SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Staff Report
Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities

October 2018

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CHAPTER 1: BACKGROUND

INTRODUCTION

In March 2017, the SCAQMD adopted the Final 2016 Air Quality Management Plan (2016 AQMP) which includes a series of control measures to achieve the National Ambient Air Quality Standards for ozone. The adoption resolution of the 2016 AQMP directed staff to achieve additional NOx emission reductions and to transition the Regional Clean Air Incentives Market (RECLAIM) program to a command-and-control regulatory structure requiring Best Available Retrofit Control Technology (BARCT) as soon as practicable. Additionally, California State Assembly Bill (AB) 617, approved by the Governor on July 26, 2017, requires air districts to develop, by January 1, 2019, an expedited schedule for the implementation of BARCT no later than December 31, 2023 for facilities that are in the state greenhouse gas cap-and-trade program.

Rule 1135 – Emissions of Oxides of Nitrogen from Electric Power Generating Systems (Rule 1135) was adopted in 1989 and currently applies to electric power generating steam boiler systems, repowered units, and alternative electricity generating sources. Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities (PAR 1135) is being amended to facilitate the transition of the NOx RECLAIM program to a command-and-control regulatory structure and to implement Control Measure CMB-05 – Further NOx Reductions from RECLAIM Assessment (Control Measure CMB-05) of the 2016 AQMP. PAR 1135 applies to RECLAIM and non-RECLAIM electricity generating facilities that are investor-owned electric utilities, publicly owned electric utilities, or have a generation capacity of at least 50 megawatts of electrical power.

BACKGROUND

The SCAQMD Governing Board adopted the RECLAIM program in October 1993. The purpose of RECLAIM is to reduce NOx and SOx emissions through a market-based approach. The program replaced a series of existing and future command-and-control rules and was designed to provide facilities with the flexibility to seek the most cost-effective solution to reduce their emissions. It also was designed to provide equivalent emission reductions, in the aggregate, for the facilities in the program compared to what would occur under a command-and-control approach. Regulation XX – Regional Clean Air Incentives Market (RECLAIM) (Regulation XX) includes a series of rules that specify the applicability and procedures for determining NOx and SOx facility emissions allocations, program requirements, as well as monitoring, reporting, and recordkeeping requirements for RECLAIM facilities.

Various rules within Regulation XX have been amended throughout the years. On December 4, 2015, Regulation XX was amended to achieve programmatic NOx emission reductions through an overall reduction in RECLAIM trading credits (RTC) of 12 tons per day from compliance years 2016 through 2022. Regulation XX was amended on October 7, 2016 to incorporate provisions that limited use of RTCs from facility shutdowns. The most recent amendments to Regulation XX on January 5, 2018 was to amend Rules 2001 – Applicability and 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) to commence the initial steps to transition RECLAIM facilities to a command-and-control regulatory approach.

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 sunset 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. Staff provided a report on transitioning the NOx RECLAIM program to a command-and-control regulatory structure at the May 5, 2017 Governing Board meeting and provides quarterly updates to the Stationary Source Committee, with the first quarterly report provided on October 20, 2017.

On July 26, 2017, AB 617 was approved by the Governor, which addresses non-vehicular air pollution (criteria pollutants and toxic air contaminants). It is a companion legislation to AB 398, which was also approved, and extends California's cap-and-trade program for reducing greenhouse gas emissions from stationary industrial sources. Electricity generating facilities are not classified as stationary industrial sources. RECLAIM facilities that are in the cap-and-trade program are subject to the requirements of AB 617. Among the requirements of this bill is an expedited schedule for implementing BARCT for cap-and-trade facilities. Air Districts are to develop by January 1, 2019, an expedited schedule for the implementation of BARCT no later than December 31, 2023. The highest priority would be given to older, higher polluting units that will need to install retrofit controls.

In 2015, staff conducted a programmatic analysis of the RECLAIM equipment at each facility to determine if there are appropriate and up to date BARCT NOx limits within existing SCAQMD command-and-control rules for all RECLAIM equipment. It was determined that command-and-control rules would need to be adopted and/or amended to update emission limits to reflect current BARCT and to provide implementation timeframes for achieving BARCT compliance limits for certain RECLAIM equipment.

Rule 1135 is being amended to facilitate the transition of the NOx RECLAIM program to a command-and-control regulatory structure and to implement Control Measure CMB-05, of the 2016 AQMP. PAR 1135 applies to RECLAIM and non-RECLAIM electricity generating facilities that are investor-owned electric utilities, publicly owned electric utilities, or have a generation capacity of at least 50 megawatts of electrical power. The proposed amended rule will update emission limits to reflect current BARCT and to provide implementation timeframes. The provisions in PAR 1135 establish NOx and ammonia (NH3) emission limits for boilers and gas turbines and NOx, ammonia, carbon monoxide, volatile organic compounds, and particulate matter for internal combustion engines located on Santa Catalina Island. Additionally, PAR 1135 establishes provisions for monitoring, reporting, and recordkeeping, and establishes exemptions from specific provisions.

REGULATORY BACKGROUND

Rule 1135 was adopted in 1989 and applied to electric power generating steam boiler systems, repowered units, and alternative electricity generating sources. Rule 1135 set a NOx system-wide average emission limit of 0.25 lb/MW-hr and a daily NOx emissions cap for each utility system. Rule 1135 established interim emissions performance levels with a 1996 final compliance date. Additionally, Rule 1135 required Emission Control Plans and continuous emissions monitoring systems.

Rule 1135 was submitted to the California Air Resources Board (CARB) for review, prior to submittal to the Environmental Protection Agency (EPA), Region IX, for revision to the State Implementation Plan (SIP). In March 1990, CARB staff informed SCAQMD that the adopted rule was lacking specificity in critical areas of implementation and enforcement, and was therefore, considered incomplete for submission to EPA as a SIP revision.

The December 21, 1990 amendment of Rule 1135 was principally developed to resolve many of the implementation and enforceability issues. This amendment included accelerated retrofit dates for emission controls, unit-by-unit emission limits, modified compliance plan and monitoring requirements, computerized telemetering, and an amended definition of alternative resources.

Furthermore, in order to consider additional staff recommendations regarding system-wide emission rates, daily emission caps, annual emission caps, oil burning, and cogeneration, the Board continued the public hearing. The July 19, 1991 amendment addressed all of these outstanding issues, including those related to modeling and BARCT analysis. EPA approved Rule 1135 into the SIP on August 11, 1998.

Electricity Generating Facilities and RECLAIM

Throughout the RECLAIM program, there have been specific provisions for electricity generating facilities. When RECLAIM was adopted in 1993, pursuant to Rule 2001 electricity generating facilities were initially included in NOx RECLAIM and could opt-in to SOx RECLAIM. Electricity generating facilities that were owned and operated by the City of Burbank, City of Glendale, or the City of Pasadena were not initially included in NOx and SOx RECLAIM program, but were allowed to opt-in to the program. The cities of Burbank and Pasadena opted-in to RECLAIM, while the City of Glendale remained regulated by command-and-control rules.

In June 2000, RECLAIM program participants experienced a sharp and sudden increase in NOx RECLAIM trading credit (RTC) prices for both the 1999 and 2000 compliance years. Based on the 2000 RECLAIM Annual Report, electricity generating facilities had an initial allocation of 2,302 tons of NOx per year. In compliance year 2000, these facilities reported NOx emissions of 6,788 tons per year, approximately 4,400 tons per year over their initial allocation. This was primarily due to an increased demand for power generation and delayed installation of controls by electricity generating facilities. The electric power generating industry purchased a large quantity of RTCs, which depleted the available RTCs. This situation was compounded because few RECLAIM facilities added control equipment. As a result, in May 2001, the Board adopted Rule 2009 – Compliance Plan for Power Producing Facilities (Rule 2009). To facilitate emission reduction projects at the facilities with the majority of the emissions in RECLAIM, Rule 2009 required installation of BARCT through compliance plans at electricity generating facilities. Diesel internal combustion engines providing power to Santa Catalina Island were not subject to Rule 2009 because the facility only generates 9 megawatts of energy and did not qualify as a Power Producing Facility in RECLAIM.

A case-by-case technical and cost-effectiveness evaluation was performed to determine BARCT for electric generating units at electricity generating facilities. At that time BARCT for utility boilers was determined to be 9 ppmv NOx at 3% oxygen on a dry basis and for gas turbines was determined to be 9 ppmv NOx at 15% oxygen on a dry basis. Where technically feasible and cost-effective, RECLAIM electric generating units were retrofitted, repowered, or retired. There were electric generating units that could not cost-effectively control emissions and were given permit limits with higher NOx concentrations. Between 2001 and 2005, more than 35 simple and combined cycle gas turbines were repowered to BARCT levels or below. Despite the increase in NOx RTC demand, emissions from electricity generating facilities fell from 26 tons per day of NOx emissions in 1989 to less than 10 tons per day of NOx emissions by 2005. Since then, with equipment replacement and increased reliance on renewable sources, NOx emissions have further decreased to less than 4 tons per day.

PUBLIC PROCESS

Development of Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities was conducted through a public process. SCAQMD has held five working group meetings at the SCAQMD Headquarters in Diamond Bar on January 24, 2018, April 26, 2018, June 13, 2018, July 5, 2018, and September 25, 2018. The Working Group is composed of representatives from businesses, environmental groups, public agencies, and consultants. The purpose of the working group meetings is to discuss proposed concepts and work through the details of staff's proposal. Additionally, a Public Workshop was held at the SCAQMD Headquarters in Diamond Bar on August 2, 2018.

CHAPTER 2: BARCT ASSESSMENT

INTRODUCTION

Staff conducted an assessment of Best Available Retrofit Control Technology (BARCT) for electric generating units including diesel internal combustion engines located on Santa Catalina Island, natural gas boilers, and natural gas turbines and associated duct burners. BARCT is defined in the California Health and Safety Code section 40406 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." Consistent with state law, BARCT emissions limits take into consideration environmental impacts, energy impacts, and economic impacts. In addition to NOx reductions sought in the proposed amended rule, SCAQMD, through the California Environmental Quality Act (CEQA) process, identified potential environmental and energy effects of the proposed rule. Economic impacts are assessed at the equipment category level by a review of cost-effectiveness and incremental cost-effectives contained in this report and at the macro level as part of the socio-economic assessment contained in a separate report.

BARCT – RETROFIT VERSUS REPLACEMENT

A question was raised in the Regional Clean Air Incentives Market (RECLAIM) Working Group concerning the scope of "best available retrofit control technology," which the SCAQMD must impose for all existing stationary sources, including sources that exit RECLAIM or that exist after RECLAIM has ended pursuant to Health & Safety Code section 40440(b)(1). A commenter stated that the use of the word "retrofit" precludes the SCAQMD from requiring emissions limits that can only be cost-effectively met by replacing the basic equipment with new equipment. Staff believes that the use of the term "retrofit" does not preclude replacement technology. A review of on-line dictionaries supports this view.

The on-line Merriam-Webster Dictionary defines "retrofit" in a manner that does not preclude replacing equipment. That dictionary establishes the following definition for retrofit: "1: to furnish (something, such as a computer, airplane, or building) with new or modified parts or equipment not available or considered necessary at the time of manufacture, 2: to install (new or modified parts or equipment) in something previously manufactured or constructed, 3: to adapt to a new purpose or need: modify." https://www.merriam-webster.com/dictionary/retrofit. This definition does not preclude the use of replacement parts as a retrofit.

The on-line Dictionary.com is more explicit in allowing replacement parts. It includes the following definitions for retrofit as a verb: "1. to modify equipment (in airplanes, automobiles, a factory, etc.) that is already in service using parts developed or made available after the time of original manufacture, 2. to install, fit, or adapt (a device or system) or use with something older; to retrofit solar heating to a poorly insulated house, 3. (of new or modified parts, equipment, etc.) to fit into or onto existing equipment, 4. to replace existing parts, equipment, etc., with updated parts or systems." http://www.dictionary.com/browse/retrofit. This definition clearly includes replacement of existing equipment within the concept of "retrofit." Accordingly, the use of the term "retrofit" can include the concept of replacing existing equipment.

Moreover, the statutory definition of "best available retrofit control technology" does not preclude replacing existing equipment with new cleaner equipment. Health & Safety Code section 40406 provides: "As used in this chapter, 'best available retrofit control technology' means an emission limitation that is based on the maximum degree of emission reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source." Thus, it is clear that BARCT is an emissions limitation, and is not limited to a particular technology, whether add-on or replacement. Certainly this definition does not preclude replacement technologies.

Staff also notes that the argument precluding replacement equipment would have an effect contrary to the purposes of BARCT. For example, staff has proposed a BARCT that may be more cost-effectively be met for diesel-fueled engines by replacing the engine with a new Tier IV diesel engine rather than installing additional add-on controls on the current engine which may be many decades old. If the SCAQMD were precluded from setting BARCT for these sources, the oldest and dirtiest equipment could continue operating for possibly many more years, even though it would be cost-effective and otherwise reasonable to replace those engines. There is no policy reason for insisting that replacement equipment cannot be an element of BARCT as long as it meets the requirements of the statute including cost-effectiveness.

The case law supports an expansive reading of BARCT. In explaining the meaning of BARCT, the California Supreme Court held that BARCT is a "technology-forcing standard designed to compel the development of new technologies to meet public health goals." *American Coatings Ass'n. v. South Coast Air Quality Mgt. Dist.*, 54 Cal. 4th 446, 465 (2012). In fact, the BARCT requirement was placed in state law for the SCAQMD in order to "encourage more aggressive improvements in air quality" and was designed to augment rather than restrain the SCAQMD's regulatory power. *American Coatings, supra*, 54 Cal. 4th 446, 466. Accordingly, BARCT may actually be more stringent than BACT, because BACT must be implemented today by a source receiving a permit today, whereas BARCT may, if so specified by the SCAQMD, be implemented a number of years in the future after technology has been further developed. *American Coatings, supra,* 54 Cal. 4th 446, 467.

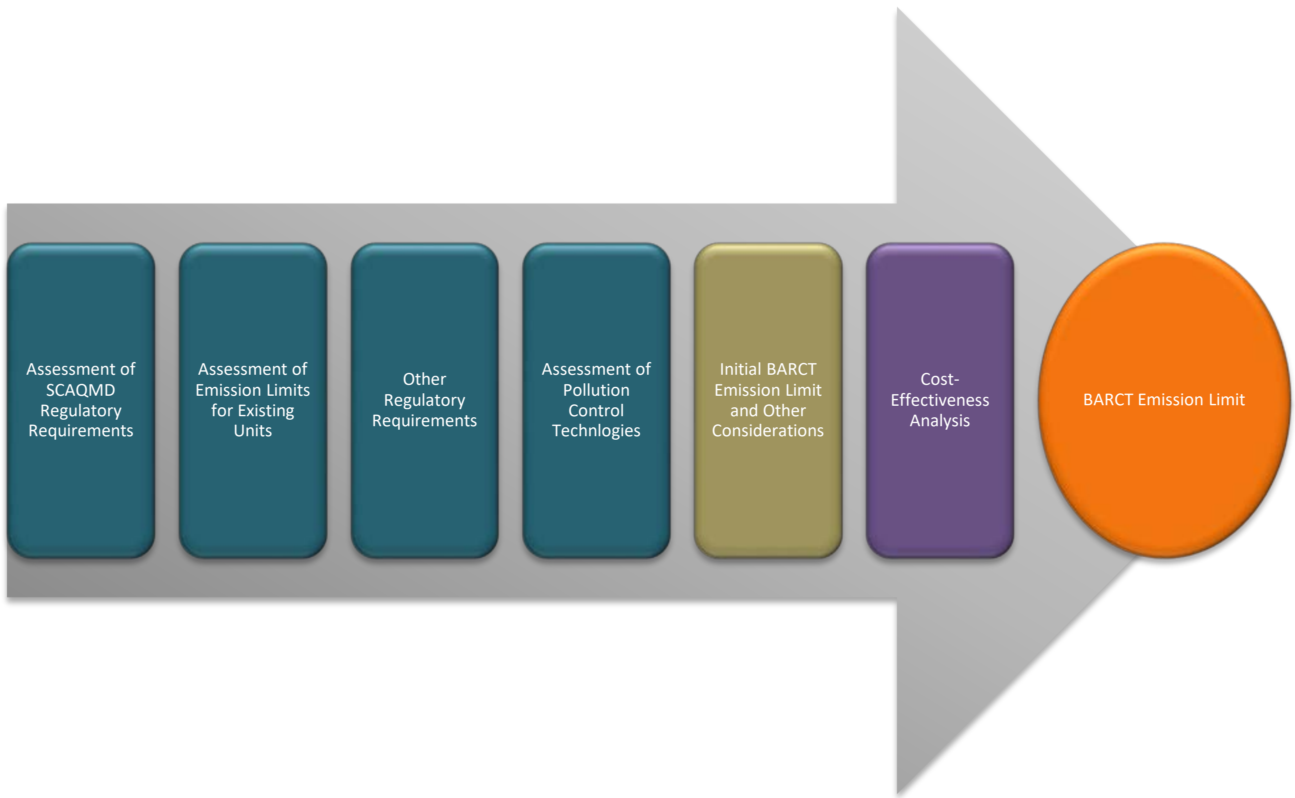
The Supreme Court further held that when challenging the SCAQMD's determination of the scope of a "class or category of source" to which a BARCT standard applies, the challenger must show that the SCAQMD's determination is "arbitrary, capricious, or irrational." *American Coatings, supra,* 54 Cal. 4th 446, 474. Therefore, the SCAQMD may consider a variety of factors in determining which sources must meet any particular BARCT emissions level. If, for example, some sources could not cost-effectively reduce their emissions further because their emissions are already low, these sources can be excluded from the category of sources that must meet a particular BACT. Therefore, the SCAQMD may establish a BARCT emissions level that can cost-effectively be met by replacing existing equipment rather than installing add-on controls, and the SCAQMD's definition of the category of sources which must meet a particular BARCT is within the SCAQMD's discretion as long as it is not arbitrary or irrational.

BARCT ANALYSIS APPROACH

The BARCT analysis approach follows a series of steps conducted for each equipment category and fuel type. For Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities (PAR 1135), liquid petroleum (diesel) fueled internal combustion engines and natural gas fired boilers and turbines were analyzed. Liquid petroleum fuels are only allowable during force majeure natural gas curtailment periods for boiler and turbines and for internal combustion engines on Santa Catalina Island where natural gas is unavailable. Natural gas fuel burning is required in all other situations.

The steps for BARCT analysis consist of:

- Assessment of SCAQMD Regulatory Requirements
- Assessment of Emissions Limits for Existing Units
- Other Regulatory Requirements
- Assessment of Pollution Control Technologies
- Initial BARCT Emission Limit and Other Considerations
- Cost-Effectiveness Analysis
- Final BARCT Emission Limit



Assessment of SCAQMD Regulatory Requirements

As part of the BARCT assessment, staff reviewed existing SCAQMD regulatory requirements that affect NOx emissions for equipment at electricity generating facilities. NOx emissions from electricity generating facilities are regulated under Rule 1135 – Emissions of Oxides of Nitrogen from Electric Power Generating Systems (Rule 1135), Regulation XX – Regional Clean Air Incentives Market (RECLAIM) (Regulation XX), and Rule 2009 – Compliance Plan for Power Producing Facilities (Rule 2009) within RECLAIM. Under Rule 1135, the NOx emission standard is a system-wide standard and does not include equipment-specific NOx emissions standards. The current NOx system-wide standard is as follows in Table 2-1 below.

Table 2-1 – Current Rule 1135 System-Wide NOx Limits

Electric Power Generating System	NOx Limit (tons per year)
Southern California Edison	1,640
Los Angeles Department of Water and Power	960
City of Burbank	56
City of Glendale	35
City of Pasadena	80

Similarly, the RECLAIM program limits NOx emissions from electricity generating facilities, but does not limit emissions or establish concentration limits by equipment category or fuel type. However, emissions limits are established at the time of permitting, and permits include concentration limits for NOx and emissions limits for non-RECLAIM pollutants such as particulate matter. A facility's NOx allocations are diminished over time, requiring facilities to lower emissions or to purchase credits from other facilities that have lowered emissions below their allocations.

In 2001, Rule 2009 was adopted in response to California energy issues. The rule required RECLAIM electricity generating facilities to install pollution controls to help stabilize RECLAIM Trading Credit (RTC) prices. Electricity generating facilities submitted compliance plans demonstrating that all RECLAIM NOx emitting equipment achieved BARCT emission levels. A case-by-case technical and cost-effectiveness evaluation was performed to determine BARCT. At that time BARCT for natural gas utility boilers was determined to be 9 ppmv NOx at 3% oxygen on a dry basis and natural gas turbines was determined to be 9 ppmv NOx at 15% oxygen on a dry basis. Where technically feasible and cost-effective, RECLAIM electric generating units were retrofitted, replaced, or retired. There were electric generating units that could not cost-effectively control emissions and were given permit limits with higher NOx concentrations. The proposed amendments to Rule 1135 do not obviate implementation or compliance plans under Rule 2009. The assessment of SCAQMD regulatory requirements found a BARCT emission limit of 9 ppmv at 15% O2 dry for both natural gas turbines and natural gas boilers. No assessment was made for diesel internal combustion engines as they were not subject to Rule 2009 due to low output.

Assessment of Emission Limit for Existing Units

Staff examined all of the current electric generating units to assess the emission rate of equipment located in SCAQMD. Permit limits for NOx concentrations were identified for all equipment to identify what is already being done in practice. Currently, there are approximately 124 pieces of equipment at 31 facilities: six diesel internal combustion engines at one facility; 23 natural gas boilers at 8 facilities; 59 natural gas simple cycle gas turbines at 20 facilities; and 23 natural gas combined cycle gas turbines and 11 associated duct burners at 12 facilities.

<u>Diesel Internal Combustion Engines</u>

Six diesel internal combustion engines are located on Santa Catalina Island. Five of these engines were installed more than 33 years ago and one was installed 23 years ago. All units are controlled with selective catalytic reduction. The permitted NOx emission limits range between 51 ppmv to 140 ppmv at 15% oxygen on a dry basis. The permitted ammonia emission limit is 10 ppmv at 15% oxygen on a dry basis. In 2003, the higher emitting units were retrofitted, while the lowest emitting unit was a new installation in 1995. The lowest permitted NOx limit for a diesel engine used for electricity generation in SCAQMD is 51 ppmv at 15% oxygen on a dry basis. The details of the diesel internal combustion engines subject to PAR 1135 are listed below in Table 2-2 below.

Table 2-2 – Diesel Internal Combustion Engines

Unit	Size (HP)	Output (MW)	Install Year	Retrofit Date	Control[3]	NOx Permit Limit[1]	Ammonia (ppmv at 15% oxygen, dry)	2016 NOx Emissions (tons)
ICE1	1575	1.125	1968	2003	SCR	6.5 lbs/MWh[2]	10	16
ICE3	1950	1.4	1985	2003	SCR	6.5 lbs/MWh[2]	10	5.3
ICE6	2150	1.5	1964	2003	SCR	6.5 lbs/MWh[2]	10	8.2
ICE5	1500	1	1967	2003	SCR	6.5 lbs/MWh[2]	10	12
ICE2	2200	1.5	1976	2003	SCR	6.5 lbs/MWh[2]	10	22
ICE4	3900	2.8	1995	None	SCR	51 ppmv at 15% oxygen, dry; 6.5 lbs/MWh[2]	10	5.9

[1] – Actual NOx concentrations emitted are generally lower than the NOx permit limits
[2] – Averaged over one calendar year, limit is based on total mass NOx emitted from Units 1 – 6 and micro turbines
[3] – SCR: Selective Catalytic Reduction

Natural Gas Boilers

Of the 23 natural gas boilers used to generate electricity, 16 of them are subject to the Clean Water Act's once-through-cooling (OTC) provisions and are scheduled for shutdown. Eight of the 17 units were retrofitted between 1990 and 2002 to meet a NOx limit of 5 ppmv at 3% oxygen on a dry basis. Ammonia ranges between 10 ppmv and 20 ppmv at 3% oxygen on a dry basis. Information regarding natural gas boilers subject to the Clean Water Act's once-through-cooling regulation is provided in Table 2-3 below.

There are seven natural gas boilers that are not subject to the Clean Water Act's OTC provisions. Two of the natural gas boilers are scheduled for shut down and retirement by 2019. Three natural gas boilers, all with NOx permit limits between 38 and 82 ppmv NOx at 3% oxygen on a dry basis, are operated by a municipality. The operator has informed their city council of plans to shut down the natural gas boilers and replace them with one or more natural gas turbines and the project is pending city council approval. The remaining two natural gas boilers have not been in operation since 2012. For these remaining seven natural gas boilers, the lowest permitted NOx concentration limit is 5 ppmv at 3% oxygen on a dry basis, which was retrofitted in 2002. The lowest permitted NOx limit for a natural gas boiler used for electricity generation in SCAQMD is also 5 ppmv at

3% oxygen on a dry basis. The details of the natural gas boilers subject to PAR 1135 are listed below in Table 2-3 below.

