Gas Turbine NOx Emissions Approaching Zero – Is it Worth the Price?

Marvin M. Schorr, Consulting Engineer
Joel Chalfin, Manager, Environmental Engineering
General Electric Power Systems
Schenectady, New York

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ABSTRACT

The requirement for gas turbines to meet ever lower NOx emission levels results from a regulatory approach developed before combustion systems existed that are capable of achieving single digit NOx. Dry low NOx (DLN) combustors for GE Frame 7FAs, 7EAs and 6Bs are now demonstrating 9 ppm NOx. This paper compares the energy, environmental and economic impacts of requiring add-on emission controls to achieve a lower level of NOx, with a gas turbine combustion system that is already capable of achieving single digit NOx. The conclusion reached is that ratcheting NOx down to lower and lower levels through the use of add-on emission controls reaches the point of diminishing return when the gas turbine combustion system is capable of achieving single digit NOx. The cost of add-on emission controls to achieve a lower NOx level becomes excessive, the heat rate increases and the overall environmental impacts are actually worsened. The recommendation is made for the U.S. EPA to amend the regulatory process to allow permit authorities to consider conflicting environmental, energy and economic impacts in nonattainment areas, as they now can in attainment areas, in cases where add-on emission controls will result in only a small reduction in emissions.

INTRODUCTION

The current regulatory process for permitting gas turbines is the product of a regulatory approach that does not seem to have anticipated gas turbine combustion systems capable of achieving single digit NOx without add-on controls (such as selective catalytic reduction, SCR). The technology forcing approach of the Clean Air Act New Source Review process has been especially successful with respect to gas turbine combustion system emissions through the use of Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) requirements. Allowable NOx emissions have been ratcheted down from an New Source Performance Standards (NSPS) level of 75 ppm (plus heat rate correction) to less than 10 ppm (when firing natural gas) in about 12 years. However, the point of diminishing returns appears to have been reached, at least for GE gas turbine combus-

tion systems that are now achieving single digit NOx without the use of post combustion, add-on emission controls. The response of gas turbine manufacturers to the technology forcing programs of the Clean Air Act has been truly impressive.

Dry low NOx (DLN) combustors for GE Frame 7FAs, 7EAs and 6Bs are now operating at 9 ppm NOx and even lower levels are likely to be achieved in the next few years. The cost of add-on emission controls to achieve a NOx level below 9 ppm becomes excessive and the overall environmental impacts may actually be worsened when the gas turbine combustion system is capable of achieving single digit NOx. The recommendation is made for the U.S. EPA to amend the regulatory process to allow permit authorities to consider conflicting environmental, energy and economic impacts in nonattainment areas, as they now can in attainment areas, in cases where add-on emission controls will result in only a marginal reduction in emissions.

REGULATORY BACKGROUND

The decade of the 1980s was one of rapid change for both gas turbine emission control regulations and the technologies used to meet those regulations. The primary pollutant of concern from gas turbines has been, and continues to be, oxides of nitrogen. The Gas Turbine New Source Performance Standards (NSPS), issued in 1979, did not regulate the emissions of carbon monoxide or unburned hydrocarbons from gas turbines because the levels are very low at base load. However, in December 1987, EPA's "top-down approach" for determining the Best Available Control Technology (BACT) became a requirement. This ratcheted allowable gas turbine NOx emission levels down to levels significantly lower than the NSPS. As the allowable NOx levels decreased, with steam or water injection the primary technology used for NOx control, carbon monoxide emissions started to become more of a concern. Increases in CO levels resulted from massive amounts of steam or water being injected to control NOx to the lower levels and part load operation in cogeneration applications. As a result, advances in dry low NOx combustion technology and new add-on emission controls allowed gas turbine op-

erators to achieve very low levels of NOx without injection. The Clean Air Act Amendments of 1990 have resulted in new emission control requirements, not only for NOx, but also for CO and VOCs in ozone non-attainment areas.

GAS TURBINE EMISSIONS

Potential pollutant emissions from gas turbines include oxides of nitrogen (NO and NO2, collectively referred to as NOx), carbon monoxide (CO), unburned hydrocarbons (UHC, usually expressed as equivalent methane), oxides of sulfur (SO2 and SO3) and particulate matter (PM). Unburned hydrocarbons are made up of volatile organic compounds (VOCs), which contribute to the formation of ground level atmospheric ozone, and compounds such as methane and ethane, that do not contribute to ozone formation. SO2, UHC and PM are generally considered negligible when burning natural gas. Thus, NOx and possibly CO are the only emissions of significance when combusting natural gas in combustion turbines.

