SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

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

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Chapter 1

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 Final 2016 Air Quality Management Plan (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. California State Assembly Bill 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 was adopted in 1989 and 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 is being amended to facilitate the transition of the NOx RECLAIM program to a command-and-control regulatory structure and to implement CMB-05 – Further NOx Reductions from RECLAIM Assessment in the 2016 Air Quality Management Plan. PAR 1135 applies to RECLAIM and non-RECLAIM electricity generating facilities that are market participants of California Independent System Operator Corporation (California ISO), owned by a municipality, or located on Santa Catalina Island.

BACKGROUND

The SCAQMD Governing Board adopted the Regional Clean Air Incentives Market (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) 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 – RECLAIM 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. RECLAIM was amended on October 7, 2016 to incorporate provisions that limited use of RTCs from facility shutdowns. The most recent amendments to RECLAIM on January 5, 2018 was to amend Rules 2001 and 2002 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 Air Quality Management Plan (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 Best Available Retrofit Control Technology (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 California State Assembly Bill (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 – Emissions of Oxides of Nitrogen from Electric Power Generating Systems is being amended to facilitate the transition of the NOx RECLAIM program to a command-and-control regulatory structure and to implement CMB-05, Further NOx Reductions from RECLAIM Assessment, in the 2016 Air Quality Management Plan. Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electric Power Generating Systems (PAR 1135) applies to RECLAIM and non-RECLAIM electricity generating facilities that are market participants of California Independent System Operator Corporation (California ISO), owned by a municipality, or located on Santa Catalina Island. The proposed amended rule will update emission limits to reflect current Best Available Retrofit Control Technology (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. Additionally, PAR 1135 establishes provisions for monitoring, reporting, and recordkeeping, and establishes exemptions from specific provisions.

REGULATORY BACKGROUND

Rule 1135 – Emissions of Oxides of Nitrogen from Electric Power Generating Boilers 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– Emissions of Oxides of Nitrogen from Electric Power Generating Systems 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 Best Available Retrofit Control Technology (BARCT) analysis. EPA approved Rule 1135 into the State Implementation Plan on August 11, 1998.

ELECTRICITY GENERATING FACILITIES AND RECLAIM

Throughout RECLAIM, 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, but also allowed to enter the program. Cities of Burbank and Pasadena opted-in to RECLAIM, while City of Glendale stayed in command-and-control.

In June 2000, RECLAIM program participants experienced a sharp and sudden increase in NOx RECLAIM trading credit (RTC) prices for both 1999 and 2000 compliance years. Based on the 2000 RECLAIM Annual Report, power producing facilities had an initial allocation of 2,302 tons per year. In compliance year 2000, these facilities reported 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 and 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 electricity generating facilities. At that time BARCT for utility boilers and gas turbines was determined to be 9 ppmv @ 15% O2 dry for both. Where technically feasible and cost-effective, RECLAIM electricity generating units were retrofitted, repowered, or retired. There were electricity generating units that could not cost effectively control emissions and were given permit limits with higher 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 electrical 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 3 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 four working group meetings at the SCAQMD Headquarters in Diamond Bar on January 24, 2018, April 26, 2018, June 13, 2018, and July 5, 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 is scheduled for August 2, 2018.

Chapter 2

BARCT ASSESSMENT

Staff conducted an assessment of BARCT for electric power generating units including natural gas boilers, natural gas turbines and associated duct burners, and diesel internal combustion engines. 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 emission limits take into consideration environmental impacts, energy impacts, and economic impacts. In addition to NOx reductions sought in the proposed 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.

A question was raised in the 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 §40440(b)(1). A commenter stated that the use of the word "retrofit" precludes the SCAQMD from requiring an emissions limit 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. 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.

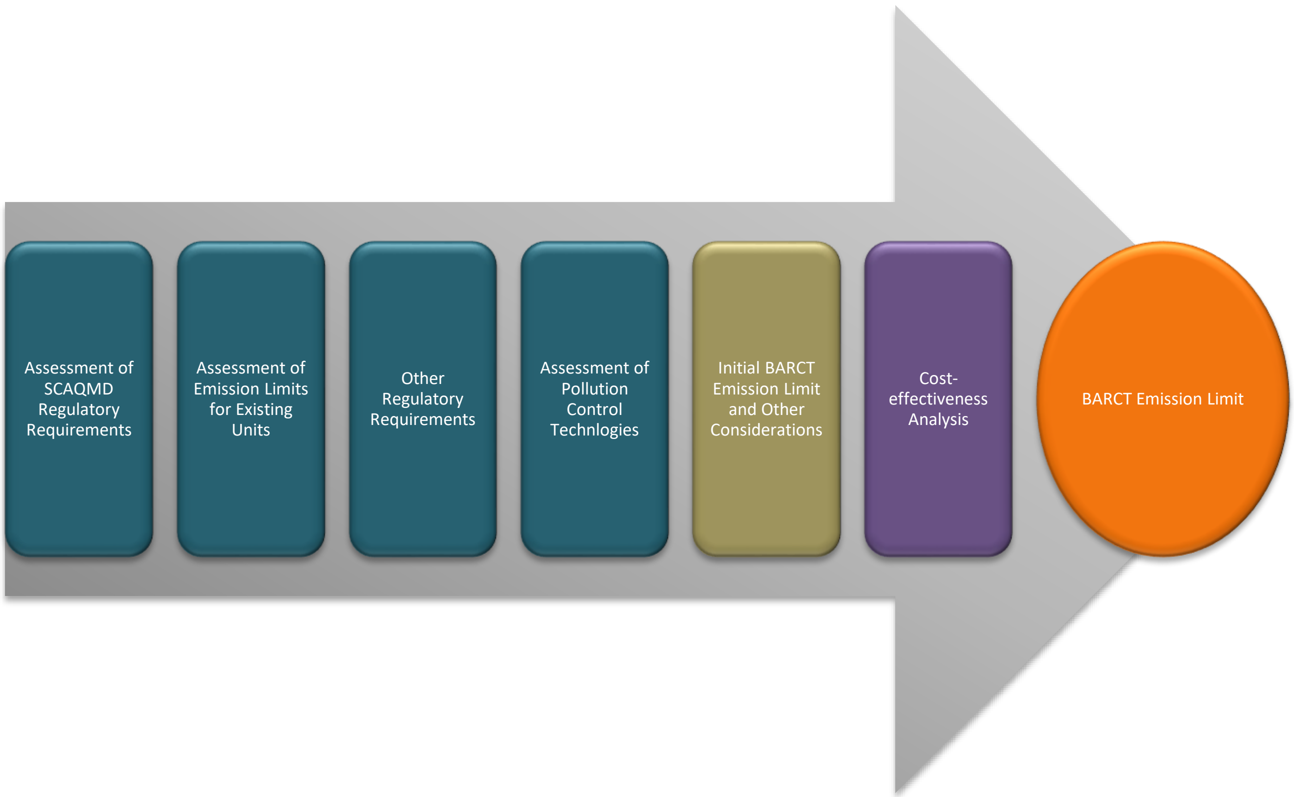
The case law supports an expansive reading of BARCT. In explaining the meaning of BARCT, the California Supreme Court held that BARCT is a "technology-forcing standard designed to compel the development of new technologies to meet public health goals." *American Coatings Ass'n. v. South Coast Air Quality 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 District'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 District, 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 District's discretion as long as it is not arbitrary or irrational.

