DOE/NETL-2001/1140

Enhancing the Use of Coals by Gas Reburning-Sorbent Injection

A DOE Assessment

January 2001

U.S. Department of Energy
National Energy Technology Laboratory

P.O. Box 880, 3610 Collins Ferry Road
Morgantown, WV 26507-0880
and
P.O. Box 10940, 626 Cochrans Mill Road
Pittsburgh, PA 15236-0940

website: www.netl.doe.gov

Disclaimer

Executive Summary

This document serves as a U.S. Department of Energy (DOE) post-project assessment of a project in Clean Coal Technology (CCT) Round 1, "Enhancing the Use of Coals by Gas Reburning-Sorbent Injection" (GR-SI), conducted by Energy and Environmental Research Corporation (EER). In July 1987, EER entered into a cooperative agreement to conduct this demonstration project, along with the Gas Research Institute (GRI) and the State of Illinois (Department of Commerce and Natural Resources) as the other project participants. The three intended hosts for the project were Illinois Power Company (IP); Central Illinois Light Company (CILCO); and the City of Springfield, Illinois, Department of Water, Light, and Power (CWLP). DOE provided 50% of the total project funding of $38 million.

The demonstrations of the combined NO_x and SO_2 emission control technology were conducted between December 1987 and April 1994 on IP's Hennepin 71-MWe tangentially fired Unit 1, and on CWLP's Lakeside 33-MWe cyclone-fired Unit 7. Field testing on CILCO's Unit 7, a 117-MWe wall-fired boiler, could not be performed because of excessive cost requirements determined during the design phase of the project.

GR-SI is a combination process that controls both NO_x and SO_2 emissions from coal-fired utility boilers. NO_x is controlled using staged fuel firing, and 10 to 25% of the total heat input is supplied by injecting natural gas into the reburn zone located in the boiler's upper furnace. The use of natural gas in the reburn zone is referred to as gas reburning (GR). Overfire air is injected downstream of the reburn zone, followed by dry calcium-based sorbent injection (SI) for SO_2 capture. The performance objectives of this project were to demonstrate:

- 60% reduction in NO_x emissions
- 50% reduction in SO_2 emissions when firing medium- to high-sulfur coals
- Acceptable unit operability and economical operating cost.

The project performance met these objectives. The emissions reduction targets were exceeded at both units tested, averaging 67% for NO_x and 53% for SO_2 at Hennepin, and 60% for NO_x and 58% for SO_2 at Lakeside. The operability of both units was found acceptable in long-term testing, although SI required more maintenance such as increased frequency of sootblowing of heat transfer surfaces in the convective pass. No significant adverse boiler impacts were observed, such as large decreases in thermal performance or electrostatic precipitator collection efficiency. Other emission impacts on air, water, and land remained within acceptable limits.

Economics of the GR-SI process have been estimated for a hypothetical 300-MWe cyclone boiler fired with 3% sulfur coal, and assuming a $\$1.00/10^6$ Btu price differential between gas and coal fuels. For GR, the capital cost is \$17/kWe and the levelized cost is \$545/ton NO_x removed (constant dollar basis). For SI, the capital cost is \$13/kWe and the levelized cost is \$489/ton SO_2 removed (constant dollar basis), using hydrated lime sorbent.

While the performance objectives of the project were met, no U.S. market potential can be identified either for the combined GR-SI process or for the SI technology alone. The reason is that while EER's cost estimates indicate that SI could be competitive with conventional flue gas desulfurization processes using wet limestone scrubbing, SI cannot meet currently mandated or future SO_2 emission standards.

On the other hand, the U.S. market potential appears to be promising for NO_x control via GR, especially for cyclone boiler NO_x control for which no other combustion modification alternative exists. Although neither Hennepin nor Lakeside currently operate the GR systems retained from this demonstration project, 11 existing and planned reburning installations by EER in the U.S. have a total capacity of 1700 MWe.

The U.S. Environmental Protection Agency, GRI, and DOE were the recipients of the Air & Waste Management Association's 1997 J. Dean Sensenbaugh Award for their collaborative work in developing GR as a viable commercial NO_x control option.

Contents

List of Tables

List of Figures

I Introduction

The goal of the U.S. Department of Energy (DOE) Clean Coal Technology (CCT) program is to furnish the energy marketplace with a number of advanced, more efficient, and environmentally responsible coal utilization technologies through demonstration projects. These projects seek to establish the commercial feasibility of the most promising advanced coal technologies that have developed beyond the proof-of-concept stage.

This document serves as a DOE post-project assessment of a project selected in CCT Round 1, "Enhancing the Use of Coals by Gas Reburning and Sorbent Injection" (GR-SI), as described in a Report to Congress [1]. In July 1987, Energy and Environmental Research Corporation (EER) entered into a cooperative agreement to conduct this study. Other project participants were the Gas Research Institute (GRI) and the State of Illinois (Department of Commerce and Natural Resources). DOE provided 50% of the total project cost of $38 million.