Table 2-3 – Natural Gas Boilers

Unit	Size (MMBTU/HR)	Output (MW)	Install Year	Retrofit Year	Control[2]	NOx Permit Limit[1] (ppmv @ 3% oxygen, dry)	Ammonia (ppmv @ 3% oxygen, dry)	2016 NOx Emissions (tons)	Shut Down Date
B15	492	44	1959	None	LNB/FGR	82	N/A	177.5	Pending
B12	260	20	1953	None	LNB/FGR	40	N/A	39.7	Pending
B18	527.25	44	1969	2002	FGR/SNCR	38	10	133.6	Pending
B2	2021	215	1958	2001	SCR	7	10	8.2	OTC 11/1/19
B17	1785	175	1954	2001	SCR/staged comb	7	10	1.3	OTC 11/1/19
B20	1785	175	1957	2001	SCR/staged comb	7	10	3.3	OTC 11/1/19
B1	1785	175	1956	2001	SCR/FGR/staged comb	7	10	2.0	OTC 12/29/19
B6	1785	175	1957	2001	SCR/FGR/staged comb	7	10	3.8	OTC 12/29/19
B10	3350	320	1961	2001	SCR/FGR	7	10	14	OTC 12/31/20
B13	3350	320	1962	2001	SCR/FGR	7	10	8.6	OTC 12/31/20
B7	2021	215	1958	2001	SCR	7	10	7.6	OTC 12/31/20
B11	2900	320	1963	2001	FGR/Staged Comb/SCR	7	10	3.6	12/31/2018
B14	2900	320	1963	2001	FGR/Staged Comb/SCR	7	10	4.1	12/31/2018
B9	1750	179	1959	2002	SCR	5	10	1.8	OTC 12/31/24
B4	1750	179	1958	2002	SCR	5	10	6.9	OTC 12/31/24
B23	551.84	44	1959	2002	SCR/LNB	5	10	0.0	None
B24	604.7	55	1964	2002	SCR	5	10	0.0	None
B3	2240	230	1962	1993	SCR	5	20	5.3	OTC 12/31/29
B8	2240	230	1963	1993	SCR	5	20	5.5	OTC 12/31/29
B21	4752.2	480	1968	1994	SCR/FGR/staged comb	5	20	5.4	OTC 11/1/19
B22	4752.2	480	1968	1994	SCR/FGR/staged comb	5	20	3.3	OTC 11/1/19
B19	4752.2	480	1966	1994	SCR/FGR	5	20	2.3	OTC 12/29/19
B16	4750	480	1969	1994	SCR/LNB/FGR	5	20	2.1	OTC 12/31/20

[1] – Actual NOx concentrations emitted are generally lower than the NOx permit limit

[2] – FGR: Flue Gas Recirculation, LNB: Low NOx Burner, SCR: Selective Catalytic Reduction, SNRC: selective non-catalytic reduction, staged comb: staged combustion

Natural Gas Combined Cycle Gas Turbines

For natural gas combined cycle gas turbines, 15 of 23 units are permitted at 2 ppmv NOx at 15% oxygen on a dry basis. All units were replacement units installed in 2005 or later. Two units were installed as late as 2015, still with a permitted NOx limit of 2 ppmv at 15% oxygen on a dry basis. Units that were permitted at 2 ppmv NOx at 15% oxygen on a dry basis also had ammonia permit limits of 5 ppmv at 15% oxygen on a dry basis. The lowest permitted NOx limit for a natural gas combined cycle gas turbines used for electricity generation in SCAQMD is 2 ppmv at 15% oxygen on a dry basis. Table 2-4 lists the information regarding natural gas combined cycle gas turbines.

Table 2-4 – Natural Gas Combined Cycle Gas Turbines

Unit	Size (MMBTU/HR)	MW Rating	Install	Control	NOx Permit Limit[1] (ppmv @ 15% oxygen, dry)	Ammonia Permit Limit (ppmv @ 15% oxygen, dry)	2016 NOx Emissions (tons)
T-CC-1	442	48	1993	SCR	9 and 7.6	20	4.3
T-CC-26	350	30	1976	SCR	9	5	0.75
T-CC-27	350	60	1976	SCR	9	5	0.51
T-CC-28	350	60	1976	SCR	9	5	0.51
T-CC-22	1088	182	1993	SCR/water injection	7	20	12
T-CC-23	1088	182	1993	SCR/water injection	7	20	8.9
T-CC-24[4]	1944	290	2002	SCR/DLN	2.5	5	33
T-CC-25[4]	1944	290	2002	SCR/DLN	2.5	5	36
T-CC-10	2597	405	2008	SCR/DLN	2	5	1.8
T-CC-11[4]	535	71.7	2005	SCR	2	5	20
T-CC-12[4]	535	71.7	2005	SCR	2	5	20
T-CC-13[4]	2126	264	2005	SCR/DLN	2	5	24
T-CC-14[4]	2126	264	2005	SCR/DLN	2	5	23
T-CC-15[4]	2126	264	2005	SCR/DLN	2	5	23
T-CC-16[4]	2126	264	2005	SCR/DLN	2	5	25
T-CC-18[3,4]	2043.6	295	2008	SCR/DLN	2	5	22
T-CC-19[3,4]	2043.6	295	2008	SCR/DLN	2	5	39
T-CC-20	2205	321	2015	SCR/DLN	2	5	26
T-CC-21	547.5	71	2015	SCR/water injection	2	5	0.4
T-CC-6	2096	286.5	2013	SCR/DLN	2	5	11
T-CC-7	2096	386.5	2013	SCR/DLN	2	5	11
T-CC-8[4]	2370	328	2005	SCR/DLN	2	5	33
T-CC-9	2597	405	2008	SCR/DLN	2	5	6.2

[1] – Actual NOx concentrations emitted are generally lower than the NOx permit limit
[2] – DLN: Dry Low NOx, SCR: Selective Catalytic Reduction
[3] – Subject to the Clean Water Act once-through-cooling (OTC) provisions and scheduled for shutdown 12/31/29
[4] – Natural Gas Combined Cycle Gas Turbine with Associated Duct Burner

Natural Gas Simple Cycle Gas Turbines

For natural gas simple cycle gas turbines, 37 of 59 units are permitted at or below 2.5 ppmv NOx at 15% oxygen on a dry basis. Two of the 37 units are permitted at 2.3 ppmv NOx at 15% oxygen on a dry basis. However, the operator of the two units is seeking permit changes to raise the limit to 2.5 ppmv NOx at 15% oxygen on a dry basis to avoid compliance issues. All of the low concentration natural gas simple cycle turbines were new installations commissioned after 2006. Units that were permitted at 2.5 ppmv NOx at 15% oxygen dry also have ammonia permit limits of 5 ppmv at 15% oxygen on a dry basis. Table 2-5 lists the information regarding natural gas simple cycle turbines.

Table 2-5 – Natural Gas Simple Cycle Gas Turbines

Unit	Size (MMBTU/HR)	Output (MW)	Install Year	Control[2]	NOx Permit Limit[1] (ppmv at 15% oxygen, dry)	Ammonia (ppmv at 15% oxygen, dry)	2016 NOx Emissions (tons)
T-SC-61	69.12	6	1989	Water Injection	24	NA	0.058
T-SC-63	69.12	6	1989	Water Injection	24	NA	0.13
T-SC-64	298	31	1975	SCR/water injection	9	5	0.088
T-SC-65	298	30	1975	SCR/water injection	9	5	0.0
T-SC-68	450	46	2002	SCR/water injection	5	5	1.2
T-SC-10	450	45	2001	SCR/water injection	5	5	1.9
T-SC-30	450	45	2001	SCR/water injection	5	5	1.5
T-SC-40	450	45	2001	SCR/water injection	5	5	1.6
T-SC-13	128.8	10.5	2001	SCR/DLN	5	5	0.030
T-SC-33	128.8	10.5	2001	SCR/DLN	5	5	0.037
T-SC-43	128.8	10.5	2001	SCR/DLN	5	5	0.036
T-SC-52	128.8	10.5	2001	SCR/DLN	5	5	0.026
T-SC-66	448	47.4	2003	SCR/water injection	5	5	2.4
T-SC-67	448	47.4	2003	SCR/water injection	5	5	8.9
T-SC-18	466.8	47.4	2001	SCR/water injection	5	5	2.0
T-SC-19	466.8	47.4	2001	SCR/water injection	5	5	1.6
T-SC-21	466.8	47.4	2001	SCR/water injection	5	5	1.1
T-SC-23	466.8	47.4	2001	SCR/water injection	5	5	1.0
T-SC-25	466.8	47.4	2001	SCR/water injection	5	5	2.0
T-SC-57	466.8	47.4	2001	SCR/water injection	5	5	1.5
T-SC-75	470	49.6	2003	SCR/water injection	5	5	3.6
T-SC-15	456.5	48	2003	SCR/water injection	3.5	5	0.49
T-SC-71	505	47	2007	SCR/water injection	2.5	5	1.5
T-SC-70	511.5	47	2007	SCR/water injection	2.5	5	2.0
T-SC-72	522	47	2007	SCR/water injection	2.5	5	1.7
T-SC-29	871.3	65	2007	SCR/water injection	2.5	5	1.2
T-SC-39	871.3	65	2007	SCR/water injection	2.5	5	1.2
T-SC-49	871.3	65	2007	SCR/water injection	2.5	5	1.2
T-SC-9	871.3	65	2007	SCR/water injection	2.5	5	0.91
T-SC-14	490	50	2006	SCR/water injection	2.5	5	1.3
T-SC-34	490	50	2006	SCR/water injection	2.5	5	1.3
T-SC-16	891.7	100	2013	SCR/water injection	2.5	5	9.7
T-SC-35	891.7	100	2013	SCR/water injection	2.5	5	10.2
T-SC-45	891.7	100	2013	SCR/water injection	2.5	5	9.7
T-SC-54	891.7	100	2013	SCR/water injection	2.5	5	8.0
T-SC-58	891.7	100	2013	SCR/water injection	2.5	5	7.7
T-SC-69	505.7	47	2007	SCR/water injection	2.5	5	1.9
T-SC-1	891.7	100	2013	SCR/water injection	2.5	5	2.7
T-SC-2	891.7	100	2013	SCR/water injection	2.5	5	2.7
T-SC-3	891.7	100	2013	SCR/water injection	2.5	5	2.5
T-SC-4	891.7	100	2013	SCR/water injection	2.5	5	2.7
T-SC-5	891.7	100	2013	SCR/water injection	2.5	5	2.6
T-SC-6	891.7	100	2013	SCR/water injection	2.5	5	2.6
T-SC-7	891.7	100	2013	SCR/water injection	2.5	5	2.6
T-SC-8	891.7	100	2013	SCR/water injection	2.5	5	2.0

Unit	Size (MMBTU/HR)	Output (MW)	Install Year	Control[2]	NOx Permit Limit[1] (ppmv at 15% oxygen, dry)	Ammonia (ppmv at 15% oxygen, dry)	2016 NOx Emissions (tons)
T-SC-17	479	50	2011	SCR/water injection	2.5	5	1.5
T-SC-36	479	50	2011	SCR/water injection	2.5	5	1.3
T-SC-46	479	50	2011	SCR/water injection	2.5	5	1.4
T-SC-55	479	50	2011	SCR/water injection	2.5	5	1.5
T-SC-20	906.6	103	2013	SCR/water injection	2.5	5	4.9
T-SC-22	906.6	103	2013	SCR/water injection	2.5	5	0.9
T-SC-24	906.6	103	2013	SCR/water injection	2.5	5	4.6
T-SC-26	906.6	103	2013	SCR/water injection	2.5	5	1.1
T-SC-27	906.6	103	2013	SCR/water injection	2.5	5	4.4
T-SC-28	906.6	103	2013	SCR/water injection	2.5	5	3.8
T-SC-60	959	106	2015	SCR/water injection	2.5	5	7.0
T-SC-62	959	106	2015	SCR/water injection	2.5	5	8.2
T-SC-44	490	50	2009	SCR/water injection	2.3	5	0.7
T-SC-53	490	50	2009	SCR/water injection	2.3	5	0.9

[1] – Actual NOx concentration emitted are generally lower than the NOx permit limit
[2] – DLN: Dry Low NOx, SCR: Selective Catalytic Reduction

Summary

A summary of permitted limits in SCAQMD for the four types of electrical power generating units is provided in Table 2-6. While previous SCAQMD regulatory requirements established BARCT at 9 ppmv at 15% oxygen on a dry basis for natural gas boilers and natural gas turbines, existing equipment in SCAQMD in all categories have been found at lower NOx concentration limits as seen in the Table 2-6.

Table 2-6 – Assessment of NOx Concentration Levels for Existing Units

Equipment	Initial Recommendation for NOx Concentration Limit Based on Existing Units	Number of Units Meeting Retrofit Concentration Limit	Pollution Control Technology
Diesel Internal Combustion Engine	45 ppmv at 15% oxygen, dry	0 units	Selective Catalytic Reduction (Replacement)
Natural Gas Boiler	5 ppmv at 3% oxygen, dry	10 units	Selective Catalytic Reduction, Low-NOx Burners, Flue Gas Recirculation, Staged Combustion (Retrofit)
Natural Gas Combined Cycle Gas Turbine	2 ppmv at 15% oxygen, dry	15 units	Selective Catalytic Reduction, Water Injection, Dry Low NOx (Replacement)
Natural Gas Simple Cycle Gas Turbine	2.5 ppmv at 15% oxygen, dry	37 units	Selective Catalytic Reduction, Water Injection, Dry Low NOx (Replacement)

Other Regulatory Requirements

As part of the BARCT assessment, staff examined NOx limits for electric generating units promulgated by Bay Area Air Quality Management District (BAAQMD) and San Joaquin Valley Air Pollution Control District (SJVAPCD). BAAQMD Regulation 9, Rule 8 – Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines; Regulation 9, Rule 9 – Nitrogen Oxides and Carbon Monoxide from Stationary Gas Turbines; and Regulation 9, Rule 11 – Nitrogen Oxides and Carbon Monoxide from Utility Electric Power Generating Boilers were reviewed. Similarly, SJVAPCD Rule 4306 – Boilers, Steam Generators, and Process Heaters – Phase 3, Rule 4702 – Internal Combustion Engines, and Rule 4703 – Stationary Gas Turbines were reviewed. Finally, U.S. EPA Final rule for Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel was reviewed. Tables 2-7 through 2-9 below note the NOx limits in the two air districts and U.S. EPA's diesel engine NOx limit for Tier IV Final engines. The applicable equipment sizes differ by regulation. All limits except the Tier IV Final limits are applicable to new units and retrofitted units.

Table 2-7 – Non-Emergency Internal Combustion Engines (Diesel)

Agency	Rule Adoption Date	Rule Effective Date	NOx Limit (ppmv @ 15% oxygen, dry)
BAAQMD – Rich Burn	July 2007	January 2012	56
BAAQMD – Lean Burn	July 2007	January 2012	140
SJVAPCD	September 2003	June 2007	80
U.S. EPA	May 2004	2008 - 2015	45 (0.67 g/kWh)[1]

[1] – EPA Tier IV limit is 0.67 g/kWh, 45 ppmv is assuming 40% efficiency

Table 2-8 – Boilers (Natural Gas)

Agency	Rule Adoption Date	Rule Effective Date	Boiler Capacity (MMBTU/HR)	NOx Limit (ppmv @ 3% oxygen, dry)
BAAQMD	February 1994	May 1995	> 1,750	10
			> 1,500 to < 1,750	25
			< 1,500	30
SJVAPCD	October 2008	December 2008	> 20	6

Table 2-9 – Turbines (Natural Gas)

Agency	Rule Adoption Date	Rule Effective Date	Capacity (MMBTU/HR)	Output (MW)	NOx Limit (ppmv @ 15% oxygen, dry)
BAAQMD[1]	December 2006	January 2010	5 - 50	N/A	42
			>50 - 150	N/A	25-42
			>150 - 250	N/A	15
			>250 - 500	N/A	9
			>500	N/A	5
SJVAPCD	September 2007	January 2012	<35[2]	<3	25
			>35 – 130[2]	>3 – 10	25
			>130[2]	>10	25-42

[1] – Currently under review

[2] – Non-regulatory, converted for comparison purposes only

For natural gas boilers, natural gas combined cycle gas turbines, and natural gas simple cycle gas turbines, the NOx concentration limits in other Air District regulations was higher than existing units located in SCAQMD. For diesel internal combustion engines, the U.S. EPA Final rule for Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel NOx concentration limits were lower than existing units located in SCAQMD.

Assessment of Pollution Control Technologies

As part of the BARCT assessment, staff conducted a technology assessment to evaluate NOx pollution control technologies for electric generating units. Staff reviewed scientific literature, vendor information, and strategies utilized in practice. The technologies are presented below and the applicability for use with various electric power generating units is noted. In most cases, post-combustion technologies may be utilized in conjunction with pre-combustion technologies.

Pre-Combustion Technologies

Dry Low-NOx or Lean Premix Emission Combustors (Natural Gas Turbines)

Prior to combustion, gaseous fuel and compressed air are pre-mixed, minimizing localized hot spots that produce elevated combustion temperatures and therefore, less NOx is formed. Atmospheric nitrogen from the combustion air is mixed with air upstream of the combustor at deliberately fuel-lean conditions. Approximately twice as much air is supplied as is actually needed to burn the fuel. This excess air is a key to limiting NOx formation, as very lean conditions cannot produce the high temperatures that create thermal NOx. Using this technology, NOx emissions, without further controls, have been demonstrated at single digits (< 9 ppmv at 15% oxygen, dry). The technology is engineered into the combustor that becomes an intrinsic part of the turbine design. Fuel staging or air staging is utilized to keep the flame within its operating boundaries. It is not available as a "retrofit" technology and must be designed for each turbine application.

Water or Steam Injection (Natural Gas Turbines)

Demineralized water is injected into the combustor through the fuel nozzles to lower flame temperature and reduce NOx emissions. Water or steam provides a heat sink that lowers flame temperature. Imprecise application leads to some hot zones so NOx is still created. NOx levels in natural gas turbines can be lowered by 80% to 25 ppmv at 15% oxygen on a dry basis. Addition of water or steam increases mass flow through the turbine and creates a small amount of additional power. The addition of water increases carbon monoxide emissions and there is added cost to demineralize the water. Turbines using water or steam injection have increased maintenance due to erosion and wear.

Catalytic Combustion (Natural Gas Turbines)

A catalytic process is used instead of a flame to combust the natural gas. Flameless combustion lowers combustion temperature resulting in reduced NOx formation. The overriding constraints are operating efficiency over a wide operating range of the turbine. Initial engine demonstrations have shown that catalytic combustion reduces NOx emissions. In its first commercial installation, NOx concentrations were lowered from approximately 20 ppmv to below 3 ppmv at 15% oxygen on a dry basis without post-combustion controls. Several turbine manufacturers are in the development stage to incorporate this technology.

Low-NOx Burners (Natural Gas Boilers)

Controlled fuel and air mixing at the burner reduces the peak flame temperature resulting in reduced NOx formation. Lean pre-mixed combustion gases and low turbulence flow of combustion gases combine to achieve NOx reductions of 80 to 90%. Ultra-Low-NOx Burners are able to reduce NOx concentration to 5 to 7 ppmv at 3% oxygen on a dry basis. The burners are scalable for various sizes of boilers and heating units. The burners can be designed for retrofit or new installations. However, retrofits to existing boilers may require complex engineering and re-design.

Post-Combustion Technologies

Selective Catalytic Reduction (Diesel Internal Combustion Engines/Natural Gas Boilers/Natural Gas Turbines)

Selective Catalytic Reduction is the primary post-combustion technology for NOx reduction and is widely used in turbines, boilers, and engines including stationary engines and heavy duty trucks. It is the primary control for engines that meet U.S. EPA's Tier IV Final standards. The technology can reduce NOx emissions 95% or greater. In many cases the NOx reduction is limited by the release of other pollutants (ammonia and carbon monoxide), space constraints, or reaches the practical limit of the NOx measuring device. Nearly all electric generating units already utilize selective catalytic reduction. Further reductions could be possible by adding catalyst modules. From observations made during site visits, space is not readily available to add catalyst modules and would require construction.

Ammonia is injected into the flue gas and reacts with NOx to form nitrogen and water. Catalysts are made from ceramic materials and active catalytic components of base metals, zeolites, or precious metals. The catalyst may be configured into plates but many new systems are configured into honeycombs to ensure uniform dispersion and reduce ammonia emissions to below 5 ppmv. The reductant, ammonia, is available as anhydrous ammonia, aqueous ammonia, or urea. Anhydrous ammonia is toxic and SCAQMD does not permit new installations of anhydrous ammonia storage tanks. Urea is an alternative but requires conversion to ammonia to be used. Most new selective catalytic reduction installations utilize aqueous ammonia in a 19%solution.

To perform optimally, the gas temperature in the control device should be between 400°F and 800°F. During start-up and shutdown, the temperature will be below optimal range greatly reducing the effectiveness. Thus, NOx concentration limits are generally not applicable during start-up or shutdown. Newer electric generating units reduce the low temperature periods where emissions are out of control.

The catalyst is susceptible to "poisoning" if the flue gas contains contaminants including sulfur compounds, particulates, reagent salts, or siloxanes. Poisoned catalysts require cleaning or replacement resulting in additional costs and extended periods of non-operation for the electrical power generating equipment. In those cases, filtering may be used to reduce the impacts on the catalyst.

Catalytic Absorption Systems (Natural Gas Turbines)

Catalytic absorption is based on an integration of catalytic oxidation and absorption technology resulting in similar control efficiency as selective catalytic reduction without the use of ammonia.

Carbon monoxide and nitrogen oxide catalytically oxidize to carbon dioxide and nitrogen dioxide, then the nitrogen dioxide molecules are absorbed onto the catalyst. The catalyst is a platinum-based substrate with a potassium carbonate coating. The catalyst appears to be very sensitive to sulfur, even the small amounts in pipeline natural gas. Initial issues regarding catalyst failures have been addressed by conducting more frequent and extensive catalyst washing. At one facility, they have determined that emission levels are best met when all three layers of catalyst are washed about every four months. During the wash process, the turbine is non-operational for about three days.

The NOx concentration levels achieved by the various technologies assessed were consistent with the NOx concentration levels found in existing natural gas boilers, natural gas combined cycle gas turbines, and natural gas simple cycle gas turbines located in SCAQMD. Additionally, the NOx concentration levels from the technology assessment were consistent with the NOx concentration levels found in diesel internal combustion engines compliant with U.S. EPA's Final rule for Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel.

Initial BARCT Emission Limit and Other Considerations

The recommendation for the NOx BARCT emission limits are established using information gathered from existing SCAQMD regulations, existing units permitted in SCAQMD, regulatory requirements for other air districts, and the technology assessment. Both retrofit and new installations are considered. Once the initial limits are established, a cost-effectiveness determination is made at that initial limit. If the initial limit is not cost-effective, an alternative limit may be recommended. Unique circumstances are taken under consideration to distinguish alternative limits or to create provisions in the rule to address equipment that would otherwise not be cost-effective.

Diesel Internal Combustion Engines

Existing diesel internal combustion engines have been found in SCAQMD to be retrofitted to 82 ppmv NOx at 15% oxygen on a dry basis. In other air districts, regulations require retrofit on existing engines to meet a NOx concentration limit between 56 and 140 ppmv at 15% oxygen on a dry basis. For new diesel internal combustion engines, SCAQMD has an engine permitted at 51 ppmv NOx at 15% oxygen on a dry basis. Stationary diesel internal combustion engines installed after 2015 must meet U.S. EPA's Regulation for Emissions from Heavy Equipment with Compression-Ignition (Diesel) Engines Tier IV Final standard of 0.67 g/kWh NOx concentration limit (approximately 45 ppmv NOx at 15% oxygen on a dry basis, assuming 40% efficiency). Replacing existing engines with new engines that meet the Tier IV Final standard were initially used to determine cost-effectiveness.

Table 2-10 – Initial BARCT Recommendation for Diesel Internal Combustion Engines

	Existing Units (ppmv @ 15% oxygen, dry)	Other Regulatory Requirements	Technology Assessment	Initial BARCT Recommendation
Retrofit	82 ppmv	56-140 ppmv @ 15% oxygen dry	290 -420 ppmv @ 15% oxygen dry	56-140 ppmv @ 15% oxygen dry
New Install	51 ppmv	0.67 g/kWh	0.67 g/kWh	0.67 g/kWh

Natural Gas Boilers

Both new installations and retrofits of natural gas boilers have been found in the SCAQMD that meet a 5 ppmv NOx at 3% oxygen on a dry basis concentration limit. Other air districts require retrofit of existing boilers to meet a concentration limit of 6 ppmv NOx at 3% oxygen on a dry basis and new boilers to meet a concentration limit of 5 ppmv NOx at 3% oxygen on a dry basis. The technology assessment has shown that selective catalytic reduction, in conjunction with ultra-low NOx burners can meet a limit of 5 ppmv NOx at 3% oxygen on a dry basis. Therefore, the initial BARCT recommendation for new installations and retrofitted natural gas boilers will be 5.0 ppmv NOx at 3% oxygen on a dry basis.

Table 2-11 – Initial BARCT Recommendation for Natural Gas Boilers

	Existing Units (ppmv @ 3% oxygen, dry)	Other Regulatory Requirements (ppmv @ 3% oxygen, dry)	Technology Assessment (ppmv @ 3% oxygen, dry)	Initial BARCT Recommendation (ppmv @ 3% oxygen, dry)
Retrofit	5	6	5	5
New Install	5	5 - 6	5	5

Natural Gas Combined Cycle Gas Turbines

In all but one case, natural gas combined cycle gas turbines at electricity generating facilities have been new installations. In the single retrofit instance, the natural gas combined cycle gas turbine was retrofitted to meet a limit of 5 ppmv NOx at 15% oxygen on a dry basis. Otherwise, the lowest NOx concentration limit for new installations in SCAQMD is 2 ppmv at 15% oxygen on a dry basis. Other air districts limit NOx emissions to between 5-25 ppmv at 15% oxygen on a dry basis for existing units and 2-25 ppmv at 15% oxygen on a dry basis for new installations. The technology assessment found that a for natural gas combined cycle turbines, a combination of pre-combustion technology and post-combustion control can meet a concentration of 2 ppmv NOx at 15% oxygen on a dry basis. The initial BARCT recommendation for both new installations and retrofits of natural gas combined cycle gas turbines is 2 ppmv NOx at 15% oxygen on a dry basis.

Table 2-12 – Initial BARCT Recommendation for Natural Gas Combined Cycle Gas Turbines

	Existing Units (ppmv @ 15% oxygen, dry)	Other Regulatory Requirements (ppmv @ 15% oxygen, dry)	Technology Assessment (ppmv @ 15% oxygen, dry)	Initial BARCT Recommendation (ppmv @ 15% oxygen,dry)
Retrofit	5	5-25	2	2
New Install	2	2-25	2	2

Natural Gas Simple Cycle Gas Turbines

The lowest NOx concentration for a retrofitted natural gas simple cycle gas turbine is 9 ppmv at 15% oxygen on a dry basis. For new installations, numerous natural gas simple cycle gas turbines have a NOx concentration limit of 2.5 ppmv at 15% oxygen on a dry basis. Other air districts limit NOx emissions to between 5 and 25 ppmv at 15% oxygen on a dry basis for existing units and 2.5-25 ppmv at 15% oxygen on a dry basisfor new installations. The technology assessment found that a combination of pre-combustion technology and post-combustion control can meet a concentration of 2.5 ppmv NOx at 15% oxygen on a dry basis for natural gas simple cycle gas turbines. The initial BARCT recommendation for both new installations and retrofits of natural gas simple cycle gas turbines is 2.5 ppmv NOx at 15% oxygen on a dry basis.