The BARCT analysis approach follows a series of steps conducted for each equipment category and fuel type. For 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 BARCTY analysis consist of:

- Assessment of SCAQMD Regulatory Requirements
- Assessment of Emission 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 and Regulation XX and Rule 2009 within RECLAIM. Under Rule 1135, the NOx emission standard is a system-wide standard and does not include an equipment-specific NOx emission standard. The current NOx system-wide standard is as follows in Table 1 below.

Table 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 the remaining electricity generating facilities, but does not limit emissions or establish a concentration limit by equipment category or fuel type. Equipment permits include limits for NOx emissions standards. NOx emissions standards included a concentration limit that was established at the time of permitting and many emissions limits for non-RECLAIM pollutants such as particulate matter. Facilities 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 – Compliance Plan for Power Producing Facilities 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 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 and natural gas turbines was determined to be 9 ppmv @ 15% O2 dry for both. Where technically feasible and cost-effective, RECLAIM electricity generating units were retrofitted, replaced, or retired. There were electricity generating units that could not cost effectively control emissions and were given permit limits with higher 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 @ 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 electricity generating equipment 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 150 pieces of equipment at 34 facilities. Six are diesel fueled internal combustion engines located at a single facility. There are 24 natural gas boilers located at 8 facilities. Sixty-seven natural gas simple cycle gas turbines are operated at 21 facilities and 35 natural gas combined cycle gas turbines and associated duct burners at 13 facilities.

<u>Diesel Internal Combustion Engines</u>

Six diesel fueled 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 NOx permit emission limits range between 51 ppmv to 140 ppmv at 15% O2 dry. Ammonia is 10 ppmv at 15% O2 dry. The higher emitting units were retrofitted in 2003 while the lowest emitting unit was an new installation. The details of the diesel internal combustion engines subject to PAR 1135 are listed below in Table 2 below.

Table 2 – Diesel Internal Combustion Engines

Unit	Size (MMBTU/HR)	Output (MW)	Install Year	Retrofit Date	Control	NOx Permit Limit[1] (ppmv@ 15% O2 dry)	Ammonia (ppmv@ 15% O2 dry)	2016 NOx Emissions Tons)
ICE1	1575	1.125	1968	2003	SCR	140	10	16
ICE3	1950	1.4	1985	2003	SCR	103	10	5.3
ICE6	2150	1.5	1964	2003	SCR	97	10	8.2
ICE5	1500	1	1967	2003	SCR	97	10	12
ICE2	2200	1.5	1976	2003	SCR	82	10	22
ICE4	3900	2.8	1995	None	SCR	51	10	5.9

1 – Actual NOx concentration emitted are generally lower than the NOx permit limit

The lowest permitted NOx limit for a diesel engine used for electricity generation in SCAQMD is 51 ppmv at 15% O2 dry.

Natural Gas Boilers

Of the 24 natural gas boilers used to generate electricity, 17 of them are subject to the Clean Waters Act once-through-cooling provisions 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% O2 dry. Ammonia ranges between 10 ppmv and 20 ppmv at 3% O2 dry. Information regarding natural gas boilers subject to the Clean Waters Act once-through-cooling regulation is provided in Table 3 below.

Table 3 – Natural Gas Boilers

Unit	Size (MMBTU/HR)	Output (MW)	Install Year	Retrofit Year	Control	NOx Permit Limit[1] (ppmv @ 15% O2 dry)	Ammonia (ppmv @ 15% O2 dry)	2016 AER NOx Emissions (tons)	OTC Repower Date
B9	1750	179	1959	2002	SCR	5	10	1.48	12/31/2024
B4	1750	179	1958	2002	SCR	5	10	6.9	12/31/2024
B23	551.84	44	1959	2002	SCR/LNB	5	10	0.0	
B24	604.7	55	1964	2002	SCR	5	10	0.0	
B3	2240	230	1962	1993	SCR	5	20	28.92	12/31/2029
B8	2240	230	1963	1993	SCR	5	20	27.05	12/31/2029
B21	4752.2	480	1968	1994	SCR/FGR/staged comb	5	20	17.83	9/30/2019
B22	4752.2	480	1968	1994	SCR/FGR/staged comb	5	20	8.01	11/1/2019
B19	4752.2	480	1966	1994	SCR/FGR	5	20	12.08	12/29/2019
B16	4750	480	1969	1994	SCR/LNB/FGR	5	20	8.89	12/31/2020
B2	2021	215	1958	2001	SCR	7	10	36.57	11/1/2019
B17	1785	175	1954	2001	SCR/staged combustion	7	10	4.73	11/1/2019
B20	1785	175	1957	2001	SCR/staged combustion	7	10	10.85	11/1/2019
B1	1785	175	1956	2001	SCR/FGR/staged comb	7	10	5.76	12/29/2019
B6	1785	175	1957	2001	SCR/FGR/staged comb	7	10	11.3	12/29/2019
B10	3350	320	1961	2001	SCR/FGR	7	10	50.92	12/31/2020
B13	3350	320	1962	2001	SCR/FGR	7	10	49.84	12/31/2020
B7	2021	215	1958	2001	SCR	7	10	33.97	12/31/2020
B11	2900	320	1963	2001	FGR/Staged Comb/SCR	7	10	12.82	
B14	2900	320	1963	2001	FGR/Staged Comb/SCR	7	10	9.47	
B18	527.25	44	1969	2002	FGR/SNCR	38	10	13.1	
B12	260	20	1953		LNB/FGR	40	N/A	3.7	
B15	492	44	1959		LNB/FGR	82	N/A	9.2	
B5	514.14		1948		none	90	N/A	0.0	11/1/2019