Baseline testing was started in December 1987 and field testing was completed in June 1994. The independent evaluation contained herein is based primarily on information from several EER reports: the Final Report dated February 1997 [10], three site-specific reports [7, 8, 9], and a Guideline Manual dated June 1998 [11].

The GR-SI process accomplishes simultaneous NO_x and SO_2 control for coal-fired utility boilers. Gas reburning (GR) controls air emissions of NO_x through natural gas injection downstream of the primary furnace into the NO_x reducing reburn zone, followed by burnout air addition. Sorbent injection (SI) controls emissions of SO_2 through the injection of a calcium-based sorbent, such as hydrated lime, further downstream in the furnace.

The Clean Air Act, initially promulgated in 1970 and amended in 1977, established New Source Performance Standards (NSPS) for emissions of SO_2, NO_x, and particulates, among other pollutants, from stationary coal-fired power plants. These regulations were made more stringent in the Clean Air Act Amendments (CAAA) of 1990. The GR-SI process offers a potential means of meeting the SO_2 and NO_x emissions requirements of the CAAA.

Three host sites were proposed and selected for this project. The first demonstration was Illinois Power's (IP) Hennepin Unit 1, a 71 MWe (net) tangentially fired (T-fired) boiler in Hennepin, Illinois, which fires high-sulfur Illinois coal. The second demonstration was performed at City Water Light and Power's (CWLP) Lakeside Unit 7, a 33 MWe (net) cyclone-fired boiler in Springfield, Illinois, which also fires a high-sulfur Illinois coal. The third demonstration was proposed for Central Illinois Light Company's (CILCO) Edwards Unit 1, a 117 MWe (net) wall-fired unit in Bakersville, Illinois. The last host site was eliminated from consideration after completing the engineering assessment due to the excessive capital cost required for upgrading the existing electrostatic precipitator (ESP), which would have been needed to test SI for SO_2 removal.

The performance objectives for this project were to demonstrate:

- 60% reduction in NO_x emissions
- 50% reduction in SO_2 emissions when firing medium- to high-sulfur coals
- Acceptable unit operability and economical operating cost.

II Technical and Environmental Assessment

A. Promise of the Technology

This project was undertaken to evaluate the technical and economic feasibility of simultaneously achieving between 50-60% reductions in the emissions of NO_x and SO_2 from uncontrolled coal-fired utility boilers having various firing system designs. The original scope of the project to demonstrate the GR-SI technology on cyclone-, wall-, and T-fired units was reduced to demonstrations on the tangential and cyclone boiler host units, due to budget limitations.

In the combined GR-SI process, GR controls the emissions of NO_x by staged fuel combustion, which involves the introduction of about 10-25% of the total heat input as natural gas into the flue gas stream. SI consists of the injection of dry, calcium-based sorbents into the flue gas to achieve sulfur capture.

The benefits anticipated from the use of the combined GR-SI technology were low capital cost relative to more expensive scrubbers, compatibility with high-sulfur coal, no adverse effects on boiler thermal performance, and minimal system operating complexity. There had been several demonstrations of the separate GR and SI technologies prior to this project. This CCT project was the first full-scale demonstration of the combined technology.

B. Process Description

A schematic flow diagram of the GR-SI process is shown in Figure 1. As described in the following sections, GR is a combustion modification process which serves to reduce the amount of NO_x formed in the boiler. SI is a flue gas treatment process which removes SO_2 from the combustion products. Sorbents generally include limestone [$CaCO_3$] or hydrated lime [$Ca(OH)_2$]. In the furnace, the sorbent first undergoes calcination to form calcium oxide [CaO], which is highly reactive when contacted with the SO_2 in the combustion gas. The calcination reactions take place according to the following equations:

$$CaCO_3 + heat \rightarrow CaO + CO_2$$
$$Ca(OH)_2 + heat \rightarrow CaO + H_2O$$

The second step is the reaction of CaO with SO_2 in the presence of oxygen, giving solid calcium sulfate [$CaSO_4$] as the primary product. Side reactions involve formation of (1) solid calcium sulfite [$CaSO_3$] and (2) additional $CaSO_4$ resulting from the reaction of CaO with minor amounts of SO_3 in the combustion gas. These reactions are shown in the following equations:

$$CaO + SO_2 + \frac{1}{2} O_2 \rightarrow CaSO_4$$
$$CaO + SO_2 \rightarrow CaSO_3$$
$$CaO + SO_3 \rightarrow CaSO_4$$

The two processes are discussed in greater detail in the following sections.

Gas Reburning (GR)

GR involves injecting natural gas downstream of the existing coal-fired burners to create a reducing or reburning zone for destruction of NO_x. This is followed by the injection of burnout or overfire air (OFA) downstream of the reburning zone to complete the combustion of the reducing gases (mainly CO) formed in the reburning zone. The process is shown schematically in Figure 2.

The staged combustion technology involves three zones: (1) a primary zone wherein coal is fired through conventional burners; (2) a reburning zone where additional fuel is added to create a reducing gas condition to convert the NO_x produced in the primary zone to molecular nitrogen (N_2); and (3) a burnout zone to complete the combustion of the reducing gases produced in the reburning zone.