The NOx production rate falls sharply as either the combustion temperature decreases, or as the fuel-air ratio decreases, due to an exponential temperature effect. Therefore, the introduction of a small amount of any diluent into the combustion zone will decrease the rate of thermal NOx production. This is the physics behind the injection of water or steam and of lean combustors. Because the diluent effect is a thermal one, the higher specific heat of steam means that less steam needs to be introduced than air and less water than steam to achieve the equivalent NOx reduction. However, the introduction of steam or water to the gas turbine combustor is a thermodynamic loss, whereas redistributing combustor airflow splits (combustion vs. dilution/cooling) has no impact on the cycle efficiency. As a result, the use of very lean combustors to achieve the lower NOx levels is more desirable than steam/water injection.

NO$_X$ CONTROL TECHNOLOGIES

The "front-end" technologies that are available for the control of NOx emissions from gas turbines include: (1) injection of water or steam into the combustion zone, a control technology that lowers flame temperature, (2) dry low NOx combustion (DLN), a technology that uses staged combustion and lean-premixed fuel-air mixtures, and (3) catalytic combustion, a new technology that holds the promise of achieving extremely low emission levels. "Back-end" exhaust gas clean-up systems include (4) selective catalytic reduction (SCR) and (5) SCONOXTM, a new catalytic technology.

Water/Steam Injection

Most of the experience base with gas turbine NOx emission control prior to 1990 was with diluent injection into the combustion zone. The injected diluent provides a heat sink that lowers the combustion zone temperature, which is the primary parameter affecting NOx formation. As the combustion zone temperature decreases, NOx production decreases exponentially.

Manufacturers continue to develop machines having higher firing temperatures as a way to increase the overall thermodynamic efficiency. However, higher firing temperatures mean higher combustion temperatures, which produce more NOx, resulting in the need for more diluent injection to achieve the same emission levels of NOx. There has also been a reduction of allowable NOx emissions and lower NOx levels require even more injection. The increased injection rate lowers the thermodynamic efficiency, seen as an increase in heat rate (fuel use), due to taking some of the energy from combustion gases to heat the water or steam. Furthermore, as injection increases, dynamic pressure oscillation activity (i.e., noise) in the combustor also increases, resulting in increased wear of internal parts. Carbon monoxide, which may be viewed as a measure of the inefficiency of the combustion process, also increases as the injection rate increases. Basically, as more and more water or steam is injected into the combustor to lower the combustion temperature, flame stability is affected until, if it were increased sufficiently, the water would literally put out the flame. Thus, a design dichotomy exists whereby increasing firing temperature to increase the efficiency of the combustion process, unfortunately produces more NOx, requiring more injection, which lowers the thermodynamic efficiency, producing more CO and also decreasing parts life. Increased injection to meet lower NOx emission limits simply exacerbates the problems associated with increased injection. The lowest practical NOx levels achieved with injection are generally 25 ppm when firing natural gas and 42 ppm when firing oil.

Selective Catalytic Reduction, SCR

In the SCR process, ammonia (NH) injected into the gas turbine exhaust gas stream as it passes through the heat recovery steam generator (HRSG), reacts with nitrogen oxides (NOx) in the presence of a catalyst to form molecular nitrogen and water. Based on experience, SCR works best in base loaded combined cycle gas turbine applications where the fuel is natural gas. The reasons for that relate to the temperature dependency of the catalytic NOx-ammonia reaction and the catalyst life, and to major problems associated with the use of sulfur bearing (liquid) fuels. The reaction takes place over a limited temperature range, 600-750°F, and above approximately 850°F the catalyst is damaged irreversibly. In addition, because of the tempera-

ture dependency of the chemical reaction and catalyst life, SCR cannot be used in simple cycle configurations, except possibly in lower exhaust temperature systems. Other issues associated with SCR include exhaust emissions of ammonia (known as ammonia slip); concerns about accidental release of stored ammonia to the atmosphere, environmental concerns and costs of disposal of spent catalyst.

Ammonia Release

The use of ammonia in the SCR chemical process for NOx control presents several problems. Ammonia is on EPA's list of Extremely Hazardous Substances under Title III, Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Releases of ammonia to the atmosphere may occur due to unreacted ammonia going out the stack (known as ammonia "slip"), or it can be accidentally released during transport, transfer, or storage. In addition, ammonia is a PM-10 precursor emission (particulate matter smaller in diameter than 10 microns).

Some ammonia slip is unavoidable with SCR due to the non-uniform distribution of the reacting gases. Thus, some ammonia and unreacted NOx will pass through the catalyst and in fact some catalyst manufacturers recommend operating with excess ammonia to compensate for imperfect distribution. An ammonia slip of 10-20 ppm is generally permitted in a new system (although higher slip has been noted) and will increase with catalyst age. In the past, ammonia slip was not considered to be a problem by regulatory agencies because they felt that by releasing it from an elevated stack, the ground level concentration would be low. However, it has never appeared to be good environmental policy to allow ammonia to be released to the atmosphere in place of NOx and ammonia emissions are now of concern because of PM–2.5 considerations.