Table 2-13 – Initial BARCT Recommendation for Natural Gas Simple Cycle Gas Turbines

	Existing Units (ppmv @ 15% oxygen, dry)	Other Regulatory Requirements (ppmv @ 15% oxygen, dry)	Technology Assessment (ppmv @ 15% oxygen, dry)	Initial BARCT Recommendation (ppmv @ 15% oxygen, dry)
Retrofit	9	5-25	2.5	2.5
New Install	2.5	2.5-25	2.5	2.5

In summary, the initial BARCT recommendations are presented in Table 2-14 below:

Table 2-14 – Summary of Initial BARCT Recommendation

Equipment	Initial BARCT Recommendation
Diesel Internal Combustion Engine	0.67 g/kWh @ 15% oxygen, dry
Natural Gas Boiler	5 ppmv @ 3% oxygen, dry
Natural Gas Combined Cycle Gas Turbine	2 ppmv @ 15% oxygen, dry
Natural Gas Simple Cycle Gas Turbine	2.5 ppmv @ 15% oxygen, dry

Cost-Effectiveness Analysis

Cost-effectiveness is examined for each equipment category type. Cost-effectiveness is measured in terms of control costs (dollars) per air emissions reduced (tons). If the cost per ton of emissions reduced is less than the maximum required cost-effectiveness, then the control method is considered to be cost-effective. The 2016 Air Quality Management Plan (AQMP) establishes a cost-effectiveness threshold of $50,000 per ton of NOx reduced.

The discounted cash flow method (DCF) is used in to determine cost-effectiveness. The DCF method calculates the present value of the control costs over the life of the equipment by adding the capital cost to the present value of all annual costs and other periodic costs over the life of the equipment. A real interest rate of four per cent and a 25-year equipment life is used. The cost-effectiveness is determined by dividing the total present value of the control costs by the total emission reductions in tons over the same 25-year equipment life.

Baseline emissions are determined by using reported fuel consumption and the permit NOx concentration limit corrected to 15% oxygen on a dry basis except for natural gas boilers where it is corrected to 3% oxygen on a dry basis. Proposed Amended 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities (PAR 1135) emissions are determined by using reported fuel consumption and the proposed emission limit. Emission reductions are the difference between baseline emissions and PAR 1135 emissions.

Costs for retrofitting natural gas boilers, natural gas combined cycle gas turbines, and natural gas simple cycle gas turbines were determined using U.S. EPA's Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction. The methodology used in the spreadsheet is based on U.S. EPA Clean Air Markets Division Integrated Planning Model. Size and costs of selective catalytic reduction control equipment and operational costs are based on size, fuel burned, NOx removal efficiency, reagent consumption rate, and catalyst costs. Fuel consumption is based on 2016 reported fuel usage. Values are reported in 2015 dollars.

Diesel Internal Combustion Engines

Replacement cost for a 2.8 MW (4,000 brake horsepower) U.S. EPA Tier 4 Final diesel internal combustion engine is approximately $3.9 million based on a vendor quote to the electricity generating facility using the diesel internal combustion engines. No change is expected for operating costs. Infrastructure costs are included because the replacement engines are larger requiring some facility modifications. The vendor quote includes:

Engine replacement and exhaust after treatment:	$2.1 million
Generator set refurbishment and testing:	$0.3 million
Removal and transportation:	$0.5 million
Infrastructure:	$1.0 million
Total Cost:	$3.9 million

Using the $3.9 cost estimate for all six engines, the cost-effectiveness is provided below in Table 2-15.

Table 2-15 – Diesel Internal Combustion Engine Cost-Effectiveness

Unit	Size (BHP)	2016 Annual NOx Emissions (tons)	NOx Permit Limit (ppmv @ 15% oxygen dry)	Proposed BARCT NOx Emission Limit (ppmv @ 15% oxygen, dry)	Capital Cost (million)	Annual Emission Reductions (tons)	Cost-Effectiveness ($/ton NOx)
ICE1	1,575	16	6.5 lbs/MWh2	45	$3.9	9.9	$14,826
ICE3	1,950	5.3	6.5 lbs/MWh2	45	$3.9	2.7	$52,034
ICE6	2,150	8.2	6.5 lbs/MWh2	45	$3.9	3.9	$35,414
ICE5	1,500	12	6.5 lbs/MWh2	45	$3.9	5.6	$24,768
ICE2	2,200	22	6.5 lbs/MWh2	45	$3.9	8.4	$15,520
ICE4	3,900	5.9	51	45	$3.9	0.7	$224,221

Average Cost-Effectiveness: $27,000

The average cost-effectiveness for replacing all six units is approximately $27,000 per ton of NOx reduced. Total NOx reduced is 31.2 tons annually. The average cost-effectiveness for replacing five units and excluding the 3,900 brake horsepower engine with a 51 ppmv NOx limit is approximately $23,000 per ton of NOx reduced. In that scenario, total NOx reduced is 30.5 tons annually.

Natural Gas Boilers

Because of the Clean Water Act's once-through-cooling provisions and business decisions by electricity generating facilities, 18 of 23 natural gas boilers are planned to be shutdown. Of those 18 natural gas boilers, all but four of them will be shutdown by January 1, 2024. Due to the shutdowns, 273 tons of NOx will be reduced annually by 2024 from natural gas boilers at electricity generating facilities. Another 57 tons of NOx will be reduced annually from the two natural gas boilers scheduled for shutdown in 2025 and the two natural gas boilers scheduled for shutdown in 2029. Three natural gas boilers are expected to be repowered to natural gas turbines or renewable power sources. However, if they are not, they will be required to meet the proposed limit. Repowering or retrofitting those three boilers will result in another 318 tons of NOx reductions annually. The last two natural gas boilers have not been in operation since 2012, but the electricity generating facility intends to keep them as low-use units.

Table 2-16 – Natural Gas Boiler Cost-Effectiveness

Unit	Input (MM/BTU/HR)	Output (MW)	2016 Annual NOx Emissions (tons)	Average Annual Capacity Factor (%)	NOx Permit Limit (ppmv @ 3% oxygen dry)	Proposed BARCT NOx Emission Limit (ppmv @ 3% oxygen, dry)	Capital Cost (millions)	Operating Cost (millions)	Annual Emission Reductions (tons)	Cost-Effectiveness ($/ton reduced)	Annual Capacity Factor (%) at $50,000 per ton of NOx Reduced
B18	527	44	113.6	42.6	38	5	7.5	0.8	116.3	$6,922	5.9
B12	260	20	39.7	25.6	40	5	4.8	0.4	34.6	$13,262	6.8
B15	492	44	177.5	29.5	82	5	5.9	0.4	167.1	$3,149	1.9

Average Cost-Effectiveness: $5,630

The average cost-effectiveness is approximately $5,630 per ton of NOx reduced. Previous calculations only included natural gas fuel usage and did not include landfill gas that the boilers utilize as their primary fuel. PAR 1135 includes a low-use provision that would allow natural gas boilers to continue to operate at levels below an average annual capacity factor of 1 percent in any one year and 2.5% averaged over three consecutive years.

Natural Gas Combined Cycle Gas Turbines

Eight of 23 natural gas combined cycle gas turbines currently have NOx permit limits greater than the proposed NOx concentration limit of 2 ppmv at 15% oxygen on a dry basis. Two units are permitted at 2.5 ppmv NOx at 15% oxygen on a dry basis and the other six units are permitted between 7 – 9 ppmv NOx at 15% oxygen on a dry basis. The cost-effectiveness for natural gas combined cycle gas turbines is presented below in Table 2-17 below.

Table 2-17 – Natural Gas Combined Cycle Gas Turbine Cost-Effectiveness

Unit	Input (MMBTU/HR)	Output (MW)	2016 Annual NOx Emissions (tons)	Estimated MWh/yr	% Capacity	NOx Permit Limit (ppmv @ 15% oxygen, dry)	Capital Cost (Millions)	Operating Cost (millions)	Emission Reductions (tons)	Cost-Effectiveness ($/ton reduced)	Annual Capacity Factor (%) at $50,000 per ton of NOx Reduced
T-CC-24[1]	1944	290	33	900,000	35%	2.5	$20.1	$1.6	6.6	$282,898	198.0
T-CC-25[1]	1944	290	36	1,000,000	39%	2.5	$20.1	$1.6	7.2	$261,226	203.8
T-CC-22	1088	182	12.1	60,000	4%	7	$14.8	$1.1	7.8	$169,744	12.8
T-CC-23	1088	182	8.9	40,000	3%	7	$14.8	$1.1	5.2	$253,696	12.7
T-CC-1	442	48	4.3	35,000	8%	7.6	$6.2	$0.5	3.2	$174,447	29.0
T-CC-26	350	30	0.8	6,000	2%	9	$4.6	$0.3	0.6	$669,774	30.6
T-CC-27	350	60	0.5	4,000	1%	9	$7.2	$0.5	0.4	$1,579,869	24.0
T-CC-28	350	60	0.5	4,000	1%	9	$7.2	$0.5	0.4	$1,579,869	24.0

Average Cost-Effectiveness: > $100,000

1 – Natural Gas Combined Cycle Gas Turbine with Associated Duct Burner

In all cases, the cost-effectiveness exceeds $50,000 per ton of NOx reduced. For the natural gas combined cycle gas turbines permitted at 2.5 ppmv NOx at 15% oxygen on a dry basis, the cost-effectiveness threshold of $50,000 per ton reduced is never reached, even when used at 100% annual capacity factor. Those two units will not be required to retrofit to the proposed BARCT limit. For the remaining units, a low-use provision is included in the proposed rule allowing the units to operate at current permitted levels if their annual capacity factor remains below 25% in any one year and 10% averaged over three consecutive years.

Natural Gas Simple Cycle Gas Turbines

Twenty-two of 67 natural gas simple cycle gas turbines have permitted NOx limits greater than the proposed BARCT limit of 2.5 ppmv at 15% oxygen on a dry basis. One unit is permitted at 3.5 ppmv NOx at 15% oxygen on a dry basis, 17 units are permitted at 5 ppmv NOx at 15% oxygen on a dry basis, two units are permitted at 9 ppmv NOx at 15% oxygen on a dry basis, and two units are permitted at 24 ppmv NOx at 15% oxygen on a dry basis. The natural gas simple cycle gas turbines that are permitted at NOx concentration levels above the proposed limit are used sporadically to support renewable power generation. The cost-effectiveness for natural gas simple cycle gas turbines is presented below in Table 2-18 below.

Table 2-18 – Natural Gas Simple Cycle Gas Turbine Cost-Effectiveness

Unit	Input (MMBTU/HR)	Output (MW)	2016 Annual NOx Emissions (tons)	Estimated MWh/yr	%Capacity	NOx Permit Limit (ppmv @ 15% oxygen, dry)	Capital Cost (Millions)	Operating Cost (millions)	Emission Reductions (tons)	Cost-Effectiveness ($/ton reduced)	Annual Capacity Factor (%) at $50,000 per ton of NOx Reduced
T-SC-15	456.5	48	0.5	1500	0.36%	3.5	$6.2	$0.41	0.14	$3,679,674	26%
T-SC-68	450	46	1.2	4000	0.99%	5	$6.1	$0.41	0.62	$820,407	16%
T-SC-10	450	45	1.9	4000	1.01%	5	$6.0	$0.39	0.97	$513,404	10%
T-SC-30	450	45	1.5	4000	1.01%	5	$6.0	$0.39	0.75	$664,064	13%
T-SC-40	450	45	1.6	4000	1.01%	5	$6.0	$0.39	0.81	$613,190	12%
T-SC-13	128.8	10.5	0.0	120	0.13%	5	$2.3	$0.15	0.01	$12,993,169	34%
T-SC-33	128.8	10.5	0.0	120	0.13%	5	$2.3	$0.15	0.02	$10,320,468	27%
T-SC-43	128.8	10.5	0.0	120	0.13%	5	$2.3	$0.15	0.02	$10,624,725	28%
T-SC-52	128.8	10.5	0.0	120	0.13%	5	$2.3	$0.15	0.01	$14,756,563	39%
T-SC-66	448	47.4	2.4	8000	1.93%	5	$6.2	$0.41	1.20	$426,186	16%
T-SC-67	448	47.4	8.9	40000	9.63%	5	$6.2	$0.42	4.45	$116,440	22%
T-SC-18	466.8	47.4	2.0	6000	1.45%	5	$6.2	$0.41	1.00	$512,207	15%
T-SC-19	466.8	47.4	1.6	5000	1.20%	5	$6.2	$0.41	0.81	$636,213	15%
T-SC-21	466.8	47.4	1.1	4000	0.96%	5	$6.2	$0.41	0.53	$971,264	19%
T-SC-23	466.8	47.4	1.0	4000	0.96%	5	$6.2	$0.41	0.51	$1,004,867	19%
T-SC-25	466.8	47.4	2.0	5000	1.20%	5	$6.2	$0.41	0.99	$519,131	13%
T-SC-57	466.8	47.4	1.5	4000	0.96%	5	$6.2	$0.41	0.74	$693,129	13%
T-SC-75	470	49.6	3.6	12000	2.76%	5	$6.4	$0.42	1.79	$295,758	16%
T-SC-64	298	31	0.09	270	0.10%	9	$4.7	$0.34	0.06	$6,419,676	13%
T-SC-65	298	30	0.0	0		9	$0.0	$0.00	0.00		
T-SC-61	69.12	6	0.06	120	0.23%	24	$1.6	$0.12	0.05	$2,697,954	12%
T-SC-63	69.12	6	0.13	240	0.46%	24	$1.6	$0.12	0.11	$1,254,841	11%

The current average annual capacity factor is approximately 1%. A low-use provision is included in the proposed rule allowing the units to operate at current permitted levels if their annual capacity factor remains below 25% in any one year and 10% averaged over three consecutive years.

BARCT Emission Limit Recommendation

In all four categories, the technology is available to meet the Initial BARCT NOx concentration limits. For diesel internal combustion engines, the cost-effectiveness is approximately $27,000 per ton of NOx reduced. In all three remaining categories, the cost-effectiveness is high because the units are used far below their capacity. If these were to operate at higher annual capacity factors, NOx reductions would become cost-effective. To address these sporadically used electric generating units, a low-use provision is included in the rule. The provision allows low-use equipment to continue operating without retrofit provided that they do not exceed an annual capacity factor limit and that they include an annual capacity factor in their Permit to Operate. This ensures that electric generating units that increase use to the point where the cost-effectiveness threshold is reached, that they will be required to retrofit the units to meet the proposed BARCT concentration limits.

The BARCT emission limits for the proposed rule are listed below in Table 2-19.

Table 2-19 – Recommended BARCT Emission Limits

Equipment Type	NOx (ppmv)	Ammonia (ppmv)	Oxygen Correction (%, dry)
Diesel Internal Combustion Engine	45	5	3
Natural Gas Boiler	5	5	15
Natural Gas Combined Cycle Gas Turbine	2	5	15
Natural Gas Simple Cycle Gas Turbine	2.5	5	15

CHAPTER 3: SUMMARY OF PROPOSALS

INTRODUCTION

Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities (PAR 1135) establishes the following emission limits at electricity generating facilities: NOx and ammonia emission limits for boilers and gas turbines, and NOx, ammonia, carbon monoxide, volatile organic compounds, and particulate matter for internal combustion engines located on Santa Catalina Island. Additionally, PAR 1135 establishes provisions for monitoring, reporting, and recordkeeping, and establishes exemptions from specific provisions.

TITLE

The title for Rule 1135 is changed from "Emissions of Oxides of Nitrogen from Electric Power Generating Systems" to "Emissions of Oxides of Nitrogen from Electricity Generating Facilities"; the term "electric power generating system" is replaced with "electricity generating facilities" to reflect changes in definitions in the proposed amended rule.

PURPOSE (Subdivision (a))

Purpose (subdivision (a)) is added to PAR 1135 to be consistent with the structure of current SCAQMD rules. The purpose of PAR 1135 is to reduce emissions of oxides of nitrogen from electric generating units (diesel internal combustion engines located at Santa Catalina Island, boilers, combined cycle turbines, and simple cycle turbines) at electricity generating facilities.

APPLICABILITY (Subdivision (b))

While there is no specific language excluding RECLAIM facilities from current Rule 1135, only one facility is currently subject to Rule 1135. Rule 2001 – Allocations of Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) allowed the municipal utilities the option to enter RECLAIM. Current Rule 1135 applies to electric power generating systems and establishes system-wide NOx emission limits; PAR 1135 will apply to electric generating units at electricity generating facilities. Electric power generating systems consists of boilers, turbines, other advanced combustion resources, and alternative equipment that are capable of producing power and owned by or under contract to sell power to an electric utility. PAR 1135 no longer uses the term "electric power generating system" and now refers to "electric generating units," including diesel internal combustion engines located on Santa Catalina Island, boilers, combined cycle gas turbines, and simple gas cycle turbines at electricity generating facilities. An electricity generating facility is an investor-owned electric utility, publicly owned electric utility, or a facility with 50 megawatts or more of combined generation capacity. The rule will not apply to units located at landfills, petroleum refineries, or publicly owned treatment works. NOx generating equipment located at petroleum refineries and refinery associated facilities will be subject to forthcoming Proposed Rule 1109.1 – Refinery Equipment. Equipment at landfills and publicly owned treatment works will be subject to equipment specific regulations.

DEFINITIONS (Subdivision (c))

PAR 1135 adds and modifies definition to clarify and explain key concepts and removes obsolete definitions. Please refer to PAR 1135 for each definition.

Proposed Deleted Definitions:	Advanced Combustion Resource Alternative Resource Approved Alternative or Advanced Combustion Resource Alternative Resource or Advanced Combustion Resource Breakdown Cogeneration Facility Displace District-Wide Daily Limits Electric Power Generating System Replacement Unit Start-up or Shutdown Useful Thermal Energy
Proposed Modified Definitions:	Boiler Daily Force Majeure Natural Gas Curtailment NOx Emissions
Proposed Added Definitions:	Annual Capacity Factor Cogeneration Turbine Combined Cycle Gas Turbine Duct Burner Electric Generating Unit Electricity Generating Facility Former RECLAIM NOx Source Internal Combustion Engine Investor-Owned Electric Utility Landfill Non-RECLAIM NOx Source Petroleum Refinery Publicly Owned Electric Utility Publicly Owned Treatment Works RECLAIM NOx Source SCAQMD-Wide Daily Limits Shutdown Simple Cycle Gas Turbine Start-up Tuning

EMISSIONS LIMITS (Subdivision (d))

Throughout subdivision (d), due to the deletion of the term “electric power generating system,” any reference to “electric power generating system” was changed to “electric generating unit” or “electricity generating facility.”

The emissions limits in subdivision (d) will be applicable to all electricity generating facilities, including RECLAIM electricity generating facilities. PAR 1135 includes a provision which states RECLAIM facilities will still be applicable to the requirements of PAR 1135 despite Rule 2001 subdivision (j) – Rule Applicability and Table 1: Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions exempting them from Rule 1135 NOx emissions requirements. Staff is working on amendments to Rule 2001 to specify that NOx RECLAIM facilities are required to comply with all NOx provisions in rules contained in Table 1 that are adopted or amended after Proposed Amended Rule 2001 is adopted.

The emission limits in Tables 1 and 2 of PAR 1135 are based on the BARCT assessment presented in Chapter 2 – BARCT Assessment.

PAR 1135, Table 1: Emissions Limits for Boilers and Gas Turbines

Equipment Type	NO_x[1] (ppmv)	Ammonia (ppmv)	Oxygen Correction (%, dry)
Boiler	5	5	3
Combined Cycle Gas Turbine and Associated Duct Burner	2	5	15
Simple Cycle Gas Turbine	2.5	5	15

[1] – The NOx emission limits in Table 1 shall not apply during start-up, shutdown, and tuning.

PAR 1135, Table 2: Emissions Limits for Diesel Internal Combustion Engines Located on Santa Catalina Island

NO_x[1, 4] (ppmv)	Ammonia[1] (ppmv)	Carbon Monoxide[2] (ppmv)	Volatile Organic Compounds[3] (ppmv)	Particulate Matter (lbs/mmbtu)
45	5	250	30	0.0076

[1] – Corrected to 15% oxygen on a dry basis and averaged over a 60 minute rolling average
[2] – Corrected to 15% oxygen on a dry basis and averaged over 15 minutes
[3] – Measured as carbon, corrected to 15% oxygen on a dry basis, and averaged over sampling time required by the test method
[4] – The NOx emission limits in Table I shall not apply during start-up, shutdown, and tuning.

To help achieve the emission reduction goals of the 2016 AQMP and AB 617 requirement of BARCT implementation, PAR 1135 subparagraphs (d)(1) and (d)(2) set the compliance date for electric generating units as January 1, 2024.

Subparagraph (d)(1)(A) requires the emissions limits of boilers and turbines that are installed after [*Date of* Adoption] to be averaged over a 60 minute rolling average. For diesel internal combustion engines, Table 2 specifies that NOx and ammonia limits are averaged over a 60 minute rolling average, carbon monoxide is averaged over 15 minutes, and volatile organic compounds are averaged according to the test method. For electric generating units installed before [*Date of Adoption*], subparagraphs (d)(1)(B) and (d)(2)(B) allow the units to retain their current averaging time. The averaging times for these units were evaluated during the permitting process and should be maintained.

Subparagraph (d)(3) states that requirements for start-up, shutdown, and tuning periods will be put in each electric generating unit's permit. The requirements will specify duration, mass emissions, and number of start-ups, shutdowns, and, if applicable, tunings. Requirements for start-up, shutdown, and tuning of existing electric generating units are currently in the permits for that equipment. Additionally, start-up, shutdown, and tuning are unique to each unit and evaluated during the permitting process. Therefore, PAR 1135 does not specify specific start-up, shutdown, and tuning requirements, but instead states that the requirements will be put in each electric generating unit's permit.

Under paragraph (d)(2)(A), the compliance date for diesel internal combustion engines located on Santa Catalina Island is January 1, 2024. However, paragraph (d)(4) includes an alternative compliance approach in order to accommodate potential plans for less emissive electricity generating equipment than diesel internal combustion engines. In 2016, the diesel internal combustion engines on Santa Catalina Island emitted 69 tons of NOx. Assuming the same throughput, but with diesel internal combustion engines with 45 ppmv NOx emission limits, the annual NOx emissions would be 39 tons. The alternative approach was designed to reduce NOx emissions by 67% from diesel internal combustion engines, and therefore under this approach the operator must reduce emissions to 13 tons of NOx annually. By January 1, 2022, the owner or operator of diesel internal combustion engines located on Santa Catalina Island must submit a notification that they are electing the alternative compliance approach. The notification must include a description of the proposed technologies, schedule of permit submittals, and timeframes for ordering and installing equipment. Additionally, the facility must take a permit condition limiting their total annual NOx emissions to 13 tons.

To further incentivize lower emitting electricity generating technologies, paragraph (d)(5) allows Santa Catalina an extension of up to three years for compliance with Table 2 or the alternative compliance approach as the facility. The extension is allowed for both compliance approaches as the facility may initially pursue lower emitting technologies later to discover that hurdles to permitting, land acquisition, or some other extenuating circumstance prevents the implementation of the lower emitting technology. The extension includes a mitigation fee of $100,000/year. 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 approximately the amount they would have had to pay to go through the variance process, including excess emissions fees, notification fees, and other procedural fees. In order to qualify for the extension, the facility must reduce some NOx upfront. If the facility wants an extension for installing diesel internal combustion engines, two diesel internal combustion engines must be retrofitted or repowered to 45 ppmv NOx at 15% oxygen on a dry basis by January 1, 2023. If requesting an extension for the alternative compliance approach, Santa Catalina Island must reduce actual mass emissions to 50 tons of NOx for compliance year 2022 and 40 tons of NOx for compliance year 2023. The time extension must be submitted at least one year before the compliance deadlines and must include: which units need a time extension, the reason an extension is need, and the progress to date of the project. To be approved for the time extension, the Executive Officer will determine if the facility followed the proper procedure for submitting a request for time extension and if the time extension was needed due to an extenuating circumstance. Examples of extenuating circumstances would include engineering designs, construction plans, land acquisition contracts, permit applications, and purchase orders that impact scheduling.

Current Rule 1135 paragraphs (d)(1) and (d)(2) have been deleted as the requirements are no longer applicable. Current Rule 1135 paragraph (d)(3), PAR 1135 paragraph (d)(6), maintains only provisions applicable to the City of Glendale. The District-wide daily limits on emissions rate and emissions cap and the annual emissions limits for Southern California Edison, Los Angeles Department of Water and Power, the City of Burbank, and the City of Pasadena, became obsolete once these facilities entered into RECLAIM. Since City of Glendale is still a Rule 1135 facility, their current SCAQMD-wide daily limits on emissions rates and emissions cap and annual emissions limits will be maintained and references to older limits will be removed. The SCAQMD-wide daily limits on emissions rates and emissions caps and annual emissions limits need to be maintained for the City of Glendale in the interim period until the emissions limitations in paragraph (d)(1) is achieved.

Paragraph (d)(7) requires that by July 1, 2022 facilities submit applications to reconcile their permits with Rule 1135. As electricity generating facilities transition out of RECLAIM to Rule 1135, their permits will need to be revised to remove references to RECLAIM rules and include references to Rule 1135.

Several additional obsolete provisions will be deleted. Current Rule 1135 subparagraphs (d)(6) will be removed since those dates have passed. Current Rule 1135 subparagraph (d)(8), the provision stating that a violation of any unit specific NOx emission limit in a permit or a compliance plan constitutes a violation of Rule 1135 will be removed since permits and compliance plans are enforceable and it would be redundant to also make it a violation of the Rule.

Compliance Plans

Current Rule 1135 subdivision (d) – Compliance Plans, will be deleted, as those dates have passed and Compliance Plans will no longer be necessary with the emissions limits in PAR 1135 subdivision (d).

MONITORING, RECORDKEEPING, AND REPORTING (Subdivision (e))

Staff is currently working on adopting Rule 113 – Monitoring, Reporting, and Recordkeeping (MRR) Requirements for NOx and SOx Sources. Once Rule 113 is adopted, all Rule 1135 equipment will transition to Rule 113 for MRR. For the interim period, the intention of the PAR 1135 MRR is to maintain current MRR for all facilities and minimize the RECLAIM reporting requirements.

All the provisions in the current Rule 1135 subdivision (e) will be deleted. These provisions are no longer necessary because of the 125 units under PAR 1135, there are only three units that are required to follow the current Rule 1135 monitoring requirements. In addition to following current Rule 1135, these three units also conduct monitoring according to current Rule 218 – Continuous

Emission Monitoring. Deleting Current Rule 1135 monitoring requirements will not affect these three units.