Each zone has a unique stoichiometric air ratio (ratio of air used to that theoretically required for complete combustion) as determined by the flow of primary fuel, burner air, natural gas, and OFA. Flue gas recirculation (FGR) through the reburning injectors may also be used to increase the momentum of the injected natural gas jets to improve furnace penetration and mixing. Since recirculated flue gas has a low oxygen content, FGR has a minor impact on the reburning zone fuel requirements and burnout zone air rates. More detailed descriptions of the reburning technology oxidizing and reducing zones are presented as follows:

- Primary Burner Zone: Fuel is fired at a rate corresponding to 75% to 90% of the total heat input, under normal-to-low excess air conditions. The amount of NO_x created in this zone is reduced by about 10% because less fuel is fired (lower production of fuel NO_x), the heat release rate is lower (lower production of thermal NO_x), and, if possible, the excess air level to the burners is reduced (lower fuel and thermal NO_x production).

- Reburning Zone: Reburning fuel (natural gas in this case) injection creates a reducing gas (gasification) region within which methane breaks down to hydrocarbon fragments (CH, CH_2, etc.) that react with NO_x, producing reduced nitrogen species, including molecular nitrogen (N_2). The optimum reburning zone stoichiometry is around 0.90; i.e., 90% of the stoichiometric air required for complete combustion is used. This is achieved by injecting natural gas at a rate corresponding to 10% to 25% of the total heat input. The amount of natural gas depends on the primary zone excess air level. The lower the excess air, the lower will be the reburning fuel requirement.

- Burnout Zone: OFA is injected downstream of the reburning zone to complete combustion of the reburning zone fuel gases. In addition to the N_2 produced in the reburn zone, other reduced nitrogen species are also converted to N_2. OFA is typically 20% of the total air flow. An excess air level of 15% to 25%, depending on the primary fuel type, is normally maintained. The OFA injection rate is optimized for each specific application to minimize CO emissions and unburned carbon in fly ash.

Ambient air is used to cool the gas injection nozzles when the GR system is not in operation. The GR-SI process is controlled by a Westinghouse Distributed Process Family system (WDPF). The WDPF provides integrated modulating control, sequential control, and data acquisition for a wide variety of system applications.

Sorbent Injection (SI)

As described above, SI technology controls SO_2 emissions through injection of a calcium-based sorbent into the upper furnace, where it reacts with SO_2 to form a mixture of solid $CaSO_4$ and $CaSO_3$. The solids are removed from the flue gas through the use of an ESP or baghouse.

Sorbent is transported from a storage silo to the boiler and is introduced into the furnace flue gas through injection nozzles. A flow splitter in the sorbent line distributes the sorbent equally to the individual nozzles. To obtain the optimum nozzle velocities required for proper dispersion of the sorbent throughout the furnace flue gases, additional injection air pressure may be required, which can be accomplished with a booster air fan. Ambient air is used to cool the nozzles when the sorbent system is not in operation.

GR-SI Integration

GR and SI are applied simultaneously to achieve both NO_x and SO_2 control. While it significantly reduces NO_x emissions, the use of GR to replace about 20% of the coal also results in a corresponding reduction in SO_2 emissions since natural gas contains negligible amounts of sulfur. This complements the SO_2 reduction achieved through SI sulfur capture and reduces the amount of sorbent otherwise required.

C. Project Objectives/Results

The performance objectives for this project were to demonstrate:

- 60% reduction in NO_x emissions
- 50% reduction in SO_2 emissions when firing medium- to high-sulfur coals
- Acceptable unit operability and economical operating cost.

These objectives were to be achieved on coal-fired utility boilers of different firing design types, including wall-, cyclone-, and T-fired boilers. These firing design types represent the majority of the U.S. boiler population.

As discussed earlier, detailed engineering design indicated an excessively high cost for upgrading the ESP of the wall-fired host site. Therefore, field demonstration measurements were carried out only on the T- and cyclone-fired boilers. Field testing at each of these sites included parametric optimization studies, followed by one-year duration long-term testing.

The results are summarized in Table 1. The NO_x and SO_2 emission reduction targets were exceeded at both sites. For the T-fired 71 MWe Hennepin Unit 1, average NO_x and SO_2 reductions of 67% and 53% were achieved, respectively, using 18% gas heat input and a calcium-to-sulfur (Ca/S) molar ratio of 1.6. Average calcium utilization was 24%.

For the cyclone-fired 33 MWe Lakeside Unit 7, the average NO_x and SO_2 reductions were 60% and 58%, respectively, using a relatively high gas heat input of 23% and a Ca/S ratio of 1.8. Calcium utilization was 24%. The higher gas heat input required for the cyclone-fired boiler was due to the need to maintain the air/fuel stoichiometric ratio in the cyclone; a decrease in this ratio could alter the slagging characteristics of the cyclone.