1 – Actual NOx concentration emitted are generally lower than the NOx permit limit

There are seven natural gas boilers that are not subject to the Clean Waters Act once-through-cooling provision. While they are not required to shut down, early indications are that all the remaining boilers will be shut down prior to 2024. Two are already non-operational. The operator of two others has written that the natural gas boilers are scheduled for shut down by 2020. The last three natural gas boilers, all with NOx permit limits between 38 and 82 ppmv NOx at 3% O2 dry, 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. The city council asked the operator to revise their plans to replace the natural gas boilers with more renewable power generating systems. For the remaining natural gas boilers, the lowest permitted NOx concentration limit was 5 ppmv at 3% O2 dry which was retrofitted in 2002.

Natural Gas Combined Cycle Gas Turbines

For natural gas combined cycle gas turbines, 24 of 35 units are permitted at 2.0 ppmv NOx at 15% O2 dry. 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 2.0 ppmv @ 15% O2 dry. Units that were permitted at 2.0 ppmv NOx at 15% O2 dry were also seen to have ammonia permit limits of 5.0 at 15% O2 dry. Table 4 lists the information regarding natural gas combined cycle gas turbines.

Table 4 – Natural Gas Combined Cycle Gas Turbines

Unit	Size (MMBTU/HR)	MW Rating	Install	Control	NOx Permit Limit[1] ppmv(@ 15% O2 dry)	Ammonia Permit Limit ppmv (@ 15% O2 dry)	2016 AER NOx Emissions (tons)
TC4	2275	346.8	pending	SCR/DLN	2	5	
TC5	2275	346.8	pending	SCR/DLN	2	5	
TC2	2273	346.8	pending	SCR/DLN	2	5	
TC3	2273	346.8	pending	SCR/DLN	2	5	
TC10	2597	405	2008	SCR/DLN	2	5	1.8
TC9	2597	405	2008	SCR	2	5	6.2
TC18	1757	295	2008	SCR /water injection	2	5	21
TC19	1757	295	2008	SCR /water injection	2	5	38
DB18	286.6				2		1
DB19	286.6				2		1
TC20	2205	321	2015	SCR/DLN	2	5	26
TC8	1787	328	2005	SCR/DLN	2	5	33
DB8	583				2		0
TC11	454.05	71.7	2005	SCR	2	5	9.8
TC12	454.05	71.7	2005	SCR	2	5	9.9
DB11	81.2				2		10
DC12	81.2				2		10
TC13	1991	264	2005	SCR/DLN	2	5	24
TC14	1991	264	2005	SCR/DLN	2	5	23
TC15	1991	264	2005	SCR/DLN	2	5	23
TC16	1991	264	2005	SCR/DLN	2	5	25
DB13	135				2		0
DB14	135				2		0
DB15	135				2		0
DB16	135				2		0
TC6	2096	286.5	2013	SCR/DLN	2	5	11
TC7	2096	386.5	2013	SCR/DLN	2	5	11
TC21	547.5	71	2015	SCR/water injection	2	5	0.43
TC17	258.6	32	2010	SCR/water injection	2.5	5	1.1
TC24	1805	290	2002	SCR /water injection/LNB	2.5	5	32.8
DB24	139			SCR	2.5	5	0.3
TC25	1805	290	2002	SCR /water injection/LNB	2.5	5	35.3
DB25	139			SCR	2.5	5	0.3
TC26	350	30	1976	SCR/Water Injection	9	5	0.8
TC27	350	60	1976	SCR/Water Injection	9	5	0.3
TC28	350	60	1976	SCR/Water Injection	9	5	0.3
TC22	1088	182	1993	SCR/water injection	7	20	12.1
TC23	1088	182	1993	SCR/water injection	7	20	8.9
TC1	442	48	1993	SCR/Water injection	7.6	20	5.9

1 – Actual NOx concentration emitted are generally lower than the NOx permit limit

Natural Gas Simple Cycle Gas Turbines

For natural gas simple cycle gas turbines, 37 of 67 units are permitted at or below 2.5 ppmv NOx at 15% O2 dry. Two of the 37 units are permitted at 2.3 ppmv NOx at 15% O2 dry. However, the operator of the two units is seeking permit changes to raise the limit to 2.5 ppmv NOx at 15% O2 dry to avoid compliance issues. All of the low concentration simple cycle turbines were new installations commissioned after 2006. Units that were permitted at 2.5 ppmv NOx at 15% O2 dry were also seen to have ammonia permit limits of 5.0 at 15% O2 dry. Table 5 lists the information regarding simple cycle turbines.

