GER-4192

GE Power Systems

Combustion Modification – An Economic Alternative for Boiler NO_x Control

Blair A. Folsom
Thomas J. Tyson
GE Power Systems
Schenectady, NY

Combustion Modification – An Economic Alternative for Boiler NO_x Control

Contents

Combustion Modification – An Economic Alternative for Boiler NO_x Control

Abstract

Several provisions of the Clean Air Act Amendments of 1990 will require "deep" NO_x control on a large number of large utility and industrial boilers in the eastern United States. EPA's final ruling on Section 126 petitions filed by several northeastern states (December 1999) and the more recent revival of the "NO_x SIP Call" both include provisions for trading of NO_x credits and state-wide NO_x budgets that are based on emissions of 0.15 lb/10^6 Btu of heat input.

Selective Catalytic Reduction (SCR) and Combustion Modification using Reburn or Advanced Reburn are the only commercially viable alternatives capable of reducing NO_x to this level. Although the optimum cost effective approach for any given unit will depend on site specific factors, the general trend is expected to be towards SCR as the technology of choice for the larger, higher baseline NO_x units and for Combustion Modification (with Reburn or Advanced Reburn) for smaller units or units with lower baseline NO_x emissions.

Reburn is a commercially proven control technology that can reduce NO_x by as much as 60% by the staging of fuel and air within the furnace. The level of NO_x reduction can be increased to over 70% by integrating a "trim" Selective Non-Catalytic Reduction system with the basic Reburn system (the integrated system is referred to as Advanced Reburn). Although both Reburn and Advanced Reburn systems can utilize a wide range of fuels, natural gas generally produces the deepest NO_x control.

By integrating Advanced Reburn using natural gas as the reburn fuel (Advanced Gas Reburn) with Dense Pack steam turbine technology, deep NO_x control can be achieved along with additional power generating capacity and heat rate improvement. The economics of this integrated approach are particularly attractive.

Introduction

This paper presents an overview of compliance alternatives for U.S. coal-fired utility boilers facing requirements for deep NO_x control under Title I (Attainment of National Ambient Air Quality Standards for ozone) of the Clean Air Act Amendments of 1990. The focus is on the performance and economic tradeoffs between Combustion Modification, using Reburn and Advanced Reburn, and Selective Catalytic Reduction (SCR). The regulations and implications for NO_x reduction requirements are discussed first. Then, the Reburn and Advanced Reburn technologies are presented including design factors and performance experience on coal-fired utility applications. The economic tradeoffs between Combustion Modification and SCR alternatives are then addressed for both emissions trading and non-trading scenarios. Finally, the integration of Advanced Gas Reburn with GE's Dense Pack steam turbine technology is discussed including an overview of the technology and the economic benefits for deep NO_x control applications.

Regulatory Drivers

The NO_x emissions from many U.S. coal-fired utility boilers must be reduced due to several recent and ongoing regulatory actions under the Clean Air Act of 1990 designed to achieve attainment of the ambient air quality standards for ozone. In September 1998, the EPA issued a ruling regarding NO_x emissions from a 22 State region in the eastern U.S. that were contributing to ozone levels exceeding the national ambient air quality during a five month summer period (the ozone season). The EPA established reduced NO_x budgets for each state in the region and required them to submit state Implementation Plans (the "NO_x SIP Call") wherein NO_x emissions would be reduced to meet those NO_x budgets. The NO_x budgets were prepared assuming that NO_x emissions from utility power plants as a group would average 0.15 lb/10^6 Btu (SIP Call NO_x Level) in 2007.

In May 1999, the U.S. Court of Appeals reviewed the SIP Call and indefinitely suspended EPA's implementation schedule. More recently (March 2000), the court removed this suspension of the NO_x SIP Call and confirmed its provisions but reduced the 22-state region to 19 states.

In the midst of this NO_x SIP Call activity, EPA also implemented other provisions (Section 126) of the Clean Air Act that require comparable ozone season emission reductions from about 400 industrial and utility plants within the same region. There are also several other areas in the U.S. with local ambient ozone problems, such as Atlanta and Texas, that are implementing additional NO_x control regulations.

These ozone season regulations typically include the potential for emissions trading among affected units. With emission trading, it is not necessary to control each unit to meet the specific NO_x emission limit. Plant owners have the flexibility to over-control some units where site specific factors reduce the NO_x control cost and to use the extra NO_x reduction (below the NO_x emission limit) to offset higher NO_x on other units where deep NO_x control may be particularly expensive.

While the final requirements and implementation schedules may well be resolved in the courts, it is clear that a large number of coal-fired utility boilers will need deep NO_x emission control to near the SIP Call NO_x level in the next few years to meet these ozone season NO_x regulations.

Annual NO_x emission control is required under Title IV of the Clean Air Act of 1990 for acid rain mitigation. The Title IV NO_x reduction requirements were established by EPA based on the capabilities of "Low NO_x Burner Technology" and are not as stringent as Title I. *Table 1* lists the Title IV target NO_x levels for boilers by firing configuration.

Firing Configuration	Title IV NO_x (lb/10^6 Btu)
Tangential	0.40
Wall	0.46
Cell	0.68
Cyclone	0.86

Table 1. Title IV target NO_x levels

Title IV allows intra-utility trading and requires compliance in 2000 on an annual average basis. Since the compliance dates for the Title I NO_x regulations discussed above are in the 2003-2005 time frame, plant owners must provide additional control beyond the Title IV target levels over a 3-5 year period to meet the ozone season NO_x regulations.

Figure 1 shows the NO_x reduction required to achieve 0.15 and 0.20 lb/10^6 Btu as a function of the initial NO_x level, presumably the level required for compliance with Title IV. The nominal maximum NO_x reduction capabilities of Reburn, Advanced Reburn and Selective Catalytic Reduction (SCR) are overlaid.

The NO_x control capability of SCR can be adjusted by varying the volume of the catalyst and/or rate of ammonia injection. NO_x reductions as high as 90% are achievable. This is sufficient to reduce baseline NO_x from as high as 1.50 lb/10^6 Btu to the SIP Call NO_x Level and thus covers the full range of Title IV baseline levels.

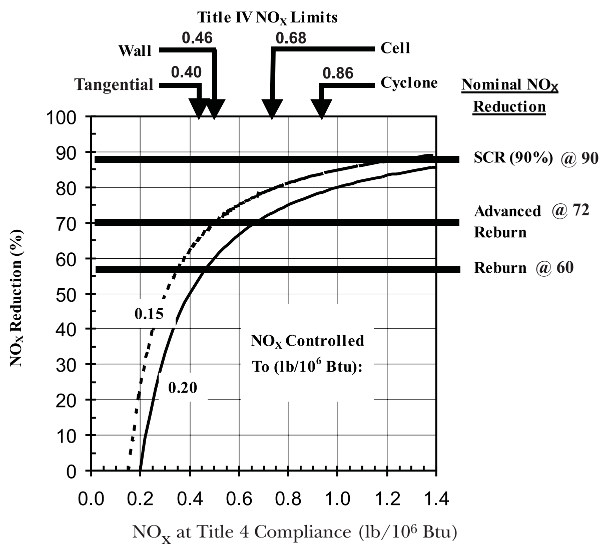

Figure 1. NO_x reduction required to achieve SIP call NO_x limit from Title IV target NO_x levels

As will be discussed in *Figure 1*, Combustion Modification via Reburn and Advanced Reburn can typically achieve NO_x reductions of 60% and greater than 70%, respectively. This is sufficient to meet the SIP Call NO_x Level from baselines as high as 0.55 lb/10^6 Btu. Thus, tangential and wall-fired units operating at the Title IV target levels of 0.40 and 0.46 lb/10^6 Btu, respectively, can use Combustion Modification to meet the SIP Call NO_x limit. Also, cell burner units, where site specific factors allow low NO_x burners to control NO_x below the Title IV target level to 0.55, may also use Combustion Modification.

