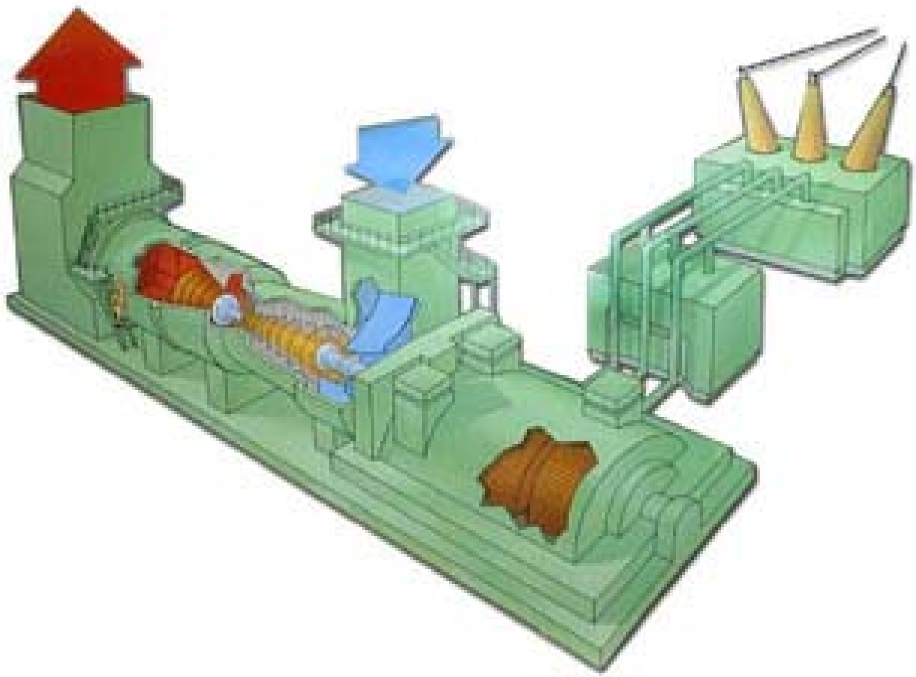
Bay Area Air Quality Management District

939 Ellis Street
San Francisco, CA 94109

Bay Area Ozone Strategy
Control Measure SS 14

BAAQMD Regulation 9, Rule 9:
Nitrogen Oxides from Stationary Gas Turbines



Workshop Report
April 26, 2006

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REGULATION 9, RULE 9

Nitrogen Oxides from Stationary Gas Turbines

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I. INTRODUCTION

This Workshop Report provides background information for the accompanying draft amendments to Bay Area Air Quality Management District (BAAQMD or District) Regulation 9, Rule 9: Nitrogen Oxides from Stationary Gas Turbines. The District is considering adopting amendments to Regulation 9, Rule 9 in connection with Control Measure SS-14 in the District's 2005 Ozone Strategy. In Control Measure SS-14, the District committed to evaluate emissions of nitrogen oxides (NOx) from stationary gas turbines and determine if recent advances in NOx emissions control technology could be implemented to further reduce NOx emissions from the stationary gas turbines in the Bay Area. District staff has prepared this Report and the accompanying draft amendments for purposes of convening a public workshop to seek input from interested parties about how further NOx emissions reductions from this source category could best be achieved.

Stationary gas turbines are internal combustion engines, typically powered by natural gas, used to generate electricity or mechanical power. An example is shown in Figure 1. Regulation 9, Rule 9 governs NOx emissions from stationary gas turbines. The rule was first adopted in 1993, and amended in 1994. The rule was based primarily on Reasonably Available Control Technology (RACT) and Best Available Retrofit Control Technology (BARCT) guidelines developed by the California Air Resources Board (ARB) in 1992. Several other air districts in California adopted similar regulations.

Since that time, there have been improvements in turbine emission control devices. In 1999, ARB published "Guidance for Power Plant Siting and Best Available Control Technology" which identified possible controls for new, large (> 50 Mega Watt [MW]) power generating turbines. The San Joaquin Valley Air Pollution Control District has recently updated its stationary gas turbine rule, and it is currently the most stringent rule in place in California. This report discusses the feasibility of amending Regulation 9, Rule 9 with more stringent NOx limits.

Figure 1. Typical view of a simple cycle gas turbine power generator

A. Rule Overview

The objective of the amendments being considered for Regulation 9, Rule 9 is to further reduce NOx emissions from stationary gas turbines in order to reduce ozone levels in the Bay Area and reduce transport of air pollutants to neighboring air basins. The Bay Area and neighboring regions are not yet in attainment with the State one-hour ozone standard, so further reductions in ozone precursors, NOx and reactive organic gases (ROG) are needed. Additional NOx reductions can be achieved by taking advantage of improvements in Dry Low NOx (DLN) combustion technology, and improvements in the performance of Selective Catalytic Reduction (SCR) catalysts that have occurred since this rule was last amended in 1994. Best Available Control Technology (BACT) can now achieve 2 – 2.5 parts per million (ppm) NOx from combined cycle or cogeneration gas turbine trains, and less than 5 ppm NOx from simple gas turbine configurations. Carbon monoxide (CO) emissions are generally controlled by the good combustion practices required to achieve the NOx standards.

The current rule establishes three levels* for NOx emissions:

Small and mid-sized gas turbines (<10MW)	42 ppm NOx
Large gas turbines (>10MW) without an SCR	15 ppm NOx
Large gas turbines (>10MW) with an SCR	9 ppm NOx

Note: NOx is measured in volumetric ppm, dry basis at 15% O_2.
* Higher limits are provided for certain circumstances such as standby/backup turbines and those burning refinery or landfill gas, or liquid fuels.

B. Current Population of Stationary Gas Turbines

Staff has identified 155 permitted turbines in the District. These units cover a wide range of sizes, fuels (natural gas, refinery or waste gas, or liquid fuels), operating configurations (simple cycle or combined cycle), operating modes (continuous, intermittent, or emergency standby), and existing NOx limits. These turbines currently emit an estimated 6.5 tons/day of NOx. These estimated emissions were calculated based on a review of each permitted turbine's current fuel use, permit conditions, and source tests.

The District's emissions inventory contains three source categories that include stationary gas turbines. They are Cogeneration turbines, Power Plant turbines, and Turbines (which include the gas turbines located in oil refineries). Cogeneration and Power Plant turbines are included in this evaluation, although they were not included in the Ozone Strategy Control Measure SS-14 discussion of emissions subject to control. For this reason, the total emissions subject to control identified in this report are greater than suggested in the Ozone Strategy.