Table 5 – Natural Gas Simple Cycle Gas Turbines

Unit	Size (MMBTU/HR)	Output (MW)	Install Year	Control	NOx Permit Limit[1] ppmv (at 15% O2 dry)	Ammonia (at 15% O2 dry)	2016 AER NOx Emissions (tons)
T-SC-44	490	50	2009	SCR/water injection	2.3	5	0.72
T-SC-53	490	50	2009	SCR/water injection	2.3	5	0.87
T-SC-71	505	47	2007	SCR/water injection	2.5	5	1.50
T-SC-70	511.5	47	2007	SCR/water injection	2.5	5	1.97
T-SC-72	522	47	2007	SCR/water injection	2.5	5	1.66
T-SC-29	871.3	65	2007	SCR/water injection	2.5	5	1.20
T-SC-39	871.3	65	2007	SCR/water injection	2.5	5	1.21
T-SC-49	871.3	65	2007	SCR/water injection	2.5	5	1.20
T-SC-9	871.3	65	2007	SCR/water injection	2.5	5	0.91
T-SC-38	885	100.8	pending	SCR/DLN	2.5	5	
T-SC-48	885	100.8	pending	SCR/DLN	2.5	5	
T-SC-37	882	100.8	pending	SCR/DLN	2.5	5	
T-SC-47	882	100.8	pending	SCR/DLN	2.5	5	
T-SC-56	882	100.8	pending	SCR/DLN	2.5	5	
T-SC-59	882	100.8	pending	SCR/DLN	2.5	5	
T-SC-14	490	50	2006	SCR/water injection	2.5	5	1.27
T-SC-34	490	50	2006	SCR/water injection	2.5	5	1.33
T-SC-16	891.7	100	2013	SCR/water injection	2.5	5	9.75
T-SC-35	891.7	100	2013	SCR/water injection	2.5	5	10.17
T-SC-45	891.7	100	2013	SCR/water injection	2.5	5	9.72
T-SC-54	891.7	100	2013	SCR/water injection	2.5	5	7.96
T-SC-58	891.7	100	2013	SCR/water injection	2.5	5	7.68
T-SC-69	505.7	47	2007	SCR/water injection	2.5	5	1.92
T-SC-1	891.7	100	2013	SCR/water injection	2.5	5	2.66
T-SC-2	891.7	100	2013	SCR/water injection	2.5	5	2.66
T-SC-3	891.7	100	2013	SCR/water injection	2.5	5	2.48
T-SC-4	891.7	100	2013	SCR/water injection	2.5	5	2.72
T-SC-5	891.7	100	2013	SCR/water injection	2.5	5	2.65
T-SC-6	891.7	100	2013	SCR/water injection	2.5	5	2.58
T-SC-7	891.7	100	2013	SCR/water injection	2.5	5	2.64
T-SC-8	891.7	100	2013	SCR/water injection	2.5	5	2.00
T-SC-17	479	50	2011	SCR/water injection	2.5	5	1.51
T-SC-36	479	50	2011	SCR/water injection	2.5	5	1.32
T-SC-46	479	50	2011	SCR/water injection	2.5	5	1.43
T-SC-55	479	50	2011	SCR/water injection	2.5	5	1.48
T-SC-73		50	pending	SCR/water injection	2.5	5	0
T-SC-74		50	pending	SCR/water injection	2.5	5	0
T-SC-20	906.6	103	2013	SCR/water injection	2.5	5	4.94
T-SC-22	906.6	103	2013	SCR/water injection	2.5	5	0.94
T-SC-24	906.6	103	2013	SCR/water injection	2.5	5	4.63
T-SC-26	906.6	103	2013	SCR/water injection	2.5	5	1.07
T-SC-27	906.6	103	2013	SCR/water injection	2.5	5	4.38

Unit	Size (MMBTU/HR)	Output (MW)	Install Year	Control	NOx Permit Limit[1] ppmv (at 15% O2 dry)	Ammonia (at 15% O2 dry)	2016 AER NOx Emissions (tons)
T-SC-28	906.6	103	2013	SCR/water injection	2.5	5	3.78
T-SC-60	959	106	2015	SCR/water injection	2.5	5	7.01
T-SC-62	959	106	2015	SCR/water injection	2.5	5	8.20
T-SC-15	456.5	48	2003	SCR/water injection	3.5	5	0.49
T-SC-68	450	46	2002	SCR/water injection	5	5	1.24
T-SC-10	450	45	2001	SCR/water injection	5	5	1.93
T-SC-30	450	45	2001	SCR/water injection	5	5	1.49
T-SC-40	450	45	2001	SCR/water injection	5	5	1.62
T-SC-13	128.8	10.5	2001	SCR/DLN	5	5	0.03
T-SC-33	128.8	10.5	2001	SCR/DLN	5	5	0.04
T-SC-43	128.8	10.5	2001	SCR/DLN	5	5	0.04
T-SC-52	128.8	10.5	2001	SCR/DLN	5	5	0.03
T-SC-66	448	47.4	2003	SCR/water injection	5	5	2.41
T-SC-67	448	47.4	2003	SCR/water injection	5	5	8.91
T-SC-12	136.5	10.5	2001	SCR	5	5	0.01
T-SC-32	136.5	10.5	2001	SCR	5	5	0.02
T-SC-42	136.5	10.5	2001	SCR	5	5	0.02
T-SC-51	136.5	10.5	2001	SCR	5	5	0.02
T-SC-11	136.5	10.5	2001	SCR	5	5	0.12
T-SC-31	136	10.5	2001	SCR	5	5	0.00
T-SC-41	136.5	10.5	2001	SCR	5	5	0.00
T-SC-50	136.5	10.5	2001	SCR	5	5	0.00
T-SC-18	466.8	47.4	2001	SCR/water injection/LNF	5	5	2.00
T-SC-19	466.8	47.4	2001	SCR/water injection/LNF	5	5	1.61
T-SC-21	466.8	47.4	2001	SCR/water injection/LNF	5	5	1.06
T-SC-23	466.8	47.4	2001	SCR/water injection/LNF	5	5	1.02
T-SC-25	466.8	47.4	2001	SCR/water injection/LNF	5	5	1.98
T-SC-57	466.8	47.4	2001	SCR/water injection/LNF	5	5	1.48
T-SC-75	470	49.6	2003	SCR/water injection	5	5	3.58
T-SC-64	298	31	1975	SCR/water injection	9	5	0.09
T-SC-65	298	30	1975	SCR/water injection	9	5	0.00
T-SC-61	69.12	6	1989	Water Injection	24	NA	0.06
T-SC-63	69.12	6	1989	Water Injection	24	NA	0.13

1 – Actual NOx concentration emitted are generally lower than the NOx permit limit

A summary of permitted limits in SCAQMD for the four types of electrical power generating units is provided in Table 6. While previous SCAQMD regulatory requirements established BARCT at 9 ppmv at 15% O2 dry 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 summary table.

