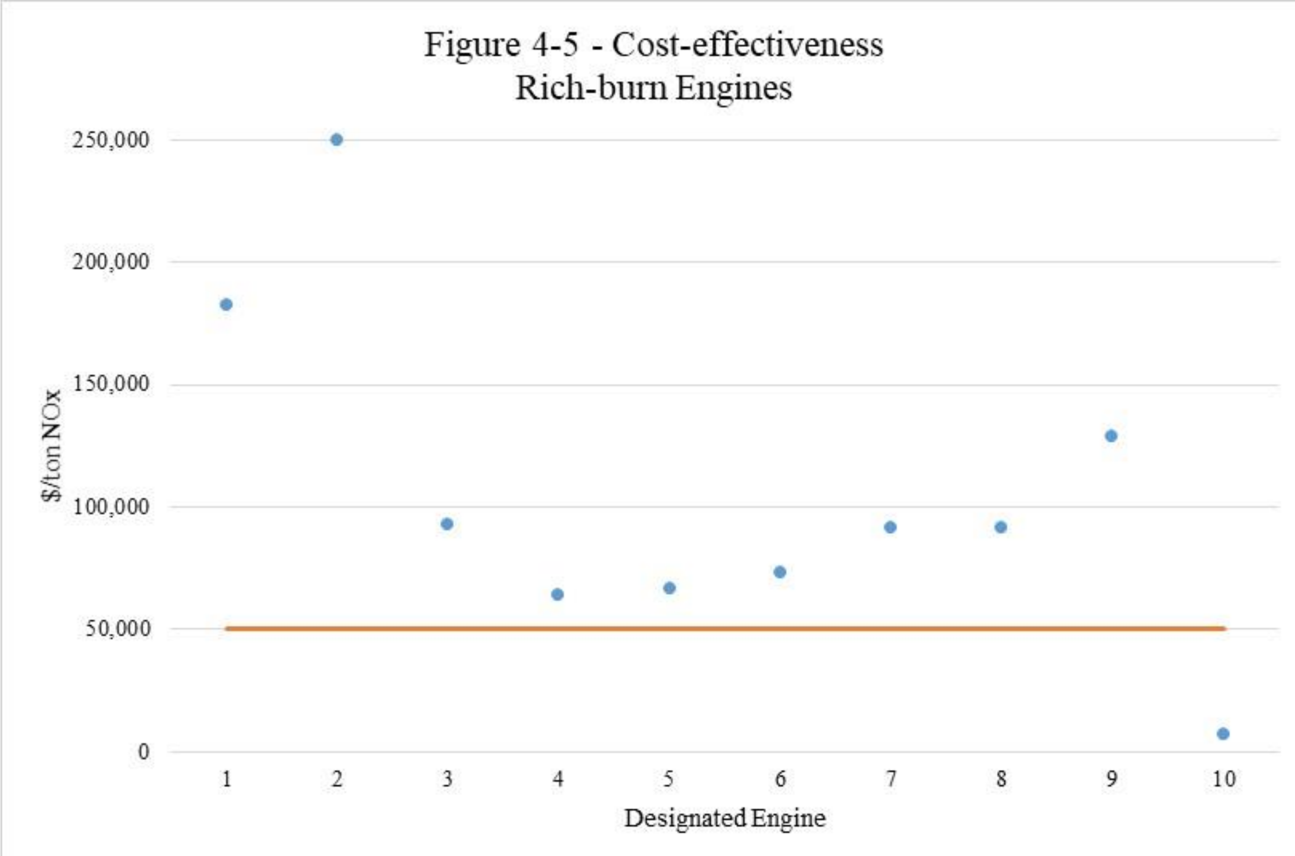


Figure 4-5 presents the distribution of cost-effectiveness for rich-burn engines. The straight bar represents a value of $50,000. Ten engines were evaluated. In this category, an outlier was determined to be a value greater than $256,900 per ton of NOx reduced. Although no engine was identified as an outlier, as a category, the engines had a high cost-effectiveness value relative to a $50,000 per ton of NOx reduced threshold. This was due in large part to CEMS costs that would be required per Rule 1110.2, specifically for those that would fall under the aggregate facility requirement for CEMS. These engines would be able to comply with the proposed emission limit easily with tuning and/or minor catalyst changes. The increased monitoring costs are the main driver for the increased cost effectiveness for this engine subcategory.

Although the cost-effectiveness for rich-burn engines had a high cost-effectiveness value relative to the $50,000 per ton of NOx reduced threshold, the overall cost-effectiveness for all engines affected by the transition from the RECLAIM program to a command-and-control regulatory structure is calculated to be $33,800 per ton of NOx reduced.

SOCIOECONOMIC ASSESSMENT

A Draft Socioeconomic Impact Assessment will be prepared and released at least 30 days prior to the South Coast AQMD Governing Board Hearing on PAR 1110.2 and PAR 1100, which are anticipated to be heard on October 4, 2019.

CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) and South Coast AQMD's Certified Regulatory Program (Rule 110), the South Coast AQMD, as lead agency for the proposed project, has determined that PARs 1110.2 and 1100 are considered a "project" as defined by CEQA. South Coast AQMD staff has determined that the proposed project contains new information of substantial importance which was not known and could not have been known at the time the March 2017 Final Program Environmental Impact Report (EIR) was certified for the 2016 AQMP (referred to herein as March 2017 Final Program EIR). Because the proposed project may create new, potentially significant effects that were not analyzed in the March 2017 Final Program EIR, the South Coast AQMD has prepared a Subsequent Environmental Assessment (SEA) with significant impacts, which will tier off of the March 2017 Final Program EIR as allowed by CEQA Guidelines Sections 15168 and 15385. The March 2017 Final Program EIR, upon which the Draft SEA will rely, is available from the South Coast AQMD's website at: http://www.aqmd.gov/home/research/documents-reports/lead-agency-South Coast AQMD-projects/South Coast AQMD-projects---year-2017. The SEA will allow public agencies and the public the opportunity to obtain, review, and comment on the environmental analysis.

In addition, since the proposed project could have statewide, regional or area wide significance, a CEQA scoping meeting is required to be held pursuant to Public Resources Code Section 21083.9(a)(2). The CEQA scoping meeting was held on July 31, 2019 in conjunction with the public workshop. A Draft SEA will be released for a 45-day public review and comment period. Comments made at the public workshop/CEQA scoping meeting and responses to the comments will be included in the Final SEA.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

Requirements to Make Findings

California Health and Safety Code Section (H&SC) 40727 requires that prior to adopting, amending or repealing a rule or regulation, the South Coast AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the staff report.

Necessity

PARs 1110.2 and 1100 are needed for engines under the RECLAIM program that will be transitioning to a command-and-control regulatory structure to establish NOx emission limits for engines that are representative of BARCT, their time of transition, as well as monitoring, reporting, and recordkeeping requirements.

Authority

The South Coast AQMD obtains its authority to adopt, amend, or repeal rules and regulations pursuant to H&SC Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, 40920.6, and 41508.

Clarity

PARs 1110.2 and 1100 are written or displayed so that their meaning can be easily understood by the persons directly affected by them.

Consistency

PARs 1110.2 and 1100 are in harmony with and not in conflict with or contradictory to, existing statutes, court decisions or state or federal regulations.

Non-Duplication

PARs 1110.2 and 1100 will not impose the same requirements as any existing state or federal regulations. The proposed amended rules are necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

Reference

In amending these rules, the following statutes which the South Coast AQMD hereby implements, interprets or makes specific are referenced: H&SC Sections 39002, 40001, 40406, 40702, and 40440(a).

COMPARATIVE ANALYSIS

Under H&SC Section 40727.2, the South Coast AQMD is required to perform a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing or proposed South Coast AQMD rules and air pollution control requirements and guidelines which are applicable to internal combustion engines. See Table 4-3 below.

Table 4-3: Comparative Analysis

Rule Element	PAR 1110.2	PR 1100	RECLAIM	Equivalent Federal Regulation Title 40, Part 60, Subpart JJJJ	Equivalent Federal Regulation Title 40, Part 60, Subpart IIII
Applicability	All stationary and portable engines over 50 rated brake horsepower (bhp) are subject to this rule	RECLAIM or post-RECLAIM facilities	Facilities regulated under the NOx RECLAIM program (SCAQMD Reg. XX)	Stationary spark ignition (SI) internal combustion engines	Stationary compression ignition internal combustion engines
Requirements* *All parts per million (ppm) emission limits are referenced at 15 percent gas oxygen on a dry basis averaged over a period of 15 consecutive minutes.	Non-emergency engines hp ≥ 50: **11 ppmvd**	•Schedule for meeting BARCT emission limits and MRR requirements	• Major Source **None** • Large Source **36 ppmvd** • Process Unit Natural gas **3400 lb/mmscf** LPG, propane, butane **139/mgal** Diesel **469 lb/mgal**	• Non-emergency, natural gas and LPG hp ≥ 100: **82 ppmvd** • Landfill/digester gas: **150 ppmvd**	For engines installed prior to January 1, 2012 • 12.7 g/hp-hr when max engine speed < than 130 rpm • 34 · $n^{-0.2}$ g/hp-hr) when 130 ≤ max engine speed < 2,000 rpm, where n is max engine speed; and • 7.3 g/hp-hr when max engine speed > 2,000 rpm For engines installed on or after January 1, 2012 and before January 1, 2016 • 10.7 g/hp-hr when max engine speed < 130 rpm; • 33 · $n^{-0.23}$ g/hp-hr) when 130 ≤ max engine speed < 2,000 rpm, where n is max engine speed; and • 5.7 g/hp-hr) when max engine speed > 2,000 rpm. For engines installed on or after January 1, 2016, • 2.5 g/hp-hr when max engine speed < 130 rpm; • 6.7 · $n^{-0.20}$ g/hp-hr) when 130 ≤ max engine speed < 2,000 rpm, where n is max engine speed; and • 1.5 g/hp-hr when max engine speed > 2,000 rpm.
Reporting	Report breakdowns subject to breakdown provisions	As specified in Rule 1110.2	• Daily electronic reporting for major sources • Monthly to quarterly reporting for large sources and process units	Annual report	Initial report

			• Quarterly Certification of Emissions Report and Annual Permit Emissions Program for all units		
Monitoring	• A continuous in-stack NOx monitor for units greater than or equal to 1000 bhp and operating 2 million bhp-hr per calendar year or for facilities with engines subject to paragraph (d)(1), having a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16 x 109 Btus per year (higher heating value) • Non-resettable totalizing time meter	As specified in Rule 1110.2	• A continuous in-stack NOx monitor for major sources • Source testing once every 3 years for large sources • Source testing once every 5 years for process units	Install a non-resettable hour meter	Install a non-resettable hour meter
Recordkeeping	• Monthly log • All data, logs, test reports and other information required by this rule shall be maintained for at least five years and made available for inspection by the Executive Officer	As specified in Rule 1110.2	• Quarterly log for process units • < 15-min. data = min. 48 hours; ≥ 15-min. data = 3 years (5 years if Title V) • Maintenance & emission records, source test reports, RATA reports, audit reports and fuel meter calibration records for Annual Permit Emissions Program = 3 years (5 years if Title V)	• Maintain an operating log	• Maintain an operating log

INCREMENTAL COST EFFECTIVENESS

Health and Safety Code section 40920.6 requires an incremental cost-effectiveness analysis for Best Available Retrofit Control Technology (BARCT) rules or emission reduction strategies when there is more than one control option which would achieve the emission reduction objective of the proposed amendments relative to ozone, carbon monoxide, sulfur oxides, oxides of nitrogen, and their precursors. Incremental cost-effectiveness is the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control options as compared to the next less expensive control option.

Incremental cost-effectiveness is calculated as follows:

Incremental cost-effectiveness = $(C_{alt}–C_{proposed}) / (E_{alt}–E_{proposed})$

Where:

$C_{proposed}$ is the present worth value of the proposed control option;
$E_{proposed}$ are the emission reductions of the proposed control option;
C_{alt} is the present worth value of the alternative control option; and
E_{alt} are the emission reductions of the alternative control option

The proposed project would require retrofits of replacements of engines to meet 11 ppm NOx at 15% oxygen. The next progressively more stringent potential control option would be to require the engines to meet a 7 ppm NOx concentration limit. Lean-burn engines would require more significant SCR system changes that would include more catalyst layers as well as ammonia slip catalysts. Larger diesel engines with existing SCR would require a complete replacement of their emission control systems. Rich-burn engines would require installation of Tecogen retrofits that can achieve these emission levels, and smaller diesel engines would require replacement with Tier IV Final units to achieve 11 ppm. The present worth value of the proposed control option is $89,646,144 and the emission reductions are 2,649 tons over 25 years. The present worth value of the alternative control option is $269,894,022 and the emission reductions of the alternative control option is 2,881 tons over 25 years. The incremental cost-effectiveness for requiring retrofits to meet 7 ppm NOx as well replacement for smaller diesel engines to meet 11 ppm NOx is $69,500 per ton of NOx reduced as calculated below.

Incremental cost-effectiveness = ($221,257,192 – $89,646,144) / (2,881 – 2,649) = $566,389 per ton of NOx reduced

The incremental cost analysis presented above demonstrates that the alternative control option is not viable when compared to the control strategy of the proposed amendments.

APPENDIX A – LIST OF RECLAIM FACILITIES AFFECTED BY PAR 1110.2

Table A-1: RECLAIM Facilities Affected by PAR 1110.2

Facility ID	Facility Name
4242	San Diego Gas & Electric
5973	So Cal Gas Co/Honor Rancho Facility
8547	Quemetco Inc.
8582	So Cal Gas Co/Playa del Rey Facility
9755	United Airlines
18931	Tamco
43201	Snow Summit Inc.
61962	LA City, Harbor Dept
62548	The Newark Group, Inc.
68118	Tidelands Oil Production Company Etal
124723	Greka Oil & Gas
143740	DCOR LLC
143741	DCOR LLC
150201	Breitburn Operating LP
155877	Millercoors, LLC
166073	Beta Offshore
169754	So Cal Holding, LLC
173904	Lapeyre Industrial Sands, Inc.
174544	Breitburn Operating LP
800128	So Cal Gas Co/Aliso Canyon Facility
800189	Disneyland Resort

Table A-2: Equipment at RECLAIM Facilities Affected by PAR 1110.2

Engine	bhp	Fuel type	Current Controls	Current NOx Limit (ppm[1])	Proposed Limit (ppm[1])	Capital Cost ($)	Annual Cost ($)	Present Worth Value ($)	Estimated NOx Reduction (tpd)	CE ($/ton)
Lean-burn, 2-stroke engines										
1	450	Diesel	Oxi-cat	675	11	603,368	711,619	1,492,711	.000	318,900
2	450	Diesel	Oxi-cat	675	11	603,368	711,619	1,492,711	.001	152,900
3	995	Nat gas	Oxi-cat	150	11	947,181	1,221,826	2,169,007	.004	66,000
4	995	Nat gas	Oxi-cat	150	11	947,181	1,221,826	2,169,007	.003	74,300
5	995	Nat gas	Oxi-cat	150	11	947,181	1,221,826	2,169,007	.003	71,500
6	2000	Nat gas	Oxi-cat	225	11	1,683,747	1,607,860	3,291,607	.024	14,800
7	2000	Nat gas	Oxi-cat	225	11	1,683,747	1,607,860	3,291,607	.012	30,500
8	2000	Nat gas	Oxi-cat	225	11	1,683,747	1,607,860	3,291,607	.025	14,400
9	3000	Nat gas	Oxi-cat	116	11	1,380,480	1,605,864	2,986,344	.003	94,100
10	3000	Nat gas	Oxi-cat	116	11	1,380,480	1,605,864	2,986,344	.004	74,900
11	3200	Nat gas	Oxi-cat	116	11	1,441,430	1,659,134	3,100,564	.029	11,800
Lean-burn, 4-stroke engines										
12	131	Diesel	N/A	208	11	506,152	534,986	1,218,863	0.000	920,400
13	190	Compliant								
14	190									
15	190									

Engine	bhp	Fuel type	Current Controls	Current NOx Limit (ppm[1])	Proposed Limit (ppm[1])	Capital Cost ($)	Annual Cost ($)	Present Worth Value ($)	Estimated NOx Reduction (tpd)	CE ($/ton)
16	190									
17	190									
18	190									
19	190									
20	450	Diesel	N/A	344	11	603,368	647,641	1,251,008	0.000	637,800
21	853	Diesel	Oxi-cat	450	11	903,907	1,161,297	2,065,204	0.010	23,500
22	853	Diesel	Oxi-cat	450	11	903,907	1,161,297	2,065,204	0.010	23,500
23	853	Diesel	Oxi-cat	450	11	903,907	1,161,297	2,065,204	0.006	35,300
24	853	Diesel	Oxi-cat	450	11	903,907	1,161,297	2,065,204	0.006	35,300
25	853	Diesel	Oxi-cat	450	11	903,907	1,161,297	2,065,204	0.001	176,400
26	853	Diesel	Oxi-cat	450	11	903,907	1,161,297	2,065,204	0.001	176,400
27	881	Digester	Oxi-cat	36	11	912,440	1,173,350	2,085,790	0.005	49,800
28	881	Digester	Oxi-cat	36	11	912,440	1,173,350	2,085,790	0.005	43,900
29	1468	Compliant								
30	2000	Nat gas	Oxi-cat	23	11	1,075,730	1,295,420	2,371,150	0.005	54,600
31	2000	Nat gas	Oxi-cat	43	11	1,075,730	1,295,420	2,371,150	0.004	61,800
32	2000	Nat gas	Oxi-cat	30	11	1,075,730	1,295,420	2,371,150	0.008	33,300
33	2000	Nat gas	Oxi-cat	46	11	1,075,730	1,295,420	2,371,150	0.008	32,800
34	2000	Nat gas	Oxi-cat	24	11	1,075,730	1,295,420	2,371,150	0.005	54,600

Engine	bhp	Fuel type	Current Controls	Current NOx Limit (ppm[1])	Proposed Limit (ppm[1])	Capital Cost ($)	Annual Cost ($)	Present Worth Value ($)	Estimated NOx Reduction (tpd)	CE ($/ton)
35	3043	Diesel	SCR	50	11	214,408	423,617	638,024	0.001	49,300
36	3043	Diesel	SCR	50	11	214,408	423,617	638,024	0.002	42,500
37	3043	Diesel	SCR	50	11	214,408	423,617	638,024	0.001	90,200
38	3043	Diesel	SCR	50	11	214,408	423,617	638,024	0.002	37,400
39	3043	Diesel	SCR	50	11	214,408	423,617	638,024	0.001	46,800
40	3043	Diesel	SCR	50	11	214,408	423,617	638,024	0.002	42,600
41	5500	Nat gas	Oxi-cat	41	11	2,142,355	2,060,472	4,202,827	0.024	19,300
42	5500	Nat gas	Oxi-cat	54	11	2,142,355	2,060,472	4,202,827	0.011	41,600
43	5500	Nat gas	Oxi-cat	40	11	2,142,355	2,060,472	4,202,827	0.020	22,500
44	5500	Nat gas	Oxi-cat	54	11	2,142,355	2,060,472	4,202,827	0.022	20,600
45	5500	Nat gas	Oxi-cat	82	11	2,142,355	2,060,472	4,202,827	0.022	21,400
Rich-burn engines										
46	147	Compliant								
47	147									
48	189									
49	189									
50	268									
51	268									
52	268									

Engine	bhp	Fuel type	Current Controls	Current NOx Limit (ppm[1])	Proposed Limit (ppm[1])	Capital Cost ($)	Annual Cost ($)	Present Worth Value ($)	Estimated NOx Reduction (tpd)	CE ($/ton)
53	385									
54	738	Nat Gas	NSCR	20	11	177,725	462,713	640,438	0.000	182,200
55	738	Nat Gas	NSCR	20	11	177,725	462,713	640,438	0.000	250,000
56	790	Compliant								
57	790									
58	818	Nat Gas	NSCR	20	11	177,725	473,973	651,698	0.001	92,900
59	818	Nat Gas	NSCR	20	11	177,725	473,973	651,698	0.001	64,000
60	818	Nat Gas	NSCR	20	11	177,725	473,973	651,698	0.001	66,700
61	818	Nat Gas	NSCR	20	11	177,725	473,973	651,698	0.001	73,200
62	818	Nat Gas	NSCR	20	11	177,725	473,973	651,698	0.001	91,600
63	818	Nat Gas	NSCR	20	11	177,725	473,973	651,698	0.001	91,700
64	818	Nat Gas	NSCR	20	11	177,725	473,973	651,698	0.001	129,100
65	830	Compliant								
66	845	Nat Gas	NSCR	28	11	0	165,334	165,334	0.003	7,215
67	1150	Compliant								
68	2000									

Notes:

- Engines 9-11: The emission factor was based on the calculation used in the engineering evaluation at the time of permitting.

- Engines 14-19: Identical engines in the process of installation at a single facility. The engines were permitted at 12.3 ppmvd NOx; however, staff reviewed the respective permit file and determined that the engines are actually certified to emit less than 0.15 g/bhp-hr NOx. Staff also reviewed initial source test information and noted that the engines emit less than 11 ppm NOx. Although the individual permits list 12.3 ppmvd NOx emission limit, staff confirmed that the permit limit should have been set at 11 ppmvd. During the rule making process, questions on the validity of the source test and how the results were attained have come up. For this evaluation, however, staff assumed that no additional requirement is needed at this time.

- Engines 21-26: Identical engines installed at a single facility. Reviewing operational information for 2016 and 2017, staff noted that hours of operation varied for each engine; however, each engine can be used interchangeably. In its cost-effectiveness evaluation, staff therefore used 1,500 hours of operation for engines 21 and 22, 1,000 hours of operation for engines 23 and 24, and 200 hours of operation for engines 25 and 26 as a basis for its calculation. In addition, due to the aggregate facility horsepower greater than 1,500 hp, staff assumed that each engine would require a CEMS installation; no potential sharing of CEMS was considered at this time.

- Engines 30-34: Identical engines installed at a single facility. The emission factor for each engine was based on source test data found in the engineering evaluation file.

- Engines 41-45: Identical engines installed at a single facility. The emission factor for each engine was based on source test data found in the engineering evaluation file.

- Engines 56-57: Identical engines installed at a single facility. Although the aggregate horsepower at the facility is greater than 1,500 bhp, these engines operate well below 1,000 hours. It is assumed that these engines would not require a CEMS installation.

- Engines 58-64: Identical engines installed at a single facility. Since these engines are greater than 500 hp but less than 1,000 hp and the facility aggregate horsepower is greater than 1,500 hp, CEMS would be required on these engines.

- In general, for the rich-burn engine category, it is anticipated that lowering the emissions to 11 ppmvd will be accomplished through minimal catalyst modifications and/or retuning of the respective AFRC. However, engines, greater than or equal to 500 bhp but less than 1,000 bhp and where the aggregate horsepower for the facility is greater than 1,500 bhp, may be required to install a CEMS unit. The cost of adding CEMS and the low expected reduction in NOx is driving a high value for this category. Staff did not assume any potential sharing of CEMS equipment in its cost-effectiveness evaluation.

APPENDIX B – ANALYSIS OF NOX EMISSION LIMITS FOR OTHER AIR DISTRICTS

As part of the BARCT analysis, staff reviewed similar regulations related to internal combustion engines in other jurisdictions both within California and outside. In jurisdictions where limits were expressed in g/bhp-hr, conversion to ppmvd equivalent was based on a 33% thermal efficiency.

Antelope Valley

Staff reviewed Antelope Valley AQMD Rule 1110.2 – Emissions from Stationary, Non-road and Portable Internal Combustion Engines. The rule applies to all ICEs with a rated brake horsepower greater than 50 bhp. Per Rule 1110.2 (C)(1)(a)(iii), the owner or operator of any stationary ICE subject to this rule shall comply with the general emission limits of 36 ppm NOx, 250 ppm VOC, and 2000 ppm CO (corrected to 15% O2 on a dry basis, averaged over a 15-minute interval). The rule does not differentiate by fuel source whether the source is natural gas, diesel, biogas, or other hydrocarbon. The rule applicability also does not distinguish by engine type whether the engine is two-cycle, four-cycle, lean-burn, or rich-burn.

Bay Area

Staff reviewed Bay Area AQMD Regulation 9 – Inorganic Gaseous Pollutants, Rule 8 – Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines. Regulation 9, Rule 8 applies to stationary ICEs with an output rating greater than 50 bhp. The regulation sets different NOx emission limits based on fuel source whether fossil derived or waste derived and engine type whether spark-ignited or compression-ignited or whether lean-burn or rich-burn. The lowest NOx limit is set at 25 ppmvd (corrected to 15% O2 on a dry basis) for a spark-ignited, rich-burn engine powered by fossil derived fuels. CO emissions are limited to 2000 ppmvd (corrected to 15% O2 on a dry basis).

Mojave Desert

Staff reviewed Mojave Desert AQMD Rule 1160 – Internal Combustion Engines. Rule 1160 applies to any stationary, non-agricultural, ICE with a rated brake horsepower greater than 50 bhp. The regulation sets different NOx emission limits based on engine type whether spark-ignited or compression-ignited or whether lean-burn or rich-burn. The lowest NOx limit is set at 50 ppmvd (corrected to 15% O2 on a dry basis averaged over 15 minutes) for a spark-ignited, rich-burn engine. The VOC and CO compliance limits are established as 106 ppmvd and 4500 ppmvd respectively.

Santa Barbara

Staff reviewed Santa Barbara County APCD Rule 333 – Control of Emissions from Reciprocating Internal Combustion Engines. Rule 333 applies to any engine with a rated brake horsepower greater than 50 bhp. The regulation sets different NOx emission limits based on engine type whether spark-ignited or compression-ignited, whether cyclically or non-cyclically loaded, or whether lean-burn or rich-burn. The lowest NOx limit is set at 50 ppmvd (corrected to 15% O2 on a dry basis) for a spark-ignited, non-cyclically-loaded, rich-burn engine. The most stringent VOC and CO compliance limits are established as 250 ppmvd and 4500 ppmvd respectively.

