HYDROGEN-ENRICHED NATURAL GAS OFFERS ECONOMIC NOX REDUCTION ALTERNATIVE

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Nitrogen oxide (NO_x) emission requirements for gas turbines are becoming tighter and tighter. Last year, California adopted a new standard for best available control technology (BACT) for gas turbines that calls for 5 ppmvd of NO_x emissions from new simple cycle gas turbine plants and 2.5 ppmvd NO_x for new combined cycles.[1] Meanwhile, the Massachusetts Department of Environmental Protection mandated that NO_x emissions in new combined-cycle and cogeneration plants should not exceed 2.0 ppmvd.

Even for existing machines, the need to purchase NO_x emission credits creates an incentive to find ways to lower NO_x emissions. The U.S. EPA now requires that every major new source of emissions must be offset by a reduction of an equal or greater amount of emissions from an existing source. The price in California in 1998 for NO_x offset credits averaged $11,750 for one ton per year of emissions. For power generators, the most feasible method of creating these emissions “offsets” is often reducing emissions at their older power plants.

In this regulatory climate, gas turbine operators are searching for cost-effective means to reduce NO_x emissions. An analysis of laboratory data and a screening level feasibility study has indicated that enriching natural gas with 10 to 15 percent hydrogen (H_2) could be an economically attractive way to reduce NO_x emissions from some gas turbines.

TRADITIONAL CONTROL

Since the 1970s, gas turbine operators have used steam or water injection into the combustor to control NO_x emissions. Because NO_x formation increases exponentially with flame temperature, by adding water or steam, the flame temperature decreases and NO_x emissions fall as well.

A drawback to steam and water injection is that a reduction in flame temperature also tends to increase CO emissions. With Pratt & Whitney’s FT-4 gas turbine, for example, when using water injection, the FT-4 can only decrease NO_x to 75 ppmv without having the CO emissions exceed 100 ppmv, and at 25 ppmv NO_x, the CO emissions are at 250 ppmv.[2]

Pratt & Whitney's FT-4 gas turbine is one candidate for the use of hydrogen-enriched natural gas for emissions reduction.

Since the mid-1980s, gas turbine manufacturers have been offering dry, low NO_x (DLN) combustors, which produce low NO_x emissions without the addition of water or steam. DLN combustors are designed to produce pre-mixed flames, in which the fuel and air are mixed together in a region where ignition does not begin. The flame front is located downstream of the mixing zone. The advantage of a pre-mixed flame is that lean air-fuel ratios can be used, where more air is present than is needed to completely burn the fuel. The presence of the excess air serves the same purpose as water or steam injection: it provides added thermal mass which decreases the flame temperature.

One problem faced by DLN combustors is the ability to operate at part-loads. Because the flow of air through a gas turbine is essentially constant, at part-loads the air-fuel ratio is leaner than it is at full load. At some point the lean flammability limit of natural gas is approached and problems arise with flame stability. DLN designers avoid this problem by adding equipment to adjust the amount of air going to the pre-mixing chamber (i.e., variable geometry), or by switching to a diffusion flame at low loads. Both of these techniques, however, tend to increase the complexity and cost of DLN combustors and lead to higher NO_x levels.

POST-COMBUSTION CONTROL

Currently, most gas turbine manufacturers cannot guarantee NO_x exhaust of less than about 25 ppmvd (corrected to 15 percent O_2 in the exhaust) when firing natural gas. Consequently, to meet the single digit limits now being demanded by regulatory authorities, a selective catalytic reduction (SCR) system must be installed downstream of the turbine.

In general, SCR catalysts are most effective in the temperature range of 600 to 800 F. The SCR is typically installed in the boiler section of a heat recovery steam generator (HRSG), therefore, where the exhaust gases have been cooled to the optimal temperature range for NO_x conversion. When installed as part of a combined cycle, an SCR will generally add \$15 to \$25/kW to the total cost of the plant.