Table 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	55 ppmv at 15% O2 dry	1 unit	Selective Catalytic Reduction (Replacement)
Natural Gas Boiler	5 ppmv at 3% O2 dry	6 units	Selective Catalytic Reduction, Low-NOx Burners, Flue Gas Recirculation (Retrofit)
Natural Gas Combined Cycle Gas Turbine with or without Duct Burner	2.0 ppmv at 15% O2 dry	24 units	Selective Catalytic Reduction, Water Injection, Dry Low NOx (Replacement)
Natural Gas Simple Cycle Gas Turbine	2.5 ppmv at 15% O2 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 electrical power generating equipment 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 7 through 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 7 – Non-Emergency Internal Combustion Engines (Diesel)

Agency	Rule Adoption Date	Rule Effective Date	NOx Limit (ppmv @ 15% 02)
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			44 (0.67 g/kw-hr)

Table 8 –Boilers

Agency	Rule Adoption Date	Rule Effective Date	Boiler Capacity (MM Btu/hr)	NOx Limit (ppmv @ 3% O2 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 9 – Turbines

Agency	Rule Adoption Date	Rule Effective Date	Capacity (MM Btu/hr)	Output (MW)	NOx Limit (ppmv @ 15% O2 dry)
BAAQMD*	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**	<3	25
			>35 – 130**	>3 – 10	25
			>130**	>10	25-42

For boilers, combined cycle turbines, and simple cycle 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 electrical power generating equipment. Staff reviewed scientific literature, vendor information, and strategies utilized in practice. The technologies are presented below and the applicability for use with various electrical power generating equipment is noted. In most cases, post-combustion technologies may be utilized in conjunction with pre-combustion technologies.

Pre-Combustion Technologies

<u>Dry Low-NOx or Lean Premix Emission Combustors (Turbines)</u>

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% O2 dry). The technology is engineered into the combustor that becomes and intrinsic part of the turbine design. Fuel staging or air staging is utilized 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 (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% O2 dry. 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 has increased maintenance due to erosion and wear.

Catalytic Combustion (Turbine)
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 reducing NOx emissions. In its first commercial installation, NOx concentrations were lowered from approximately 20 ppmv to below 3 ppmv at 15% O2 dry without post-combustion controls. Several turbine manufacturers are in the development stage to incorporate this technology.

Low-NOx Burners (Boilers)
Controlled fuel and air mixing at the burner reduced 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% O2 dry. 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/Boilers/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 percent 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 electricity generating equipment already utilize selective catalytic reduction already. 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 made be configured into plates but many new systems are configured into honeycombs to ensure uniform dispersion and reduce ammonia emissions to below 5.0 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 percent solution.

To perform optimally, the gas temperature in control device should be between 400F and 800F. During startup and shutdown, the temperature will be below optimal range greatly reducing the effectiveness. Thus, NOx concentration limits are generally not applicable during startup or shutdown. Newer electrical power generating equipment reduces 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 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 (Turbine)

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 and 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 more frequent and extensive catalyst washing is conducted. 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 boilers, combined cycle turbines, and simple cycle 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 concentration. In other air districts, regulations require retrofit on existing engines to meet a NOx concentration limit between 56 to 140 ppmv at 15% O2 dry. For new diesel internal combustion engines, SCAQMD has an engine permitted at 51 ppmv at 15% O2 dry. Stationary diesel 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% O2 dry, assuming 40% efficiency). Replacing existing engines with new engines that meet the Tier IV Final standard will initially be used to determine cost-effectiveness.

Table 10 –Initial BARCT Recommendation for Diesel Internal Combustion Engines

	Existing Units	Other Regulatory Requirements	Technology Assessment	Initial BARCT Recommendation
Retrofit	82 ppmv @ 15% O2 dry	56-140 ppmv @ 15% O2 dry		
New Install	51 ppmv @ 15% O2 dry	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 5.0 ppmv NOx concentration limit. Other air districts require retrofit of existing boilers to meet a 6.0 ppmv NOx concentration limit and new boilers to meet a 5.0 ppmv NOx concentration limit. The technology assessment has shown that selective catalytic reduction, in conjunction with ultra-low NOx burners can meet at 5.0 ppmv NOx limit. Therefore, the initial BARCT recommendation for new installations and retrofitted natural gas boilers will be 5.0 ppmv NOx.

Table 11 – Initial BARCT Recommendation for Natural Gas Boilers

	Existing Units (ppmv @ 15% O2 dry)	Other Regulatory Requirements (ppmv @ 15% O2 dry)	Technology Assessment (ppmv @ 15% O2 dry)	Initial BARCT Recommendation (ppmv @ 15% O2 dry)
Retrofit	5.0	6.0	5.0	5.0
New Install	5.0	5.0-6.0	5.0	5.0

Natural Gas Combined Cycle 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 5.0 ppmv NOx limit. Otherwise, the lowest NOx concentration limit for new installations in SCAQMD is 2.0 ppmv. Other air districts limit NOx emissions to between 5-25 ppmv for existing units and 2.0-25 for new installations. The technology assessment found that a combination of pre-combustion technology and post-combustion control can meet 2.0 ppmv NOx concentration for natural gas combined cycle gas turbines. The initial BARCT recommendation for both new installations and retrofits of natural gas combined cycle gas turbines is 2.0 ppmv NOx.

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

	Existing Units (ppmv @ 15% O2 dry)	Other Regulatory Requirements (ppmv @ 15% O2 dry)	Technology Assessment (ppmv @ 15% O2 dry)	Initial BARCT Recommendation (ppmv @ 15% O2 dry)
Retrofit	5.0	5-25	2.0	2.0
New Install	2.0	2.0-25	2.0	2.0

Natural Gas Simple Cycle Turbines

The lowest NOx concentration for a retrofitted natural gas simple cycle gas turbine is 9.0 ppmv. For new installations, numerous natural gas simple cycle gas turbines have a NOx concentration limit of 2.5 ppmv. Other air districts limit NOx emissions to between 5-25 ppmv for existing units and 2.5-25 ppmv for new installations. The technology assessment found that a combination of pre-combustion technology and post-combustion control can meet 2.5 ppmv NOx concentration 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.

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

	Existing Units (ppmv @ 15% O2 dry)	Other Regulatory Requirements (ppmv @ 15% O2 dry)	Technology Assessment (ppmv @ 15% O2 dry)	Initial BARCT Recommendation (ppmv @ 15% O2 dry)
Retrofit	9.0	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 14 below:

Table 14 – Summary of Initial BARCT Recommendation

Equipment	Initial BARCT Recommendation
Diesel Internal Combustion Engine	0.67 g/kWh % 15% O2 dry
Natural Gas Boiler	5.0 ppmv @ 3% O2 dry
Natural Gas Combined Cycle Gas Turbine	2.0 ppmv @ 15% O2 dry
Natural Gas Simple Cycle Gas Turbine	2.5 ppmv @ 15% O2 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 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 percent, 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 10-year equipment life.