The Use of Sulfur-Bearing Fuels

The Problem – Distillate oil contains sulfur. There is no successful operating experience when SCR is used for NOx control while firing a gas turbine with sulfur bearing oil. However, some regulatory agencies require the use of SCR, even when distillate oil is used as a backup fuel. In most cases regulators have simply pointed to the many combined cycle plants with SCR permitted with oil as the backup fuel, ignoring the fact that most of those plants actually operate almost exclusively on gas and use little or no oil fuel. Those that have used oil have experienced significant problems.

The problems associated with the use of sulfur bearing fuels are due to the formation of the ammonium salts ammonium bisulfate, NH_4HSO_4, and ammonium sulfate, $(NH_4)SO_4$. These compounds are formed by the chemical reaction between the sulfur oxides in the exhaust gas and the ammonia injected for NOx control. Ammonium bisulfate causes rapid corrosion of boiler

tube materials; and both ammonium compounds cause fouling and plugging of the boiler and an increase of PM–10 emissions.

Ammonium bisulfate forms in the lower temperature section of the HRSG where it deposits on the walls and heat transfer surfaces. These surface deposits can lead to rapid corrosion in the HRSG economizer and downstream metal surfaces resulting in increased pressure drop and reduced heat transfer (lower power output and cycle efficiency). While ammonium sulfate is not corrosive, its formation also contributes to plugging and fouling of the heat transfer surfaces (leading to reduced heat transfer efficiency) and higher particulate emissions. The increase in emissions of particulates due to the ammonium salts can be as high as a factor of five due to conversion of SO_2 to SO_3. Some of the SO_2 formed from the fuel sulfur is converted to SO_3 and it is the SO_3 that reacts with water and ammonia to form ammonium bisulfate and ammonium sulfate. The increase is a function of the amount of sulfur in the fuel, the ammonia slip (ammonia that does not react with NOx) and the temperature. It can also be increased by supplementary firing of the HRSG and by the use of a CO oxidizing catalyst (which significantly increases the conversion of SO_2 to SO_3).

The only effective way to inhibit the formation of ammonium salts appears to be to limit the sulfur content of the fuel to very low levels (or switch to a sulfur free fuel such as butane) and/or limit the excess ammonia available to react with the sulfur oxides. Pipeline quality natural gas usually has a sulfur content low enough that ammonium salt formation, while it is present, has not yet been a significant problem with natural gas-fired units. However, the sulfur content of even very low sulfur distillate oil (e.g., 0.05 percent) or liquid aviation fuel (Jet–A) may not be low enough to prevent enough formation of ammonium bisulfate to avoid the problems discussed above (ambient sulfates may also contribute). This potential is usually handled by a requirement to limit the operating time on the low sulfur distillate oil to a relatively few hundred hours between shutdowns and then clean the HRSG internals (although disposal of the deposits may be a problem due to the presence of hazardous materials). Lowering the ammonia slip or the sulfur concentration could lengthen the time between cleanings. Limiting the ammonia that is available to react with the sulfur oxides to negligible levels does not appear practical at NOx removal efficiencies above 80 percent because higher excess ammonia levels are required to achieve the higher NOx removal efficiencies. Limiting the excess ammonia may work at lower NOx removal efficiencies because the lower NH_3/NOx ratios required ensure that all the ammonia is consumed. However, when oil is to be used as the primary fuel, the experience would indicate that SCR should not be used, as there appears to be significant risk of equipment damage or

failure, performance degradation and increased emissions of fine PM.

Disposal of Spent Catalyst

SCR materials typically contain heavy metal oxides such as vanadium and/or titanium, thus creating a human health and environmental risk related to the handling and disposal of spent catalyst. Vanadium pentoxide, the most commonly used SCR catalyst, is on the EPA's list of Extremely Hazardous Materials. The quantity of waste associated with SCR is quite large, although the actual amount of active material in the catalyst bed is relatively small.

SCONOX

SCONOX is a post-combustion catalytic system that removes both NOx and CO from the gas turbine exhaust, but without ammonia injection. The catalyst is platinum and the active NOx removal reagent is potassium carbonate. At present, the only operating SCONOX system is being used with an LM2500 injected with steam to 25 ppm NOx at a facility in Vernon, CA. Stack NOx is maintained at 2 ppm or less and CO at less then 1 ppm.

How SCONOX Works

The exhaust gases from a gas turbine flow into the reactor and react with potassium carbonate which is coated on the platinum catalyst surface. The CO is oxidized to CO_2 by the platinum catalyst and the CO_2 is exhausted up the stack. NO is oxidized to NO_2 and then reacts with the potassium carbonate absorber coating on the catalyst to form potassium nitrites and nitrates at the surface of the catalyst. When the carbonate becomes saturated with NOx it must be regenerated. The effective operating temperature range is 280 to 750°F, with 500 to 700°F the optimum range for NOx removal. The optimum temperature range is approximately the same as that of SCR.

