# SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

**Preliminary Draft Staff Report**
**Proposed Rule 1150.3 – Emissions of Oxides of Nitrogen from Combustion Equipment at Landfills**

**September 2020**

**Deputy Executive Officer**
Planning, Rule Development, and Area Sources
Philip M. Fine, Ph.D.

**Assistant Deputy Executive Officer**
Planning, Rule Development, and Area Sources
Susan Nakamura

**Planning and Rules Manager**
Planning, Rule Development, and Area Sources
Michael Morris

| | |
|---|---|
| Author: | Isabelle Shine – Air Quality Specialist |
| Co-Author: | Melissa Gamoning – Air Quality Specialist |
| Contributors: | John Anderson – Air Quality Analysis & Compliance Supervisor<br>Monica Fernandez-Neild – Senior Air Quality Engineer<br>Glenn Kasai – Senior Air Quality Engineer<br>Huy Anh Ngoc Le – Assistant Air Quality Engineer<br>Dipankar Sarkar – Program Supervisor<br>Angela Shibata – Supervising Air Quality Engineer<br>Bill Welch – Senior Air Quality Engineer<br>Mike Wickson – Senior Air Quality Engineer<br>Lisa Wong – Air Quality Specialist |
| Reviewed By: | Karin Manwaring – Senior Deputy District Counsel<br>Kevin Orellana – Program Supervisor<br>William Wong – Principal Deputy District Counsel |

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## EXECUTIVE SUMMARY

Organic waste is deposited in municipal solid waste (MSW) landfills where it decomposes with the aid of methane-producing bacteria. This process results in a byproduct called landfill gas, a form of biogas. Landfill gas can be used to generate electricity directly by MSW landfills. Alternatively, raw landfill gas can be sold to landfill gas to energy facilities, which process landfill gas to generate electricity for sale. Landfill gas differs from other process gases because it contains specific contaminants which can damage combustion equipment and impact the effectiveness of air pollution control equipment.

During the rulemaking for other equipment specific regulations, the South Coast AQMD received comments describing the unique challenges faced by MSW landfills associated with landfill gas. Staff recommended to separate provisions for combustion equipment at MSW landfills (and at publicly owned treatment works, which face similar challenges and was subject to a separate rulemaking). Proposed Rule 1150.3 – Emissions of Oxides of Nitrogen from Combustion Equipment at Landfills (PR 1150.3) was developed to establish Best Available Retrofit Control Technology (BARCT) requirements for boilers, process heaters, and turbines located at MSW landfills and landfill gas to energy facilities using landfill gas and contains provisions applicable to MSW landfills and landfill gas to energy facilities in one rule.

A total of twenty-one biogas fueled boilers and turbines, at seven facilities, will be affected by PR 1150.3. Staff excluded landfill gas engines from PR 1150.3 based on survey results from affected facilities; landfill gas engines will continue to be regulated under source-specific rules. Oxides of nitrogen (NOx) emission limitations are contained in PR 1150.3 for applicable equipment categories. Boilers, process heaters, and turbines with a rated output greater than or equal to 0.3 MW without post-combustion control are required to meet lower emission limits. The proposed NOx emission limit for boilers and process heaters is 9 ppmv at 3 percent oxygen on a dry basis. The proposed NOx emission limit for turbines with a rated output greater than or equal to 0.3 MW without post-combustion control is 12.5 ppmv at 15 percent oxygen on a dry basis. The proposed emission limits will reduce NOx emissions by 0.15 tpd[1]. The cost-effectiveness to meet the proposed emission limits is $27,033 per ton of NOx reduced[2].

PR 1150.3 was developed through a public process. Five Working Group meetings were held on: March 21, 2019, August 13, 2019, November 6, 2019, and February 12, 2020, and August 12, 2020. Working Group meetings included staff and representatives from affected businesses, environmental groups, public agencies, consultants, and other interested parties. The purpose of the Working Group meetings is to discuss details of proposed amendments and to listen to concerns and issues with the objective to build consensus and resolve key issues.

In addition, a Public Workshop will be held on October 7, 2020. The purpose of the Public Workshop is to present the proposed rule language to the general public and stakeholders, as well as to solicit comments. Staff has also conducted multiple site visits as part of this rulemaking process and has met with individual facility operators.

[1] Reductions calculated are based on current permitted concentration emission levels and proposed emission limit.
[2] Reductions calculated as part of the cost-effectiveness determination are based on current concentration emission levels of the turbines as demonstrated in recent source tests.

# CHAPTER 1: BACKGROUND

## BACKGROUND

A municipal solid waste (MSW) landfill is an entire disposal facility in a contiguous geographical space where solid waste is placed in or on land. The organic waste deposited in MSW landfills decomposes with the aid of methane-producing bacteria. This process results in a byproduct called landfill gas, a form of biogas. Landfill gas can be captured in wells and processed to generate electricity sold directly to utilities. Alternatively, raw landfill gas can be sold to landfill gas to energy facilities, which process landfill gas to generate electricity for sale. Landfill gas differs from other process gases because it contains specific contaminants which can damage equipment used in energy production.

During the rulemaking for the December 2018 amendments for Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146), Rule 1146.1 - Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146.1), and Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters (Rule 1146.2), the South Coast AQMD received comments describing the unique challenges faced by MSW landfills associated with landfill gas. As a result, staff recommended to separate provisions for combustion equipment at MSW landfills, and publicly owned treatment works (POTWs), as POTWs have similar challenges MSW landfills. Proposed Rule 1150.3 – Emissions of Oxides of Nitrogen from Combustion Equipment at Landfills (PR 1150.3) was developed to establish Best Available Retrofit Control Technology (BARCT) requirements for boilers, process heaters, and turbines located at MSW landfills and landfill gas to energy facilities using landfill gas and contain provisions applicable to MSW landfills and landfill gas to energy facilities in one rule. Staff identified characteristics of MSW landfills and landfill gas to energy facilities that required consideration throughout the rule development. These unique characteristics include the properties of landfill gas and financial considerations. Staff excluded landfill gas engines from PR 1150.3 based on survey results from affected facilities. Landfill gas engines will continue to be regulated under Rule 1110.2 – Emissions from Gaseous- and Liquid- Fueled Engines (Rule 1110.2).

*Landfill Gas*

Landfill gas has different properties than natural gas or other conventional fuels. Landfill gas has a lower Btu content (higher heating value) than that of natural gas. Btu content has been reported in the range of 295-841 Btu/scf for landfill gas produced by facilities in the South Coast AQMD, whereas natural gas has a higher heating value of approximately 1050 Btu/scf. Active landfills typically have higher Btu landfill gas, but when a landfill closes the Btu content declines.

The composition of landfill gas changes over time. Initially, aerobic bacteria decompose organic waste and produce $CO_2$ as a byproduct. After oxygen is depleted, anerobic bacteria continue to breakdown organic waste, and methane and $CO_2$ production become relatively steady. After a landfill stops accepting waste, there is a finite amount of material to decompose and produce landfill gas. At which point, the volume and quality of landfill gas declines.

Another significant difference between landfill gas and natural gas or other conventional fuels is the presence of contaminants such as siloxanes and hydrogen sulfide. Siloxanes are a type of organosilicon compound which exists in many cosmetic, personal and household products. Products containing siloxanes are deposited at landfills and decompose alongside other organic wastes. The presence of siloxanes in landfill gas can affect combustion processes. When siloxane compounds are combusted, silicon dioxide is formed. This glass-like compound forms deposits on combustion equipment, increasing maintenance and if not maintained, causes damage to combustion equipment. Another complication of siloxane presence in landfill gas streams is the damaging impact they have on post combustion control equipment, specifically, selective catalytic reduction (SCR) units. Siloxanes can deactivate the catalyst within the SCR, causing SCR to be ineffective. To resolve this problem, facilities use gas cleaning technology to remove siloxanes before combustion. However, inadequate cleaning of the landfill gas could cause the facility to change the SCR catalyst more frequently, increasing operating and maintenance costs.

*Financial Considerations*

MSW landfills are essential public services which have structured procurement processes. New projects require approval from governing bodies which may be by city council, board of directors, or board of county supervisors, for example. Securing the financial means for a project to comply with regulations may be more difficult for an essential public service than for private industry. Even private entities that lease the gas from MSW landfills need appropriate approvals. To recover costs of implementing a control project, MSW landfills may need to increase utility rates for the consumer. Increased costs for a public utility may be difficult for MSW landfills to impose.

MSW landfills often sell excess electricity and raw landfill gas to utilities and landfill gas to energy facilities, respectively. These gas to energy contracts, also known as power purchase agreements, can last for decades. A control project implemented during a power purchase agreement may not be cost-effective if the agreement is not renewed and there are stranded assets.

## REGULATORY HISTORY

Combustion equipment located at MSW landfills and landfill gas to energy facilities are currently regulated under the following source specific rules. NOx and CO emissions from boilers, process heaters, and steam generators are regulated under Rules 1146, 1146.1, and 1146.2. This series of rules includes emission limits for all fuels, including landfill gas. Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines (Rule 1134) was amended on April 5, 2019 and excluded turbines located at landfills or turbines fueled by landfill gas considering that PR 1150.3 was in development. Rule 1134 contains emission limits for all fuels, but does not apply to equipment located at landfills or POTWs. Equipment that is not regulated by South Coast AQMD rules remains subject to the requirements specified in the permit. Table 1-1 lists the combustion equipment located at MSW landfills and landfill gas to energy facilities and applicable rules.

**TABLE 1-1**
**RULES APPLICABLE TO COMBUSTION EQUIPMENT AT MSW LANDFILLS AND LANDFILL GAS TO ENERGY FACILITIES**

| Equipment | South Coast AQMD Rule | General Provisions |
|---|---|---|
| Boilers >2 MMBtu/hr | Rules 1146 and 1146.1 (NOx and CO) | Emission limits, source testing frequency, CEMS, monitoring, recording, recordkeeping |
| Boilers ≤ 2 MMBtu/hr | Rules 1146.2 (NOx and CO, natural gas only). No requirements for boilers ≤ 2 MM Btu/hr using landfill gas | Emission limitations for manufactured equipment fired with natural gas, monitoring, recording, recordkeeping |
| Emergency internal combustion engines | Rule 1470 – Requirements for Stationary Diesel-Fueled Internal Combustion Engines and Other Compression Ignition Engines (Diesel PM) | Operation limitations, emissions standards, fuel and fuel additive requirements, monitoring, recordkeeping, and reporting requirements |
| Non-emergency internal combustion engines | Rule 1110.2 – Emissions from Gaseous- and Liquid- Fueled Engines (NOx, VOC, and CO) | Emission limits, source testing frequency, source testing protocols, CEMS, monitoring, recording, recordkeeping, I&M plan requirements |
| Non-refinery flares | Rule 1118.1 – Control of Emissions from Non-Refinery Flares (NOx, VOC) | Flare gas, including landfill gas, emission limits, source testing requirements, monitoring, recording and recordkeeping |
| Turbines ≥ 0.3 MW | Currently no source specific rule for turbines ≥ 0.3 MW at landfills or those fueled with landfill gas | N/A |
| Turbines < 0.3 MW | Currently no source specific rule for turbines < 0.3 MW | N/A |

## AFFECTED FACILITIES AND EQUIPMENT

*PR 1150.3 Universe*

Seven MSW landfills and landfill gas to energy facilities were identified as the universe of PR 1150.3. There are 3 boilers, 14 turbines with a rated output ≥ 0.3 MW, 4 turbines with a rated output < 0.3 MW, fueled by landfill gas at these facilities.

*Applicability to Engines*

Biogas engines, including landfill gas fired engines, were analyzed in the 2012 Rule 1110.2 technology assessment and are currently regulated in Rule 1110.2. During the initial PR 1150.3 working group meetings, some stakeholders expressed a preference for including engines in PR

1150.3. In subsequent working group meetings, however, staff informed stakeholders that the inclusion of engines in PR 1150.3 would require permit revisions and the submission of an application for a new I&M plan.

Staff presented fees associated with the inclusion of engines in PR 1150.3. The higher costs associated with engine permit revisions, in comparison to other combustion equipment permit revisions, are due to the structure of engine permits; they reference specific rule provisions and require I&M plans. Staff surveyed facilities that operate permitted landfill gas engines to ascertain if facilities would be in favor of including engines in PR 1150.3, even if there were associated fees. Staff explained that the waiving of any fees may not be possible.

Staff sent surveys to three facilities that operate non-emergency internal combustion engines. The two facilities that responded indicated they were not in favor of including engines as part of Rule 1150.3. Therefore, engines will instead remain subject to Rule 1110.2.

Seven MSW landfills and landfill gas to energy facilities were identified to have equipment subject to PR 1150.3. Table 1-2 contains the equipment affected by PR 1150.3.