San Diego

Staff reviewed San Diego County APCD Rule 69.4.1 – Stationary Reciprocating Internal Combustion Engines – Best Available Retrofit Control Technology. Rule 69.4.1 applies to all stationary ICEs with a horsepower rating greater than 50 bhp. The regulation sets different NOx emission limits based on fuel source whether fossil derived gaseous, gasoline, waste derived gaseous, diesel, or kerosene based and engine type whether lean-burn or rich-burn. The lowest NOx limit is set at 25 ppmvd (corrected to 15% O2 on a dry basis) for a rich-burn engine powered by either fossil derived fuels or gasoline. The VOC and CO compliance limits are established as 250 ppmvd and 4500 ppmvd respectively.

San Joaquin Valley

Staff reviewed San Joaquin Valley Unified APCD Rule 4702 – Internal Combustion Engines. Rule 4702 applies to engines rated at greater than 50 bhp. The regulation sets different NOx emission limits based on fuel source whether gaseous, waste derived, or field derived and engine type whether two-stroke or four-stroke, whether lean-burn or rich-burn, or whether spark-ignited or compression-ignited. The regulation also provides consideration for lean-burn engines used for gas compression and engines used in agricultural operations. The lowest NOx limit is set at 11 ppmvd (corrected to 15% O2 on a dry basis) for rich-burn or lean-burn engines not specifically exempted. The most stringent VOC and CO compliance limits are set as 250 ppmvd and 2000 ppmvd respectively.

San Luis Obispo

Staff reviewed San Luis Obispo County APCD Rule 431 – Stationary Internal Combustion. Rule 431 applies to any stationary ICE with a rated brake horsepower greater than 50 bhp. The regulation sets different NOx emission limits based on engine type whether lean-burn or rich-burn, or whether spark-ignited or compression-ignited. The regulation also provides consideration for engines used in agricultural operations. The lowest NOx limit is set at 50 ppmvd (corrected to 15% O2 on a dry basis) for a spark-ignited, rich-burn engine. CO emissions are limited to 4500 ppmvd (corrected to 15% O2 on a dry basis).

Ventura County

Staff reviewed Ventura County APCD Rule 74.9 – Stationary Internal Combustion Engines. Rule 74.9 applies to any stationary engine with a rated brake horsepower greater than 50 bhp. The regulation sets different NOx emission limits based on fuel source whether gaseous, diesel or waste derived and engine type whether spark-ignited or compression-ignited or whether lean-burn or rich-burn. The lowest NOx limit is set at 25 ppmvd (corrected to 15% O2 on a dry basis) for a general rich-burn engine. The most stringent VOC and CO compliance limits are established as 250 ppmvd and 4500 ppmvd respectively.

Pennsylvania

Staff reviewed the Commonwealth of Pennsylvania Code, Title 25 – Environmental Protection, Chapter 129 –Standards for Sources, subpart 129.97, subsection (g)(3). The code applies to any stationary internal combustion engine with a rated brake horsepower greater than or equal to 500 bhp. The regulation sets different NOx emission limits based on fuel source whether natural gas or liquid-fueled and engine type whether lean-burn or rich-burn. The lowest NOx limit is set at 2.0 g/bhp-hr or 155 ppmvd for a rich-burn engine fired on natural gas. VOC emissions are limited to 1.0 g/bhp-hr for engines fired on natural gas. The regulation established no CO compliance limit.

New Jersey

Staff reviewed the New Jersey State Department of Environmental Protection, New Jersey Administrative Code, Title 7, Chapter 27, Subchapter 19 – Control and Prohibition of Air Pollution from Oxides of Nitrogen, Section 7:27-19.8 – Stationary Reciprocating Engines. Section 7:27-19.8 applies to various rated engines beginning at approximately 50 bhp. The regulation sets different NOx emission limits based on engine rating, fuel source whether gaseous or liquid fueled and engine type whether lean-burn or rich-burn. The lowest NOx limit is set at 0.9 g/bhp-hr or 70 ppmvd for an engine with a rated brake horsepower greater than 50 bhp that started operation on or after March 7, 2007. The regulation established no VOC or CO compliance limit.

New York

Staff reviewed the New York Codes, Rules and Regulations, 6 CRR-NY 227-2.4, subpart (f) – Control Requirements for Stationary Internal Combustion Engines. The Code varies by engine size whether an engine is in a severe ozone nonattainment zone or not regulating engines greater than or equal to 200 bhp in severe ozone nonattainment zones or engines greater than or equal to 400 bhp in areas outside these zones. The regulation sets different NOx emission limits based on type of fuel used whether natural gas, landfill or digester gas, or diesel. The lowest NOx limit is set at 1.5 g/bhp-hr or 116 ppmvd for an internal combustion engine fired solely on natural gas. The regulation established no VOC or CO compliance limit.

Texas

Staff reviewed the Texas Administrative Code, Title 30, Part 1, Chapter 117, Subchapter D, Division 2, Rule 117.2110. The rule applies to stationary reciprocating internal combustion engines. The regulation sets different NOx emission limits based on fuel source whether gaseous, diesel or landfill gas and engine type whether spark-ignited or compression-ignited or whether lean-burn or rich-burn. The lowest NOx limit is set at 0.5 g/bhp-hr or 39 ppmvd for an engine fired on natural gas. CO emissions are limited to 400 ppmvd. The regulation established no VOC compliance limit.

References

Antelope Valley AQMD Source Specific Rules, Rule 1110.2 – Emissions from Stationary, Non-road and Portable Internal Combustion Engines, Website: https://avaqmd.ca.gov/regulation-xi-source-specific-standards.

Bay Area AQMD, Current Rules, Regulation 9 – Inorganic Gaseous Pollutants, Rule 8 – Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines, Website: http://www.baaqmd.gov/rules-and-compliance/current-rules.

Commonwealth of Pennsylvania Code, Title 25 – Environmental Protection, Chapter 129 – Standards for Sources, subpart 129.97, Website: https://www.pacode.com/secure/data/025/chapter129/s129.97.html.

Mojave Desert AQMD, Regulation XI – Source Specific Standards, Rule 1160 – Internal Combustion Engines, Website: http://mdaqmd.ca.gov/rules/rule-book/regulation-xi-source-specific-standards.

New Jersey State Department of Environmental Protection, New Jersey Administrative Code, Title 7, Chapter 27, Subchapter 19 – Control and Prohibition of Air Pollution from Oxides of Nitrogen, Section 7:27-19.8 – Stationary Reciprocating Engines, Website: https://www.nj.gov/dep/aqm/rules27.html

New York Codes, Rules and Regulations, 6 CRR-NY 227-2.4, subpart (f) – Control Requirements for Stationary Internal Combustion Engines, Website: https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?contextData=(sc.Default)&transitionType=Default.

Santa Barbara County APCD, Current Rules and Regulations, Rule 333 – Control of Emissions from Reciprocating Internal Combustion Engines, Website: https://www.ourair.org/current-rules-and-regulations/.

San Diego County APCD, List of Current Rules, Rule 69.4.1 – Stationary Reciprocating Internal Combustion Engines – Best Available Retrofit Control Technology, Website: https://www.arb.ca.gov/drdb/sd/cur.htm.

San Joaquin Valley Unified APCD, Current District Rules and Regulations, Rule 4702 – Internal Combustion Engines, Website: https://www.valleyair.org/rules/1ruleslist.htm#reg4.

San Luis Obispo County APCD, List of Current Rules, Rule 431 – Stationary Internal Combustion Engines, Website: https://www.arb.ca.gov/drdb/slo/cur.htm.

Texas Administrative Code, Title 30, Part 1, Chapter 117, Subchapter D, Division 2, Rule 117.2110, Website: https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2110.

Ventura County APCD, List of Current Rules, Rule 74.9 – Stationary Internal Combustion Engines, Website: https://www.arb.ca.gov/drdb/ven/cur.htm.

APPENDIX C – ENGINE SURVEY

Rule 1110.2 Survey – October 2018

Facility ID: ________________ Company Name: ________________________

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Permit No.	Size (bhp)	Primary Fuel Type	2-stroke engine (Y/N)	Lean/ Rich Burn	Age of Engine (yrs)	Primary Engine Use	Type of Emission Control	Ammonia Slip (ppmv)	Ammonia Type	Type of Monitoring
1											
2											
3											
4											
5											
6											

	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
	Engine Portable (Y/N)	Tier Rating	Engine Efficiency (%)	Typical Load Factor	Any Retrofit (Y/N)	Fuel Usage Units	Annual Fuel Usage		Annual Operating Hours	
							CY 2016	CY 2017	CY 2016	CY 2017
1										
2										
3										
4										
5										
6										

Additional Comments:

Instructions:

- Please provide data (1) – (21) for each engine.
- Attach most recent emissions data for each engine (e.g. source test report, hand-held portable data, etc.)

Prepared by: ________________________

Contact Phone: ________________________

Email: ________________________

Please return survey to:

South Coast Air Quality Management District
Attn: Kevin Orellana
21865 Copley Drive
Diamond Bar, California 91765-4178
Or via E-mail: korellana@aqmd.gov

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Key

(1) Permit number per engine

(2) Size as rated in bhp

(3) Primary fuel type
1. NG – Natural Gas
2. Diesel
3. Digester
4. Other [Provide type]

(4) 2 Stroke Engine – Y/N

(5) Lean or Rich Burn engine

(6) Age of engine based on initial installation

(7) Primary engine use
1. Prime generator
2. Back-up generator
3. Pump
4. Compressor
5. Other: [Describe]

(8) Type of Emissions Control
1. Three-way catalyst with air/fuel ratio controller
2. Three-way catalyst without air/fuel controller
3. Selective catalyst reduction (SCR)
4. Pre-stratified charge combustion (PSC)
5. Combustion modifications
6. Other: [Provide type]

(9) Ammonia slip ppmv @ 15% O_2

(10) Ammonia type (if applicable)
1. Anhydrous
2. Aqueous
3. Urea
4. Other: [Provide type]

(11) Type of monitoring (if applicable)
1. Fuel meter
2. Timer
3. CEMS (list constituent: NOx, CO, O_2, stack flow, etc.)
4. Other: [Provide type]

(12) Is engine portable?

(13) Tier rating (if applicable)

(14) Engine efficiency based on higher heating value

(15) Typical load factor

(16) Has the unit been retrofitted? Please describe any retrofits made to engine. (e.g., catalytic controls, DPF, etc.) and indicate the year when retrofitted.

(17) Fuel usage units
1. MMSCFD
2. gal/day
3. Other: [Provide alternate type]

(18) – (19) Annual fuel usage for CY 2016 / CY 2017

(20) – (21) Annual operating hours for CY 2016 / CY 2017

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APPENDIX D – ASSESSMENT OF AIR POLLUTION CONTROL TECHNOLOGIES

The following assessment of pollution control technologies is derived from the November 2001 California Air Resources Board report, "Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines – Appendix B". Focus is on post-combustion controls.

Post combustion controls generally consist of catalysts or filters that act on the engine exhaust to reduce emissions. Post combustion controls also include the introduction of agents or other substances that act on the exhaust to reduce emissions, with or without the assistance of catalysts or filters.

<u>Oxidation Catalyst</u>

Applicability: This control method is applicable to all engines. For stationary engines, oxidation catalysts have been used primarily on lean-burn engines. Rich-burn engines tend to use 3-way catalysts, which combine nonselective catalytic reduction (NSCR) for NOx control and an oxidation catalyst for control of CO and VOC. The oxidation catalyst has been used on lean-burn engines for nearly 30 years. Oxidation catalysts are used less frequently on stationary engines. In the United States, only about 500 stationary lean-burn engines have been fitted with oxidation catalysts.

Principle: An oxidation catalyst contains materials (generally precious metals such as platinum or palladium) that promote oxidation reactions between oxygen, CO, and VOC to produce carbon dioxide and water vapor. These reactions occur when exhaust at the proper temperature and containing sufficient oxygen passes through the catalyst. Depending on the catalyst formulation, an oxidation catalyst may obtain reductions at temperatures as low as 300 or 400 ºF, although minimum temperatures in the 600 to 700 ºF range are generally required to achieve maximum reductions. The catalyst will maintain adequate performance at temperatures typically as high as 1350 ºF before problems with physical degradation of the catalyst occur. In the case of rich-burn engines, where the exhaust does not contain enough oxygen to fully oxidize the CO and VOC in the exhaust, air can be injected into the exhaust upstream of the catalyst.

Typical Effectiveness: The effectiveness of an oxidation catalyst is a function of the exhaust temperature, oxygen content of the exhaust, amount of active material in the catalyst, exhaust flow rate through the catalyst, and other parameters. Catalysts can be designed to achieve almost any control efficiency desired. Reductions greater than 90 percent for both CO and VOC are typical. Reductions in VOC emissions can vary significantly and are a function of the fuel type and exhaust temperature.

Limitations: A sufficient amount of oxygen must be present in the exhaust for the catalyst to operate effectively. In addition, the effectiveness of an oxidation catalyst may be poor if the exhaust temperature is low, which is the case for an engine at idle. Oxidation catalysts, like other catalyst types, can be degraded by masking, thermal sintering, or chemical poisoning by sulfur or metals. If the engine is not in good condition, a complete engine overhaul may be needed to ensure proper catalyst performance.

Sulfur, which can be found in fuels and lubricating oils, is generally a temporary poison, and can be removed by operating the catalyst at sufficiently high temperatures. However, high temperatures can damage the substrate material. Other ways of dealing with sulfur poisoning include the use of low sulfur fuels or scrubbing of the fuel to remove the sulfur. Besides being a catalyst poison, sulfur can also be converted into sulfates by the catalyst before passing through the exhaust pipe. Catalysts can be specially formulated to minimize this conversion, but these special formulations must operate over a relatively narrow temperature range if they are to effectively reduce VOC and CO and also suppress the formation of sulfates. For engines operated over wide power ranges, where exhaust temperatures vary greatly, special catalyst formulations are not effective.

Metal poisoning is generally more permanent, and can result from the metals present in either the fuel or lubricating oil. Specially formulated oils with low metals content are generally specified to minimize poisoning, along with good engine maintenance practices. Metal poisoning can be reversed in some cases with special procedures. Many catalysts are now formulated to resist poisoning.

Masking refers to the covering and plugging of a catalyst's active material by solid contaminants in the exhaust. Cleaning of the catalyst can remove these contaminants, which usually restores catalytic activity. Masking is generally limited to engines using landfill gas, diesel fuel, or heavy liquid fuels, although sulfate ash from lubricating oil may also cause masking. Masking can be minimized by passing the exhaust through a particulate control device, such as a filter or trap, before this material encounters the catalyst. In the case of landfill gas, the particulate control device can act directly on the fuel before introduction into the engine.

Thermal sintering is caused by excessive heat and is not reversible. However, it can be avoided by incorporating over temperature control in the catalyst system. Many manufacturers recommend the use of over temperature monitoring and control for their catalyst systems. In addition, stabilizers such as CeO2 or La2O3 are often included in the catalyst formulation to minimize sintering. High temperature catalysts have been developed which can withstand temperatures exceeding 1800 ºF for some applications. This temperature is well above the highest IC engine exhaust temperature that would ever be encountered. Depending on the design and operation, peak exhaust temperatures for IC engines range from 550 to 1300 ºF.

Other recommendations to minimize catalyst problems include monitoring the pressure drop across the catalyst, the use of special lubricating oil to prevent poisoning, periodic washing of the catalyst, the monitoring of emissions, and the periodic laboratory analysis of a sample of catalyst material.

Other Effects: A catalyst will increase backpressure in the exhaust, resulting in a slight reduction in engine efficiency and maximum rated power. However, when conditions require an exhaust silencer, the catalyst can often be designed to do an acceptable job of noise suppression so that a separate muffler is not required. Under such circumstances, backpressure from the catalyst may not exceed that of a muffler, and no reduction in engine efficiency or power occur. Often, engine manufacturers rate their engines at a given backpressure, and as long as the catalyst does not exceed this backpressure, no reduction in the engine's maximum power rating will be experienced.

Nonselective Catalytic Reduction (NSCR)

Applicability: This control method is applicable to all rich-burn engines, and is probably the most popular control method for rich-burn engines. The first wide scale application of NSCR technology occurred in the mid- to late-1970s, when 3-way NSCR catalysts were applied to motor vehicles with gasoline engines. Since then, this control method has found widespread use on stationary engines. NSCR catalysts have been commercially available for stationary engines for over 15 years, and over 3,000 stationary engines in the U.S. are now equipped with NSCR controls. Improved NSCR catalysts, called 3-way catalysts because CO, VOC, and NOx are simultaneously controlled, have been commercially available for stationary engines for over 10 years. Over 1,000 stationary engines in the U.S. are now equipped with 3-way NSCR controls.

The dual bed NSCR catalyst is a variation of the 3-way catalyst. The dual bed contains a reducing bed to control NOx, followed by an oxidizing bed to control CO and VOC. Dual bed NSCR catalysts tend to be more effective than 3-way catalysts, but are also more expensive, and have not been applied to as many engines as 3-way catalysts. Improved 3-way catalysts can approach the control efficiencies of dual bed catalysts at a lower cost, and for this reason dual bed catalysts have lost popularity to 3-way catalysts.

Principle: The NSCR catalyst promotes the chemical reduction of NOx in the presence of CO and VOC to produce oxygen and nitrogen. The 3-way NSCR catalyst also contains materials that promote the oxidation of VOC and CO to form carbon dioxide and water vapor. To control NOx, CO, and VOC simultaneously, 3-way catalysts must operate in a narrow air/fuel ratio band (15.9 to 16.1 for natural gas-fired engines) that is close to stoichiometric. An electronic controller, which includes an oxygen sensor and feedback mechanism, is often necessary to maintain the air/fuel ratio in this narrow band. At this air/fuel ratio, the oxygen concentration in the exhaust is low, while concentrations of VOC and CO are not excessive.

For dual bed catalysts, the engine is run slightly richer than for a 3-way catalyst. The first catalyst bed in a dual bed system reduces NOx. The exhaust then passes into a region where air is injected before entering the second (oxidation) catalyst bed. NOx reduction is optimized in comparison to a 3-way catalyst due to the higher CO and VOC concentrations and lower oxygen concentrations present in the first (reduction) catalyst bed. In the second (oxidation) bed, CO and VOC reductions are optimized due to the relatively high oxygen concentration present. Although the air/fuel ratio is still critical in a dual bed catalyst, optimal NOx reductions are achievable without controlling the air/fuel ratio as closely as in a 3-way catalyst.

Typical Effectiveness: Removal efficiencies for a 3-way catalyst are greater than 90 percent for NOx, greater than 80 percent for CO, and greater than 50 percent for VOC. Greater efficiencies, below 10 parts per million NOx, are possible through use of an improved catalyst containing a greater concentration of active catalyst materials, use of a larger catalyst to increase residence time, or through use of a more precise air/fuel ratio controller.

For dual bed catalysts, reductions of 98 percent for both NOx and CO are typical.

The previously mentioned reduction efficiencies for catalysts are achievable as long as the exhaust gases are within the catalyst temperature window, which is typically 700 to 1200 ºF. For many engines, this temperature requirement is met at all times except during startup and idling.

The percentage reductions are essentially independent of other controls that reduce the NOx concentration upstream of the catalyst. Thus, a combination of combustion modifications and catalyst can achieve even greater reductions.

Limitations: As with oxidation catalysts, NSCR catalysts are subject to masking, thermal sintering, and chemical poisoning. In addition, NSCR is not effective in reducing NOx if the CO and VOC concentrations are too low. NSCR is also not effective in reducing NOx if significant concentrations of oxygen are present. In this latter case, the CO and VOC in the exhaust will preferentially react with the oxygen instead of the NOx. For this reason, NSCR is an effective NOx control method only for rich-burn engines.

When applying NSCR to an engine, care must be taken to ensure that the sulfur content of the fuel gas is not excessive. The sulfur content of pipeline-quality natural gas and LPG is very low, but some oil field gases and waste gases can contain high concentrations. Sulfur tends to collect on the catalyst, which causes deactivation. This is generally not a permanent condition, and can be reversed by introducing higher temperature exhaust into the catalyst or simply by heating the catalyst. Even if deactivation is not a problem, the water content of the fuel gas must be limited when significant amounts of sulfur are present to avoid deterioration and degradation of the catalyst from sulfuric acid vapor.

For dual bed catalysts, engine efficiency suffers slightly compared to a 3-way catalyst due to the richer operation of engines using dual bed catalysts.

In cases where an engine operates at idle for extended periods or is cyclically operated, attaining and maintaining the proper temperature may be difficult. In such cases, the catalyst system can be designed to maintain the proper temperature, or the catalyst can use materials that achieve high efficiencies at lower temperatures. For some cyclically operated engines, these design changes may be as simple as thermally insulating the exhaust pipe and catalyst.

Most of these limitations can be eliminated or minimized by proper design and maintenance. For example, if the sulfur content of the fuel is excessive, the fuel can be scrubbed to remove the sulfur, or the catalyst design or engine operation can be modified to minimize the deactivation effects of the sulfur. Poisoning from components in the lube oil can be eliminated by using specially formulated lube oils that do not contain such components. However, NSCR applications on landfill gas and digester gas have generally not been successful due to catalyst poisoning and plugging from impurities in the fuel.

Other Effects: A very low oxygen content in the exhaust must be present for NSCR to perform effectively. To achieve this low oxygen content generally requires richening of the mixture. This richening tends to increase CO and VOC emissions. However, use of a 3-way catalyst can reduce CO and VOC emissions to levels well below those associated with uncontrolled engines.

Another effect of NSCR is increased fuel consumption. This increase is very slight when compared to an uncontrolled rich-burn engine. However, when compared to a lean-burn engine, a rich-burn engine uses 5 to 12 percent more fuel for the same power output. If a rich-burn engine uses a dual bed catalyst, a further slight increase in fuel consumption is generally experienced.

Hybrid System

Applicability: This control method can be applied to all engines. This control method was conceived by Radian Corporation, and has been developed by AlliedSignal and Beaird Industries. There has been one field prototype demonstration in San Diego, and it appears that the system has been offered commercially. However, there are no commercial applications of this technique.

Principle: The hybrid system is a modification of the dual bed NSCR system. The hybrid system adds a burner in the engine exhaust between the engine and the dual bed catalysts. The burner is operated with an excess amount of fuel so that oxygen within the engine exhaust is almost completely consumed, and large amounts of CO are generated. The exhaust then passes through a heat exchanger to reduce temperatures before continuing on to a reducing catalyst. The NOx reduction efficiency of the reducing catalyst is extremely high due to the high CO concentration (the CO acts as a reducing agent to convert NOx into nitrogen gas. The exhaust next passes through another heat exchanger, and air is added before the exhaust passes through an oxidation catalyst. The oxidation catalyst is extremely efficient in reducing CO and VOC emissions due to the excess oxygen in the exhaust.

Typical Effectiveness: NOx concentrations as low as 3 to 4 ppm are achievable with this system. Concentrations of CO and VOC are typical of systems using oxidation catalysts.

Limitations: When the oxygen content of the engine's exhaust is high, such as for lean-burn engines, the burner must use a large amount of fuel to consume nearly all the oxygen and generate sufficient amounts of CO. Therefore, use of this method on lean-burn engines is only practical in cogeneration applications, where heat generated by the burner can be recovered and converted to useful energy.

Other Effects: For rich-burn engines, this method has a fuel penalty of about one to five percent. However, for lean-burn engines, the fuel penalty could be equal to the uncontrolled engine's fuel consumption.

Selective Catalytic Reduction (SCR)

Applicability: This method was patented in the U.S. in the 1950s, and there have been over 700 applications of SCR to combustion devices worldwide. Some of these applications include stationary IC engines. However, most of these applications are external combustion devices such as boilers. SCR systems for IC engines have been commercially available for a number of years, but there have only been a few dozen SCR retrofits of IC engines. SCR is applicable to all lean-burn engines, including diesel engines.

Principle: The exhaust of lean-burn engines contains high levels of oxygen and relatively low levels of VOC and CO, which would make an NSCR type of catalyst ineffective at reducing NOx. However, an SCR catalyst can be highly effective under these conditions. Oxygen is a necessary ingredient in the SCR NOx reduction equation, and SCR performs best when the oxygen level in the exhaust exceeds 2 to 3 percent.

Differing catalyst materials can be used in an SCR catalyst, depending on the exhaust gas temperature. Base metal catalysts are most effective at exhaust temperatures between 500 and 900 ºF. Base metal catalysts generally contain titanium dioxide and vanadium pentoxide, although other metals such as tungsten or molybdenum are sometimes used. Zeolite catalysts are most effective at temperatures between 675 to over 1100 ºF. Precious metal catalysts such as platinum and palladium are most effective at temperatures between 350 and 550 ºF.

In SCR, ammonia (or, in some cases, urea) is injected in the exhaust upstream of the catalyst. The catalyst promotes the reaction of ammonia with NOx and oxygen in the exhaust, converting the reactants to water vapor and nitrogen gas. Ammonia injection can be controlled by the use of a NOx monitor in the exhaust downstream of the catalyst. A feedback loop from the monitor to the ammonia injector controls the amount injected, so that NOx reductions are maximized while emissions of ammonia are minimized. To eliminate the use of a costly NOx monitor, some applications use an alternative system that measures several engine parameters. Values for these parameters are then electronically converted into estimated NOx concentrations.

Typical Effectiveness: The NOx removal efficiency of SCR is typically above 80 percent when within the catalyst temperature window.

Limitations: SCR can only be used on lean burn engines. Relatively high capital costs make this method too expensive for smaller or infrequently operated engines.

Some SCR catalysts are susceptible to poisoning from metals or silicon oxides that may be found in the fuel or lubricating oil. Poisoning problems can be minimized by using specially formulated lubricating oils that do not contain the problem metals, the use of fuels with low metals or silicon oxides content, or the use of zeolite catalysts which are not as susceptible to poisoning.

If platinum or palladium is used as an active catalyst material, the sulfur content of the exhaust must be minimized to avoid poisoning of the catalyst. In addition, for all types of SCR catalysts, high sulfur fuels will result in high sulfur oxides in the exhaust. These sulfur compounds will react with the ammonia in the exhaust to form particulate matter that will either mask the catalyst or be released into the atmosphere. These problems can be minimized by using low sulfur fuel, a metal-based SCR system specially designed to minimize formation of these particulate matter compounds, or a zeolite catalyst.