Paragraph (e)(1) requires that facilities maintain all their monitoring, recordkeeping, and reporting documents for five years and make it available to SCAQMD upon request.

Paragraph (e)(2) applies to current RECALIM NOx sources and these sources will continue complying with SCAQMD Rule 2012 to demonstrate compliance with the NOX emissions limits.

Paragraph (e)(3) applies to former RECLAIM facilities. To demonstrate compliance with the NOx emissions limits, these facilities will be required to comply with SCAQMD Rule 2012 with the exception of the following provisions that reference reporting requirements or that do not apply to electric power generating units:

- (c)(3) – facility permit holder of a major NOx source
- (c)(4) – Super Compliant Facilities
- (c)(5) – facility Permit holder of a facility which is provisionally approved for NOx Super Compliant status
- (c)(6) – after final approval of Super Compliant status
- (c)(7) – facility designated as a NOx Super Compliant Facility
- (c)(8) – super Compliant Facility exceeds its adjusted allocations
- (d)(2)(B) – install, maintain and operate a modem
- (d)(2)(C) – equipment-specific emission rate or concentration limit
- (d)(2)(D) – monitor one or more measured variables as specified in Appendix A
- (d)(2)(E) – comply with all applicable provisions of subdivision (f)
- (e) – NOx Process Unit
- (g)(5) – system is inadequate to accurately determine mass emissions
- (g)(6) – sharing of totalizing fuel meters
- (g)(7) – equipment which is exempt from permit requirements pursuant to Rule 219 - Equipment Not Requiring A Written Permit Pursuant to Regulation II
- (g)(8) – rule 2012 and Appendix A
- (h)(1) – facilities with existing CEMS and fuel meters as of October 15, 1993
- (h)(2) – interim emission reports
- (h)(4) – installation of all required or elected monitoring and reporting systems
- (h)(5) – existing or new facility which elects to enter RECLAIM or a facility which is required to enter RECLAIM
- (h)(6) – new major NOx source at an existing facility
- (k) – Exemption
- (l) – Appeals
- Reported Data and Transmitting/Reporting Frequency requirements from Appendix A – “Protocol for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NOx) Emissions”

Paragraph (e)(4) applies to non-RECLAIM facilities. To demonstrate compliance with the NOx emissions limits, these facilities have the option to comply with 40 CFR Part 75 or Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx)

Emissions. If opting to comply with 40 CFR Part 75, the facility must calculate NOx in ppmv pursuant to Rule 218.

Paragraph (e)(5) applies to the City of Glendale. To demonstrate compliance with the SCAQMD-wide daily limits on emissions rates and emissions caps and annual emissions limits, the City of Glendale must calculate these NOx emissions in accordance with their approved CEMS plan.

Paragraph (e)(6) applies to the diesel internal combustion engines located on Santa Catalina Island. To demonstrate compliance with the carbon monoxide and volatile organic compound emissions limits, the facility must comply with Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines subdivisions (f) – Monitoring, Testing, Recordkeeping and Reporting and (g) – Test Methods. To demonstrate compliance with the particulate matter emission limit, the facility must conduct yearly source tests according to SCAQMD Method 5.1 – Determination of Particulate Matter Emissions from Stationary Sources Using a Wet Impingement Train or SCAQMD Method 5.2 – Determination of Particulate Matter Emissions from Stationary Sources using Heated Probe and Filter. Yearly is defined as a period of twelve consecutive months determined on a rolling basis with a new twelve month period beginning on the first day of each calendar month.

Paragraph (e)(7) applies to electric generating units with catalytic control devices. To demonstrate compliance with the ammonia emission limit, subparagraph (6)(A) requires facilities to conduct source testing according to SCAQMD Method 207.1 – Determination of Ammonia Emissions from Stationary Sources. Source testing will be quarterly for the first twelve months of operation and then annually thereafter if four consecutive quarterly source tests determines that the unit is in compliance with the ammonia limit. In lieu of ammonia source testing, subparagraph (6)(B) allows facilities to utilize ammonia CEMS certified under an approved SCAQMD protocol. At this time, SCAQMD is in the process of finding a host site for an ammonia CEMS demonstration project. Upon successful demonstration, SCAQMD will develop an ammonia CEMS protocol. Once an ammonia CEMS protocol is developed then SCAQMD intends to require ammonia CEMS instead of source testing to demonstrate compliance with the ammonia limits. At this time, an ammonia CEMS is approximately $60,000. The provision that allows for ammonia CEMS instead of source testing allows facilities to transition to ammonia CEMS once a protocol is ready, but is not specifically required by Rule 1135.

In addition to demonstrating compliance with the emissions limits of the rule, paragraph (e)(8) requires all facilities to maintain an operating log for each electricity generating unit. The log must include: time and duration of start-ups and shutdowns; total hours of operation; quantity of fuel; cumulative hours of operation to date for the calendar year; megawatt hours of electricity produced; and net megawatt hours electricity produced.

USE OF LIQUID PETROLEUM FUEL (Subdivision (f))

Throughout subdivision (f), due to the deletion of the term electric power generating system, any reference to electric power generating system was changed to electric power generating unit or electricity generating facility. Also, to encompass all electric power generating units, the term boiler is replaced with the term electric power generating unit.

Current Rule 1135 paragraph (f)(1) allows the use of liquid petroleum fuel and an exemption from the District-wide daily limits on emissions rate and emissions cap during force majeure natural gas curtailment. Since District-wide daily limits on emissions rate and emissions cap have been removed for almost all facilities, PAR 1135 paragraph (f)(1) replaces the term with emissions limits from paragraph (d)(1). The requirement in current Rule 1135 subparagraph (f)(1)(B) will be deleted since all units will have to comply with the emissions limits specified in paragraph (d)(1). Current Rule 1135 subparagraph (f)(1)(D) will be deleted because it is a duplicative requirement to current Rule 1135 subparagraph (f)(1)(C) (proposed to be subparagraph (f)(1)(B)). If an electricity generating facility can meet the requirements of subparagraph (f)(1)(C), it would be able to meet the requirements of subparagraph (f)(1)(D); alternatively if an electricity generating facility cannot meet the requirements of subparagraph (f)(1)(C), it would not be able to meet the requirements of subparagraph (f)(1)(D).

PAR 1135 subparagraph (f)(1)(B) states that during force majeure natural gas curtailment and when burning liquid petroleum fuel exclusively, the NOx emission limit for an electric power generating unit must comply with the limit in the permit for that unit. Not all permits for electric power generating units have a NOx emission limit when exclusively burning liquid petroleum fuel. But, the limit is unique to each unit and evaluated during the permitting process. Therefore, PAR 1135 does not specify a NOx emission limit for liquid petroleum fuel and instead states that this emissions limit in the permit must be complied with.

PAR 1135 paragraph (f)(2) increases the hours allowed for readiness testing from 24 hours in a calendar year to sixty minutes per day on one day per week; weekly readiness testing is necessary to assure reliability of the oil firing units in case of emergencies. To be consistent with subparagraph (f)(1)(B), subparagraph (f)(2)(B) states that during readiness testing and when burning liquid petroleum fuel exclusively, the NOx emission limit for an electric power generating unit must comply with the limit in the permit for that unit. Several requirements are being added to readiness testing. The first added requirement, subparagraph (f)(2)(C), states that readiness testing can only occur once the equipment has reached the emissions limitation in paragraph (d)(1) while running on natural gas and must start within 60 minutes of achieving that emissions limitation. For clarification purposes, subparagraph (f)(2)(D) defines readiness testing as the time from when the equipment is switched from natural gas to liquid petroleum fuel to the time the equipment is switched back to natural gas.

PAR 1135 will add a provision, paragraph (f)(3), that allows liquid petroleum fuel to be used during source testing, initial certification of Continuous Emissions Monitoring Systems (CEMS), and semi-annual Relative Accuracy Test Audits (RATAs). The RATA tests must be conducted at the same time as weekly readiness testing.

Municipal Bubble Options

The subdivision regarding Municipal Bubble Options, Current Rule 1135 subdivision (g), has been removed because PAR 1135 will establish emissions limits for each unit and will no longer have limits for electric generating systems.

EXEMPTIONS (Subdivision (g))

All of the current Rule 1135 exemptions will be removed. These exemptions were based on old technology and are no longer necessary.

Rule 1135 will be amended to include several exemptions. The first exemption, subparagraph (g)(1), exempts existing combined cycle gas turbines at 2.5 ppmv NOx at 15% oxygen on a dry basis from the emissions limitations in paragraph (d)(1), with the condition that the units keep their NOx and ammonia limits, start-up, shutdown, and tuning requirements, and averaging times on the current permit. According to the BARCT assessment, it is not cost-effective for combined cycle gas turbines at 2.5 ppmv NOx at 15% oxygen on a dry basis to reduce their limits to 2 ppmv at 15% oxygen on a dry basis.

Paragraph (g)(2) exempts once-through-cooling electric generating units that are subject to the Clean Water Act Section 316(b) from the emissions limitations in paragraph (d)(1) under the conditions that the units keep their NOx and ammonia limits, start-up, shutdown, and tuning requirements, and averaging times on the current permit and the units comply with their current compliance dates established pursuant to Table 1 of Section 2(B) of the State Water Resources Control Board's Statewide Water Quality Control Policy on the Use of Coastal Estuarine Waters for Power Plant Cooling (Once-Through-Cooling Policy) implementing Section 316(b) of the Clean Water Act. Notifications of shutdown and retirements dates must be submitted for each once-through-cooling electric generating unit by January 1, 2023. This provision coordinates the compliance date for PAR 1135 NOx concentration limit and the compliance dates in Clean Water Act Section 316(b). Additionally, the provision avoids stranded assets of adding pollution controls for interim period of time. If the once-through-cooling electric generating unit is granted an extension by the State Water Resources Control Board, the facility must notify SCAQMD of the extension within three months. This extension is not applicable to facilities that have utilized the Modeling and Offset Exemptions in Rule 1304 (a)(2) and the associated replacement electric generating unit is in operation as the emission credits transferred to the replacement unit are no longer available.

The BARCT assessment determined that it is not cost-effective for diesel internal combustion engines at 51 ppmv NOx at 15% oxygen on a dry basis to reduce their limits to 45 ppmv at 15% oxygen on a dry basis. Therefore, PAR 1135 paragraph (g)(3) exempts existing diesel internal combustion engines at 51 ppmv NOx at 15% oxygen on a dry basis from the emissions limitations in paragraph (d)(2), with the condition that the units keep their NOx, ammonia, carbon monoxide, volatile organic compounds, and particulate matter limits, start-up, shutdown, and tuning requirements, and averaging times on the current permit.

To address low-use electrical power generating units, a low-use provision, paragraph (g)(4) is included in PAR 1135. The provision allows low-use equipment to continue operating without retrofit provided that they: do not exceed annual capacity factor limits; include annual capacity factor limits in their permit; and keep the NOx and ammonia limits, start-up, shutdown, and tuning requirements, and averaging times on the current permit. The annual capacity factor, paragraph (c)(1), is defined as the ratio between the actual annual input and the annual maximum heat input if operated continuous over one year excluding usage during an Emergency Phase of the California Energy Commission Energy Emergency Response Plan or a Governor-declared State of Emergency or Energy Emergency. The annual capacity factor limits for gas turbines in subparagraph (g)(4)(A) is less than twenty-five percent in one calendar year and less than ten percent averaged over three years. For boilers, the low-use provision in subparagraph (g)(4)(B) establishes the annual capacity factor limit as less than two and one half percent in one calendar year and less than one percent averaged over three years. In order to obtain the low-use exemption, subparagraph (g)(4)(C) requires that an application for the low-use exemption be submitted by July 1, 2022. Subparagraph (g)(4)(D) requires that annual capacity factor to be determined annually and submitted to the Executive Officer no later than March 1 following the reporting year. If a unit exceeds the annual capacity factor, clause (g)(4)(E)(i) states the owner or operator is subject to a notice of violation for each year of exceedance and for each annual and/or three year exceedance. Subclause (g)(4)(E)(ii)(C) requires that after two years of the date of reported exceedance, the unit must come into compliance with the emissions limits in paragraph (d)(1). There are also interim milestone requirements in subclauses (g)(4)(E)(ii)(A) and (g)(4)(E)(ii)(B): submitting a permit application within six months from the date of reported exceedance and a CEMS plan within six months from the date of permit application submittal.

The last exemption, paragraph (g)(5) exempts internal combustion engines on Santa Catalina Island from the requirements in subdivision (f) – Use of Liquid Petroleum Fuel.

CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS) REQUIREMENTS DOCUMENT FOR ELECTRIC POWER GENERATING UNITS

The document specifying requirements under Rule 1135 for continuous emission monitoring systems has been removed. The MRR requirements have been updated and no longer reference the document.

CHAPTER 4: IMPACT ASSESSMENT

POTENTIALLY IMPACTED FACILITIES

EMISSIONS INVENTORY AND EMISSION REDUCTIONS

INCREMENTAL COST-EFFECTIVENESS

RULE ADOPTION RELATIVE TO COST-EFFECTIVENESS

SOCIOECONOMIC ASSESSMENT

CALIFORNIA ENVIRONMENTAL QUALITY ACT

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

COMPARATIVE ANALYSIS

POTENTIALLY IMPACTED FACILITIES

There are 31 electricity generating facilities that are potentially impacted by Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities (PAR 1135). Of these 31 facilities, 26 are currently in the NOx RECLAIM program. The remaining five facilities are not in the RECLAIM program; one is currently subject to SCAQMD Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines and Rule 1135 – Emissions of Oxides of Nitrogen from Electric Power Generating Systems, and four are not subject to Rule 1134 or 1135 because of current applicability requirement in those rules.

There are approximately 123 electric generating units at these 31 electricity generating facilities: 61 are at the proposed emissions limits, 5 are exempt, 27 qualify for the low-use provisions, and 21 are schedule for shutdown. The remaining 9 electric generating units at 3 facilities will need to be replaced, repowered, or retrofitted to come into compliance with PAR 1135.

Of the five exempt units, two are natural gas combined cycle turbines with associated duct burners and one is a diesel internal combustion engine located on Santa Catalina Island. The natural gas combined cycle gas turbines with associated duct burners are exempt from emissions limits in Table 1 because of the exemption in paragraph (g)(1). The diesel internal combustion engine located on Santa Catalina Island is exempt from the emissions limits in Table 2 because of the exemption in paragraph (g)(3). Table 4-1 summarizes equipment exempt due to paragraphs (g)(1) and (g)(3).

Table 4-1: Units Exempt Due to PAR 1135 Paragraphs (g)(1) and (g)(3)

Facility	Equipment	Current NOx Permit Limit (ppmv at 15% oxygen, dry)
Southern California Edison (Pebbly Beach)	ICE 12	51
LADWP Valley	Combined cycle turbine 6 and duct burner 6	2.5
LADWP Valley	Combined cycle turbine 7 and duct burner 7	2.5

Assuming similar usage as in 2016, 27 electric generating units would qualify for the low-use provisions. At this time, staff is aware of 12 electric generating units that will be retrofitting to come into compliance with PAR 1135 emissions limits. Staff believes the remaining 15 will be using the low-use provisions, as summarized in Table 4-2.

Table 4-2: Units Potentially Utilizing Low-Use Provisions in Paragraph (g)(4)

Facility	Equipment	Current NOx Permit Limit (ppmv at 15% oxygen, dry)
Vernon	Simple cycle turbine 6	24
Vernon	Simple cycle turbine 7	24
Glendale DWP	Combined cycle turbine 8A	9
Glendale DWP	Combined cycle turbine 8B/C	9
Glendale DWP	Combined cycle turbine 8B/C	9
Burbank DWP	Simple cycle turbine 1	5
Glendale DWP	Simple cycle turbine 9	5
Riverside DWP	Simple cycle turbine 1	5
Riverside DWP	Simple cycle turbine 2	5
Riverside DWP	Simple cycle turbine 3	5
Riverside DWP	Simple cycle turbine 4	5
Wildflower/Indigo	Simple cycle turbine 1	5
Wildflower/Indigo	Simple cycle turbine 2	5
Wildflower/Indigo	Simple cycle turbine 3	5
City of Colton	Simple cycle turbine 1	3.5

EMISSION INVENTORY AND EMISSION REDUCTIONS

The original NOx emission inventory for electricity generating facilities was 25.6 tons per day in 1986. After the adoption of Rule 1135 and Rule 2009 – Compliance Plan for Power Producing Facilities, the NOx inventory declined to under 10 tons NOx per day. With a greater reliance on renewable power sources and further replacement of equipment, the emission inventory fell to 3.5 tons NOx per day in 2016.

Table 4-2 – NOx Emission Inventory and MWh Capacity

Equipment Type	2016 NOx Emission Inventory (tons per day)	MWh Capacity
Diesel Internal Combustion Engines	0.2	9
Boilers	1.9	5,355
Combined Cycle Turbine	1.0	6,082
Simple Cycle Turbine	0.4	4,458

Most of the emissions from combined cycle turbines and simple cycle turbines come from units that meet the proposed BARCT limits. Only 23 tons per year of NOx are emitted from turbines that do not meet the proposed BARCT limits.

Table 4-3 – NOx Emission Inventory from BARCT and Non-BARCT Equipment

Equipment Type	2016 NOx Emission Inventory (tons per day)	2016 NOx Emissions from BARCT Equipment (tons per day)	2016 NOx Emissions from Equipment Not Meeting BARCT (tons per day)
Diesel Internal Combustion Engines	0.2	0.0	0.2
Boilers	1.9	0.2	1.7
Combined Cycle Turbine	1.0	0.9	0.1
Simple Cycle Turbine	0.4	0.4	0.0

After the implementation of the BARCT limits and the Clean Water Act once-through-cooling provision, 1.9 tons per day of NOx emission reductions will be realized.

Table 4-4 – NOx Emission Reductions

Equipment Type	2016 NOx Emission Inventory (tons per year)	NOx Emissions from BARCT Equipment (tons per year)	2016 NOx Emissions Reductions (tons per year)
Diesel Internal Combustion Engines	0.2	0.1	0.1
Boilers	1.9	0.1	1.8
Combined Cycle Turbine	1.0	0.9	< 0.1
Simple Cycle Turbine	0.4	0.4	0.0
Total	3.5	1.5[1]	1.9[1]

[1] – Totals do not add correctly due to rounding

The use of ammonia in the selective catalytic reduction (SCR) process results in an increase of particulate matter emissions. There are 11 low-use turbines that already utilize SCR but will change catalysts and increase their ammonia usage by an estimated 27% to meet the proposed emissions limits. As these turbines are used rather infrequently, the particulate matter increase is 818.2 pounds annually or 0.001 tons per day. The three boilers are used considerably more and do not currently utilize SCR. The particulate increase from incorporating SCR into their process is expected to increase particulate matter emissions by 8,971.4 pounds annually or 0.01 tons per day.

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, sulphur 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 option 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

Diesel Internal Combustion Engines

PAR 1135 paragraph (g)(3) exempts diesel internal combustion engines meeting 51 ppmv NOx at 15% oxygen on a dry basis from the proposed NOx limit of 45 ppmv at 15% oxygen on a dry basis. The progressively more stringent potential control option would be to remove the exemption and require all engines to meet the 45 ppmv at 15% oxygen on a dry basis NOx limit. The present worth value of the proposed control option is $19,500,000 and the emission reductions of the proposed control option are 762.5 tons over the 25 year life of the equipment. The present worth value of the alternative control option is $23,400,000 and the emission reductions of the alternative control option is 780 tons. The incremental cost-effectiveness for removing the exemption for diesel internal combustion engines is $222,900 per ton of NOx reduced as calculated below.

Incremental cost-effectiveness = ($23,400,000 – $19,500,000) / (780 – 762.5) = $222,900 per ton of NOx reduced

Natural Gas Boilers

Removing subparagraph (g)(4)(B), the provision for low-use boilers allowing boilers operating below one percent annual capacity factor, would require boilers to install and operate SCR. Under the proposed rule, a low-use boiler could apply for a permit restriction at a cost of $24,119. This would result in no emission reductions. Under the alternative scenario, the boilers would be retrofitted at present worth value of $16,788,600 and realize 242.5 tons of NOx reductions over 25 years. The incremental cost-effectiveness for removing the low-use provisions for natural gas boilers is $759,400 per ton of NOx reduced as calculated below.

Incremental cost-effectiveness = ($16,788,600 – $72,400) / (242.5 – 0) = $68,900 per ton of NOx reduced

Natural Gas Combined Cycle Gas Turbines

Paragraph (g)(1) exempts natural gas combined cycle gas turbines meeting 2.5 ppmv NOx at 15% oxygen on a dry basis from the proposed NOx limit of 2 ppmv at 15% oxygen on a dry basis. The progressively more stringent potential control option would be to remove the exemption and require all natural gas combined cycle gas turbines to meet the 2 ppmv @ 15% oxygen on a dry basis NOx limit. The present worth value of the proposed control option is $57,066 and there are no emission reductions. The present worth value of the alternative control option is $39,062,000 and the emission reductions of the alternative control option is 362.5 tons over 25 years. The incremental cost-effectiveness for removing the exemption for natural gas combined cycle gas turbines meeting 2.5 ppmv NOx at 15% oxygen on a dry basis is $222,900 per ton of NOx reduced as calculated below.

Incremental cost-effectiveness = ($39,062,000 – $57,000) / (362 – 0) = $107,800 per ton of NOx reduced

The proposed rule also includes low-use provisions for combined cycle natural gas turbines that operate at less than ten percent of their annual capacity. The progressively more stringent proposal control option would be to remove the exemption. The present worth value of the proposed control option is $114,132 and there are no emission reductions. The present worth value of the alternative control option is $45,644,000 and the emission reductions of the alternative control option is 440 tons over 25 years. The incremental cost-effectiveness for removing the exemption for natural gas combined cycle gas turbines is $103,500 per ton of NOx reduced as calculated below.

Incremental cost-effectiveness = ($45,644,000 – $114,000) / (440 – 0) = $103,500 per ton of NOx reduced

Natural Gas Simple Cycle Gas Turbines

Subparagraph (g)(4)(A) is a low-use provision for natural gas simple cycle gas turbines that operate at less than ten percent of their annual capacity. The progressively more stringent proposal control option would be to remove the exemption. The present worth value of the proposed control option is $418,484 and there are no emission reductions. The present worth value of the alternative control option is $80,712,000 and the emission reductions of the alternative control option is 390.0 tons over 25 years. The incremental cost-effectiveness for removing the exemption for natural gas simple cycle gas turbines is $205,000 per ton of NOx reduced as calculated below.

Incremental cost-effectiveness = (80,712,000 – $418,000) / (390.0 – 0) = $205,900 per ton of NOx reduced

Overall Incremental Cost-Effectiveness

If the low-use provisions and provisions for equipment near the proposed limits were removed the overall incremental cost-effectiveness would be the sum of all of the alternative control options less the sum of the proposed control options divided by the sum of the alternative control option emission reductions less the sum of the proposed control option emission reductions.

Overall incremental cost-effectiveness =
(($23,400,000 + $16,788,600 + $39,062,000 + $80,712,000) – ($19,500,000 + $72,400 + $114,000 + $418,000)) / ((778 + 242.5 + 362 + 390.0) – 762.5) =
($159,962,600 - $20,104,400) / (1,772.5 – 762.5) = $138,473 per ton of NOx reduced

The incremental cost analyses presented above demonstrate that the provisions for low-use equipment and equipment already permitted near the proposed limit are necessary to avoid imposing costs that would exceed the cost-effectiveness threshold.

RULE ADOPTION RELATIVE TO COST-EFFECTIVENESS

On October 14, 1994, the Governing Board adopted a resolution that requires staff to address whether rules being proposed for amendment are considered in the order of cost-effectiveness. The 2016 Air Quality Management Plan (AQMP) ranked, in the order of cost-effectiveness, all of the control measures for which costs were quantified. It is generally recommended that the most cost-effective actions be taken first. Proposed Amended Rule 1135 implements Control Measure CMB-05. The 2016 AQMP ranked Control Measure CMB-05 sixth in cost-effectiveness.

SOCIOECONOMIC ASSESSMENT

A Draft Socioeconomic Impact Assessment has been prepared and is being released on October 2, 2018, 30 days prior to the SCAQMD Governing Board Hearing on PAR 1135, which is anticipated to be heard on November 2, 2018.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

PAR 1135 is considered a "project" as defined by the California Environmental Quality Act (CEQA), and the SCAQMD is the designated lead agency. Pursuant to CEQA and SCAQMD's Certified Regulatory Program (Rule 110), the SCAQMD, as lead agency for the proposed project, has prepared a Draft Mitigated Subsequent Environmental Assessment (SEA) for a 30-day public review and comment period from September 18, 2018 to October 18, 2018. The Draft Mitigated SEA indicated that while the project reduces NOx emissions, complying with the proposed project may also create secondary adverse environmental impacts that would not result in significant adverse impacts to any environmental topic areas after mitigation. The proposed project will have no statewide, regional, or area-wide significance; therefore, no CEQA scoping meeting is required pursuant to Public Resources Code Section 21083.9(a)(2) or CEQA Guidelines Section 15162(d). Responses to comments will be prepared for any comment letters that are received during the comment period relative to the Draft Mitigated SEA. After the public review and comment period, the Draft Mitigated SEA will be updated to reflect any modifications that are made to the proposed project and the Draft Mitigated SEA will be converted to a Final Mitigated SEA. The comment letters and the individual responses to the comments will be included in an appendix to the Final Mitigated SEA. The Final Mitigated SEA will be included as an attachment to the Governing Board package.

Prior to making a decision on the adoption of PAR 1135, the SCAQMD Governing Board must review and certify the Final Mitigated SEA, including responses to comments, as providing adequate information on the potential adverse environmental impacts that may occur as a result of adopting PAR 1135.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

Requirements to Make Findings

California Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing a rule or regulation, the SCAQMD 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

Proposed Amended Rule 1135 is needed to establish BARCT requirements for electricity generating facilities, including facilities that will be transitioning from RECLAIM to a command-and-control regulatory structure.

Authority

The SCAQMD Governing Board has authority to adopt amendments to Proposed Amended Rule 1135 pursuant to the California Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, 41508, and 41508.

Clarity

Proposed Amended Rule 1135 is written or displayed so that its meaning can be easily understood by the persons directly affected by it.

Consistency

Proposed Amended Rule 1135 is in harmony with and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.

Non-Duplication

Proposed Amended Rule 1135 will not impose the same requirements as any existing state or federal regulations. The proposed amended rule is necessary and proper to execute the powers and duties granted to, and imposed upon, the SCAQMD.