Reburn and Advanced Reburn

Reburn and Advanced Reburn are combustion modification NO_x control technologies. Reburn integrates fuel and air staging techniques and has been applied commercially to a broad range of coal-fired utility boilers. *Table 2* shows GE EER's experience to date.

Any hydrocarbon fuel can be used to provide the staged fuel for Reburn. Most Reburn installations to date have utilized natural gas as the Reburn fuel (Gas Reburn) since it provides the greatest NO_x reduction and lowest retrofit cost. With Gas Reburn, NO_x emissions are typically reduced by about 60% [References 1-3].

Advanced Gas Reburn (AGR) is the integration of Gas Reburn with injection of a nitrogen containing NO_x reduction agent (N-Agent) such as urea or ammonia. This can be accomplished in a number of configurations which may be selected based on site specific conditions [References 4-7].

Utility	Plant	Capacity (MW)	Firing Config	Status
Allegheny Power	Hatfield 2	595	Opp	Install 00
Potomac Electric	Chalk Point 1	355	Opp	Install 00
Potomac Electric	Chalk Point 2	355	Opp	Install 00
Tennessee Valley Authority	Allen 1	330	Cyc	Complete
Tennessee Valley Authority	Allen 2	330	Cyc	OFA Complete
Tennessee Valley Authority	Allen 3	330	Cyc	OFA Complete
Baltimore Gas & Electric	Crane 1	205	Cyc	Complete
Baltimore Gas & Electric	Crane 2	205	Cyc	Complete
Conectiv	Edge Moor 4	160	Tan	Complete
P.S. Company of Colorado	Cherokee 3	158	FW	Complete
New York State E&G	Greenidge 4	104	Tan	Complete
Illinois Power	Hennepin 1	71	Tan	Complete
Eastman Kodak	Kodak Park 15	50	Cyc	Complete
City Water, Light & Power	Lakeside 7	33	Cyc	Complete

Table 2. GE EER reburn experience on utility boiler

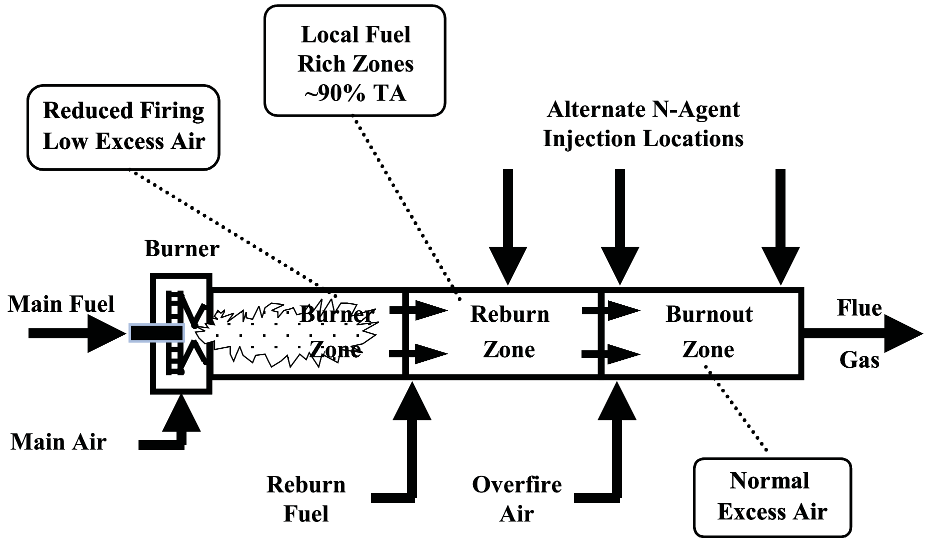

Figure 2. Schematic diagram of reburn and advanced reburn

Figure 2 is a schematic representation of Gas Reburn and AGR. The combustion process is divided into three zones. In the Burner Zone the main fuel is burned with combustion air. Although no changes to the main burners are required, it is generally cost-effective to replace the existing burners with low NO_x burners or modify them to achieve comparable low NO_x performance for additional NO_x reduction. The main burners are turned down to accommodate the subsequent injection of the Reburn fuel (natural gas for Gas Reburn) and are operated at the lowest excess air commensurate with satisfactory lower furnace performance considering flame stability, flame shape, combustion efficiency and ash deposition. The reburn fuel is injected downstream of the flames. The reburn fuel injection system is designed to produce locally fuel rich zones operating at approximately 90% theoretical air (TA) which is optimum for NO_x reduction. The NO_x reduction increases with the reburn fuel injection rate. For low injection rates, the reburn fuel is stratified to produce locally fuel rich zones. As the reburn fuel injection rate is increased, these locally fuel rich zones eventually merge to cover the entire furnace cross-section. Overfire air is injected to complete the combustion of fuel fragments exiting the reburn zone. The overfire air injection system is designed for variable injection to optimize mixing of the overfire air with the furnace gases as the reburn fuel injection rate is varied.

Advanced Gas Reburn adds a trim NO_x reduction via injection of a N-Agent. The N-Agent can be injected in a number of configurations including: downstream of the overfire air, with the overfire air, and into the reburn zone. Site specific factors determine the optimum injection configuration. Injection downstream of the overfire is equivalent to the Selective Non-Catalytic Reduction (SNCR) process. This is a commercial process offered by several vendors using ammonia and urea as the N-Agents.

Reburn and Advanced Reburn can be applied to boilers with all firing configurations. As an example, *Figure 3* shows the application Advanced Gas Reburn to a front wall fired utility boiler. The main burners can be conventional or low NO_x burners and the flames from these burners are in the Burner Zone. The reburn fuel injectors are positioned on the furnace walls above the top row of main burners.

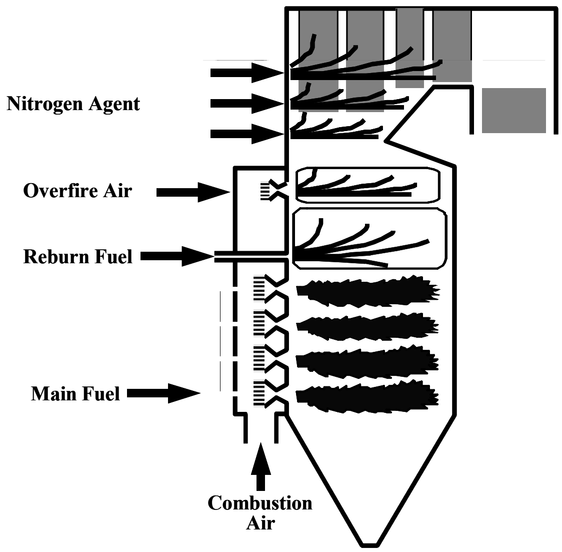

Figure 3. Advanced reburn on a wall-fired boiler

The specific reburn fuel injection elevation is selected to be close to the burners where temperature is high, but displaced enough so that the combustion in the flames is essentially complete. GE EER utilizes second generation gas injectors for Gas Reburn systems to convert the pressure in the natural gas supply line to high injection velocity. The injector arrangement is optimized based on site specific factors to produce optimum mixing over the full operating range of the boiler and with variable natural gas injection rates. This generally involves multiple injectors grouped in several tubewall penetrations. The Reburn Zone extends from the gas injectors to the overfire air ports which are higher in the furnace.

The elevation of the overfire air ports is selected by balancing the need for residence time in the Reburn Zone with completion of combustion prior to the convective pass. This generally results in positioning the overfire air ports near the nose of the furnace. GE EER uses a dual concentric overfire air port design with variable swirl. This allows the overfire air injection velocity to be varied independent of the injection flow rate so that optimum mixing can be maintained as the reburn gas injection rate (and hence overfire air injection rate) and load vary. The burnout zone is the region between the overfire air ports and the convective pass.

Figure 3 shows N-Agent injectors above the overfire air ports to complete the Advanced Gas Reburn process.

GE EER has developed a design methodology for applying Reburn and Advanced Reburn. It uses physical flow and Computational Fluid Dynamic (CFD) modeling along with heat transfer and chemical kinetic codes in the context of GE EER's extensive database on pilot and full-scale Reburn applications to optimize the design for site specific factors.