Ammonia gas has an objectionable odor, is considered an air pollutant at low concentrations, becomes a health hazard at higher concentrations, and is explosive at still higher concentrations. Safety hazards can occur if the ammonia is spilled or there are leaks from ammonia storage vessels. These safety hazards can be minimized by taking proper safety precautions in the design, operation, and maintenance of the SCR system. Safety hazards can be substantially reduced by using aqueous ammonia or urea instead of anhydrous ammonia. If a concentrated aqueous solution of urea is used, the urea tank must be heated to avoid recrystallization of the urea. In addition, if too much ammonia is injected into the exhaust, excessive ammonia emissions may result. These emissions can be reduced to acceptable levels by monitoring and controlling the amount of ammonia injected into the exhaust.

SCR may also result in a slight increase in fuel consumption if the backpressure generated by the catalyst exceeds manufacturer's limits.

Lean NOx Catalyst

Applicability: This control method can be used on any lean-burn engine, although development work has concentrated on diesel engines. This control method is still in the development stage and is not commercially available, but may be available in a few years.

Principle: A number of catalyst materials can be used in the formulation of lean NOx catalysts. The constituents are generally proprietary. NOx reductions are generally minimal unless a reducing agent (typically raw fuel) is injected upstream of the catalyst to increase catalyst performance to acceptable levels. Depending on the catalyst formulation, this method can reduce NOx, CO, and VOC simultaneously.

Typical Effectiveness: Claims for NOx control efficiencies have ranged from 25 to 50 percent. Steady state testing on a diesel-fueled engine yielded NOx reductions of 17 to 44 percent.
Limitations: Use of a reducing agent increases costs, complexity, and fuel consumption. The reducing agent injection system must be carefully designed to minimize excess injection rates. Otherwise, emissions of VOC and particulate matter can increase to unacceptable levels. Tests have shown that lean NOx catalysts produce significant amounts of nitrous oxide (N2O), and that this production increases with increasing NOx reduction efficiencies and reducing agent usage. This method is not commercially available, and is still in the development and demonstration stage.

Other Effects: None known.

Urea Injection

Applicability: This control method is applicable to all lean-burn engines and is also known as selective non-catalytic reduction. It has been used on several boilers to control NOx, but there have been no applications to internal combustion engines.

Principle: Urea injection is very similar to cyanuric acid injection, as both chemicals come in powder form, and both break down at similar temperatures to form compounds which react with nitric oxide. Differences are that a high temperature heating system is not required for urea injection. Instead, the urea is usually dissolved in water, and this solution is injected into the exhaust stream.

Typical Effectiveness: Unknown.

Limitations: The temperature window for urea is higher than the highest exhaust temperature of nearly all engines. Therefore, due to cost-effectiveness considerations, practical applications of urea injection are limited to engines in cogeneration applications. Specifically, these applications are limited to situations where supplemental firing is applied to the engine's exhaust to increase its temperature, and the exhaust heat is recovered and used.

Other Effects: Unknown

Replacement

Another method of reducing NOx is to replace the existing IC engine with an electric motor, or a new engine designed to emit lower NOx emissions. In some instances, the existing engine may be integral with a compressor or other gear, and replacement of the engine will require the replacement or modification of this other equipment as well.

Applicability: This control method is applicable to all engines.

Principle: Rather than applying controls to the existing engine, it is removed and replaced with either a new, low emissions engine or an electric motor.

Typical Effectiveness: New, low emissions engines can reduce NOx by a substantial amount over older, uncontrolled engines. Potential NOx reductions of over 60 percent can be realized by replacing existing SI engines with new certified low emission engines fueled by natural gas or propane.

Another approach is to replace an engine with an electric motor. An electric motor essentially eliminates NOx emissions associated with the removed engine, although there may be minor increases in power plant emissions to supply electricity to the electric motor.

Limitations: In remote locations or where electrical infrastructure is inadequate, the costs of electrical power transportation and conditioning may be excessive. Similarly, the cost of replacing an engine with a natural gas fired unit could be prohibitive if a natural gas pipeline is not in reasonably close proximity to the engine. In cases where the existing engine operates equipment integral to the engines (such as some engine/compressors that share a common crankshaft), both the engine and integral equipment would require replacement.

APPENDIX E – CEMS DATA ANALYSIS FOR AVERAGING TIME

Option to Average on an Hourly Basis for CEMS-equipped Engines

Staff reviewed concerns raised by stakeholders in the averaging of data for compliance purposes. In particular, one stakeholder operates three natural gas-fired, rich-burn internal combustion engines with each rated at greater than 2,000 bhp. The engines are used to drive cogeneration units that provide power to the facility. Each engine is equipped with a NSCR system and a CEMS unit. To determine compliance with its permitted limit, the facility calculates a rolling 15-minute average of CEMS 1-minute data.

At times, the engines experience transient operational shifts. These shifts may result from load demand variability, fuel compositional changes, or ambient weather fluctuations. Although the facility responds to these changes, they claim that the 15-minute averaging does not give them enough time to adequately address temporary phenomena before a permitted limit is exceeded. In 2017, the South Coast AQMD recorded forty-five notifications by the facility that were related to exceedances. In 2018, the facility made twenty-five similar notifications. About 90% of these calls describe exceedances due to transients.

In 2018, the South Coast AQMD issued a Notice of Violation to the facility for failure to operate their equipment in compliance to their permitted limits, referencing the volume of exceedances albeit transient as they may be. As a practice and to minimize the time of potential non-compliance, the facility now responds to 15-minute exceedances by shutting down an engine if and when a permitted limit is exceeded. The engine is then restarted and operation resumes.

Shutting down an engine and restarting it introduces several negative impacts. For example, upon a restart, it is anticipated that more emissions will be released into the atmosphere in comparison to if an engine were allowed to continue to operate during a transient. Staff evaluated 1-minute CEMS data from the facility that covers such instances. The following information presents findings from this analysis:

<u>Incident #1</u>

2/17/2018
NOx emissions rise as a transient: 0119 hrs – 0125 hrs (Duration – 7 minutes to go through the system)

Maximum Corrected NOx – 29.15 ppmvd @ 15% O_2
Maximum Raw NOx Value – 103 ppmvd

Unit shutdown at 0138 hrs

During the 7 minutes of the incident, excess emissions (above 11 ppmvd @ 15% O_2) are calculated to be 0.0724 lbs NOx

Subsequent Start-up
0245 – 0301 (Duration – 8 minutes to start up)
Maximum Corrected NOx – 34.42 ppmvd @ 15% O_2

Maximum Raw NOx Value – 121 ppmvd

During the 8 minutes of start-up, excess emissions (above 11 ppmvd @ 15% O_2) are estimated to be 0.1637 lbs NOx

The extra NOx emissions of undergoing a start-up is greater by 0.0913 lbs

---

Incident #2

2/17/2018
NOx emissions rise as a transient: 0417 hrs – 0423 hrs (Duration – 7 minutes to go through the system)

Maximum Corrected NOx – 23.29 ppmvd @ 15% O_2
Maximum Raw NOx Value – 82 ppmvd

Unit shutdown at 0439 hrs

During the 7 minutes of the incident, excess emissions (above 11 ppmvd @ 15% O_2) are estimated to be 0.0394 lbs NOx

Subsequent Start-up
0620 – 0626 (Duration – 7 minutes)
Maximum Corrected NOx – 34.92 ppmvd@15% O_2
Maximum Raw NOx Value – 121 ppmvd

During the 7 minutes of start-up, excess emissions (above 11 ppmvd @ 15% O_2) are estimated to be 0.1409 lbs NOx

The extra NOx emissions of undergoing a start-up is greater by 0.1015 lbs.

As a result of this analysis, staff concluded that there can be an emissions benefit by having less frequent shutdowns and restarts. In addition to calculating additional NOx emissions due to start-up activity, staff considered two common 1-hour averaging methods versus a rolling 15-minute averaging procedure. The first method uses an averaging of four 15-minute quadrants in one hour on the hour patterned after the procedure used in Rule 2012. The second method extends the rolling averaging to one hour versus 15 minutes. Based on these alternative averaging methods, the facility would have been able to demonstrate compliance to its permitted limits during these transient events. Moreover, if the facility had been able to use a one-hour averaging procedure, it would have avoided the shutdown and subsequent startup of their engine and any corresponding net increase of emissions due to the startup.

Comparing the 1-hour Quadrant Averaging versus the 1-hour Rolling Averaging, staff notes a difference in the results. The 1-hour Quadrant procedure produces a slightly lower value than the 1-hour Rolling method. This may be attributed to what is considered a "double-smoothing" effect where 1-minute data is averaged first over a 15-minute period and then each period is averaged for the block hour. In terms of ease of calculation, the Quadrant Averaging procedure requires several steps to complete whereas the 1-hour Rolling method is simpler.

Table E-1: Averaging – Highest Peak Value (ppmvd @ 15% O_2)

Methodology	Incident #1	Incident #2
15-minute Rolling Averaging	29.15	23.29
1-hour Quadrant Averaging	9.59	8.82
1-hour Rolling Averaging	9.72	9.07

In analyzing the data, staff made the following observations and assumptions:

- The beginning of a transient incident was noted to occur when a raw NOx value exceeded the previous reading by 50% or more.
- The end of a transient incident was noted to occur when a previously high value returned to within 50% of the value before the start of the transient.
- In each transient incident, the 1-minute data would first show the occurrence of an event but then because of averaging, the rolling 15-minute would show the occurrence a short time later.
- The data suggests that each transient analyzed lasted approximately seven minutes.
- In response to an excess of a permit limit based on a 15-minute averaged value, the engine was shutdown. In these instances, the data showed that the transient had passed through the system prior to the shutdown.
- The beginning of a startup period was considered at which point the data showed either NOx emission values, stack flow rate, or oxygen readings.
- The end of a startup period was considered when emission levels were steady and in compliance to permit limits.
- Excess emissions were calculated as emissions greater than the permitted limit.
- It was noted upon start-up, several raw NOx values peaked and flat-lined at 121 ppmvd. To calculate emissions in these cases, the maximum reported value was used. There is a possibility that actual values were greater, but without additional information, staff used the maximum reported value in calculations.
- To calculate extended hour averaging after an engine was shutdown, staff assigned a value of 8 ppmvd NOx @ 15% O_2 to model the effect of the transient.

After evaluation of the issue and analysis of the emissions impact, staff recommends providing an option to average on a 1-hour, fixed-interval basis in accordance to the provisions in Rules 218 and 218.1. This would assure compliance with the existing emission limits, while also achieving emissions benefits from the reduction of shutdown and startup emissions.

APPENDIX F – PUBLIC COMMENTS

Public Comments
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Comment Letter No. 1 – Hoag Hospital, Newport Beach

Yorke
ENGINEERING, LLC
www.YorkeEngr.com

August 2, 2019

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Subject: Proposed Limit on Unplanned Emission-Related Shutdowns for Cogen Engines Subject to PAR 1110.2; Hoag Hospital

Dear Mr. Orellana:

Thank you for agreeing to accommodate Hoag Hospital's (Facility ID 11245) request to increase the emission averaging time from 15 to 60 minutes for their cogeneration engines by amending Rule 1110.2. On the morning of July 25, you called to inform us that you spoke with EPA about the proposed change and that EPA is agreeable. On July 31, Mike Morris spoke with Erik Lidecis and Duane Suby of Hoag Hospital and Yorke about the proposed rule amendments. 1-1

These changes are justified and will reduce real emissions by reducing the number of unplanned shutdowns and startups, during which emissions are uncontrolled, and allowing the engines to continue operating during load transients.

We reviewed Hoag's shutdown data for 2018 and the first half of 2019 and found as many as 7 shutdowns in a month for one engine due to potential emission exceedances of the 15-minute average limit. We believe that Hoag would agree to limit the number of unplanned shutdowns due to emission-related causes to no more than 5 per engine per month.

We propose the following rule language: 1-2

> *There shall be no more than five unplanned shutdowns per month due to emission-related causes. Planned shutdowns and shutdowns due to non-emission-related causes, including emergency reasons, shall not be subject to this limit. The operator shall maintain a log explaining the reason for each shutdown.*

We appreciate your assistance in addressing this matter.

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Mr. Kevin Orellana
August 2, 2019
Page 2 of 2

Sincerely,

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cc: Erik Lidecis, Hoag Hospital
Duane Suby, Hoag Hospital
Peter Moore, Yorke Engineering
Corina Chang, Yorke Engineering
Brian Yorke, Yorke Engineering

References:

1. Letter from Yorke to Mr. Kevin Orellana, dated October 26, 2018
2. Letter from Yorke to Mr. Kevin Orellana, dated May 29, 2019
3. Letter from Hoag to Ben Benoit of the Stationary Source Committee, dated July 23, 2019
4. Letter from Yorke to Mr. Kevin Orellana, dated July 26, 2019

Yorke Engineering, LLC

Hoag Hospital Reference Letter No. 1

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October 26, 2018

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Subject: Proposed Amended Rule 1110.2 – Emissions from Gaseous and Liquid-Fueled Engines;
Emissions Averaging Time for Hoag Hospital (Facility ID 11245) Based on June 3, 2016 Current Rule Language

Dear Mr. Orellana:

On behalf of Hoag Hospital (Facility ID 11245), Yorke Engineering, LLC is submitting this letter to request that the SCAQMD consider increasing the emissions averaging time for NO_x and CO in Rule 1110.2. We understand the rule is being amended to accommodate the sunset of the Regional Clean Air Incentives Market (RECLAIM) program.

FACILITY BACKGROUND

Hoag Hospital currently operates three (3) natural gas fired cogeneration engines to provide electricity and steam to the hospital. All three engines are Waukesha, model no. P9390GSI rated at 2080 brake horsepower (bhp). NO_x and CO emissions are monitored by a continuous emissions monitoring system (CEMS) subject to Rule 218. Hoag is a non-RECLAIM Title V facility.

EMISSIONS AVERAGING TIME

Based on current Rule 1110.2 Table I language dated June 3, 2016, the averaging time for NO_x, VOC, and CO emissions is 15 minutes. Rule 1110.2(B)(ii) currently allows for longer averaging times up to 6 hours for engines combusting non-pipeline-quality natural gas due to varying heating value of the gas. Current Rule 218(f)(2)(B) language dated May 14, 1999 does not state a specific averaging time but requires the averaging time for the CEMS to be consistent with the corresponding permit condition.

Hoag would like to request that the SCAQMD consider increasing the averaging period for NO_x and CO emissions to one hour for their natural gas engines to allow more time for the operators and control systems to accommodate unpredictable fluctuations in hospital electrical and thermal demands that result in minor deviations when averaged over 15 minutes. In 2018 the engines at Hoag have experienced approximately 20 events where NO_x and/or CO emissions slightly exceeded the 15-minute average emission limit. The magnitude of these exceedances is small with the yearly aggregate excess emissions adding up to less than half a pound for each NO_x and CO. Emissions calculated over a 1-hour average would most certainly be in compliance. In addition, a 1-hour averaging time would reduce the frequency of engine shut-downs and start-ups necessary to diagnose the engines. Each time the engine is restarted there is a period of time that engines are

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exempt from the emission limits and emissions are higher while the catalyst warms up (Facility Permit Condition 6).

This request to increase the compliance averaging time was suggested by SCAQMD Engineer Roy Olivares during permitting discussions. At his recommendation, we raised our concern about emissions averaging time at the September 27, 2018 Working Group Meeting. Mr. Olivares stated via email on October 5, 2018 that there may be multiple facilities with the same concern.

ACTIONS TAKEN BY HOAG

Hoag has made significant progress in mitigating emission exceedances for their cogen engines. In response to a variance in 2014 (Case No. 6005-1), Hoag agreed to install and maintain an alarm system that would notify the operator in the event emissions were going to exceed the 15-minute limits. The alarm system helped reduce the number of these exceedances but did not completely eliminate them. As such, Hoag has continued to tighten the alarm system trigger levels to give even earlier notice to the operators. For example, the alarm is currently configured to alert the operator when NO_x and CO emissions will exceed 10 ppm and 32 ppm, respectively. Current permit limits for NO_x and CO are 11 ppm and 33 ppm, respectively. To make the alarm system even more sensitive, it calculates emissions over a 5-minute averaging period. Even with this level of advanced notice, there are still incidents where the operators have insufficient time to adjust engine parameters or shut the engine down before the 15-minute average is exceeded.

In addition to maintaining the alarm system, Hoag also diligently maintains the engines per the manufacturer's specifications. Each engine is subject to a stringent maintenance schedule and is routinely overhauled so that it operates properly. Non-Selective Catalytic Reduction (NSCR) systems are also meticulously maintained. Hoag has continued to experiment with new cutting-edge NSCR technologies to minimize the small exceedances. The process of replacing the NSCR system is cumbersome and expensive. Hoag currently has a brand new NSCR system on standby awaiting installation during the next scheduled overhaul for one of the engines. Hoag has yet to find an NSCR system capable of completely eliminating these exceedances.

CONCLUSION

Hoag would like to request that the SCAQMD consider increasing the NO_x and CO emission averaging time in Rule 1110.2 for natural gas engines from 15 minutes to one hour to smooth out perturbations in the hospital energy demands and reduce the incidence of minor reportable exceedances. Since the overall emissions would not increase, there is no negative impact on the air quality. Hoag diligently maintains an alarm system, all three cogeneration engines, and the NSCR systems. Increasing the averaging period would reduce the number of minor deviations and the associated burden of reporting for both Hoag and the SCAQMD.

Mr. Kevin Orellana
October 26, 2018
Page 3 of 3

Should you have any questions or comments, please contact me at (949) 556-7074.

Sincerely,

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cc: Erik Lidecis, Hoag
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Peter Moore, Yorke Engineering
Corina Chang, Yorke Engineering

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Hoag Hospital Reference Letter No. 2

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May 29, 2019

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Subject: Request to Increase Emission Averaging Time to 60 Minutes; Proposed Amended Rule 1110.2 – Emissions from Gaseous and Liquid-Fueled Engines

Dear Mr. Orellana:

On behalf of Hoag Hospital (Facility ID 11245), Yorke Engineering, LLC (Yorke) is submitting this letter to the PAR1110.2 Working Group to request consideration for increasing the emissions averaging time to 60 minutes for NO_x and CO in Rule 1110.2. We previously submitted a letter[1] on this subject.

This letter includes specific examples of the benefit of 60-minute averaging versus 15-minute averaging for several incidents reported by Hoag. We are sharing this data with Rodolfo Chacon/SCAQMD, who contacted us on March 15, 2019.

FACILITY BACKGROUND

Hoag Hospital currently operates three (3) natural gas-fired cogeneration engines to provide electricity and steam to the hospital. All three engines are Waukesha, Model No. P9390GSI, rated at 2,080 brake horsepower (bhp). NO_x and CO emissions are monitored by a continuous emissions monitoring system (CEMS) subject to Rule 218. Hoag is a non-RECLAIM Title V facility.

EMISSIONS AVERAGING TIME

As stated in our email on May 15, 2019:

"We need your help increasing the averaging time for internal combustion engine emission limits from 15 minutes to 60 minutes. We sent you the attached letter in October 2018 and want to pursue this change in Rule 1110.2 in order to address compliance issues caused by load changes.

"During the 3rd WGM for PAR1110.2 on February 6, 2019, we were told that SCAQMD staff conducted an initial investigation into this and their preliminary thoughts were that increasing the averaging time may not solve all non-compliance issues, and may mask significant emissions in some cases. Variable load situations can create spikes, but increases in emissions may be minor (Hoag Hospital was discussed specifically). The operator response to minor exceedances has been to turn off the engine to stay below the 15 minute average. However, this actually results in higher overall emissions as startup and shutdown periods are exempt from emission standards. Therefore, we ask for consideration of increasing the averaging time for cases like Hoag, with

[1] Letter from Yorke to Mr. Kevin Orellana, dated October 26, 2018

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Mr. Kevin Orellana
May 29, 2019
Page 2 of 4

only small exceedances based on the 15-minute average. As stated in our October 2018 letter, "...the yearly [2018] aggregate excess emissions adding up to less than half a pound for each NO_x and CO." The concept of increasing averaging time should not be disregarded only because not all facilities would benefit. We were told that the rule developers would go back to AQMD staff and reconsider the averaging time.

"However, no mention was made about this concept at the 4th WGM for PAR1110.2 on April 24, 2019. On behalf of Hoag Hospital, we again submit a request for the SCAQMD to consider increasing the averaging time from 15 to 60 minutes for emission standards from reciprocating engines. As stated in our comment letter dated October 26, 2018, increasing the averaging time to one hour would allow more time for Hoag's operators and control systems to accommodate unpredictable fluctuations in hospital electrical and thermal demands that result in minor deviations when averaged over 15 minutes."

CEMS DATA EXAMPLES

In response to our email, Rodolfo Chacon/SCAQMD called us. He requested 1-minute raw CEMS data for the Hoag Cogen Engines for all of 2018 through 2019. He stated they would like to crunch the numbers to show if the 15-minute average versus the 60-minute average would make a difference with regards to number of excess emissions events. We explained to Rodolfo that the 1-minute CEMS data is not stored beyond a limited period of time per SCAQMD regulations. However, we worked with Hoag to obtain what was readily available.

We were able provide CEMS data with 15-minute and 60-minute averages for the exceedances that occurred on the dates noted in Table 1. Table 1 summarizes the 2018 NO_x exceedances reported for Internal Combustion Engine (ICE) No. 1. This unit was the one with the most incidents in 2018, and NO_x was the pollutant that most commonly exceeded the regulatory requirements (for NO_x, the limit is 11 ppm @ 15% O_2). Comparing the 15-minute averages to the 60-minute averages shows that the NO_x emissions are below the NO_x limit on those dates since short-term spikes in NO_x concentration are smoothed over the longer period.

Table 1: 2018 NO_x Emission 15-Minute vs. 1-Hour Averages for ICE 1

Date	Time of Incident	15-Min NO_x Average[1] (ppm)	1-Hr NO_x Average[2] (ppm)
2/17/2018	1:30	13.89	8.05
2/17/2018	2:30	12.44	7.59
2/22/2018	0:30	15.42	9.47
3/9/2018	2:15	11.04	2.76
3/14/2018	8:00	16.76	7.37
3/19/2018	19:00	12.05	8.77

[1] Reported for the 15-minute period prior to the time of incident listed, as measured consecutively from time 0:00.

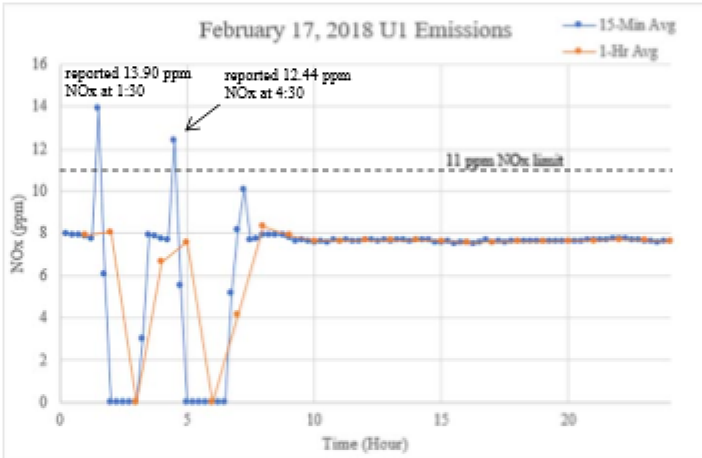
[2] Reported for the 1-hour period including the time of incident listed, as measured consecutively from time 0:00.

As shown in Figure 1, the operator typically responds to high emission alarms by shutting down the engine in an attempt to avoid exceeding the 15-minute average limit. Engine shut-downs create transients in otherwise stable operations. Following shut-down, the probable cause is diagnosed as quickly as possible and the engine restarted. Start-ups typically cause emission transients until the system reaches stable operation, during which time the emissions are exempt from meeting

Yorke Engineering, LLC

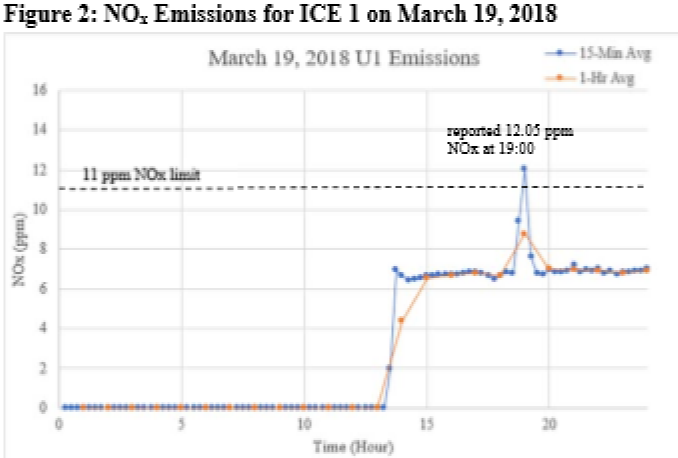
permit limits. The cycle of shutting down the engine and restarting results in more emissions in comparison to allowing the engine to remain operating.

Figure 1: NO_x Emissions for ICE 1 on February 17, 2018



In Figure 2 we see continuous operation past the exceedance, showing that this exceedance corresponds only to one 15-minute data point and is not sustained over an extended time period. Hourly NO_x emission averages would allow the system to continue operating past such short-term spikes such that it can re-stabilize without measures such as powering down, which may cause greater fluctuations in NO_x output.

Figure 2: NO_x Emissions for ICE 1 on March 19, 2018



Yorke Engineering, LLC

Mr. Kevin Orellana
May 29, 2019
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Table 2 summarizes the 2019 NO_x exceedances reported for ICE 1.

Table 2: 2019 NO_x Emission 15-Minute vs. 1-Hour Averages for ICE 1

Date	Time of Incident	15-Min NO_x Average[1] (ppm)	1-Hr NO_x Average[2] (ppm)
4/8/2019	17:00	12.06	8.68
4/30/2019	15:00	11.87	9.19
5/19/2019	0:30	19.37	8.65
5/19/2019	11:30	12.01	8.52

[1] Reported for the 15-minute period prior to the time of incident listed, as measured consecutively from time 0:00.
[2] Reported for the 1-hour period including the time of incident listed, as measured consecutively from time 0:00.