The GR-SI demonstration was conducted primarily with a conventional commercially available sorbent, Linwood hydrated lime. At the conclusion of the long-term testing, advanced sorbent preparations were also evaluated. At a Ca/S ratio of 1.75, these sorbents provided SO_2 captures of up to 66%, with 38% calcium utilization. The impact of such an improvement is a significant reduction in sorbent requirement, with concomitant reductions in ash volume, boiler fouling, and sootblower usage frequency.

Economic calculations (discussed in more detail in a subsequent section) show that capital and operating costs of the GR-SI technology depend largely on site-specific factors, such as gas availability, the coal/gas cost differential, SO_2 removal requirements, and the value of SO_2 credits. Based on the results of this project, it is expected that most GR installations can achieve at least 60% NO_x control using 15% gas heat input. The economics of GR for NO_x control are favorable compared with other combustion modification techniques.

SI achieves a lower degree of SO_2 removal at a somewhat higher operating cost than that for wet scrubbers, while the capital cost for SI is much lower. The operating costs are dominated by the costs of the sorbent and of spent sorbent/ash disposal. Since the cost of SO_2 removal via SI exceeds the current cost of purchasing SO_2 allowances, commercial application of SI in the United States is not expected in the near future except under special circumstances.

D. Environmental Performance

As discussed in Section C above, the GR-SI project demonstrated the feasibility of reducing NO_x emissions by at least 60% and SO_2 by 50% for coal-fired utility boilers. This represents successful achievement of the project goals for the tangential and cyclone boilers tested. Since both GR and SI are injection technologies (natural gas, FGR, OFA, and sorbent), the issues of scaleup for adequate gas jet penetration, coverage, and mixing with the bulk flue gases still need to be evaluated on larger scale applications. Based on experience in other countries and ongoing U.S. projects using GR for NO_x emission control, the technical feasibility of GR for larger units appears to be promising. However, there are some further questions to be answered concerning the technical feasibility of SI applied to such units.

During the year-long GR-SI demonstration project, other environmental impacts were also evaluated. The primary waste product is the high calcium content solid waste (a mixture of fly ash with spent and unreacted sorbent). The SI operation increases solid waste production by a factor of two, compared to operation without SI. At Hennepin, the waste mixture was sluiced directly to the existing ash pond, where CO_2 was injected to control the pH level to a range between 6 and 9 as required by State of Illinois environmental regulations.

Compliance monitoring at Hennepin included fly ash characterization and the analysis of the ash sluice water. Elevated groundwater concentrations of sulfates, relative to standards, were measured in some of the wells. As far as particulate emissions are concerned, the total mass was reduced by a small amount under GR-SI operating conditions, which compensated for the slight increase in the fraction of PM_{10} collected.

At the cyclone-fired Lakeside No. 7 boiler, similar environmental monitoring was conducted. Because the existing ash pond could not accommodate the additional solid waste produced by the GR-SI operation, the fly ash/spent sorbent mixture was conveyed to a newly constructed sorbent silo for subsequent off-site disposal in a landfill. Characterization of the fly ash/spent sorbent mixture showed that the material increased in temperature when hydrated, indicating pozzolanic (cementitious) behavior. This showed the need for care in handling this material, but, overall, it was determined not to be hazardous. No significant particulate emission problem was encountered during the long-term Lakeside test program.

It should be noted that the use of lower carbon content natural gas to replace part of the coal feed results in a modest reduction (about 7% at 18% gas input) in emissions of CO_2, a greenhouse gas.

E. Post-Demonstration Achievements

At the conclusion of the demonstration project, the GR system was retained both by IP at Hennepin and by CWLP at Lakeside. CWLP also retained the SI system after the demonstration. None of the equipment is currently in operation; its potential use will be determined by future emission regulations.

During the course of this project, a database was developed for the commercial application of the GR or GR-SI technologies to control emissions of NO_x, or both NO_x and SO_2, from coal-fired boilers of all major firing configurations. The GR technology for NO_x control is being commercialized, based on customer interest. There are no current plans to commercialize SI for SO_2 control or GR-SI for combined NO_x and SO_2 control, due to the lack of interest by the electric utility industry.

Effective January 1, 2000, the emissions limit for SO_2 under Title IV will decrease from the present 2.5 lb/10^6 Btu to 1.2 lb/10^6 Btu. This more stringent regulation represents a barrier to implementation of SI technology, since SI cannot meet the newer standard. Outside the United States, there may be some interest in SI, as shown by some queries received by EER from certain electric utilities in China and India.

Regarding the commercialization of GR, EER installed and started up GR systems on a glass furnace at an Anchor Glass factory, and on a 100 MWe (net) T-fired utility boiler at the Greenidge Station of New York State Electric and Gas (NYSEG). In addition, EER recently awarded contracts for GR retrofit installations on up to five large coal-fired cyclone boilers. These include the 330 MWe Unit 1 of the Allen Fossil Station of TVA with options for Units 2 and 3 (330 MWe each), and the 200 MWe Unit 2 of the C.P. Crane Station of Baltimore Gas and Electric with an option for Unit 1 (also 200 MWe). These new projects would increase EER's U.S. reburning installations to 11 with a total capacity of 1700 MWe. Ultimately, NO_x emissions regulations will be the driving force for GR commercialization.