**TABLE 1-2**
**AFFECTED EQUIPMENT**

| Equipment Type | Number of Units |
|---|---|
| **Boilers** | |
| Landfill gas | 3 |
| **Turbines ≥ 0.3 MW** | |
| Landfill Gas | 11 |
| Dual Fuel | 3 |
| **Turbines < 0.3 MW** | |
| Landfill gas | 4 |

Landfill gas turbines and landfill gas boilers were not assessed in the April 2019 amendments to Rule 1134 (turbines) or the December 2018 amendments to Rules 1146, 1146.2, and 1146.2 (boilers and process heaters). Rule 1134 does not apply to any turbine located at a landfill or any turbine fueled by landfill gas. Currently, turbines located at MSW landfills or landfill gas to energy facilities are not subject to any rule. Provisions for landfill gas and other gaseous fueled turbines will be contained in PR 1150.3. All combustion equipment permitted to fire only non-landfill gas fuels will remain subject to source-specific rules, with the exception of turbines with a rated output greater than or equal to 0.3 MW. Other equipment at MSW landfills or landfill gas to energy facilities will not be affected by PR 1150.3. Emergency engines, flares, and most natural gas fired equipment (excluding turbines ≥ 0.3 MW) will be subject to existing source-specific rules and will not be subject to PR 1150.3. Flares located at MSW landfills and landfill gas to energy facilities were assessed as part of the January 4, 2019, rulemaking for Rule 1118.1 – Control of Emissions from Non-Refinery Flares and will remain subject to Rule 1118.1.

**PUBLIC PROCESS**

The development of PR 1150.3 was conducted through a public process. Five Working Group meetings were held on: March 21, 2019, August 13, 2019, November 6, 2019, February 12, 2020, and August 12, 2020. Working Group meetings included staff and representatives from affected businesses, environmental groups, public agencies, consultants, and other interested parties. The purpose of the Working Group meetings is to discuss details of proposed amendments and to listen to concerns and issues with the objective to build consensus and resolve key issues.

In addition, one Public Workshop will be held on October 7, 2020. The purpose of the Public Workshop is to present the preliminary staff report and proposed rule language to the general public and to stakeholders. Staff has also conducted multiple site visits as part of this rulemaking process and has met with individual facility operators.

# CHAPTER 2: BARCT ASSESSMENT

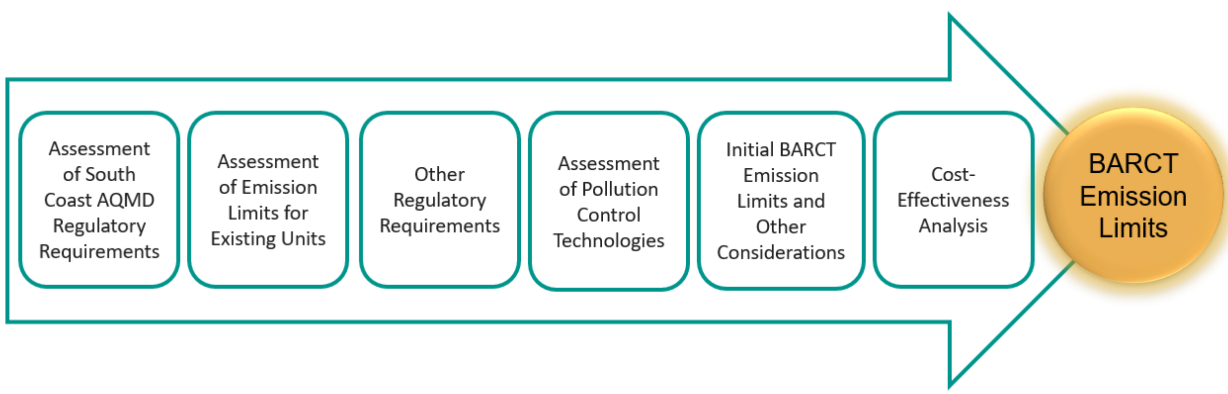
## INTRODUCTION

The purpose of a Best Available Retrofit Control Technology (BARCT) assessment is to identify any potential emission reductions from specific equipment or industries and establish an emission limit that is consistent with state law. Under California Health and Safety Code § 40406, BARCT is defined as:

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

BARCT assessments are performed periodically for equipment categories to determine if current emission limits are representative of BARCT emission limits. The BARCT assessment process identifies current regulatory requirements for equipment categories established by South Coast AQMD and other air districts. Permit limits and source test data are analyzed to identify the emission limits being achieved with existing technology. Current and emerging technologies are assessed to determine the feasibility of achieving lower NOx emission levels. An initial BARCT emission limit is proposed based on the BARCT assessment. A cost-effectiveness calculation is made that considers the cost to meet the initial proposed NOx limit and the emission reductions that would occur from implementing technology that could meet that proposed limit. A final BARCT emission limit is established based on the BARCT assessment, including the cost-effectiveness analysis.

**Figure 2-1 — BARCT Assessment Process**




BARCT assessments were conducted for landfill gas fired boilers and turbines as part of the rulemaking for PR 1150.3.

## BARCT ANALYSIS APPROACH

<u>Assessment of South Coast AQMD Regulatory Requirements</u>

*Boilers and Process Heaters*
South Coast AQMD Rules 1146 and 1146.1 require boilers and process heaters to meet a NOx emission limit of 25 ppmv at 3 percent oxygen on a dry basis when firing landfill gas.

*Turbines < 0.3 MW*

There is currently no South Coast AQMD rule that establishes a NOx limit for turbines with a rated output less than 0.3 MW. Rule 219 allows turbines, including microturbines, with a rated maximum heat input capacity of 3.5 MMBtu/hr or less to be exempt from permitting provided that the cumulative power output of all turbines at a facility is less than 2 MW. To qualify for this exemption, the turbines must be certified by the state of California at the time of manufacture or operated prior to May 3, 2013 and submit a filing pursuant to Rule 222.

*Turbines ≥ 0.3 MW*

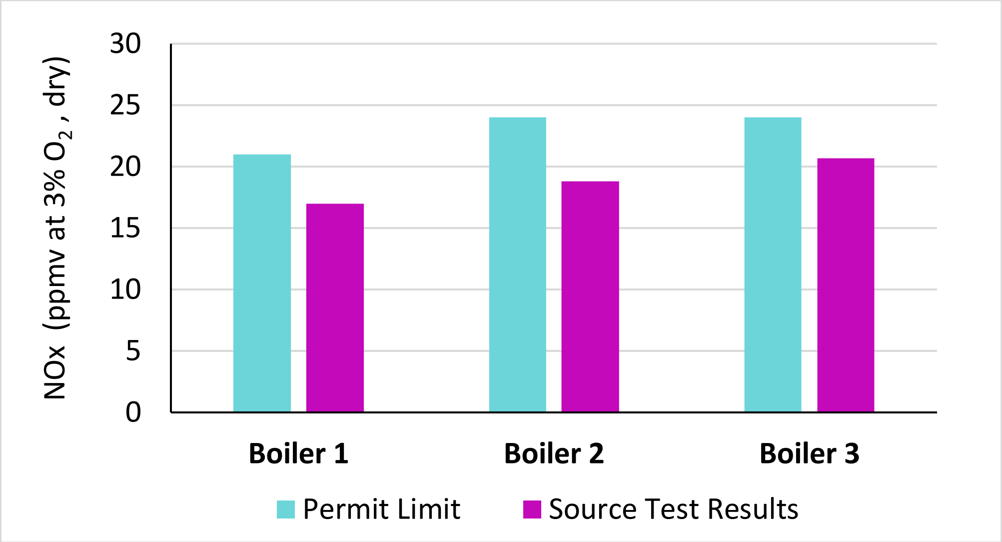
Turbines fueled by landfill gas are currently unregulated by any South Coast AQMD rule. Rule 1134 — Emissions of Oxides of Nitrogen from Stationary Gas Turbines, which applies to stationary gas turbines with a rated output of 0.3 MW and greater, excludes stationary gas turbines located at landfills or fueled by landfill gas.

<u>Assessment of Emission Limits for Existing Units</u>

*Boilers and Process Heaters*

There are three permitted landfill gas fired boilers, located at two facilities, in the South Coast AQMD. One boiler has a NOx limit of 21 ppmv at 3 percent oxygen on a dry basis; this boiler utilizes flue gas recirculation and is equipped with a low NOx burner. This boiler has source tested at 17 ppmv NOx. Two boilers utilize flue gas recirculation and have NOx limits of 24 ppmv at 3 percent oxygen on a dry basis. These boilers have source tested at 18.8 ppmv NOx and 20.7 ppmv NOx at 3 percent oxygen on a dry basis. All boilers have source tested below their respective permit limits of 21 ppmv and 24 ppmv NOx.

**Figure 2-2 Landfill Gas Fired Boiler Source Test Results**



*Turbines <0.3 MW*

There are four permitted landfill gas turbines with a rated output less than 0.3 MW located at one facility in the South Coast AQMD. All four turbines have a NOx concentration limit of 9 ppmv at 15 percent oxygen on a dry basis. Source test results for these turbines are between 3.29 ppmv and 3.39 ppmv NOx at 15 percent oxygen on a dry basis.

*Turbines ≥ 0.3 MW*

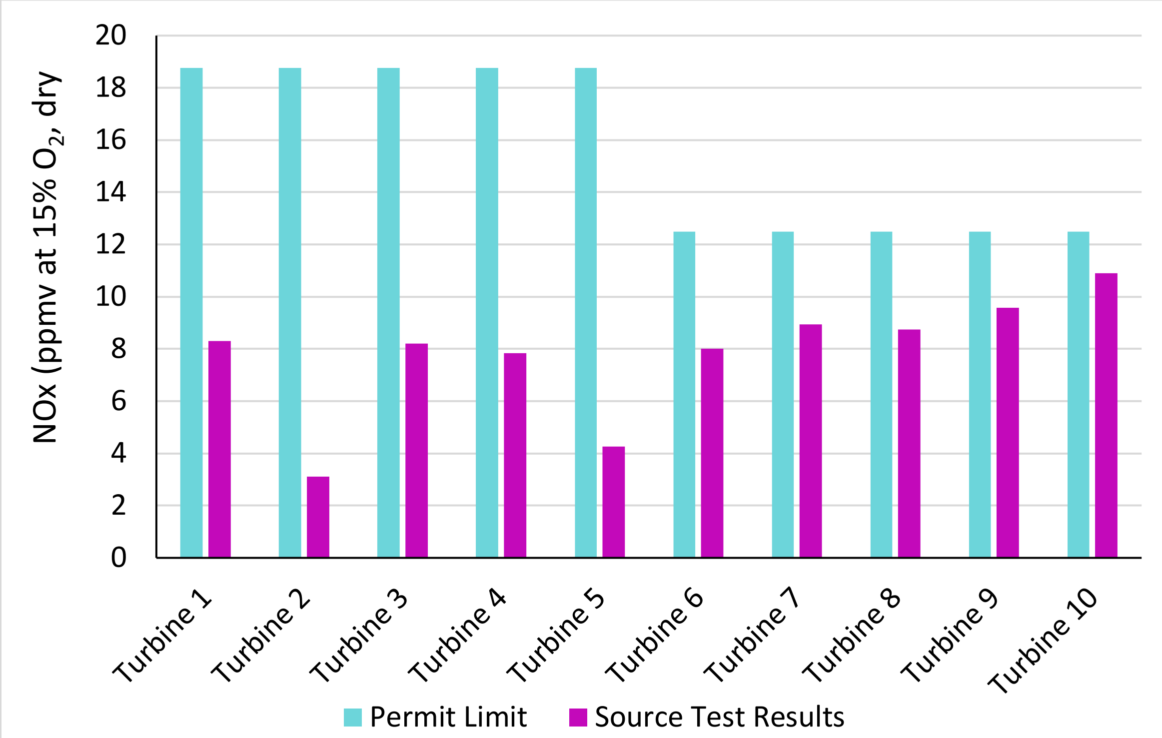
There are fourteen turbines with a rated output greater than or equal to 0.3 MW permitted to fire landfill gas at four facilities in the South Coast AQMD. Ten are simple cycle turbines which utilize ultra-lean pre-mix control technology as NOx controls. Five of these simple cycle turbines have a NOx limit of 18.75 ppmv for loads greater than 3000 kW and a 25 ppmv NOx limit for loads less than or equal to 3000 kW, at 15 percent on a dry basis. The other five simple cycle turbines have a NOx limit of 12.5 ppmv at 15 percent oxygen on a dry basis. There are four combined cycle turbines which utilize selective catalytic reduction (SCR) to control NOx emissions. These turbines have a NOx limit of 25 ppmv at 15 percent oxygen on a dry basis.