Baseline emissions are determined by using reported fuel consumption and the Permit NOx concentration limit corrected to 15 percent O2 dry except for natural gas boilers where it is corrected to 3 percent O2 dry. 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.

<u>Diesel Internal Combustion Engines</u>

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 electrical generating facility using the engines. No change is expected for operating costs. 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 15.

Table 15 – Diesel Internal Combustion Engine Cost-Effectiveness

Size (BHP)	Annual NOx Emissions (tons)	NOx Permit Limit (ppmv @ 15% O2 dry)	Proposed BARCT NOx Emission Limit (ppmv @ 15% O2 dry)	Capital Cost (million)	Emission Reductions (tons)	Cost Effectiveness ($/ton NOx)
1575	16	140	45	$3.9	9.9	$14,826
1950	5.3	103	45	$3.9	2.7	$52,034
2150	8.2	97	45	$3.9	3.9	$35,414
1500	12	97	45	$3.9	5.6	$24,768
2200	22	82	45	$3.9	8.4	$15,520
3900	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 once-through-cooling provision and business decisions by electrical generating facilities, 21 of 24 natural gas boilers are planned to be shutdown. All but two of those natural gas boilers will be shutdown by 2024. Because of the shutdowns, 78 tons of NOx will be reduced annually by 2024 from electrical generating facility natural gas boilers. Another 11 tons of NOx will be reduced annually from the two natural gas boilers scheduled for shutdown in 2029. The remaining 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.

Table 16 – Natural Gas Boiler Cost-Effectiveness

Current NOx Permit Limit (ppmv @ 3% O2 dry)	Proposed BARCT NOx Emission Limit (ppmv @ 3% O2 dry)	Average Annual Capacity Factor (%)	Emission Reductions (tons)	Average Cost-Effectiveness ($/ton reduced)	Capacity Threshold for Cost-Effectiveness (%)
38	5	6.0	13.3	$45,991	5
40	5	3.5	3.7	$94,424	6
82	5	1.97	9.2	$59,804	2.01

Average Cost-Effectiveness: $58,000

The average cost effectiveness is approximately $58,000 per ton of NOx reduced. PAR 1135 includes a low-use provision that would allow the three natural gas boilers to continue to operate at levels below an average annual capacity factor of 2.5%. It is expected that these three units would use this provision if they continue to operate after 2023.

Natural Gas Combined Cycle Gas Turbines

Nine of 28 natural gas combined cycle gas turbines currently have NOx permit limit greater than the proposed NOx concentration limit of 2.0 ppmv at 15% O2 dry. Three units are permitted at 2.5 ppmv at 15% O2 dry NOx, and the other six units are permitted between 7 – 9 ppmv NOx at 15% O2 dry. The cost-effectiveness for natural gas combined cycle gas turbines is presented below in Table 16 below.

Table 17 – Natural Gas Combined Cycle Turbine Cost-Effectiveness

Unit	Input (MM Btu/hr)	Output (MW)	Annual NOx Emissions (tons)	Estimated MWh/yr	%Capacity	NOx Permit Limit (ppmv @ 15% O2 dry)	Capital Cost (Millions)	Operating Cost (millions)	Emission Reductions (tons)	Cost-Effectiveness
TC17	258.6	32	1.1	32,000	11%	2.5	$4.8	$0.3	0.2	$2,086,891
TC24	1805	290*	32.8	900,000	35%	2.5	$20.1	$1.6	6.8	$274,577
TC25	1805	290*	35.3	1,000,000	39%	2.5	$20.1	$1.6	7.5	$250,777
TC22	1088	182	12.1	60,000	4%	7	$14.8	$1.1	7.8	$169,744
TC23	1088	182	8.9	40,000	3%	7	$14.8	$1.1	5.2	$253,696
TC1	442	48	4.3	35,000	8%	7.6	$6.2	$0.5	3.2	$97,935
TC26	350	30	0.8	6,000	2%	9	$4.6	$0.3	0.6	$669,774
TC27	350	60	0.5	4,000	1%	9	$7.2	$0.5	0.4	$1,579,869
TC28	350	60	0.5	4,000	1%	9	$7.2	$0.5	0.4	$1,579,869

Average Cost-Effectiveness: > $100,000

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 at 15% O2 dry NOx concentration, the cost-effectiveness threshold of $50,000 per ton reduced is never reached, even when used at 100% annual capacity factor. Those three 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.

Natural Gas Simple Cycle Gas Turbines

Thirty of 75 natural gas simple cycle gas turbines have permitted NOx limits greater than the proposed BARCT limit of 2.5 ppmv at 15% O2 dry. One unit is permitted at 3.5 ppmv NOx at

15% O2 dry, 25 units are permitted at 5.0 ppmv NOx at 15% O2 dry, two units are permitted at 9 ppmv NOx at 15% O2 dry, and two units are permitted at 24 ppmv NOx at 15% O2 dry. 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 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.

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 electrical power 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 ensure that electrical power 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 18.

Table 18 – Recommended BARCT Emission Limits

Equipment Type	NOx (ppmv)	Ammonia (ppmv)	Oxygen Correction (%, dry)
Diesel Internal Combustion Engine	45	5.0	3
Natural Gas Boiler	5.0	5.0	15
Natural Gas Combined Cycle Gas Turbine	2.0	5.0	15
Natural Gas Simple Cycle Gas Turbine	2.5	5.0	15

Chapter 3

PROPOSED AMENDED RULE 1135

PAR 1135 establishes 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 at electricity generating facilities. Additionally, PAR 1135 establishes provisions for monitoring, reporting, and recordkeeping, and establishes exemptions from specific provisions.

Title

The title for PAR 1135 is "Emissions of Oxides of Nitrogen from Electricity Generating Facilitates"; 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 power generating units (diesel internal combustion engines, 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 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 power generating units at electricity generating facilities. Electric power generating systems consisted 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 power generating units, including diesel internal combustion engines, boilers, combined cycle gas turbines, and simple gas cycle turbines at electricity generating facilities. An electricity generating facility is 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. The rule will not apply to units located at landfill, petroleum refineries, or publicly owned treatment works and cogeneration turbines which will be regulated under Proposed Rule 1109.1 – Refinery Equipment and Proposed Amended Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines.