CONCLUSION

Hoag requests that the SCAQMD consider increasing the NO_x and CO emission averaging time in Rule 1110.2 for reciprocating internal combustion cogeneration engines to 60 minutes to allow more time for the engine control system to accommodate changes in the hospital energy demands and reduce the incidence of minor reportable exceedances.

The magnitude of mass emission exceedances is miniscule. Increasing emission averaging time would result in no overall emissions increase. In fact, by reducing the number of shutdown/startup cycles, the true air emissions would likely decrease.

Hoag diligently maintains all three cogeneration engines, the NSCR systems, CEMS, and an emissions alarm system. Increasing the averaging period will reduce the number of minor deviations and the associated burden of reporting for both Hoag and the SCAQMD.

Submitted with this letter is an Excel file with CEMS data for ICE 1 for the dates covered in this letter.

Should you have any questions or comments, please contact me at (949) 248-8490, x226.

Sincerely,

Corina Chang

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cc: Erik Lidecis, Hoag
Duane Suby, Hoag
Peter Moore, Yorke Engineering
Corey Luth, Yorke Engineering
Brian Yorke, Yorke Engineering

Enclosure:
1. Attachment 1 – Excel File with CEMS Data (ICE 1)

Yorke Engineering, LLC

ATTACHMENT 1 – EXCEL FILE WITH CEMS DATA (ICE 1)

Yorke Engineering, LLC

Hoag Hospital Reference Letter No. 3

hoag

HOAG MEMORIAL HOSPITAL PRESBYTERIAN
One Hoag Drive, PO Box 6100
Newport Beach, CA 92658-6100

July 23, 2019

Council Member Ben Benoit
Chair, Stationary Source Committee
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: **Request to Increase Emission Averaging Time to 60 Minutes; Proposed Amended Rule 1110.2 (SSC Agenda Item 4)**

Chairperson Benoit:

Hoag Hospital in Newport Beach (SCAQMD Facility ID 11245) is a world class health care facility that serves Orange County and all of Southern California. Hoag requests consideration for proposed amendments to Rule 1110.2 which are being heard under Item 4 of the Stationary Source Committee (SSC) agenda for July 26, 2019. The amendment to increase the emission averaging time from 15 minutes to 60 minutes will increase Hoag's operational efficiency, improve compliance with air quality rules, reduce costs, and lower real air emissions from cogeneration engines.

Hoag's three cogeneration engines provide electricity and thermal energy to support hospital operations. SCAQMD permits for these engines impose emission limits that are monitored by Continuous Emissions Monitoring Systems (CEMS). Any small deviations from the emission limits are reported by Hoag as required under Title V. While Hoag meticulously maintains their equipment in good condition, hospital energy demand transients sometimes cause small emission exceedances, and often result in shutting-down the engines. Increasing the emission averaging time from 15 minutes to 60 minutes would allow time for the system to adjust to load transients and reduce the number of engine shutdowns. Emissions during startups and shutdowns are much higher than normal operations.

Hoag has been working with SCAQMD staff to amend Rule 1110.2 and allow up to one hour for emissions averaging time from cogen engines. Hoag met with SCAQMD staff on July 18 and presented detailed data to support this request. SSC agenda item 4 mentions Hoag's request under "Remaining Key Issues."

We appreciate the SSC's consideration of Hoag's request to increase the emission averaging time to 60 minutes.

Sincerely,

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July 26, 2019

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Subject: Request to Increase Engine Emission Averaging Time to 60 Minutes for PAR 1110.2; Hoag Hospital

Dear Mr. Orellana:

Thank you for taking steps to accommodate Hoag Hospital's (Facility ID 11245) request to increase the emission averaging time from 15 to 60 minutes by proposing changes to Rule 1110.2. Yesterday morning you called to inform us that you spoke with EPA about the proposed change and that EPA is agreeable. EPA has requested that SCAQMD propose a cap on the number of unplanned shutdowns along with allowing 60-minute averaging of emissions. We understand that you will write justification for inclusion in the staff report. Yorke and Hoag will review data on shutdowns and propose a reasonable cap as soon as possible.

Thanks also to you and other SCAQMD staff that attended the July 18, 2019 conference call with representatives of Hoag and Yorke Engineering. The SCAQMD listened to Hoag's concerns and is considering increasing the emission averaging time from 15 to 60 minutes in PAR 1110.2.

Attachment 1 lists the meeting attendees for both conference calls.

Hoag has submitted a letter to the Stationary Source Committee (SSC) and will attend the meeting on July 26. Hoag and Yorke will support the PAR Public Workshop and CEQA Scoping Meeting on July 31. Reference is made to the letters previously submitted to SCAQMD on this topic.

We appreciate your assistance in addressing this matter.

Sincerely,

Corina Chang

Corina Chang
Senior Engineer
Yorke Engineering, LLC
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(949) 248-8490 x226

LOS ANGELES/ORANGE COUNTY/RIVERSIDE/VENTURA/SAN DIEGO/FRESNO/BERKELEY/BAKERSFIELD
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Mr. Kevin Orellana
July 26, 2019
Page 2 of 2

cc: Erik Lidecis, Hoag Hospital
Duane Suby, Hoag Hospital
Peter Moore, Yorke Engineering
Corey Luth, Yorke Engineering
Brian Yorke, Yorke Engineering

References:

1. Letter from Yorke to Mr. Kevin Orellana, dated October 26, 2018
2. Letter from Yorke to Mr. Kevin Orellana, dated May 29, 2019

Attachment:

1. Meeting Attendees

Yorke Engineering, LLC

MEETING ATTENDEES

Table 1: Conference Call, July 18, 2019

Kevin Orellana	SCAQMD
Rudy Chacon	SCAQMD
Melissa Gamoning	SCAQMD
Charlie Tupac	SCAQMD
Mike Wickson	SCAQMD
Dipankar Sarkar	SCAQMD
Mike Morris	SCAQMD
Erik Lidecis	Hoag Hospital
Duane Suby	Hoag Hospital
Kimban Sim	Hoag Hospital
Corina Chang	Yorke Engineering
Corey Luth	Yorke Engineering
Pete Moore	Yorke Engineering

Table 2: Conference Call, July 25, 2019

Kevin Orellana	SCAQMD
Rudy Chacon	SCAQMD
Mike Morris	SCAQMD
Duane Suby	Hoag Hospital
Kimban Sim	Hoag Hospital
Corina Chang	Yorke Engineering
Corey Luth	Yorke Engineering
Pete Moore	Yorke Engineering

Yorke Engineering, LLC

Response to Comment 1-1

South Coast AQMD appreciates your comments and agrees that a longer averaging time can result in less emissions. Regarding your request to increase the averaging time from 15 minutes to 60 minutes, PAR 1110.2 has been revised to allow a 1-hour averaging period for engines equipped with CEMS.

Response to Comment 1-2

Staff has reviewed your comment regarding limiting the number of emissions-related shutdowns. PAR 1110.2 allows a 1-hour averaging period which should address the transient load changes that were causing the need to excessively shutdown engines.

Comment Letter No. 2 – Snow Summit

Yorke
ENGINEERING, LLC
www.YorkeEngr.com

August 9, 2019

Mr. Michael Morris
Planning and Rule Manager
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91795

Subject: Rule 1110.2 Comments and BARCT Cost Effectiveness Analysis for Snow Summit, LLC (SCAQMD Facility ID No. 185353

Dear Mr. Morris:

On behalf of Snow Summit, LLC (Snow Summit), Yorke Engineering LLC (Yorke) is pleased to present this Rule 1110.2 Best Available Retrofit Control Technology (BARCT) cost effectiveness analysis for the proposed retrofit of the existing Selective Catalytic Reduction (SCR) systems on its six (6) diesel generator engines currently in operation at the ski area. In addition to the BARCT analysis, this letter also includes general comments pertaining to the proposed revisions to Rule 1110.2. 2-1

INTRODUCTION

Snow Summit has been working with the South Coast Air Quality Management District (SCAQMD) to determine if upgrades to the existing SCR systems on the generator engines would be cost effective based on SCAQMD criteria. The upgraded SCRs would enable the engines to meet the current Rule 1110.2 nitrogen oxide (NOx) emission standard of 11 parts per million (ppm). The engines are currently permitted to emit 50 ppm NOx.

Yorke evaluated the cost effectiveness using the following general assumptions: 2-2

- An annual operating limit of 1,000 hours per year;
- An interest rate (cost of money) of 5.5%;
- An operational life of a new SCR of 15 years; and
- A cost-effectiveness threshold of $50,000.

Yorke believes that these values are supportable and consistent with the guidance provided for the method.

Snow Summit is suggesting 1,000 hours per year be used as the BARCT threshold for their unique case. By accepting a permit condition limiting the operating hours of each engine to less than 1,000 per year, the engines would not be required to meet the NOx standard of 11 ppm @ 3% O_2. 2-3

The subsequent paragraphs provide more detail regarding our cost-effectiveness calculations and conclusions.

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Mr. Michael Morris
August 9, 2019
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FACILITY INFORMATION

The Snow Summit ski area was established in 1952 in the San Bernardino Mountains. It is located near Big Bear Lake along with its sister resort Bear Mountain. Snow Summit is one of the larger ski areas in Southern California and is considered to be one of the most popular ski and snowboard destinations in the Southern California area. Snow Summit is a mid-sized resort, with 1,209 feet vertical drop, and 240 acres of skiable terrain, all of it covered by snowmaking. Snow Summit's extensive snowmaking system draws water from Big Bear Lake. Snowmaking operations can cover all of the ski areas' marked terrain with skiable man-made snow when natural snow is insufficient and ambient conditions are amenable for snowmaking. Snow Summit is also one of the areas' largest and most important employers. During the ski season, Snow Summit typically employees approximately 1,800 employees. In addition, Snow Summit is very active in the local community and sponsors many local events. Snow Summit also works openly with the SCAQMD and fosters a positive working relationship. 2-4

BARCT ANALYSIS METHODOLOGY

The costs and estimating methodology are recommended by EPA in the Office of Air Quality Planning Service Air Pollution Cost Control Manual (referred to simply as "OAQPS" throughout the remainder of this document).

In brief, the methodology seeks to provide an annual cost of ownership which incorporates the direct operating costs (e.g., labor, utility, and maintenance costs) and an annualized capital cost. The annualized capital cost can be thought of like an annual lease payment for the equipment; it takes into account the installed equipment cost, equipment life, and the cost of money (i.e., the interest rate for borrowing). By adding the operating costs to the annualized capital cost, the cost of ownership is reduced to a numerical single value. This allows the comparison of different technologies on a common basis. For example, one technology may have high capital cost and low operating cost, and a different technology may have low capital cost and high operating cost. 2-5

This annualized cost of ownership is used by the SCAQMD to calculate a cost-effectiveness value in units of dollars per ton of emissions reduced/avoided. That cost-effectiveness value is compared to a standard that the SCAQMD has determined is appropriate for the pollutant. A more complete explanation of the methodology is provided in Attachment 1.

BARCT EMISSIONS

The premise of this analysis is that the upgraded SCR would reduce NOx emissions from the six diesel generator engines from 50 ppm to 11 ppm. Yorke calculated emissions based 1,000 hours per year, per engine. The change in emissions is summarized in Table 1. Emission calculations are provided in Attachment 2. 2-6

Yorke Engineering, LLC

Mr. Michael Morris
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Table 1: Net Change in NOx Emissions

Period	Emissions at 1,000 hours per year (ton/yr)
Pre-Project	12.7
Post-Project	2.8
Net Decrease	9.9

2-6 Cont.

BARCT DATA AND ASSUMPTIONS

The OAQPS methodology provides factors for estimating the costs associated with an air emissions control project. The factors are generally based on the cost of the air pollution control device itself (i.e., a percentage of the capital cost). While OAQPS provides a methodology for estimating the basic capital cost for an SCR, for this analysis, Yorke used the proposal for the upgraded SCR provided by [redacted] which is provided as Attachment 3.

In addition to the equipment provided by [redacted] for the project, Yorke assumed the following equipment would be required to execute the project, along with estimated costs: 2-7

- Urea Tank (one additional 5,000-gallon tank is assumed to be needed) ($20,000);
- Vaporizer (for urea vaporization)($45,000);
- Compressor (used to dilute urea to ensure better distribution) ($30,000);
- Structural Steel ($80,000); and
- Flex Couplings (to connect the SCR to the existing ducting/stack) ($36,000).

Yorke did not include the cost of new CEMS for the engines, but did include a cost of $25,000 per engine for instrumentation and process control. Whether the project would require modifications to the existing CEMS, or some other type of instrumentation to control urea feed has not been determined (and would depend on whether the SCAQMD provides a CEMS exemptions for limited use engines). 2-8

Yorke made the following assumptions:

- An equipment life of 15 years is assumed. Yorke reviewed several BACT analyses for SCR installations; the life expectancy for an SCR was reported as 10 years (SMAQMD and BAAQMD for BACT analyses), 10 years (ENSR/AECOM for Duke), 15 years (Onsite Sycom for DOE), and 25 years (SCAQMD for Rule 1110.2). The 25 year estimate used by the SCAQMD appears unreasonably long for several reasons:
    - Engine technology changes rapidly – in the last 25 years, diesel engines have gone from Tier 0 to Tier 4. 2-9
    - Rule 1110.2 has been amended nine times in the last 25 years (although not always to reduce NOx emission levels).
    - The State is making great strides to force replacement of older mobile and portable diesel engines by a mandatory phase-out of Tier 1, 2, and 3 engines by 2027.

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Given the rapid change of both technology and regulations, it is not reasonable to assume that Snow Summit could continue to operate these engines without further modification for 25 more years. For these reasons, Yorke selected 15 years as the life expectancy of the control equipment. 2-9 Cont.

- Yorke used an interest rate of 5.5% as the cost of money, as published by the Wall Street Journal, June 6, 2019. This is the rate at which banks would load money to their preferred customers. 2-10
- The operating and maintenance labor costs for the proposed SCR are assumed to be zero because Snow Summit already operates SCR on each of the six generator engines. The additional costs associated with the proposed new SCR are assumed to be negligible. 2-11
- The Miratech proposal includes new diesel particulate filters for the project. It is assumed that the particulate filters are required to protect the catalyst from fouling and, as such, are integral to the project. Thus, the cost of the particulate traps is included in the analysis. 2-12
- Catalyst replacement is assumed to be required after 24,000 hours of operation based on OAQPS guidance. Catalyst replacement cost is annualized based on the catalyst life, the cost of replacement catalyst, and the cost of money. 2-13
- The existing SCR will have to be demolished and removed prior to the installation of the proposed new SCR equipment. Demolition is estimated at $60,000. 2-14
- The proposed catalyst is assumed to have higher pressure drop than the existing SCR. The energy cost is estimated at 0.3% of the generator output based on OAQPS guidance. 2-15
- The additional cost for urea is estimated based on the urea required for the reduction from 50 ppm to 11 ppm only. The additional urea has to be vaporized for use; the heat required for vaporization is estimated assuming an electric heater. 2-16
- SCAQMD permitting costs have been included in the capital cost estimate. The cost estimate includes the SCAQMD application fees and an estimate of the cost for a consultant to prepare the applications. 2-17

The OAQPS cost factors that are used without adjustment are listed in Tables 1-1 and 1-2 in Attachment 1.

BARCT RESULTS

The total estimated capital and operating costs, along with the cost effectiveness values are summarized in Table 2. As noted, the operating costs only include the incremental costs that would be incurred if the proposed new SCR were to be installed. The operating costs exclude operating and maintenance labor and exclude the cost for supplies and utilities associated with the operation of the current SCR systems. 2-18

The SCAQMD published a cost-effectiveness threshold in conjunction with rule development activities for Rule 1110.2; the value is $28,957 per ton of NOx reduced for lean-burn, 4-stroke engines. In an e-mail from the SCAQMD, Kevin Orellana stated that the District would use $50,000 per ton as the cost-effectiveness threshold for their analysis of this project. Mr. Orellana did not indicate the basis for this value or why he is not using the value that was published for the Rule 1110.2 rule development. To ensure that this analysis is sufficiently conservative (i.e., 2-19

Mr. Michael Morris
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protective of air quality), Yorke uses the $50,000 per ton value in our analysis. The cost-effectiveness calculations are provided in Attachment 4. 2-19 Cont.

Table 2: Cost and Cost-effectiveness Summary

Category	Value
Operating Hours	1,000 Hrs/Yr
Total Capital Cost	$3,275,587
Annualized Capital Cost	$326,332
Annual Operating Cost	$40,355
Indirect Annual Cost	$139,933
Total Annualized Cost	$497,711
NOx Reduction	9.70 Tons/Yr
Cost Effectiveness	$51,332 per Ton
Cost Effectiveness Threshold	$50,000 per Ton
Cost Effective (Yes/No)?	No

RULE 1110.2 BARCT CONCLUSIONS AND RECOMMENDATIONS

Yorke offers the following conclusions:

- The proposed new SCR systems are not cost effective based on 1,000 hours per year of operation per engine using 5.5% interest rate, 15-year equipment life, and a cost-effectiveness threshold of $50,000 per ton. 2-20
- A commercial interest rate of 4% used by SCAQMD in its analysis is unrealistic. While some assumptions are generally required in a cost-effectiveness analysis, the cost of money does not require assumption – it is a published value that is readily available. We encourage SCAQMD to use the current cost of money in its analysis. 2-21
- The SCR equipment life of 25-years assumed by the District in its analysis is very conservative. Snow Summit's operations are seasonal operations and the generator engines are more than 16 years old and near the end of their useful life. Engines such as these typically have a useful service life of 10,000 to 12,000 hours before a major engine overhaul or complete replacement is necessary. A more realistic SCR equipment life of 15 years is recommended. 2-22
- Using a cost-effectiveness threshold of $50,000 per ton is very conservative. This value does not appear to be based on EPA criteria or standards used by other California air districts for similar analyses. Given this, we suggest the SCAQMD uses its discretion when establishing a cost-effective threshold appropriate for Snow Summit. 2-23
- Snow Summit is suggesting 1,000 hours per year to be used as the BARCT threshold for its unique case. By accepting a permit condition limiting the operating time of each engine to less than 1,000 hours per year, the engines would not be required to meet the NOx standard of 11 ppm @ 3% O_2. 2-24

Yorke Engineering, LLC

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GENERAL RULE 1110.2 COMMENTS

Yorke offers the following comments on draft Rule 1110.2:

- The rule should include provisions that specify emergency use, testing, and maintenance hours are not counted towards normal operations for any rule requirements such as CEMS requirements and NOx retrofit requirements. 2-25
- The averaging period for rule compliance for large lean-burn diesel engines such as these should be based on a 60-minute averaging period, which accounts for normal engine operating fluctuations such as air-to-fuel ratio time-lag, SCR stabilization, and load changes. 2-26
- We agree that engines with a permit condition that limits operating hours to less than 1,000 per year (not including emergency use, testing, and maintenance hours) should be exempt from CEMS requirements. 2-27

CLOSING

Should you have any questions or concerns, please contact me at (805) 293-7756, or John Furlong at (949) 248-8490 x 233.

Sincerely,

Russell Kingsley
Principal Engineer
Yorke Engineering, LLC
RKingsley@YorkeEngr.com

cc: John Furlong, Yorke Engineering, LLC

Enclosures:

1. Attachment 1 – OAQPS Cost Analysis Methodology
2. Attachment 2 – Emission Calculations
3. [redacted] Proposal
4. Cost Effectiveness Calculations

Yorke Engineering, LLC

ATTACHMENT 1 – OAQPS COST ANALYSIS METHODOLOGY

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ATTACHMENT 1 – OAQPS COST ANALYSIS METHODOLOGY

Overview of Methodology

The costs and estimating methodology in this report are directed toward the "study" level estimate with a nominal accuracy of +/- 30 percent, which is consistent with the methodology recommended by EPA in the Office of Air Quality Planning Service Air Pollution Cost Control Manual (referred to simply as "OAQPS" throughout the remainder of this document). According to Perry's Chemical Engineer's Handbook, a study estimate is "… used to estimate the economic feasibility of a project before expending significant funds for piloting, marketing, land surveys, and acquisition … [However] it can be prepared at relatively low cost with minimum data." Specifically, to develop a study estimate, the following must be known:

- Location of the source within the plant;
- Rough sketch of the process flow sheet (i.e., the relative locations of the equipment in the system);
- Preliminary sizes of, and material specifications for, the system equipment items;
- Approximate sizes and types of construction of any buildings required to house the control system;
- Rough estimates of utility requirements (e.g., electricity);
- Preliminary flow sheet and specifications for ducts and piping;
- Approximate sizes of motors required.

(EPA, 2002)

Financial Evaluation

There are many ways of evaluating the cost of a project. Five common methods are:

- Cash Flow;
- Payback Period;
- Internal Rate of Return (IRR);
- Return on Investment (ROI); and
- Net Present Value (NPV).

While these can be used to evaluate projects, these five methods are better suited to projects with a positive cash flow – such as equipment used to make a product that is sold. Because pollution control projects generally have only negative cash flow for initial capital equipment purchase and annual operating expenses, these methods yield negative values, and evaluation is a comparison of negative numbers. While the comparison is possible, it can be hard to follow logically.

For this report, Yorke uses an alternative method described in OAQPS as "Annualization". This method determines a series of equal payments over a long period of time that fully funds a capital project and its operations and maintenance by multiplying the present value of those costs by a capital recovery factor. This method derives what can be described as the "annual cost of ownership". The initial capital investment is allocated over the life of the equipment, taking into account the time value of money, and added to the annual cost of operation (utilities, labor, etc.).

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This allows comparison of projects with differing capital costs, equipment life expectancy and operating costs on a common basis.

Annualization involves determining the NPV of each alternative equipment investment and then determining the equal (in nominal terms) payment that would have to be made at the end of each year to attain the same level of expenditure. In essence, annualization involves establishing an annual "payment" sufficient to finance the investment for its entire life.

The capital recovery cost (CRC) is calculated by multiplying the net present value (NPV) of the investment by the capital recovery factor (CRF):

$$CRC = NPV \ x \ CRF$$

Where CRF is defined according to the formula:

$$CRF = \left[\frac{i(1+i)^n}{(1+i)^n - 1}\right]$$

And where:

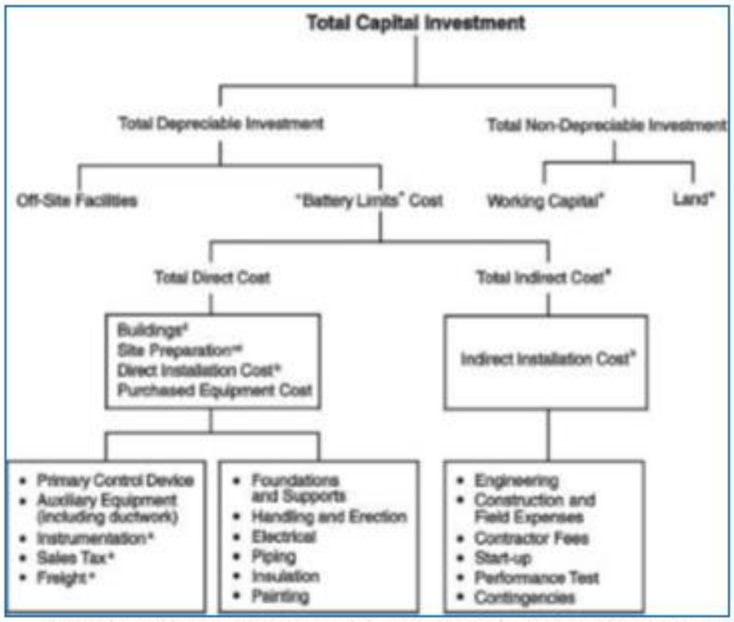
i is the interest rate, and

n is the number of years (usually the life of the equipment)

Capital Cost

Total capital investment (TCI) includes all costs required to purchase equipment needed for the control system (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also [typically] includes costs for land, working capital, and off-site facilities.

The sum of the purchased equipment cost, direct and indirect installation costs, site preparation, and buildings costs comprises the battery limits estimate. By definition, this is the total estimate for a specific job without regard to required supporting facilities which are assumed to already exist at the plant. This would mainly apply to control systems installed in existing plants, though it could also apply to those systems installed in new plants when no special facilities for supporting the control system (i.e., off-site facilities) would be required. Off-site facilities include units to produce steam, electricity, and treated water; laboratory buildings; and railroad spurs, roads, and other transportation infrastructure items. Pollution control systems do not generally have off-site capital units dedicated to them since pollution control devices rarely consume energy at that level (EPA, 2002). The elements of total capital investment are displayed in Figure 1-1.



a. Typically factored from the sum of the primary control device and auxiliary equipment costs.
b. Typically factored from the purchases equipment cost.
c. Usually required only at "grass roots" installations.
d. Unlike the other direct and indirect costs, costs for these items usually are not factored from the purchased equipment cost. Rather, they are sized and costed separately.
e. Normally not required with add-on control systems.

(Source: EPA, 2002)

Figure 1-1: Elements of Total Capital Investment

Operating Costs

Total Annual Cost (TAC) has three elements: direct costs (DC), indirect costs (IC), and recovery credits (RC). The basis of these costs is one year, as this period allows for seasonal variations in production (and emissions generation) and is directly usable in financial analyses. The various annual costs and their interrelationships are displayed in Figure 1-2.

Direct costs include costs for raw materials (reagents or adsorbers), utilities (steam, electricity, process and cooling water), waste treatment and disposal, maintenance materials (greases and other lubricants, gaskets, and seals), replacement parts, and operating, supervisory, and maintenance labor. Generally, raw materials, utilities, and waste treatment and disposal are variable costs, but there is no hard and fast rule concerning any of the direct cost components.