**TABLE 2-1**
**CURRENT PERMIT LIMITS FOR LANDFILL GAS TURBINES**

| Facility | Number of Turbines | Turbine Size (MW) | Emission Controls | NOx Permit Limit (ppmv at 15% O2) |
|---|---|---|---|---|
| 1 | 3 | 4.6 | Ultra-lean Premix | 18.75 at loads >3000 kW; 25 at loads ≤ 3000 kW |
| 2 | 2 | 4.6 | Ultra-lean Premix | 18.75 at loads >3000 kW; 25 at loads ≤ 3000 kW |
| 3 | 5 | 4.9 | Ultra-lean Premix | 12.5 |
| 4 | 4 | 6.3 | SCR | 25 |

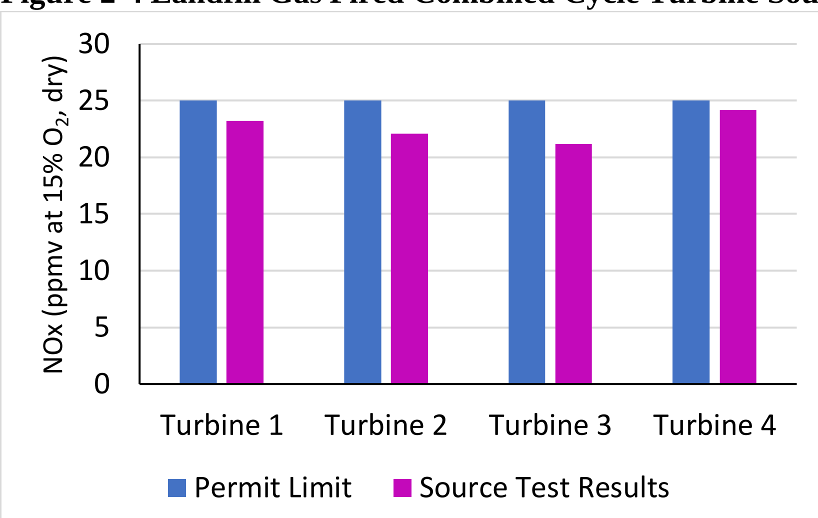
Staff analyzed recent source test results for the fourteen turbines. Source test results for the simple cycle turbines showed NOx concentrations between 3.1 ppmv and 10.9 ppmv NOx at 15 percent oxygen on a dry basis. All simple cycle turbines have source tested below their respective permit limits.

**Figure 2-3 Landfill Gas Fired Simple Cycle Turbine Source Test Results**




Source test results for the combined cycle turbines have showed NOx concentrations between 21.2 and 24.2 ppmv. These turbines all source tested below their permit limit of 25 ppmv at 15 percent oxygen on a dry basis.

**Figure 2-4 Landfill Gas Fired Combined Cycle Turbine Source Test Results**



<u>Other Regulatory Requirements</u>

*Boilers and Process Heaters*

Staff identified two air districts with NOx emission limits more stringent than the South Coast AQMD for landfill gas fired boilers and process heaters.

San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 4320 restricts NOx emissions to 6 ppmv – 9 ppmv at 3 percent oxygen for boilers and process heaters with a total rated heat input greater than 5 MMBtu/hr to ≤ 20 MMBtu/hr. SJVAPCD limits NOx emissions to 5 ppmv – 7 ppmv at 3 percent oxygen for boilers and process heaters with a total rated heat input greater than 20 MMBtu/hr. These NOx limits apply to gaseous or liquid fired boilers and process heaters, where "gaseous fuel" is defined as any fuel which is a gas at standard conditions.

Sacramento Metropolitan Air Quality Management District (SMAQMD) Rule 411 restricts NOx emissions to 15 ppmv at 3 percent oxygen for boilers and process heaters rated greater than or equal to 5 MMBtu/hr fired on landfill gas or a combination of landfill gas and natural gas. Records indicated a landfill gas boiler in SMAQMD complied in 2009 with the 15 ppmv NOx limit. Source test results showed a 6.9 ppmv NOx concentration for this boiler.

*Turbines <0.3 MW*

Staff did not identify any air districts that adopted rules regulating NOx emissions for turbines with a rated output less than 0.3 MW.

*Turbines ≥ 0.3 MW*

Staff identified that SJVAPCD, SMAQMD, and Bay Area Air Quality Management District (BAAQMD) adopted rules that are as stringent or more stringent than South Coast AQMD permit limits for landfill gas fired turbines with a rated output of 0.3 MW or greater.

SJVAPCD Rule 4703 limits NOx emissions to 9 ppm for gas fueled turbines rated less than 3 MW. Gas turbines rated 3 – 10 MW that operate less than 877 hours per year are subject to a 9 ppm NOx limit; turbines that operate 877 hours or more per year are subject to a 5 ppmv NOx limit. Simple cycle gas turbines rated greater than 10 MW that operate no greater than 200 hours per year are subject to a 25 ppm NOx limit; turbines that operate more than 200 hours per year, but no greater than 877 hours per year, are subject to a 5 ppmv NOx limit.

SMAQMD Rule 413 limits NOx emissions to 9 ppm for gaseous fueled turbines that are rated 10 MW or greater, operate 877 hours or more per year, and equipped with SCR. Gaseous fueled turbines rated 10 MW or greater and operate 877 hours or more per year without SCR, are subject to a 15 ppmv NOx limit. Gaseous fueled turbines rated greater than or equal to 2.9 MW and less than 10 MW, which operate 877 hours or more per year, are subject to a 25 ppm NOx limit.

BAAQMD Regulation 9 – Rule 9 limits NOx emissions to 15 ppmv for refinery fuel gas, waste gas (which includes landfill gas), or LPG fired turbines rated greater than 150 MMBtu/hr to 250 MMBtu/hr. This rule also limits NOx emissions to 9 ppmv for refinery gas, waste gas, or LPG fired turbines greater than 250 MMBtu/hr.

Assessment of Pollution Control Technologies

Gas treatment technology is commonly used to remove siloxanes, moisture, hydrogen sulfide, and other undesirable contaminants from raw landfill gas prior to combustion. The removal of siloxanes from raw landfill gas is vital for combustion equipment and control technology to work efficiently and prevent damage. There are three primary types of gas treatment systems for siloxane removal: consumable media, regenerative media, and chiller/adsorption. A gas treatment system may contain one or more siloxane removal system types.

The effectiveness of siloxane removal depends on the media characteristics and the types of contaminants in the gas stream. Three common types of media used at landfills and landfill gas to energy facilities are activated carbon, molecular sieve, and silica gel. Each type of media has its advantages. Activated carbon is a versatile adsorbent that is highly porous and is suitable to absorb organic molecules. A molecular sieve has pores of uniform size and is capable of performing selective removal of contaminants at low concentrations. Silica gel is a shapeless and porous adsorbent that has a greater capacity than activated carbon to adsorb siloxanes and has a high affinity for water that aids in moisture removal.

Consumable media systems commonly use activated carbon as media. The activated carbon is typically stored in a series of parallel canisters which are changed out after the carbon is saturated. Activated carbon media is quickly saturated due to the adsorption of many contaminants. The removal and disposal of media can have a significant cost depending on the frequency the media is changed. However, initial installment and maintenance costs are typically less than regenerative media and chiller/adsorption systems due to the lack of complex machinery.

Regenerative media includes molecular sieve, silica gel, clay, and zeolite. These systems consist of at least two media canisters in parallel— one canister remains online and treats the gas while one canister remains offline to regenerate media with hot purged air. Regenerative media require smaller canisters and less media in comparison to consumable media systems. Regenerative media can be enhanced by applying polymetric resins. Polymetric resins can increase service life, increase adsorbent capacity, and removes contaminants more quickly and at a lower temperature during regeneration.

Chiller/adsorption gas treatment systems remove contaminants by reducing the temperature of the gas to below dew point to condense out moisture and siloxanes. These systems have been used in combination with consumable media systems and regenerative media systems at landfills.

*Boilers and Process Heaters*

Low NOx burners, ultra-low NOx burners, flue gas recirculation, and selective catalytic reduction (SCR) are control technologies which reduce NOx emissions from boilers and process heaters.

Low NOx burners and ultra-low NOx burners control the air-fuel mixture at the burner. Optimal air-fuel ratios reduce the peak flame temperature which reduces NOx. Low NOx burners can reduce NOx by 60% and result in NOx concentrations of approximately 15 ppmv at 3 percent oxygen on a dry basis. Ultra-low NOx burners can reduce NOx by 80% to NOx concentrations of approximately 9 ppmv at 3 percent oxygen on a dry basis. Burner retrofits to an existing boiler may require complex engineering and design. One landfill gas fired boiler in the South Coast AQMD utilizes a low NOx burner.

Flue gas recirculation is a method of NOx control that returns hot combustion exhaust products out of the flue gas and recirculates them back into the furnace. This process helps preheat the incoming combustion air and lowers the combustion zone temperature to reduce NOx formation. This technology can reduce NOx by 30–55%. Flue gas recirculation is currently used on all landfill gas fired boilers in South Coast AQMD.

SCR is a post-combustion control technology for NOx reduction and is capable of reducing 80–95% of post-combustion NOx. This technology would be capable of reducing NOx to approximately 5 ppmv at 3 percent oxygen on a dry basis for landfill gas fired boilers. SCR reduces NOx to nitrogen and water through a reaction with ammonia and oxygen. However, the catalyst used for the reaction is susceptible to fouling if the gas contains contaminants. Landfill gas fired turbines utilizing SCR would require gas treatment to preserve the catalyst. SCR may be used in combination with combustion control technologies to achieve greater NOx reductions. Additionally, SCR requires on-site storage of ammonia or urea and the technology carries the potential of creating unwanted stack ammonia emissions (ammonia slip) from unreacted ammonia. SCR is also limited by its range of optimum operating temperatures. The technology typically requires exhaust temperatures to be between 400–800°F, so it is not suitable for combustion equipment with low exhaust temperatures.

*Turbines <0.3 MW*

Lean premixed combustion is a NOx control technology commonly used for turbines with a rated output less than 0.3 MW. This control technology premixes gaseous fuel and compressed air which minimizes localized hot spots that produce elevated combustion temperatures. Lean premixed combustion can reduce NOx to approximately 9 ppmv at 15 percent oxygen. However, this control technology requires that the combustor is an intrinsic part of the turbine design and is not available as a retrofit technology. One turbine supplier guarantees a 9 ppmv NOx limit at 15 percent oxygen on a dry basis for turbines <0.3 MW that fire landfill gas. However, proper gas treatment and maintenance is imperative to meet the target emission levels. All landfill gas fired turbines with a rated output less than 0.3 MW use lean premixed combustion technology in combination with a gas treatment system.

*Turbines ≥ 0.3 MW*

Lean premixed combustion, water or steam injection, and SCR are NOx control technologies commonly used for turbines with a rated output 0.3 MW or greater.

As previously stated above for turbines < 0.3 MW, lean premixed combustion is a control technology that reduces NOx from turbines. Prior to combustion, gaseous fuel and compressed air are premixed which minimizes localized hot spots that produce elevated combustion temperatures. Lean premixed combustion can reduce NOx to approximately 12.5 ppmv at 15 percent oxygen on a dry basis. However, this control technology requires that the combustor is an intrinsic part of the turbine design and is not available as a retrofit technology. All ten simple cycle landfill gas fired turbines rated 0.3 MW and greater use lean premixed combustion in combination with a gas treatment system.

Water or steam injection reduces NOx by injecting water or steam into the flame zone to lower the combustion zone temperature. Water injection can reduce NOx by 80–90% and steam injection can reduce NOx by 70–80%. However, water and steam injection require demineralized water which increases operational costs. Imprecise application can also lead to hotspots and cause NOx formation. Furthermore, water and steam injection increases fuel usage and carbon monoxide (CO) emissions.

SCR is a post-combustion control technology for NOx reduction and is capable of reducing 80–95% of post-combustion NOx. This technology can reduce NOx concentrations to 2.5 ppmv at 15 percent oxygen on a dry basis for simple cycle turbines and 2 ppmv at 15 percent oxygen on a dry basis for combined cycle turbines. SCR reduces NOx to nitrogen and water through a reaction with ammonia and oxygen. However, the catalyst used for the reaction is susceptible to fouling if the gas contains contaminants. Landfill gas fired turbines utilizing SCR require gas treatment to preserve the catalyst. SCR may be used in combination with combustion control technologies to achieve greater NOx reductions. However, SCR requires on-site storage of ammonia or urea and the technology carries the potential of creating unwanted stack ammonia emissions (ammonia slip) from unreacted ammonia. SCR is limited by its range of optimum operating temperatures. The technology typically requires exhaust temperatures to be between 400–800°F, so it is not suitable for combustion equipment with low exhaust temperatures. All four combined cycle landfill gas fired turbines rated 0.3 MW and greater use SCR in combination with a gas treatment system.

Initial BARCT Emission Limits and Other Considerations

*Boilers and Process Heaters*

Staff proposed a NOx emission limit of 5 ppmv at 3 percent oxygen on a dry basis. This initial BARCT limit was based on the technology assessment of SCR used with landfill gas fired boilers.