The U.S. Environmental Protection Agency (EPA), GRI, and DOE were the recipients of the Air & Waste Management Association's 1997 J. Dean Sensenbaugh Award for their collaborative work in developing GR into a viable and commercial emissions control option for utility and industrial power generation boilers.

III Operating Capabilities Demonstrated

A. Size of Units Demonstrated

The demonstrations of GR-SI completed as part of this project involved a 71 MWe tangential boiler and a 33 MWe cyclone boiler. As discussed earlier, the design for a 117 MWe wall-fired unit could not be implemented because of cost constraints. However, EER demonstrated 60% NO_x reduction through GR alone on a 172 MWe (net) wall-fired boiler at Public Service Company of Colorado's Cherokee Station in a Round 4 CCT project, which combines GR with low-NO_x burner (LNB) technology for NO_x control [5]. In addition, GR successfully applied abroad on a 300 MWe T-fired boiler in Ukraine [3]. Reburning has also been used on a number of utility boilers ranging up to 800 MWe in Italy [4], and work is in progress on testing a GR installation on a 700 MWe wall-fired boiler of Scottish Power [6].

So far, no upper size limitations for GR applications have been encountered. The minimum size is probably close to that of CWLP's Lakeside Unit 7, based on requirements of sufficient residence time at the appropriate temperatures in the reburn zone. The demonstrated applicability of the SI and GR-SI technologies is limited at present to the boiler sizes tested in the CCT project. Further testing would be needed to determine upper and lower boiler size limitations for SI applications.

B. Firing Systems Demonstrated

The two demonstration units, Hennepin Unit 1 and Lakeside Unit 7, represent two distinctly different firing system types used for coal-fired utility boilers. Hennepin Unit 1 is a tangential boiler fired with pulverized coal. The firing system involves injecting both the coal fuel and the associated air streams through slots located in each corner of the unit. The number of firing levels used is a function of the size of the unit, as is the case with most utility boilers. A large fireball is produced in the furnace, which tends to limit NO_x production to relatively low levels (on the order of 0.6-0.8 lb/10^6 Btu).

The cyclone firing system is very different. Here, the fuel is crushed coal, which is injected horizontally along the central axis of the cyclone barrel. Air is swirled around the periphery of the refractory lined cyclone barrel burners, which may be located in a single wall or in horizontally opposed walls of the boiler. This mode of injection creates a high speed cyclonic motion, accompanied by the formation of a molten slag layer along the burner walls. While small coal particles are burned in the air stream as combustion products leave the cyclone barrel, most of the coarse coal particles are burned in the molten slag layer, which is removed through a slag trap located at the bottom of the cyclone barrel.

Since there is no heat removal from the cyclone burners, the combustion products exit at very high temperatures. This leads to high levels of NO_x, typically 1.0-2.0 lb/10^6 Btu. Heat from the combustion gases is recovered by the water walls, which line the boiler downstream of the cyclone burners. However, the high concentrations of NO_x produced remain essentially "frozen" in cyclone boilers under standard operating conditions; i.e., only a small degree of NO decomposition to N_2 and O_2 takes place.

In this CCT project, the effectiveness of GR for NO_x control was demonstrated for two types of boilers which represent the extremes of design features for utility boilers from the standpoint of propensity for NO_x formation. Thus, the success of controlling NO_x and SO_2 emissions (particularly NO_x emissions that are significantly affected by the boiler's firing system) is a promising indication of the broad applicability of GR and GR-SI.

C. Performance Level Demonstrated

Properties of the coals used in the demonstration project are given in Table 2. The GR installation at Hennepin achieved 67% NO_x reduction in long-term testing of GR-SI in full load operation with 18% average gas heat input (the maximum NO_x reduction was 75% at mid-load). At Lakeside, GR achieved 60% NO_x reduction with an average 23% gas heat input at full load.

The corresponding average SO_2 emission reductions with GR-SI were 53% at Hennepin, using a Ca/S ratio of 1.6, and 58% at Lakeside, using a Ca/S molar ratio of 1.8. The maximum SO_2 reduction achieved was 81% at a Ca/S ratio of 2.59, using EER's proprietary advanced sorbent preparation, PromiSORB™ B.

To achieve this performance, a higher gas heat input ratio was required for the cyclone-fired Lakeside boiler than for the T-fired Hennepin boiler because of the need to maintain a higher air/fuel stoichiometric ratio in the cyclone burners than in the lower furnace of the tangential boiler. This higher gas usage resulted in greater SO_2 reduction at Lakeside.