Regeneration is accomplished by passing a dilute hydrogen reducing gas (diluted to less than 4 percent hydrogen using steam) across the surface of the catalyst in the absence of oxygen. The sections of reactor catalyst undergoing regeneration are isolated from exhaust gases using sets of louvers on the upstream and downstream side of each reactor box. The Vernon LM2500 facility has 12 vertically stacked catalyst reactor boxes, nine of which are in the oxidation/absorption cycle at any given time, while three are in the regeneration cycle. When regen is completed in the three reactor boxes, the louvers open on those reactors and the louvers on three other reactors close and those reactors go into the regeneration cycle. Motor drives outside each box drive the shaft that opens and closes the louvers on each side of the box (inlet and outlet sides).

SCONOX Issues

There are several issues associated with the use of SCONOX. First, it is very sensitive to sulfur, even the small amount in pipeline natural gas. Second, the initial capital cost is about three times the cost of SCR, although this may come down once there are more in operation. Third, it has moving parts reliability and performance degradation due to leakage may be significant issues, especially on scale-up to bigger gas turbines (a 7FA would require 20 modules of 4 reactor boxes each vs. LM2500 using 3 modules of 4 reactor boxes). Last, use of any exhaust gas treatment technology (SCR or SCONOX) results in a pressure drop that reduces gas turbine efficiency. Thus, by adding a back-end cleanup system, more fuel must be burned to reduce NOx and SCONOX produces about twice the pressure drop of SCR.

The GE Dry Low NOx Combustor

GE began development of a dry low NOx combustor in 1973, primarily in response to increasingly stringent emission control requirements in California. The initial goal was a NOx level of 75 ppmvd at 15 percent oxygen, the NSPS requirement for utility gas turbines. An oil-fired combustor designed for a Frame 7 gas turbine achieved this goal in the laboratory in 1978. Field testing of the prototype dry low NOx combustor design demonstrated that the combustor was capable of meeting the NSPS. The design, tested at Houston Lighting and Power (HL and P) in 1980, has evolved into a system that is achieving a NOx level of 9 ppmvd at 15 percent oxygen in GE Frame 7EA, FA, and 6B gas turbines fired on natural gas.

DISCUSSION

Cost in $/ton of NOx Removed/Energy Output Reduction

The annual cost of reducing NOx using SCR from 9 ppm to 3.5 ppm for a GE Frame 7FA, 170 MW class gas turbine operating 8,000 hr/year is $8,000 to $12,000 per ton of NOx removed when a non sulfur bearing fuel is used and $15,000 to $30,000 if a sulfur bearing fuel is used. The cost will be the same or more than that with SCONOX, which in addition, cannot be used with sulfur bearing fuels without additional cost for sulfur removal. (The SCR cost effectiveness estimate with a sulfur bearing fuel is based on six year replacement of catalyst, 20 percent fixed charge rate and a vendor quote of 25 percent increase in HRSG cost for a redesigned economizer section to allow for cleaning of ammonium bisulfate. If a redesigned HRSG is not acceptable, the cost of periodic replacement of LP economizer tubes should be used in the BACT analysis.) Most gas turbine combined cycle or cogeneration systems today operate with natural gas as the primary

fuel and fuel oil as the backup fuel. SCR operating and maintenance costs include continuous ammonia injection, periodic catalyst replacement, and the cost associated with a small decrease in power output (more than 650 kW for a 7FA). The output drop is due to power for auxiliaries associated with ammonia injection, catalyst pressure drop in the new and clean condition, which increases as ammonia-sulfur salts build up, and decrease in heat transfer as the salt build-up increases over time. This cost is considered too high for BACT in ozone attainment areas by most states. The decrease in output efficiency results in an increase in CO_2 emissions due to the need to burn more fuel to make up for the output reduction.

It is often argued that economics should not be considered at all in LAER determinations. There is, however, an implicit "reasonableness test" in all LAER determinations. Thus, no regulator has required that trains of multiple SCR be utilized to reduce NOx to zero (although this is technically possible) because the cost would be so high that we would conclude that it would not be "reasonable". This same rationale should apply to adding any emission control if the cost is unreasonably high, as is the case for adding SCR or SCO-NOX to a combustion system achieving 9 ppm NOx in a combined cycle.