**TABLE 2-2**

**INITIAL NOx EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS**

| Equipment Type | NOx Limit at Rule Adoption (ppmv)* |
|---|---|
| Boilers and Process Heaters | 5 |

**All emission limits are in parts per million by volume (ppmv) are referenced at 3 percent oxygen on a dry basis.*

*Turbines < 0.3 MW*

Staff proposed a NOx limit of 9 ppmv at 15 percent oxygen on a dry basis based on supplier discussions and current permitted levels of landfill gas fired turbines rated less than 0.3 MW. Source test results from existing turbines demonstrate that the 9 ppmv NOx limit has been achieved.

**TABLE 2-3**

**INITIAL NOx EMISSION LIMITS FOR TURBINES < 0.3 MW**

| Equipment Type | NOx Limit at Rule Adoption (ppmv)* |
|---|---|

| | |
|---|---|
| Turbines < 0.3 MW | 9 |

**All emission limits are in parts per million by volume (ppmv) are referenced at 15 percent oxygen on a dry basis.*

*Turbines ≥ 0.3 MW*

Staff proposed a NOx limit of 2.5 ppmv at 15 percent oxygen on a dry basis for simple cycle turbines and 2 ppmv at 15 percent oxygen on a dry basis for combined cycle turbines. These initial BARCT limits were based on the technology assessment of SCR used with landfill gas fired turbines.

**TABLE 2-4**
**INITIAL NOx EMISSION LIMITS FOR TURBINES ≥ 0.3 MW**

| Equipment Type | NOx Limit at Rule Adoption (ppmv)* |
|---|---|
| Simple Cycle Turbines ≥ 0.3 MW | 2.5 |
| Combined Cycle Turbines ≥ 0.3 MW | 2 |

**All emission limits are in parts per million by volume (ppmv) are referenced at 15 percent oxygen on a dry basis.*

<u>Cost- Effectiveness</u>

A complete discussion of cost-effectiveness is provided in Chapter 4 of this report. The findings are summarized here as part of the BARCT assessment process.

*Boilers and Process Heaters*

Staff conducted a cost-effectiveness analysis to retrofit landfill gas fired boilers with SCR. The average cost effectiveness to meet a 5 ppmv NOx limit at 3 percent oxygen on a dry basis is greater than $50,000 per ton of NOx reduced.

Staff proceeded to conduct a cost-effectiveness analysis to retrofit landfill gas fired boilers with ultra-low NOx burners. The average cost effectiveness to meet a 9 ppmv NOx limit at 3 percent oxygen on a dry basis is less than $50,000 per ton of NOx reduced.

*Turbines < 0.3 MW*

All of the existing landfill gas fired turbines with a rated output less than 0.3 MW are permitted at the initial BARCT emission limit and no cost-effectiveness analysis was conducted.

*Turbines ≥ 0.3 MW*

Staff conducted a cost-effectiveness analysis to retrofit simple cycle landfill gas fired turbines with SCR. The average cost effectiveness to meet a 2.5 ppmv NOx limit at 15 percent oxygen on a dry basis is greater than $50,000 per ton of NOx reduced.

The four existing combined cycle turbines currently utilize SCR as a control technology. Staff conducted a cost-effectiveness analysis to install a gas treatment system to meet a 12.5 ppmv NOx limit at 15 percent oxygen on a dry basis. The average cost effectiveness to meet a 12.5 ppmv NOx is greater than $50,000 per ton of NOx reduced.

BARCT Emission Limits

*Boilers and Process Heaters*
Staff is proposing a NOx emission limit of 25 ppmv at 3 percent oxygen on a dry basis at rule adoption. This NOx emission limit is consistent with Rules 1146 and 1146.1. Staff is proposing a NOx limit of 9 ppmv at 3 percent oxygen on a dry basis on or before January 1, 2030.

**TABLE 2-5**
**PROPOSED BARCT NOx EMISSION LIMITS**
**FOR BOILERS AND PROCESS HEATERS**

| Equipment Type | Limit at Rule Adoption (ppmv)* | Limit on January 1, 2030 (ppmv)* |
|---|---|---|
| Boilers and Process Heaters | 25 | 9 |

**All emission limits are in parts per million by volume (ppmv) are referenced at 3 percent oxygen on a dry basis.*

*Turbines < 0.3 MW*
Staff is proposing a NOx emission limit of 9 ppmv at 15 percent oxygen on a dry basis at rule adoption.

**TABLE 2-6**
**PROPOSED BARCT NOx EMISSION LIMIT FOR TURBINES < 0.3 MW**

| Equipment Type | Limit at Rule Adoption (ppmv)* |
|---|---|
| Turbines < 0.3 MW | 9 |

**All emission limits are in parts per million by volume (ppmv) are referenced at 15 percent oxygen on a dry basis.*

*Turbines ≥ 0.3 MW*
Staff is proposing a NOx emission limit of 25 ppmv at 15 percent oxygen for turbines with post-combustion control upon rule adoption. This NOx limit is consistent with existing permit limits for landfill gas fired turbines with post-combustion control (i.e. SCR). Staff is proposing a NOx emission limit of 12.5 ppmv at 15 percent oxygen for turbines without post-combustion control upon rule adoption. Source test results from existing turbines demonstrate that the 12.5 ppmv NOx limit has been achieved. Staff is proposing a NOx emission limit of 12.5 ppmv for all turbines with a rated output equal to or greater than 0.3 MW upon turbine replacement.

**TABLE 2-7**
**PROPOSED BARCT EMISSION LIMTS FOR TURBINES ≥ 0.3 MW**

| Equipment Type | Limit at Rule Adoption (ppmv)* | Limit Upon Turbine Replacement (ppmv)* |
|---|---|---|
| Turbines ≥ 0.3 MW with post-combustion control | 25 | 12.5 |
| Turbines ≥ 0.3 MW without post-combustion control | 12.5 | 12.5 |

**All emission limits are in parts per million by volume (ppmv) are referenced at 15 percent oxygen on a dry basis.*

## SUMMARY OF BARCT EMISSION LIMITS

Table 2-8 contains a summary of proposed BARCT emission limits for landfill gas fired boilers, process heaters, and turbines effective upon rule adoption, a fixed date, and upon replacement.

**TABLE 2-8**
**EMISSION LIMITS AND COMPLIANCE SCHEDULE**

| Equipment Type | Limit at Rule Adoption (ppmv) | Limit on January 1, 2030 (ppmv) | Limit Upon Turbine Replacement (ppmv) |
|---|---|---|---|
| Boilers and Process Heaters[1] | 25 | 9 | 9 |
| Turbines[2] < 0.3 MW | 9 | 9 | 9 |
| Turbines[2] ≥ 0.3 MW with post-combustion control | 25 | 25 | 12.5 |
| Turbines[2] ≥ 0.3 MW without post-combustion control | 12.5 | 12.5 | 12.5 |

[1] *All emission limits are in parts per million by volume (ppmv) are referenced at 3 percent oxygen on a dry basis.*
[2] *All emission limits are in parts per million by volume (ppmv) are referenced at 15 percent oxygen on a dry basis.*

# CHAPTER 3: PROPOSED RULE 1150.3

**INTRODUCTION**

**PROPOSED RULE STRUCTURE**

**PROPOSED RULE 1150.3**

*a) Purpose*
*b) Applicability*
*c) Definitions*
*d) Emission Limits*
*e) Source Testing*
*f) CEMS*
*g) Diagnostic Emission Checks for Boilers and Process Heaters*
*h) Recordkeeping*
*i) Other Requirements*
*j) Schedule for Permit Revisions*
*k) Exemptions*

## INTRODUCTION

The following information describes the structure of PR 1150.3 and explains the provisions incorporated from other source-specific rules. New provisions and any modifications to existing provisions that have been incorporated are also explained.

## PROPOSED RULE STRUCTURE

PR 1150.3 will contain the following subdivisions that will contain all the requirements for the applicable equipment:

- *a) Purpose*
- *b) Applicability*
- *c) Definitions*
- *d) Emission Limits*
- *e) Source Testing*
- *f) CEMS*
- *g) Diagnostic Emission Checks for Boilers and Process Heaters*
- *h) Recordkeeping*
- *i) Other Requirements*
- *j) Schedule for Permit Revisions*
- *k) Exemptions*

## PROPOSED RULE 1150.3

*Subdivision (a) – Purpose*

The purpose of this rule is to limit emissions from combustion equipment located at MSW landfills and landfill gas to energy facilities. The regulated pollutants subject to PR 1150.3 include NOx and CO.

*Subdivision (b) – Applicability*

This rule applies to boilers and process heaters with a rated heat input capacity greater than 2 MMBtu/hr and turbines with a rated output less than 0.3 MW, located at a MSW landfill or landfill gas to energy facility, which are permitted to fire landfill gas, including dual fuel units that are permitted to fire landfill gas and another fuel. PR 1150.3 also applies to all turbines with a rated output equal to or greater than 0.3 MW located at a MSW landfill or landfill gas to energy facility, regardless of the fuels the unit is permitted to fire, since Rule 1134 requirements (which regulate turbines) specifically exclude turbines located at landfills or fueled by landfill gas.

*Subdivision (c) – Definitions*

Definitions in PR 1150.3 that applied in other source-specific rules are incorporated to define equipment, fuels, and other rule terms. New or modified definitions added to PR 1150.3 are:

- *BOILER means any combustion equipment fired with a liquid or gaseous fuel and used to produce steam or to heat water. Boiler does not include any open heated tank, adsorption* *chiller unit, or waste heat recovery boiler that is used to recover sensible heat from the exhaust of a combustion turbine or any unfired waste heat recovery boiler that is used to recover sensible heat from the exhaust of any combustion equipment.*

This definition is from Rule 1146 and modified to include boilers used exclusively to produce electricity for sale.

- *CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) means the total combined equipment and systems, including the sampling interface, analyzers, and data acquisition and handling system, required to continuously determine air contaminants and diluent gas concentrations and/or mass emission rate of a source effluent (as applicable).*

  This definition is from Rule 218.1 and modified for clarity by incorporating the system description at the beginning of the definition.

- *DUAL FUEL UNIT means any combustion equipment subject to this rule permitted to fire landfill gas and another fuel.*

  This definition was added to describe a type of unit that PR 1150.3 is applicable to. Some landfill gas fired units have the capability to supplement the fuel with natural gas, for example.

- *LANDFILL GAS TO ENERGY FACILITY means a facility that receives and processes landfill gas to generate electricity for sale. Landfill gas to energy facility does not include MSW landfills.*

  This definition was added to describe a type of facility that PR 1150.3 is applicable to.

- *MUNICIPAL SOLID WASTE or MSW LANDFILL means an entire disposal facility in a contiguous geographical space where solid waste is placed in or on land. An MSW landfill may be active, inactive, or closed.*
  - *A) Active MSW landfill means a Municipal Solid Waste landfill that has received solid waste on or after November 8, 1987.*
  - *B) Inactive MSW landfill means a Municipal Solid Waste landfill that has not accepted solid waste after November 8, 1987 and subsequently no further solid waste disposal activity has been conducted within the disposal facility.*
  - *C) Closed MSW landfill means a Municipal Solid Waste landfill that has ceased accepting solid waste for disposal and the closure was conducted in accordance with all applicable federal, state and local statutes, regulations, and ordinances in effect at the time of closure.*

  This definition is from Rule 1150.1 and modified to include the definitions of *ACTIVE MSW LANDFILL, INACTIVE MSW LANDFILL, AND CLOSED MSW LANDFILL.* This definition was modified to clarify that the closure of a *CLOSED MSW LANDFILL* was conducted in accordance with applicable rules and regulations.

- *OXIDES OF NITROGEN (NOx) means nitric oxide and nitrogen dioxide. NOx emissions means the sum of nitric oxides and nitrogen dioxides emitted, collectively expressed as nitrogen dioxide emissions.*

  This definition is from Rule 1118.1 and modified to include the definition of *NOx EMISSIONS* from Rule 1146.

- *RATED HEAT INPUT CAPACITY means the heat input capacity as specified by the permit issued by the South Coast AQMD, or if not specified on the permit, as specified on the nameplate of the combustion unit. If the combustion unit has been altered or modified such that its maximum heat input is different than the heat input capacity specified on the nameplate, the new maximum heat input shall be considered as the rated heat input capacity. Heat input means the chemical heat released due to assumed complete combustion of fuel in a unit, using the higher heating value of the fuel. This does not include the sensible heat of incoming combustion air.*

  This definition is from Rule 1146 and modified to include the definition of *HEAT INPUT* from Rule 1146 and to refer to the South Coast AQMD instead of the Executive Officer.

- *RATED OUTPUT means the continuous MW (megawatt) rating or mechanical equivalent by a manufacturer for a turbine without including the increase in the turbine shaft output and/or the decrease in turbine fuel consumption by the addition of energy recovered from exhaust heat.*

  This definition is modified from the Rule 1134 definition *RATING OF A GAS TURBINE* to include the definition of *POWER AUGMENTATION* from Rule 1134.

- *SHUTDOWN means time period that begins when an operator reduces load and which ends in a period of zero fuel flow.*

  This definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 1150.3.