Both units required significant equipment modifications to achieve these results. For GR, the principal modification was the use of FGR to enhance the momentum of the gas jets and the supply of OFA to ensure complete burnout of the combustibles produced in the fuel-rich reburn zone. Design changes made after Hennepin and Lakeside eliminated the need for the FGR. For SI, equipment modifications included the installation of sorbent storage and delivery systems, and, at Hennepin, the installation and use of a humidification system to promote the collection of the fly ash/spent sorbent mixture with the existing ESP. Special disposal steps were required for the solids captured at both sites.

The above performance levels were demonstrated without incurring adverse boiler impacts, such as significant reduction in boiler efficiency, increased water wall tube wastage, or reduction of ESP efficiency. However, the GR-SI operation (particularly the SI component of the combined process) required increased boiler maintenance, including removal of solid deposits using sootblowing to prevent plugging.

D. Major Operating and Design Variables Studied

The variables studied in the field demonstration of the GR-SI technology were the following: (a) primary zone excess air level; (b) natural gas heat input as a fraction of the total heat input; (c) reburn zone air/fuel stoichiometric ratio; (d) FGR rate; (e) OFA rate; (f) Ca/S ratio; (g) sorbent transport air rate; (h) sootblowing cycle; and (i) humidification (at Hennepin). These variables and their functions are summarized in Table 3.

The most important findings were as follows:

- A reburn zone stoichiometric ratio to about 0.9 resulted in the greatest reduction in NO_x emissions.

- SO_2 reduction through SI is principally a function of the Ca/S ratio.

- All GR-SI operating zones must be designed to achieve appropriate residence times at the temperatures most favorable for these processes.

E. Boiler Impacts

GR-SI operation at the two demonstration units resulted in impacts on boiler thermal performance, furnace slagging, convective pass fouling, and ESP performance. Thermal performance parameters monitored were steam flow rate, temperature and pressure, steam attemperation flow rate, heat transfer to water/steam, gas side temperatures, thermal efficiency, and heat rate.

The most significant impacts were observed in the boilers' temperature profiles. Operational changes, such as increasing the steam attemperation flow rates during the Hennepin test program, were required to maintain the thermal performance of the units tested. Thermal efficiency and, therefore, heat rate were affected to a minor extent (about 0.5-1.5%) for the tangential Hennepin unit as a result of two factors: (a) increased dry gas heat loss due to higher economizer inlet temperatures (not observed with GR alone, since there was no convective pass fouling); and (b) increase in moisture from combustion under GR operating conditions.

Higher heat losses and, therefore, decreased thermal efficiency were observed for the cyclone-fired Lakeside unit (85.13% baseline efficiency vs. 84.15% under GR-SI conditions at full load, due to significant increases in boiler O_2 levels).

Other boiler impacts included furnace slagging, convective pass fouling, ESP performance, and auxiliary power requirements. At Hennepin, some ash deposition was observed around the gas injection and OFA ports, which necessitated weekly cleaning of these components to limit problems caused by furnace slagging. In the Lakeside cyclone boiler, increased slag deposition was observed as a result of natural gas injection and FGR. The installation included a cleaning feature for the nozzles, which had to be rodded out on a weekly basis.

Convective pass fouling did occur in both test boilers, but its effect on heat transfer performance was mitigated through increased frequency of sootblowing. In spite of increased particulate mass loading in the flue gas, ESP performance for particulate removal was not impaired in either unit. At Hennepin, this resulted from the use of the flue gas humidification system (which decreased fly ash resistivity by two orders of magnitude); at Lakeside it was the result of the excess ESP specific surface collection area available. It should be noted, however, that GR-SI appeared to cause an increase in plume opacity at Hennepin.

Auxiliary power requirements for GR-SI at full load were found to be modest at Hennepin (about 300 kWe), but more significant at Lakeside (712 kWe). This reduction in net plant output is reflected in the process economics.

F. Commercialization of the Technology

Current Status

As stated earlier, there is definite interest in GR for NO_x emissions control on the part of the U.S. power generation industry. In contrast, there is no indication of interest in SI for SO_2 emissions control since it cannot meet present and projected regulatory requirements in most locations. Also, SI is not cost competitive with more effective SO_2 control measures, including the purchase of SO_2 allowances. The Guideline Manual [11] issued by EER as part of the final report on this project summarizes the technical and economic performance of GR and SI.

The progress in commercialization of GR is evidenced by the following existing installations:

- In addition to the two retrofits of the CCT project, EER demonstrated GR on a 172 MWe wall-fired boiler of Public Service Company of Colorado at its Cherokee Station. The NO_x reduction on this coal-fired boiler is about 60% with 15-20% gas heat input, using GR alone.

- Babcock & Wilcox installed GR for NO_x control on three electric utility-size coal-fired industrial cyclone boilers (about 40 MWe equivalent each) at Kodak Park, Rochester, NY. One commercial installation was also supported by GRI as part of its "Validation and Deployment of Gas Injection Technologies" project.

- Although it is an industrial application, rather than power generation, EER retrofitted a commercial glass furnace (Anchor Glass) with GR for NO_x control.

- EER designed and installed a commercial GR retrofit with performance guarantees on a 100 MWe (net) coal-fired tangential boiler at NYSEG's Greenidge Station.