C. Control Requirements Being Considered

The District is contemplating reducing the NOx emission standards for each class of gas turbine to the levels set forth below, to take effect on July 1, 2008:

Small gas turbines (<3 MW)	42 ppm NOx
Mid-sized gas turbines (3-10 MW) if DLN combustion technology is commercially available	25 ppm NOx
Mid-sized gas turbines (3-10 MW) if DLN combustion technology is NOT commercially available	35 ppm NOx
Large gas turbines (>10 MW)	5 ppm NOx

Emission standards would also be reduced for turbines burning refinery fuel gas and waste gas, and for limited use (testing and emergency/standby) turbines used less than 877 hours per year, as set forth in Appendix C and the draft Amendments.

Current technology is capable of reducing NOx emissions by an estimated 1.8 tons/day. District staff estimates that two thirds of these reductions will prove to be practical, reducing NOx emissions by approximately 1.2 tons/day (subject to further investigation).

D. Industry Impact

The District is not contemplating any changes to the rule's current exemptions. Small gas turbines and emergency / standby turbines would be largely unaffected. Mid-sized turbines would require DLN combustion technology retrofits or upgrades in their steam or water injection systems to meet the more stringent NOx emission limits. All large gas turbines that operate continuously would require SCR's. Units with existing SCR's would likely be able to make minor alterations to achieve the required emissions limits. Units without an existing SCR would require installation of an SCR and associated ammonia transportation, storage, injection and control equipment. Large gas turbines that operate intermittently will require enhanced steam or water injection, or possibly a high temperature SCR, to achieve the required emissions limits. Further detailed cost estimates must be developed to ensure that these improvements are practical.

II. BACKGROUND

Ozone is the principal component of smog. Ozone is highly reactive, and at high concentrations near ground level can be harmful to public health. Ozone forms when NOx chemically reacts with ROG. Ozone formation is higher in the summer when warm temperatures and strong sunlight facilitate the reaction. The San Francisco Bay Area air basin – consisting of all of Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo and Santa Clara counties, and the southern portions of Solano and Sonoma counties – periodically experiences high ozone levels. In addition, ARB has determined that the Bay Area sometimes transports ozone and ozone precursors into other northern California air basins. The Bay Area 2005 Ozone Strategy continues on-going Bay Area efforts to reduce ozone precursors in order to assure that the region attains and maintains compliance with health-based ozone standards and to reduce transport to neighboring regions. Amending Regulation 9, Rule 9 is one element of the 2005 Ozone Strategy.

The Bay Area is also not in attainment for the California standards for particulate matter (both 10 microns in size and smaller [PM_{10}], and 2.5 microns and smaller [$PM_{2.5}$]). In the winter months, cold air can cause NOx and ROG emissions to produce secondary $PM_{2.5}$ in the form of nitrates and elemental carbon. NOx reductions will have the added benefit of reducing secondary $PM_{2.5}$ formation.

A. Industry Description

District staff has identified 155 permitted gas turbines in the Bay Area. Ninety two turbines operate continuously in a wide variety of applications. Forty three of these turbines are large, greater than 10 MW capacity, with ten of them already achieving BACT levels of NOx emissions (<2.5 ppm). Eight currently meet 5 ppm NOx limits. Another ten large turbines currently meet 9-10 ppm limits using SCR, and emissions reductions achieved by requiring them to achieve a 5 ppm limit are likely to be relatively minor. Thirteen are mid-sized turbines, ranging from 3 to 10 MW capacity, with 2 of them already achieving 5 ppm NOx. Thirty six gas turbines are small, less than 3 MW, and don't generate enough NOx to be good candidates for any significant reductions. Figure 2 shows an example of a large gas turbine.

Figure 2: Scale view of a large gas turbine

Of the continuously operating turbines, nine large and six mid-sized gas turbine power trains burn refinery fuel or waste gas as their primary fuel. Two large turbines burn diesel fuel. Refinery fuel gas, waste gas, and liquid fuels generate more NOx because it is more difficult to control turbine flame temperatures when burning a mixture of gases or liquids. There has been very little technology development effort to improve NOx performance from gas turbines burning gas or liquid mixtures, so significant improvements from these gas turbines are not currently feasible.

Fifteen turbines operate intermittently as peaking power turbines. In spite of their low utilization, the largest of these intermittent use turbines may still be good candidates for NOx reductions. Forty eight turbines operate on a limited use basis, less than 877 hours per year. Eleven are used for testing and research, and 37 are used for standby/emergency power. Most of these turbines only operate a few hours each week, or are tested monthly.

A summary of the existing gas turbines is shown in Appendix A.

B. Regulatory History

The 1988 California Clean Air Act (CCAA) set the overall air quality planning requirements statewide. The CCAA requires the District to adopt BARCT for existing permitted stationary sources.

The California ARB, in coordination with local air districts, developed a guidance document in 1992 entitled "Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for the Control of Oxides of Nitrogen from Stationary Gas Turbines" to aid local districts with the adoption of NOx regulations. The RACT/BARCT Guidelines included a suggested NOx control rule for air districts to use in developing their respective BARCT rules for the control of NOx from gas turbines. The District used this ARB guideline as a template for Regulation 9, Rule 9.

Regulation 9, Rule 9 was adopted pursuant to the region's first plan prepared under the CCAA's ozone planning requirements, the Bay Area 1991 Clean Air Plan (CAP). Regulation 9, Rule 9 was adopted on May 5, 1993, and amended on September 21, 1994 to accommodate a delay in development of DLN combustion technology necessary to meet the NOx standards. By January 1, 1997 all gas turbines subject to the regulation were required to be in compliance with all applicable standards.

The current rule contains the following exemptions and emission limits:

Exemptions

- Testing of aircraft gas turbine engines for flight certification.
- Gas turbines used exclusively for fire fighting and/or flood control.
- Laboratory turbines used exclusively in turbine technology research.
- Small turbines under 0.3 MW (or under 4.0 MW for backup/standby turbines used less

than 877 hours/year).

- Emission limits do not apply during startup, shutdown, or inspection and maintenance periods.