Reference

In amending Rule 1135, the following statutes which the SCAQMD hereby implements, interprets or makes specific are referenced: Health and Safety Code sections 39002, 40000, 40001, 40702, 40440(a), and 40725 through 40728.5.

COMPARATIVE ANALYSIS

Health and Safety Code Section 40727.2 requires a comparative analysis of the proposed amended rule with any Federal or District rules and regulations applicable to the same source. A comparative analysis is presented below in Table 4-5.

Table 4-5: PAR 1135 Comparative Analysis

Rule Element	PAR 1135	Rule 1110.2	Rule 2009	RECLAIM	40 CFR Part 60 Da	40 CFR Part 60 GG	40 CFR Part 60 KKKK	40 CFR Part 72
Applicability	Boilers, internal combustion engines, and turbines located at investor-owned electric utilities, publicly owned electric utilities, facilities with combined generation capacity of ≥ 50 MW	Gaseous and liquid fueled engine over 50 rated brake horsepower	Facility generating ≥ 50MW and owned or operated by Southern California Edison, Los Angeles Dept. of Water and Power, City of Burbank, City of Glendale, City of Pasadena, or any their successors	Facilities regulated under the NOx RECLAIM program (SCAQMD Reg. XX)	Electric utility steam generating units at a facility generating > 73 MW and constructed or modified after 9/18/78	Gas turbines with heat input of ≥ 10 MMBtu/hr constructed or modified before 2/18/2005	Gas turbines with heat input of ≥ 10 MMBtu/hr constructed or modified after 2/18/2005	Facilities regulated under the national sulfur dioxide and nitrogen dioxide air pollution control and emission reductions program
Requirements	Emission limits: • Boiler: NOx 5 ppmv @ 3% O2; Ammonia 5 ppmv @ 3% O2 • Combined Cycle Gas Turbine and Associated Duct Burner: NOx 2 ppmv @ 15% O2; Ammonia 5 ppmv @ 15% O2 • Simple Cycle Gas Turbine: NOx 2.5 ppmv @ 15% O2; Ammonia 5 ppmv @ 15% O2 Internal Combustion Engine: NOx 45 ppmv @ 15% O2; Ammonia 5 ppmv @ 15% O2; CO 250 ppmv @ 15% O2; VOC 30 ppmv @ 15% O2; PM 0.0076 lbs/MMBtu @ 15% O2	Existing Internal Combustion Engine: NOx 11 ppmv @ 15% O2; CO 250 ppmv @ 15% O2; VOC 30 ppmv @ 15% O2;	Submit Compliance Plan to demonstrate BARCT by 2003/2004	As determined by Rule 2009	NOx limit: 0.15 lb/MMBtu	NOx limit @ 15% O2: 0.0075*(14.4/Y) +F where Y = manufacture's rated heat input and F = NOx emission allowance for fuel-bound nitrogen	NOx limit for electric generating units (@ 15% O2): • ≤ 50 MMBtu/hr – 42 ppm when firing natural gas • 50 MMBtu/hr and ≤ 850 MMBtu/hr – 15 ppm when firing natural gas • >850 MBtu/hr – 15 ppm when firing natural gas • ≤ 50 MMBtu/hr – 96 ppm when firing other fuel • 50 MMBtu/hr and ≤ 850 MMBtu/hr – 74 ppm when firing other fuel • >850 MBtu/hr – 42 ppm when firing natural gas	NOx limits for boilers = 0.40 lb/MMBtu
Reporting	Annual reporting of NOx emissions	Breakdowns, monthly portable engine logs,	None	• Daily electronic reporting for major sources • Quarterly Certification of Emissions Report and Annual Permit Emissions	Daily written reports or quarterly electronic reports	Excess emissions and CEMS downtime within 30 days	Excess emissions and CEMS downtime within 30 days; annual performance testing within 60 days	40 CFR 75 requirements for quarterly reports of information and hourly data from CEMS monitors, and calibration

Rule Element	PAR 1135	Rule 1110.2	Rule 2009	RECLAIM	40 CFR Part 60 Da	40 CFR Part 60 GG	40 CFR Part 60 KKKK	40 CFR Part 72
				Program for all units				
Monitoring	• A continuous in-stack NOx monitor	A continuous in-stack NOx monitor for engines ≥ 1,000 bhp and operating more than two million bhp-hr per calendar year	None	A continuous in-stack NOx monitor for major sources	A continuous in-stack NOx monitor	A continuous in-stack NOx monitor	A continuous in-stack NOx monitor	A continuous in-stack NOx monitor
Recordkeeping	Performance testing; emission rates; monitoring data; CEMS audits and checks maintained for five years	Source testing or Relative accuracy tests per 40 CFR 70 at least once every two years	None	• < 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)	Performance testing; emission rates; monitoring data; CEMS audits and checks	Performance testing; emission rates; monitoring data; CEMS audits and checks	Performance testing; emission rates; monitoring data; CEMS audits and checks	Performance testing; emission rates; monitoring data; CEMS audits and checks maintained for three years
Fuel Restrictions	Liquid petroleum fuel limited to Force Majeure natural gas curtailment, readiness testing, and source testing	None	None	None	None	None	None	None

APPENDIX A – COMMENTS AND RESPONSES

Comment Letter 1

Montrose Air Quality Services – July 31, 2018

MONTROSE
AIR QUALITY SERVICES

July 31, 2018

Ms. Uyen-Uyen Vo
Air Quality Specialist
South Coast Air Quality
Management District
21865 Copley Drive
Diamond Bar, California 91765

Subject: Proposed Amended Rule 1135

Dear Ms. Vo:

Montrose Air Quality Services (MAQS) is pleased to offer the following comments in response to SCAQMD Proposed Amended Rule 1135. Our comments reflect our many years of compliance management and permitting experience with local municipal utilities.

Sections (b), (d)(3), (d)(4) and (d)(5)– Change is Rule Applicability from Electric Power Generating Systems to Electric Power Generating Facilities

Presently, Rule 1135 is applied to power generating units defined as legacy boilers and their replacements. According to the proposed amendments, emission rate limits and mass emission caps that currently apply only to defined generating units would now be applied to all generating devices at a regulated facility.

The City of Glendale Grayson Power Plant includes three boilers (boilers 3, 4 and 5) that are currently defined as "electrical power generating systems" and are subject to the mass emission caps (or emission rate limits) and annual emission caps of Rule 1135. The facility also includes several turbines that are not boiler replacements and classified as "electric power generating systems". The proposed language would subject these additional devices to emission rate limits and mass emission caps. 1.1

Additionally, paragraph (d)(3) specifies that the daily and annual emission limits would remain in place until the new concentration limits specified in paragraph (d)(1) take 1.2

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effect, even though modifications may be made to ensure compliance with paragraph (d)(1) prior to the effective date.

To ensure continuity in applicability until facility modifications are implemented, we suggest the following changes to paragraphs (d)(3) and (d)(4):

Until compliance with the emission limits pursuant to paragraph (d)(1) ~~becomes effective~~ is achieved, the City of Glendale shall not operate ~~its electric generating facility~~ electric generating units as defined on July 19, 1991 unless 1.2

Paragraph (d)(5) should also be modified to specify "a violation of any requirement specified in paragraph (d)(3) or (D)(4) shall constitute a violation of this rule for every ~~permitted~~ applicable unit 1.3

Paragraph (c)(20) – Startup Definition

The proposed definition is confusing because it reflects a time period with a defined start point but no end point. 1.4

MAQS recommends the following modification:
"Startup means the time period in which an electric power generating unit begins combusting fuel after a period of zero fuel flow, and ends when compliance with emission limits is sustained, or as otherwise defined in the SCAQMD permit."

Paragraph (d)(1), Table I – Emission Limits

The proposed rule language specifies an ammonia limit of 5.0 ppmv. While the proposed limit of 5.0 ppmv reflects BACT for new units based upon recent changes to BACT policy, existing permits for turbines that already comply with the proposed NOx limit may have a permitted limit of 5 ppmv. Existing emission control systems have been designed for the slightly more flexible permitted limit. 1.5

MAQS suggests that the 5.0 ppm ammonia limit apply only for new installations or in cases where turbines or emission control systems are modified to meet the proposed NOx emission concentration limits. 1.5

Paragraph (d)(1)(A) – Exclusions

The proposed rule language excludes startup, shutdown and tuning operations from Table I NOx limits. It makes sense that these operations, especially tuning operations, could also result in ammonia emissions in excess of Table I limits. Additionally, SCAQMD's reference to "tuning" is sometimes referenced as "maintenance operations" in existing permits. 1.6

MAQS suggests the following change to paragraph (d)(1)(a):

"The NOx <u>and ammonia</u> emission limits in Table I shall not apply during start-up, shutdown and tuning<u>/maintenance</u>."

Paragraph (d)(2)(A)(i) should also be accordingly modified.

Paragraphs (e)(2) and (e)(3) – Monitoring

MAQS continues to believe that RECLAIM facilities should have the flexibility to voluntarily transition away from RECLAIM CEMS and DAS requirements. The unique requirements of RECAIM subject local operators to a limited number of available vendors. RECLAIM facility operators are also subjected to increased software and maintenance costs and a higher risk of noncompliance due to software deficiencies. 1.7

The proposed rule language seems to reinstate the concept of former RECLAIM facilities continuing to be subject to RECLAIM monitoring provisions but gives no reference to the possibility of a future voluntary option to transition to more widely accepted DAS software. The adjoining CEMS requirements document, however, seems to carry on past Rule 1135 monitoring requirements without distinguishing between RECLAIM and non-RECLAIM facilities. Additional discussion regarding SCAQMD's intent for short-term, intermediate and long-term monitoring strategies is warranted.

Ms. Uyen-Uyen Vo 4 July 31, 2018
South Coast AQMD

Paragraph (f)(3) – Exclusions During Source Testing

It is not clear if SCAQMD intended to apply the proposed exclusion only to paragraphs (d)(3) and (d)(4), or if the intent is to also provide exclusions during source testing from paragraphs (d)(1) and (d)(2). 1.8

Paragraphs (g)(1) and (g)(2) - Exemptions

Paragraphs (g)(1) and (g)(2) include exemption provisions for tuning operations, but do not include "maintenance" as referenced in existing permits. 1.9

MAQS recommends that "tuning" be replaced with "tuning / maintenance".

Paragraph (g)(5)(C) – Low-Use Demonstration

The proposed language provides reasonable exemptions from Table I emission limits for low-use units. However, capacity factor is loosely defined and eligibility for the exemption is based upon 2016- 2018 operations, rather than future operations.

The concept of low-use exemptions from proposed emission limits has been proposed by the regulated community since the initial discussions about PAR 1135. However, SCAQMD has not been able to define its low use thresholds until the most recent working group meeting. It seems unreasonable to avoid defining what "low use" really means and now specify eligibility based upon historic operations.

1.10

By defining eligibility for low use exemptions based upon prior year operations, SCAQMD eliminates the ability for facility operators to incorporate low use concepts into their future compliance strategies. This is especially important in the electricity generating industry where low use assets can play a critical role in future peak power production to ensure reliability and grid stability without significantly adding to regional ozone formation.

Allowing facility operators to reduce operations by 2023 to meet low use exemption thresholds provides the same long-term air quality benefits that the proposed language provides, but also provides practical flexibility for facility operators.

MAQS suggests the following revision to proposed paragraph (g)(5)(C):

The owner or operator shall:

(i) Submit a compliance plan to SCAQMD by January 1, 2020 demonstrating that the low use exemption will be achieved by calendar year 2023. 1.10

(ii) Submit SCAQMD permit applications.......by January 1, 2021

Paragraph (g)(5)(D) – Emergencies

The proposed emergency exclusion provisions are limited to operations in response to a CEC emergency response plan or an energy emergency declared by the Governor. However, local municipalities can operate utilities and local transmission lines but may not control the point of connection to the CAISO grid. As such local emergencies can occur without necessarily being declared by the Governor, CEC or CAISO. Many municipal utility assets have been designed and installed to avert these local emergencies. 1.11

MAQS suggests that paragraph (g)(5)(D) be modified to state "When calculating the annual capacity factor to demonstrate eligibility for......during a phase of the California Energy Commission Energy Emergency Response Plan or a declared state of emergency or energy emergency declared by the Governor <u>or local official</u> shall not be included."

Ms. Uyen-Uyen Vo 6 July 31, 2018
South Coast AQMD

Again, MAQS appreciates the opportunity to submit these comments and welcomes the opportunity to discuss these concepts in more detail as we proceed through the rule development process. I am also available to discuss at your convenience and best reached at (714) 282-8240.

Sincerely,
Montrose Air Quality Services, LLC

Karl Lany, C.P.P.
District Manager
Regulatory Compliance Services

Par 1135 comments 7-31-18

Response to Comment 1-1

Staff has clarified the rule language in subparagraphs (d)(6)(A) and (d)(6)(B) to reflect that the SCAQMD-wide daily limits and annual emissions limits currently applicable to the City of Glendale boilers will remain applicable to the City of Glendale boilers only.

Response to Comment 1-2

Staff has revised the rule language in subparagraphs (d)(6)(A) and (d)(6)(B) to include provisions that remove the City of Glendale's SCAQMD-wide daily limits and annual emissions limits as soon as the City of Glendale complies with the BARCT emission limits in paragraph (d)(1).

Response to Comment 1-3

Staff has revised the rule language in subparagraph (d)(6)(C).

Response to Comment 1-4

Staff has revised the rule language in paragraph (c)(23) to reflect an endpoint for when startup concludes.

Response to Comment 1-5

Staff has revised the rule language in Tables 1 and 2 and elsewhere to provide consistency in the rules regarding emission limits.

Response to Comment 1-6

Ammonia does not need to be excluded during start-up, shutdown, and tuning operations because staff's understanding of the operation of the turbine during these time periods is that ammonia is either not being injected at all, or the rate of injection is limited to the extent that an exceedance is highly unlikely. Additionally, excluding "maintenance" periods is inappropriate as this term is too broad and can be interpreted to include many types of work performed on a turbine without regards to whether or not the work has the potential to affect emissions. Furthermore, maintenance activities should occur when the equipment is not operating to generate power. In the cases where existing permits refer to "maintenance" rather than "tuning," the facility may consider requesting a permit condition change.

Response to Comment 1-7

At this time, Rule 1135 will require each facility to maintain their current monitoring and recordkeeping practices. SCAQMD will be adopting a new rule, Proposed Rule 113 – Monitoring, Reporting, and Recordkeeping (MRR) Requirements for NOx and SOx Sources. Once Rule 113 is adopted, then all facilities will transition to Rule 113 which should address concerns regarding RECLAIM CEMS and DAS requirements. Staff is reluctant to allow transitions in the interim as Proposed Rule 113 will likely impose different requirements for CEMS and DAS resulting in lost or stranded assets if the facility made changes during the interim period.

Response to Comment 1-8

Paragraph (f)(3) applies to all emissions limits in subdivision (d).

Response to Comment 1-9

Please refer to Response to Comment 1-6.

Response to Comment 1-10

The low-use demonstration provisions have been revised to require that permit applications requesting low-use status be submitted by July 1, 2022, and low-use thresholds be achieved beginning calendar year 2024. The historical demonstration has been removed as many potential low-use electric generating units will be needed to bridge power generation gaps as more emissive units are retrofitted, replaced, or repowered in the years leading up to the January 1, 2024 compliance date.

Response to Comment 1-11

Staff does not believe that local emergencies should be excluded from the calculation for annual capacity factor. The low-use provision has a higher one year average to take into account local emergencies. If a local emergency required electric generating units to operate greater than 25% of its annual capacity in a year, then the equipment should be retrofitted or repowered within the two years provided pursuant to subparagraph (g)(4)(E).

Comment Letter 2

Los Angeles Department of Water & Power, July 25, 2018

LA DWP Los Angeles Department of Water & Power

CUSTOMERS FIRST

July 25, 2018

Ms. Uyen-Uyen Vo
South Coast Air Quality
Management District
Planning, Rule Development and Area Sources
21865 Copley Drive
Diamond Bar, CA 91765

Dear Ms. Vo:

Subject: Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electric Power Generating Systems

The Los Angeles Department of Water Power (LADWP) appreciates the opportunity to provide comments on Proposed Amended Rule (PAR) 1135. LADWP remains committed to working with the South Coast Air Quality Management District (SCAQMD) to transition electric generating facilities (EGFs) from the current RECLAIM program to Rule 1135 in an efficient and effective manner. LADWP strongly believes that SCAQMD should strive to complete that transition in a manner that will achieve the air quality goals of the federal Clean Air Act (CAA), while taking into account energy and economic impacts – including the minimization of any potential adverse impacts on the electric power grid and the economy. To that end, LADWP respectfully submits the following comments on the July 20, 2018, version of PAR 1135.

Municipal or Public Electric Utility Definition

PAR 1135 (c)(7) defines "Electricity Generating Facility" as "a facility that generates electrical power and is owned or operated by or under contract to sell power to California Independent System Operator Corporation, a municipal or public electric utility, or an electric utility on Santa Catalina Island…" This approach of differentiating between the segments of the electric generating sector is potentially confusing. It seems to conflict with SCAQMD's stated intent to establish only one regulation that applies to all affected EGFs. For these reasons, LADWP recommends that SCAQMD establish one set of applicability criteria for determining whether a facility is subject to the PAR 1135 requirements. We suggest SCAQMD consider using the following language for the definition of "Electric Generating Facility:" 2.1

> ELECTRIC GENERATING FACILITY (EGF) means a facility with electric power generating unit(s) that generates electricity for distribution in a local or state grid system, regardless of

111 N. Hope Street, Los Angeles, California 90012-2607 Mailing Address: PO Box 51111, Los Angeles, CA 90051-5700
Telephone (213) 367-4211 ladwp.com

Ms. Uyen-Uyen Vo
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> whether it also generates electricity for its own use or for use pursuant to a contract, with the exception of landfills, petroleum refineries, or publicly owned treatment works.

If SCAQMD decides to retain the current definition of EGF, LADWP has concerns with SCAQMD's proposed definition of "Municipal or Public Electric Utility" in PAR 1135 (c)(11). SCAQMD proposes to define this term as "a special-purpose district or other jurisdiction that provides electricity to residents of that district or jurisdiction." However, PAR 1135 does not further define "a special-purpose district" and, for that reason, is not clear if it includes EGFs under the jurisdiction of LADWP. As an alternative, in lieu of introducing a new definition for "a special-purpose district," LADWP recommends clarifying the definition of EGF as shown below in underline/strikeout format: 2.1

> ELECTRIC GENERATING FACILITY means a facility that generates electrical power and is owned or operated by or under contract to sell power to California Independent System Operator Corporation, ~~municipal or public electric utility,~~ a local publicly owned electric utility (as defined in the California Public Utilities Code Section 224.3), or an electric utility on Santa Catalina Island.

Force Majeure Natural Gas Curtailment Definition

According to the SCAQMD Staff Report to the original Rule 1135,[1] the intent of the force majeure natural gas curtailment definition is to provide a relief mechanism for natural gas curtailments and, as part of the definition, include as an eligible force majeure event supply restrictions resulting from California Public Utilities Commission priority allocations. In order to provide clarity and be consistent with SCAQMD's original intent for setting NOx standards for EGFs under Rule 1135, LADWP recommends revising the proposed definition as follows:

> FORCE MAJEURE NATURAL GAS CURTAILMENT means an interruption in natural gas service due to any one of the following unforeseeable or unavoidable events: failure, malfunction, natural disaster, or a supply restriction resulting from a California Public Utilities Commission priority allocation system; provided that such event is not the result of an intentional or negligent act or omission on the part of the owner or operator of an electric power generating unit; and provided further that as a result of such event, the daily fuel needs of an electric power generating unit cannot be met with the natural gas available. 2.2

[1] SCAQMD Staff Report PAR 1135, letter from Stephen Rhoads, California Energy Commission, to James Lents, Ph.D (5/20/91) (comment letter no. 4, page 000156) (enclosure).

Ms. Uyen-Uyen Vo
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Cost-Effectiveness Analysis

The draft staff report provides cost-effectiveness analysis of reducing NOx emissions from natural gas boilers and natural gas combined cycle turbines based on NOx emissions and capacity factor levels. However, the assumptions associated with the emissions and capacity factors are not clear. For example, the draft report does not indicate whether the annual NOx emissions and percent capacity factors used in the cost-effectiveness analysis are based on a historic annual average over a multi-year period and if so, what years are used. In addition, SCAQMD has not provided a cost-effectiveness analysis for natural gas simple cycle turbines. Without this information, stakeholders cannot evaluate the accuracy and appropriateness of the proposed cost-effectiveness analysis.

In addition, LADWP has questions on the technical basis that SCAQMD is using for setting the capacity factor limitations under the proposed low-use exemption. The proposed exemption provides that gas turbines and boilers installed prior to the adoption date of a final Rule 1135 would not be subject to the otherwise applicable NOx limits in paragraph (d)(1) provided that these generating units do not exceed specific capacity factor levels on a calendar year and average three-year basis. However, the draft staff report does not show the cost-effectiveness analysis used to justify the proposed capacity factor levels. LADWP urges SCAQMD provide this cost-effective analysis (and assumptions associated with the analysis) so that stakeholders have an opportunity to review and provide meaningful comments on the cost-effectiveness analysis methodology and approach used for setting the capacity factor cutoff levels used for determining eligibility for the low-use exemption. Currently, stakeholders do not know if affected generating units having to operate above these capacity factor cutoff levels could be required to incur NOx emissions control costs that exceed SCAQMD's own cost-effectiveness threshold of $50,000 per ton of NOx reduced. 2.3

Use of Liquid Petroleum Fuel

As part of efforts to maintain a reliable electric system and minimize power outages during potential natural gas curtailments, LADWP recommissioned twelve existing dual fuel electric generating units to be able to operate on California Air Resources Board ultra-low sulfur diesel fuel in 2016. At the time of recommissioning, LADWP worked closely with SCAQMD permitting staff to amend the Title V operating permits to meet acceptable NOx emission limits in the event of force majeure natural gas curtailment. In addition, permit conditions related to diesel fuel readiness testing time limits were also established based on the projected air quality impacts determined by extensive air dispersion modeling and electric generating unit manufacturer recommendations. In light of these thorough and rigorous efforts in setting limitations on the use of liquid petroleum fuel that are tailored to the design and operating scenarios of each electric generating unit, LADWP agrees with SCAQMD's decision to rely on these limitations under PAR 1135, instead of setting one-size-fits-all requirements on using diesel fuel at affected generating units. Furthermore, significant 2.4

Ms. Uyen-Uyen Vo
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July 25, 2018

variability exists depending on the type, design and operating parameters of each specific electric generating unit. Attempting to address all of these variables for the many different types of affected units by rule would be very difficult to achieve. 2.4

Internal Combustion Engines – Emergency Use

PAR 1135 (f)(1)(4) indicates that the owner of an EGF shall not install internal combustion engines that burn liquid petroleum as the primary fuel. Although the draft staff report states that the restriction on new installations of electric power generating internal combustion engines using liquid petroleum as the primary fuel would not apply to engines installed for the purpose of providing emergency backup power, the revised rule language in the July 20 version of PAR 1135 is not clear on this point. In particular, the relevant proposed rule language is silent on whether there is an exclusion for emergency diesel generators that are necessary in the event of "emergency use" as defined in SCAQMD Rule 1470. Therefore, LADWP recommends clarifying PAR 1135 (f)(1)(4) to state: 2.5

> Effective [Date of Adoption], the owner or operator of an electricity generating facility shall not install prime electric power generating unit internal combustion engines that burn liquid fuel as the primary fuel.

Also, LADWP recommends adding the following language in (f)(1)(4):

> This requirement does not apply to stationary diesel fueled internal combustion and other compression ignition engines that have been installed at an electric generating facility for only the purpose of providing emergency backup power to assure electric grid reliability.

Once-Through Cooling

LADWP supports SCAQMD's proposed exemption for electric generating boiler units that are subject to once-through cooling (OTC) requirements under Clean Water Act Section 316(b) as it would avoid stranded costs incurred for installing NOx pollution control equipment for a short interim period of time. However, other equipment types such as combined cycle and simple cycle turbines are subject to Clean Water Act Section 316(b) and would also have stranded costs associated with pollution controls resulting from the shutdown of the electric generating unit. Therefore, LADWP requests PAR 1135 (g)(3) be revised to broaden the applicability of OTC units: 2.6

> Once-Through Cooling ~~Boilers~~ Electric Power Generating Units
> An ~~boiler~~ electric power generating unit subject to the Clean Water Act Section 316(b) shall not be subject to paragraph (d)(1) provided that:

Ms. Uyen-Uyen Vo
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July 25, 2018

(A) The NOx and ammonia limits, averaging times, start-up, shutdown and tuning requirements specified on the SCAQMD permit as [Date of Adoption] are retained." 2.6

In addition, the requirement for the owner or operator of an OTC unit to submit a shutdown and retirement plan (Subparagraph (g)(3)(B)) should be deleted from PAR 1135. Owners and operators of OTC units are already required to submit implementation plans in compliance with Clean Water Act Section 316(b) and the information in the plans are included in the National Pollution Discharge Elimination System facility permits. Similarly, the OTC plans are posted on the California State Water Resources Control Board's website. Therefore, the proposed OTC shutdown and retirement plan requirement would be duplicative and unnecessary. 2.7

LADWP appreciates the opportunity to provide comments on PAR 1135. If you have questions or would like additional information, please contact me at (213) 367-0403 or Ms. Jodean Giese at (213) 367-0409.

Sincerely,

Mark J. Sedlacek

Mark J. Sedlacek
Director of Environmental Affairs

JG/EK/TG:rs
Enclosure
c/enc.: Ms. Susan Nakamura, SCAQMD
Mr. Michael Morris, SCAQMD
Mr. Gary Quinn, SCAQMD
Mr. Tracy Goss, SCAQMD
Mr. Kevin Orellana, SCAQMD
Ms. Jodean Giese

STATE OF CALIFORNIA—THE RESOURCES AGENCY PETE WILSON, Governor

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814-5512

May 20, 1991

James Lents, Ph.D
Executive Office
South Coast Air Quality Management District
9150 Flair Drive
El Monte, California 91731

Dear Dr. Lents:

We received your PAR Rule 1135E last week, and appreciate the opportunity for one final round of comment. Your decision to defer adoption another month makes sense, since this draft contains significant changes and new provisions which merit further discussion.