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
	Electricity Generating Facility
	Electric Power Generating Unit
	Internal Combustion Engine
	Landfill
	Municipal or Public Electric Utility
	Petroleum Refinery
	Publicly Owned Treatment Works
	RECLAIM NOx Source
	SCAQMD-Wide Daily Limits
	Shutdown
	Simple Cycle Gas Turbine
	Start-up
	Tuning

Emission Limitations (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 power 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) and Table I 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 the date the amendments to Rule 2001 are approved.

The emission limits in Tables I and II of PAR 1135 are based on the BARCT assessment presented in Chapter 2.

Figure 1: PAR 1135 – Table I

Table I: Emissions Limits for Boilers and Gas Turbines

Equipment Type	NO_x (ppmv)	Ammonia (ppmv)	Oxygen Correction (%, dry)
Boiler	5.0	5.0	3
Combined Cycle Gas Turbine and Associated Duct Burner	2.0	5.0	15
Simple Cycle Gas Turbine	2.5	5.0	15

Figure 2: PAR 1135 – Table II

Table II: Emissions Limits for Internal Combustion Engines

Equipment Type	NO_x (ppmv)	Ammonia (ppmv)	Carbon Monoxide (ppmv)	Volatile Organic Compounds (ppmv)	Particulate Matter (lbs/mmbtu)	Oxygen Correction (%, dry)
Internal Combustion Engine (Diesel)	45.0	5.0	250	30	0.0076	15

Subparagraphs (d)(1)(A) and (d)(2)(A) state that these emissions limits are not applicable during start-up, shutdown, and tuning periods and that these emissions limitations will be put in each electric power generating unit's permit. The requirements will specify duration, mass emissions, and number of start-ups, shutdowns, and, if applicable, tunings. Emissions limitations for start-up, shutdown, and tuning of existing electric power generating units are currently in the permit. 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 emissions limitations, but instead states that these emissions limitations will be put in each electric power generating unit's permit.

For units that are installed after [*Date of* Adoption], subparagraphs (d)(1)(B) and (d)(2)(B) require the emissions limits to be averaged over a sixty minute rolling average. For units installed before [*Date of Adoption*], subparagraphs (d)(1)(C) and (d)(2)(C) require units to retain their current averaging time. The averaging times for these units were evaluated during the permitting process and should be maintained.

To help achieve the emission reduction goals of the 2016 AQMP and AB 617 requirement of BARCT implementation, PAR 1135 subparagraph (d)(1) sets the compliance date for boilers and gas turbines to January 1, 2024.

Under paragraph (d)(2), the compliance date for internal combustion engines (diesel) is January 1, 2024. However, alternative effective dates are provided for diesel internal combustion engines to accommodate potential plans for less emissive electricity generating equipment than diesel internal combustion engines. The owner or operator of diesel internal combustion engines may submit a compliance plan by January 1, 2022 to extend the effective date provided emission reductions are substantially greater than if the engines were replaced with Tier IV compliant diesel engines. If the owner or operator can provide specifications of electric power generating units or other electrical generation or transmission equipment to provide power to Santa Catalina Island that will reduce emissions by an additional 33% to 20 tons per year, then the effective date will be delayed unit January 1, 2025. If the specifications demonstrate that emissions will be reduced by 67% or more, then the effective date will be delayed until January 1, 2026. This provision is intended to incentivize the transition to cleaner technologies or alternative power transmission options.

Existing paragraphs (d)(1) and (d)(2) have been deleted as the requirements are no longer applicable. 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, will be removed as they 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) become effective.

Several additional obsolete provisions will be deleted. Current Rule 1135 subparagraphs (d)(6) and (d)(7) 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

The subdivision for Compliance Plans will be deleted, as those dates have passed and Compliance Plans will no longer be necessary with the emissions limits in subdivision (d).

Measurements (Subdivision (e))

The current Rule 1135 facility will retain existing Rule 1135 monitoring and recordkeeping requirements and RECLAIM facilities will retain Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions excluding reporting requirements.

All references to the District's "CEMS Requirement Document for Utility Boilers," dated July 19, 1991 will be replaced with SCAQMD's "CEMS Requirement Document for Electric Power Generating Units," date [Date of Adoption]. All references to boiler, replacement unit and approved alternative or advanced combustion resource will be replaced with electric power generating unit. This will replace all the obsolete terms with PAR 1135 terminology.

For the current Rule 1135 facility, the requirement for Remote Terminal Unit (RTU) in paragraph (e)(1) will be replaced with a data acquisition system (DAS). Current Rule 1135 paragraph (d)(3) refers to RTUs and will be deleted. Current Rule 1135 paragraph (d)(4) will be deleted since the date has passed. The provision for a backup data gathering and storage system is removed; having the requirement for a DAS makes this provision unnecessary.

Current RECLAIM 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
- (f) – Permit Conditions for Large Sources and Process Units,
- (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

- (j) – Source Testing
- (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"

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.

Paragraph (f)(4) will be added which restricts any new installations of electric power generating internal combustion engines where the primary fuel is liquid petroleum. This provision does not apply the installation of engines installed for emergency backup power and fire pumps.

Municipal Bubble Options

The subdivision regarding Municipal Bubble Options 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 combined cycle gas turbines at 2.5 ppmv NOx at 15% O2 dry 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% O2 dry to reduce their limits to 2.0 ppmv at 15% O2 dry.

PAR 1135 paragraph (g)(2) exempts boilers at 7.0 ppmv NOx or less at 3% O2 dry from the emissions limitations in paragraph (d)(1), with the condition that the units adhere to their NOx and ammonia limits, start-up, shutdown, and tuning requirements, and averaging times on the current Permit. For boilers, the BARCT assessment determined that it is not cost-effective for boilers at 7.0 ppmv NOx at 3% O2 dry to reduce their limits to 5.0 ppmv at 3% O2 dry. Other units that are at or below 7.0 ppmv NOx may have different ammonia limits that were evaluated during the permitting process and since these units will not be modified or re-permitted, the ammonia limits from the permits should be maintained.

Paragraph (g)(3) exempts once-through-cooling boilers 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 shutdown dates established in the Clean Water Act Section 316(b). Shutdown and retirements plans must be submitted for each once-through-cooling boiler 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 will avoids stranded assets of adding pollution controls for interim period of time.

The BARCT assessment determined that it is not cost-effective for internal combustion engines (diesel) at 51.0 ppmv NOx at 15% O2 dry to reduce their limits to 45.0 ppmv at 15% O2 dry.