Ammonia Slip/Ammonium-Sulfur Salts

The impact of slip on the environment may be at least as detrimental as if NOx were to be released. Where an ammonia emission limit is imposed, and there is often no such emission limit, slip is generally targeted at 10-20 ppm, although there are units operating with ammonia slip well below and well above that level. Most recent SCRs operate with 5 ppm slip or less, but slip is expected to be on the high side when the NOx level entering the catalyst bed is already very low. Unless there is perfect mixing, the ammonia molecules must "find" the fewer NOx molecules in order to react and this will require adding more excess ammonia. Thus, 20 ppm or more ammonia slip would be released in place of the reduction in NOx in going from 9 to 3.5 ppm. Table 1 shows that for a Frame 7FA with 20 ppm ammonia slip (base load, 8,000 hr/yr, 45°F ambient, natural gas) there are 24 tons per year (TPY) more ammonia emitted than NOx reduction by lowering NOx from 9 to 3.5 ppm with SCR. There also is an increase of 5 TPY in particulate matter emitted, or 36 TPY if a CO catalyst is also used. Note also that as the catalyst ages, ammonia slip increases as the efficiency of conversion decreases, until at the end of catalyst life the ammonia slip may be much higher than a new and clean catalyst. In fact that is one way that catalyst replacement is indicated. Some ammonia released to the atmosphere will be converted to NOx and ultimately to ozone. Finally, ammonia is on the SARA (Superfund) list of Extremely Hazardous Materials. Accident studies of transport and on-site storage of ammonia for use with SCR, performed for the Massachusetts DEP and California's South Coast AQMD, resulted in a change from anhydrous ammonia to aqueous ammonia. Aqueous ammonia has a lower ammonia concentration and lower storage pressure (resulting in a slower release rate) than anhydrous. Anhydrous ammonia was used until these studies revealed the potential public hazard in the event of catastrophic release. The hazard was reduced, but not eliminated.

GE Power Systems analysis of measurements of ammonia emissions on six plants with SCR showed a great deal of inconsistency (<1 ppm to 30 ppm). All of the tests were performed using different ammonia sampling methodologies. EPA Method 206 for ammonia was recently published for applicability to coal-fired plants. There is no specific method for gas turbine plants. The conclusion drawn from this study is that the ammonia slip on plants with SCR is not actually known with any accuracy.

Spent Catalyst

From a policy standpoint, the disposal of spent catalyst as hazardous waste, simply transfers an air problem (NOx) into a long-term solid waste disposal problem. This is not a good environmental tradeoff.

Use of Sulfur Bearing Fuels

It has been GE Power System's position for some time that SCR should not be used in gas turbine applications where a sulfur bearing fuel, such as distillate oil, is used. With the recent concern expressed by EPA through the promulgation of the National Ambient Air Quality Standards for fine particulate matter (PM 2.5), GE Power Systems feels even more strongly that the use of SCR should be avoided when such fuels are used. Unreacted ammonia from the SCR, and sulfur from the fuel react to form ammonium salts that are released as particulate matter, as previously discussed. EPA is very concerned with PM–2.5 (very fine, inhalable particulates) which would increase significantly. The example in Table 1 for a Frame 7FA shows an 8 TPY increase in PM with SCR and almost 50 TPY if a CO catalyst is also used, with only 400 hours per year of oil firing. Aside from the important health risks that EPA has indicated are posed by PM 2.5, the impact of the increase in fine particulates on regional haze should also be considered. A CO oxidizing catalyst, supplementary firing and noble metal catalysts will all result in much higher SO_2 to SO_2 conversion and greater sulfur salt formation. Note that particulate emission controls have never been used on gas turbines.

Although there are many gas turbine combined cycle plants using SCR that are permitted to use distillate oil as the backup fuel, GE Power Systems is not

aware of ANY successful operation with this combination. Actual operating experience indicates that ammonium-sulfur salt formation and boiler damage occur without exception, when ANY sulfur bearing fuel is fired in the gas turbine and SCR is used for NOx control. This is not usually accounted for in BACT determinations, but adds significant cost and should be considered. Beside the down time associated with periodic cleaning, the added cost includes periodic replacement of the low pressure tube sections of the HRSG damaged by ammonium bisulfate corrosion, or the cost of an alternative design HRSG (which was used for the estimated cost in Section V.1). Reference 1 documents the damage done to the HRSGs on several representative plants.

State Example

The New York State Department of Environmental Conservation (DEC) Gas Turbine NOx Policy (93–AIR–39), allows a BACT NOx limit higher than normal when firing oil as a backup fuel, to either avoid the use of SCR, or to minimize ammonia slip. This is specifically stated to be in recognition of the increased particulate and ammonium bisulfate problems and concerns related to ammonia emissions. The NOx policy also states that the DEC "has determined that 6 ppmv (dry, corrected to 15 percent O) was the lowest emission limit for NOx which can be accurately measured in the stack, based on current monitoring/testing technology." This is the same finding as the ASME B133 Committee on emission measurements from gas turbines, Reference 2. Several other states also allow higher NOx levels if the use of SCR can be avoided to eliminate ammonia emissions. New Jersey has considered low sulfur kerosene for the backup fuel (rather than distillate oil) as BACT, when SCR is used for NOx control.