Figure 4 shows the NO_x reduction achieved with several commercial Reburn systems on coal fired utility boilers. These applications represent a broad range of unit and fuel characteristics: wall, tangential and cyclone firing; coal and gas as the main and Reburn fuels; baseline NO_x ranging from 0.13 to 2.0 lb/10^6 Btu; and unit capacities from 40 to 330 MW. (A 600 MW Gas Reburn system is being installed in Spring 2000.) The NO_x reductions for all units in the figure exceed 60% with some substantially higher.

For maximum NO_x reduction and minimum NH_3 slip from the SNCR component, the N-Agent must be injected so that it is available for reaction with the furnace gases within a temperature window close to 1800°F. This typically requires multiple N-Agent injection elevations in the upper furnace and/or convective pass to accommodate varying load and ash deposition patterns over the sootblowing cycle. However, if the NO_x reduction requirement is reduced, a much simpler SNCR system can be employed. In conjunction with Elkraft Power Company of Denmark, GE EER has applied this simplified

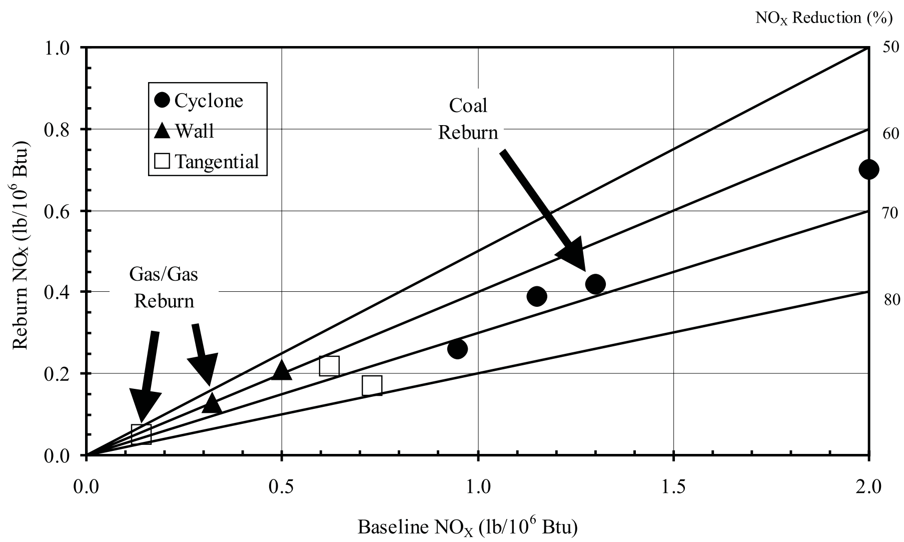

Figure 4. NO_x control results from GE EER reburn applications on utility boilers

SNCR concept to a 285 MW utility boiler [Reference 8]. *Figure 5* shows the NO_x reduction and ammonia (NH_3) slip for injection of urea through a single elevation for two loads. At 46% load, the urea is injected at near optimum temperature so that NO_x reduction is maximized with low NH_3 slip. At full load, the same injection location achieves less NO_x reduction and NH_3 slip is higher. The 30%

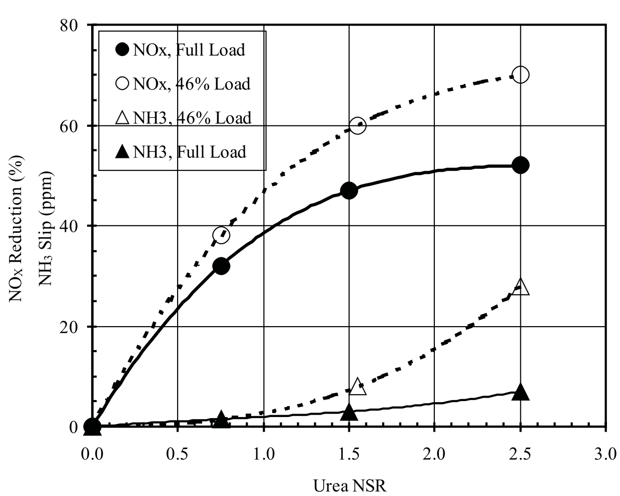

Figure 5. NO_x reduction and NH_3 slip for SNCR on 285 MW utility boiler

NO_x reduction level corresponds to nitrogen stoichiometric ratio (NSR) of 0.5 to 0.7 and results in NH_3 slip well under 2 ppm. NH_3 slip of 2 ppm or less avoids air heater plugging with high sulfur coals.

With AGR, the NO_x reduction is produced by two components: Gas Reburn and SNCR. This provides the opportunity to adjust the relative contribution of the two components to optimize performance. *Figure 6* illustrates these tradeoffs for NO_x reduction to the SIP Call NO_x level for wall and tangentially fired units operating with low NO_x burners at the Title IV target levels of 0.46 and 0.40 lb/10^6 Btu, respectively. For example, for the wall fired unit NO_x must be reduced by 67% reduction to meet 0.15 lb/10^6 Btu. This can be achieved with the Gas Reburn component at 53% reduction and the SNCR component at 30% reduction, respectively, both conservative levels for the respective technologies. The modest NO_x reduction from the Gas Reburn component allows the reburn fuel injection rate to be lowered which reduces operating cost. The modest level of NO_x reduction from SNCR can be achieved with a much

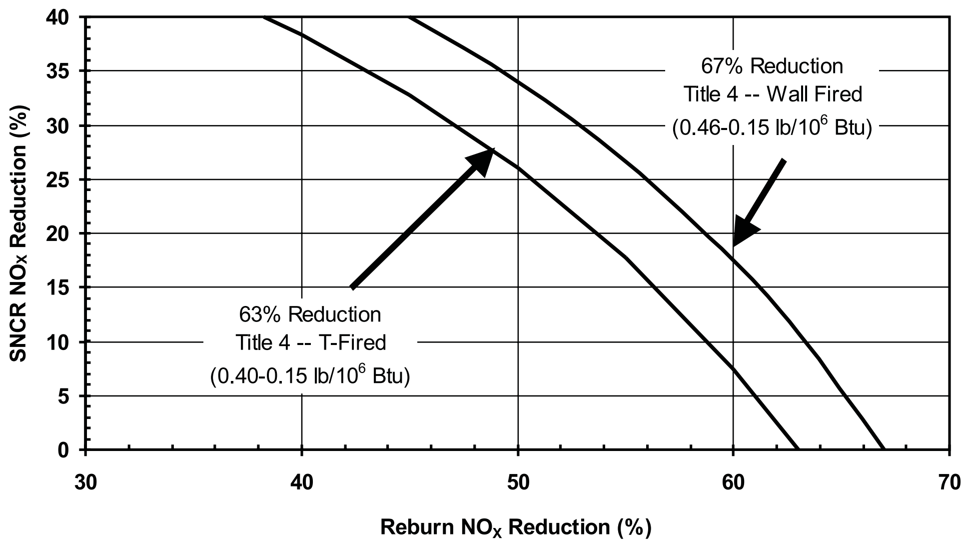

Figure 6. Advanced Reburn tradeoffs for SIP Call compliance: Reburn and SNCR components

simpler system than the conventional highly tuned SNCR system and with reduced risk of NH_3 slip (and air heater plugging).

Figure 7 shows the cumulative NO_x reduction achievable by layering combustion modification NO_x control technologies on a typical wall-fired boiler. Low NO_x burners provide the initial 50% reduction from 0.92 lb/10^6 Btu down to the Title IV target level of 0.46 lb/10^6 Btu. Gas Reburn reduces NO_x by an additional 53 to 60% depending on the reburn fuel flow of 13 to 16%, respectively. Adding SNCR (AGR) reduces NO_x further to less than 0.15 lb/10^6 Btu. The 0.12 lb/10^6 Btu point corresponds to 16% reburn fuel and 33% NO_x reduction from SNCR. The 0.15 lb/10^6 Btu point corresponds to 13% reburn fuel with 30% NO_x reduction from SNCR. *Figure 8* shows these same points as circles on a plot of NO_x vs. gas injection rate to better illustrate the tradeoffs.