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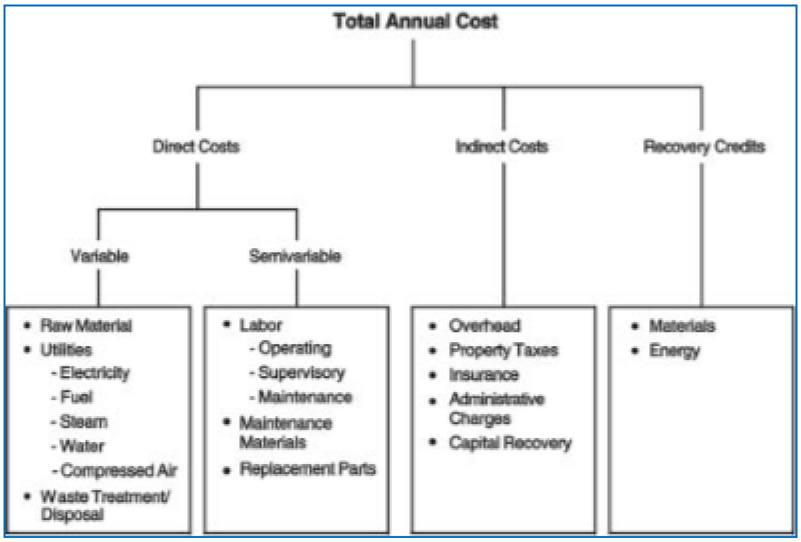

(Source: EPA, 2002)

Figure 1-2: Elements of Total Annual Cost

The control equipment is assumed to fully depreciate over the useful life, and no salvage value can be taken for the system equipment at the conclusion of its useful life. This is a reasonable assumption for add-on control systems, as most of the equipment, which is designed for a specific source, cannot be used elsewhere without modification. Even if it were reusable, the cost of disassembling the system into its components (i.e., "decommissioning cost") could be as high (or higher) than the salvage value.

Indirect, or "fixed", annual costs are independent of the level of production (or whatever unit of measure serves as the analytical metric) and, in fact, would be incurred even if the control system were shut down. Indirect costs include such categories as administrative charges, property taxes, insurance, and capital recovery.

Given the nature of the emission controls under consideration in this evaluation, recovery credits, taken for materials or energy recovered by the control system, which may be sold, recycled to the process, or reused elsewhere at the site are assumed to be negligible.

Capital Cost Factors

The basic cost of the control equipment is only one part of the overall control project cost. Other costs may include demolition, construction of foundations, structural steel, buildings, and installation of the equipment, including electrical, plumbing, ducting and painting. For this study, Yorke uses a combination of OAQPS factors, industry and regulatory references, and estimates based on our experience. The capital cost factors applicable to the proposed SCR project are summarized in Table 1-1.

Table 1-1: SCR Capital Cost Factors

Cost Category	Cost and/or Factor and Basis of Estimate
Direct Costs	
Purchased equipment costs:	
Equipment + auxiliary equipment	Vendor quote + estimates for auxiliary equipment
Instrumentation (CEMS)	BAAQMD BACT Example
Sales taxes	8% for San Bernardino County
Freight	Estimate
Purchased equipment cost (PEC)	Sum of above
Direct installation costs:	
Demolition	Estimate
Foundations and supports	0.08*PEC (OAQPS)
Handling and erection	0.14*PEC (OAQPS)
Electrical	0.04*PEC (OAQPS)
Piping	0.02*PEC (OAQPS)
Insulation for piping and duct work	0.01*PEC (OAQPS)
Painting	0.01*PEC (OAQPS)
Direct Installation Cost (DIC)	Sum of above
Total Direct Cost (TDC)	Sum of DIC and PEC
Indirect Costs	
Engineering	0.10*PEC (OAQPS)
Construction and field expenses	0.05*PEC (OAQPS)
Contractor fees	0.10*PEC (OAQPS)
Start-up	Incl. in vendor quote
Performance tests	Estimate
Permitting	SCAQMD Fee Schedule + Yorke estimate for consulting fees
Contingencies	0.03*PEC (OAQPS)
Total Indirect Cost (TIC)	Sum of above
Total Capital Investment (TCI)	**TCI = TDC + TIC**

Utilities and Administrative Costs

The costing assumptions and cost factors used in this evaluation for utilities and administrative overhead costs are shown in Table 1-2. OAQPS factors are used unless otherwise noted.

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Table 1-2: Cost Factors and Assumptions

Resource Category	Value	Reference
Electricity	$0.16466/kWh	http://www.pge.com/tariffs/electric.shtml#INDUSTRIAL
Compressed Air	$0.25 /1000 ft^3	OAQPS
Sales Tax	8.00%	San Bernardino County
Overhead	60% of labor and materials	OAQPS
Administrative	2% of Total Capital Investment	OAQPS
Property taxes	1% of Total Capital Investment	OAQPS
Insurance	1% of Total Capital Investment	OAQPS

Excluded Cost Items

For this study, Yorke did not take into account the following cost items:

- Operating or maintenance labor costs;
- Income tax; and
- The cost of buildings and land value.

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ATTACHMENT 2 – EMISSION CALCULATIONS

Information not included; business confidential.

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ATTACHMENT 3 – [redacted] PROPOSAL

Information not included; business confidential.

Yorke Engineering, LLC

ATTACHMENT 4 – COST EFFECTIVENESS CALCULATIONS

Yorke Engineering, LLC

REFERENCES

Topic	Web Address
BAAQMD BACT Example	http://www.baaqmd.gov/~/media/files/engineering/bact-tbact-workshop/appendix/cost-effectiveness-calculations-nox.pdf
Catalyst and Urea Costs	EPA SCR Workbook: scr_cost_manual_spreadsheet_2016_vf.xls
Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines (Onsite Sycom)	https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf
Duke Auxiliary Boiler BACT Analysis (prepared by ENSR/AECOM)	https://files.nc.gov/ncdeq/Air%20Quality/permits/psd/docs/cliffside/Top-down_BACT_for_Auxiliary_Boiler_%25209-19-06.pdf
Interest Rate	https://www.bankrate.com/rates/interest-rates/wall-street-prime-rate.aspx
OAQPS	https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf
Proposed Amended Rule 1110.2 Presentation for WORKING GROUP MEETING NO. 5 Date – May 30, 2019	http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/rule-1110-2-working-group-meeting-5-final.pdf?sfvrsn=6
SMAQMD BACT Determinations #57 and #199	http://www.airquality.org/StationarySources/Documents/BACT%20Clearinghouse.pdf
Tank Cost Estimate	http://www.bvsde.paho.org/bvsacd/cd47/texas/cap6.pdf
Urea Reaction	http://eel.ecsdl.org/content/4/10/E5.full

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Response to Comment 2-1

The Draft Staff Report includes a discussion of the cost-effectiveness for implementation of PAR 1110.2. Staff has reviewed the information provided on cost-effectiveness as discussed in more detail in the Response to Comment # 2-2.

Response to Comment 2-2

Some assumptions that are presented in your cost-effectiveness calculations of $51,467 per ton of NOx reduced differ from the ones used to evaluate cost-effectiveness for PAR 1110.2. For example, staff assumes a uniformed series present worth factor at a 4% interest rate and a 25-year equipment life expectancy, while your analysis is based on an interest rate of 5.5% with a useful life of 15 years. Staff assumptions for the cost-effectiveness analysis is consistent with other rulemakings such as Rule 1134 for turbines which was amended in March 2019 and Rule 1135 for electrical generating facilities which was amended in November 2018. The cost-effectiveness threshold of $50,000 per ton of NOx reduced is based on the 2016 Air Quality Management Plan cost-effectiveness threshold and is used as a guide for NOx rulemaking projects. This threshold is a guidance and is used to compare the average cost-effectiveness for implementation of a proposed or proposed amended rule. Compliance with the NOx emission limit may result in some units with a higher and some units with a lower cost-effectiveness than $50,000 per ton of NOx reduced. The average cost-effectiveness for 4-stronke lean burn engine category is $35,500 per ton of NOx reduced.

Response to Comment 2-3

Currently, limiting an engine that is rated at or greater than 1,000 bhp by permit conditions to 1,000 hours per year or a fuel usage of less than 8 x 10^9 Btus per year (higher heating value of all fuels used) may provide relief from equipping an engine with CEMS [Rule 1110.2 (f)(1)(A)(ii)(III)]. However, there is no similar provision for exempting an engine from meeting the NOx standard of 11 ppmvd @ 15% O_2 if the engine is limited by permit conditions to 1,000 hours per year or a fuel usage of less than 8 x 10^9 Btus per year (higher heating value of all fuels used). Under PAR 1110.2 engines that are operated less than 500 hours per year or use less than 1 x 10^9 Btus per year (higher heating value of all fuels used), the NOx, CO, and VOC emission limits are either Table II (Low-Use) or Table III-A (Low-Use) are applicable.

Response to Comment 2-4

Thank you for your comment.

Response to Comment 2-5

Thank you for your comment.

Response to Comment 2-6
Staff similarly calculated a reduction in NOx emissions by taking the difference in emission rates from a 50 ppmvd level to an 11 ppmvd level (@ 15% O_2) for each engine. Staff calculated emissions based on the previous year's operating information and source testing data as provided by Snow Summit.

Response to Comment 2-7
Thank you for providing estimates on your system upgrades. Appendix A includes capital and annual cost estimates used for the cost-effectiveness analysis. The Draft Socioeconomic Analysis includes additional details of the cost assumptions.

Response to Comment 2-8
Staff recognizes that the CEMS for the engines are currently uncertified. It was conservatively assumed that the CEMS would be installed at a cost of $120,000 per unit with an annual cost of $10,000 per CEMS. Proposed Amended Rule 1110.2, clause (f)(1)(A)(i) does not require a NOx or CO CEMS for engines greater than 1,000 bhp that are operate less than 2 million bhp-hours per calendar year.

Response to Comment 2-9
A 25-year useful life for an SCR is consistent with the useful life used for other rule projects where SCR is used. The useful life covers the equipment and installation. The Tiered standards for engines apply to new engines and are not the same as retrofit emission limits in Rule 1110.2. In addition the references to state requirements are for mobile and portable diesel engines, and focuses on replacements, which is different than limits for existing stationary engines.

The last major amendment to the NOx emission standard was in 2008 which required the 11 ppmvd. During this rule development process, staff conducted another BARCT analysis and concluded that 11 ppmvd still represents BARCT, and the eleven year-old NOx limit will be retained. If the NOx emission limit for diesel engines is re-assessed in the future, staff would conduct a full BARCT analysis that includes an evaluation of the cost-effectiveness taking into consideration the useful life of the equipment. As a result, staff believes that a 25-year useful life for SCR is appropriate.

Response to Comment 2-10
Staff uses a 4% interest rate consistent with other similar rulemaking efforts and analysis.

Response to Comment 2-11
Staff recognized that the facility already operates an SCR on each of the six generator engines. The cost-effectiveness analysis used similar assumptions for operation and maintenance (O&M).

Response to Comment 2-12
The cost of particulate filters was not included in the cost-effectiveness analysis since PAR 1110.2 addresses NOx emissions, and the engines are already required to meet the CO and VOC concentration limits. Staff considers retrofits to control diesel particulate emissions outside the scope of PAR 1110.2 since PM emissions are not addressed in this rule or its proposed amendments. Rule 1470 addresses diesel PM from engines. There is no expected change to PM emissions from the retrofit of the SCR as the ammonia slip emission limits will remain the same or be lower.

Response to Comment 2-13
Staff used a 3-year operational expectancy for the catalyst life. The catalyst replacement cost is annualized based on a three-year cycle. Typically, the engines operated at the facility do not run for more than 1,000 hours per year. So, it is possible that the catalyst can be used well beyond the assumed three-year replacement cycle.

Response to Comment 2-14
It is unclear why the commenter assumes that the SCR will be demolished and removed. Staff assumed the continued use of existing infrastructure and equipment.

Response to Comment 2-15
Any additional pressure drop was considered negligible due to new catalyst designs and manufacture.

Response to Comment 2-16
Additional cost for an increase in urea usage was included, but staff assumed the continued use of existing infrastructure and equipment.

Response to Comment 2-17
Permitting costs were not included in the capital costs that were subsequently annualized but were considered as initial, one-time costs and with associated renewals.

Response to Comment 2-18
Thank you for your comment.

Response to Comment 2-19
Staff estimates that the average cost-effectiveness for the six engines is $51,467 per ton of NOx reduced which includes SCR and CEMS. In light of some differences in assumptions, the

calculated value of $51,332 per ton of NOx reduced provided in the comment letter is comparable. Please note that using a threshold of $50,000 per ton of NOx reduced is used as a guidance. As a whole for all affected engines, the transition of engines from the RECLAIM program over to a command-and-control regulatory structure is $35,500 which is below the $50,000 per ton of NOx reduced threshold. In cases where unique circumstances or exorbitant costs exists, provisions may be made to accommodate or to reduce negative impacts arising from these situations. Calculating the cost effectiveness at $51,332 per ton of NOx reduced does not appear to meet a situation of uniqueness or exorbitant costs relative to other affected engines.

Response to Comment 2-20

Based on staff's assumptions and calculations, the cost-effectiveness value calculated for the category of engines at this facility is $35,500 per ton of NOx reduced. It is expected that if the facility were to re-evaluate their data instead with a 4% interest rate and a 25-year equipment life expectancy, the cost-effectiveness for this category would remain below $50,000 per ton. Moreover, staff evaluated cost-effectiveness based on actual reported NOx emissions and on actual hours of operation. Staff did not conduct its evaluation based on 1,000 hours of operation or associated emission levels at this level of hours of operation. There do exist differences in what the facility considered as part of their potential retrofit and upgrade costs; but, with the facility's basis of a higher operational level (higher emission levels), the cost effectiveness calculations in the end were similar to what staff calculated.

Response to Comment 2-21

Thank you for your comment.

Response to Comment 2-22

The facility's operation is seasonal. Data for the past two compliance years shows that individual engines operated between 148 hours and 490 hours. Assuming that operation continues at about 500 hours per year, then if 10,000 hours to 12,000 hours is used as a milestone, then a theoretical operational life would be between 20 years to 24 years before a major engine overhaul or potential complete replacement would be necessary. With this consideration, then using a 25-year basis seems appropriate.

Response to Comment 2-23

As previously discussed, the cost-effectiveness threshold of $50,000 per ton of NOx reduced is based on the 2016 Air Quality Management Plan cost-effectiveness threshold and is used as a guide for NOx rulemaking projects. This threshold is a guidance and is used to compare the average cost-effectiveness for implementation of a proposed or proposed amended rule.

Response to Comment 2-24

Staff does not consider limiting operation to 1,000 hours as an option. At this time, an alternate option is to limit operation to less than 500 hours where the engines may meet the emission levels for a low-use engine. Table II sets a NOx emission level of 36 ppmvd for engines rated greater than 500 bhp. Taking this option would be at the discretion of the facility and should be incorporated into their operating permit.

Response to Comment 2-25
Currently, an engine may be permitted and operated as either a prime engine or an emergency engine. As an emergency engine, the provisions of subdivision (d) do not apply to the engine. If an engine is not subject to the provision of paragraph (d)(1), then no CEMS would be required. Rule 1110.2 currently limits emergency engines to operate no more than 200 hours per year. An example of an emergency would be in response to an unplanned power interruption where the safety of staff or the facility is of critical importance.

Response to Comment 2-26
Staff concurs that averaging over a longer period of time may allow a facility to account for transient load changes and other normal engine operating fluctuations. As such, staff is including an option in the rule to allow for a 1-hour averaging period with engines equipped with CEMS.

Response to Comment 2-27
Thank you for your comment.

Comment Letter No. 3 – Wärtsilä North America

WÄRTSILÄ

Wärtsilä North America Inc.

August 13, 2019

Mr. Rodolfo Chacon
Planning, Rule Development and Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: Proposed Amendments to Rule 1110.2

Dear Mr. Chacon:

Wärtsilä North America greatly appreciates the time and effort the District has spent in evaluating proposed changes to Rule 1110.2. As Wärtsilä discussed at a meeting with District staff in 2015, Wärtsilä has developed an advanced reciprocating engine control system that is capable of meeting the South Coast AQMD's stringent requirements for Best Available Control Technology, including the numerical limits contained in District Rule 1110.2. At that time (in 2015), we had proposed that the District revise the rule to provide additional flexibility in meeting the 15-minute average compliance requirement while preserving the operational flexibility that our clients need to operate in a modern electrical grid that includes a substantial input from intermittent renewable resources such as wind and solar. 3-1

As you know, Rule 1110.2, Section (d)(L) requires that all (non-emergency) electrical generators meet the emissions specified in Table IV.

TABLE IV
EMISSION STANDARDS FOR NEW ELECTRICAL GENERATION ENGINES

Pollutant	Emission Standard (lbs/MW-hr)[1]
NOx	0.070
CO	0.20
VOC	0.10[2]

1. The averaging time of the emission standards is 15 minutes for NOx and CO and the sampling time required by the test method for VOC, except as described in the following clause. 3-2
2. Mass emissions of VOC shall be calculated using a ratio of 16.04 pounds of VOC per lb-mole of carbon.

Since our meeting with District staff in 2015, Wärtsilä has confirmed its ability to comply with the rule as written, if necessary. However, Wärtsilä believes that the steps we need to take to meet these stringent limits on a 15-minute average basis will inhibit the ability of our customers to take full advantage of our technology's ability to respond to rapid fluctuations in demand in an electrical grid

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increasingly dominated by generation from intermittent resources. This 15-minute averaging period is relatively unique in District rules, and it is not tied to any ambient air quality standard. 3-2 Cont.

In the July 19, 2019 draft PAR 1110.2, the District has acknowledged the need for, and benefit of, providing additional operating flexibility for some classes of engines subject to the Rule. For example, Staff has proposed language allowing a 60-minute averaging period for the applicable NOx emission limit for certain engines subject to the requirements of Table II, and current rule 1110.2 allows up to 24-hour averaging for certain biogas engines subject to the requirements of Table III-B. The staff report for PAR 1110.2 indicate that these longer averaging periods are intended to facilitate compliance for certain two-stroke engines used for gas compression and which are equipped with post-combustion emission controls, and for certain engines using biogas (also when equipped with post-combustion controls). The challenges faced by the operators of these engines (transient operating loads and/or varying fuel composition) are similar to those faced by operators of Wärtsilä's engines for electric power generation with advanced emission controls in an environment in which the incremental demand for electricity can vary significantly within a matter of seconds due to changes in generation by wind and solar resources. Since the average emissions from our engines will be below the Table IV limits of 0.070 / 0.20 / 0.10 pounds per megawatt-hour on an hourly average basis regardless of whether compliance is assessed on a 15-minute or 60-minute average basis, no increase in emissions is associated with this proposed revision. 3-3

We therefore request that the footnote (1) to Table IV be modified as follows:

(1) The averaging time of the emission standards is 15 minutes for NOx and CO and the sampling time required by the test method for VOC, except as described in the following clause. For owners and operators of any new engine installation with catalytic controls, an averaging time of 60 minutes shall be used for demonstrating compliance with the NOx and CO requirements of Table IV.

We believe that this change provides an environmental benefit in that it will allow Wärtsilä's engines to provide even more flexibility to our customers as they integrate ever-larger fractions of renewable generation while delivering clean, flexible, efficient power to the grid. 3-4

Sincerely,

Matthew Fisher
Senior Sales Manager, Wärtsilä North America

Response to Comment 3-1

South Coast AQMD appreciates your comment letter submitted for the proposed amendments to Rule 1110.2. Staff has proposed options to provide additional flexibility in meeting the 15-minute average compliance requirement. Staff is recommending an averaging time of 1 hour for units equipped with CEMS.

Response to Comment 3-2

See Response 3-1.

Response to Comment 3-3

See Response 3-1.

Response to Comment 3-4

See Response 3-1.

Comment Letter No. 4 – Southern California Alliance of Publicly Owned Treatment Works

SOUTHERN CALIFORNIA ALLIANCE OF PUBLICLY OWNED TREATMENT WORKS

August 14, 2019

Mr. Kevin Orellana, Program Supervisor
Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

Dear Mr. Orellana:

Re: Comments on Proposed Amended Rule 1110.2

The Southern California Alliance of Publicly Owned Treatment Works (SCAP) appreciates this opportunity to provide comments on Proposed Amended Rule 1110.2. SCAP represents 83 public agencies that provide essential water supply and wastewater treatment to nearly 19 million people in Los Angeles, Orange, San Diego, Santa Barbara, Riverside, San Bernardino and Ventura counties. SCAP's wastewater members provide environmentally sound, cost-effective management of more than two billion gallons of wastewater each day and, in the process, convert wastes into resources such as recycled water and biogas.

The purpose of this letter is to expand upon comments provided by our members at the July 31, 2019 Public Workshop. We greatly appreciate SCAQMD's acknowledgment that it is challenging for biogas engines to comply with Rule 1110.2. Due to the differences between natural gas and biogas, we believe that the biogas requirements contained in Rule 1110.2 should be moved to Proposed Rule 1179.1. Our specific comments on the July 2019 version of Proposed Amended Rule 1110.2 are outlined below. 4-1

Ammonia Limit (d)(1)(B)(vii)

This proposed provision establishes an ammonia limit of 5 ppmv, corrected to 15% O_2 and averaged over 60 minutes for any new or retrofit engine installation with selective catalytic reduction (SCR) pollution control equipment. While we appreciate this requirement would only apply to new installations with an SCR, the lower limit can be challenging for biogas engines to achieve. Biogas contains contaminants derived from waste discharged to the sanitary sewer system and tends to cause accelerated catalyst degradation. Accordingly, SCAP requests the ammonia limit for biogas engines with SCR be established at 10 ppmv, corrected to 15% O_2 and averaged over 60 minutes. 4-2

CEMS Applicability (e)(3)

One of our members elected to install an SCR system on their biogas engine at a minor source facility. 4-3

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Mr. Orellana August 14, 2019

The operation of the SCR and CEMS has proved to be more difficult and time-consuming than anticipated. Rather than shutting-down their engine and flaring biogas from the wastewater treatment process, this facility went the extra mile to beneficially use this waste gas. We would appreciate providing some relief for this facility, which happens to be the only biogas engine non-Title V facility with a CEMS. 4-3 cont.

CEMS Averaging Time (d)(1)(I)

Longer averaging period would be allowed by proposed provision (d)(1)(I), if the operator demonstrates through CEMS data that the engine meets 90% of the emission limits of Table III-B. Provisions (d)(1)(I) and (f)(1)(D)(i) require facilities with biogas engines using longer averaging period to submit an I&M plan even for those engines that are equipped with NOx and CO CEMS and include all items listed in Attachment 1. At the July 31st Public Workshop, Staff clarified that only Attachment 1, Item G is required for those engines with CEMS utilizing longer averaging period. In order to clarify that no other I&M requirements are triggered, we request that Item G in the Attachment 1 be moved to (d)(1)(I) or referenced as Attachment 2. 4-4

Source Testing (f)(1)(C)(i)

This proposed provision requires source testing at least once every two years (within the same calendar month of the previous source test), or every 8,760 operating hours, whichever occurs first. For those facilities with multiple engines, it is less burdensome to test the engines during one event rather than testing at different dates based on each engine's operating hours. Oftentimes the testing of multiple engines can take two months or more. The proposed wording "within the same calendar month of the previous source test" implies that each engine must be tested in the exact same month as the previous test and does not allow any flexibility to accommodate operational or scheduling limitations. We request the deletion of the proposed wording in this provision.

The same provision allows RATA required by Rule 218.1 or 40 CFR Part 75 Subpart E to satisfy the source test requirements for those pollutants monitored by CEMS. NOx and CO RATA is typically conducted at one load (e.g. maximum load) only whereas (f)(1)(C)(ii) requires source testing at three different loads – normal, max and min. Please confirm using one maximum load will satisfy both the RATA and source testing requirements. 4-5

Last, but not least, (f)(1)(C)(i) allows an extension of the source test deadline, if the engine has not been operated within three months of the source test due date. We request this provision not be limited to just a long-term shutdown of the engine, but any length of shutdown due to unforeseen maintenance or repair events.

Ammonia Testing (f)(1)(C)(iii)

This proposed provision requires quarterly ammonia source testing during first 12-months of operation of the SCR not utilizing certified ammonia CEMS and annually thereafter. It appears that this requirement applies only to the new or retrofit engine installation. However, during the July 31st Public Consultation meeting, Staff noted that this requirement also applies to the existing engine installation with SCR, if an engine does not pass the annual testing. Source testing engines is not only expensive, but laborious. Source testing requires extensive facility's operations and maintenance resources to execute without disrupting other critical operations. We respectfully 4-6

2

Mr. Orellana August 14, 2019

request to require ammonia testing concurrent with existing source test requirements. This is consistent with the statement in page 3-7 of the Preliminary Draft Staff Report which states that "the requirements for ammonia source testing would mirror those that exist and that are proposed for NOx, VOC, and CO (e.g., source testing deadline extension and the source testing interval between tests)". 4-6 cont.

In addition, biogas engines with NOx CEMS that utilize inlet ammonia analyzers to "estimate" ammonia slip should be not be required to perform additional source testing for ammonia.

Thank you for the opportunity to comment on Proposed Amended Rule 1110.2. If you have any questions regarding our concerns or recommendations, please do not hesitate to contact Mr. David Rothbart of the Los Angeles County Sanitation Districts, SCAP Air Quality Committee Chair at (562) 908-4288, extension 2412.

Sincerely,

Steve Jepsen, Executive Director

cc: Ms. Susan Nakamura, SCAQMD
Mr. Mike Morris, SCAQMD

3

Response to Comment 4-1

South Coast AQMD appreciates your comment letter submitted for the proposed amendments to Rule 1110.2. Staff is currently working on Proposed Rule 1179.1 and has not yet decided if engines at Public Owned Treatment Works (POTWs) should stay in Rule 1110.2 or be moved into Proposed Rule 1179.1. A provision has been added in PAR 1110.2 paragraph (i)(3) that states that "the provisions of this rule [Rule 1110.2] shall not apply to units located at landfills or publicly owned treatment works that are subject to a NOx concentration limit in a Regulation XI rule adopted or amended after *[Date of Amendment]*." This provision will provide the South Coast AQMD staff the flexibility to move engines subject to POTWs in Proposed Rule 1179.1 if that is the decision.

Response to Comment 4-2

The initial proposed amended Rule 1110.2 contained a provision for an ammonia limit of 5 ppmvd @ 15% O2 for a new SCR installation or retrofit. However, staff has reviewed the addition of ammonia emission limits into the rule. The requirements for ammonia limits will be deferred to the permit evaluation process for new installations of SCRs. BACT may apply for any proposed increases in emissions. For existing retrofitted SCRs, ammonia limits may be specified in a permit to operate based on what is achieved in practice in similar installations.