Emission limits

For clarity, Table 1 shows only the general emissions limits (all limits shown are ppm by volume dry, corrected to 15% O_2):

Table 1: Current Regulation 9, Rule 9 Emissions Limits

Turbine Size / Hours of Operation	NOx ppm		
	Gas	**Refinery Gas**	**Oil**
> 0.3MW and < 10.0MW and > 877 hr/yr	42	55	65
> 4MW and < 877 hr/yr	42		65
Existing Low NOx gas turbines (installed before May, 1993)	18		42
> 10MW and > 877 hr/yr, without SCR	15 x EFF/25*		42 x EFF/25*
> 10MW and > 877 hr/yr, with SCR	9 x EFF/25*		25 x EFF/25*

* requirements are adjusted for actual thermal efficiency compared to 25% design efficiency.

Some of the District's emission standards are based on the turbines' thermal efficiency (EFF) by providing adjustments in emission standards for the more efficient units. More efficient units use less fuel, resulting in less total emissions. In addition, special provisions were included to adopt immediate Reasonably Available Control Technology (RACT) standards, and to accommodate turbines equipped with then-current BACT permitted before May, 1993.

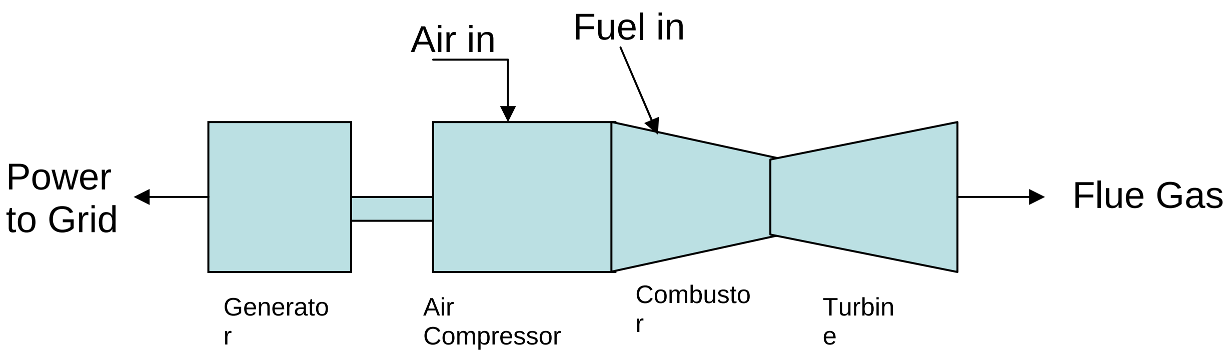
III. TECHNICAL REVIEW

A. Process Operation

A gas turbine is an internal combustion engine which consists of a compressor, a combustor and a power turbine. The compressor provides pressurized air to the combustor where the fuel is burned. Hot exhaust gases enter the power turbine where the gases expand across the turbine blades, driving one or more shafts to power the compressor and an electric generator or other device. Stationary gas turbines are generally used to generate electricity, although some are designed to compress gases or pump water. Gas turbines can be designed in two configurations.

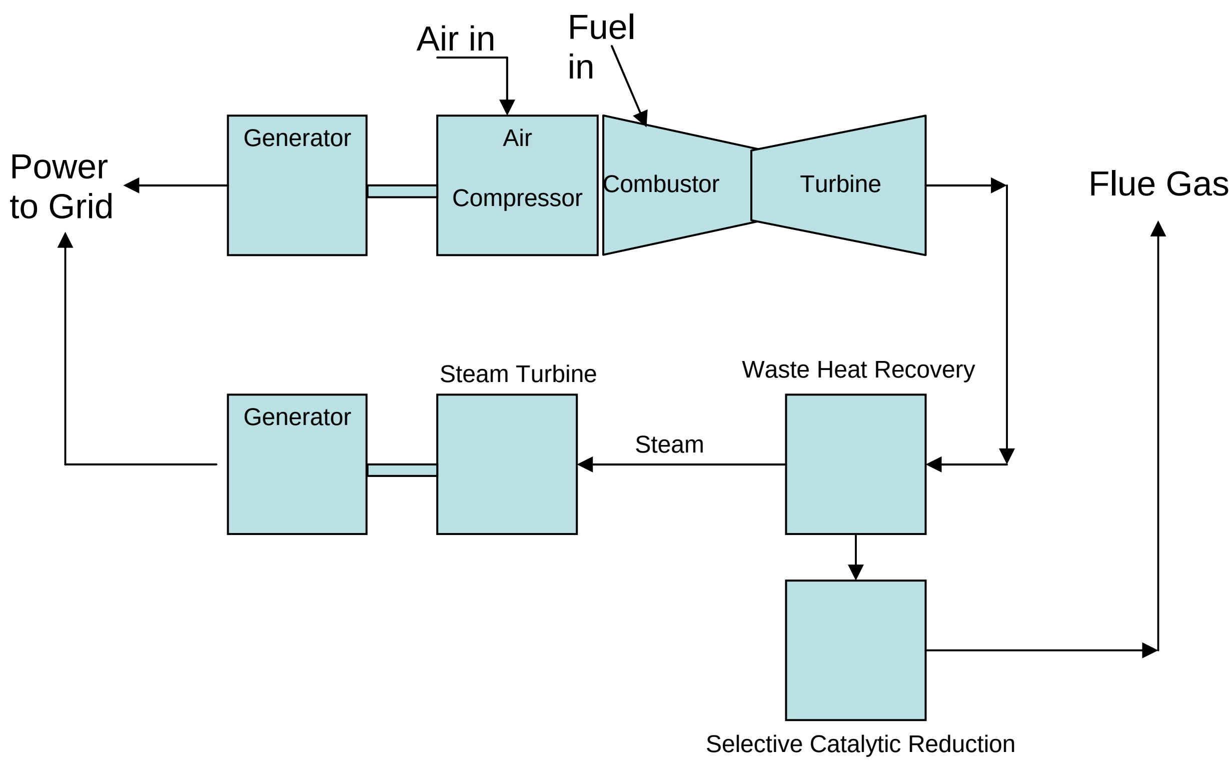
- Simple cycle gas turbines do not recover secondary heat from the hot combustion gases for additional electrical or steam productivity, and therefore have a thermal efficiency between 25 and 41%. Simple cycle gas turbines have flue gas exhaust temperatures of 700 – 900°F. These gas turbines are generally used to supplement electricity during "peak" electrical demand periods, and are commonly referred to as "peaking" power turbines. Figure 3 is a schematic diagram of a simple cycle gas turbine.

Figure 3: Simple Cycle Gas Turbine



- Combined cycle or cogeneration gas turbines recover the "waste heat" in the flue gas stream to produce additional electricity or steam for use within an industrial plant. Cogeneration plants have a thermal efficiency of 45 to 52% and flue gas exhaust temperatures of 300 – 500°F. These gas turbines are generally used for base load electrical generation. Figure 4 is a schematic diagram of a combined cycle gas turbine.