- ABB-Combustion Engineering installed and tested a commercial "close-coupled" gas reburn retrofit on a 200 MWe gas- and oil-fired boiler at Long Island Electric Company's E.G. Barrett Station. This work was also supported by Empire State Electric Energy Corporation (ESEERCO), Electric Power Research Institute (EPRI), and GRI.

As mentioned earlier, a number of reburn installations exist worldwide. Of those, Japan had the earliest ones, but these are now idle because the stringent Japanese NO_x emission regulations can be satisfied only by post-combustion processes such as selective catalytic reduction (SCR). A combination of GR and SCR may play an important role in future NO_x control strategies.

Future Applications

In the United States, EER and other organizations are actively pursuing the commercialization of GR. Recent commercial developments include two contract awards to EER, on which work is in progress:

- A GR retrofit on TVA's Allen Fossil Station Unit 1, a 330 MWe cyclone-fired boiler, with options for two identical boilers, Units 2 and 3. Startup of Unit 1 was completed. OFA was installed on Units 2 and 3 by TVA. The reason for the NO_x control installations at TVA is to meet the Title IV acid rain regulations of the CAAA.

- GR installed and operated on Baltimore Gas and Electric Company's C.P. Crane Generating Station (Units 1 and 2), 200 MWe cyclone boilers.

These new projects (if the options are exercised) will increase EER's U.S. reburning installations to 11, with a total generating capacity of 1,700 MWe, including the retrofit at Kodak Park.

IV Market Analysis

A. Potential Markets

Having recognized that the GR-SI demonstration project produced performance and cost information relevant to three different emission control technology options (GR-SI for combined NO_x and SO_2 control, GR for NO_x control only, and SI for SO_2 control only), EER assessed the market potential for GR and SI applications separately. Because of the limited potential of SI for SO_2 control, no separate market analysis for GR-SI was prepared.

GR Technology

The driving force for the application of GR to control NO_x emissions from coal- fired utility boilers stems from the Titles I and IV of the CAAA, administered by EPA. Title IV (acid rain) regulations for Phase I Group 1 boilers (dry bottom wall-fired and T-fired) became effective January 1, 1996, followed by regulations for Phase II Group 1 and Phase II Group 2 boilers (cyclone, cell burner, wet bottom, dry bottom vertical, stoker, and fluidized bed firing systems), which will become effective January 1, 2000. The Title IV regulations for utility boiler NO_x emissions are shown in Table 4.

Title I ozone nonattainment regulations are also expected to become a significant driving force for utility boiler NO_x control. A rule promulgated by EPA in September 1998 would apply stringent NO_x controls to 22 states and the District of Columbia. This could result in a large number of coal-fired utility boilers having to meet NO_x emission limits as low as 0.15 lb/10^6 Btu.

From the perspective of the potential market for GR applications, the cyclone boilers in Group 2 represent the best opportunity (in addition to the existing potential for Group 1 boilers), because inexpensive LNBs and staged fuel firing seem to provide the solution for cell burner and wet bottom boilers, respectively. There are about 75 cyclone boilers, having a total capacity of about 20,000 MWe, which exceed the Title IV, Phase II NO_x emissions standard of 0.86 lb/10^6 Btu.

As reburning technology can be applied to any type of utility boiler, the cyclone units represent a significant potential because only post-combustion treatment technologies can compete with reburning. (It should be noted that virtually any fossil fuel can be used for reburning, so GR would not have all of the reburning market to itself). For example, coal reburning, which is another demonstrated technology, has higher capital and lower operating costs than GR, so the choice is site-specific.

The availability and price of natural gas are barriers to the application of GR. Availability impacts the capital cost, while the price of natural gas (or the gas/coal price differential) is of critical importance to the operating cost impact. As regards technical requirements, high furnace temperatures ($\geq$2,600°F) and adequate residence times are desirable for efficient NO_x reduction.

SI Technology

Based on the results of this project, SI for SO_2 control may be viewed as a "niche" technology with very limited U.S. market potential. It may be applicable to utility boilers that marginally exceed their SO_2 emission limits in the year 2000 (but at a cost lower than purchasing SO_2 allowances). Some foreign applications may also be possible in countries such as India and China, which have less restrictive emissions regulations. It follows from the preceding discussion that the largest market barriers to the SI technology are the stringent SO_2 regulations in the U.S. and the relatively low cost of SO_2 allowances (about $100/ton of SO_2 at present). By itself (i.e., without the fuel substitution SO_2 reduction effect of natural gas use in GR), SI achieves only about 35% SO_2 capture at a Ca/S ratio of 1.35.

B. Economic Assessment of Utility Boiler Applications

GR-SI Costs

The EER Final Report [10] includes preliminary economics for both GR and SI. EER expects the accuracy of these cost estimates to be on the order of -10% to +15%. For both of these technologies, the economics assume a hypothetical 300 MWe cyclone boiler burning 3.0 wt% sulfur coal, with a 10,000 Btu/kWh heat rate, a capacity factor of 65%, 20.1% gas heat input, and a cost differential between gas and coal of $1.00/10^6 Btu.