I should begin by reiterating the California Energy Commission (CEC) staff's continuing support for adoption of an effective, flexible retrofit rule. Clearly, the changes in the May 2 draft rule indicate you are listening to the concerns raised by the affected parties. You have made progress in addressing the definition of alternative resources and thermal credit, force majeure oil use and conditional exemptions for periods of low load or emergency conditions not exceeding ten days per year. Finally, you have made another bold step forward by incorporating the California Air Resources Board's (CARB) Best Available Retrofit Control Technology (BARCT) cost-effectiveness threshold, as well as the resultant rates and caps.

Each of these topics is likely to raise some spirited discussion at the workshop. To further that exchange, the following sections highlight issues which should be addressed.

<u>Section (b)(9) Force Majeure</u>

The 1135E revision removing the post 1996 oil phase-out requirement is a major improvement. Since this is likely to put increased and permanent focus on the definition of force majeure, some additional scrutiny may be in order. Potential questions include:

-- Is this definition a reasonable representation of legal language currently used in practice in state and federal administrative and contract law? 4-1

-- Should supply restrictions resulting from CPUC priority allocations due to unexpected supply shortfalls or emergency redirections be allowed force majeure treatment? 4-2

000150

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May 20, 1991
Page 2

Section (c) Emissions Limitations

The emission rate limits in the rule have been lowered in this draft to .15 Lb/MWh for Southern California Edison (SCE) and Los Angeles Department of Water and Power (LADWP). (.20 Lb/MWh remains constant for the smaller cities). Caps have also been adjusted for all utilities, some up, some down.

CEC staff recognizes CARB's statutory responsibility to make BARCT determinations, and we appreciate their willingness to accept and attempt to define a flexible "system" BARCT. The limits in the current draft are, however, below the ER-90 results we reported in our testimony in December. This is primarily due to the fact that the ER-90 analysis did not examine 1135 limits per se, but simply assumed utility-proposed compliance plans meeting a .25 Lb/MWh rate in the "ICEM" electricity system resource cost effectiveness testing. To the extent that District and ARB cost thresholds result in rates below .25, an ER-90 "equivalent" outcome would reflect lower daily and annual caps. For example, at .15 and $26,500 average cost, illustrative ER-90 results for SCE are summarized in Table 1. (CEC staff has not yet completed its review of PAR 1135E requirements for the municipal utilities.)

The same analysis is presented in Table 2, but with the assumption that repowered units will meet a BACT requirement of .10, rather than .15, which was the assumption in the adopted ER-90 data sets. As the results in Table 2 demonstrate, this question can have a significant impact upon results.

A second issue of consequence is how the repowered resources are treated in the modelling analysis. Tables 1 and 2 show this sensitivity for the .15 and .10 BACT assumption, respectively.

Key clarification questions include:

-- What is the District's assumption regarding BACT for repower or replacement combustion projects? 4-3

-- What is the District's intention regarding qualification of .10 utility repower or replacement projects as "alternative" resources? 4-4

-- What additional PROSYM modelling is planned or needed to address peak day variations or other contingency concerns? 4-5

000151

Dr. James Lents
May 20, 1991
Page 3

Section (h) Exemptions

As emphasized in the Attachment to Jim Boyd's recent letter to you, CEC staff recognizes that increasing cost-effectiveness thresholds can make rule limits lower; these rule limits in turn require recognition of potential emergency situations which cannot be accounted for under expectable average conditions, even with standard deviations taken into account. Your staff and ARB agree, and as a result you have added a new Section (h) to PAR 1135E.

All parties appear to be in agreement that exemption provisions are needed for both "minimum load" and unforeseen "high emission" circumstances. A number of differing options exist to provide high emission exemptions. At District staff's request, CEC staff developed the following language:

(h) System Emergency Exemptions

The emissions limitations specified in sections (c) 1, (c) 2 and (c) 3 shall not apply under emergency conditions in which a utility system is required to request or provide emergency support, as defined in Item 5 of the Coordinated Bulk Power Supply Program (April, 1990). This exemption is limited to those situations in which the specified procedure for requesting emergency relief have been followed, including a utility determination that normal arrangements for capacity and energy are not sufficient to meet a system's requirements, and the next relief measure for either the requesting or responding utility is reduction of firm load.

PAR 1135E chooses an alternative approach, one which contains specific conditions and specifies a limited number of days for which an exemption can be utilized. 4-10

CEC staff understands this is a difficult issue, and is willing to work with you to evaluate all options. Specific questions in the current draft language meriting workshop discussion include:

-- What is the numerical basis for the 10 day exemption limitation? 4-6

-- Is the 10-day language adequate to cover emergency and other unforeseen circumstances? 4-7

-- Why do the conditions specified in Section (h) not include interruption of non-firm load? 4-8

000152

Dr. James Lents
May 20, 1991
Page 4

In closing I want to emphasize that your staff has made a tremendous effort to produce a staff report which does address the many complex energy and air quality questions the rule raises. And, we recognize that lingering questions such as those above are challenging, and that neither your staff nor the CEC and California Public Utilities Commission staffs have easy answers. These issues, and others, are, however, certain to be raised in the coming weeks. A continuing dialogue can best inform the final decision your board members will make in July.

One final note regarding the compliance plan schedule is needed. In our April comments we urged you to acquire and approve utility compliance plans as expeditiously as possible. While we understand that adoption has been deferred one month, this draft actually defers plan submittal and approval by over 3 months beyond the April Rule. Again, we ask why utilities need 6 months to develop plans, and why approval--even with public hearings-- will require another 6? This schedule appears to add as much as 6 months to actual implementation without justification. Moreover, this will preclude the approved plans from being incorporated into ER-92. We thus recommend amendments to Section (d) as follows: 4-9

"(d) Compliance Plans

(1) Compliance Plan (Plan) approval and disapproval:

(A) Each owner or operator of a boiler should submit a Plan by November 1, 1991..."

(D) On or after March 1, 1992, failure to have an approved plan...".

Sincerely,

STEPHEN RHOADS
Executive Director

000153

RESPONSE TO RULE COMMENTS
STEPHEN RHOADS, EXECUTIVE DIRECTOR
THE CALIFORNIA ENERGY COMMISSION
(5/20/91)
LETTER NO. 4

4-1 We believe that the definition of force majeure gas curtailment is clear, unambiguous, and enforceable.

4-2 Staff believes that available evidence shows that very few gas curtailments would actually occur in the District from the mid-1990s. However, a relief mechanism has been built into the proposed regulation for gas curtailments. This definition includes supply restrictions due to the reasons mentioned in the comment.

4-3 We assumed 0.15 lbs NOx/MWH for new combined cycle gas turbine generators.

4-4 Gas turbines and other resources that meet the requirements for Approved Alternative or Advanced Combustion Resources would qualify to participate in the Rule 1135 bubble.

4-5 Staff does not intend to conduct additional model runs to study peak day variations any further. Sufficient data is currently available to enable the adoption of regulatory limits.

4-6 Staff believes 10 days is a good compromise. On one hand it should provide compliance on 355 days per year or more. On the other, it allows the utilities to plan for less than 100% compliance, in case of unusual circumstances beyond their control. It is important to realize that the utilities will not be allowed any of the exemption days unless they can justify they meet the exemption requirements. If a severe emergency were to require extraordinary in-basin generation for more that 10 days, as happened with SCE in 1985, they would be justified to petition the hearing board for a variance. The 10-day exemption will eliminate the burden of a variance for every short-term, high -generation incident that occurs.

4-7 The proposed higher daily limits for upto 10 days per year is expected to address anticipated needs. However, totally unforeseen and unusual conditions that make compliance impossible may merit the attention of the Hearing Board.

4-8 We have added the condition requested for interruption of non-firm load.

4-9 Due to the major changes proposed to the emission rates and caps, the District thinks the almost 6 months provided after rule adoption is a reasonable time to allow the utilities to prepare and submit their compliance plans.

000156

Assuming the District receives CARB, CEC and PUC comments by February 1, 1992, the District will have till March 1, 1992 to review the comments and the plans, and to notify the utilities of necessary changes. This provides the utilities with a month, until April 1, 1992, to consider comments and revise their plans. Because the plans will be submitted as SIP revisions, a public hearing is also required. The public hearing could be set at the May 1, 1992 District Board meeting to be heard at the June 5, 1992 Board meeting. This would be the last opportunity for the Board to approve the plans in time for the July 1, 1992 deadline.

4-10 Staff believes that the CEC-recommended language does not address emergency, high-generation situations which do not require emergency support between utilities. Also there should not be an automatic exemption for emergency support days when the support occurs during a low-demand period that does not require high daily generation.

000157

Response to Comment 2-1

To address the potential confusion from the definition for “electricity generating facility,” staff has revised the rule language in paragraphs (c)(7), (c)(8), (c)(12), and (c)(17). “Electricity generating facility” is now defined as a facility that is an investor-owned electric utility, is a publicly owned electric utility, or has combined generation of 50 MW. Investor-owned utility is an electric power distribution company overseen by the California Public Utilities Commission. Publicly owned electric utility is a special purpose district, including municipal districts or municipalities, which operates electric generating units for power distribution to residents of that district or jurisdiction. With the change in applicability, no new facilities are subject to PAR 1135, but Colton Power, LP (SCAQMD ID #s 182561 and 182563) and City of Riverside, Public Utilities Department (SCAQMD ID # 164204) will no longer be subject to PAR 1135 and will instead be subject to PAR 1134.

Response to Comment 2-2

Staff added “unavoidable” to the definition of force majeure natural gas curtailment in paragraph (c)(9). The definition of force majeure natural gas curtailment was amended to be consistent with SCAQMD Rule 701 – Air Pollution Emergency Contingency Actions. The definition is also consistent with the language recommended by the commenter. Therefore, unavoidable or unforeseen events include failures, malfunctions, natural disasters, or supply restrictions from CPUC priority allocation system that are not an intentional or negligent act or omission.

Response to Comment 2-3

As noted in the tables for the assessment of existing equipment (Tables 2-2 through 2-5), the emissions evaluated are from reporting year 2016. The other tables (Tables 2-15 through 2-18) have been updated to clarify that the same data is used to determine cost-effectiveness. Information for the cost-effectiveness for natural gas simple cycle gas turbines has been included in the staff report. Cost-effectiveness varies by unit with the cost-effectiveness threshold for natural gas simple cycle gas turbines reaching annual capacity levels between 10.4% and 38.5% with an average of 18.7% and a mean of 16.3%.

Response to Comment 2-4

Thank you for the comment.

Response to Comment 2-5

Staff has removed subparagraph (f)(1)(4). The definition for “electric generating unit” has been changed to include only internal combustion engines located on Santa Catalina Island and therefore this provision is no longer needed.

Response to Comment 2-6

The rule language in paragraph (g)(2) has been clarified to include turbines as well as boilers subject to once-through-cooling regulation.

Response to Comment 2-7

Staff understands that the owner and operators of once-through-cooling electric generating units subject to the Clean Water Act Section 316(b) have already submitted implementation plans and the information is posted on California State Water Resources Control Board’s website. SCAQMD will instead require notification of the shutdown and retirement date by January 1, 2023, and any further updates to the shutdown and retirement dates.

Comment Letter 3

Burbank Water & Power, August 10, 2018

August 10, 2018

VIA ELECTRONIC MAIL
(mmorris@aqmd.gov)

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

SUBJECT: **Comment Letter – Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities**

Dear Mr. Morris,

Burbank Water and Power (BWP) is pleased to provide comments on the proposed amendments to Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities (PAR 1135). The proposed amendments are of significant interest and concern to BWP.

Overall, it is BWP's opinion that the South Coast Air Quality Management District (SCAQMD) has done a great job addressing stakeholder concerns during the development of PAR 1135. While BWP is supportive of the proposed amended rule, there is one area that BWP feels requires additional review.

The current PAR 1135 language includes a low use provision, paragraph (g)(6). The provision allows low-use equipment to continue operating without retrofit provided that they do not exceed an annual capacity factor limit. According to PAR 1135, a facility will have to submit a permit application requesting a change of permit conditions to incorporate the low use provision by July 1, 2019. Because of the pending New Source Review (NSR) issues, which may not be resolved by July 1, 2019, BWP is requesting that the deadline to submit a permit application to incorporate the low use provision be extended to July 1, 2022. 3.1

This will allow facilities to have a clear understanding of the path going forward prior to making major decisions on retrofitting equipment.

Burbank Water and Power
164 West Magnolia Boulevard, P.O. Box 631, Burbank CA 91503-0631

BWP looks forward to your response. Please feel free to contact Claudia Reyes, Senior Environmental Engineer, at (818) 238-3510 if you have any questions, or would like to discuss further.

Sincerely,

Frank Messineo

Frank Messineo
Power Production Manager – BWP Power Supply Division

cc: Claudia Reyes (via electronic mail)
Sean Kigerl (via electronic mail)
Dr. Krishna Nand (via electronic mail)

Response to Comment 3-1

In subparagraph (g)(4)(C), staff has extended the submission date of permit applications for the low-use exemption to July 1, 2022. Staff believes this is the latest date in which a permit could be submitted that allows enough time for the permit change to be completed by January 1, 2024, the deadline required in paragraph (d)(1).

Comment Letter 4

Pasadena Water & Power, August 16, 2018

PASADENA WATER AND POWER
POWER SUPPLY BUSINESS UNIT

August 16, 2018

Sent via electronic mail to mmoris@aqmd.gov and US Mail

Mr. Michael Morris
Planning and Rules Manager
21865 Copley Drive
Diamond Bar, CA 91765

Subject: Pasadena Water and Power Comments on Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electrical Generating Facilities

Dear Mr. Morris:

The City of Pasadena Water and Power Department (PWP) appreciates the opportunity to comment on the proposed amendments to Rule 1135 (PAR 1135) – Emissions of Oxides of Nitrogen from Electrical Generating Facilities, which would impose additional requirements on PWP's Electrical Power Generating Facility.

PWP is a municipal utility responsible for providing safe, reliable and reasonably priced water and electric power to its customers. PWP's local electric generation units are located at a single facility and consist of five stationary combustion gas turbines ("GT"): GT-1, GT-2, GT-3, and GT-4 are simple cycle units and GT-5 is a combined cycle unit. GT-5 is PWP's new state of the art combined cycle gas turbine system with the lowest emission concentration limits in the basin. It replaced a 1960's era steam boiler system to modernize and increase the efficiency of the City's electrical generating fleet.

These gas turbine units provide reliability and protection against energy market price spikes for our customers, and are an essential part of the Pasadena's electrical system. Under existing agreements their capacity and electrical output is available to California Independent System Operator ("CAISO") as required.

There are several days in a year when sufficient amount of electricity cannot be imported into Pasadena due to the equipment and transmission constraints. During such times, these gas turbine units make up for the shortfall in the electrical power.

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PWP Comments: Proposed Amended Rule 1135
August 16, 2018
Page 2

PWP staff has been regularly meeting and working with the South Coast Air Quality Management District (SCAQMD) PAR 1135 team. We commend their outreach and work to solicit and address stakeholders concerns during this rule-making process. PWP offers its qualified support for PAR 1135 and requests further review of the current language relating to the submission of the permit application for low-use exemption under [g(5)(c)(ii)].

1) **Low use provision paragraph (g)(5)**

As the rulemaking analysis has shown, this is a much needed and beneficial option for the electric power generating units. However, the following change is needed to provide the necessary flexibility to allow PWP to upgrade GT-1, GT-2, GT-3, and GT-4 units to meet the proposed NOx BARCT emission limit of 2.5 ppmv before the PAR 1135 deadline. It will also preserve PWP's ability to run these units past January 1, 2024 as low-use units, if they are not able to meet the NOx BARCT emission limit of 2.5 ppmv after these upgrades.

(C) Initial Requirement for Low-Use Exemption

The owner or operator of an electricity generating facility that elects the low-use exemption pursuant to paragraph (g)(5) for a gas turbine or a boiler shall:

(i) Demonstrate compliance with subparagraph (g)(5)(A) or (g)(5)(B) using data from calendar years 2016, 2017 and 2018; and
(ii) Submit SCAQMD Permit applications for each electric power generating unit requesting the change of SCAQMD permit conditions to incorporate the low-use exemption by July 1, ~~2019~~ 2023. 4.1

The reasons for the request for the change in the date of submission of the permit application (from July 1, 2019 to July 1, 2023) are provided below.

As discussed with your team, PWP has completed a feasibility study for upgrading PWP's existing simple cycle gas turbines (GT-1 through GT-4) to meet the proposed NOx BARCT emission limit of 2.5 ppmv. Based on the results of this study, PWP plans to begin these upgrades upon the final adoption of PAR 1135 in the following order: (a) GT-2, (b) GT-1, (3) GT-3 and (4) GT-4. Due to the length of time needed for permitting and procurement, and constraints on taking gas turbine units out of service for the upgrades, PWP will not be able to complete upgrades to all the gas turbine units until April 2023. (See the attached tentative schedule for upgrades to the gas turbine units GT-1 through GT-4).

It is possible that some of the upgraded gas turbine(s) may not be able to meet the NOx BARCT emission limit of 2.5 ppmv and PWP may have to submit permit application(s) requesting the change of permit conditions to incorporate the low-use exemption.

PWP Comments: Proposed Amended Rule 1135
August 16, 2018
Page 3

Therefore, we request the change in permit submission date from July 1, 2019 to July 1, 2023 in (g)(5)(c)(ii). Note that PWP may not operate a gas turbine unit that does not meet the NOx BARCT emission limit of 2.5 ppm after December 31, 2023, unless the modified permit incorporating the low-use exemption has been issued by the SCAQMD.

PWP would also like to discuss with PAR 1135 team another approach for preparing
only one permit application for upgrading the gas turbines as well as for incorporating
the low-use exemption. Under this approach, the permit issued by the SCAQMD will 4.1
have a provision for upgrading the gas turbines. The SCAQMD permit will also have a
provision for low-use exemption, effective January 1, 2024 if the gas turbine(s) is not
able to meet NOx BARCT emission limit of 2.5 ppmv.

Making the requested change in the permit submission date from July 1, 2019 to July 1, 2023 in (g)(5)(c)(ii) will allow PWP to proceed with the upgrades and preserve our ability to apply for the low-use exemption should the upgraded gas turbine units fall short of the NOx BARCT emission limit of 2.5 ppmv.

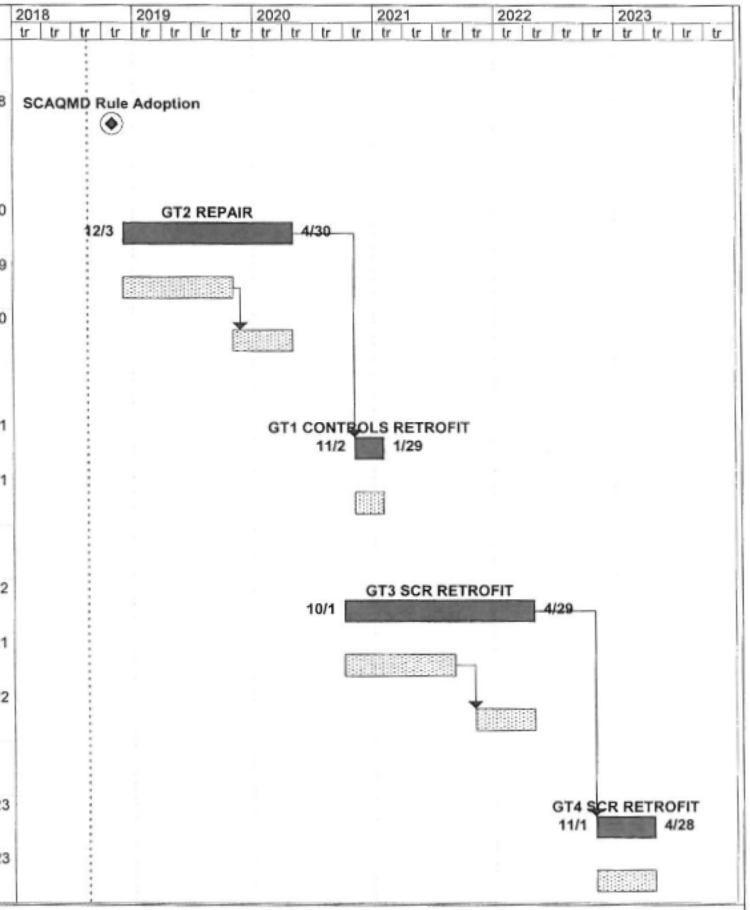
We look forward to your response. Please contact Kim Yapp, Environmental Engineer at (626) 744-3926 or me at (626) 744-4568 should you have any questions.

Sincerely,

Arturo Silva, Power Plant Manager

cc: Dr. Krishna Nand (via electronic mail)

ID	Task Name	Duration	Start	Finish
1				
2	**SCAQMD Rule Adoption**	1 day?	Fri 11/2/18	Fri 11/2/18
3				
4	**GT2 REPAIR**	369 days?	Mon 12/3/18	Thu 4/30/20
5	Spec Prep & Contracting	239 days?	Mon 12/3/18	Thu 10/31/19
6	Design, Construction, & Commissioning	130 days?	Fri 11/1/19	Thu 4/30/20
7				
8	**GT1 CONTROLS RETROFIT**	65 days?	Mon 11/2/20	Fri 1/29/21
9	Design, Construction, & Commissioning	65 days?	Mon 11/2/20	Fri 1/29/21
10				
11	**GT3 SCR RETROFIT**	412 days	Thu 10/1/20	Fri 4/29/22
12	Spec Prep & Contracting	239 days?	Thu 10/1/20	Tue 8/31/21
13	Design, Construction, & Commissioning	130 days?	Mon 11/1/21	Fri 4/29/22
14				
15	**GT4 SCR RETROFIT**	129 days?	Tue 11/1/22	Fri 4/28/23
16	Design, Construction, & Commissioning	129 days?	Tue 11/1/22	Fri 4/28/23



PWP COMPLIANCE SCHEDULE
Rule 1135 Amendment
(Proposed)

Task · Split · Progress · Milestone · Summary · Project Summary · External Tasks · External Milestone · Deadline

Page 1

Response to Comment 4-1

Please refer to Response to Comment 3-1. There are no provisions in Rule 1135 precluding the incorporation of the low-use exemption as a contingency measure when modifying the gas turbine to meet the proposed emission limits under the same permit application.

Comment Letter 5

Southern California Edison, August 16, 2018

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

Laura Renger
Principal Manager, Air & Climate Policy
Regulatory Affairs
626-302-6984
laura.renger@sce.com

August 16, 2018

Dr. Phil Fine, Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765
Via e-mail at: pfine@aqmd.gov

SUBJECT: Proposed Amended Rule 1135: Emissions of Oxides of Nitrogen from Electricity Generating Facilities

Dear Dr. Fine:

Southern California Edison (SCE) appreciates the opportunity to comment on the South Coast Air Quality Management District's (District) Proposed Amended Rule (PAR) 1135. This rule would establish Best Available Retrofit Control Technology (BARCT) and the monitoring, recordkeeping, and reporting (MRR) requirements for Electricity Generating Facilities (EGFs) after the sunset of the Regional CLean Air Incentive Market (RECLAIM) Program as required by Assembly Bill 617. SCE greatly appreciates the extra effort that District staff has put into working with us on this complicated set of issues.

SCE generally supports the proposed rule as it relates to our Mountainview Generating Station, two gas turbine peaking units, and two hybrid gas turbine/battery energy storage units. However, SCE has significant concerns about its effect on our Pebbly Beach Generating Station (PBGS) on Catalina Island. Specifically:

- The Proposed Rule's unreasonably tight deadlines likely will prevent SCE from investing in the clean, lower-emission generation we would prefer – instead, forcing us to opt for diesel engines (which can be installed much faster). For the past 3 years, SCE has engaged in an integrated resource planning effort to develop a strategy for ensuring clean, reliable electricity generation for Catalina Island. This effort is currently before the California Public Utilities Commission and includes stakeholders from the public and private sector, as well as other state agencies. We are concerned that there is insufficient time to evaluate potential options – including renewable energy – that would result in lower emissions than could be attained by the installation of new diesel engines. 5.1

PO Box 800
2244 Walnut Grove Ave.
Rosemead, CA 91770

Dr. Phil Fine
Deputy Executive Officer
August 16, 2018
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- The proposed rule has a nitrogen oxides (NOx) emission concentration limit of 45 ppm for internal combustion engines based on a 40% efficiency factor. However, emission concentrations vary based on efficiency – higher efficiency generally results in higher NOx concentrations. SCE sees the need for a method to adjust the emissions limit based on actual engine efficiency. 5.2
- SCE would appreciate additional time to work with District staff to clarify Monitoring, Recordkeeping, and Reporting requirements before the Proposed Rule is finalized. 5.3

Additional Time is Needed for BARCT Implementation and Additional Study of the Feasibility of Alternative Technology

Due to the unique geographic and resource constraints on Catalina Island, electricity generation there is so complex that compliance with the Proposed Rule's deadlines will pose a serious challenge. The proposed compliance timeline requires the facility to meet specific emission limits that are quite aggressive. Given this compressed timeline, SCE would need to move quickly to replace the engines with new Tier 4 diesel engines. SCE anticipates this course of action will be met by strong opposition by environmental organizations and possibly state regulators as well.

Rather than replacing the engines with Tier 4 diesel engines, SCE is exploring cleaner options as part of our integrated resource planning effort for PBGS. These options include renewable energy resources and energy storage. It must be noted that all alternative options to diesel replacement face significant issues that are outside SCE's control such as securing the necessary land rights and permits, and even determining the technical feasibility given Catalina's unique 5.1 geographic issues. As a part of SCE's resource planning process, we will seek input from numerous stakeholders including the CPUC, and conduct engineering studies to determine which options may be feasible based on costs, permitting feasibility, and the likelihood of CPUC approval. To do this, SCE will need at least one year to conduct the analysis of potential alternatives, and two additional years to determine the feasibility of obtaining required land rights and permits. If additional land rights are necessary (for a renewable energy project), the condemnation process could also require an additional 18 months. (This timeline is SCE's best estimate now, and could be affected by actions outside of our control, such as agency delays and stakeholder opposition.)

If it is determined that alternative options cannot be permitted and SCE needed to move forward with the acquisition of new diesel engines, SCE may still need to acquire some additional land rights, which could take up to 18 months to acquire.

Dr. Phil Fine
Deputy Executive Officer
August 16, 2018
Page 3 of 4

The Proposed Emission Concentration Limits May Not Appropriately Account for Engines' Performance in Practice

PAR 1135 sets a requirement for NOx emissions at 45 ppmv corrected to 15% O_2, based on EPA's certified Tier 4 engine's emissions of 0.67 g/kWh and assuming an engine efficiency of 40%.