Therefore, PAR 1135 paragraph (g)(5) exempts boilers at 51.0 ppmv NOx at 15% O2 dry from the emissions limitations in paragraph (d)(1), 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)(6) is included in PAR 1135. The provision allows low-use equipment to continue operating without retrofit provided that they: using historical data to demonstrate that they have not exceeded the annual capacity factor limits; do not exceed an 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. The annual capacity factor limits for gas turbines in subparagraph (g)(5)(A), is less than twenty-five percent in one calendar year and ten percent averaged over three years. For boilers, the low-use provision in subparagraph (g)(5)(B), establishes the annual capacity factor limit as less than two and one half percent in one calendar year and one percent averaged over three years. In order to obtain the low-use exemption, subparagraph (g)(5)(C) requires that an application for the low-use exemption be submitted by May 1, 2019 and the unit can demonstrate compliance with the annual capacity factor limits using data from calendar years 2016, 2017, and 2018. Annual capacity factor shall be determined annually and submitted to the Executive Officer no later than April 1 following the reporting year. Usage during an Emergency Phase of the California Energy Commission Energy Emergency Response Plan or a declared State of Emergency or Energy Emergency by the Governor will not be used to calculate the annual capacity factor. If a unit exceeds the annual capacity factor, then subparagraph (g)(5)(E) states that after three years of date of reported exceedance, the unit cannot operate unless it is compliance with the paragraph (d)(1). There are also interim milestones, submitting a permit application within nine 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)(6) 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 for the lone existing Rule 1135 has been updated to be consistent with the revised definitions. Section 4.2.1 for Final Reporting Procedures has been revised to remove the requirement for an RTU. Instead, records demonstrating compliance will be required to be maintained for five years and provided to the Executive Officer upon request. Additionally, the provisions for Cogeneration Systems has been removed as the measurement of thermal energy is no longer necessary.

POTENTIALLY IMPACTED FACILITIES

There are thirty-four electricity generating facilities that are potentially applicable to Proposed Amended Rule 1135. Of these thirty-four facilities, twenty-nine are currently in the NOx RECLAIM program. The remaining five facilities are not in the RECLAIM program; one is currently subject to SCAQMD Rules 1134 and 1135 and four are not subject to Rule 1134 or 1135 because of current applicability requirement in the rules.

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, the NOx inventory had declined to under 10 tons per day. With a greater reliance on renewable power sources and further replacement of equipment, the emission inventory had fallen to 2.5 tons per day in 2016.

Table 19 – 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	0.9	5,355
Combined Cycle Turbine	1.0	6,082
Simple Cycle Turbine	0.4	4,540

Most of the emissions from combined cycle turbines and simple cycle turbines come from units that meet the proposed BARCT limits. Only 24 tons per year of NOx are emitted from turbines that do not meet the proposed BARCT limits.

Table 20 – 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	0.9	0.1	0.8
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, 1.0 tons per day of NOx emission reductions will be realized.

Table 21 – 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	0.9	0.0	0.9
Combined Cycle Turbine	1.0	0.9	0.1
Simple Cycle Turbine	0.4	0.4	0.0
Total	2.5	1.5*	1.0*

* Totals do not add correctly due to rounding

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. The incremental cost effectiveness analysis will be conducted and released in the draft staff report at least 30 days prior to the SCAQMD Governing Board Hearing on Proposed Amended Rule 1135, which is anticipated for October 5, 2018.

Chapter 4

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 socioeconomic impact assessment will be prepared and released for public review and comment at least 30 days prior to the SCAQMD Governing Board Hearing of Proposed Amended Rule 1135, which is anticipated for October 5, 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 Rule 110, the SCAQMD, as lead agency for the proposed project, has determined that a Subsequent Environmental Assessment (SEA) will be required for PAR 1135. The Draft SEA to be prepared will analyze the potential effects that the project may cause on the environment. In the event that the proposed project may have statewide, regional, or area-wide significance, a CEQA scoping meeting is required pursuant to Public Resources Code Section 21083.9(a)(2) and will be held concurrently with the Public Workshop for PAR 1135. As part of the CEQA Scoping Meeting, SCAQMD staff will solicit input from the public on the CEQA evaluation. The Draft SEA, upon its release, will be available for a public review and comment period.

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 will be prepared and released for public review and comment at least 30 days prior to the SCAQMD Governing Board Hearing of Proposed Amended Rule 1135, which is anticipated for October 5, 2018.

Chapter 5

REFERENCES

"Staff Report, Proposed Rule 1135 - Emissions of Oxides of Nitrogen from Electric Power-Generating Boilers", South Coast Air Quality Management District, June 30, 1989

"Final 2016 Air Quality Management Plan", South Coast Air Quality Management District, March 2017

"SCAQMD NOx RECLAIM – BARCT Feasibility and Analysis Review, Norton Engineering Consultants, Inc., Nov 26, 2014

Clean Water Act, 33 U.S.C. § 1326(b), Section 316(b)

"Regulation 9, Rule 8: Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines", Bay Area Air Quality Management District, July 2007

"Regulation 9, Rule 9: Nitrogen Oxides and Carbon Monoxide from Stationary Gas Turbines", Bay Area Air Quality Management District, December 2006

"Regulation 9, Rule 11: Nitrogen Oxides and Carbon Monoxide from Utility Electric Power Generating Boilers", Bay Area Air Quality Management District, May 2000

"Rule 4306 – Boilers, Steam Generators, and Process Heaters – Phase 3", San Joaquin Valley Air Pollution Control District, October 2008

"Rule 4702 – Internal Combustion Engines (Certified Equipment for Internal Combustion Engines)", San Joaquin Valley Air Pollution Control District, November 2013

"Rule 4703 – Stationary Gas Turbines", San Joaquin Valley Air Pollution Control District, September 2007

"Final Rule for Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel", U.S. Environmental Protection Agency, June 2004

"Chapter 2 – Selective Catalytic Reduction", U.S. Environmental Protection Agency, May 2016
"Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR), U.S. Environmental Protection Agency, May 2016

"Catalytic Combustion", Office of Energy Efficiency and Renewable Energy, https://www.energy.gov/eere/amo/catalytic-combustion, accessed July 19, 2018

"Catalog of CHP Technologies", U.S. Environmental Protection Agency Combined Heat and Power Partnership, September 2017