- *SOLID WASTE means all decomposable and non-decomposable solid, semisolid and liquid wastes including garbage, trash, refuse, paper, rubbish, ashes, industrial waste, manure, vegetable or animal solid and semisolid waste.*

  This definition is from Rule 1150.1 and modified to clarify the types of waste disposed of at an MSW landfill.

- *TUNING means adjusting, optimizing, rebalancing, or other similar operations to a unit or an associated control device. Tuning does not include normal operations to meet load fluctuations.*

  This definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 1150.3.

- *TURBINE REPLACEMENT means installing new equipment with the same function in place of currently installed equipment. Replacement does not include turbine overhauls that do not trigger New Source Performance Standards requirements, and overhauls in which the original turbine unit returns to operation at the facility within 90 days.*

  This definition is added to clarify a type of equipment modification made to a turbine. Turbine replacement includes replacing the combustor or burner of a turbine.

- *UNIT means a boiler, process heater, or turbine subject to this rule.*

  This definition is added for clarity when referencing equipment subject to the requirements of PR 1150.3.

*Subdivision (d) – Emission Limits*

Paragraph (d)(1) includes Table 1, which contains the emission requirements for NOx and CO for all the equipment subject to PR 1150.3. These emission requirements would not apply during periods of startup and shutdown, as further explained in paragraph (d)(5) – Startup and Shutdown.

Table 1 Concentration Limits for Boilers and Process Heaters (at 3% O2)

<table>
<tr><th colspan="4">BOILERS AND PROCESS HEATERS</th></tr>
<tr><th>Equipment Category</th><th>Compliance Schedule</th><th>NOx (ppmv)[1]</th><th>CO (ppmv)[1]</th></tr>
<tr><td rowspan="2">Landfill gas</td><td>On or before [Date of Adoption]</td><td>25</td><td rowspan="4">400</td></tr>
<tr><td>On or before January 1, 2030</td><td rowspan="2">9</td></tr>
<tr><td>Rated heat input capacity > 2 MMBtu/hr and < 75 MMBtu/hr and firing other fuel</td><td rowspan="2">On or before [Date of Adoption]</td></tr>
<tr><td>Rated heat input capacity ≥ 75 MMBtu/hr and firing other fuel</td><td>5</td></tr>
</table>

1 All parts per million by volume (ppmv) emission limits are referenced at 3% volume stack gas oxygen on a dry basis and averaged over 15 minutes.

**Boilers and Process Heaters:**

- Boilers will continue to comply with permit limits of 21 ppmv and 24 ppmv NOx at 3 percent oxygen on a dry basis at the time of rule adoption.
- Boilers and process heaters firing any amount of landfill gas would meet a 9 ppmv NOx at 3 percent oxygen on a dry basis by January 1, 2030.

- Boilers and process heaters with a rated heat input capacity < 75 MMBtu/hr firing other fuels will meet the current Rule 1146 (Group II and Group III units) and Rule 1146.1 limit of 9 ppmv NOx at 3 percent oxygen at municipal sanitation service facilities at the time of rule adoption.
- Boilers and process heaters with a rated heat input capacity ≥ 75MMBtu/hr firing other fuels will meet the current Rule 1146 limit of 5 ppmv NOx at 3 percent oxygen for Group I units at the time of rule adoption.
- All boilers and process heaters will continue to meet the current CO limit of 400 ppmv in Rules 1146 and 1146.1

Table 1 Concentration Limits for Turbines (at 15% O2)

<table>
<tr><th colspan="4">TURBINES</th></tr>
<tr><th>Equipment Category</th><th>Compliance Schedule</th><th>NOx (ppmv)[2]</th><th>CO (ppmv)[2]</th></tr>
<tr><td>Rated output < 0.3 MW and firing landfill gas, landfill gas with other gaseous fuel, or other gaseous fuel</td><td rowspan="3">On or before [Date of Adoption]</td><td>9</td><td rowspan="6">130</td></tr>
<tr><td>Rated output ≥ 0.3 MW with post-combustion control and firing 75% landfill gas or more[3]</td><td>25</td></tr>
<tr><td>Rated output ≥ 0.3 MW without post-combustion control and firing 75% landfill gas or more[3]</td><td rowspan="2">12.5[4]</td></tr>
<tr><td>Rated output ≥ 0.3 MW and firing 75% landfill gas or more[3]</td><td>Upon turbine replacement</td></tr>
<tr><td>Combined cycle with a rated output ≥ 0.3 MW and firing 100% natural gas or other gaseous fuel, excluding landfill gas</td><td rowspan="2">On or before [Date of Adoption]</td><td>2</td></tr>
<tr><td>Simple cycle with a rated output ≥ 0.3 MW and firing 100% natural gas or other gaseous fuel, excluding landfill gas</td><td>2.5</td></tr>
</table>

2 All parts per million by volume (ppmv) emission limits are referenced at 15% volume stack gas oxygen on a dry basis and averaged over 1 hour.

3 Percent of landfill gas is based on the total heat input on a rolling 12-month basis.

4 Concentration limit applicable to turbines operating at a load of 60% rated output or greater.

**Turbines with a Rated Output Less Than 0.3 MW**

These landfill gas or dual fuel turbines will be subject to the requirements of PR 1150.3 when firing landfill gas, landfill gas and another gaseous fuel simultaneously, or another gaseous fuel only. Turbines in this category would be subject to a 9 ppmv NOx limit at 15 percent oxygen on a dry basis at the time of rule adoption. Units would also be subject to a 130 ppmv CO concentration limit at 15 percent oxygen on a dry basis. Turbines with a rated output less than 0.3 MW permitted to fire only non-landfill gas fuels is not subject to this rule.

**Turbines with a Rated Output Greater Than or Equal To 0.3 MW**

- Turbines with a rated output ≥ 0.3 MW with post-combustion control are subject to their current permit limit of 25 ppmv NOx at 15 percent oxygen on a dry basis at the time of rule adoption
- Turbines with a rated output ≥ 0.3 MW without post-combustion control are subject to a 12.5 ppmv NOx limit at 15 percent oxygen on a dry basis at the time of rule adoption
- All turbines with a rated output ≥ 0.3 MW (with or without post-combustion control) are subject to a 12.5 ppmv NOx limit at 15 percent oxygen on a dry basis at the time of turbine replacement

The above requirements would apply to turbines that fire 75 percent or more landfill gas. Seventy-five percent was chosen because it reflects the current permit thresholds for the minimum use of landfill gas for the affected facility, and is based on the total heat input on a rolling 12-month basis. Any unit that fires 100 percent natural gas or another gaseous fuel, excluding landfill gas would be required to meet the natural gas BARCT emission levels established in Rule 1134. Rule 1134 requires natural gas simple cycle turbines to meet 2.5 ppm at 15 percent oxygen on a dry basis and natural gas combined cycle turbines to meet 2 ppm at 15 percent oxygen on a dry basis. There are no turbines firing 100 percent natural gas or another gaseous fuel, excluding landfill gas, at an MSW landfill or landfill gas to energy facility, currently. However, since Rule 1134 specifically excludes all turbines operating at landfills, regardless of fuel, it is appropriate that PR 1150.3 covers these requirements.

Any landfill gas fired turbine that fires less than 75 percent landfill gas would be required to use a weighted emission limit determined by Equation 1, in paragraph (d)(2) explained below. The weighted emission limit only applies to turbines that fire landfill gas and another fuel simultaneously.

The CO emission limit for all turbines of 130 ppmv NOx at 15 percent oxygen on a dry basis is based on permit limits from the affected facilities. If a permit contains a more stringent CO limit than what the rule contains, the facility must comply with the more stringent limit.

<u>Emission limits for Turbines that Fire Less than 75 percent Landfill Gas Simultaneously with Natural Gas or Other Gaseous Fuel – Paragraph (d)(2)</u>

Turbines which fire more than 25 percent but less than 100 percent natural gas or another gaseous fuel, excluding landfill gas, are subject to a weighted emission limit calculated by Equation 1. The landfill gas higher heating value used in the equation must be obtained using an approved procedure by the South Coast AQMD. Approved South Coast AQMD procedures include submitting landfill gas samples for laboratory analyses and using portable monitoring devices, for example. A representative sample of the facility's landfill gas would be allowed as long as this same gas is sent to the subject turbine. The flowrates of the fuels used must be obtained using an approved non-resettable totalizing fuel flow meter. The flowrate must be obtained at the time compliance is determined and the landfill gas sample used to obtain the higher heating value must be collected no earlier than 30 days before compliance is determined, to ensure there is accurate representation of the landfill gas.

$$\text{Weighted Limit} = \frac{(CL_A \times Q_A \times V_A) + (CL_B \times Q_B \times V_B)}{(Q_A \times V_A) + (Q_B \times V_B)} \quad \text{(Equation 1)}$$

Where:

$CL_A$ = compliance limit in Table 1 when firing 75% landfill gas or more

$Q_A$ = higher heating value of landfill gas in Btu per scf

$V_A$ = flowrate of landfill gas in scf per unit of time

$CL_B$ = compliance limit in Table 1 when firing 100% natural gas or other gaseous fuel

$Q_B$ = higher heating value of natural gas or other gaseous fuel in Btu per scf

$V_B$ = flowrate of natural gas or other gaseous fuel in scf per unit of time

Emission Limits for Turbines ≥ 0.3 MW Operating at Loads less than 60 Percent Rated Output – Paragraph (d)(3)

The 12.5 ppmv NOx limit in Table 1 does not apply to turbines with a rated output greater than or equal to 0.3 MW while operating at loads less than 60 percent rated output. In this instance, these turbines would be subject to a 25 ppmv NOx limit, but for a limited amount of run time. After operating at loads less than 60 percent rated output for 250 hours per calendar year, the 12.5 ppmv NOx limit would then become effective even if the facility continued to operate at loads less than 60 percent rated output for the duration of the calendar year.

Averaging Times for Units with CEMS – Paragraph (d)(4)

PR 1150.3 provides averaging time requirements for boilers, process heaters, and turbines with CEMS, consistent with those under proposed Rule 1179.1– NOx Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities. The proposed averaging times are as follows:

- Boilers and Process Heaters: Fixed interval of 1 clock hour
- Turbines: Rolling period of 1 hour

Startup and Shutdown – Paragraph (d)(5)

Startup and shutdown requirements are provided in PR 1150.3 for boilers, process heaters, and turbines. The startup and shutdown requirements for boilers and process heaters are as follows:

- Boilers and process heaters without post-combustion control: No longer than is necessary for the proper operation of the boiler or process heater for startup and not longer than 6 hours for startup or shutdown (same as current Rule 1146/1146.1 requirements)
- Boilers and process heaters with post-combustion control: No longer than is necessary to reach minimum catalyst operating temperature for startup and not longer than 6 hours for startup or shutdown
- Boilers and process heaters ≥ 5 – 40 MMBtu/hr cannot exceed 10 scheduled startup/shutdown events per month (same as current Rule 429 requirements)
- Boilers and process heaters > 40 MMBtu/hr cannot exceed 10 scheduled startup/shutdown events per year (same as current Rule 429 requirements)

Maximum startup and shutdown requirements reflect current requirements in Rule 429 – Start-Up and Shutdown Exemption Provision for Oxides of Nitrogen. Boilers and process heaters currently subject to Rule 1146 are required to comply with Rule 429. Since landfill gas and dual fuel boilers would no longer be subject to Rule 1146, Rule 429 requirements have been included in PR 1150.3. Facilities are required to submit a startup and shutdown schedule by January 1 of each year to the South Coast AQMD and notify the South Coast AQMD prior to each startup and shutdown event with the dates, times, and duration of the scheduled startup and shutdown and of any other process variables requested by the South Coast AQMD. Scheduled startup and shutdown events include, but are not limited to, those planned for maintenance, service, tuning or construction, and do not include startups or shutdowns triggered by demand response systems.

The startup and shutdown requirements for turbines are as follows:

- Turbines without post-combustion controls: No longer than is necessary for proper operation of the turbine and cannot exceed 30 minutes
- Turbines with post-combustion controls (e.g. SCR): No longer than is necessary for the post-combustion control equipment to reach minimum catalyst operating temperature for startup and not longer than 1 hour

<u>Prohibition of Liquid Fuel – Paragraph (d)(6)</u>

PR 1150.3 contains a prohibition on the use of any liquid fuel, such a diesel, for the operation of any turbine at an MSW landfill or landfill gas to energy facility. This provision would not apply to emergency use turbines as described in the proposed exemptions under subdivision (k).

*Subdivision (e) – Source Testing*

For units and for pollutants not monitored by CEMS, PR 1150.3 provides a source testing schedule in Table 2.