Measurement and Control of NOx

Recent regulatory agency actions in some states has resulted in excessively low NOx levels being required for gas turbines. Based on the performance of SCO-NOX at the single facility in California, NOx permit levels as low as 2 ppm are being required in some states. Even if such a level of NOx can be achieved, the question of how low a NOx level can be monitored and controlled has apparently not been addressed. Can we monitor and control on 2 ppm NOx? 40CFRPart 75 requires that a majority of readings be between 20 and 8 percent of the measurement range. A 10 ppm range is the lowest certified for a process NOx analyzer. With a 2 ppm NOx limit, the +/-10 percent of standard criterion is 0.2 ppm so that a CEMS would need to report no

greater than 1.8 ppm NOx minus margin to insure not exceeding 2 ppm. The ASME B133 Committee study (Reference 2) concluded that if the reading is outside the 20 to 80 percent of scale range the error could be as high as 25%. Since the plant must actually operate below 2 ppm with a 2 ppm limit, EPA's Part 75 regulations are violated. Further, to insure not exceeding 2 ppm, a 7FA gas turbine would need to operate at:

- 1.5 ppm max to compensate for instrument error (25% of 2 ppm reading error)
- ~1.0 ppm max to compensate for combustion system operating variability
- Below 1.0 ppm (0 to 1 ppm) to compensate for ambient variability effects

The conclusion is that 2 ppm NOx is not a practical emission limit for gas turbines.

Environmental Impact of a Deregulated Electricity Market

The advent of electricity market deregulation is bringing in a new factor to consider for new power plants called "displacement". This process has been observed in the United Kingdom where deregulation is generally the furthest along among the mature industrialized nations. Parts of the USA are already seeing the development of new "merchant" power plants that will compete with traditional utility plants and non-utility power plants. The concept is that new combined cycle merchant plants will be added until the market price of electricity from the new merchant plants is at parity with the composite market price, including less environmentally friendly older plants. This in turn will force either reduced operation or shut down of the less competitive of these older plants, with a resultant net emissions reduction. However, if the cost of a new, cleaner plant is increased (by adding SCR) it becomes more difficult to compete with older plants and less displacement occurs. Figure 1 shows the environmental benefits of displacing a coal or oil-fired power plant meeting the 1979 NSPS with a new gas-fired combined cycle plant of the same MW output. Also shown is the impact of the incremental premium that must be paid for SCR on the ability of a plant to bid its power under the market clearing price (the highest price the market will pay for power). Figure 2 shows the relative costs for various control technologies, first as a function of the initial capital cost of the power plant and then as a life cycle cost, both as functions of the NOx emission level. DLN at 9 ppm NOx is a clear winner over SCR in this competitive market environment, where the cleanest total solution is one where the economics of reducing the usage of the older plants is a significant consideration.

Regulatory Policy Consistency and Fairness

The EPA promulgated a new NOx NSPS for utility and industrial steam generators in October 1998. The revised Utility and Industrial Boiler NSPS for NOx is:

Applicability	NOx Emission Limit	Fuels
New Utility Units	1.6 LB per MW-Hr of output	Fuel Neutral
Modified/Reconstructed Existing Utility Units	0.15 LB per MMBtu fuel input	Fuel Neutral
New & Existing Industrial Units	0.20 LB per MMBtu fuel input	Fuel Neutral

Note the change from pounds of NOx per unit of heat input to pounds of NOx per unit of electrical output for utility units. There is no percent reduction required and it is fuel neutral.

For a Frame 7FA, 9 ppm NOx is less than 1/8 of the newly revised utility boiler NSPS and for 8,760 hours per year of operation will total less than the 250 tons per year PSD threshold for simple cycle gas turbines.

- Utility Boiler NSPS, NOx limit = 1.6 # NOx/MW-hr
- 7FA STAG, 9 ppm NOx = 0.19 # NOx/MW-hr

A 7FA at 3 ppm NOx emits less than one-twenty fourth of the utility boiler NSPS. For 8,760 hours per year of operation NOx will total less than the 100 TPY PSD threshold for steam electric power plants (EPA has ruled that combined cycle power plants are steam electric power plants).

The new 22-state eastern ozone transport region created by EPA's NOx SIP Call requires that an average NOx limit of 0.15 lb of NOx per million Btu of heat input be achieved. For a gas turbine this is equivalent to about 37 ppm NOx at 15 percent O.

When the boiler NSPS and the SIP call NOx requirements are compared with the extremely stringent gas turbine NOx emission requirements it is obvious that there is neither consistency nor fairness in the NOx emission requirements for gas turbines.

QUESTIONS REGULATORY POLICY MAKERS SHOULD ADDRESS

If a gas turbine can achieve an uncontrolled NOx level of 9 ppm, must the permit require less than that at any cost? The cost effectiveness of reducing NOx from 9 ppm to 3.5 ppm with SCR is approximately $15,000 to $30,000/ton of NOx as previously discussed. Is this reasonable for a BACT or LAER determination? If the cost effectiveness of an add-on control is $100,000/ton should it be required, even as LAER in nonattainment areas? $1,000,000/ton?

While a state agency can impose more stringent requirements than EPA, should a state agency that requires the use of the top-down approach for the determination of BACT, ignore cost effectiveness or impose an arbitrary effectiveness threshold that is much higher for some gas turbines than for other emission sources. Should agencies arbitrarily take a one-number fits all gas turbines approach to BACT, recognizing that BACT, by its very definition, is supposed to be site/project specific?