Response to Comment 4-3

PAR 1110.2 includes a provision for Essential Public Service facilities that are operating a biogas engine that is between 1,000 and 1,200 bhp which allows an alternative compliance approach of conducing diagnostic emission checks weekly instead of using CEMS.

Response to Comment 4-4

PAR 1110.2 includes a provision for biogas engines equipped with CEMS that allows a 48-hour averaging period provided the engine can meet a NOx emission limit of 9.9 ppmvd and a CO emission limit of 225 ppmvd.

Response to Comment 4-5

Your concerns regarding when a source test is conducted and what happens if delays occur are noted. Staff has revised PAR 1110.2 to address your concerns. Under PAR 1110.2, conducting a source test should be timely and completed before any compliance due date. However, staff recognizes that operators may require flexibility on testing. To balance these interests, staff is proposing that a test be conducted no later than the month in which the previous testing was done. If the facility wants to do so before, then it can. However, the month when a subsequent test is done will be reset to that new month. Staff does not want to see situations where testing is somehow extended past the prescribed frequency of testing. The rule has also been revised to allow for unexpected shutdowns of equipment prior to a source test being conducted. If an owner or an operator however does shutdown an engine for operational considerations not due to unexpected factors prior to a testing deadline, then the engine will be tested within a reasonable time once it returns to service.

Response to Comment 4-6

During the Public Workshop forum, staff may have miscommunicated the applicability for ammonia testing. The initial proposed rule had targeted new SCR installations or retrofits to existing equipment. However, staff has reviewed the addition of ammonia emission limits into the rule. The requirements for ammonia limits was removed from PAR 1110.2 and will be deferred to the permit process evaluation for new installations of SCRs. BACT will apply for any proposed increases in emissions.

Comment Letter No. 5 – Montrose Environmental

MONTROSE ENVIRONMENTAL

August 14, 2019

Mr. Kevin Orellana
Program Supervisor
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

Subject: **Proposed Amended Rule 1110.2 – Emissions from Gaseous and Liquid-fueled Engines Compliance Demonstration Averaging Period**

Dear Mr. Orellana:

During the July 31, 2019 Rule 1110.2 public workshop, SCAQMD indicated that at least one facility operator had expressed concern regarding the 15-minute averaging period that is used to demonstrate compliance with NOx and CO emission standards. Montrose works with many engine and emission control system manufacturers, data acquisition system (DAS) developers and facility operators. We agree that the 15-minute averaging period is inappropriate when demonstrating compliance with the distributed generation emission standards of Rule 1110.2.

Unlike most rules that specify emission concentration limits, Rule 1110.2 specifies mass emission limits that are normalized to generator power output. A Rule 1110.2 DAS must correlate emission concentrations with independent operating parameters to calculate a mass emission value. The DAS must then correlate the mass emission value with independent generator output data in order to determine compliance with a lb./MW-hr. standard. 5-1

The ability to manage load swings is a necessity as facility owners build hybrid systems that incorporate renewable energy sources to accommodate fluctuating demands. During abrupt engine operation shifts, however, changes in engine operations may not directly correlate with changes in generator output and the temporary data. The short-term inconsistencies can result in perceived excess NOx or CO emissions when measured as lb./MW-hr. during a 15-minute averaging period. These perceived noncompliance events occur even when emission concentrations are stable and within reasonable ranges.

Montrose suggests that amendments to Rule 1110.2 include a 60-minute averaging period when a CEMS is used to determine compliance with NOx and CO emission limits. The 60-minute averaging period also complements the way in which compliance is determined for gas turbine installations that are regulated pursuant to Rules 1134 and 1135. 5-2

Montrose welcomes the opportunity to discuss Rule 1110.2 averaging periods with SCAQMD and we are happy to engage other stakeholders as warranted. You can reach me at (714) 282-8240 if you would like to discuss this matter further. Otherwise, I look forward to the upcoming working group meeting.

Sincerely,
Montrose Environmental Solutions

Karl S Lany

Karl Lany
District Manager
Rule 1110.2 8-14-19

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www.montrose-env.com

Response to Comment 5-1

South Coast AQMD appreciates your comment letter submitted for the proposed amendments to Rule 1110.2. Staff concurs that averaging over a longer period of time may allow a facility to account for transient load changes and other normal engine operating fluctuations. As such, staff is including an option in the rule to allow for a 1-hour averaging period with engines equipped with CEMS.

Response to Comment 5-2

See Response 5-1.

Comment Letter No. 6 – Hoag Hospital, Newport Beach

hoag
HOAG MEMORIAL HOSPITAL PRESBYTERIAN
One Hoag Drive, PO Box 6100
Newport Beach, CA 92658-6100

August 19, 2019

Mr. Kevin Orellana
Program Supervisor
Planning, Rule Development, and Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765
Work: (909) 396-3492
E-mail: KOrellana@aqmd.gov

Subject: **Proposed Rule Language to Allow Engines with CEMS to Average Emissions Over 60 Minutes; Proposed Amended Rule 1110.2 (August 2019)**

Dear Mr. Orellana:

We reviewed the updated version of Proposed Amended Rule 1110.2 dated August 2019 in preparation for Working Group Meeting #6.

Hoag Hospital supports the added language under paragraph (f)(1)(A)(x) which allows engines with CEMS to average emissions on an hourly basis. We appreciate the District's willingness to accommodate Hoag's request to increase the emission averaging time from 15 to 60 minutes for their cogeneration engines in Newport Beach. 6-1

However, we are concerned about the potential for confusion over the emission limit requirements since this language is proposed for Section (f) *Monitoring, Testing, Recordkeeping and Reporting*. One might interpret the requirements in Section (d), which establish emission limits with a 15-minute average, to also apply. It would be clearer to list an alternative emission standard in Section (d) for engines monitored by a CEMS, similar to the alternative requirements for other engine types:

- (d)(1)(B)(v) – 24 hours for engines combusting non-pipeline quality natural gas; and 6-2
- (d)(1)(B)(v) – 180 minutes for compressor gas lean-burn engines with SCR.

Another option may be to include this language under an exemption in Section (i).

We appreciate your assistance in addressing this matter.

Sincerely,

Erik Lidecis
Manager of Utilities/Operations
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cc: Duane Suby, Hoag Hospital
Corina Chang, Yorke Engineering
Peter Moore, Yorke Engineering
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Response to Comment 6-1

South Coast AQMD appreciates your comment letter submitted for the proposed amendments to Rule 1110.2. Staff concurs that averaging over a longer period of time may allow a facility to account for transient load changes and other normal engine operating fluctuations. As such, staff is including an option in the rule to allow for a 1-hour averaging period with engines equipped with CEMS.

Response to Comment 6-2

Staff has amended the rule where the averaging provision is located. The proposed 1-hour averaging will be located in section (d).

Comment Letter No. 7 – City of Glendale

CITY OF GLENDALE, CALIFORNIA
Glendale Water & Power
Administration

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August 19, 2019

Mr. Kevin Orellana
Program Supervisor
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

Subject: **Proposed Amended Rule 1110.2 – Emissions from Gaseous and Liquid-fueled Engines; Compliance Demonstration Averaging Period**

Dear Mr. Orellana:

The City of Glendale Department of Water and Power (GWP) is taking steps to modernize the Grayson Power Plant. Based upon many technical proposals that were evaluated in response to Glendale's 2018 Clean Energy Request for Proposals, GWP plans to develop a hybrid solution that integrates energy efficiency, distributed photovoltaic installations, and new demand reduction programs throughout the City, as well as 50-75 megawatts of battery storage, and approximately 95 MW of fossil-fueled power generation at the Grayson Power Plant.

The proposed new power generation system will be comprised of reciprocating internal combustion engine technology that will:

- provide a lower and flatter heat rate across the range of operating loads relative to gas turbine alternatives, and 7-1
- With a smaller individual unit size, provide a lower and more efficient minimum load than the gas turbine alternatives.

Taken together, the proposed reciprocating internal combustion engines and their ability to operate flexibly and efficiently is especially important due to their role in supporting GWP's proposed hybrid generation program and reliance upon the regional transmission of renewable and otherwise carbon-free electricity into the City of Glendale.

GWP's proposed engines would be subject to the distributed generation emission limits of SCAQMD Rule 1110.2 which are measured in lb./MW-hr. and averaged over a 15-minute period. GWP is concerned that the 15-minute averaging period, when combined with the complexity of simultaneously measuring mass emissions and power output, will complicate the effective management of the electricity system given the dynamics of the renewable energy sources, distributed generation, and a constrained electrical transmission system that GWP must rely upon. In this environment, the ability to effectively 7-2
manage fluctuations in both demand and generation is dependent upon the ability to quickly cycle engine load.

Based upon feedback from engine and emission control system vendors, correlating emission monitoring data with independent engine and generator operating parameters to obtain a lb./MW-hr. value within a

Mr. Kevin Orellana Page 2 August 19, 2019

15-minute averaging period may lead to perceived excess emissions, even when emission concentration values are stable and within an expected range. Because of the way in which compliance is determined, the data acquisition handling system must corelate emission concentrations with independent operating parameters such as fuel flow rates, temperature, and moisture to obtain a mass emission value and then correlate that value with independent generator output data in order to determine compliance with Rule 1110.2.

During rapid engine load swings, short-term changes in engine and emissions data may not directly correlate with changes in generator output data. The temporary data inconsistencies can result in perceived excess NOx or CO emissions when measured as lb./MW-hr. during a 15-minute interval. Those inconsistencies, however, would be less prone to distort lb./MW-hr. emission rates when measured on a 60-minute basis. With a 60-minute averaging period, GWP would be able to more efficiently track load swings and accommodate the diverse energy portfolio that we are obligated to manage. 7-2 cont.

GWP requests SCAQMD to allow compliance with the Rule 1110.2 distributed generation emission limits to be determined based upon a 60-minute average when a CEMS is in use. GWP also reminds SCAQMD that the NOx emission limits of Rule 1110.2 were intended to closely reflect what can be achieved by a gas turbine and SCAQMD Rules 1134 and 1135 specify a 60-minute averaging period. In this respect, instituting a 60-minute averaging period for Rule 1110.2 distributed generation systems would be an equitable action. 7-3

GWP welcomes the opportunity to discuss Rule 1110.2 averaging periods with SCAQMD and we are also happy to engage engine, emission control system and emission monitoring system vendors in those discussions as warranted. You can reach me at (818) 548-2107 if you would like to arrange for a follow-up conversation.

Sincerely,

Stephen M. Zurn
General Manager, Glendale Water & Power

Response to Comment 7-1
South Coast AQMD appreciates your comment letter submitted for the proposed amendments to Rule 1110.2.

Response to Comment 7-2
Staff concurs that averaging over a longer period of time may allow a facility to account for transient load changes, other normal engine operating fluctuations, and temporary data inconsistencies. As such, staff is including an option in the rule to allow for a 1-hour averaging period with engines equipped with CEMS.

Response to Comment 7-3
See Response 7-2

Comment Letter No. 8 – Beta Offshore

Beta OFFSHORE

August 20, 2019

Kevin Orellana, Program Supervisor
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-0830

Subject: Beta Offshore comments for PAR 1110.2 Emissions from Gaseous - and Liquid-Fueled Engines

Dear Mr. Orellana,

Beta Offshore attended Working Group #6 for Proposed Amended Rule (PAR) 1110.2 and would like to offer the following comments and recommendations for inclusion in the proposed Rule 1110.2 language update for Emissions from Gaseous and Liquid Fueled Engines. Beta maintains that the SCAQMD should include rule provisions which allow our newly installed Tier 4 crane engines operated on our platforms located 9 miles offshore in the Outer Continental Shelf (OCS) to comply with the PAR without the need for additional source testing beyond what is already required by permit to demonstrate compliance with Best Available Control Technology (BACT). The comments are summarized as follows: 8-1

1) Beta requests an exemption to the provisions of subdivision (d) for crane engines operating in the OCS provided that the facility operate engines certified by CARB to meet Tier 4 emissions standards and which are considered BACT. 8-2
2) Tier 4 engines that meet BACT have been used by the SCAQMD as a basis for demonstrating compliance with Rule 1110.2 as stated in existing exemptions for agricultural stationary engines. Beta requests this precedent extend similarly to crane engines operating in the OCS. R1110.2 (i)(1)(I)(ii) & (iii) 8-3
3) Source testing in accordance with subsection (f)(1)(C) will not apply to crane engines operating in the OCS because these engines will not be subject to the provisions of paragraph (d)(1). 8-4

Thank you for your cooperation and consideration of these requests for inclusion to Proposed Amended Rule 1110.2. If you have any questions, please don't hesitate to contact me via phone at 562-628-1529 or via e-mail at diana.lang@amplifyenergy.com .

Sincerely,

Diana Lang

Diana Lang
HSE Manager, Beta Offshore

Response to Comment 8-1

South Coast AQMD appreciates your comment letter submitted for the PAR 1110.2. Staff recognizes the challenges that source testing your equipment can involve; however, based on operational utilization, source testing may be required once every two or three years. Based on the NOx limit under Rule 1110.2, all new diesel engines must be Tier IV Final. It is important to note that the certification process is much different than the source testing requirement. The certification is a laboratory test where the engine is tested at a higher load than normal operating conditions. The certification process does not require that each engine be tested, but that an engine in the family be tested. Under PAR 1110.2, the purpose of the source test is to capture the emissions under normal operating conditions and to periodically verify that the engine is maintaining those emissions.

Response to Comment 8-2

Staff has considered your request for an exemption to the provisions of subdivision (d) for cranes operating in the Outer Continental Shelf (OCS) waters provided that the facility operate engines certified by CARB to meet Tier 4 emissions and which are considered BACT. Staff acknowledges that crane operations at an offshore platform have unique challenges. Staff has offered an alternative emission limit where the operator could conduct a source test to establish an emission factor specific to the duty cycle of the crane, with a concentration cap of 45 ppm which is four times the NOx concentration limit for most other engines. The facility's response to this proposal was a complete exemption and they declined staff's proposal. As a result, staff removed the proposed revision. Staff believes that a complete exemption from subdivision (d) is not appropriate and period source testing is needed to confirm the emissions from the engine on an ongoing basis.

Response to Comment 8-3

Staff has reviewed the "agricultural" exemption contained in Rule 1110.2 (i)(1)(I). This exemption *does not* provide a complete absolution from any and all emission limits. These certified engines must still meet the Tier 4 emission standards of 40 CFR Part 1039, Section 1039.101, Table 1. For engines with a maximum engine power between 56 kW and 560 kW, Table 1 gives a NOx emission standard of 0.40 g/KW-hr which converts to approximately 22 ppmvd @ 15% O_2. In addition, the operator *may not* operate the Tier 4 engines in a manner that exceeds the not-to-exceed standards of 40 CFR Section 1039.101, Paragraph (e) as determined by the appropriate source test. The not-to-exceed NOx emission standard set by Paragraph (e) is calculated to be approximately 33 ppmvd @ 15% O_2.

Response to Comment 8-4

Staff has reviewed your request to exempt engines operating in the OCS from source testing assuming that these engines are not subject to the provisions of paragraph (d)(1). At this time, staff is not considering an exemption from paragraph (d)(1) for engines operating in the OCS. Therefore, these engines would still be subject to source testing requirements. Moreover, if the "agricultural" exemption were to be adopted as suggested by Comment 8-3, some measure of compliance determination would still be required via source testing. Lastly, staff acknowledges that there exist concerns with source testing these engines related to personnel safety, undue equipment stress and what constitutes an operating cycle. With input from the South Coast AQMD's source testing group, a source testing protocol is being developed that should address these concerns.

Comment Letter No. 9 (received as an email) – Eastern Municipal Water District

Kevin Orellana

From: Torres, Alison <torresa@emwd.org>
Sent: Tuesday, August 20, 2019 11:22 AM
To: Kevin Orellana
Subject: Proposed Rule 1110.2 Comments-Ammonia Test Frequency

Good morning Kevin,

Thank you for the discussion at today working group meeting. I would like to reiterate the request to clarify that the added ammonia testing provisions in the proposed amended rule applies to new installations. We have an existing installation with extremely low ammonia concentrations. We are currently required to test ammonia concurrently with our Rule 1110.2 (NOx, CO, VOC) testing. It is burdensome to require more frequent testing for this installation, especially when our results are very low. The last ammonia test was required in 2018 with results <1 ppm. Based on the current proposed language, upon rule adoption, this installation would not meet the requirements of the rule due to the annual requirement. 9-1

13. THE AMMONIA SLIP SHALL BE TESTED CONCURRENTLY WITH THE REQUIRED RULE 1110.2 ENGINE TESTING, USING AQMD APPROVED TEST METHODS. RECORDS OF THE AMMONIA SLIP TESTS SHALL BE KEPT FOR AT LEAST FIVE YEARS AND BE MADE AVAILABLE TO DISTRICT PERSONNEL UPON REQUEST.

Please let me know if you need additional information.

Thank you,

Alison Torres
Senior Air Quality Compliance Analyst
Environmental & Regulatory Compliance Dept
Eastern Municipal Water District
(951) 928-3777, ext. 6345
torresa@emwd.org

Serving our community today and tomorrow

Response to Comment 9-1

South Coast AQMD appreciates your comment letter submitted for the proposed amendments to Rule 1110.2. Staff removed ammonia emission limits from PAR 1110.2. The requirements for ammonia limits will be deferred to the permit evaluation process for new installations of SCRs. BACT may apply for any proposed increases in emissions.

Comment Letter No. 10 – EtaGen

ETAGEN

August 21, 2019

Mr. Michael Morris
Planning and Rules Manager
Planning, Rule Development, and Area Sources
South Coast Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765

Re: EtaGen Comments on Proposed Amended Rule 1110.2, Emissions from Gaseous- and Liquid-Fueled Engines

Dear Mr. Morris

EtaGen appreciates the opportunity to submit comments on Proposed Amended Rule 1110.2 (PAR 1110.2), Emissions from Gaseous- and Liquid-Fueled Engines. Driven by its mission to advance global access to low-carbon, dispatchable energy, EtaGen has developed a new category of power generation — the linear generator. EtaGen's linear generator has the ability to deliver on-site, fuel-flexible power at a lower cost than the electric grid due to its high efficiency.

EtaGen's linear generator uses a low-temperature reaction of air and fuel to drive magnets through copper coils to efficiently produce electricity. The patented design and adaptive control enable high efficiency, near-zero NOx emissions, full dispatchability, and seamless switching between renewable fuels such as biogas and natural gas or propane. Additional information on our technology is available on our website.[1] 10-1

Rule 1110.2 is a command-and-control "landing" rule which establishes Best Available Retrofit Control Technology (BARCT) requirements for facilities with internal combustion engines. Under California Health and Safety Code § 40406, BARCT is defined as:

> "... an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by <u>each class or category of source</u>." [emphasis added] 10-2

[1] http://www.etagen.com/technology/

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EtaGen's linear generator technology is fundamentally different than the four engine categories currently addressed by current Rule 1110.2.[2] Attachment A presents a comparison of equipment features for various electrical generation technologies. It demonstrates that linear generators have very few features in common with traditional engines or microturbines. Because the linear generator technology has not been previously considered by the District under Rule 1110.2, EtaGen respectfully requests that a new category be added to Rule 1110.2 for linear generators. Consequently, we are also requesting a number of rule language clarifications and additions to ensure that linear generators have requirements available which are appropriate to the technology. 10-2 cont.

Our proposed language and comments are presented in the attached redline/strikeout version of PAR 1110.2 (August 20, 2019 version). We provide a brief description of these proposed language changes below:

Definitions – Subdivision (c)

- ENGINE: Add a language clarification to recognize the linear generator as a discrete category of equipment. 10-3
- LINEAR GENERATOR: New definition for the linear generator category.

Requirements – Subdivision (d)

- Section (d)(1)(L) et Seq.: Proposed amendments to specify new requirements for the new Linear Generator category. Proposed emissions standards for the linear generator category are technically feasible; a requirement of BARCT. 10-4

Compliance – Subdivision (e)

- Section (e)(5) et Seq.: Proposes language clarifications to explicitly exclude linear generators from consideration under sections applicable to other (non-linear generator) engine categories. Also proposes amendments specifying new compliance requirements for the new Linear Generator category. 10-5

Monitoring, Testing, Recordkeeping and Reporting – Subdivision (f)

- Section (f)(1)(C): Proposes language clarifications to explicitly exclude linear generators from consideration under sections applicable to other (non-linear generator) engine categories. Also proposes amendments specifying new compliance requirements for the new Linear Generator category. 10-6
- Section (f)(1)(D)(ii) et Seq.: Proposes amendments specifying new I&M requirements for the new Linear Generator category. Also makes language clarifications to explicitly exclude linear 10-7

[2] PAR 1110.2 currently groups engines in four categories based on the unique characteristics of each type of engine and the associated emissions controls available to each category: (1) Lean-Burn, 2 stroke, (2) Lean-Burn, 4 stroke, (3) Rich-Burn, and (4) Engines subject to the Air Toxics Control Measure. See Preliminary Draft Staff Report for PAR 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, July 2019.

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generators from consideration under sections applicable to other (non-linear generator) engine categories. 10-7 cont.

Attachment 1: I&M Plan Requirements

- Proposes amendments specifying new I&M requirements for the new Linear Generator category. Also makes language clarifications to explicitly exclude linear generators from consideration under sections applicable to other (non-linear generator) engine categories. 10-8

We believe these language changes would successfully resolve the issue with Rule 1110.2, which at present has not evaluated the linear generator technology and does not have suitable requirements. Adding this new class/category specific to linear generator technology would provide requirements which are appropriate for the technology, while establishing a BARCT standard which is technically feasible and cost effective. 10-9

EtaGen appreciates the District's consideration of these comments. Should you or your colleagues have any questions concerning the foregoing or need additional information, please contact me [adam.simpson@etagen.com or 610.721.5670] or our consultant, Scott Weaver at Ramboll [msweaver@ramboll.com or 213.943.6360] at your earliest convenience.

Yours sincerely,

Adam Simpson, PhD
CPO & Co-Founder
EtaGen

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Table 1. Comparison of Equipment Features for Various Electrical Generation Technologies EtaGen

Equipment feature	ICE (Lean Burn)	Microturbine (Capstone)	Microturbine (FlexEnergy)	Linear Generator (EtaGen)
Spark Plug	y			
Oil	y		y	
Flame Combustion	y	y	y	
Pistons	y			y
Cylinders	y			y
Valves	y			
Head	y			
Block	y			
Liquid Cooling	y	y	y	
Rotating Shaft	y	y	y	
Operable w/o Generator	y	y	y	
Oxidation Catalyst	y	y	y	y

Response to Comment 10-1
South Coast AQMD appreciates your comment letter submitted for the proposed amendments to Rule 1110.2. Thank you for your description on the EtaGen technology process.

Response to Comment 10-2
Staff has evaluated the linear generator process and has considered whether a new, separate category is warranted. At this time, staff does not propose to create a new class or category for this technology, but believes that this technology should be considered a compression-ignited combustion source.

Response to Comment 10-3
At this time, staff does not propose to recognize this technology as a discrete type of engine, but believes that this technology should be considered a combustion source.

Response to Comment 10-4
Concentration limits have been added in lieu of the emission standards for new electrical generating devices which are currently expressed as pounds of NOx per Mega-Watt Hour. The concentration limits were determined by converting the current standard using an assumed 40 percent engine efficiency. The basis for using a 40% thermal efficiency value is derived from information contained in a patent filing by a linear generator manufacturer. An expected thermal efficiency for a regular combustion engine is about 30%. In comparison, a linear generator has a theoretical increase in thermal efficiency to about 50%. However, to meet potential VOC requirements, this overall increase may not be realized in practice. Therefore, an average between 30% and 50% was used. So, for this rule development, 40% was used as the thermal efficiency value for this technology. In determining the equivalent emission limits, staff did not include any credit for recovered energy. The final determination of these values included a 10% rounding margin.

A manufacturer of linear generator technology has informed staff that due to the inherent low temperature of the exhaust, the oxidation catalyst cannot reach temperatures to completely oxidize VOC emissions, particularly propane emissions, to meet a VOC concentration limit of 10 ppmvd. The manufacturer has expressed that the company is working towards a solution to lower the VOC emissions. There are, however, several beneficial aspects with linear generators: low NOx emissions at start up and no ammonia emissions associated with SCR. With linear generators, the NOx concentration limit of 2.5 ppmvd can be achieved at start up with no after controls such as SCR. As a result there is no need for ammonia injection that would result in increased ammonia or PM emissions, and immediate compliance with NOx concentration limits. In other combustion technologies where SCR is used to achieve lower NOx emission limits, start-up emissions are uncontrolled until the SCR catalyst can reach optimum temperatures to control NOx emissions, which is generally 20 to 30 minutes. PAR 1110.2 includes a provision that allows engines that can achieve the NOx concentration limits at start-up with no ammonia emissions from SCR to meet an alternative VOC concentration limit of 25 ppmvd, until December 31, 2023. Any new installation after this date would be required to meet the lower VOC emission limit of 10 ppmvd in Table IV. Additionally, PAR 1110.2 includes a cap of 45 lbs of VOC per day that can be installed that are meeting the alternate VOC concentration limit of 25 ppmvd to ensure that the operational emissions would not exceed the VOC significance threshold under CEQA which is currently limited to 55 lbs of operational VOC per day.

Response to Comment 10-5

Linear generators would be required to meet the same monitoring, recordkeeping, and reporting requirements of other electrical generating engines.

Response to Comment 10-6

Linear generators would be required to meet the same monitoring, recordkeeping, and reporting requirements of other electrical generating engines.

Response to Comment 10-7

Staff advocates source testing under normal operating conditions which includes low load and high load situations. If a linear generator operates normally and exclusively at 100% of max generator net output, then testing should reflect this operation. However, if the generator operates at a lower output, then that consideration should be included in the analysis. It is possible that at a lower output, combustion is less complete which may lead to additional emissions in the engine exhaust.

Response to Comment 10-8

Diagnostic emission checks are conducted periodically as required by other engine categories. Although engines may be equipped with parametric monitoring capabilities, the diagnostic checks rely on actual emission measurements to determine performance and compliance. As such, staff advocates for the continued use of frequent and portable diagnostic testing. However, staff has proposed a provision in Attachment I that gives the operator of any type of engine the opportunity to argue their case that alternate monitoring or diagnostic tools may exhibit equivalency to requirements of this section.