Figure 4: Combined Cycle (Cogen) Gas Turbine



There are two major types of gas turbines. Industrial gas turbines, which evolved from aircraft jet engines, are generally more durable and powerful than aeroderivatives. Aeroderivatives are aircraft jet engines used in ground installations. Aeroderivatives are lightweight, compact and less powerful than industrial gas turbines. However, aeroderivatives operate at higher compression ratios and thus are more efficient than industrial gas turbines. Figure 5 shows a cutaway view of a typical gas turbine.

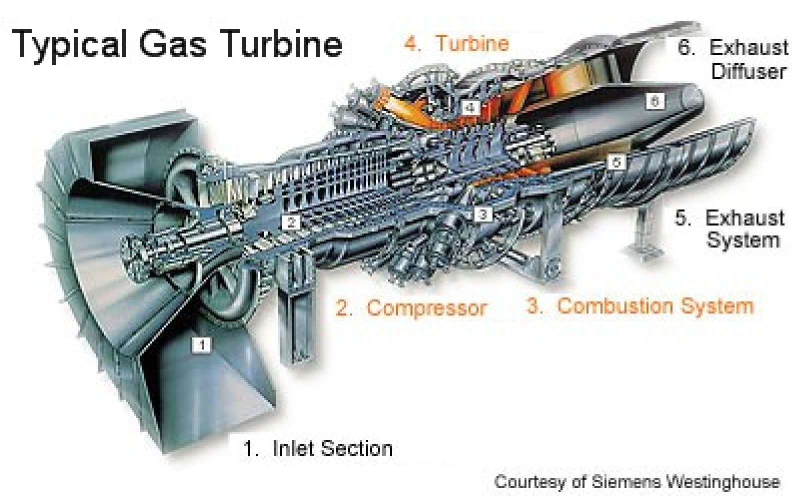


Figure 5: Cutaway view of a typical gas turbine

B. Emissions

Emissions from stationary gas turbines include all the products of combustion. The primary concern with emissions from gas turbines in the Bay Area is NOx. Gas turbines also produce minor amounts of CO, sulfur oxides (SOx), ROG, and particulates (PM), but the contribution from gas turbines for each is relatively insignificant in the total emission inventory for the Bay Area. Combustion in a stationary gas turbine also produces carbon dioxide (CO_2), a growing concern with respect to climate change.

NOx is formed from combustion of nitrogen in the fuel (fuel NOx), but the primary source of NOx is from the oxidation of nitrogen in the air (thermal NOx). Most gas turbines in the Bay Area burn only natural gas, which is negligible in nitrogen content. A few gas turbines can also burn liquid fuels (propane, butane, jet fuel or diesel fuel), but the nitrogen content in these fuels is very low.

CO comes from incomplete combustion. CO limits are normally included as a District permit condition for each turbine. Lean premix combustion design generates excellent combustion efficiency – CO emissions are typically 10 – 50 ppm from natural gas, and 20 – 50 ppm from diesel fuel. The District is not considering any action with respect to CO limits as part of possible amendments to Regulation 9, Rule 9. ROG emissions are also controlled by excellent combustion efficiency, so no standard is recommended. Particulates are generated by trace non-combustible constituents in the fuel. PM emissions are negligible when natural gas is burned. PM emissions are only marginally significant with distillate fuels. The District is not contemplating regulatory action with respect to ROG or PM as part of possible amendments to Regulation 9, Rule 9.

C. Means for Controlling Emissions

There are two basic approaches for reducing NOx emissions: 1) minimize NOx generated during combustion; and 2) treat exhaust gases with various agents to reduce the NOx therein. The primary means for controlling generation of NOx emissions is to prevent NOx formation by cooling the flame temperature inside the combustion chamber in the gas turbine. In the earliest efforts to reduce combustion emissions, steam or water was injected into the combustor to absorb heat and cool the peak combustion temperature. A more recent approach is to regulate the flow of fuel into the combustor and thoroughly mix the fuel with the air using Dry Low NOx (DLN) combustion technology to reduce combustion temperatures. Most manufacturers have developed DLN technology for their new gas turbines, but offer retrofit DLN on only select models of their older gas turbines. A few manufacturers have incorporated catalysts into their combustor designs to achieve complete combustion at even lower flame temperatures.

The primary means to treat NOx emissions after they are created is by chemically reacting the NOx with ammonia or urea in the presence of a catalyst to convert the NOx back into nitrogen. This process is referred to as Selective Catalytic Reduction (SCR). This technology has demonstrated 90 - 95% effectiveness in reducing NOx. A new means of treating the NOx in the flue gas, called SCONOX, has been developed in the last five years. It uses a catalyst to absorb the NOx, CO, and SOx from the flue gas. The catalyst is then regenerated, recycling the pollutants back to the inlet of the gas turbine. More complete discussions of each of the control technologies are available in Appendix B.

IV. RULE AMENDMENTS BEING CONSIDERED

The District is contemplating amendments to Regulation 9-9 to provide the maximum feasible reduction of NOx and to reduce ground level ozone in the Bay Area and neighboring air basins during the summer months. These standards reflect best technology advancements since this rule was last amended. Implementation of proposed standards would reduce NOx emissions by an estimated 1.2 tons / day. This represents an 18% reduction in daily NOx from gas turbines.

A. New Emission Control Requirements

The District is considering reducing NOx emissions limits for large (10 MW+) gas turbines to 5 ppm from 15 ppm for gas turbines without SCR's, and from 9 ppm for gas turbines with SCR's. The District is considering reducing NOx emissions limits from mid-size (3 – 10 MW) gas turbines from 42 ppm to 35 ppm for turbines where DLN technology is not available, and to 25 ppm for turbines with DLN technology available. The District intends to retain the current NOx emission limits as interim standards until new standards come into effect. The limits set forth in Table 2 are identified as BARCT limits and are based on currently available and demonstrated retrofit control devices. The District is not contemplating any changes to the exemptions in the current regulation.

Recently established BACT for small and mid-sized (<10 MW) turbines and limited use peak power generation units recognizes that they are usually simple-cycle units with lower annual emissions than the larger cogeneration facilities. Very low emission standards for small and mid-sized turbines are more difficult to justify. In addition, these units are often used as distributed power generators in space-constrained locations, and may not physically have the room to add a large SCR system to an existing unit. The BARCT limits the District is considering reflect these constraints.