As previously discussed, some gas turbines can currently achieve an uncontrolled NOx emission level of 9 ppm. Some environmental agencies require the use of add-on controls for those gas turbines to reduce the NOx to 2 or 3 ppm in attainment and nonattainment areas, simply because it can be done, ignoring all other factors. If an uncontrolled NOx Level of 5 ppm is eventually achieved, should add-on controls still be required in attainment or nonattainment areas to reduce NOx to 3 ppm? To 2 ppm? In the extreme case, if an uncontrolled NOx level of 3 ppm is achieved by a gas turbine manufacturer, should such gas turbines be required to use add-on NOx control to reduce NOx to 2.5 ppm if that level were achievable, no matter what the cost? Did the Clean Air Act anticipate this kind of situation?

Many regulators state that economics cannot be considered in determining LAER. Should the negative environmental impacts resulting from emission controls that are required to reduce emissions of a nonattainment pollutant, also be ignored in determining LAER?

Is it a good environmental trade-off to emit ammonia in place of NOx? If the reduction in atmospheric loading (TPY) of NOx is of the same order of magnitude as the ammonia emitted in its place? Is it good environmental policy?

Does it make economic sense to require the use of any technology to control NOx emissions to extremely low levels when it is not clear that control at such low levels can be practically achieved? Is a 2 ppm NOx emission control level achievable even if it can be measured? 3 ppm? While these levels can probably be measured, has anyone considered the ability to control a gas turbine at such low levels under all operating

conditions? The one unit operating with SCONOX that appears to be achieving the 2 ppm level operates only at full load with no load following.

10 ppm is the lowest scale certified for a process NOx analyzer. Can the plant to be controlled below 20 percent of scale? Part 75 requires that a majority of readings must be between 20 and 80 percent of measurement range. The reason for that requirement is accuracy!

CONCLUSIONS/ RECOMMENDATIONS

In view of current gas turbine combustion system emission control achievements and the previous discussion, it is recommended that EPA re-examine its nonattainment requirements and amend the regulatory process. First, competing environmental impacts resulting from the use of add-on emission controls should be considered in both attainment and nonattainment areas, when the use of add-on emission controls will result in only a small reduction in nonattainment pollutant emissions. Second, cost effectiveness should be considered in determining LAER when the cost is clearly not "reasonable".

In the case of gas turbine combustion systems, the technology has forged ahead of the regulations for NOx emission control. It makes no economic sense, nor does it provide any real environmental benefit, to require add-on emission controls when combustion systems produce single digit pollutant emissions. Furthermore, gas turbine manufacturers will continue to develop lower NOx combustion systems only as long as economic incentives exist. If it is apparent that add-on controls such as SCR will be required no matter how low the uncontrolled NOx level achieved, the development of lower NOx combustion systems will be discouraged. Contrary to EPA policy, pollution prevention as a concept becomes meaningless for such systems and the inconsistency with that and other government programs and policy, such as the DOE advanced turbine system (ATS) with its 9 ppm NOx goal, becomes all to apparent. While this might not be considered important in combined cycles because SCR could be required, it could be very important for the many simple cycle machines that will be sold in coming years. No SCR currently exists that can be used with simple cycle, high firing temperature, F-technology gas turbines, or the next generation of even higher firing temperature, H-class machines from the ATS program.

VIII. REFERENCES

1. Schorr, M.M.; "NOx Emission Control for Gas Turbines: A 1995 Update on Regulations and Technology," CIBO NOx Control Conference, March 1995.

2. ASME Codes and Standards Committee B133, Subcommittee 2, Environmental Standards for Gas Turbines, Report 9855-3, *Low NOx Measurement: Gas Turbine Plants*, Dec. 4, 1998.

Table 1
Estimated Tons/Year Change in Emissions for STAG 207FA* With SCR & COC (Base Load, 8000 hr/yr, 20 ppm NH Slip, 45 oF Ambient)

	9 ppm NOx w/o SCR	3.5 ppm NOx w/SCR	TPY	3.5 ppm NOx w/SCR & COC	TPY
Natural Gas Only					
NOx	240	92	-148	92	−148
PM	36	41.6	+5.6	69.6	+33.6
NH	0	172	+172	164	+164
SO	40	39	−1	25	−15
Gas+400 hr/yr Oil					
NOx	294	116	−178	116	−178
PM	37.6	45.8	+8.2	86	+48.4
NH	0	172	+172	161	+161
SO	57	56	−1	36	−21