The preceding discussion focused on AGR with the N-Agent injection downstream of the reburn overfire air. A number of other configurations are under development including injection with the overfire air, into the reburn zone and multiple stages of N-Agent injection [*References 6-7*]. These alternate configurations provide retrofit flexibility and by optimizing the coupling the N-Agent injection with the Reburn system, NO_x reduction is synergistically enhanced.

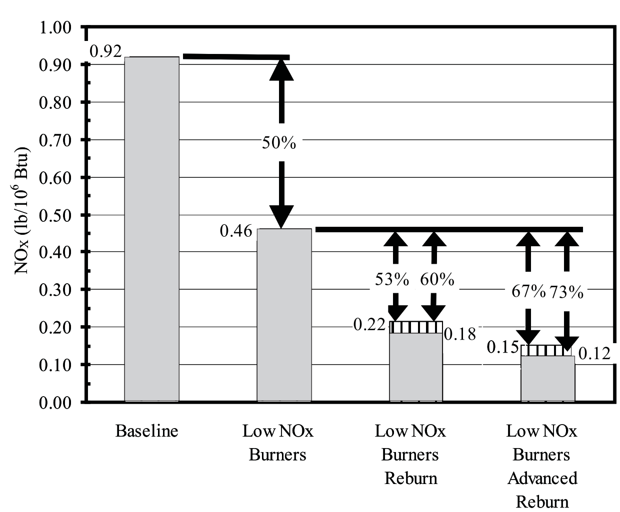

Figure 7. Cumulative NO_x for layered combustion modification technologies

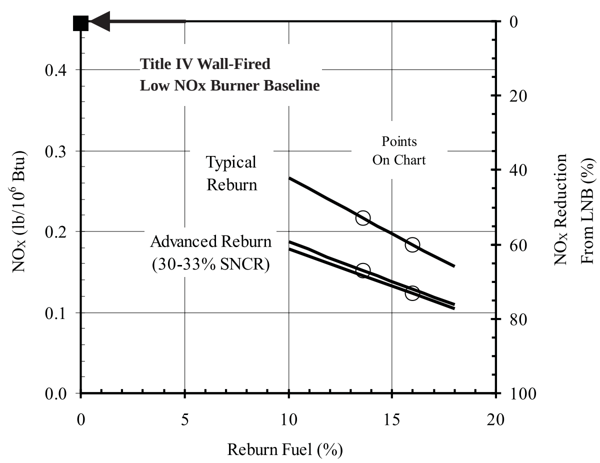

Figure 8. Effect of gas firing rate on reburn and advanced reburn NO_x

Comparative Economics of SIP Call Compliance with Combustion Modification and SCR

A comparative economic analysis of Reburn and Advanced Reburn (using coal, oil and natural gas as Reburn fuels) and overfire air (OFA) with SCR has been conducted. OFA was included with SCR since it results in a slightly lower net NO_x control cost compared to SCR alone by reducing catalyst volume. *Table 3* lists the parameters for each NO_x control technology; the key parameters are highlighted below. The ratio of reburn NO_x reduction to reburn fuel flow is the Reburn Efficiency Factor (REF). Based on EER's full scale experience, the REF was approximated as 5.0 and 3.0 for less than and greater than 30% NO_x reduction, respectively. Maximum Reburn and Advanced Reburn NO_x reductions were capped at 60 and 73% respectively corresponding to a maximum of 33% NO_x reduction from the SNCR component. For SCR, the catalyst cost and life was based on the work of Cichanowicz [Reference 9].

The analysis utilized a modified Electric Power Research Institute (EPRI) Technology Assessment Guide methodology which has been widely used to compare the economics of emission control alternatives. This involves determining the total annual cost of NO_x control in \$/ton. The retrofit capital cost is estimated and then distributed over the life of the equipment as a series of constant annual costs. The first year operating cost is also estimated and converted to a series of annual costs accounting for

	Units	Reburn	Advanced Reburn	SCR + OFA
Capital cost (300 MW)				
Reburn (G/O/C)	\$/kw	10/15/20	10/15/20	
SNCR	\$/kw		12	
OFA	\$/kw			5
SCR	\$/kw			Vary
Total	\$/kw	10/15/20	22/27/32	Vary
Max. NOx reduction	%	60	73	92
Reb eff below 30%	$\%NO_x/\%Reb.$	5.0	5.0	
Reb eff above 30%	$\%NO_x/\%Reb.$	3.0	3.0	
N-agent				
Type			Urea	Aq. NH_3
Utilization	%		26.7	100.0
Non fuel eff. impact	%	0.50	0.50	0.50
Catalyst bypass				Yes
Catalyst life	Years			4

Table 3. NO_x control technologies in economic analysis

inflation, etc. These two annual cost components are then added and divided by the annual NO_X reduction to calculate the total cost of NO_X control in $/ton. *Table 4* shows the economic factors and other parameters used in the analysis.

Two scenarios were evaluated: No trading and full inter-utility trading.

Parameter	Units	Value
Final NO_X	lb/10^6 Btu	0.15
Ozone season	Months	5.00
Capacity factor	%	65
Coal sulfur	lb/10^6 Btu	1.20
Economics		
Life	Years	15.00
Interest rate	%/yr	8.00
Levelization factor		1.00
Ash disposal cost	$/ton	10.00
Value of SO_2	$/ton	200.00
Maintenance	%Cap./yr	4.00

Table 4. Economic analysis parameters

No NO_X Trading Scenario – Control to 0.15 Lb/10^6 Btu

This “no trading” scenario involves comparison of the NO_X control costs to meet 0.15 lb/10^6 Btu for each technology. The following variables were evaluated. (*See Table 5*.)

Parameter	Range	Units
Baseline NO_X	0.25 – 1.6	Lb/10^6 Btu
Boiler Capacity	50 - 1,300	MW
Reburn Fuel Cost	0.00 - 1.50	$/$10^6$ Btu over coal
SCR Installed Cost	40 - 80	$/kw for 300 MW

Table 5. NO_X control costs per variable

Figures 9 and 10 show the results for a 300 MW unit with NO_X reduced from a variable initial level to 0.15 lb/10^6 Btu. *Figure 9* shows Reburn and Advanced Reburn using coal, oil and gas as the reburn fuels with variable reburn fuel to coal cost differential. *Figure 10* shows the *Figure 9* Reburn and Advanced results as an outline and adds OFA-SCR with variable SCR cost.

In *Figure 9*, the maximum NO_X reduction for Reburn has been set at 60%, a conservative level

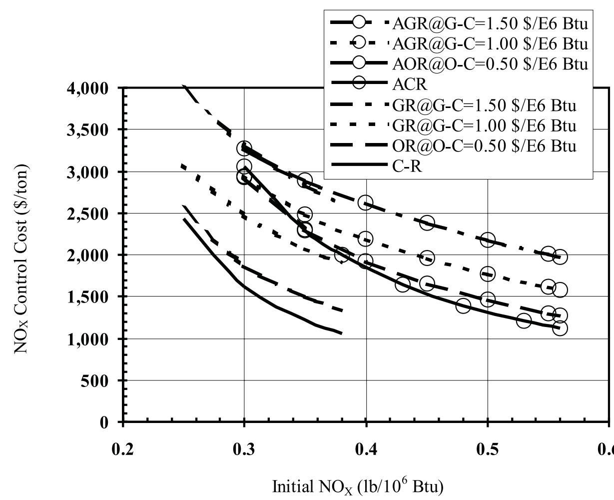

Figure 9. NO_X control cost for Reburn and Advanced Reburn to 0.15 lb/10^6 Btu – effect of initial NO_X

based on full-scale utility boiler experience. For Advanced Reburn, the maximum NO_X reduction has been set at 73% which corresponds to 33% reduction from the Reburn level. Based on these reductions, to achieve 0.15 lb/10^6 Btu, the maximum initial NO_X is 0.38 and 0.55 lb/10^6 Btu, respectively. For all Reburn and Advanced Reburn configurations, the cost of NO_X control decreases as the initial NO_X increases.