In simple-cycle applications, one does not have the luxury of being able to cool the exhaust gas to the favorable temperature range. However, at least one catalyst manufacturer, Engelhard, has developed a zeolite-based catalyst that is more tolerant of high temperatures. While this high-temperature catalyst is more expensive than traditional SCR catalyst and has to be replaced more frequently, the favorable experience in several simple-cycle applications prompted California’s mandate of 5 ppmvd NO_x for simple-cycle applications.

To eliminate the concerns associated with the use of ammonia in SCR systems, an alternative catalytic exhaust conversion technology called SCONOx has recently been developed that does not use ammonia. SCONOx systems have been shown to achieve low levels of NO_x emissions (down to 2 ppmvd). SCONOx systems are currently significantly more expensive than traditional SCRs, however; it remains to be seen whether increased application will reduce costs.

RETROFIT ECONOMICS

When looking at the options for achieving NO_x emission reductions from existing gas turbines, it becomes clear that few cost-effective options are available. The one exception is the use of water injection. If demineralized water is already available, water injection can generally be implemented on a 20-30 MW gas turbine for less than \$50,000. If a water demineralization system has to be added, the cost jumps to \$150,000. However, because of the inverse relationship between CO and NO_x, the amount of NO_x reduction that can be achieved before running into CO emissions limits may be small.

Because of the complexity of DLN designs, retrofitting an older gas turbine with a DLN combustion system is a costly option. In addition to the combustors themselves, new fuel valves and fuel control systems must be provided. Retrofitting DLN combustors to a 20- 30 MW gas turbine will typically cost \$1 million, which translates to \$33-50/kW. Consequently, DLN combustors are typically only installed in new machines.

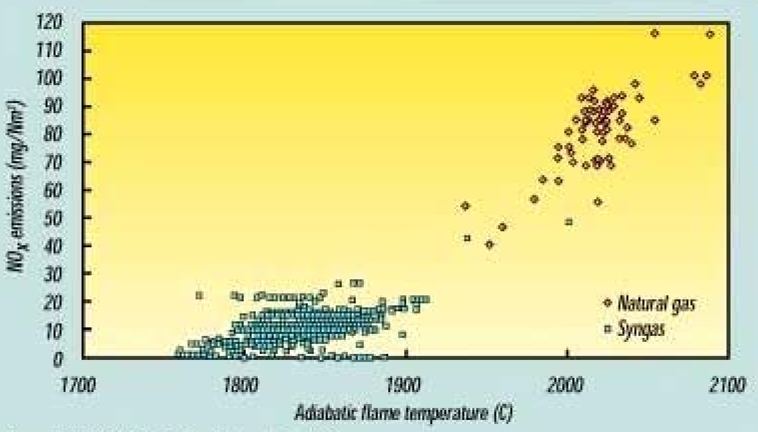
Adding SCR to an existing combined-cycle unit is prohibitively expensive unless the HRSG was designed with room for the SCR catalyst rack, in which case the cost will be on the order of \$25/kW. The SCR will also result in a slight increase in heat rate due to the added pressure drop through the exhaust system.

Adding SCR to an existing simple-cycle plant is also an expensive undertaking. In addition to the SCR, the existing exhaust stack must be moved to allow room for the SCR. The exhaust duct also typically must be widened considerably to reduce the flow velocity to levels required in SCR systems.

HYDROGEN-ENRICHED NATURAL GAS

Various studies have examined the feasibility of using hydrogen-enriched natural gas as a method for achieving NO_x reductions in gas turbines. GE has conducted a series of tests on H_2-rich fuels at their combustion lab in Schenectady, NY.[3] These tests have confirmed the superior flame stability of H_2-rich fuels. The tests have also shown that natural gas with 10-20 volume percent H_2 will also have improved emissions performance. Specifically, H_2-enriched natural gas was shown to allow lower NO_x emissions with steam injection (for a given CO limit), and to provide a greater flame out operating range with a pre-mixed combustor.