BACT limits for large, combined-cycle turbines apply to new turbines, designed as cleaner-burning units. Applying the same controls to older, less-efficient units can not produce the same level of control. Therefore, the retrofit standards the District is considering are less stringent than those found in the BACT guidelines.

The District is considering a July 1, 2008 effective date for these new emission limits. June 30, 2007 would be the deadline for each facility to submit to the District what actions are planned to bring their facility into compliance. December 31, 2006 would be the deadline to determine whether DLN combustion technology is commercially available for any specific turbine. This timeframe should provide DLN combustion technology manufacturers adequate time to finalize demonstration of any viable DLN combustion technology products and still allow operators sufficient time to plan and carryout the DLN retrofit.

District staff is considering the standards for NOx emissions summarized in Table 2.

Table 2: Proposed Regulation 9, Rule 9 Emission Limits

Turbine Size / Hours of Operation	NOx ppm		
	Natural Gas Fuel	**Refinery Gas**	**Liquid Fuel**
< 0.3 MW	Exempt	Exempt	Exempt
0.3 - 4.0 MW, < 877 hours / year	Exempt	Exempt	Exempt
0.3 – 3.0 MW, > 877 hours / year	42*	55*	65*
3 – 10 MW if DLN combustion technology is commercially available, > 877 hours / year	25	45	65*
3 – 10 MW if DLN combustion technology is not available, > 877 hours / year	35	50	65*
4 - 10 MW, < 877 hours / year	42*	N/A	65*
> 10 MW, < 877 hours / year	25	N/A	42
10+ MW, > 877 hours / year	5	N/A	25

* current limits

Several other California air districts have rules for the control of turbine emissions. The standards under consideration by the District are as stringent as, or more stringent than, any within the State, with the exception of the standards set in the San Joaquin Valley Air Pollution Control District (Rule 4703) for those facilities that choose to delay compliance for an additional three years, or until their next major overhaul. The standards set by the San Joaquin district for delayed compliance represent BACT, rather than BARCT. BARCT is the basis for the standards that the District is considering for existing turbines in the Bay Area. BACT standards apply to new and modified facilities, and are not necessarily applicable to retrofits of existing units.

B. Special Considerations

The following considerations influenced the development of the proposed emission limits.

Small Gas Turbines: For the units rated less than 3 MW, staff is not contemplating any changes to the existing emission limits. These units provide little or no opportunity for significant NOx reductions.

Mid-size Gas Turbines: For the units rated 3 - 10 MW, staff is considering emission limits comparable to those achievable by DLN combustion technology (25 ppm). If a DLN combustion technology system (i.e. a retrofit package for an older unit) is not available, staff is considering emissions limits comparable with a water or steam injection system (35 ppm).

Other districts have established a 25 ppmvd NOx BARCT level for turbines rated between 2.9 and 10 MW. Based on current technology, this can be achieved only with DLN combustion technology systems or SCR. Since SCR may not be feasible at all locations, the 25 ppm limit would only apply to units which for which DLN combustion technology is commercially available.

The DLN combustion technology systems are not available for all existing units, and some that are available may not meet the required emission limit. To avoid requiring a DLN combustion technology system when water injection would provide greater emission reductions at lower costs, a definition for "commercially available" would be included in the rule. The definition of "commercial availability" requires that a DLN combustion technology retrofit system be offered by at least one vendor and guaranteed to achieve the required emission control performance. Some DLN systems may be available for a given unit, but not guaranteed to meet the required emission level. Such equipment would not be considered to be "commercially available" for the purposes of this rule. A date of December 31, 2006 is suggested as a deadline to determine "commercial availability".

Future development of DLN combustion technology may occur for some existing turbines in the Bay Area. If so, operators would be required to meet the more stringent emission limits within two years of the time the DLN combustion technology becomes commercially available.

<u>Standby Gas Turbines:</u> Many standby or emergency generator gas turbines are rated greater than 10 MW but limited to operations of no more than 877 hours per year. Considerations for establishing emissions limits for these turbines include the following.

Eleven large gas turbines are permitted by the District to operate no more than 877 hours per year. Seven of these are designed to burn distillate fuel oil. These units have relatively high emissions rates (42 – 65 ppm), and typically, but not exclusively, operate during the peak electrical demand season. Peak electrical demands often occur on the hottest summer days which are also the days with the highest ozone levels. Further, the large size of these gas turbines, and their higher rates of emissions, mean that these units have a potential to produce significant NOx.

Because of the annual operational limits, the potential total emissions from the restricted-hour units are much lower than that of comparably sized fulltime units with the same emissions rates. Justification for possible control options is more challenging. However, since emissions from one of these plants operating only 1/10th of the year are approximately equal to a BACT level unit operating all year, their emissions warrant scrutiny.

These units are generally simple cycle operations which lead to higher exhaust gas temperatures (greater than 800^{o}F). High temperature SCR systems are being developed that can control these units, but initial installations have experienced problems meeting design emission levels. Water injection systems are available, however, and can provide NOx control approaching 25 ppm on some units. Therefore, for units that can comply by using enhanced water injection, the District is contemplating a 25 ppm limit.

For units with power agreement or contractual concerns, a longer deadline with a lower emission limit may be a solution. Although the lower emission standard would require high-temperature SCR, the District believes that there will be sufficient time for this technology to mature and correct the problems encountered in the early installations.

Power contracts: Some power producers have concerns about new requirements that might take effect before service agreement contracts expire. It is uncertain whether some of these service agreements will be renewed or if the facilities will cease operations at the end of their contracts. A few operators could find themselves in the situation of installing a costly SCR system which might only be operated for one summer.

Compliance schedules: A typical compliance schedule option would allow operators to demonstrate compliance with 67% of their units by the deadline, and demonstrate compliance with the remaining unit(s) within the following year. This would allow operators of multiple units to properly sequence the equipment downtime and provide system reliability.

Startup and shutdown periods: Due to the nature of their operation and design, turbines must operate within normal operating pressure and temperature ranges to achieve low NOx emissions. In addition, emission control devices, especially SCR, are very temperature sensitive. The current rule provides exemption from the emissions standards for up to three hours during startup, and up to one hour during shutdown to allow the time required to transition to/from normal operating conditions. Some existing operating permits have specified startup or shutdown time limits that are inconsistent with these requirements. The District is not contemplating any changes to the current exemptions for startup and shutdown periods.