The reburn fuels include coal and oil with differential costs over coal of $0.00 and $0.50/$10^6$ Btu, respectively, and natural gas with differential costs over coal of $1.00 and $1.50/$10^6$ Btu. For both Reburn and Advanced Reburn, the differential cost of the reburn fuel over the main coal fuel is the key variable influencing the total cost of NO_x reduction. For the initial NO_x range where Reburn can be applied, Reburn is lower in cost than Advanced Reburn except at the highest reburn fuel cost differential (natural gas at \$1.50 /10^6 Btu). For higher initial NO_x, the NO_x control cost of Advanced Reburn continues to decrease down into the same \$/ton range as Reburn.

In *Figure 10*, the full range of the Reburn and Advanced Reburn results from *Figure 9* are shown as an enclosed region. It should be noted that this includes all reburn fuels with reburn fuel to coal cost differentials ranging from 0.00 to \$1.50/10^6 Btu. OFA-SCR results are shown for SCR capital costs ranging from \$40 to \$80/KW. The center of the range (\$60/KW) corresponds to a straightforward application (Nominal). The low end of the range (\$40/KW) corresponds to an advanced low cost future SCR application. The high end of the range (\$80/KW) represents an increase from Nominal but is by no means the maximum. Several utilities have recently been quoted SCR systems at well over \$100/KW. The NO_x control costs for all of the SCR cases are higher than the highest Reburn and Advanced Reburn results at the same initial NO_x. The differences are substantial. For example at an initial NO_x of 0.40 lb/10^6 Btu, the highest cost for Advanced Reburn is 68% of the cost for the Nominal SCR case.

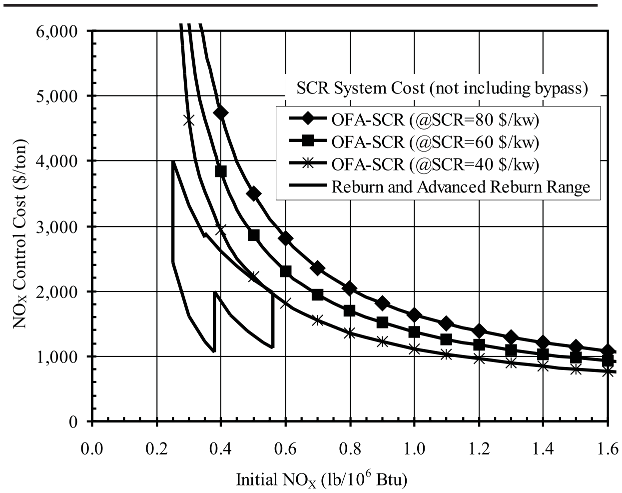

Figure 10. NO_x control cost for all technologies to 0.15 lb/10^6 Btu – effect of initial NO_x

As with Reburn and Advanced Reburn, the NO_x control cost for SCR decreases as the initial NO_x increases. Thus, for high initial NO_x, such as from a cell or cyclone unit, the NO_x control cost for SCR drops into the \$/ton range for Reburn and Advanced Reburn at lower initial NO_x.

All of the preceding results were for a 300 MW unit. Similar analyses were conducted for a range of unit capacities from 50 to 1300 MW. Since the capital cost of the OFA-SCR systems is substantially greater than the Reburn and Advanced Reburn systems, the capacity effect is greater for OFA-SCR. At high capacity, the costs for OFA-SCR approach those for Reburn and Advanced Reburn.

In summary, for control to 0.15 lb/10^6 Btu, the selection of the lowest cost technology depends on the initial NO_x. For initial NO_x less than about 0.55 lb/10^6 Btu, Reburn and Advanced Reburn have lower cost than OFA-SCR. For initial NO_x greater than 0.55 lb/10^6 Btu, Reburn and Advanced Reburn cannot meet the requirement and OFA-SCR must be used with \$/ton cost approaching or lower than those of Reburn and Advanced Reburn, especially for the large high baseline NO_x units.

NO_x Trading Scenario

The preceding analysis showed that two key boiler variables, initial NO_x and boiler capacity have significant effects on the NO_x control cost with the cost decreasing as both initial NO_x and boiler capacity increase. This suggests the potential for reducing total NO_x control cost by over-controlling on the large, high initial NO_x units (where \$/ton costs are low) and under controlling on the other units. It is expected that the final ozone related NO_X regulations will allow emission trading similar to the Title IV SO_2 allowance trading system where SO_2 prices are established by market forces on a $/ton basis. Of course, there is potential for more complex trading structures which may limit trading to specific geographical areas or make a ton of NO_X in one region equivalent to a different amount in another region.

The cost of NO_X allowances available on the open market has a significant impact on the selection of the lowest cost NO_X control approach. An analysis has been conducted to evaluate the economic tradeoffs of such trading. *Table 6* lists the parameters used in the analysis. The objective is to determine the lowest cost NO_X control strategy for a 300 MW tangentially fired boiler operating at the Title IV NO_X limit of 0.40 lb/10^6 Btu to reach 0.15 lb/10^6 Btu via emission control and/or purchased allowances. Four alternatives are considered:

- **Do Nothing.** In this case the required NO_X allowances are purchased on the open market.
- **Gas Reburn.** Gas Reburn can be applied to reduce NO_X by 60% to 0.16 lb/10^6 Btu, just slightly above the 0.15 lb/10^6 Btu level. This requires purchasing a small amount of NO_X emission allowances on the open market.
- **Advanced Reburn.** Advanced Reburn can be applied to reduce NO_X by 73% to 0.11 lb/10^6 Btu, which is below the 0.15 lb/10^6 Btu level. The excess NO_X reduction is sold as NO_X allowances on the open market.
- **SCR.** An SCR system is installed to reduce NO_X by 80% to 0.08 lb/10^6 Btu, well below the 0.15 lb/10^6 Btu level. The excess NO_X reduction is sold as NO_X allowances on the open market.

Unit Capacity (MW)	300		
Firing Configuration	Tang.		
Title 4 NO_x lb/10^6 Btu	0.40		
Ozone Season Cap. Fac. (%)	65		
SO_2 Allow. Price (%/ton)	200		
Life (Years)	15		
Interest Rate (%)	8		
Dollars	Con.		
Technology	**Reburn**	**Adv. Reburn**	**SCR**
Capital Cost ($/kW)	10	22	50
NO_x Reduction (%)	50	72	80
Reburn Fuel - Coal ($/$10^6$ Btu)	1.00	1.00	
Catalyst Life (Years)			4

Table 6. Trading analysis parameters

The results are shown in *Figure 11* where the total annual cost of NO_X control is plotted as a function of the NO_X allowance trading price for each control approach. Lines which slope upward as NO_X emission allowance trading price increases correspond to under-control and vice versa.

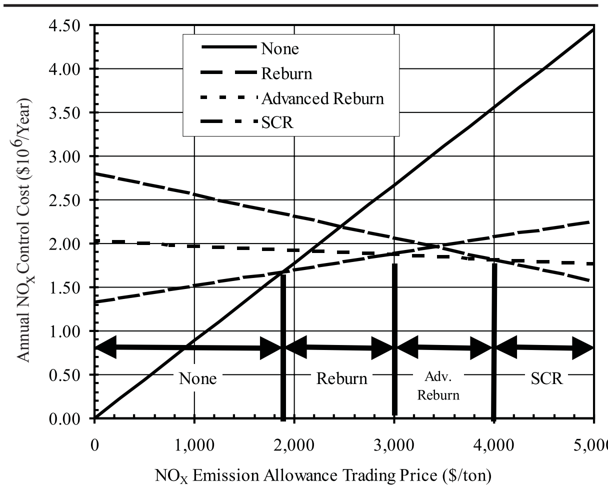

Figure 11. NO_X control cost for trading, 300 MW wall-fired boiler, initial NO_X 0.40 lb/10^6 Btu

For low NO_x allowance trading price (less than about $1,900/ton), the lowest cost approach is to Do Nothing and simply purchase all required NO_x allowances. At high NO_x emission allowance trading price (greater than about 4,000 $/ton), the lowest cost approach is to massively over-control with SCR and sell the extra NO_x allowances at the high price. For intermediate NO_x emission allowance trading prices ($1,900 to $4,000/ton) Reburn and Advanced Reburn are the lowest cost approaches. Thus the market price for NO_x allowances is a key factor affecting both the selection of the lowest cost approach and the total cost of NO_x control.