* DLN 2.6 combustor; emissions are per unit
SCR – Selective Catalytic Reduction
COC – CO oxidizing catalyst
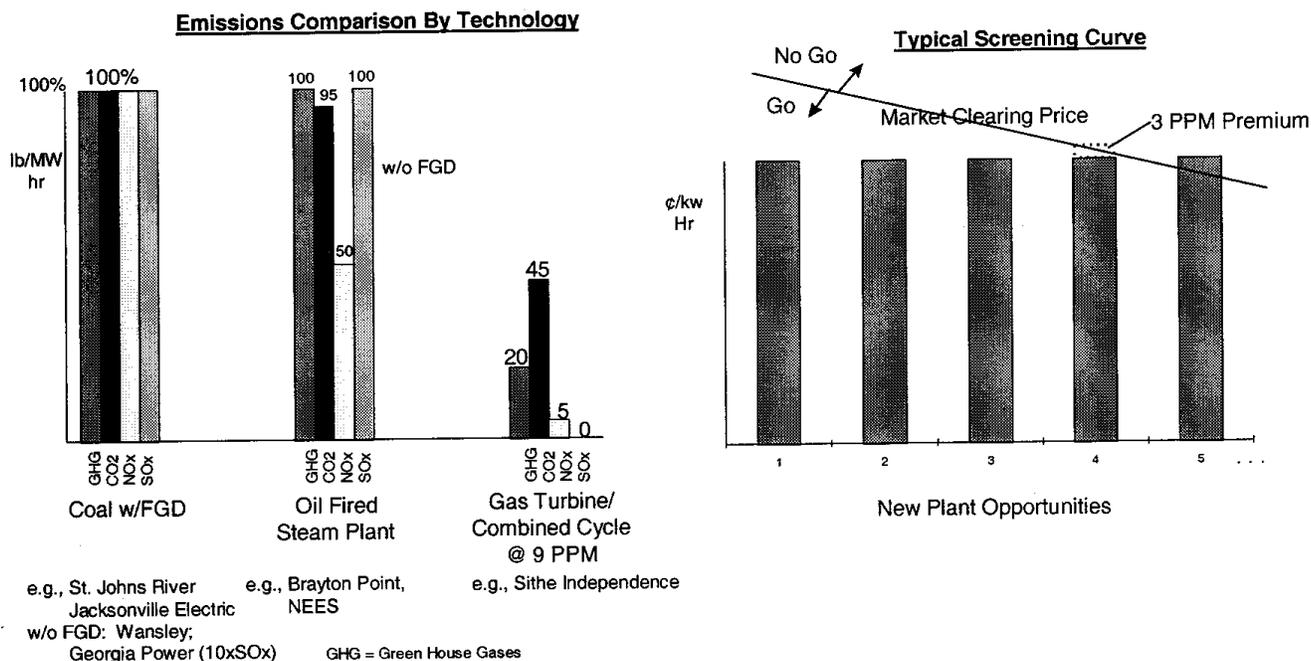
Figure 1.   Optimizing Emissions in a Deregulated Electricity Market
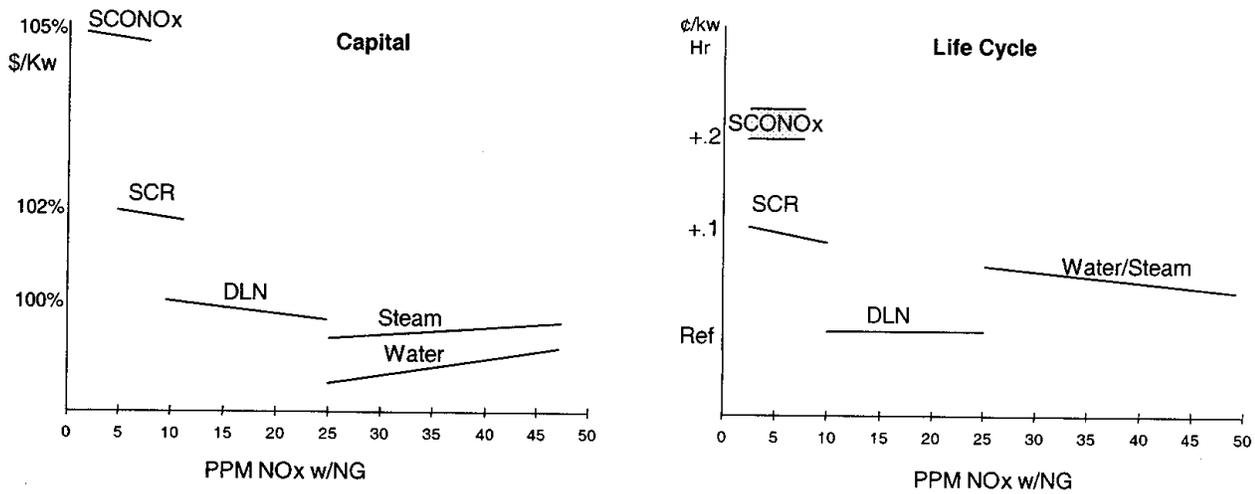
Figure 2.   Economic Break Points for Gas Turbine Combined Cycle Plants