Averaging periods for NOx excursions: There has been inconsistency in the analysis and averaging of NOx emissions, particularly when a process upset and NOx excursion occurs. Permit conditions vary widely, prescribing one hour to three hour averaging periods. The BAAQMD Manual of Procedures Volume IV prescribes three 30-minute tests to determine compliance. The BAAQMD Manual of Procedures Volume V (for Continuous Emissions Monitors) prescribes averaging for each “clock hour”. The District intends to review the issue and adopt an appropriate averaging period, and solicits input on this issue.

Appendix C shows a summary of the current and proposed standards.

V. RULE DEVELOPMENT / PUBLIC CONSULTATION PROCESS

The preliminary rule development process has taken advantage of the work done by the San Joaquin Valley Air Pollution Control District in its development of Rule 4703. Rule 4703, combined with background work by California ARB and U.S. EPA, have provided the technical basis for the rule amendments the District is currently considering. Informal discussion with various gas turbine operators has directed their attention to Rule 4703 as a model for possible rule amendments in the Bay Area.

The next step in the District’s rule development process is a Public Workshop to review the rule amendments the District is considering, and to solicit input. The District is holding the Public Workshop to solicit comments from the public, members of State agencies, industry, environmental organizations, and other interested parties on potential amendments to Regulation

9, Rule 9. The District will also respond to questions about information set forth in this Workshop Report. The District will use the public input it receives, along with further investigation and analysis by District staff, to develop appropriate amendments for proposal to the District's Board of Directors.

VI. PRELIMINARY FINDINGS

NOx reductions will reduce ozone precursors, and are the primary objective of this amendment. NOx reductions may have the additional benefit of slight reduction in particulate pollution. Preliminary work indicates these amendments are feasible, and will reduce NOx emissions more than 1 ton/day. District staff is proceeding with a Public Workshop to gather input on proposed amendments to Regulation 9, Rule 9.

Cost information will be an important part of the information still needed to ensure the proposed amendments are cost effective. Gas turbines for which emission limits will be reduced from 9 ppm to 5 ppm may require modifications of the existing SCR system or enhanced SCR catalyst. Cost of these and other modifications will be critical in assessing cost effectiveness. Similar cost information is needed for large and simple cycle gas turbines that currently do not have an SCR. Costs for installing new or high temperature SCRs will be critical in assessing cost effectiveness.

Appendix A: Summary of Current Inventory of Bay Area Gas Turbines

Regulation 9, Rule 9 NOx Emission Limits

	Number of Gas Turbines at each NOx limit			
Turbine Size / Operating Mode	**Gas**	**Refinery / Waste Gas**	**Oil**	**Total**
Continuous Operation				
< 0.3 MW	4 @ 9 ppm 1 @ 105ppm 17 exempt			22
0.3 - 3.0 MW	1 @ 20 ppm 13 @ 42 ppm			14
3.0 – 10 MW	2 @ 5 ppm 5 @ 42 ppm	3 @ 42 ppm 3 @ 55 ppm		13
> 10MW	10 @ 2.5 ppm 8 @ 5 ppm 6 @ 9 ppm 3 @ 10 ppm 5 @ 15 ppm	1 @ 2.5 ppm 2 @ 5 ppm 1 @ 9 ppm 2 @ 15 ppm 3 @ 22 ppm	2 @ 42 ppm	43
Subtotal				**92**
Intermittent Operation				
< 0.3 MW				
0.3 - 3.0 MW				
3.0 – 10 MW			4 @ 65 ppm	4
> 10MW			11 @ 42 ppm	11
Subtotal				**15**
Limited Use (Testing, Emergency / Standby) **(<877 hrs/yr)**				
< 0.3 MW	3 exempt		10 exempt	13
0.3 - 3.0 MW			18 exempt	18
3.0 – 4 MW			5 exempt	5
4 – 10 MW			1 @ 65 ppm	1
> 10MW	4 @ 42 ppm		7 @ 65 ppm	11
Subtotal				**48**
Totals	**82**	**15**	**58**	**155**

Appendix B: Current Gas Turbine Control Technologies

Prevention Technologies:

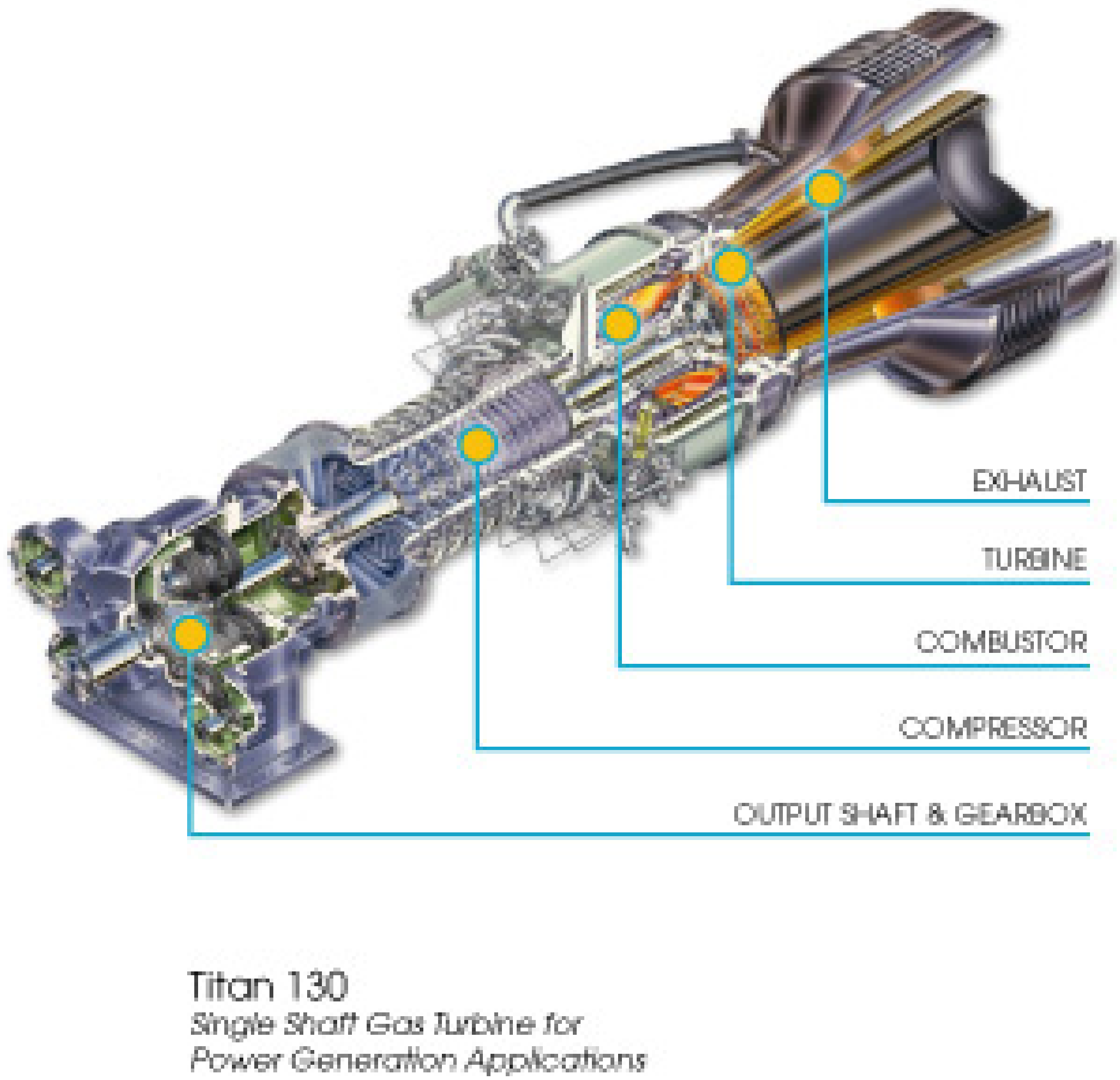


Figure B-1: Cutaway view of large single shaft gas turbine

NOx emissions from gas turbines can be reduced by lowering combustion temperatures. Significant improvements have occurred in pre-mixing fuel and air in the Dry Low NOx (DLN) combustor technology design. These designs are lower in cost than water or steam injection in preventing NOx formation. These DLN combustors can now achieve 25 ppm NOx. However, DLN combustor technology has not been developed for all turbine makes and models. Research and small pilot projects have been developed for a newer technology called catalytic combustion (incorporating a catalyst bed in the combustor design to further reduce combustion temperatures and NOx formation). However, only minor commercialization of this technology has occurred to date. Kawasaki is the only vendor offering this technology (trade name is Xonon Cool Combustor), and it is only available for one of their small (1.4MW) gas turbines. Xonon Cool Combustors have achieved 3 ppm NOx.

Diluents (Water or steam) injection systems – NOx control

This is the most commonly used NOx control on permitted turbines. All gas turbines installed before the mid-1990's used steam or water injection to control NOx. It may be used separately, or in conjunction with flue gas treatment control such as SCR. In this process, either water or steam is injected into the combustor of the turbine to quench the flame temperature. Formation of thermal NOx is related to peak flame temperature in the combustion zone. The resulting cooler flame produces less NOx. Older turbines use water injection while newer turbines tend to use steam as the diluent. Diluent injection systems create slight power increases due to the mass of the diluent, but they also require additional fuel compared to non-injected turbines. There is also an upper limit at which any additional increase in diluent injected will impact the balance of the turbine blades and impact combustion mechanics leading to undesirable vibration from pressure oscillations. Finally, injected water must be relatively pure to prevent scaling of the turbine blades as it exhausts through the turbine. This usually requires the added expense of installing and maintaining a water purification system. Despite the drawbacks and limitations of this system, it has been widely used on turbines. Manufacturers' guaranteed emission levels are typically 42 ppm NOx or less with these systems, which satisfies the District's current control requirements for turbines smaller than 10 MW. Source test data indicates that diluent injection systems are able to obtain emission rates in the 30 – 35 ppmvd NOx range. Steam or water injection continues to be the only viable means to reduce NOx formation when burning refinery gas or landfill waste gas, or liquid fuels.

Dry, Low-NOx Combustors - NOx control

Dry, Low-NOx (DLN) combustion technology uses specially designed burner elements to change the turbine's combustion mechanics, reducing flame temperature and preventing thermal NOx formation. The new burner elements result in lower NOx emissions than diluent injection systems without the necessity of providing a clean water supply. This system is gaining favor as original manufacturer equipment and is commonly found in new turbines. Figure B-2 illustrates the complex piping surrounding a DLN Combustor System. Existing turbines require a specifically tailored retrofit package which may not be commercially available for all units. Gas turbines more than 10 years old are unlikely to have a DLN retrofit package available. DLN manufacturers guarantee emission rates as low as 9 ppmvd on new units, although 25 ppm is more common for retrofit applications. For some units, the guarantee is only 42 ppm or less. For these units, such systems would not offer an emissions control advantage compared to the diluent injection systems, but could be a preferred option where water availability is limited.

Figure B-2: Close up of Piping to Dry Low NOx Combustor System

Lean Premix Burners - NOx control

These burners represent an enhancement of the Dry, Low-NOx (DLN) combustion technology. More mixing of air and fuel is needed to further reduce flame temperatures, so longer pre-mix tubes are used, followed by the cooling and re-injection of some of the combustion gas along with staged injection of fresh air, and better swirling / mixing of the fuel, air and recycle combustion gas with diffusion flame nozzles. These burners do not represent new technology, just an additional development of the Dry, Low-NOx combustion approach.

Catalytic Oxidation - NOx control

Research and development continues on combining a catalyst with the lean pre-mix burner concept to provide complete combustion at even lower combustion temperatures. Early pilot and test facility demonstrations have shown that catalytic combustion can control both NOx and CO from gas turbines to very low levels. Two products in the category of catalytic combustion, Xonon Cool Combustion™ from Catalytica Energy, and RCL Combustor by Precision Combustion, have demonstrated NOx at less than 3 ppmvd and CO at less than 10 ppmvd. However, this technology is currently available for only one or two models of gas turbines. This technology is not considered commercially available for widespread application at this time.

Exhaust Gas Treatment Technologies:

NOx emissions can also be reduced by treating the exhaust gases. Significant improvements in Selective Catalytic Reduction (SCR) catalysts and ammonia injection control have contributed to overall reductions in NOx emissions. SCR flue gas treatment systems can now achieve 3 – 5 ppmvd NOx. In addition, reduction of CO and residual organic emissions has occurred by including a bed of oxidation catalyst in the SCR. This oxidation catalyst is now considered to be BACT. Un-reacted ammonia (known as ammonia slip) can be a by-product of the SCR approach, and must be controlled. Ammonia slip is generally limited to 10 ppm as a District permit condition because ammonia is a PM2.5 precursor. Transportation and storage of ammonia in bulk represents a concern for a potential leak or spill because it is hazardous in large quantities.