Engine efficiencies vary depending upon an engine's type, model, size, and manufacturer's guarantee. Engines with high efficiency will result in high emissions concentrations but can still meet the certified Tier 4 engine's emissions level. For example, while an efficiency factor of 40% yields NOx emissions of 45 ppmv, an engine with an efficiency factor of 60% will have NOx emissions of 67 ppmv. At PBGS, SCE needs to use various sizes of engines to allow operational flexibility and ensure grid reliability. Some of the engines we need to use cannot meet the new proposed limit. 5.2

SCE understands the need to demonstrate compliance in term of concentration limits and has done so successfully on one of the most critical units on the island. Working closely with the District's permitting staff, we have achieved and maintained a low and reasonable NOx concentration level on Unit 15. SCE would like an opportunity to continue working with the District's permitting staff in future permit applications to determine appropriate emissions concentration levels for the engines.

To address the need to correct the emissions concentrations based on the engine efficiency, SCE respectfully suggests that the District include the following language in Table II: "or EPA's certified Tier 4 engine emissions equivalence as established and approved by Executive Officer" to the proposed emissions limits, or provide clarification or guidance to correct the concentration in the event that the engine efficiency is greater or less than 40%.

Additional Details and Clarity are Needed for Monitoring, Recordkeeping, and Reporting

The proposed MRR, in particularly the Continuous Emissions Monitoring Systems (CEMS) requirements, were designed primarily for existing utility boilers. SCE recognizes that the District staff has been working diligently to address MRR requirements for various types of electricity generating units (namely gas turbines, utility boilers, and internal combustion engines). 5.3 However, significant changes are needed to the provisions regarding CEMS, including for non-RECLAIM facilities. For example, SCE's CEMS for the four peaking units, which are currently subject to Rule 1134, will be required to add additional reporting codes per Section 2.1(h). At this time, SCE is not confident that CEMS manufacturers will be able to effectuate the required changes in order to meet the new requirements and as written, there is not enough definition in the proposal to make that determination. SCE requests more time to work with District staff to provide clarity on these issues.

Dr. Phil Fine
Deputy Executive Officer
August 16, 2018
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Conclusion

SCE appreciates the time and effort the District staff has invested on this issue, as well as the collaboration between District staff and SCE. As many complex issues remain, more time is needed for additional collaboration.

SCE is committed to delivering safe, reliable, affordable, and clean energy. We welcome a partnership with the District and interested parties to develop and execute the vision for PBGS's energy future. Thank you for considering these comments. We look forward to continuing to work with you and your staff on this rulemaking process.

If you have any questions or would like to discuss these issues, please contact me at (626) 302-6984, or by email at Laura.Renger@sce.com, or contact Thomas Gross, Senior Advisor, Environmental Affairs and Compliance, at (626) 302-9545 or by email at Thomas.Gross@sce.com.

Sincerely,

Laura Renger
Principal Manager, Air and Climate Policy

Cc: Dawn Wilson, SCE
Jim Buerkle, SCE
Don Neal, SCE
Wayne Nastri, SCAQMD
Clerk of the Board, SCAQMD

Response to Comment 5-1

Rule 2009 – Compliance Plan for Power Producing Facilities allowed only three years for electric generating units to achieve BARCT. However, staff recognizes the unique challenges of construction on Santa Catalina Island and has included a provision for that facility to request a three-year time extension for electric generating units located on Santa Catalina island in paragraph (d)(5). A mitigation fee of $100,000 per year extended is included in the proposed rule. The mitigation fee closely approximates the excess emission fees that would be charged if the facility sought a variance to extend the compliance date. The extension would forgo up to an estimated 4.7 tons per year of NOx emission reductions. Rule 303 Table I – Schedule of Excess Emissions Fees establishes a fee of $3,643.58 per ton of excess NOx. This would result in a fee of $17,125 per year or $47 per day. However, Rule 303 (f) establishes a minimum fee of $192.36 per day. Over a 365-day period, the excess emission fee would be $70,211. Including filing and appearance fees, and adjusting for inflation, staff approximated the mitigation fee at $100,000 per year.

Response to Comment 5-2

Staff believes that Rule 1135 needs to have concentration limits to demonstrate continuous compliance. Including compliance provisions allowing demonstration by Tier IV engine emission standards through source testing is periodic at best. This would preclude the use of a continuous emission monitoring system. The internal combustion engine that currently meets a 51 ppmv at 15% oxygen on a dry basis NOx concentration permit limit was installed decades ago and has been shown to meet the permit limit and the proposed NOx concentration rule limit. Engine efficiency typically ranges between 32% and 46%. SCAQMD assumed this range of engine efficiency, and thus, the ability to meet the proposed rule limit are expected to be achievable using readily available diesel technology without needing to allow for differing engine efficiencies.

The 45 ppmv at 15% oxygen on a dry basis was calculated using the EPA Tier IV limit of 0.67 g/kwh, assuming an engine efficiency of 40%, and the equations below.

$$\frac{0.67g}{kwh\ out} X \frac{0.7457\ kwh\ out}{1\ bhp\ out} X \frac{lb}{454g} X \frac{0.4\ bhp\ out}{1\ bhp\ in} X \frac{bhp\ in}{0.002545\ mmbtu} = 0.173\ lbs/mmbtu$$

$$\frac{0.173\ lbs}{mmbtu} X \frac{mmbtu}{9190\ scf} X \frac{20.9 - 15}{20.9} X \frac{ppm}{1.194E - 7} = 44.5\ ppm$$

Response to Comment 5-3

The monitoring, recordkeeping, and reporting requirements for non-RECLAIM units has been revised to allow for use of SCAQMD Rule 218 or 40 CFR Part 75 with the additional requirement to calculate NOx ppmv pursuant to SCAQMD Rule 218. This should allow SCE's four peaking units to continue current monitoring procedures in the interim until Rule 113 is adopted.

Comment Letter 6

NRG Energy, August 17, 2018

From: Piantka, George
To: Uyen-Uyen Vo
Subject: PAR 1135 Comments
Date: Friday, August 17, 2018 12:00:09 AM

Ms. Vo,

I attended the August 2nd Proposed Amended Rule 1135 Workshop on behalf of the electrical generating facilities owned and operated by NRG Energy in the South Coast. I gave verbal comments which were primarily focused on the request for air district staff to clarify the implementation of PAR 1135 with respect to CEMS data management to ensure compliance with the amended rule. For example, I noted that it is possible for peaking plants to be dispatched infrequently and for short durations such that less than 90% of daily data validations points are possible, in particular for brief operations that are coincident with a daily calibration. The rule should alleviate the potential for non-compliance for short duration operations. I also noted that the full scale span should remain at 10-95% to be consistent with 40 CFR Part 75. Calibration of MW meters should remain consistent with CAISO annual calibration requirements. During the amendment of Rule 1135, we ask staff consider the elimination of the requirement to maintain chart recorders. 6.1

Best Regards,
George Piantka, PE
Sr. Director, Regulatory Environmental Services
NRG Energy, Inc.
5790 Fleet Street, Suite 200
Carlsbad, CA 92008
760.710.2156 office
760.707.6833 mobile
george.piantka@nrg.com

Response to Comment 6-1

Please refer to Response to Comment 1-7.

Comment Letter 7

NRG Energy, August 17, 2018

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August 16, 2018

South Coast Air Quality Management District
ATTN: Ms. Uyen-Uyen Vo
Planning, Rule Development and Area Sources
21865 Copley Drive
Diamond Bar, CA 91765

Subject: Request for Comments and Questions Relevant to the Proposed Amended Rule 1135

Dear Ms. Vo,

Thank you for the opportunity to have open communication with South Coast Air Quality Management District relevant to the Proposed Amended Rule 1135, and the possible impact the amendment has on our customers. Below I have outlined my comments and questions regarding this proposition.

1. PAR 1135 is a command and control regulation, given that most if not all of the facilities that are or will be regulated by this do have limits in their air permits that are similar to the ones stated in the proposed rule, how will a facility transition out of the NOX RECLAIM program into being subject to only PAR 1135? 7.1

2. If a facilities current air permit does not have limits as low as the PAR 1135 proposed limits, does that force them out of the NOX RECLAIM program? And if yes, what it the timeframe for the facility to make the necessary changes to their emissions units to come in compliance? Would this facility be considered a new source when doing this? 7.2

3. PAR 1135-7 (d)(1)(B) and multiple other places. Other CEMS hourly data is block hour averages and a 60-minute rolling average is a departure from that average determination. The rolling 60-minute average, can this be defined by SCAQMD as to how this is expected to be done? 7.3

4. Continuous Emission Monitoring Systems (CEMS) Requirements Document for Electric Generating Facilities - PAR-4 (2.1) (h) Can SCAQMD provide definitions for the codes that are not defined in Rule 1135 such as 3 – Tamper/security, 5 – Hot Standby ? Are the CEMS status codes to be determined on minute or hourly basis? How are these CEMS status to be reported or just recorded? 7.4

4. Continuous Emission Monitoring Systems (CEMS) Requirements Document for Electric Generating Facilities - PAR-7 (2.10) The criteria for data points gathered by the NOx CEMS to lie with 20-95 percent of span is more restrictive than R218.1 which is 10-95 percent of span. Is this intended to be more restrictive? 7.5

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2849 Sterling Drive, Hatfield, PA 19440 • Phone: 215-996-9200 • Fax: 330-860-8982 • Tech Support Phone: 800-582-1670

6. Continuous Emission Monitoring Systems (CEMS) Requirements Document for Electric Generating Facilities – PAR – 12 (4.0) The rule does not specify how the data used to demonstrate compliance is to be reported. What is the format of 4.1.5? What reporting frequency of 4.1.3 and 4.1.5? 7.6

7. Continuous Emission Monitoring Systems (CEMS) Requirements Document for Electric Generating Facilities – PAR – 12 (4.0) When will the first report be due the SCAQMD? 7.7

Please let me know if you need any further information and/or clarification to address the comments and questions herein.

Thank you for your consideration and time. My colleagues and I look forward to receiving a response prior to the public hearing date October 5, 2018.

Kind regards,

Keith Crabbe, Engineering Manager
Cemtek KVB-Enertec
Email: keith@cemteks.com
Office: (714) 437-7100 ext. 221
Cell: (714) 904-4405

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Response to Comment 7-1

Facilities will exit the NOx RECLAIM program pursuant to Rule 2001 – Applicability, and Rule 2002 – Allocations for Oxides of Nitrogen (NO_x) and Oxides of Sulfur (SO_x). Facilities that remain in the NOx RECLAIM program will be required to follow both the RECLAIM regulations and Rule 1135. PAR 1135 paragraph (e)(7) requires facilities to reconcile their permit(s) with Rule 1135 by July 1, 2022.

Response to Comment 7-2

If a facility's SCAQMD permit does not have limits as low as the proposed limits in PAR 1135, they will not be forced out of the NOx RECLAIM program. A facility is given until January 1, 2024 to make the necessary changes to their units to comply with Rule 1135. Due to the unique circumstance on Santa Catalina Island, that facility has an optional alternative compliance deadline of January 1, 2026 and also has the option to request a three year time extension. If a facility is required to modify their permit(s), depending on the equipment modification, they may be considered a new source.

Response to Comment 7-3

Staff has removed the document "Continuous Emission Monitoring Systems (CEMS) Requirements Document for Utility Boilers" and all references to the document. Units that have been permitted as of the rule adoption date will maintain their averaging time. Units installed as of the rule adoption date will have the rolling 60-minute average which will likely require new software or a software change.

Response to Comment 7-4

Staff has removed the document "Continuous Emission Monitoring Systems (CEMS) Requirements Document for Utility Boilers" and all references to the document. The CEMS status codes are no longer necessary.

Response to Comment 7-5

Staff has removed the document "Continuous Emission Monitoring Systems (CEMS) Requirements Document for Utility Boilers" and all references to the document. Criteria for data points gathered by the NOx CEMS will be in Rule 2012 for RECLAIM NO_x sources and former RECLAIM NO_x sources and Rule 218 or 40 CFR Part 75 for non-RECLAIM NO_x sources.

Response to Comment 7-6

Staff has removed the document "Continuous Emission Monitoring Systems (CEMS) Requirements Document for Utility Boilers" and all references to the document. 4.1.3 and 4.1.5 are no longer required.

Response to Comment 7-7

Staff has removed the document "Continuous Emission Monitoring Systems (CEMS) Requirements Document for Utility Boilers" and all references to the document. Reporting requirements are no longer specified in this document.

Comment Letter 8

U.S. Environmental Protection Agency, Region 9, August 16, 2018

Uyen-Uyen Vo

From:	Gong, Kevin <Gong.Kevin@epa.gov>
Sent:	Thursday, August 16, 2018 2:49 PM
To:	Uyen-Uyen Vo
Cc:	Lo, Doris; Withey, Charlotte; Law, Nicole
Subject:	EPA Region 9 Comments on SCAQMD PAR 1135, version dated July 20, 2018

Dear Ms. Vo,

Thank you for providing us an opportunity to comment on the South Coast Air Quality Management District's ("District's") Proposed Amended Rule 1135 "Emissions of Oxides of Nitrogen from Electricity Generating Facilities" ("Rule"). We have reviewed the proposed language and are providing the following comments on certain issues which may impact the EPA's ability to approve the Rule into the California State Implementation Plan (SIP).

Enforceability of "Low-Use" or "Near Limit" Permit Condition Exemptions

The provisions in sections (g)(1), (g)(2) and (g)(4) exempt combined cycle gas turbines, boilers, and internal combustion engines from the Rule's emission limits as laid out in section (d) of the Rule if these units have permit limits that are below specified thresholds, and if these units retain each of those permit limits.

Section (g)(3) exempts once-through-cooling boilers from the emission limits in section (d) if those units retain their existing permit limits and submit shutdown and retirement plans on or before January 1, 2023.

Section (g)(5) exempts low-use turbines and boilers from the emission limits in section (d) if those units operate below specified annual capacity factor thresholds, and retain their existing permit limits. 8.1

The draft rule provisions cited above appear to presume that RACT-level controls are contained in the District permits. However, these permits are not a part of the SIP. While we agree that exempting certain units from the Rule's emission limits may be consistent with the Clean Air Act's requirements (e.g., for units for which additional controls to meet the Rule's emission limits are not cost effective because the incremental improvement is prohibitively expensive), the SIP must be able to stand on its own in ensuring that all applicable units implement Reasonably Available Control Technology (RACT).

In addition, the District would need to provide a demonstration for each affected unit that the existing controls constitute RACT because more effective controls are not economically or technically feasible.

Stringency of Low Use Thresholds

Section (g)(5) allows for units that operate below a specified annual capacity factor averaged over three years (10% for turbines and 1% for boilers) to be exempt from the emission limits in section (d) of this rule, provided that they retain their permitted emission limits and do not operate above a specified annual capacity factor in any one year (25% for turbines, and 2.5% for boilers). Please clarify why such an averaging scheme is necessary for the implementation of this Rule. As with the other exemptions discussed above, the District would also need to provide a demonstration for each affected unit that the existing controls constitute RACT because more effective controls are not economically or technically feasible. 8.2

RECLAIM Replacement

Rule 1135 is intended to regulate applicable units exiting RECLAIM. Please ensure that, prior to the replacement of the RECLAIM provisions with new command and control rules such as Rule 1135, that the District documents how the emission reductions achieved under RECLAIM will be continued in Rule 1135, either in this rulemaking or in a future 8.3

1

rulemaking that will rescind or replace RECLAIM. For instance, we note that it appears cogeneration facilities are no longer covered by the Rule. 8.3

We look forward to working with the District to resolve these issues. Please let me know if you have any questions regarding our comments.

Thank you,

Kevin Gong
Rules Office, Air Division (AIR-4)
U.S. Environmental Protection Agency, Region 9
75 Hawthorne St. San Francisco, CA 94105
(415) 972-3073 | gong.kevin@epa.gov

Response to Comment 8-1

Cost-effectiveness calculations for near-limit and low-use equipment are now included in the staff report in Tables 2-15 through 2-18. To qualify for the provisions, equipment must retain federally enforceable permit condition limits as of the date of adoption of the rule.

The near-limit diesel internal combustion engine has a cost-effectiveness of $224,221 based on a replacement cost of $3.9 million, no change in annual operating costs and annual emission reductions of 0.7 tons per year.

Near-Limit Diesel Internal Combustion Engine from Table 2-15

Unit	Size (BHP)	Annual NOx Emissions (tons)	NOx Permit Limit (ppmv @ 15% oxygen dry)	Proposed BARCT NOx Emission Limit (ppmv @ 15% oxygen, dry)	Capital Cost (million)	Annual Emission Reductions (tons)	Cost-Effectiveness ($/ton NOx)
ICE4	3,900	5.9	51	45	$3.9	0.7	$224,221

The near-limit combined cycle gas turbines are utilized between 35 and 39 percent of their capacity. To reach the $50,000 cost-effectiveness threshold, these units would have to run between 198 and 204 percent of their capacity. Units with cost-effectiveness thresholds greater than 100 percent would not be cost-effective to reduce emissions under any circumstances.

Near-Limit Combined Cycle Gas Turbines from Table 2-17

Unit	Annual NOx Emissions (tons)	Estimated MWh/yr	%Capacity	NOx Permit Limit (ppmv @ 15% oxygen, dry)	Capital Cost (Millions)	Operating Cost (millions)	Emission Reductions (tons)	Cost-Effectiveness ($/ton reduced)	Annual Capacity Factor (%) at $50,000 per ton of NOx Reduced
T-CC-24[1]	33	900,000	35%	2.5	$20.1	$1.6	6.6	$282,898	198.0
T-CC-25[1]	36	1,000,000	39%	2.5	$20.1	$1.6	7.2	$261,226	203.8

For low-use boilers, the annual capacity at which the cost-effectiveness threshold is reached ranges between 1.9 and 6.8 percent. The limit established in the proposed rule is 1 percent averaged over a three-year period or 2.5 percent in any year.

Low-Use Boiler Thresholds from Table 2-16

Unit	Annual NOx Emissions (tons)	Average Annual Capacity Factor (%)	NOx Permit Limit (ppmv @ 3% oxygend ry)	Capital Cost (millions)	Operating Cost (millions)	Annual Emission Reductions (tons)	Cost-Effective ness ($/ton reduced)	Annual Capacity Factor (%) at $50,000 per ton of NOx Reduced
B18	113.6	42.6	38	7.5	0.8	116.3	$6,922	5.9
B12	39.7	25.6	40	4.8	0.4	34.6	$13,262	6.8
B15	177.5	29.5	82	5.9	0.4	167.1	$3,149	1.9

For low-use combined cycle gas turbines, the cost-effectiveness threshold ranges between 12.7 and XXX percent. The limit established is the proposed rule is 10 percent averaged over a three-year period or 25 percent in any year.

Low-Use Combined Cycle Gas Turbines from Table 2-17

Unit	Annual NOx Emissions (tons)	Estimated MWh/yr	%Capacity	NOx Permit Limit (ppmv @ 15% oxygen, dry)	Capital Cost (Millions)	Operating Cost (millions)	Emission Reductions (tons)	Cost-Effectiveness ($/ton reduced)	Annual Capacity Factor (%) at $50,000 per ton of NOx Reduced
T-CC-22	12.1	60,000	4%	7	$14.8	$1.1	7.8	$169,744	12.8
T-CC-23	8.9	40,000	3%	7	$14.8	$1.1	5.2	$253,696	12.7
T-CC-1	4.3	35,000	8%	7.6	$6.2	$0.5	3.2	$174,447	29.0
T-CC-26	0.8	6,000	2%	9	$4.6	$0.3	0.6	$669,774	30.6
T-CC-27	0.5	4,000	1%	9	$7.2	$0.5	0.4	$1,579,869	24.0
T-CC-28	0.5	4,000	1%	9	$7.2	$0.5	0.4	$1,579,869	24.0

Similarly, for low-use simple cycle gas turbines, the cost-effectiveness threshold ranges between 10 and 39 percent. The limit established is 10 percent averaged over a three-year period or 25 percent in any year.

Low-Use Simple Cycle Gas Turbines from Table 2-18

Unit	Annual NOx Emissions (tons)	Estimated MWh/yr	%Capacity	NOx Permit Limit (ppmv @ 15% oxygen, dry)	Capital Cost (Millions)	Operating Cost (millions)	Emission Reductions (tons)	Cost-Effectiveness ($/ton reduced)	Annual Capacity Factor (%) at $50,000 per ton of NOx Reduced
T-SC-15	0.5	1500	0.36%	3.5	$6.2	$0.41	0.14	$3,679,674	26%
T-SC-68	1.2	4000	0.99%	5	$6.1	$0.41	0.62	$820,407	16%
T-SC-10	1.9	4000	1.01%	5	$6.0	$0.39	0.97	$513,404	10%
T-SC-30	1.5	4000	1.01%	5	$6.0	$0.39	0.75	$664,064	13%
T-SC-40	1.6	4000	1.01%	5	$6.0	$0.39	0.81	$613,190	12%
T-SC-13	0.0	120	0.13%	5	$2.3	$0.15	0.01	$12,993,169	34%
T-SC-33	0.0	120	0.13%	5	$2.3	$0.15	0.02	$10,320,468	27%
T-SC-43	0.0	120	0.13%	5	$2.3	$0.15	0.02	$10,624,725	28%
T-SC-52	0.0	120	0.13%	5	$2.3	$0.15	0.01	$14,756,563	39%
T-SC-66	2.4	8000	1.93%	5	$6.2	$0.41	1.20	$426,186	16%
T-SC-67	8.9	40000	9.63%	5	$6.2	$0.42	4.45	$116,440	22%
T-SC-18	2.0	6000	1.45%	5	$6.2	$0.41	1.00	$512,207	15%
T-SC-19	1.6	5000	1.20%	5	$6.2	$0.41	0.81	$636,213	15%
T-SC-21	1.1	4000	0.96%	5	$6.2	$0.41	0.53	$971,264	19%
T-SC-23	1.0	4000	0.96%	5	$6.2	$0.41	0.51	$1,004,867	19%
T-SC-25	2.0	5000	1.20%	5	$6.2	$0.41	0.99	$519,131	13%
T-SC-57	1.5	4000	0.96%	5	$6.2	$0.41	0.74	$693,129	13%
T-SC-75	3.6	12000	2.76%	5	$6.4	$0.42	1.79	$295,758	16%
T-SC-64	0.09	270	0.10%	9	$4.7	$0.34	0.06	$6,419,676	13%

Unit	Annual NOx Emissions (tons)	Estimated MWh/yr	%Capacity	NOx Permit Limit (ppmv @ 15% oxygen, dry)	Capital Cost (Millions)	Operating Cost (millions)	Emission Reductions (tons)	Cost-Effectiveness ($/ton reduced)	Annual Capacity Factor (%) at $50,000 per ton of NOx Reduced
T-SC-65	0.0	0		9	$0.0	$0.00	0.00		
T-SC-61	0.06	120	0.23%	24	$1.6	$0.12	0.05	$2,697,954	12%
T-SC-63	0.13	240	0.46%	24	$1.6	$0.12	0.11	$1,254,841	11%

Response to Comment 8-2

The averaged three-year and one-year exemptions for low-use equipment is included because low-use equipment do not meet cost-effectiveness criteria. Allowing both a one-year threshold and a three-year threshold allows for minor year-to-year variations because of inclement weather or local emergencies. The one-year threshold limit avoids allowing two additional years when it is clear that the equipment will no longer qualify for the low-use exemption.

Cost-effectiveness calculations and annual capacity to reach the cost-effectiveness threshold are now included in the staff report (Tables 2-15 through 2-18). For natural gas simple cycle gas turbines, cost-effectiveness varies by unit with the cost-effectiveness threshold for simple cycle units reaching annual capacity levels between 10.4% and 38.5% with an average of 18.7% and a mean of 16.3%. For natural gas combined cycle gas turbines, the cost-effectiveness threshold is reached at annual capacity levels between 12.7% and 204%. The units with cost-effectiveness thresholds greater than 100% would not be cost-effective to reduce emissions under any circumstances. For boilers, all three remaining non-OTC operable boilers are currently cost-effective to retrofit. However, the facility is considering requesting a low-use provision. Back calculating from their current cost-effectiveness, they would reach the threshold between 1.9% and 6.8%.

Response to Comment 8-3

RECLAIM does not impose specific emission reduction requirements on individual sources. Instead, staff calculates BARCT requirements (which are more stringent than RACT) for all RECLAIM sources, and the total reductions are met on an agency basis. In contrast, Rule 1135 and other BARCT rules being adopted by the SCAQMD, impose BARCT on individual source categories. If no BARCT has changed since the last RECLAIM amendment, the emission reductions from BARCT rules would be identical to those from the last RECLAIM amendments. However, staff expects a number of source categories to have new BARCT requirements, so that aggregate emission reductions under the new BARCT rules will be greater than under existing RECLAIM.

Cogeneration turbines will be covered in Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines and will also remain subject to NOx RECLAIM regulations until the facility exits the NOx RECLAIM program.

Comment Letter 9

Bloom Energy, August 16, 2018

Bloomenergy

August 16, 2018

Chairman William A. Burke
South Coast Air Quality Management District
21865 Copley Dr.
Diamond Bar, CA 91765

Re: Proposed Amended Rule 1135

Dear Chair Burke,

Bloom Energy (Bloom) appreciates the opportunity to provide these comments on Proposed Amended Rule 1135. We strongly support the South Coast Air Quality Management District's (SCAQMD or District) efforts to protect public health, improve air quality, and reduce emissions from oxides of nitrogen (NOx)—as specified under the 2016 Air Quality Management Plan and AB 617 (2017)—from electricity generating facilities. Our comments specifically focus on the benefits fuel cells can provide in assisting SCAQMD in reaching these goals.

Bloom is a provider of a breakthrough all-electric solid oxide fuel cell technology that produces reliable power using a highly resilient and environmentally superior non-combustion process. By virtue of their non-combustion process, Bloom Energy Servers virtually eliminate emissions of criteria air pollutants including NOx, SOx, CO, VOCs, and particulate matter that are associated with traditional combustion and diesel back up power configurations while providing onsite power 24x7x365. The result is a significantly lower air emissions profile as compared to combustion-based distributed or central station power generation—reducing localized impacts in disadvantaged and vulnerable communities.