Response to Comment 10-9

Thank you for your comment.

Comment Letter No. 11 (received as an email) – Orange County Sanitation District

From: Ahn, Terry
To: Michael Morris
Cc: Kevin Orellana; Rodolfo Chacon; "Rothbart, David"
Subject: Proposed Amended Rule 1110.2 August
Date: Friday, August 23, 2019 12:34:03 PM
Attachments: image001.jpg
image003.jpg

Hi Mike,

While OCSD supports SCAP's position that biogas engine requirements contained in Rule 1110.2 should be moved to Proposed Rule 1179.1, we are submitting following comments on the PAR 1110.2 August 2019 as you have requested at Tuesday's working group meeting: 11-1

(d)(1)(I) –Longer averaging time options for biogas engines

While we appreciate removal of the proposed I&M plan requirements for biogas engines using the longer averaging period, we are concerned about your proposal to remove the four-month averaging provision. When OCSD invested $30 million to retrofit eight engines with catalyst systems along with the digester gas cleaning systems, it was driven by our a long term commitment to provide a reliable power source to our two treatment plants and to ensure full compliance with Rule 1110.1 requirements long term. The four-month averaging provision has given us that assurance. Even though the retrofits have been operating without any major issues to date, we are continued to be challenged by variable siloxane, future uncertainties with food waste loadings in our influent stream, and aging of our equipment. We request that four-month averaging period provision remain for the existing biogas engines with SCRs. 11-2

(d)(1)(B)(vii) –Ammonia limit for new or retrofit SCRs

We would like to repeat SCAP's request that the ammonia limit for biogas engines with SCR be established at 10 ppmv, corrected to 15% O2 and averaged over 60 minutes. As NOx limit gets lower even the minimal increase in amount of NH3 injection can potentially cause NH3 slip to exceed the such low limit of 5 ppmv. It is especially challenging for biogas engines to meet both limits due to the contaminants in the biogas which can cause accelerated degradation of the catalysts. We request that NH3 limit for biogas engines with SCR be established at 10 ppmv, corrected to 15% O2 and averaged over 60 minutes. Furthermore, a longer averaging period for NH3 should be allowed for units with certified NH3 CEMS. 11-3

(f)(1)(C)(i) – Source Testing

As I have commented at the working group meeting, the provision that allows an extension of the source test deadline not be limited to just a long-term shutdown of the engine, but any length of shutdown due to unforeseen maintenance or repair events. 11-4

Thank you for the opportunity to comment and please let me know if you have any questions.

Terry Ahn
Orange County Sanitation District
Laboratory, Monitoring, and Compliance | Regulatory Specialist

Office: 714.593.7082
www.ocsd.com

Response to Comment 11-1

South Coast AQMD appreciates your comment letter submitted for the proposed amendments to Rule 1110.2. Staff is currently working on Proposed Rule 1179.1 and has not yet decided if engines at Public Owned Treatment Works (POTWs) should stay in Rule 1110.2 or be moved into Proposed Rule 1179.1. A provision has been added in PAR 1110.2 paragraph (i)(3) that states that "the provisions of this rule [Rule 1110.2] shall not apply to units located at landfills or publicly owned treatment works that are subject to a NOx concentration limit in a Regulation XI rule adopted or amended after *[Date of Amendment]*." This provision will provide the South Coast AQMD staff the flexibility to move engines subject to POTWs in Proposed Rule 1179.1 if that is the decision.

Response to Comment 11-2

Your interpretation of the four-month averaging option is incorrect. This option was an initial screening mechanism to allow for a 24-hour averaging to be used. Staff is clarifying this section to reinforce this requirement. In addition, PAR 1110.2 allows a 48-hour averaging time for biogas units that can meet a 9.9 ppmvd NOx concentration limit.

Response to Comment 11-3

The ammonia emission limit has been removed from PAR 1110.2. The SCR control equipment would then be subject to BACT at the time of permitting.

Response to Comment 11-4

Staff agrees with your comment and has proposed language to clarify this issue.

Comment Letter No. 12 – (received as an email) Ramboll (EtaGen)

From: Scott Weaver [mailto:MSWeaver@ramboll.com]
Sent: Friday, August 23, 2019 4:06 PM
To: Michael Morris <mmorris@aqmd.gov>
Cc: Adam Simpson <adam.simpson@etagen.com>; Scott Weaver <MSWeaver@ramboll.com>
Subject: RE: EtaGen Proposed Rule 1110.2 Comments

Hi Mike-

Following up our discussion yesterday concerning the form of a new Linear Generator standard, EtaGen would like to propose changing the emissions standards over to a concentration basis. The attached redline/strikeout file (Revision 1) reflects this change. The concentration form is similar to other rule categories and would eliminate EtaGen's concern over compliance assurance. 12-1

Should you have any questions or wish to discuss, please let us know. Happy to convene a call as needed to keep this moving.

Best regards,

Scott

M. Scott Weaver
Principal

D +1 (213) 9436360
M +1 (626) 7202015
msweaver@ramboll.com

Proposed EtaGen Changes for Linear Generators
Working Draft for Discussion Purposes

(Adopted August 3, 1990)(Amended September 7, 1990)(Amended August 12, 1994)
(Amended December 9, 1994)(Amended November 14, 1997)(Amended June 3, 2005)
(Amended February 1, 2008)(Amended July 9, 2010)(Amended September 7, 2012)
(Amended December 4, 2015)(Amended June 3, 2016)(PAR 1110.2 August 2019)

PROPOSED AMENDED RULE 1110.2 EMISSIONS FROM GASEOUS- AND LIQUID-FUELED ENGINES

(a) Purpose

The purpose of Rule 1110.2 is to reduce Oxides of Nitrogen (NO_x), Volatile Organic Compounds (VOCs), and Carbon Monoxide (CO) from engines.

(b) Applicability

All stationary and portable engines over 50 rated brake horsepower (bhp) are subject to this rule

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) AGRICULTURAL STATIONARY ENGINE is a non-portable engine used for the growing and harvesting of crops of the raising of fowl or animals for the primary purpose of making a profit, providing a livelihood, or conducting agricultural research or instruction by an educational institution. An engine used for the processing or distribution of crops or fowl or animals is not an agricultural engine.

(2) APPROVED EMISSION CONTROL PLAN is a control plan, submitted on or before December 31, 1992, and approved by the Executive Officer prior to November 14, 1997, that was required by subdivision (d) of this rule as amended September 7, 1990.

(3) BREAKDOWN is a physical or mechanical failure or malfunction of an engine, air pollution control equipment, or related operating equipment that is not the result of operator error, neglect, improper operation or improper maintenance procedures, which leads to excess emissions beyond rule related emission limits or equipment permit conditions.

(4) CERTIFIED SPARK-IGNITION ENGINE means engines certified by California Air Resources Board (CARB) to meet emission standards in accordance with Title 13, Chapter 9, Article 4.5 of the California Code of Regulations (CCR).

(5) COMPRESSOR GAS LEAN-BURN ENGINE is a stationary gaseous-fueled two-stroke or four-stroke lean-burn engine used to compress natural

PAR 1110.2 - 1

Proposed Amended Rule 1110.2 (Cont.) **(Amended June 3, 2016)**

shall:

(i) Comply with the requirements of Best Available Control Technology in accordance with Regulation XIII if the engine requires a South Coast AQMD ~~District~~ permit; or

(ii) Not operate the engine in a manner that exceeds the emission concentration limits in Table I if the engine does not require a South Coast AQMD ~~District~~ permit.

(K) By February 1, 2009, the operator of a spark-ignited engine without a Rule 218-approved continuous emission monitoring system (CEMS) or a Regulation XX (RECLAIM)-approved CEMS shall equip and maintain the engine with an air-to-fuel ratio controller with an oxygen sensor and feedback control, or other equivalent technology approved by the Executive Officer, CARB and EPA.

(L) New Non-Emergency Electrical Generators

(i) All new non-emergency engines driving electrical-generators, excluding linear generators, shall comply with the following emission standards:

TABLE IV
EMISSION STANDARDS FOR NEW ELECTRICAL GENERATION DEVICES

Pollutant	Emission Standard (lbs/MW-hr)[1]
NOx	0.070
CO	0.20
VOC	0. 10[2]

1 The averaging time of the emission standards is 15 minutes for NOx and CO and the sampling time required by the test method for VOC, except as described in the following clause.

2 Mass emissionsofVOCshallbecalculatedusingaratioof 16.04 pounds of VOC per lb-mole of carbon.

(ii) Engines subject to this subparagraph that produce combined heat and electrical power may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr), in addition to each MW-hr of

Proposed Amended Rule 1110.2 (Cont.) **(Amended June 3, 2016)**

(v) This subparagraph does not apply to: engines installed prior to February 1, 2008; engines issued a permit to construct prior to February 1, 2008 and installed within 12 months of the date of the permit to construct; engines for which an application is deemed complete by October 1, 2007; engines installed by an electric utility on Santa Catalina Island; engines installed at remote locations without access to natural gas and electric power; engines used to supply electrical power to ocean-going vessels while at berth, prior to January 1, 2014; or landfill or digester gas-fired engines that meet the requirements of subparagraph (d)(1)(C).

(XX) New Linear Generators

(i) All new linear generators shall comply with the following emission standards:

TABLE XX
CONCENTRATION LIMITS FOR NEW LINEAR GENERATORS

Pollutant	**Concentration Limits (ppmvd @ 15% O_2)[1,2]**
NOx	2.5
CO	10
VOC	30

1 The averaging time of the emission standards is 15 minutes for NOx and CO and the sampling time required by the test method for VOC

2 VOC parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

(2) Portable Engines:

(A) The operator of any portable engine generator subject to this rule shall not use the portable generator for:

(i) Power production into the electric grid, except to maintain grid stability during an emergency event or other unforeseen event that affects grid stability; or

PAR 1110.2 - 15

Response to Comment 12-1

Concentration limits have been added for electrical generating engines. Based on staff's calculation, the following concentrations correspond to converting the values from mass emission standards in lbs/MR-hr to concentrations in ppmvd.

TABLE IV EMISSION STANDARDS FOR NEW ELECTRICAL GENERATION DEVICES		
Pollutant	**Emission Standard (lbs/MW-hr)**	**Concentration Limit (ppmvd)**
NOx	0.070	2.5
CO	0.20	12
VOC	0.10	10

In your comment letter, a VOC concentration limit of 30 ppmvd was suggested. This is greater than what staff calculated. At this time, staff has proposed an alternative emission limit for the use of this technology. A cap that limits VOC emissions to a maximum of 45 lbs of VOC emissions per day of combined installation from the PAR 1110.2 effective date up to January 1, 2024.

Comment Letter No. 13 – Southern California Gas Company

SoCalGas
A Sempra Energy utility

Deanna Haines
Director of Policy & Environmental Strategy

Southern California Gas Company
Strategy & Engagement
555 W. 5th St, GT21C5
Los Angeles, CA 90013

Tel: 213.244.3010
Mobile: 213.220.1121
DHaines@semprautilities.com

August 30, 2019

Susan Nakamura, Assistant Deputy Executive Officer
Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765
Via Electronic Mail: SNakamura@aqmd.gov

RE: Comments on draft Proposed Amended Rules 1110.2 and 1100

Dear Ms. Nakamura:

Southern California Gas Company and San Diego Gas and Electric Company (referred to herein as "the Utilities") appreciate the opportunity to provide comments to the South Coast Air Quality Management District (AQMD) regarding AQMD Proposed Amended Rule (PAR) 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines and PAR 1100 – Implementation Schedule for NOx Facilities. 13-1

I. Background

The Utilities provide services to over 25 million customers in California and operate a complex natural gas distribution, transmission and storage system spanning thirteen counties in California. Within the South Coast Air Basin, the Utilities operate three gas storage facilities and one gas transmission station. These facilities play a key role in supplying energy services to our customers, ensuring a reliable and safe gas supply to residential, commercial and industrial facilities and operations, as well as supporting one of the most critical economic regions in the country.

An integral part of this distribution, transmission and storage system, are engine-driven gas compressors. These compressors, operating under highly variable and challenging conditions, ensure the availability of natural gas every day. 13-2

The Utilities are driven by our desire to be the cleanest in the country. As part of our forward-looking operational asset planning, we are evaluating electric-driven compression technologies and hydrogen production and blending, while studying how to meet our facilities' base electricity needs with fuel cell technology. These pathways are anticipated to reduce Oxides of Nitrogen (NOx) emissions and lower the net carbon footprint at our storage fields and compressor stations.

Over the last year and a half, the Utilities have met with AQMD staff to highlight the operational significance and complexity of our facilities and compressors, including providing tours of each facility. During this time, the Utilities have provided extensive details regarding the unique nature of gas compressor engines, as well as operational and physical challenges that exist at each facility that affect these engines and the retrofit of emission controls. The Utilities have also provided and reviewed with staff, proposed emission control retrofit and replacement plans and associated time lines. 13-3

We appreciate staff's continued commitment to meet with our team and discuss our unique set of issues. The current version of the proposed amended rule reflects an understanding of the importance natural gas facility modernization projects can play in providing emission reduction benefits to the residents of the South Coast Air Basin.

II. Challenges Unique to the Utilities' Class and Category of Compressor Gas Engines

The utilities are encouraged to see that the current drafts of PARs 1110.2 and 1100 addressed many of our concerns regarding the infeasibility of previously proposed measures. As we've discussed with staff, many of the challenges associated with compressor gas engines have to do with the uniqueness of a certain type of compressor, e.g. an "integral" compressor. An integral compressor differs from other types of engines-driven equipment, in that they use a single crank shaft to drive both the engine and the compressor. This attribute contributes to many of the challenges that the Utilities' have noted. An attachment highlighting some of the characteristics of an integral compressor which impact the ability to control emissions is enclosed. 13-4

III. Comments on PARs 1110.2 & 1100 – Provisions and Suggested Changes
After reviewing these proposed draft rules, the Utilities have the following comments and recommended changes regarding specific sections in PARs 1110.2 and 1100.

Draft PAR 1110.2

Section (e) – Compliance

Section (e)(3)(C)
This section specifies the compliance milestones for installation of a new, or modification to an existing, Continuous Emissions Monitoring System (CEMS), specifically applicability of Table VII required actions and deadlines. These deadlines begin within 90 days of a Regional Clean Air Incentives Market (RECLAIM) facility becoming a "former RECLAIM facility." The date when this will happen is currently unknown but may take place sooner than required retrofit (with emission control systems) and/or replacement of engines under the schedules contained in PAR 1100. As currently written, PAR 1110.2 would require the installation or modification of existing CEMS to be constructed, made operational, and certified, prior to the rule-mandated engine emission control retrofits. 13-5

The Utilities request that this language and/or Table VII compliance actions and time frames, be modified to align with PAR 1100 compliance schedules, and preferably, be included in the Permits to Construct.

Proposed Language:

Section (e)(3)(C)
The operator of any stationary engine that is located at a RECLAIM or former RECLAIM facility that is required to modify an existing CEMS or install a CEMS on an existing engine that is subject to ~~subdivision~~ paragraph (f)(1) shall comply with the compliance schedule in Table VII such that the operator shall submit to the Executive Officer applications for a new or modified CEMS within 90 days of becoming a former RECLAIM facility for engines not requiring retrofit emission controls and not scheduled for replacement. For existing engines requiring retrofit emission control system installations, the operator shall comply with the CEMS compliance milestones specified in the Permit to Construct issued for an existing engine's retrofit emission control system. For engines scheduled for replacement, CEMS will not be required as long as the engines designated for replacement are permanently shut-down and/or removed from service by the time frame specified in the replacement equipment's Permit to Construct. 13-5 cont.

Section (i) - Exemptions

Section (i)(1)(K)
Emission control systems [Non-Selective Catalytic Reduction (NSCR), Selective Catalytic Reduction (SCR), Air to Fuel Ratio Controller (AFRC), etc.] must be maintained, and on occasions, repaired. These systems are critical to successfully controlling emissions from an engine. Once a maintenance event, such as the replacement of a catalyst bed, has been completed, the engine/emission control system must be adjusted or "tuned" to the proper settings to attain required concentration limits specified in Rule 1110.2. Tuning these systems after a maintenance event is no different than the tuning that must occur when a new engine and/or emission control system is installed, taking anywhere from a few hours to several days. Currently, emission control system maintenance and/or repair events are not covered by existing exemptions in Rule 1110.2. Therefore, SoCalGas requests that emission control system maintenance and repair events be included in this exemption. 13-6

During recent discussions with the AQMD, staff noted that the maintenance of the emission control system is covered under the term "major repair" in the current rule language. The Utilities appreciate this clarification; however, we remain concerned about ambiguity in the current language. The subsection currently requires that a "major repair" include the removal of a cylinder head on the engine. Emission control system maintenance events do not require any specific maintenance to be done on the engine, especially the removal of an engine cylinder head.

Therefore, the Utilities recommend that the current language in Rule 1110.2 section (i)(1)(K), be modified to specifically cover emission control system maintenance and repair under this exemption. The Utilities have provided suggested language below.

Additionally, the Utilities are concerned that the current allowance of 4 hours is too short of a time frame to adjust exhaust emissions out of the catalyst into compliance with rule limits. This is especially true for SCR systems that not only require adjustments to the SCR system controls, but additional adjustments to the ammonia injection control system as well, such as when an ammonia injection grid must be tuned, or a combination of engine and SCR control systems tuning is required. Therefore, the Utilities recommend that the AQMD extend the existing 4-hour exemption time frame to a minimum of 36 hours. 13-6 cont.

Proposed Language:

Section (i)(1)(K)
"An engine start-up, after an engine overhaul or major repair requiring removal of a cylinder head, or an emission control system maintenance or repair event, for a period not to exceed ~~four~~ 36 operating hours."

Draft PAR 1100

Section (d) – Rule 1110.2 Implementation Schedule

Section (d)(5)(B)
Section (d)(5)(B) allows the AQMD to consider the establishment of a case-by-case NOx emission limit, upon notification and a demonstration submitted by the Utilities, that an engine cannot achieve the limits established in Rule 1110.2 section (d)(1). An additional requirement [section (d)(5)(A)] requires the submittal of various data to support the AQMD's consideration of this request. This data submittal not only includes NOx emission data, but also ammonia (NH_3) and Volatile Organic Compound (VOC) data.

The Utilities have provided substantial technical information regarding the infeasibility of attaining low NOx and VOC limits while maintaining a maximum allowable NH_3 slip limit of 5 parts per million (ppm). The physical and chemical challenges discussed with AQMD staff over the last 18 months include: the challenging compressor loading (hourly, daily, seasonal) conditions, the unique characteristics of integral gas compressors themselves, and the difficulty NH_3 injection controls will have in keeping up with the quickly changing NOx concentrations from the engine. Additionally, the Utilities are including a letter from Environex detailing the challenges in meeting both the 11 ppm NOx and 5 ppm NH_3 limits. 13-7

Engine geometry and load control strategies unique to integral compressor units create power cylinder-to-power cylinder, and combustion cycle-to-combustion cycled differences that create variability in engine emissions (see enclosed engine compressor diagram). Note that challenges related to loading would also apply to brand new engines driving a separate compressor. Moreover, unlike generators connected to the electric grid, compressor engine load cannot be reduced to achieve compliance over the averaging period. Gas compression engines must remain at load to assure delivery of natural gas.

Page 5

Since control of emissions from integral gas compressor engines, to the levels required in section (d)(1) of Rule 1110.2 have never been achieved anywhere in the country, the current AQMD proposal, allowing only for the consideration of a technologically achievable case-by-case NOx limit, will make it inherently difficult to maintain a 5 ppm NH_3 limit, without a significant give on NOx and/or possible exceedances of the VOC limit. The Utilities strongly urge AQMD to provide an option to develop technically achievable case-by-case NOx and/or NH_3 limits. We suggest that AQMD not limit a facility's ability to apply for alternate emission limits just to NOx. Rather, by providing an additional option for the Executive Officer to approve alternate NH_3 limits, AQMD will provide itself with more flexibility to evaluate the most feasible emissions after collecting numerous months of operational data. The best pathway to minimize emissions overall may be one with alternate limits for NOx and NH_3.

The Utilities propose the following language that would provide the Executive Officer with the discretion to establish a case-by-case NOx limit, either separately, or in conjunction with, a case-by-case NH_3 limit.

Proposed Language:

13-7 cont.

PAR 1100 (d)(5)(A)(v)
"Provide detailed information steps that have been taken to
meet the NOx and NH_3 emission limits specified in Rule 1110.2 paragraph (d)(1), why the NOx and/or NH_3 emission limits cannot be met,
the number of occurrences that the NOx and/or NH_3 emission limits ~~was~~ were exceeded, and the duration and concentrations of NOx and NH_3 ~~concentrations~~ that exceeded Rule 1110.2 paragraph (d)(1)."

PAR 1100 (d)(5)(B)
"The Executive Officer will review the information provided pursuant to subparagraph (d)(5)(A) and either require that the NOx and/or NH_3 emission limits in Rule 1110.2 paragraph (d)(1) be met or establish technologically achievable case-by-case emission limits."

[NOTE: another option to amending the sections above, would be to delete the term NOx from these sections and let the section simply specify "the emission limits in Rule 1110.2 paragraph (d)(1).]

IV. Conclusion

The Utilities appreciate the effort of AQMD staff over the last 18 months in working with us to understand issues unique to our facilities and operations. We have also come to understand the complex and challenging nature of this transition out of RECLAIM. The Utilities are pleased to see that the current drafts of the rules provide us with compliance pathways. However, we are still recommending changes to a few rule provisions in order to achieve a reliable emissions control strategy that will allow us to transition our lean-burn compressor gas engines from RECLAIM to the Regulation XI rules. 13-8

Page 6

The Utilities appreciate your consideration of our comments and recommendations. Should you wish to discuss the above comments, or have any questions, please contact Daniel McGivney of my staff at 951-225-2958 or at dmcgivney@socalgas.com.

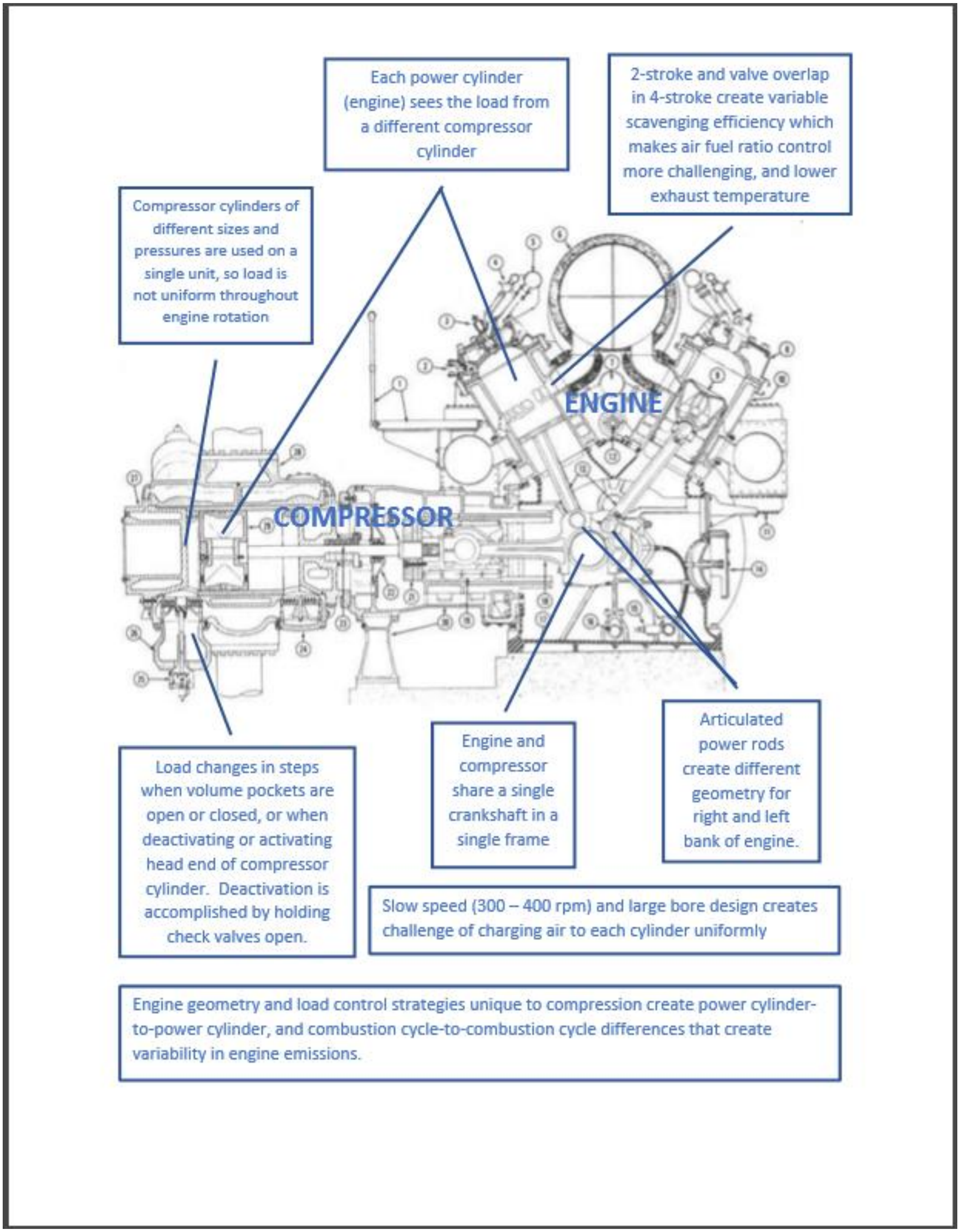
Sincerely,

Daniel R. McGivney
for

Deanna Haines
Director, Environmental Policy
Southern California Gas Company

cc:
Phil Fine, SCAQMD
Michael Morris, SCAQMD

ATTACHMENTS



Each power cylinder (engine) sees the load from a different compressor cylinder
2-stroke and valve overlap in 4-stroke create variable scavenging efficiency which makes air fuel ratio control more challenging, and lower exhaust temperature
Compressor cylinders of different sizes and pressures are used on a single unit, so load is not uniform throughout engine rotation
ENGINE
COMPRESSOR
Load changes in steps when volume pockets are open or closed, or when deactivating or activating head end of compressor cylinder. Deactivation is accomplished by holding check valves open.
Engine and compressor share a single crankshaft in a single frame
Articulated power rods create different geometry for right and left bank of engine.
Slow speed (300 – 400 rpm) and large bore design creates challenge of charging air to each cylinder uniformly
Engine geometry and load control strategies unique to compression create power cylinder-to-power cylinder, and combustion cycle-to-combustion cycle differences that create variability in engine emissions.