An analysis has been conducted to estimate the NO_x allowance market price in a free trade scenario. In such a scenario, each utility will conduct its own analysis of applicable NO_x control technologies, estimate risks and project a NO_x allowance price. To simulate this, GE EER has conducted a systematic analysis of all coal fired utility boilers in the SIP Call region. These units were grouped into categories based on their initial NO_x and capacity and an analysis similar to that outlined above was conducted for each combination of initial NO_x and capacity. The lowest cost NO_x control approach was identified as a function of the NO_x allowance trading price. Then, the NO_x credit allowance price was iterated while monitoring the total NO_x allowances bought and sold. At low NO_x allowance trading price, the purchases exceeded the sales and the NO_x allowance trading price was iterated upwards. This process was continued until the amount of purchases and sales balanced. This analysis was then repeated for a range of parameters such as cost of reburn fuel, future cost reductions in SCR, etc.

The results showed that for a broad range of parameters, the NO_x allowances should trade in the range of $2,000 to $3,000/ton. Thus, in the case presented above (300 MW tangentially fired unit), Reburn and Advanced Reburn will be the technology of choice. The results also showed that the NO_x control market will be shared between Reburn, Advanced Reburn and SCR with the distribution depending on site specific factors. Generally, SCR is favored for large high baseline NO_x units and Reburn and Advanced Reburn are favored for units with initial NO_x typical of the dry bottom wall and tangentially fired units with penetration increasing as unit capacity decreases.

Dense Pack Steam Turbine Uprate

Dense Pack is a retrofit steam turbine modification technology developed by GE Power Systems to increase the efficiency and power generating capacity of utility steam turbines. Dense Pack is custom designed for each turbine to achieve the most efficient steam path in the existing turbine section outer shell. This high efficiency steam path produces a lower heat rate and increased output for the same steam flow. The maintenance requirements of the steam turbine are also reduced due to decreased bucket and nozzle solidity and reduced rotor diameters which reduce solid particle erosion with internal repair/inspection intervals extended to ten or more years.

Dense Pack is the latest evolution of GE steam turbine designs that began in 1903. *Figure 12* shows the improvement in high pressure steam path efficiency achieved over the last 40 years. High pressure section efficiency is now in the 94–95% range. This improvement was the result of a systematic analysis of steam turbine performance to identify the sources of inefficiency followed by development of improvement for the critical components.

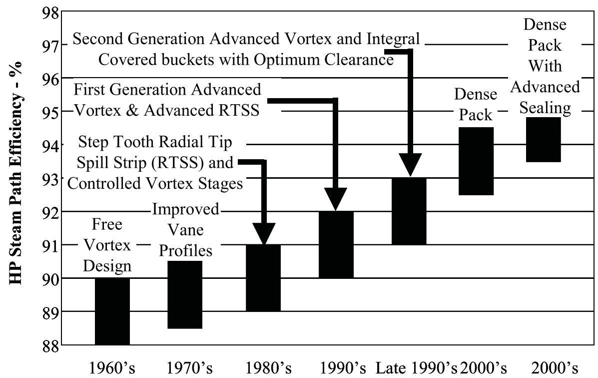

Figure 12. GE high pressure steam turbine efficiency improvement history

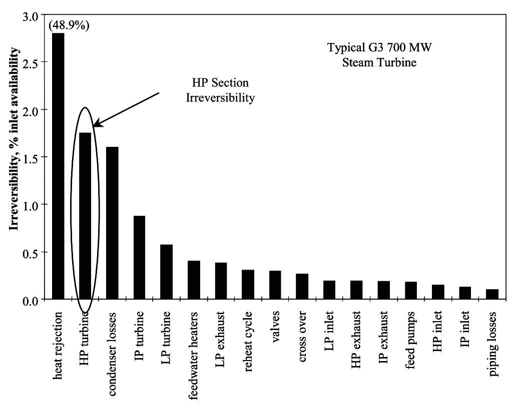

Figure 13. Irreversibilities in typical 700 MW steam turbine

Figure 13 shows the loss (irreversibility) components for a typical steam turbine (GE G3 Turbine with 700 MW capacity). Except for the loss due to the condenser, the high pressure turbine section contributes the greatest irreversibility and was the focus of the improvements. *Figure 14* shows the efficiency losses within the high pressure section. Nozzle and bucket aerodynamic profile losses, secondary flow losses, and leakage losses account for roughly 80% to 90% of the total stage losses. Hence, to ensure high-efficiency turbine designs, it is necessary to use highly efficient nozzle and bucket profiles and to minimize leakage flows without sacrificing turbine reliability.

Dense Pack replaces steam turbine internal

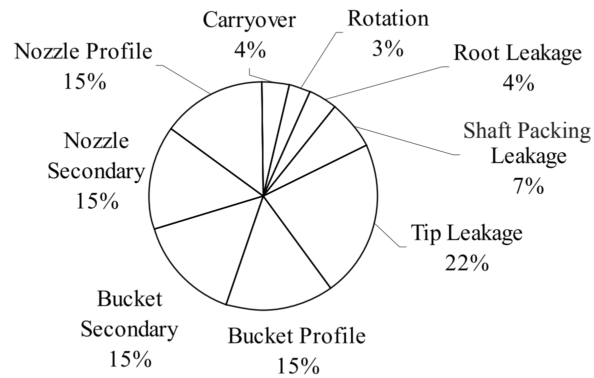

Figure 14. Distribution of high pressure section steam turbine losses

components to provide the most efficient steam path that will fit within an existing outer turbine shell. In short, the Dense Pack replaces the existing turbine stages with a larger number of stages in the same space. A Dense Pack section replacement includes the following eight basic components and features:

1. New, high efficiency, high pressure or high pressure / intermediate pressure turbine rotor with increased number of stages
2. Optimized steam path diameter
3. New, high efficiency diaphragms
4. New high efficiency first stage nozzle box plate or nozzle diaphragm
5. Lower bucket and nozzle solidity (decreased number of buckets and nozzles per stage)
6. New inner shell(s)
7. New shaft packing, packing heads and steam inlet ring assemblies
8. Improved shaft and bucket sealing capability

The basis of Dense Pack design is the fundamental thermodynamic principal that more turbine stages at smaller wheel diameters creates a more efficient steam path. Recent steam turbine technology advances now allow an

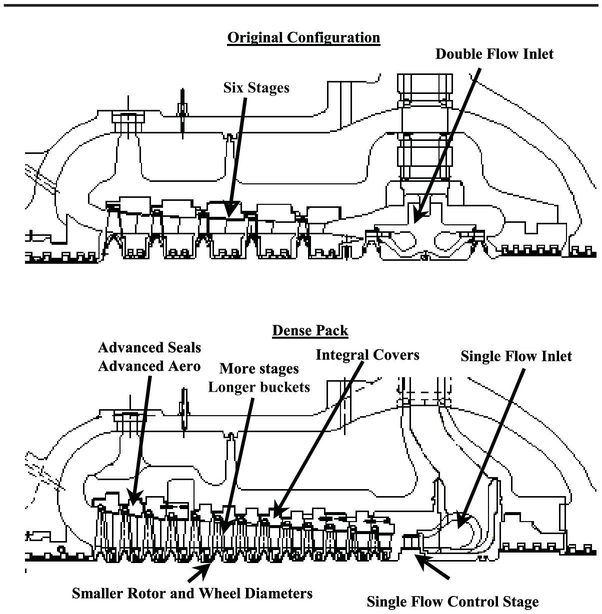

Figure 15. Comparison of high pressure steam turbines: baseline and Dense Pack

increased number of stages in the same span. *Figure 15* compares a conventional turbine with a Dense Pack.