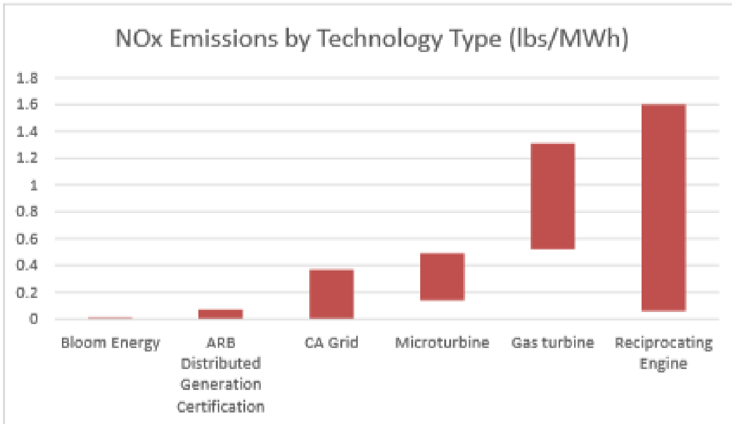
Bloom's fuel cells are fuel flexible and can operate on either natural gas or renewable natural gas. In addition, our all-electric solution allows fuel cell systems to be deployed at sites where it is not necessary to match an on-site thermal load, thereby expanding the opportunities available to address energy needs with clean, reliable distributed generation. With more than 200 MW installed across over 480 sites in California, Bloom has a proven technology with a strong track record of providing cost-competitive, clean, reliable energy solutions.

Importantly, on any fuel source, Bloom Energy Servers reduce NOx emissions compared to the grid, gas turbines, and reciprocating engines—see Table 1. These fuel cell benefits align perfectly with SCAQMD's mission to "clean the air and protect the health of all residents in the South Coast Air District through practical and innovative strategies."[1]

[1] "Goals and Priority Objectives," South Coast Air Quality Management District, http://yourstory.aqmd.gov/naw/about/goals-priority-objectives

1299 Orleans Drive, Sunnyvale CA 94089 T 408 543 1500 F 408 543 1501 www.bloomenergy.com

Table 1



[2]

Given that Bloom's fuel cells emit virtually no NOx, they are a valuable alternative compliance mechanism. We encourage the SCAQMD to explore incorporating this innovative, low-emission solution as part of PAR 1135. 9.1

We thank the District for the opportunity to provide feedback and reiterate that Bloom's fuel cell technology should be an integral component of the District's continuing efforts to protect public health and improve air quality through PAR 1135.

Respectfully,

Erin Grizard
Senior Director, Regulatory and Government Affairs

Sam Schabacker
Policy Manager

[2] "Amendments to the Distributed Generation Certification Regulation," California Air Resources Board, pg 5, https://www.arb.ca.gov/energy/dg/2006regulation.pdf; "Bloom Energy Server ES5-300kW," Bloom Energy, https://bloomenergy.com/datasheets/energy-server-es5-300kw; "Catalog of CHP Technologies," Environmental Protection Agency, page 1-6, https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_1._introduction.pdf; "Combined Heat and Power Catalog: CHP Program," New York State Energy Research and Development Authority, https://portal.nyserda.ny.gov/servlet/servlet.FileDownload?file=00Pt0000005wxi5EAA.

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Response to Comment 9-1

Thank you for providing the information regarding fuel cells. PAR 1135 does not mandate the types of electric generating units for a facility; PAR 1135 establishes the emissions limits for different types of electric generating units.

Comment Letter 10

Sanitation Districts of Los Angeles, July 23, 2018

Uyen-Uyen Vo

From: Rothbart, David <DRothbart@lacsd.org>
Sent: Monday, July 23, 2018 12:06 PM
To: Uyen-Uyen Vo
Cc: Michael Morris; Steve Jepsen (sjepsen@dudek.com); Alison Torres
Subject: Rule 1135 Comments

Hi Uyen-Uyen,

Thanks for updating the definitions in PAR 1135. While I think most existing biogas energy projects would now be excluded, we probably should address food waste and manure gas as well. With the mandatory diversion of food waste away from landfills, public and private food waste digestion facilities should become more common. At the moment a few non-wastewater treatment plant facilities are digesting food waste and generating biogas (e.g., CR&R and Kroger) . I'm not sure if any food waste digestion facilities are exporting electricity yet, but it seems probable that some facilities would eventually attempt to install engines, turbines or boilers. Similarly Inland Empire Utilities Agency had a manure digester, so including manure might be reasonable as well. 10.1

Last, but not least, it's possible to have a privately owned wastewater treatment plant, so it might be helpful to expand the Treatment Works definition. Please let me know if you have any questions. 10.2

Thanks again,

David

DAVID L. ROTHBART, P.E., BCEE
SCAP Air Quality Committee Chair
Supervising Engineer | Air Quality Engineering
SANITATION DISTRICTS OF LOS ANGELES COUNTY | 1955 Workman Mill Road, Whittier, CA 90601
Phone: 562.908.4288 x2412 | Cell: 714.878.9655 | FAX: 562.692.9690
Converting Waste Into Resources | www.LACSD.org

1

Response to Comment 10-1

If, in the future, biogas is used at electricity generating facilities, it will be subject to the proposed emission limits. Biogas used in turbines, engines, or boilers located at other types of facilities would be subject to equipment specific rules.

Response to Comment 10-2

Staff has revised the definition of electricity generating facility in paragraph (c)(8), which excludes publicly owned treatment works. If a privately owned treatment works were to begin operation, it would be subject to PAR 1135 if its combined generation capacity is 50 megawatts or more of electrical power for distribution in the state or local electrical grid system, excluding power from cogeneration units.

Comment Letter 11

Yorke Engineering, July 31, 2018

From: Greg Wolffe (GWolffe@YorkeEngr.com)
To: Uyen-Uyen Vo
Cc: jadams yorkeengr.com; Steve Bean
Subject: SCAQMD Proposed Amended Rule 1135 - OLS Energy
Date: Tuesday, July 31, 2018 11:08:53 AM
Attachments: image001.jpg
image002.jpg

Hi Uyen-Uyen.

The proposed Rule 1135 language (g)(5)(C) - Initial Requirement for Low-Use Exemption – appears to require that a EGF demonstrate compliance with the low use exemption using data from calendar years 2016, 2017, and 2018 and that they submit SCAQMD permit applications for a condition to incorporate the low-use exemption by July 1, 2019.

As we discussed with you last month, OLS is transitioning rule applicability from 1134 to 1135 in June/July 2018, based on their new contract to shift from dedicated service to being a EGF to Cal-ISO. As a result, they will not have the calendar years of inventory required to demonstrate the low-use exemption by next year. We seek your opinion as to how this can be accommodated within the current structure of the proposed rule language. For example, one option may be to add language to (g)(5)(C)(i) that states "Demonstrate compliance with subparagraph (g)(5)(A) or (g)(5)(B) using data from calendar years 2016, 2017, and 2018 or any other period deemed representative by the Executive Officer". 11.1

Please let us know if you would like to discuss options for OLS.

Thanks!

Greg

Greg Wolffe, CPP | Diamond Bar Office
Principal Scientist
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<image001.jpg>

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Response to Comment 11-1

Please see Response 3-1 and the revised rule language in subparagraph (g)(4)(C).

Comment Letter 12

California Council for Environmental and Economic Balance, August 31, 2018

California Council for Environmental and Economic Balance
101 Mission Street, Suite 1440, San Francisco, California 94105
415-512-7890 phone, 415-512-7897 fax, www.cceeb.org

August 31, 2018

Susan Nakamura
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765
Submitted electronically to snakamura@aqmd.gov

RE: PAR 1135 – Best Available Retrofit Control Technology

Dear Susan,

We submit the following comments on behalf of the California Council for Environmental and Economic Balance (CCEEB) on Proposed Amended Rule 1135 (PAR 1135), specifically concerning staff's proposal to require equipment replacement as Best Available Retrofit Control Technology (BARCT). CCEEB is a nonpartisan, nonprofit coalition of business, labor, and public leaders that advances strategies for a healthy environment and sound economy. CCEEB represents many facilities that operate in the South Coast Air Quality Management District (District) and would be affected by these amendments.

CCEEB wishes to better understand the process and authority by which the District is basing its position that a BARCT standard may require total replacement of a particular piece of equipment. We are aware of no other air district that has taken this position. Additionally, the California Health and Safety Code Section 40406 defines BARCT as:

> *As used in this chapter, "best available retrofit control technology" means 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.* 12.1

The Preliminary Draft Staff Report for PAR 1135 makes two arguments supporting staff's position. The first cites "on-line dictionaries" to reason that the definition of retrofit does not "preclude replacement technology."[1] The second cites case law, as determined by *American Coatings Ass'n. v. South Coast Air Quality Mgt. Dist.*, 54 Cal. 4th 446, 465 (2012) to support the notion that the District is not precluded from requiring

[1] SCAQMD. "Preliminary Draft Staff Report Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities." July, 2018. p.2-1.

replacement technology as long as it is not "arbitrary or irrational."[2] The notion that because the district is not explicitly *precluded* from acting does not logically – or legally – mean that the district *has* the authority to act.

In this regard, CCEEB seeks further understanding regarding staff's position. CCEEB believes the Preliminary Draft Staff Report does not adequately address or analyze the District's authority for establishing a BARCT standard that requires total replacement of equipment. Detailed analysis is warranted given the statutory requirements of BARCT. 12.1

CCEEB is also concerned regarding the implications of staff's position for future rule makings and BARCT determinations. As the first RECLAIM landing rule to be adopted, we are concerned that PAR 1135 may establish a new precedent that could be applied in future rules. CCEEB believes this may go beyond the definition of and the District's authority for BARCT. At a minimum, this concept should first be discussed with the RECLAIM working group.

We appreciate the opportunity to provide these comments on the PAR 1135 and look forward to continuing to engage staff in the rulemaking and broader public process. In the meantime, should you have any questions or wish to discuss our comments further, please contact me (billq@cceeb.org or 415-512-7890 ext. 115), Janet Whittick (janetw@cceeb.org or ext. 111), or Devin Richards (devinr@cceeb.org or ext. 110).

Sincerely,

Bill Quinn
CCEEB Vice President
South Coast Air Project Manager

cc: Philip Fine, SCAQMD
Jerry Secundy, CCEEB
Janet Whittick, CCEEB
Devin Richards, CCEEB
CCEEB South Coast Air Project Members

[2] *Ibid*

Response to Comment 12-1

As explained in detail below, BARCT may certainly include the replacement of equipment. In summary, we explain the particular instance in which SCAQMD has sought to specify a level equivalent to equipment replacement as BARCT for internal combustion engines on Santa Catalina Island. This demonstrates how public policy supports SCAQMD's interpretation. Moreover, as we explained in the Preliminary Draft Staff Report, the statutory definition of BARCT supports a broad interpretation. And applicable dictionary definitions do not preclude the view that BARCT can include equipment replacement. Finally, even if a court were to conclude that BARCT cannot encompass equipment replacement, BARCT is not a limitation on SCAQMD authority. The SCAQMD retains broad statutory authority to adopt emission-control requirements for stationary sources, and that authority may require equipment replacement, as long as the requirement is not arbitrary and capricious.

Public Policy Supports the SCAQMD's Interpretation

As noted in the staff report for PAR 1135, staff has proposed a BARCT for diesel fueled engines that appears to be more cost-effectively met by replacing the engine rather than trying to install additional add-on controls. If SCAQMD were precluded from requiring the replacement of these engines, the oldest and dirtiest power-producing equipment would continue to operate for possibly many years, even though it would be cost-effective and otherwise reasonable to replace those engines. As long as an emissions limit meets the requirements of the definition set forth in section 40406, there is no policy reason why replacement equipment cannot be an element of BARCT. And there is no policy reason why BARCT – if it does not include replacements – would somehow limit the SCAQMD from requiring equipment replacement where that requirement is reasonable and feasible. "If the statutory language permits more than one reasonable interpretation, courts may consider other aids, such as the statute's purpose, legislative history, and public policy." *Jones v. Lodge at Torrey Pines Partnership*, 42 Cal. 3d. 1158, 1163 (2008). In this case, the statue permits two reasonable interpretations, since the statutory definition in 40406 does not preclude requiring equipment replacement if it is reasonable considering economic and other factors. The legislative history and public policy both support the SCAQMD's interpretation, and a narrow interpretation is inconsistent with the broad language of the statutory definition.

The BARCT proposed for internal combustion engine power producers (replacement with Tier IV engines) is economically and practically reasonable and therefore does not "go beyond" BARCT if we look strictly at the statutory definition. As stated by the Supreme Court, the "statutes that provide the districts with regulatory authority serve a public purpose of the highest order-protection of the public health." *W. Oil & Gas Assn. v. Monterey Bay Unified Air Pollution Control Dist.*, 49 Cal. 3d 408, 419 (1989) ("WOGA"). Therefore, courts should not find that any statute causes an "implied repeal" of the districts' authority. *Id.*

The proposal to require replacement of five out of the six internal combustion engines at Santa Catalina Island is supported by overwhelming policy justifications. There are six internal combustion engines at the facility, of which three are at least 50 years old. The other three were installed in 1974, 1985, and 1995. The 1995 engine was installed with SCR; the other five had SCR installed in 2003. Staff concludes that it would be more cost-effective to replace the five oldest of these engines with new Tier IV engines rather than to install additional add-on controls. (The sixth engine was found not to be cost-effective to replace). These engines account for 0.06%

of the electric utility power produced in the District (Draft Staff Report, Table 4-1, 9 MWhr divided by 15,904 MWhr). But they account for 5.7% of the emissions inventory from electricity generating facilities (Draft Staff Report, Table 4-2, 0.2 tpd divided by 3.5 tpd). If the SCAQMD could not require replacement of these engines, then paradoxically the oldest, highest-emitting equipment would escape control.

The SCAQMD has in the past required replacement of old equipment in appropriate cases. The SCAQMD has required replacement, for example, in its dry-cleaning rule, adopted in 2002, which required all perchloroethylene dry-cleaning machines to be phased out by 2020, with other specific requirements implemented starting shortly after rule adoption. Rule 1421(d)(1)(F). Thus, a perchloroethylene machine that was installed in 2001 would be required to be replaced with a non-perchloroethylene machine when it is 19 years old. While this is a rule relating to toxic air contaminants, we do not believe the SCAQMD's authority is any less for criteria pollutants.

Dictionary Definitions Support SCAQMD's Interpretation
We do not agree that the term "retrofit" excludes replacement, such as replacement of an engine. We do not find that limitation in the dictionary definitions for the term "retrofit" including those cited in the SCAQMD staff report for Rule 1135. Instead, at least one definition provides that "retrofit" can mean "to replace existing parts, equipment, etc., with updated parts or systems." http://www.dictionary.com/browse/retrofit. Nothing in this definition requires that only part of a piece of equipment can be replaced. Indeed, according to this definition, a retrofit can include the replacement of an entire system. In our view, at least one dictionary definition of the term "retrofit" encompasses "replacement of equipment or systems." *See* definition cited above. This definition is broad enough to include replacing the entire piece of equipment or system. Therefore, the key question is what did the legislature mean when it imposed the BARCT requirement on SCAQMD?

Statutory Definition of BARCT Supports SCAQMD's Interpretation
The statutory definition of BARCT, as found in Health & Safety Code section 40406, does not contain any language precluding replacement technology. Section 40406 defines BARCT as "an emissions 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." Thus, BARCT is an emissions limitation. Nothing in the statutory definition specifies the type of technology that may be used. The California Supreme Court has made it clear that it is the definition of BARCT that controls, not implications from the language used in the term itself. Thus, the Supreme Court rejected the argument that "best available retrofit control technology" is limited to that which is readily available at the time when the regulation is enacted, and instead concluded that it encompasses technology that is "achievable," i.e. expected to become available at a future date. *American Coatings Ass'n. v. South Coast Air Quality Mgt. Dist.*, 54 Cal. 4th 446, 462 (2012). The Court focused on the actual statutory definition, which provides that BARCT is "an emissions 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." *American Coatings,* 54 Cal. 4th at 463. The Court concluded that in common usage, "achievable" means "capable of being achieved," which in turn includes "a potentiality to be fulfilled or a goal to be achieved at some future date." *Id.*

Thus, an emissions reduction was "achievable" when the rule was adopted in 1999 if it was "capable of being achieved" by the rule deadline of 2006. *American Coatings,* 54 Cal. 4th at 464. This was so even if that reduction was not "readily available" in 1999, notwithstanding the use of the word "available" in the term being defined. The Supreme Court held that the statutory definition controls, and in this case the statutory definition does not preclude replacement technology.

When the Legislature has defined a term, courts must follow that definition. *People v. Ward,* 62 Cal. App. 4th 122, 126 (1998). Following the California Supreme Court's analysis in *American Coatings,* the test of whether an emission limit constitutes BARCT is whether it meets the definition found in the statute, section 40406. If so, then it is within the statutory definition of BARCT, whether or not it is within the most common understanding of "retrofit." This does not mean that the word "retrofit" is surplusage. The use of the word "retrofit" serves to distinguish an emission limit that is imposed on existing sources, and which under the statutory definition must consider economic and other factors, from the emissions limit imposed on new sources. The limit for new sources must be met if it has been achieved in practice, regardless of cost. *See* definition of "best available control technology" [BACT] in section 40405, which includes "the most stringent emission limitation that is achieved in practice by that class or category of source." We do not argue that a replacement can be BARCT if it does not meet the definition of BARCT. Instead, if a limit meets that definition, it can be BARCT even if it can most cost-effectively be met by replacing the equipment with new equipment, as recognized in the dictionary definition discussed above.

The *American Coatings* ruling is not irrelevant just because it dealt with a rule for architectural coatings, requiring coating reformulation, which "does not typically involve the manufacture of modified production equipment or new add-on controls," whereas control technologies that require physical modification of existing equipment or installation of add-on controls may require "significant disruption to the operation of the facility." We do not know whether the claim regarding architectural coatings is correct, but even if it is, we do not understand how this relates to the question at issue since *both* retrofit add-on controls and replacements would involve the disruption of facility operations for some time.

Other Statutory References to "Retrofit" Are Inapplicable

The legislature has used the term replacement as well as retrofit in certain sections of the Health and Safety Code. §§ 43021(a), 44281(a). Furthermore, the legislature defined retrofit in sections 44275(a)(19) and 44299.80(o), and the definition does not mention replacement but rather making modifications to the engine and fuel system. Finally, these same code sections define "repower" as replacing an engine with a different engine. §§ 44275(a)(18), 44299.80(n). However, all of these code sections were adopted long after 1987, when the legislature mandated SCAQMD to require BARCT for existing sources. They do not shed any light on what the legislature meant by "retrofit" in 1987 when section 40406 was adopted. All of the sections cited (except section 43021(a)) deal with incentive programs, and the definitions are specifically stated to be only "as used in this chapter"; i.e. for the specific incentive program. §§ 44275(a); 44299.80(a). These definitions facilitate the administering agency in implementing the programs, which generally provide different amounts of funding for different types of projects, including "repowering" or "retrofitting." *See e.g.*

https://www.arb.ca.gov/msprog/moyer/source_categories/moyer_sc_on_road_hdv_2.htm
Therefore, the legislature had a specific purpose in distinguishing between replacements and retrofits in these particular chapters, whereas no one has identified a policy reason that the legislature would have wanted to exclude replacement projects from BARCT, as long as they met the statutory definition.

Section 43021(a), enacted in 2017 as Part of SB1, prohibits Air Resources Board rules that require the "retirement, replacement, retrofit, or repower" of a commercial motor vehicle for a period of time. An argument can be made that this language means that a replacement must be different than a retrofit, under that theory it must also mean that a replacement is different from a repower, whereas under the sections cited above, a repower IS a replacement. Presumably, the legislature wanted to make very sure it covered all possibilities. And to add to the confusion, the Carl Moyer statutes appear to distinguish "retrofit" (an eligible project under §44282(a)(2)) from "use of emission-reducing add-on equipment" (an eligible project under §44281(a)(3)). Normally installing add-on controls is considered a type of retrofit.

Statute Discussing Best Available Control Technology Determinations Does Not Circumscribe BARCT Definition

Section 40920.6 states that in establishing the best available control technology, (BACT), the District shall consider only "*control options* or emission limits *to be applied to the basic production or process equipment*." BACT is frequently applied to replacement of an entire source (such as repowers of electric generating units) as well as to new and modified sources. Obviously, in the case of a new source, there is no existing equipment to which to apply the technology. We interpret this statutory language to mean that in establishing BACT, the SCAQMD is not to fundamentally change the nature of the underlying process. For example, if an applicant seeks approval of a simple cycle turbine, the SCAQMD cannot require it to instead construct a combined cycle turbine, since they have different operational characteristics and needs to fill. This would be consistent with EPA's Draft NSR Workshop Manual, p. B-13, that specifies that in determining BACT, states need not redefine the design of the source, although they retain discretion to do so where warranted (i.e. to require consideration of inherently cleaner technology). https://www.epa.gov/nsr/nsr-workshop-manual-draft-october-1990. Similarly, SCAQMD does not propose to require a facility subject to BARCT to "redefine" the nature of its source but merely to replace old diesel internal combustion engines with diesel internal combustion engines meeting EPA's Tier IV standards. Therefore, section 40920.6 does not speak to the question at hand: whether BARCT precludes replacing old equipment with new equipment of the same type.

SCAQMD Has Authority to Require Equipment Replacement Which is Not Limited by the BARCT Definition

Finally, even if BARCT by itself did not include replacement equipment, the SCAQMD could still require the equipment to be replaced. We disagree that section 40440(a)(1) grants the authority to require BARCT (i.e., that without that section, the district would have no authority to require BARCT). We also disagree with the proposition that Section 40440(a)(1) limits the District's authority.

State law has explicitly granted air districts primary authority over the control of pollution from all sources except motor vehicles since at least 1975, when the air pollution regulation provisions were recodified. *See* § 40000, enacted Stats. 1975, ch. 957, §12; *see also* § 39002, containing similar language and adopted in that same section. As held by the California Supreme Court, these two sections (and their predecessors dating back to 1947) confirm that the air districts had plenary authority to regulate non-vehicular sources "for many years." *WOGA*, 49 Cal. 3d. at 418-19. And the Supreme Court had previously recognized the air districts' authority to adopt local regulations for non-vehicular sources under the predecessor statutes. *Orange County Air Pollution Control Dist. v. Public Util. Comm.*, 4 Cal. 3d 945, 948 (1971). Under these broad statutes, the districts could have adopted BARCT requirements for non-vehicular sources. Section 40440(a)(1), therefore, was not a statute granting authority, since the districts already had authority, but a statute imposing a *mandate* to adopt BARCT.

We also disagree with the claim that section 40440(a)(1) requiring the SCAQMD to impose BARCT on existing sources was a "limitation" of district authority. State law expressly provides that districts "may establish additional, stricter standards than those set forth by law" unless the Legislature has specifically provided otherwise §§ 39002; 41508. Nothing in Section 40440(a)(1) specifically limits the District's authority. In fact, the legislative history of the bill requiring SCAQMD to impose BARCT – among other requirements – states that "this bill is intended to encourage *more aggressive improvements in air quality* and to give the District new authority to implement such improvements." *American Coatings*, 54 Cal. 4th at 466 (emphasis added). As stated by the Supreme Court, "[t]the BARCT standard was therefore part of a legislative enactment designed to augment rather than restrain the District's regulatory power." *Id.* As explained by the legislative history, BARCT is a "minimum" requirement, and the legislature did not intend it to preclude the District from adopting requirements that go beyond BARCT.

Among the new authorities granted were section 40447.5, authorizing fleet rules and limits on heavy duty truck traffic and section 40447.6, authorizing the SCAQMD to adopt sulfur limits for motor vehicle diesel fuel. We do not believe that section 40440(a)(1) granted "new" authority to require BARCT, as the districts already had authority over non-vehicular sources.

Moreover, when the Legislature extended the BARCT requirement to other districts with significant air pollution, section 40919(a)(3) (districts with serious pollution and worse) the legislature expressly stated that the bill "is intended to establish minimum requirements for air pollution control districts and quality management districts" and that "[n]othing in this act is intended to limit or otherwise discourage those district from adopting rules and regulations which exceed those requirements." Stats. 1992, ch. 945 § 18. Thus it is clear that BARCT is not intended to be a limitation or restriction on existing authority.

Although the California Supreme Court found it unnecessary to decide whether the SCAQMD could adopt rules going beyond BARCT, because it held that BARCT could include technology-forcing measures, it did state that BARCT was not designed to restrain the District's regulatory power. *American Coatings*, 54 Cal 4th at 466, 469.

In an earlier case, the California Supreme Court made it clear that new legislation does not impliedly repeal an air district's existing authority unless it "gives *undebatable evidence* of an intent to supersede" the earlier law. *WOGA*, 49 Cal. 3d. at 420 (internal citation omitted; emphasis by Supreme Court). There the court noted that the present statutes and their predecessors giving air districts authority over non-vehicular sources, including the authority to regulate air toxics, had been in effect before the allegedly preempting law was enacted (in 1983; Stats 1983 Ch. 1047), and had been generally understood and acted upon. *WOGA*, 49 Cal 3d at 419. The court concluded there was no "undebatable evidence of a legislative intent to repeal the districts' statutory authority to protect the health of their citizens by controlling air pollution." *WOGA*, 49 Cal 3d at 420. By the same token here, there is no undebatable evidence of an intent to limit air districts' existing authority by imposing a *mandate* to adopt BARCT requirements. Instead, BARCT was a minimum requirement that SCAQMD must impose, not a limit on its ability to impose additional, including more stringent, requirements. Indeed, the argument that BARCT limits SCAQMD's authority is illogical. It would make no sense for the Legislature in 1987 to limit only the district with the worst air pollution (SCAQMD) while leaving untouched the authority of other districts with lesser levels of pollution.

Nor does this conclusion leave the SCAQMD with unlimited regulatory power. In going beyond the statutory minimum of BARCT for existing sources, the District would still be limited by the requirement that its rules may not be arbitrary and capricious, or without reasonable or rational basis, or entirely lacking in evidentiary support. *American Coatings*, 54 Cal. 4th at 460. And of course, the SCAQMD's rulemaking authority is limited by applicable constitutional principles. Therefore, stakeholders need not rely on an argument that BARCT restricts the SCAQMD's authority in order to ensure the SCAQMD does not implement any arbitrary action.

Conclusion

SCAQMD has the authority to require equipment replacement as a BARCT requirement as long as the requirement meets the statutory definition of BARCT. But even if BARCT were to exclude equipment replacement, the SCAQMD would still have the authority to require replacement, as long as the replacement is not arbitrary and capricious. The proposed BARCT for internal combustion engines on Santa Catalina island is reasonable and feasible, and no one has argued to the contrary.

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