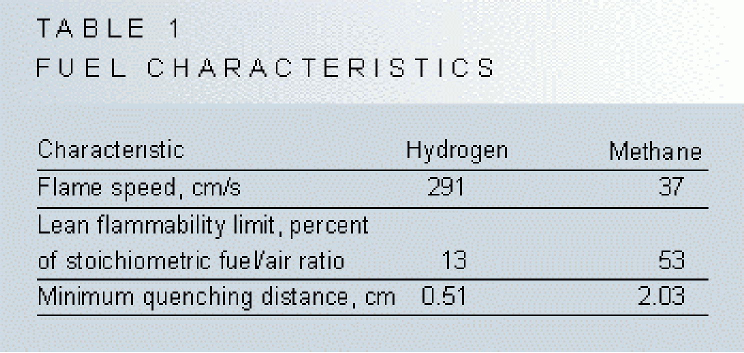
FIGURE 1
NOX EMISSIONS AT DEMKOLEC'S IGCC FACILITY



Source: EPRI 1998 Gasification Technologies Conference

Perhaps the most extensive experience burning an H_2-rich fuel in gas turbines comes from the group of integrated gasification combined-cycle (IGCC) plants that were built in the 1990s. In an IGCC plant the gas turbines are fired with syngas that typically contains more than 20 volume percent H_2 (dry basis) and even greater amounts of CO. Representatives of the Dutch IGCC project, Demkolec, have published data showing that NO_x emissions for their Siemens V94.2 gas turbine range between 6 and 30 ppmv, with less than 5 ppmv of CO, when running on syngas with approximately 60 volume percent CO and 30 volume percent H_2 (Figure 1).[4] These remarkably low levels are achieved by diluting the fuel with both N_2 and water vapor to the point that the adiabatic flame temperature of the diluted syngas is between 3,275 and 3,450 F. This is about 350 F cooler than the lowest stable natural gas flame temperature. Consequently, when running on natural gas, the turbine can only limit NO_x emissions to 150 ppmv.

TABLE 1
FUEL CHARACTERISTICS



Characteristic	Hydrogen	Methane
Flame speed, cm/s	291	37
Lean flammability limit, percent of stoichiometric fuel/air ratio	13	53
Minimum quenching distance, cm	0.51	2.03

Adding H_2 to natural gas would mitigate both the high CO emissions problem in steam and water injection applications and the part-load dynamics problem in DLN applications. When compared to natural gas, H_2 has a higher flame speed and broader flammability limits (Table 1). The latter means H_2 will continue to have a stable flame at leaner conditions than natural gas, while the former means that the kinetics of H_2 combustion are much quicker than that of natural gas, and consequently, the addition of a thermal moderator such as steam or water will be less likely to quench the reactions before completion. This enhanced reaction rate occurs as a result of the increase in the radical pool that accompanies the addition of H_2. Since the conversion of CO to CO_2 is largely controlled by the

OH radical, the CO reaction is more likely to continue to completion with added H_2 even at somewhat lower temperatures. The Demkolec experience cited above is an example of this.

HYDROGEN SUPPLY

While the benefits of using H_2 as a fuel supplement may be well-established, the practical aspect of supplying H_2 to a gas turbine is not. Several studies have examined the feasibility of using steam reforming of methane in a so-called chemically recuperated gas turbine (CRGT) cycle.[5-6] However, evaluations have revealed that a CRGT cycle would be much more expensive than a conventional combined cycle. The designers of CRGT cycles have tried to maximize methane conversion in order to reach efficiencies that are comparable to conventional combined cycles. As a result, the temperature pinch points of the steam reformer are quite small, which leads to the high capital cost.

There may be an opportunity to use steam reforming to partially convert natural gas to H_2, and thereby receive the benefits of H_2-rich fuel combustion without the cost of a full CRGT cycle. However, the simplest approach is to purchase bulk quantities of liquid hydrogen from an industrial gas supplier. An H_2 supplier will generally lease equipment for storing and vaporizing the hydrogen so that the up front capital cost is minimized. This makes it an attractive option for simple cycle applications where the small number of operating hours per year cannot justify large capital expenditures. The price of liquid H_2 depends on the region of the country and the quantity of H_2 being purchased. Prices can range from \$2-\$6 per thousand scf. Based on a calorific value for H_2 of 274 Btu/scf, these prices translate to \$7.30-21.90/MMBtu, which is clearly more than the price of natural gas.