Each Dense Pack is custom designed for the specific turbine and steam flow conditions. In general it is possible to recover all efficiency loss due to aging and to increase the efficiency above the original as new steam turbine condition. Since the high pressure section(s) is/are replaced, there is potential to design Dense Pack to match the normal MCR steam conditions or alternate conditions. This includes the case of interest here for integration with AGR where the Dense Pack is configured for increased flow at the design point steam pressure for increased power generating capacity. Depending on the capabilities of the boiler, generator and other components, it may be possible to boost heat input by as much as 17%. *Table 7* summarizes the baseline and Dense Pack performance where the Dense Pack is designed for a more modest 12% flow increase.

When the turbine is operated at the normal MCR steam flow, turbine efficiency is increased by 1.4% resulting in a commensurate 1.4% increase in power generating capacity. When steam flow is increased to 12% above MCR, steam turbine efficiency decreases slightly to a 1.2% improvement over baseline resulting in a 13.3% power generation increase. To avoid throttling losses, in this example the boiler is operated in sliding pressure service.

GE introduced Dense Pack in 1998. To date 13 units have been sold totaling over 6,000 MW. The first units will enter commercial service in 2000.

Integrated System (AGR-DP)

By integrating AGR with Dense Pack (AGR-DP) designed for flow increase, NO_x can be reduced to SIP Call levels, power generating capacity can be increased, and heat rate can be decreased. This section discusses the performance of this integrated technology focusing on application to a 300 MW wall-fired boiler operating with NO_x at the Title IV level of 0.46 lb/10^6 Btu where the Dense Pack is designed for a steam flow increase of 12%.

Steam Turbine Configuration	Steam Flow Enthalpy (% of MCR)	Steam Turbine Efficiency (% of Baseline)	Power Generation (% of Baseline)
Baseline (as new)	100.0	100.0	100.0
Dense Pack	100.0	101.4	101.4
Dense Pack	112.0	101.2	113.3

Table 7. Baseline and Dense Pack performance summary

The four equipment and operating scenarios (Cases) listed in *Table 8* will be discussed:

Figure 16 shows the fuel flows and power generation and *Figure 17* shows the emissions for the four conditions. Case A is the baseline MCR operating condition where the turbine is operating in the "as new" condition with no aging loses. Case B is AGR applied at MCR. Cases C and D are AGR-DP; Case C is operation at MCR and Case D is operation with the 12% flow increase. With AGR-DP, NO_x, SO_2 and particulate emissions are less than baseline levels even with an increase in power generation by 13.3%. Note that the total fuel flow for AGR-DP reflects the increase in steam flow plus a slight heat rate penalty for AGR, primarily due to the increased latent heat loss of natural gas compared to coal.

One possible strategy for optimum use of AGR-DP is as follows. During the summer ozone season when deep NO_x control is required and power sells for a premium, AGR-DP is operated in case D with the AGR system in service and maximum steam flow to the turbine. NO_x is reduced to the SIP Call NO_x level, SO_2 and particulate emissions are reduced slightly (since less coal is fired) and power generation is increased 13.3% over MCR. For the rest of the year, when the low NO_x burners alone can meet the NO_x requirements and power prices are lower, the system is operated in Case C with the AGR system out of service and MCR steam flow to the turbine. Due to the efficiency increase, power output is up by 1.4% firing 100% coal and emissions are at baseline.

Case	Turbine Configuration	NO_x Control Technology	Steam Flow (% of MCR)
A	Baseline (as new)	Low NO_x Burners	100%
B	Baseline (as new)	Low NO_x Burners + AGR	100%
C	Dense Pack	Low NO_x Burners + AGR	100%
D	Dense Pack	Low NO_x Burners + AGR	112%

Table 8. Four equipment and operating cases

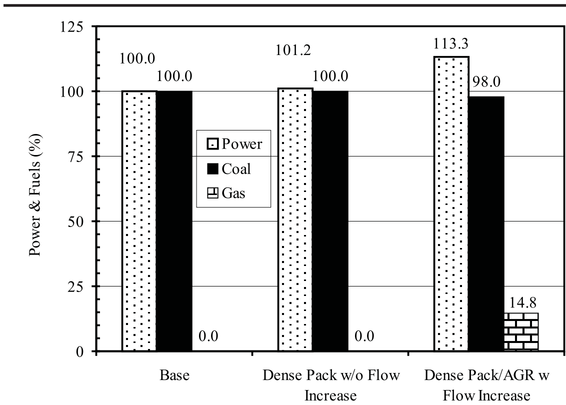

Figure 16. Firing rates and power generation for various technologies

An economic analysis has been conducted to illustrate the costs and benefits of this integrated technology comparing three approaches to reducing NO_x to the SIP Call NO_x level:

- The base turbine (as new) with SCR
- The base turbine (as new) with AGR
- AGR-DP

The AGR-DP configuration operates at peak flow in the summer and nominal flow for the rest of the year as discussed above. The SCR and AGR cases without Dense Pack operate only at MCR.

The economic factors used in the analysis are

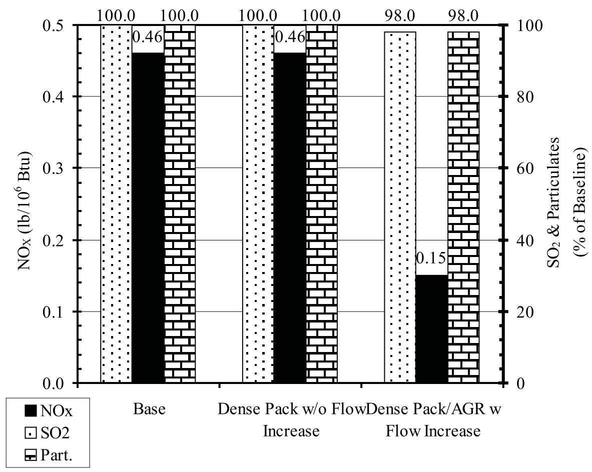

Figure 17. Emissions for various technologies

summarized in *Table 9*. The technology performance factors and capital costs are typical values which will vary with site specific factors. The capital costs are expressed in terms of the $/KW of the original MCR capacity of the unit. Note that the capital cost for the Dense Pack of $30/KW of MCR capacity corresponds to $225/KW for the increased power generation capacity (13.3%).

The results will be considered from three viewpoints:

- Cost of NO_x control where the profits from the incremental power sales are credited against the cost of NO_x control at market value
- Cost of incremental power generation where the value of the NO_x reduction is credited against the cost of power generation at market value
- Payback analysis where the costs are credited by both the incremental power sales and value of NO_x reduction

Figure 18 shows the NO_x control cost where the

Category	Variable	Units	Value
Unit	Capacity	MW	300.00
	Capacity Factor	%	65.00
	Maintenance	%/yr	4.00
Fuels	Coal	$/E6 Btu	1.50
	Gas	$/E6 Btu	2.50
NOx	Title IV Baseline	lb/E6 Btu	0.46
	Control Level	lb/E6 Btu	0.15
SCR	Capital Cost	$/kw	50.00
	Catalyst Life	Years	4.00
AGR	Capital Cost	$/kw	22.00
	Gas Firing	%	13.11
	Nitrogen Agent		Urea
	NSR		1.50
Dense Pack	Capital Cost	$/kw	30.00
	Heat rate improvement at MCR	%	1.40
	Flow increase		12.00
	Heat rate improve. With flow increase	%	1.20
	Flow Increase	%	10.00
Economic Factors	Dollars		Constant
	Levelization factor		1.00
	Life	Years	15.00
	Capital recovery factor		0.12
Plant Factors	Fuel SO2	lb/E6 Btu	1.20
	Ash disposal cost	$/ton	10.00
	Ozone season	Months	5.00