**TABLE 2**
**SOURCE TESTING SCHEDULE**

| Equipment Category | Frequency | Pollutant | Elapsed Time Prior to Conducting Source Test[1] |
|---|---|---|---|
| Boilers and process heaters with a rated heat input capacity> 2 MMBtu/hr and <10 MMBtu/hr | Every 5 years from the date the previous source test was required[2] | NOx and CO | At least 250 operating hours or at least 30 calendar days |
| Boilers and process heaters with a rated heat input capacity $\geq$ 10 MMBtu/hr | Every 3 years from the date the previous source test was required[2] | | |
| Turbines with a rated output < 2.9 MW | Every 3 years from the date the previous source test was required[2] or every 8,760 operating hours, whichever occurs later | | At least 40 operating hours or at least 7 calendar days |
| Turbines with a rated output $\geq$ 2.9 MW | Every year from the date the previous source test was required[2] | | |

1 Time elapsed or unit operating hours, subsequent to any the tuning or servicing of any boiler, unless it is an unscheduled repair.
2 Source test is due no later than the last day of the calendar month.

The boiler and process heater requirements are the same as those contained in Rules 1146 and 1146.1. The source testing schedule for turbines is based on Rule 1134 requirements. PR 1150.3 contains a new provision for turbines with a rated output less than 2.9 MW to source test every 3 years or 8,760 operating hours, whichever occurs later. The equipment categories which designate the source test frequency reflects the CEMS criterion in Rule 1134. The source testing requirements would apply to all turbines, including those with a rated output less than 0.3 MW.

Other source testing requirements, which come from existing source testing requirements from other source-specific rules, are contained in PR 1150.3 and apply to all equipment types. All equipment types would be required to source test no later than the last day of the calendar month that the source test is due.

Initial Source Testing - Paragraph (e)(2)

The owner or operator of any unit required to source test by Table 2, that has not conducted an initial source test for that unit, would be required to conduct a source test within 12 months from the adoption of PR 1150.3.

Source Test Protocol Submittal and Scheduling - Paragraph (e)(3)

PR 1150.3 provides 60 days before a scheduled source test date for the owner or operator to submit a source test protocol for approval. A new requirement is included in subparagraph (e)(3)(A) that requires a new submittal of a source testing protocol if any modification to the equipment results in a change to the permit, if any emission limits have changed since the previous source test, or at the request of the South Coast AQMD. A new submittal may be required, for example, if the prior source testing protocol is outdated. The owner or operator is allowed 90 days from the date the approval of the source test protocol was electronically distributed to conduct the source test.

Source Test Protocol Requirements - Paragraph (e)(4)

This paragraph describes the information required for submitting a source test protocol.

Source Test Date Notification - Paragraph (e)(5)

This paragraph contains requirements for notification of a scheduled source test.

Approved Contractor and Test Methods - Paragraph (e)(6):

This paragraph contains requirements that source tests are to be conducted by a South Coast AQMD approved contractor according to specific test methods. A listing of source testing methods is contained in Table 3.

**TABLE 3**

**SOURCE TESTING METHODS**

| **Pollutant** | **Test Methods** |
|---|---|
| NOx | South Coast AQMD Test Methods 100.1 or 7.1 |
| CO | South Coast AQMD Test Methods 100.1 or 10.1, or EPA Test Method 10 |
| $CO_2$ and $O_2$ | South Coast AQMD Test Method 3.1 or 100.1 |

Source Testing Infrastructure – Paragraph (e)(7)

This paragraph contains requirements for physical accommodations that allow for a source test to be conducted at a facility.

Operating Conditions During Source Testing for Boilers, Process Heaters, and Turbines - Paragraph (e)(8)

This paragraph contains requirements to conduct source tests for boilers, process heaters, and turbines in the as-found operating condition, and that no testing should be completed during periods of startup, shutdown, or under breakdown conditions. PR 1150.3 includes a minimum sampling time of 15 minutes.

Submittal of Completed Source Test - Paragraph (e)(9)

Facilities are required to submit source test reports within 60 days of the completed source test.

Using Relative Accuracy Test Audit (RATA) In Lieu of a Source Test - Paragraph (e)(10)

This paragraph contains an allowance for RATAs to be used in lieu of a source test, provided that the RATA is conducted within the same calendar year that the source test is required. It should be noted that Proposed Rules 218.2 and 218.3 are currently under development and may contain enhanced provisions and requirements for units operating with CEMS that would apply to units covered by PR 1150.3.

*Subdivision (f) – CEMS*

This subdivision contains the requirements for the installation, operation, and maintenance of CEMS equipment. Many of these requirements are also contained in Rule 218 and 218.1, which currently address monitoring requirements and performance specifications. As noted previously, Proposed Rules 218.2 and 218.3 are currently under development and may contain enhanced monitoring and performance specification requirements. Equipment subject to this rule would also be required to comply with Rules 218/218.1 as well as Proposed Rules 218.2/218.3, upon adoption. Table 4 in subdivision (f) contains the thresholds for boilers, process heaters, and turbines requiring CEMS, consistent with current requirements in Rules 1146 and 1134, respectively.

**TABLE 4**
**UNITS REQUIRING CEMS**

| **Equipment Type** | **Threshold** | **Pollutant** |
|---|---|---|
| Boilers and process heaters | Rated heat input capacity ≥ 40 MMBtu/hr and Annual heat input > 200 x $10^9$ Btu per calendar year | NOx |
| Turbines | Rated output ≥ 2.9 MW | |

Turbine Parameter Monitoring - Paragraph (f)(1)

This paragraph provides parameter monitoring requirements, specific to turbines using CEMS, including flowrate of fuel gases, ratio of water or steam added, if applicable, elapsed time of operation, and turbine output in MW.

*Subdivision (g) – Diagnostic Emission Checks for Boilers and Process Heaters*

This subdivision contains requirements that are consistent with current requirements in Rules 1146 and 1146.1. Diagnostic emission checks are required to be conducted by trained staff in accordance with the Combustion Gas Periodic Monitoring Protocol for boilers and engines subject to Rules 1146, 1146.1, and 1110.2. The minimum sampling time for diagnostic emission checks is 15 minutes.

Boilers and Process Heaters ≥ 5 MMBtu/hr – Paragraph (g)(1)

This paragraph provides a diagnostic emission check frequency for boilers and process heaters with a rated heat input capacity greater than or equal to 5 MMBtu/hr. If the diagnostic emission check frequency has been reduced to quarterly or every 2,000 unit operating hours, the facility may continue to perform diagnostic emission checks in accordance with that schedule upon rule adoption, until a diagnostic emission check exceeds the applicable limit.

Boilers and Process Heaters > 2 MMBtu/hr and < 5 MMBtu/hr – Paragraph (g)(2)

This paragraph provides a diagnostic emission check frequency for boilers and process heaters with a rated heat input capacity greater than 2 MMBtu/hr and less than 5 MMBtu/hr. If the diagnostic emission check frequency has been reduced to semi-annually or every 4,000 unit operating hours, the facility may continue to perform diagnostic emission checks in accordance with that schedule upon rule adoption, until a diagnostic emission check exceeds the applicable limit.

Diagnostic Emission Check After Emission Exceedance – Paragraph (g)(3)

This paragraph allows for the owner or operator to resolve problems in the event of an emissions exceedance. Any diagnostic emission check conducted by South Coast AQMD staff that finds an emissions exceedance would be a violation.

*Subdivision (h) – Recordkeeping*

This subdivision harmonizes the recordkeeping requirements for the various types of equipment that will be subject to PR 1150.3. PR 1150.3 would additionally require owner or operators to retain maintenance, service, and tuning records. Subdivision (h) would require records to be retained by facility owners and operators for 5 years. Although other source-specific rules contain shorter records retention timeframes, such as 2 years, accumulation of the records would begin upon the date of adoption.

Recordkeeping for Boilers and Process Heaters - Paragraph (h)(1)

Subparagraphs (h)(1)(A) and (h)(1)(B) provide recordkeeping requirements consistent with Rule 429 – Start-Up and Shutdown Exemption Provisions for Oxides of Nitrogen that boilers and process heaters subject to Rule 1146 are currently subject to.

Recordkeeping for Turbines - Paragraph (h)(2)

This paragraph provides recordkeeping requirements for operators of turbines. Records of hours of operation, type of fuel used, fuel consumption and startup and shutdown times are required. The operating log is required to specify the hours of operation at loads less than 60 percent rated output to demonstrate compliance with the requirements of paragraph (d)(3). In addition, this paragraph also requires recordkeeping of emission control system operation and maintenance to verify continuous operation while the turbine is in operation and equipment requirements to verify certain parameters.

Recordkeeping for Units Required to Conduct Source Test - Paragraph (h)(3)

This paragraph requires records of the hours of operation of a unit since any tuning or servicing prior to conducting a source test.

Recordkeeping for Units Required to Conduct Diagnostic Emission Checks - Paragraph (h)(4)

This paragraph requires records of the hours of operation between diagnostic emission checks. The records must contain the date(s) of all: diagnostic emission checks, adjustments to oxygen set points, and exceedances of the applicable emission limit in Table 1.

*Subdivision (i) – Other Requirements*

Prohibition to Derate a Boiler or Process Heater - Paragraph (i)(1)

This paragraph provides a requirement that an owner or operator cannot derate any boiler or process heater to less than or equal 2 MMBtu/hr to circumvent permitting and emissions requirements. This requirement is consistent with current requirements from Rules 1146 and 1146.1.

Non-Resettable Hour Meter - Paragraph (i)(2)

This paragraph requires that an owner or operator of a boiler, process heater, or turbine install and maintain a non-resettable hour meter.

*Subdivision (j) – Schedule for Permit Revisions*

Provides deadlines for permit applications to be submitted for revising equipment permits to reflect PR 1150.3. Facilities would only submit applications for equipment with permits that reference other source specific-rules no longer applicable once PR 1150.3 is adopted. Title V facilities would have until the next Title V permit renewal application is due to submit applications for each piece of equipment subject to PR 1150.3. Non-Title V facilities would submit applications on or before July 1, 2024 for each piece of equipment subject to PR 1150.3.

*Subdivision (k) – Exemptions*

Special Use Turbines - Paragraph (k)(1)

Provides exemption to turbines that are used only for firefighting or flood control. In addition, an exemption from PR 1150.3 requirements is provided for emergency standby turbines, which are defined here as well as in Rule 1134. An owner or operator must maintain an hour meter and an operating log to verify that each emergency standby turbine does not exceed a usage limit of 200 hours per year. If the usage threshold is exceeded, the owner or operator would be required to submit a permit application to meet the applicable compliance limits of PR 1150.3.

Non-Landfill Gas Fired Boilers, Process Heaters, and Turbines < 0.3 MW - Paragraph (k)(2)

Provides an exemption for units permitted to fire only non-landfill gas fuels. Boilers and process heaters at MSW landfills or landfill gas to energy facilities which are not permitted to fire any amount of landfill gas would remain subject to the requirements of the Rule 1146 Series, depending on size (Rules 1146 and 1146.1). Turbines with a rated output less than 0.3 MW which are not permitted to fire any amount of landfill gas would not be subject to PR 1150.3.

# CHAPTER 4: IMPACT ASSESSMENTS

## INTRODUCTION

A total of twenty-one biogas fueled boilers and turbines, at seven facilities, will be affected by PR 1150.3. Three boilers will be retrofitted or replaced to meet 9 ppmv at 3 percent oxygen on a dry basis by January 1, 2030. Four turbines with a rated output ≥ 0.3 MW with post-combustion control will be required to meet 12.5 ppmv NOx at 15 percent oxygen on a dry basis at the time of replacement. All facilities will be required to submit applications to revise permits for each unit subject to PR 1150.3.

## EMISSION REDUCTIONS

PR 1150.3 will result in emission reductions for boilers and for turbines with a rated output ≥ 0.3 MW without post-combustion control. Turbines with a rated output ≥ 0.3 MW with post-combustion control will be required to meet 12.5 ppmv NOx at 15 percent oxygen on a dry basis at the time of replacement. Turbines with a rated output < 0.3 MW will remain at the current permit limit of 9 ppmv NOx at 15 percent oxygen on a dry basis. Baseline emissions were determined using 2017 Annual Emissions Reports (AER).

*Emission Reduction Estimate for Boilers*

The total baseline emissions for one facility impacted by the proposed emission limit are approximately 22,211 pounds per year or 0.03 tons per day. The boiler has a NOx permit limit of 21 ppmv at 3 percent oxygen on a dry basis. The proposed emission limit of 9 ppmv at 3 percent oxygen on a dry basis would reduce NOx by approximately 0.02 ton per day for this boiler.

The baseline emissions for the other facility operating two boilers are approximately 104,031 pounds per year or 0.14 tons per day. These boilers have a NOx permit limit of 24 ppmv at 3 percent oxygen on a dry basis. The proposed emission limit of 9 ppmv at 3 percent oxygen on a dry basis would reduce NOx by approximately 0.09 ton per day for these boilers.

The total emission reductions for boilers is approximately 0.11 ton per day at a proposed emission limit of 9 ppmv at 3 percent oxygen on a dry basis. The proposed limit would become effective on January 1, 2030.