ENVIRONEX

August 28, 2019

Gregg Arney
Gas Engineering
SoCalGas
555 West 5th St.
Los Angeles, California 90071

Rule 1110.2 - NOx and Ammonia Limits for 2 and 4 Stroke Compressors

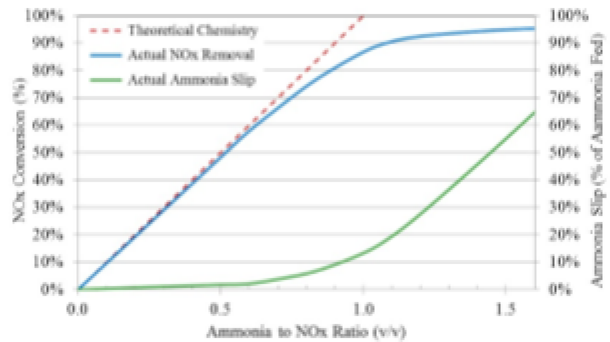
Gregg,

Environex has reviewed proposed Rules 1100 and 1110.2. We have specific concerns regarding the viability of the proposed 11 ppmvdc NOx and 5 ppmvdc ammonia slip limits for the 2 and 4 stroke gas compressors.

The concern is that the SCR technology being applied to these compressors has practical limitations that must be considered when setting the limits to provide reliable performance. All SCR systems operate on the principle of providing a target percent NOx removal for a percent ammonia slip. As an illustration, Figure 1 below shows the SCR characteristic curve for an SCR system with an inlet ammonia-to-NOx distribution of 10% RMS; a well designed, state-of-the-art system and the most widely accepted design basis for gas fired SCR applications. In this design, to achieve 90% NOx reduction 20% excess (above stoichiometric) ammonia is needed. This 20% excess ammonia exits the reactor as ammonia slip. If the system has an inlet NOx of 25 ppmvdc NOx and 90% removal is achieved, the stack NOx is 2.5 ppmvdc and the ammonia slip is 5 ppmvdc. If, however, the inlet NOx is 100 ppmvdc then the stack NOx would be 10 ppmvdc and the ammonia slip would be 20 ppmvdc.

1 Great Valley Parkway, Suite 4
Malvern, PA 19355
Tel (484) 320-8608
Fax (484) 320-8639

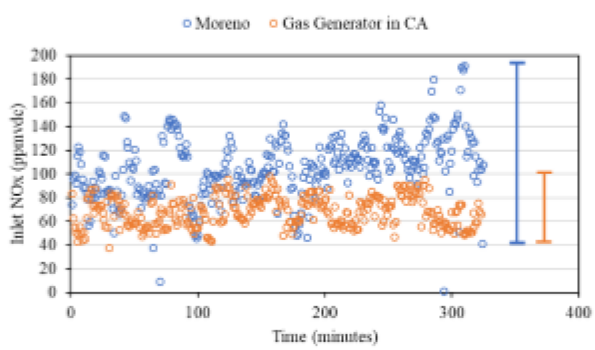
Figure 1 – SCR Characteristic Curve



The SoCal Gas compressors have an engine exit NOx of 100 to 150 ppmvdc. At 150 ppmvdc NOx and 11 ppm Stack NOx, 92.7% NOx removal is required. However, for 92.7% NOx removal 25% excess ammonia is needed and ammonia slip would be 37.5 ppmvdc. Some engines may have the capability to adjust combustion ratios and reduce NOx, but only at the expense of increasing VOCs.

Further, unique to the operation of the compressors is wide and sudden variation in engine exit NOx. Figure 2 illustrates this point by comparing actual operating data between a typical lean-burn IC engine gas generator and the Moreno engines. The variation in engine exit NOx at Moreno is more than twice that of a gas fired generator.

Figure 2 – Engine Exit NOx Moreno Compressor vs IC Engine Generator



Conventional ammonia flow control systems have a lag in response time as an artifact of the feed forward and/or feedback control signals from the CEMS. When wide variations occur, the control system is consistently lagging and the result is over or under injection of ammonia and increased variation on stack NOx and ammonia slip. This would typically be allowed for by longer averaging periods of 12 to 24 hours. In lieu of that, increased NOx and ammonia slip limits are necessary to compensate for these variations. It is also worth noting that the gas generator used in this illustration is located in California and is permitted with a 3-hr rolling NOx averaging period.

Due to the above challenges, we conclude that the gas compressors are a unique class of engine. We further recommend that the proposed NOx and ammonia slip limits of 11 ppmvdc NOx and 5 ppmvdc ammonia slip are not practical to achieve. For a stack NOx of 11 ppm the acheiveable ammonia slip limit is 20 to 30 ppmvdc. We recommend SoCal Gas request the AQMD revisit the basis for the limits in the proposed Rule 1110.2 and make allowance for some variance for those engines that demonstrate practical limitations to SCR technology.

Regards,

Daniel Ott
President

Response to Comment 13-1
South Coast AQMD appreciates your comment email submitted for the proposed amendments to Rule 1110.2.

Response to Comment 13-2
Thank you for your comment. Staff recognizes the important role that the distribution, transmission and storage of natural gas has on the residents of the South Coast AQMD. We appreciate your efforts to be the cleanest utility in the country.

Response to Comment 13-3
Thank you for your comment. Having the opportunity to tour the affected facilities has provided key insights on potential community impacts. Staff appreciates your hospitality. In addition, your participation has been a key part of the rule making process.

Response to Comment 13-4
Thank you for your comment.

Response to Comment 13-5
Your concern over the installation of a CEMS is duly noted and the proposed rule language will be modified to incorporate this concern.

Response to Comment 13-6
Staff has reviewed your proposal to include an emission control system maintenance or repair event as subject to provision to section (i)(1)(K). Staff agrees that the installation or the repair of catalytic emission control equipment should be included in this provision. However, staff believes that extending the exemption period from 4 hours to 36 hours is not warranted. Staff has not received feedback from other stakeholders suggesting that the additional time is needed. Further, tuning an engine's control system should be and is addressed in section (i)(1)(J).

Response to Comment 13-7
Staff recognizes that NOx, ammonia, and VOC are all air contaminants that may and/or will vary throughout your requested demonstration period. Within these parameters, we are asking you to balance a three-legged emissions stool with the NOx emissions representing the one parameter that is allowed to range up to 45 ppmvd @ 15% O_2 which is still an emission reduction from current operational limits. After staff's review and feedback from stakeholders, an ammonia emission limit will not be included in this rule amendment at this time but a limit may be applied to new SCR installations that show an emission increase. The SCR control equipment would be subject to BACT at the time of permitting. As such, under your particular circumstances, it may be beneficial to limit ammonia emissions to a level consistent with the installation of an SCR.

Response to Comment 13-8
Thank you for your comment.

Comment Letter No. 14 (received as an email) – Eastern Municipal Water District

Rodolfo Chacon

Subject: FW: Proposed Rule 1110.2 Comments-Ammonia Test Frequency

From: Torres, Alison [mailto:torresa@emwd.org]
Sent: Tuesday, September 17, 2019 9:30 AM
To: Kevin Orellana <korellana@aqmd.gov>
Cc: Michael Morris <mmorris@aqmd.gov>; Rodolfo Chacon <rchacon@aqmd.gov>
Subject: RE: Proposed Rule 1110.2 Comments-Ammonia Test Frequency

Good morning Kevin,

I wanted to reach out again regarding my concerns with the ammonia-testing requirement proposed in PAR 1110.2. I reviewed the latest language (8/20/19) and I did not see added clarifications regarding the applicability of the quarterly and annual ammonia testing to new installations only. 14-1

As I expressed previously, upon rule adoption, if the language is unchanged, our existing installation would immediately be considered "late" for ammonia testing since we are not currently subject to quarterly or annual ammonia testing. In addition, we would be required to test more frequently during a special test mobilization, even though our historical ammonia test results are extremely low. 14-2

We don't believe there is a need to require differing test frequencies for ammonia and request that staff consider adjusting the test frequency so it is consistent with the NOx, CO and VOC testing. Requiring annual testing for ammonia would require a separate test mobilization by a certified tester. The test frequency for NOx, CO and VOC testing occurs approximately every 1-3 years depending on engine operation. If an engine runs continuously, ammonia testing would be triggered at the desired annual frequency, along with the testing for other constituents. However, if the engine is not operating 24/7, testing would be in line with the frequencies outlined for NOx, CO and VOC (every 1-3 years). 14-3

I ask that you consider requiring the quarterly testing for the first 12 months of operation for **new installations** only, and adjust the language to reflect future testing to occur in line with the NOx, CO, VOC testing (rather than annually). 14-4

Please let me know if there are planned modifications to the proposed rule language. I would be happy to propose wording and/or provide additional information if needed.

Thank you,

Alison Torres
Senior Air Quality Compliance Analyst
Environmental & Regulatory Compliance Dept
Eastern Municipal Water District
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Perris, CA 92570
(951) 928-3777, ext. 6345
torresa@emwd.org

Serving our community today and tomorrow

Response to Comment 14-1
South Coast AQMD appreciates your comment email submitted for the proposed amendments to Rule 1110.2. PAR 1110.2 has been revised to remove an ammonia concentration limit and associated source testing provisions.

Response to Comment 14-2
PAR 1110.2 had been revised to remove ammonia limits. Ammonia limits and source testing will be addressed during permitting of new installations of SCRs.

Response to Comment 14-3
Source testing requirements for ammonia have been removed from PAR 1110.2.

Response to Comment 14-4
At this time, the provisions related to ammonia testing have not been included in the PAR 1110.2.

Comment Letter No. 15 (received as an email) – Ramboll (EtaGen)

Rodolfo Chacon

Subject: Revised Draft Rule Language - PAR 1110.2/1100 - EtaGen comment on I&M Plans for Linear Generators (or equivalent)

From: Scott Weaver [mailto:MSWeaver@ramboll.com]
Sent: Tuesday, September 24, 2019 7:05 PM
To: Michael Morris <mmorris@aqmd.gov>; Susan Nakamura <SNakamura@aqmd.gov>; Kevin Orellana <korellana@aqmd.gov>
Cc: Adam Simpson <adam.simpson@etagen.com>
Subject: [BULK] Revised Draft Rule Language - PAR 1110.2/1100 - EtaGen comment on I&M Plans for Linear Generators (or equivalent)

Susan, Mike & Kevin:

Thank you again for your time today to discuss EtaGen comments on the revised PAR1110.2 language. Wanted to provide a little more information on the I&M Plan topic that we discussed. 15-1

Background: The power output from EtaGen's linear generator is primarily controlled using controllers on air flow, fuel flow, and oscillator motion (called apex control). The linear generators are equipped with a real-time onboard diagnostic system that monitors fuel flow, air flow, apex control, power output (DC and AC), and efficiency (DC and AC) to ensure that the unit is continuously operating within emissions specification. This onboard diagnostics system is analogous to what is used in automobiles for engine emissions compliance. Today, when a car is smog checked, they don't even measure emissions. Rather they check that the onboard diagnostics are working and that there were no errors thrown. The EtaGen system can be used to ensure emissions compliance to a much higher degree than occasional portable analyzer checks, which are not well suited to the linear generator technology. As we discussed, the Permits team had reached that conclusion and had actually excluded the portable analyzer stuff in the most recent draft permit. Of course all of this will be backstopped by the source testing. 15-2

Proposed I&M Approach: As we discussed, EtaGen would like an option added to the rule for an alternative I&M Plan that could (if approved by the Executive Officer) leverage the onboard diagnostic system for emissions compliance assurance. Our proposed language would be something like: 15-3

> Proposed Section (i)(4) language: The provisions of paragraph (e)(5), (f)(D)(i) and (f)(D)(ii) shall not apply to a new non-emergency generator subject to paragraph (d)(L)(1) provided the owner/operator submits an alternative I&M Plan using real-time, onboard diagnostic monitoring and such a plan is approved by the Executive Officer.

As noted, this would be much better suited to the assuring emissions compliance for this technology. And obviously, since this would be subject to AQMD approval it presents zero risk to include it. If the AQMD does not get comfortable with the alternative I&M Plan approach, the owner/operator would be left defaulting to the standard I&M provisions. 15-4

Should you have any questions, please let us know. Thanks again for your consideration.

Best regards,

Scott

M. Scott Weaver
Principal

D +1 (213) 9436360
M +1 (626) 7202015
msweaver@ramboll.com

Response to Comment 15-1
South Coast AQMD appreciates your comment email submitted for the proposed amendments to Rule 1110.2.

Response to Comment 15-2
The initial permit was to be an experimental permit that would allow the use of the onboard diagnostics backstopped with source testing. Over several years of operation the source testing could be reviewed to determine if the onboard diagnostics would be acceptable in lieu of portable analyzer testing. However, once the manufacturer opted to pursue a permit to operate rather and forego the experimental permitting process, the existing conditions and requirements of Rule 1110.2 were applicable. The analogy of smog checking a car and validating emissions through diagnostic measures is inaccurate because diagnostic evaluation for cars has been developed over years of testing and data comparison over a wide range of automobile types. The manufacturer has not provided similar data showing the data comparison of the onboard diagnostics to portable analyzer checks. Subclause (f)(1)(D)(i)(I) has been included in the rule that allows the manufacturer to demonstrate that such a system is equivalent to current monitoring requirements eventually allowing the onboard diagnostics to be used in some situations in lieu of the portable analyzer checks.

Response to Comment 15-3
See Response 15-2.

Response to Comment 15-4
See Response 15-2.

Comment Letter No. 16 (received as an email) – Southern California Gas Company

Rodolfo Chacon

Subject: SoCalGas comments regarding September 20 draft PARs 1110.2 & 1100

From: McGivney, Daniel [mailto:DMcGivney@socalgas.com]
Sent: Tuesday, September 24, 2019 7:17 PM
To: Michael Morris <mmorris@aqmd.gov>
Cc: Nevitt, Lauren B <LNevitt@socalgas.com>
Subject: SoCalGas comments regarding September 20 draft PARs 1110.2 & 1100

Mike, please find below, SoCalGas comments on the September 20 draft PARs 1110.2 and 1100. Please let me know if you have any questions, and certainly, any comments. We are available to meet this week on these items. We would like at least a confirmation of the items where the District would agree to our requests and those the District disagrees with. We very much would like to get all these items settled as quickly as possible. Thank you. 16-1

NH_3 Flexibility

Originally, the District proposed a 5 ppm NH_3 slip limit in PAR 1110.2 and an interim NH_3 limit of 20 ppm in PAR 1100 (during the time extension period). However, the PAR 1100 language only allowed for a final case-by-case limit for NOx, keeping the final NH_3 limit at 5 ppm. At our last in-person meeting (September 12), we inquired again about additional flexibility by allowing the potential for a higher NH_3 slip limit. District staff stated that it was looking at what might be possible and said it would continue its internal discussion and see what they could do. In the recently released (Sept. 20) draft rules, the District has removed NH_3 slip limits from the rules completely, thereby establishing the permitting process as the vehicle to negotiate NH_3 slip limits. 16-2

- SoCalGas is concerned that negotiating two separate NH_3 slip limits up front in the permitting process (e.g. a limit to go with the Rule 1110.2 Table II limits, and a second "interim:" limit which would apply during the time extension period in PAR 1100) is unpredictable and creates additional, unnecessary uncertainty. 16-3
- SoCalGas, as noted at our last meeting (and other preceding meetings) is concerned that there is no allowance for the development and approval of a possible final case-by-case NH~~3~~ slip limit. As discussed in previous meetings, the best case scenario would be that SoCalGas has the option to identify the best NOx and/or NH3 limits that would achieve the greatest NOx emissions reduction (with the NOx goal being 11 ppm). SoCalGas believes having the ability to possibly reach and maintain a NOx limit of 11 ppm with a higher NH3 limit would be the best outcome for all. 16-4
- SoCalGas recommends leaving the previously proposed interim NH_3 limit of 20 ppm in PAR 1100 (d)(4)(C). 16-5
- SoCalGas recommends amending PAR 1100 Sections (4) and (5) to allow for a final case-by-case NH_3 slip limit. 16-6

NOx Interim Limit

PAR 1100 Section (d)(4)(C)(i) establishes the interim NOx limit that must be met as required by an Executive Officer approved compliance plan granting a time extension. SoCalGas previously understood that this NOx limit (and other applicable limits at the time, e.g. the 20 ppm NH_3 slip limit) would be the 45 ppm NOx concentration limit noted in the proposed rule. However, in a conversation with District staff, it appears that the interim limits would be based upon data collected during the 24 months following the issuance of a Permit to Construct, and would likely be less than, in the case of NOx, the 45 ppm limit cited in the rule. 16-7

- This would defeat the purpose of operating under interim limits while SoCalGas staff works the engines to determine first, whether the engines can achieve the Rule 1110.2 Table II limits, and if not, what NOx (and NH3) concentration can be achieved with variations in pipeline conditions through a year of operation. Lowering the interim limit would put the compliance of the engine operations in jeopardy while trying to operate the engine as it makes various load step changes. This could lead to future non- 16-8 compliant events, should the final limits be artificially and inaccurately based upon a limited set of operating conditions. 16-8 cont.

- SoCalGas requests that the 45 ppm NOx interim limit (and the 20 ppm NH_3 interim limit addressed above) be established in Rule 1100 as hard limits for the interim time extension, which would be no longer than 24 months. 16-9

NOx Averaging Period

The District has language in both PARs 1110.2 and 1100 regarding NOx emissions averaging. In PAR 1110.2 Section (d)(1)(B)(v), the draft rule requires compressor gas engines to utilize a "fixed-interval averaging time of three hours" to demonstrate compliance with the NOx emission concentration limit. PAR 1100 Section (d)(4)(C)(i) requires that NOx emissions data be "averaged over 180 minutes." 16-10

- SoCalGas seeks definition and clarification of these proposed NOx averaging periods, why they are different, how they would be calculated, and how they align/comply with Rules 218 and 218.1 (i.e. do the averaging requirements in Rules 1110.2 and 1100 supersede the requirements of Rules 218 and 218.1?).

Alternative VOC Limit for 2-Stroke Lean Burn Engines

Current Rule 1110.2 Section (d)(1)(B)(ii) allows for the demonstration that a 2-stroke, lean-burn engine cannot meet the Table II 30 ppm VOC limit, and request a case-by-case limit. The latest changes appear to eliminate that option, while grandfathering previously approved case-by-case limits . 16-11

- SoCalGas would appreciate it if the District could confirm this interpretation and discuss why this provision is being removed.

Source Test Frequency

The District is amending PAR 1110.2 Section (f)(1)(C)(i) regarding the frequency of source tests. SoCalGas is having trouble interpreting the following sentences in this section: "The above source test frequency may be reduced to once every three years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated before ~~within three months of~~ the date a source test is ~~required~~ due, the source test shall be conducted by the end of ~~when the engine resumes operation for a period longer than either~~ seven consecutive days or 15 cumulative days of resumed operation." 16-12

- SoCalGas would appreciate it, if the District could clarify the above requirement.

PAR 1100 Quarterly Reports

PAR 1100 Section (d)(3)(C) requires the submittal of quarterly reports during the 24 month period following issuance of a Permit to Construct for compressor gas engines. One of the requirements of this section specifies that the report include the "identification of applicable engine and control equipment parameters necessary to maintain pollutant concentrations within the rule and permit limits." The section additionally includes the requirement that "the parameters as well as any corrective actions shall include, but not be limited to, those specified in Attachment 1 of Rule 1110.2." Attachment 1 of Rule 1110.2 describes data elements that must be included in an Inspection and Monitoring plan per Rule 1110.2 (f)(1)(D)(i)(I), which is required for engines without NOx/CO CEMS. SoCalGas' compressor gas engines will all have CEMS. 16-13

- SoCalGas would like clarification as to the applicability of Attachment 1 to compressor gas engines, and more importantly, identification of the specific data elements applicable to compressor gas engines.

Engines affected by Other Regulation XI Rules

PAR 1100 Section (d)(3)(D) addresses engines that may be replaced by another Regulation XI rule. Currently, this section stipulates that engines that will be replaced by equipment under a different Regulation XI rule must be permanently removed from service within 24 months after issuance of the new equipment's Permit to Construct or by December 31, 2023, whichever is later. Under Rule 1134, compressor gas turbines can obtain 36 months (versus 24 months) to construct and meet compliance with applicable rule limits if the operator files the permit applications early, and additionally has the option to request up to an additional 36 months to meet the ammonia limit. 16-14

- SoCalGas has compressor gas engines that will be replaced by equipment regulated under Rule 1134. Hence we request that PAR 1100 (d)(3)(D) be amended to reflect these Rule 1134 compliance time frames, as SoCalGas cannot remove the existing compressor gas engines until the new equipment is operational and in compliance with all operational and regulatory requirements. Removing these engines early, would jeopardize SoCalGas' and SDG&E's gas system reliability. 16-15
- SCAQMD had expressed their understanding of this concern, but the proposed rule language does not address the compliance date gap between the two rules. Allowing 24 months to replace the engines does not harmonize the two rules. 16-16

Compliance Gap

PAR 1100 Section (d)(5) establishes requirements that must be met to request and obtain a final case-by-case emission limit. At the end of the time extension provided in Section (d)(4), SoCalGas may submit a demonstration that engines cannot achieve the emission limits in Rule 1110.2 (d)(1)(B) Table II. Upon review and approval by the Executive Officer, case-by-case emission limits can be determined and approved. Section (d)(5)(C)(i) stipulates that the operator must comply with the standards approved by the Executive Officer within 30 days of notification. In review of the language in Section (d)(5), it appears that there exists the possibility that there could be a compliance gap between the end of the time extension granted under (d)(4) and the notification sent to the operator in (d)(5). 16-17

- SoCalGas is concerned with this potential time gap and therefore requests that the District add language to Section (d)(5) that would require the operator to maintain compliance with the interim limits until a notification regarding the final limits is received by the operator. This would ensure that there is no compliance gap while the Executive Officer is reviewing the request submittal, the determination of final limits, and the subsequent notification to the operator.

Daniel McGivney
Environmental Affairs Program Manager
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Response to Comment 16-1
South Coast AQMD appreciates your comment email submitted for the proposed amendments to Rule 1110.2.

Response to Comment 16-2
PAR 1110.2 was revised to remove the ammonia emission limit that was initially proposed because the establishment of any ammonia limits along with monitoring requirements is determined during the permitting process.

Response to Comment 16-3
PAR 1100 allows for flexibility with the NOx concentration limit and specifically focuses on efforts to achieve the final NOx concentration limit without adjustment to any permitted ammonia limit.

Response to Comment 16-4
As noted in Comment 16-3, the facility will have flexibility with the NOx emission limit as well as with the averaging time. The limit on ammonia slip will be determined based on BACT standards for the installation of affected control equipment.

Response to Comment 16-5
Any ammonia slip limits will be determined through the permitting process. See also Comments 16-3 and 16-4.

Response to Comment 16-6
See response to Comment 16-5.

Response to Comment 16-7
It is expected that the facility should make good faith efforts to achieve 11 ppm NOx upon commissioning. The proposed rule provides flexibility through the extension period and staff will work with the facility to establish a technologically-achievable NOx limit that is based on all supporting data, if necessary. This NOx limit may be greater than 11 ppm and the rule provides for a backstop of 45 ppm.

Response to Comment 16-8
The proposed rule provides sufficient time after commissioning to operate the unit under various operating conditions with flexibility for the NOx limit. The objective of providing time extensions is to give the facility sufficient flexibility to determine what can be achievable. . In addition, the proposed rule provisions allow for averaging over an extended period of time which gives additional flexibility to account for any load changes.

Response to Comment 16-9
See the responses to Comments 16-4 through 16-7.

Response to Comment 16-10
Please refer to the staff report under *Clarification of Rule Language in Subparagraph (d)(1)(B)* for examples of fixed-interval averaging. Staff acknowledges the disparity in the language between PAR 1110.2 and PAR 1100 regarding the 3-hour averaging. The two rules have been harmonized to include a fixed-interval 3-hour averaging requirement. Although Rules 218 and 218.1 will be amended in the near future to address elements pertaining to averaging, any requirements in the source-specific rules that are considered more stringent than in Rules 218 and 218.1 should be adhered to.

Response to Comment 16-11
Thank you for your comment. It is not the intent to remove VOC limits that had been previously established on a case-by-case basis. As also explained in response to Comment 16-3, any future flexibility with emission limits would be limited to NOx. The rule has been updated to clarify this issue.

Response to Comment 16-12
Staff has contacted the commenter and has discussed the intent for the revision to the source testing requirements. Refer to the staff report discussion under *Clarified Language Regarding Source Testing Deadlines*.

Response to Comment 16-13
Reference to Attachment I is made as an example of the types of parameters that the facility may be required to report to the Executive Officer. Depending on what information is required for the data evaluation, a data acquisition process will be agreed to by the facility and the South Coast AQMD. PAR 1100 provides a listing of information that includes, but is not limited to, any applicable operating parameter under Attachment 1. This is not a requirement to submit an Inspection & Monitoring plan.

Response to Comment 16-14
The differences between Rule 1134 and PAR 1110.2 are noted and staff has added proposed rule language that will address the compliance dates.

Response to Comment 16-15
Staff has clarified these requirements in new proposed paragraph (d)(4) in Rule 1100 to address engines that will be subject to replacement with compressor gas turbines under Rule 1134. The

proposed provision would require submittal of a retirement plan that would outline the expected dates of engine removal or replacement. Through the permitting process for the replacement equipment, permit conditions will specify an appropriate time overlap that would ensure that the new equipment can operate reliably before the existing compressor gas lean-burn engines are removed from service.

Response to Comment 16-16

See response to Comment 16-15.

Response to Comment 16-17

Staff agrees and has revised the rule to address any compliance gap.