A relatively new treatment technology called SCONOX™ has been developed and piloted on gas turbine combined cycle and cogeneration trains up to about 40 MW. This technology uses a single catalyst (potassium carbonate) to remove NOx, CO and ROG, but then must be regenerated. SCONOX™ does not use ammonia, and thus has the advantage of avoiding concerns related to ammonia slip and ammonia storage and handling. SCONOX™ has achieved 2 – 3 ppm NOx emissions.

Selective Catalytic Reduction (SCR) - NOx control

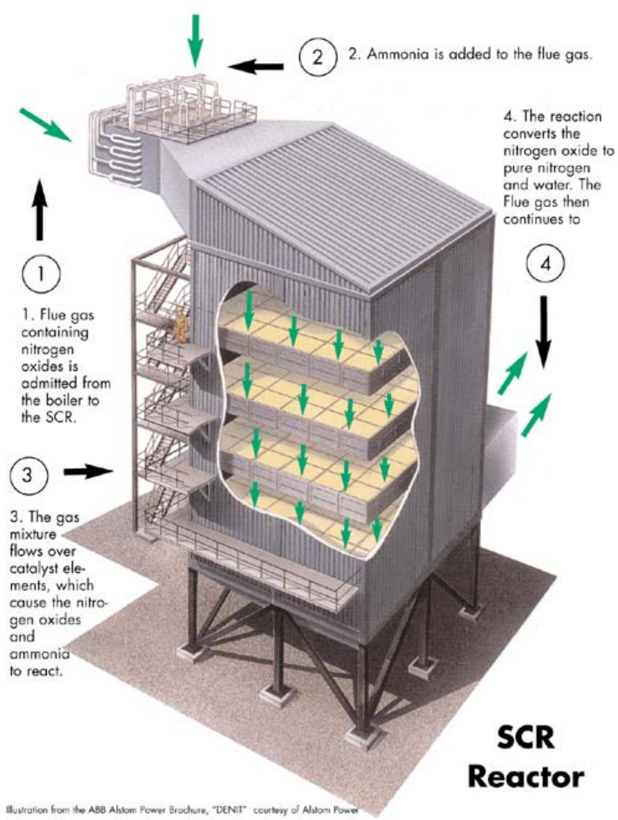


Figure B-3: Typical illustration of SCR equipment

Figure B-3 shows a typical example of SCR equipment. An SCR system uses a catalytic element and a reagent to reduce NOx emissions by converting them to water and elemental nitrogen. The reagent, typically urea or ammonia, is injected into the exhaust stream and reacts with the NOx in the presence of the catalyst. The reaction would normally occur at approximately 1,500^{o}F, but the use of the catalyst allows it to occur at the temperature window commonly found in a combined-cycle turbine exhaust stream, approximately 350 to 500^{o}F. Recently, high-temperature SCR catalysts have been developed which operate in the 900 to 1000^{o}F range that is more typical of a simple-cycle turbine.

Transportation, storage and use of bulk quantities of ammonia raise safety concerns related to SCR systems. Ammonia is not a federal hazardous air pollutant or a State identified toxic air contaminant, but exposure to significant quantities can have immediate acute and non-cancer health effects. Gaseous ammonia can pose a safety hazard from accidental releases. Such releases can be mitigated with proper operating practices or through the use of water / ammonia liquid mixtures or urea as reactants. Anhydrous (no water) ammonia is already commonly used as a fertilizer for agricultural operations and as a refrigerant in large cold storage chillers, so proper handling and safety techniques are already well established and employee training is available.

Another concern is the potential emissions caused when more ammonia is injected than is needed for reaction. Excess ammonia emissions, known as ammonia slip, results when the SCR system feedback system lags the actual NOx emission changes and calls for more reagent than required. The excess ammonia emissions produced are so dilute as to not create a personnel safety issue, but in colder weather may become precursors to $PM_{2.5}$ for which the Bay Area is not in attainment of State standards. Ammonia slip limits are included in most stationary gas turbine operating permits issued by the District.

However, because NOx is also a $PM_{2.5}$ precursor during the winter months, the benefits from using SCR systems are considered to outweigh the potential problems associated with ammonia slip. Review of existing SCR source tests show a variety of permitted levels, but indicate that the systems can and have been successfully employed on a variety of turbines ranging from 3.2 MW to 167 MW. Due to the cost and complexity of these systems, they are more typically used to control larger units.

SCONOx™ - NOx control

SCONOx™ by Goal Line Environmental Technologies is a proprietary, catalyst-based control system which reduces emissions of NOx, CO, and ROG. This technology has been developed and piloted on combined cycle and cogeneration gas turbines up to 40 MW. The system uses two parallel catalyst systems with potassium carbonate coating. The exhaust is alternated between the two catalyst systems. One system adsorbs NOx, CO and ROG while the other system undergoes on-site regeneration of the coating. This approach has the advantage of not requiring ammonia or urea as a reagent, and its associated transportation and storage risks. However it is more costly, has had some operational difficulties during its pilot applications, and has not yet been scaled up to accommodate very large gas turbines. SCONOx™ systems have been demonstrated to achieve NOx emissions of 2 to 3 ppm.

Appendix C: Summary of Current NOx Standards and Potential Amendments

NOx Emission Limits for Unlimited Turbine Usage

Turbine Size		Natural Gas			Refinery / Waste Gas			Liquid Fuel		
		Current	New	Reductio n	Current	New	Reduction	Current	New	Reductio n
Less than 0.3 MW		Exempt	Exempt	--	Exempt	Exempt	--	Exempt	Exempt	--
0.3 to 3.0 MW		42	42	--	55	55	--	65	65	--
3.0 to 10 MW	DLN combustors not commercially available	42	35	7	55	50	5	65	65	--
	DLN combustors commercially available	42	25	17	55	45	10	65	65	--
10 MW or more	without SCR	15	5	10	15	5	10	42	25	17
	with SCR	9	5	4	9	5	4	25	25	--

NOx Emission Limits for Limited Turbine Usage (Less than 877 hours per year)

Turbine Size	Natural Gas			Refinery / Waste Gas			Liquid Fuel		
	Current	New	Reduction	Current	New	Reductio n	Current	New	Reduction
Less than 4 MW	Exempt	Exempt	--	Exempt	Exempt	--	Exempt	Exempt	--
4 to 10 MW	42	42	--	N/A	N/A	--	65	65	--
10 MW or more	42	25	17	N/A	N/A	--	65	42	23