*Emission Reduction Estimate for Turbines ≥ 0.3 MW Without Post-Combustion Control*

The total baseline emissions for one facility operating two turbines impacted by the proposed emission limit are approximately 54,320 pounds per year or 0.07 tons per day. These turbines have a NOx permit limit of 18.75 ppmv at 15 percent oxygen on a dry basis at turbine loads >3000 kW. The baseline emissions for the other facility operating three turbines are approximately 37,718 pounds per year or 0.05 tons per day. These turbines have a NOx permit limit of 18.75 ppmv at 15 percent oxygen on a dry basis at turbine loads >3000 kW. The proposed emission limit of 12.5 ppmv at 15 percent oxygen on a dry basis would become effective upon rule adoption and reduce NOx by approximately 0.04 ton per day.

Both facilities have NOx permit limits of 25 ppmv at 15 percent oxygen on a dry basis when operating at loads ≤ 3000 kW. It is estimated that there will be no emission reductions when these turbines are operating at loads ≤ 3000 kW because PR 1150.3 contains a NOx limit of 25 ppmv at 15 percent oxygen on a dry basis for these turbines while operating at loads of less than 60% rated output.

Total NOx emission reductions from the proposed rule is approximately 0.15 ton per day.

## COST-EFFECTIVENESS

The California Health & Safety Code (H&SC) Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. The cost-effectiveness of a control technology is measured in terms of the control cost in dollars per ton of air pollutant reduced. The costs for the control technology include purchasing, installation, operation, and maintenance of the control technology. Emissions reductions were based on the 2017 AER and the most recent source test data. The 2016 AQMP established a cost-effectiveness threshold of $50,000 per ton of NOx reduced. The cost-effectiveness is estimated based on the present worth value of the control cost, which is calculated according to the capital cost (initial one-time equipment, installation, and startup costs) plus the annual operating cost (recurring expenses over the useful life of the control equipment times a present worth factor). In the cost-effectiveness calculation, staff assumed a uniformed series present worth factor (PWF) at a 4% interest rate and a 25-year equipment life expectancy, unless otherwise noted.

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

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

Staff obtained costs for control equipment from a variety of sources that included facilities and cost-estimation tools. The cost for control equipment considers capital costs and annual costs. Capital costs are one-time costs that cover the components required to assemble a project. These costs include, but are not limited to, equipment, installation, permitting, consulting, and testing. Annual costs are any recurring costs required to operate equipment. These costs include operating and maintenance (O&M) costs such as electricity, monitoring, and costs for consumables. Existing O&M costs are not included in the cost-effectiveness calculation.

### *Boilers*

A cost-effectiveness analysis was conducted for landfill gas fired boilers to meet a NOx concentration limit of 9 ppmv at 3 percent oxygen on a dry basis. Staff referred to the staff report for the December 2018 amendments to the Rule 1146 series for the costs of ultra-low NOx burners that meet a 9 ppmv NOx limit. Equipment costs ranged from $676,600-$1,952,600 depending on the size and the installation costs ranged from $221,300-$595,300 depending on size. Staff assumed a 15 year equipment life. The average cost effectiveness to replace existing burners with a burner that can meet a NOx limit of 9 ppmv at 3 percent oxygen on a dry basis is $24,300 per ton of NOx.

The landfill gas that fuels existing boilers at MSW landfills and landfill gas to energy facilities is declining. As a result, existing landfill gas fired boilers are expected to shut down by January 1, 2030. Staff proposed the 9 ppmv NOx limit to become effective January 1, 2030, to eliminate stranded asset costs. Table 4-1 summarizes the cost-effectiveness to require existing boilers to meet 9 ppmv NOx at 3 percent oxygen on a dry basis.

**TABLE 4-1**
**COST-EFFECTIVENESS FOR PROPOSED BOILER EMISSION LIMITS**

| **Cost-Effectiveness to Meet 9 ppmv NOx at 3 percent oxygen on a dry basis** | |
|---|---|
| Emission Reductions Over 15 Years[1] | Cost-Effectiveness |
| 63 tons (Facility 1) | $14,000 per ton of NOx reduced |
| 348 tons (Facility 2) | $29,300 per ton of NOx reduced |

[1] Reductions calculated as part of the cost-effectiveness determination are based on current concentration emission levels of the turbines as demonstrated in recent source tests.

***Turbines ≥ 0.3 MW***

A cost-effectiveness analysis was conducted for landfill gas fired turbines to meet a NOx concentration limit of 12.5 ppmv at 15 percent oxygen on a dry basis. Existing turbines with post-combustion control cannot meet a 12.5 ppmv NOx limit without enhanced gas cleanup. The estimated capital costs and O&M costs to install a gas cleanup system were obtained South Coast AQMD Biogas Toolkit Cost Estimator. The capital cost was estimated to be approximately $36,164,300 and the O&M cost was estimated to be approximately $9,237,300. The cost effectiveness for a gas cleanup system to meet a NOx limit of 12.5 ppmv at 15 percent oxygen on a dry basis is more than $50,000 per ton of NOx. PR 1150.3 would require all turbines to meet 12.5 ppmv NOx upon turbine replacement. Table 4-2 summarizes the cost-effectiveness to require existing turbines with post-combustion control to meet 12.5 ppmv NOx at 15 percent oxygen on a dry basis.

**TABLE 4-2**
**COST-EFFECTIVENESS FOR PROPOSED TURBINE EMISSION LIMITS**

| **Cost-Effectiveness for Turbines with Post-Combustion Control to Meet 12.5 ppmv at 15 percent oxygen on a dry basis** | |
|---|---|
| Emission Reductions Over 25 Years[1] | Cost-Effectiveness |
| 1194 tons<br>(Facility 3 – turbines with SCR) | $151,100 per ton of NOx reduced |

[1] Reductions calculated as part of the cost-effectiveness determination are based on current concentration emission levels of the turbines as demonstrated in recent source tests.

Existing turbines without post-combustion control can already meet 12.5 ppmv at 15 percent oxygen on a dry basis, as shown by source test results. There is only a one time capital cost for permit revision fees, so a cost-effectiveness analysis was not conducted.

***Summary of Cost-Effectiveness Analysis***

The proposed NOx BARCT emission limit for boilers of 9 ppmv NOx at 3 percent oxygen on a dry basis is proposed to be effective January 1, 2030. The proposed NOx BARCT emission limit for turbines with a rated output equal to or 0.3 MW without post-combustion control (simple cycle turbines) of 12.5 ppmv NOx at 15 percent oxygen on a dry basis is proposed to be effective on or before [Date of Adoption]. A summary of the cost-effectiveness analysis is in Table 4-3.

**TABLE 4-3**
**COST-EFFECTIVENESS ANALYSIS**

| Category | Total Installed Cost (MM) | Annual Cost (MM) | Present Worth Value (MM) | NOx Reductions (tpd) | Cost-Effectiveness ($/ton) |
|---|---|---|---|---|---|
| Boilers and Process Heaters (To meet 9 ppmv) | $11.1 | 0 | $11.1 | 0.11 | $27,000 |

*Permit Revisions*

Permits are required to be revised to reflect PR 1150.3 and to remove the references to former source-specific rules that would no longer apply to these sources under Rule 1150.3. Facilities would incur a one-time cost at the time that permit revisions are required, according to the schedule in subdivision (j) of PR 1150.3. The total combined cost for all facility permit revisions is $33,469.53 Table 4-4 contains the breakdown costs for permit revisions, based on Rule 301 – Permitting and Associated Fees.

**TABLE 4-4**
**PERMIT REVISION COSTS**

| Permit Revision Type | Cost (Non-Title V) | Cost (Title V) |
|---|---|---|
| Title V permit revision (per facility) | N/A | $1,518.26 |
| Administrative Change (per equipment) | $962.75 | $1,206.41 |

*Total Cost-Effectiveness of PR 1150.3*

The cost-effectiveness to implement PR 1150.3 is approximately $27,033 per ton of NOx reduced. Costs include the cost for three boilers at two facilities to meet 9 ppmv NOx at 3 percent oxygen on a dry basis and for five turbines at two facilities to meet 12.5 ppmv NOx at 15 percent oxygen on a dry basis. The costs also include applicable permit revision fees for all units subject to PR 1150.3.

## INCREMENTAL COST-EFFECTIVENESS

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

**Incremental cost-effectiveness is calculated as follows:**

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

Where:

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

The proposed project would require two facilities to meet 9 ppmv NOx at 3 percent oxygen on a dry basis for three boilers. The next progressively more stringent potential control option would be to require boilers and process heaters to meet 5 ppmv NOx at 3 percent oxygen on a dry basis. To meet 5 ppmv NOx, the facilities would be required to implement SCR with gas treatment on their existing boilers.

Incremental cost-effectiveness = ($416,090,656 – $11,096,155) / (955– 411) =
$744,475 per ton of NOx reduced

The proposed project would require two facilities to meet 12.5 ppmv NOx at 15 percent oxygen on a dry basis for five turbines. The next progressively more stringent potential control option would be to require turbines without post-combustion control to meet 2.5 ppmv NOx at 15 percent oxygen on a dry basis. To meet 2.5 ppmv NOx, the facilities would be required to implement SCR with gas treatment on their existing turbines.

Incremental cost-effectiveness = ($220,236,604 – $9,068) / (177 – 0) =
$1,244,223 per ton of NOx reduced

The incremental cost analyses presented above demonstrate that the alternative control options are not viable when compared to the control strategies of the proposed amendments.

## SOCIOECONOMIC ASSESSMENT

A socioeconomic impact assessment will be conducted and released for public review and comment at least 30 days prior to the South Coast AQMD Governing Board Hearing which is anticipated to be heard on February 5, 2021.

## CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) and South Coast AQMD's certified regulatory program (Public Resources Code Section 21080.5, CEQA Guidelines Section 15251(l) and South Coast AQMD Rule 110), the South Coast AQMD, as lead agency, is reviewing the proposed project to determine if it will result in any potential adverse environmental impacts. Appropriate CEQA documentation will be prepared based on the analysis.

## DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

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

*Necessity*
PR 1150.3 is needed to establish NOx and CO emission limits for landfill gas and/or other fuel fired boilers, process heaters, and turbines located at municipal solid waste landfills (MSW landfills) or landfill gas to energy facilities that are representative of BARCT, as well as monitoring, reporting, and recordkeeping requirements.

*Authority*
The South Coast AQMD obtains its authority to adopt, amend, or repeal rules and regulations pursuant to H&SC Sections 39002, 39616, 40000, 40001, 40440, 40702, 40725 through 40728, 40920.6, and 41508.

*Clarity*
PR 1150.3 is written or displayed so that their meaning can be easily understood by the persons directly affected by them.

*Consistency*
PR 1150.3 is in harmony with and not in conflict with or contradictory to, existing statutes, court decisions or state or federal regulations.

*Non-Duplication*
PR 1150.3 will not impose the same requirements as any existing state or federal regulations. The proposed amended rules are necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

*Reference*
In amending these rules, the following statutes which the South Coast AQMD hereby implements, interprets or makes specific are referenced: H&SC Sections 39002, 40001, 40702, 40440(a), and 40725 through 40728.5.

## COMPARATIVE ANALYSIS

Under H&SC Section 40727.2, the South Coast AQMD is required to perform a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing rules from other air quality management districts and/or air pollution control districts, and existing or proposed South Coast AQMD rules and air pollution control requirements and guidelines which are applicable to landfill gas and/or other gaseous fueled turbines and landfill gas fired boilers and process heaters. See Table 4-5 and Table 4-6 below.