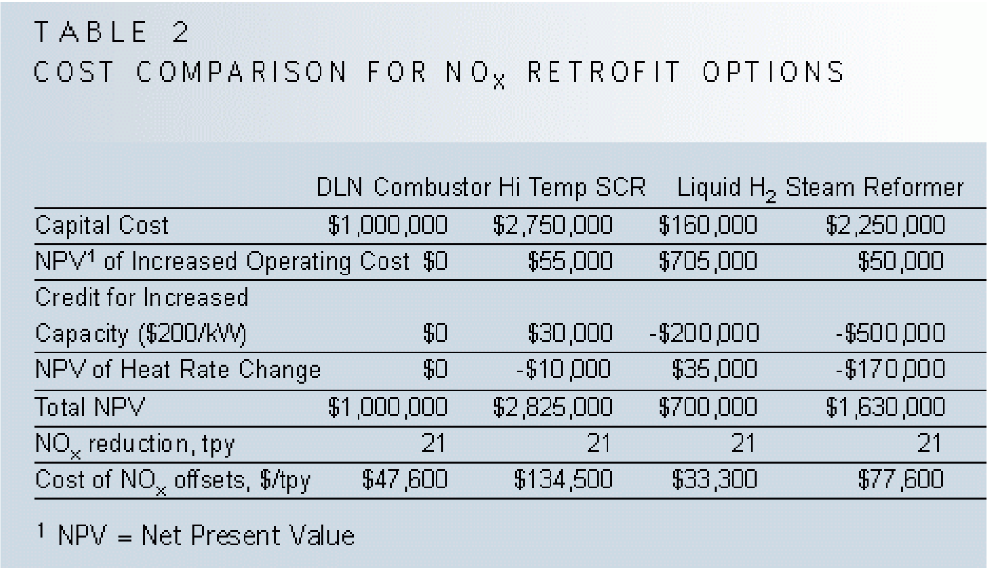


TABLE 2
COST COMPARISON FOR NO_x RETROFIT OPTIONS

	DLN Combustor	Hi Temp SCR	Liquid H_2	Steam Reformer
Capital Cost	\$1,000,000	\$2,750,000	\$160,000	\$2,250,000
NPV[1] of Increased Operating Cost	\$0	\$55,000	\$705,000	\$50,000
Credit for Increased Capacity (\$200/kW)	\$0	\$30,000	-\$200,000	-\$500,000
NPV of Heat Rate Change	\$0	-\$10,000	\$35,000	-\$170,000
Total NPV	\$1,000,000	\$2,825,000	\$700,000	\$1,630,000
NO_x reduction, tpy	21	21	21	21
Cost of NO_x offsets, \$/tpy	\$47,600	\$134,500	\$33,300	\$77,600

[1] NPV = Net Present Value

However, when burning a mixture of 12 volume percent H_2 and 88 volume percent natural gas and using water injection to limit NO_x to 25 ppmv, economic analyses indicate that the total cost of achieving the NO_x reductions would be less than the cost of retrofitting a turbine with DLN combustors. This analysis was based on applying the technology to a simple-cycle FT-4 gas turbine operating 500 hours per year. The possibility of generating H_2 on site by adding an HRSG and a steam reformer was also investigated, but the costs proved to be higher than trucking in liquid H_2. The details can be found in an ASME technical paper,[7] but the results are summarized in Table 2.

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AUTHORS

Jeffrey N. Phillips is a Project Manager with Fern Engineering, Inc., a consulting engineering firm that provides expert advice and design services to a worldwide clientele of gas turbine users.

Rick Roby is President and Technical Director of Combustion Science & Engineering, Inc., a research, development and consulting engineering firm that specializes in experimental and computational analysis of gas turbine combustion systems.