Table 9. AGR-DP analysis parameters

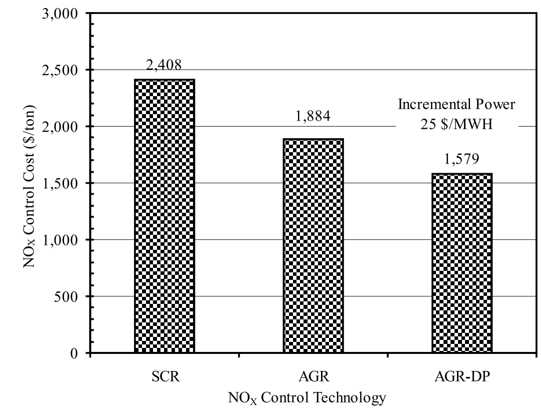

Figure 18. NO_X control cost for various technologies

incremental power is credited at $25/MWH. Compared to SCR, AGR reduces cost by 22% and AGR-DP reduces cost by 34%. The effect of the sale price of the incremental power is shown in *Figure 19*. Note that as the incremental power sale price increases, the effective cost of NO_X reduction decreases. At $44/MWH, the cost of NO_X control drops to zero. This means that the sales of the incremental power at $44/MWH entirely pay for the capital cost (annual capital charges) of the AGR-DP system and the operating cost of AGR

Figure 20 shows the cost of incremental power generation as a function of the value of the NO_X reduction. The cost of power decreases as

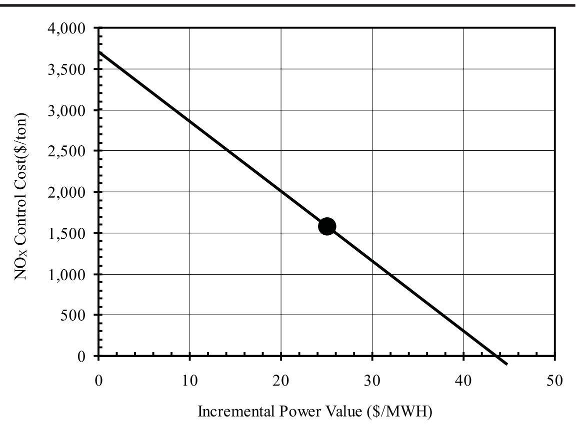

Figure 19. Effect of incremental power sale price on AGR-DP NO_X control cost

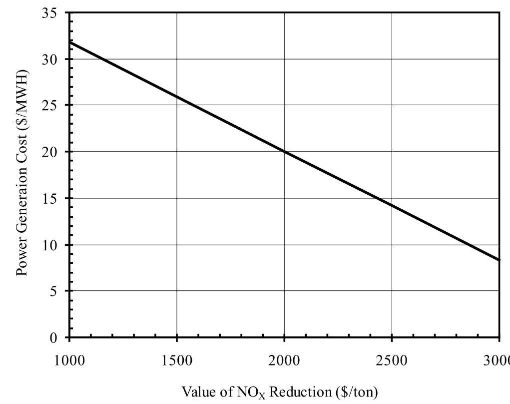

Figure 20. Incremental power generation cost for AGR-DP

the value of NO_X reduction increases. It is expected that the trading price of NO_X allowances will be in the range of $2000-2500/ton when the market matures. This corresponds to incremental power generation costs of $14-20/MWH. This means that sale of the incremental power at a price greater than this amount will be profit to the utility.

Finally, *Figure 21* shows the payback for investing in the integrated AGR Dense Pack technology

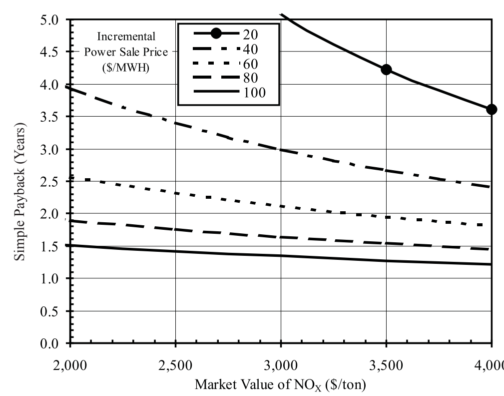

Figure 21. Payback for AGR-DP

based on variable values for NO_X and power generation. The payback can be less than two years depending on the prices.

Conclusion

Title IV will result in most units meeting the EPA target NO_x levels using low NO_x burner technology. For the additional NO_x reduction required for SIP Call compliance, the primary alternatives are Combustion Modification (with Reburn and Advanced Reburn) and Selective Catalytic Reduction (SCR). If the final regulations or utility preference require that the 0.15 lb/10^6 Btu level be achieved, SCR will be the only technology for initial NO_x greater than about 0.55 lb/10^6 Btu. However for lower initial NO_x, including the 80% of the units which have dry bottom wall and tangentially fired boilers, Reburn or Advanced Reburn will substantially undercut the cost of SCR on the smaller units. Under a NO_x trading scenario, the NO_x allowance trading price will be the key factor affecting both the selection of the lowest cost NO_x control technology and the total cost of NO_x control. A free trading scenario should result in NO_x allowances trading in the range of $2,000-3,000/ton.

The integrated AGR-DP system is a cost effective approach for deep NO_x control to meet ozone-related regulations with the added benefit of a significant increase in power generation capacity. During the summer the AGR system is in service controlling NO_x to the SIP Call level (0.15 lb/10^6 Btu) and power generation is increased by over 13%. Other pollutants (SO_2 and particulates) are slightly reduced. For the rest of the year, the AGR system is out of service and the boiler heat input is entirely from coal at the normal full load heat input. Power is increased by 1.4% with no change in emissions from baseline. Thus, this approach ensures that there is no increase in annual emissions of any pollutant.

The overall economics of AGR-DP are quite favorable to the utility: NO_x is reduced at a cost that is low compared to projected NO_x allowances, the incremental power generation cost is low compared to summer power sales prices and payback can be under two years.

It should be recognized that the NO_x control levels, steam turbine performance and costs discussed in this paper are examples of the typical values expected in commercial US utility applications. Site specific factors may alter these factors. A site specific study must be conducted to confirm the design, performance factors and economics.

References

1. C. Latham, et. al., "NO_x Control Using Combustion Modification Technologies," presented at Electric Power 2000, Cincinnati, Ohio, April 2000.

2. B. A. Folsom, et. al., "Updated Experience Using Reburn Technology for Utility Boiler NO_x Emissions Reduction," presented at the EPRI-EPA-DOE Combined Utility Air Pollutant Control Symposium, Atlanta, GA, August, 1999.

3. B. A. Folsom, et. al., "Field Experience – Reburn NO_x Control," presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium (The Mega Symposium), Washington DC, EPRI Report No. TR-108683-V1, 1997.

4. B. A. Folsom, et. al., "Advanced Gas Reburning Demonstration and Commercial Gas Reburning System Upgrade," Pittsburgh Coal Conference, 1996.

5. B. A. Folsom, et. al., "Advanced Reburning with New Process Enhancements," presented at the EPRI/EPA 1995 Joint Symposium on Stationary Combustion NO_x Control, Kansas City, Missouri, 1995.

6. V. Zamansky, et. al., "Combined Reburning/N-Agent Injection Systems for Over 90% NO_x Control," presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium (The Mega Symposium), Washington DC, EPRI Report No. TR-108683-V1, 1997.

7. V. Zamansky, et. al., "Enhanced NO_x Control Via Gas Reburning With Injection of Additives in the Reburning Zone," presented at the International Gas Research Conference, San Diego, California, 1998.

8. M. Berg, et. al., "NO_x Reduction by Urea Injection in a Coal Fired Utility Boiler," NO_x Symposium, 1993.

9. J. Cichanowicz, "SCR for Coal-Fired Boilers: A Survey of Recent Utility Cost Estimates," presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium (The Mega Symposium), Washington DC, EPRI Report No. TR-108683-V1, 1997.

List of Figures

List of Tables