**TABLE 4-5**
**PR 1150.3 COMPARATIVE ANALYSIS – BOILERS AND PROCESS HEATERS**

| Rule Element | PR 1150.3 | BAAQMD Regulation 9 Rule 7 | SMAQMD Rule 411 | SJVAPCD Rule 4320 | Equivalent Federal Regulation |
|---|---|---|---|---|---|
| **Applicability** | Located at an MSW landfill or landfill gas to energy facility: Landfill gas and dual fuel boilers and process heaters with a rated heat input capacity greater than 2 MMBtu/hr | Industrial, institutional and commercial boilers, steam generators and process heaters with a rated heat input ≥1 MMBtu/hr. | Units (i.e., boilers, steam generators and process heaters) fired on gaseous or nongaseous fuels with a rated heat input capacity ≥1 MMBtu/hr. | Any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a total rated heat input > 5 million Btu per hour. | None |
| **Requirements** | NOx emission limits @ 3% O2:<br>• Landfill gas - 25 ppmv on or before date of adoption<br>• Landfill gas - 9 ppmv on or before January 1, 2030<br>• Rated heat input capacity < 75 MMBtu/hr and firing other fuel– 9 ppmv on or before date of adoption<br>• Rated heat input capacity ≥ 75 MMBtu/hr and firing other fuel– 5 ppmv on or before date of adoption<br><br>CO Emission limit @ 3% O2: 400 ppmv<br><br>Cannot lower the rated heat input to ≤ 2 MMBtu.hr. Non-resettable hour meter. | Landfill or digester gas NOx emission limit @ 3% O2: 30 ppmv<br><br>CO emission limit @3% O2: 400 ppmv | NOx emission limits @ 3% O2:<br>• ≥ 1 and <5 MMBtu/hr input – 30 ppmvd<br>• ≥5 MMBtu/hr input and fired on landfill gas or a combination of landfill gas and natural gas – 15 ppmvd<br><br>CO emission limits @ 3% O2: 400 ppmvd | NOx emission limits @3% O2:<br>• > 5 MMBtu/hr to ≤ 20 MMBtu/hr – 9 ppmv standard schedule, 6 ppmv enhanced schedule<br>• > 20 MMBtu/hr – 7 ppmv standard schedule, 5 ppmv enhanced schedule<br>CO emission limit @3% O2: 400 ppmv | None |
| **Reporting** | Annual emissions reporting and source testing. CEMS data every six months (Rule 218). | None | Annual tune-up verification report or verification of inactivity for low fuel usage units. | None | None |
| **Monitoring** | A continuous in-stack NOx monitor. Rated heat input capacity > 40 MMBtu/hr and an annual heat input > 200 x | None | Accuracy testing once every calendar year for units with CEMS. Source testing: | CEMS or approved monitoring system. Source testing once | None |

| | | | | | |
|---|---|---|---|---|---|
| | 109 Btu per year. Source testing every 3-5 years. | | • > 20 MMBtu/hr – once every calendar year<br>• ≥ 5 but <20 MMBtu/hr – once every second calendar year | every 12 months. | |
| **Recordkeeping** | Monitoring data including CEMS, source tests, and diagnostic emission checks. Records of maintenance, service, tuning, startup and shutdown. Source test and diagnostic emission check required records. Records must be kept for 5 years. | Tune-ups and operating log for 24 months. | Monitoring data including CEMS, source tests, and portable analyzer checks for five years | Startup and shutdown for five years. | None |

**TABLE 4-6**
**PR 1150.3 COMPARATIVE ANALYSIS – TURBINES**

| Rule Element | PR 1150.3 | BAAQMD Regulation 9 Rule 9 | SMAQMD Rule 413 | SJVAPCD Rule 4703 | 40 CFR Part 60 GG | 40 CFR Part 60 KKKK |
|---|---|---|---|---|---|---|
| **Applicability** | Located at an MSW landfill or landfill gas to energy facility: landfill gas and dual fuel turbines with a rated output <0.3 MW and landfill gas, dual fuel, and other gaseous fuel turbines with a rated output ≥3 MW. | Stationary gas turbines with a heat input rating ≥ 5 MMBtu/hr | Stationary gas turbines with ratings equal to or greater than 0.3 megawatt (MW) output, or 3 MMBTU/hr input and operated on gaseous and/or liquid fuel. | Stationary gas turbines with ratings equal to or greater than 0.3 megawatt (MW) or a maximum heat input rating of more than 3,000,000 Btu per hour. | Gas turbines with heat input of ≥ 10 MMBtu/hr that commenced construction, modification or re-construction on or before 2/18/2005 | Gas turbines with heat input of ≥ 10 MMBtu/hr that commenced construction, modification or re-construction after 2/18/2005 |
| **Requirements** | NOx emission limits @ 15% O2:<br>• < 0.3 MW firing landfill gas, landfill gas with other gaseous fuel, or other gaseous fuel- 9 ppmv on or before date of adoption<br>• ≥ 3 MW with post-combustion control and firing 75% landfill gas or more – 25 ppmv on or before date of adoption<br>• ≥ 3 MW without post-combustion control and firing 75% landfill gas or more– 12.5 ppmv on or before date of adoption | General NOx emission limits (@ 15% O2) for refinery fuel gas, waste gas or LPG:<br>• < 5 MMBtu/hr- Exempt<br>• 5 – 50 MMBtu/hr – 2.53 lbs./MWhr or 50 ppmv<br>• > 50 – 150 MMBtu/hr – 2.34 lbs/MWhr or 50 ppmv<br>• > 150 – 250 MMBtu/hr – 0.70 lbs/MWhr or 15 ppmv | NOx emission limits (@ 15% O2) for gaseous fuel:<br>• ≥ 0.3 to < 2.9 MW – 42 ppmv<br>• ≥ 2.9 MW (operating < 877 hr/yr) – 42 ppmv<br>• ≥ 2.9 to < 10 MW (operating ≥ 877 hr/yr) – 25 ppmv<br>• ≥ 10 MW (no SCR, operating ≥ 877 hr/yr) – 15 ppmv | NOx emission limits (@ 15% O2) for gas fuel:<br>• < 3 MW – 9 ppmvd<br>• 3 – 10 MW pipeline gas turbine – 8 ppmvd during steady state and 12 ppmvd during non-steady state<br>• 3 – 10 MW (operating < 877 hrs/yr, not listed | NOx limit @ 15% O2, where Y = Manufacture's rated heat input and F = NOx emission allowance for fuel-bound nitrogen:<br>• 0.0075* (14.4/Y) +F<br>•0.0150* (14.4/Y) +F<br><br>SO2 limit @15% O2:<br>• 0.015% by volume | NOx limit @ 15% O2:<br>• ≤ 50 MMBtu/hr - 42 ppm new, firing natural gas, electric generating<br>• ≤ 50 MMBtu – 100 ppm new, firing natural gas, mechanical drive<br>• > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 25 ppm new, firing natural gas |

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| | • ≥ 3 MW and firing 75% landfill gas or more – 12.5 upon turbine replacement<br>• Combined cycle ≥ 3 MW and firing 100% natural gas or other gaseous fuel, excluding landfill gas – 2 ppmv on or before date of adoption<br>• Simple cycle ≥ 0.3 MW and firing 100% natural gas or other gaseous fuel, excluding landfill gas– 2.5 ppmv on or before date of adoption<br><br>Dual fuel turbine simultaneously firing landfill gas and more than 25 percent but less than 100 percent natural gas or other gaseous fuel, based on the total heat input on a rolling 12-month basis:<br>Weighted Limit= $\frac{(CL_A \text{ x } Q_A \text{ x } V_A) + (CL_B \text{ x } Q_B \text{ x } V_B)}{(Q_A \text{ x } V_A) + (Q_B \text{ x } V_B)}$<br><br>Where:<br>$CL_A$ = compliance limit in Table 1 when firing 75% landfill gas or more<br>$Q_A$ = higher heating value of landfill gas in Btu per standard cubic foot (scf)<br>$V_A$ = flow rate of landfill gas in scf per unit of time<br>$CL_B$ = compliance limit in Table 1 when firing 100% natural gas or other gaseous fuel<br>$Q_B$ = higher heating value of natural gas in Btu per scf or other gaseous fuel<br>$V_B$ = flow rate of natural gas in scf per unit of time or other gaseous fuel<br><br>CO emission limit @15% O2: 130 ppm | • > 250 – 500 MMBtu/hr – 0.43 lbs/MWhr or 9 ppmv<br>• > 500 MMBtu/hr – 0.26 lbs/MWhr or 9 ppmv<br><br>General NOx emission limits (@ 15% O2) for natural gas:<br>• < 5 MMBtu/hr- Exempt<br>• 5 – 50 MMBtu/hr - 2.12 lbs/MWhr or 42 ppmv<br>• > 50 – 150 MMBtu/hr (no retrofit available) – 1.97 lbs/MWhr or 42 ppmv<br>• > 50 – 150 MMBtu/hr (WI/SI enhancement available) – 1.64 lbs/MWhr or 35 ppmv<br>• > 50 – 150 MMBtu/hr (DLN technology available) – 1.17 lbs/MWhr or 25 ppmv<br>• > 150 – 250 MMBtu/hr – 0.70 lbs/MWhr or 15 ppmv<br>• > 250 – 500 MMBtu/hr – 0.43 lbs/MWhr or 9 ppmv<br>• > 500 MMBtu/hr – 0.15 lbs/MWhr or 5 ppmv<br><br>Low usage NOx emission limits (@ 15% O2) for refinery fuel gas, waste gas or LPG: | • ≥ 10 MW (with SCR, operating ≥ 877 hr/yr) – 9 ppmv | above) – 9 ppmvd<br>• 3 – 10 MW (operating ≥ 877 hrs/yr, not listed above) – 5 ppmvd<br>• > 10 MW (simple cycle, operating < 200 hrs/yr, except as provided in Section 5.1.3.3) – 25 ppmvd<br>• > 10 MW (simple cycle, operating >200 but no greater than 877 hrs/yr) – 5 ppmvd<br><br>CO emission limits @15% O2:<br>• Units not identified below – 200 ppmv<br>• General Electric Frame 7 – 25 ppmv<br>• General Electric Frame 7 with Quiet Combustors – 52 ppmv<br>• < 2 MW Solar Saturn gas turbine powering centrifugal compressor – 250 ppmv | | • >850 MMBtu/hr – 15 ppm new, modified, or reconstructed, firing natural gas<br>• ≤ 50 MMBtu/hr – 96 ppm new, firing fuels other than natural gas, electric generating<br>• ≤ 50 MMBtu/hr – 150 ppm new, firing fuels other than natural gas, mechanical drive<br>• > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 74 ppm new, firing fuels other than natural gas<br>• >850 MMBtu/hr – 42 ppm new, modified, or reconstructed, firing fuels other than natural gas<br>• ≤ 50 MMBtu/hr – 150 ppm modified or reconstructed<br>• > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 42 ppm modified or reconstructed, firing natural gas<br>• > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 96 ppm modified or |

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| | Non-resettable hour meter. | • < 50 MMBtu/hr – exempt<br>• 50 - > 500 MMBtu/hr – N/A<br><br>Low usage NOx emission limits (@ 15% O2) for natural gas:<br>• < 50 MMBtu/hr – exempt<br>• 50 – 250 MMBtu/hr – 1.97 lbs/MWhr or 42 ppmv<br>• > 250 – 500 MMBtu/hr – 1.17 lbs/MWhr or 25 ppmv<br>• > 500 MMBtu/hr – 0.72 lbs/MWhr or 25 ppmv | | | | reconstructed, firing fuels other than natural gas<br><br>SO2 limit:<br>• 110 ng/J<br>• 65 ng/J for turbines burning at least 50% biogas in a calendar month |
| **Reporting** | Annual emissions reporting and source testing. CEMS data every six months (Rule 218). | Source testing | None | Source testing | Semi-annual reports of excess emissions and monitor downtime | Semi-annual reports of excess emissions and monitor downtime. Annual performance test results. |
| **Monitoring** | A continuous in-stack NOx monitor for turbines with a capacity of 2.9 MW or greater. Periodic source testing. | A continuous in-stack NOx monitor for turbines with a heat input rating equal to or greater than 150 MMBtu/hr and operate for more than 4000 hours in any 36-month period. Source test at least once per calendar year, not to exceed 15 months, for turbines that operate more than 400 hours in any 12-month period and is not equipped with | Equipment which monitors control system operating parameters, elapsed time of operation, and continuous exhaust gas NOx concentrations for turbines with a rated output ≥ 10 MW and operated for more than 4000 hours in any one calendar year during | Continuous emissions monitoring equipment for NOx and CO or monitoring of operational characteristics recommended by the turbine manufacturer of emission control system supplier. Exhaust gas NOx emissions monitoring system for turbines 10 | A continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel or CEMS for stationary gas turbines using water or steam injection. Monitor the total sulfur content of the fuel being fired. | A continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel or continuous emission monitoring for stationary gas turbines using water or steam injection. Annual performance tests or continuous |

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| | | a continuous monitor. Source test every two calendar years, not to exceed 25 months, for turbines that operate 400 hours or less in any 12 month period. | the three years before April 6, 1995. Equipment which monitors control system operating parameters and elapsed time of operation for turbines with a rated output < 10 MW. Annual source testing. | MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994. Annual source testing except for turbines operated < 877 hrs/yr, which are to be source tested biennially. | | monitoring for turbines without water or steam injection. Monitor the total sulfur content of the fuel being fired. |
| **Recordkeeping** | Monitoring data including CEMS data, source tests, diagnostic emission checks, and an operating log. Maintenance, service, and tuning records. Records to demonstrate compliance with source test requirements. Required records must be maintained for 5 years. | Daily operating log for low-usage exemption maintained for two years. Records of fuel consumption, output, and flow rates if using NOx limits expressed in lbs/MWhr. | Permit number, manufacturer, model, rating in MW, actual startup and shutdown time, daily hours of operation, cumulative hours of operation to date for the calendar year, actual daily fuel usage, emission test results, and maintenance records for two years. Additional records of exemptions. | Operating log, start-up and shutdown records, records of each bypass transition period and primary re-ignition period maintained for five years | Performance testing; emission rates; monitoring data; CEMS audits and checks | Performance testing; emission rates; monitoring data; CEMS audits and checks |
| **Fuel Restrictions** | Liquid fuel | None | None | None | None | None |