The economics are presented in Table 5 for GR and Table 6 for SI. For GR, the estimated capital cost is $17/kWe, and the levelized cost is $714/ton NO_x removed (current dollar basis) or $545/ton (constant dollar basis).

For SI, the capital cost is $13/kWe, and the levelized cost is $642/ton SO_2 removed (current dollar basis) or $489/ton (constant dollar basis). These economics assume a price of $83/ton for hydrated lime. Since purchased sorbent is one of the major operating costs, the economics are sensitive to this price. It should be noted that with 3.0 wt% sulfur coal, the SO_2 emission level decreases from the baseline of 4.80 lb/10^6 Btu to 2.64 lb/10^6 Btu with controls. The controlled emission rate is more than twice the revised emission standard of 1.2 lb/10^6 Btu, effective January 1, 2000.

Comparison with Other Technologies

The EER Final Report also provides an economic comparison of GR with other technologies, using information from a separate study supported by the EPA. The same hypothetical 300 MWe cyclone boiler was used as the basis. With the rather optimistic assumptions of a $1.00 gas/coal price differential and no gas pipeline capital cost requirement, GR appears to be more cost effective than the next higher cost NO_x control technology, coal reburning. In spite of its relatively low capital cost, SNCR has a rather high levelized cost ($700/ton of NO_x removed) compared to GR. This results, in part, from the high price of 50% aqueous urea at $0.50/gal, as well as associated storage and delivery costs.

The EER cost estimates include a comparison with conventional flue gas desulfurization (FGD) processes using wet limestone scrubbing, based on an EPRI study [2]. The two processes appear to be competitive. However, as discussed above, SI is inherently limited because it cannot meet the SO_2 emission standards mandated by regulatory agencies.

V Conclusions

The GR-SI technology as demonstrated by EER at Hennepin and Lakeside Stations met the CCT project's performance objectives. In terms of emission control for coal-fired utility boilers, the performance exceeded the target reduction levels of 60% in NO_x and 50% in SO_2 at full load when firing medium- to high-sulfur coals. Acceptable unit operability was achieved with both the GR and the SI components, although significant equipment installation, modification, and maintenance are required for SI. This includes transportation, storage, and disposal for fresh and spent sorbent, potential ESP upgrading and/or flue gas conditioning, and additional cleaning of heat transfer surfaces in the convective section of the boiler. One may regard these technical issues as moot points because SI cannot meet the mandated SO_x emission levels in most applications, even though it appears to be cost competitive with alternative technologies.

On the other hand, the GR component of the combined process appears to be broadly applicable for retrofit NO_x control to most utility boilers and, in particular, to wet bottom cyclone boilers, which are high NO_x emitters and are difficult to control. Either alone or in combination with other technologies, GR can reduce NO_x to mandated emission levels under Title IV without significant adverse boiler impacts, such as reduction in thermal performance, increase in other emissions, or increased deposit formation and water wall tube wastage. The GR process is applicable to boilers significantly larger than the demonstration units.

Major results of the demonstation project are summarized as follows:

- NO_x emissions reductions of 67% and 60% were achieved with 18% and 23% gas heat input, respectively, in long-term GR tests on the T-fired Hennepin and the cyclone-fired Lakeside units.

- SO_2 emission reductions of 53% and 58% were achieved at Hennepin and Lakeside, respectively.

- The GR-SI process has no adverse impact on the local environment, including air, water, and land. Suitable waste disposal (local ponding or transportation to a remote site) needs to be established if SI is employed.

- Thermal performance of coal-fired boilers is not significantly affected by GR-SI. Convective section steam temperatures can be controlled within acceptable limits. Thermal efficiency is decreased by a small amount, typically about 0.5-2.0%, due to increased dry gas loss and higher moisture loss with the GR process.

- Furnace slagging and convective section fouling can be adequately controlled, although SI requires additional operator attention.

- Because of the higher H/C ratio of natural gas than that of coal, use of the GR process results in a modest reduction in CO_2 emissions.

References

1. "Enhancing the Use of Coal by Gas Reburning and Sorbent Injection," Comprehensive Report to Congress, Clean Coal Technology Demonstration Program, a project proposed by Energy and Environmental Research Corporation to the U.S. Department of Energy, Office of Fossil Energy, May 1987.

2. Electric Power Research Institute, Report No. GS-7193, "Economic Evaluation of Flue Gas Desulfurization Processes," Vol. 1, February 1991.

3. A. Tumanovsky, "Reduction of NO_x Emissions by Reburning Process of Gas/Oil and Coal Boilers," Proceedings of the International Gas Reburn Technology Workshop, Appendix D, Gas Research Institute, Malmo, Sweden, February 7-9, 1995.

4. J. Rhine, "The Demonstration of Gas Reburning at Longannet," Proceedings of the International Gas Reburn Technology Workshop, Appendix D, Gas Research Institute, Malmo, Sweden, February 7-9, 1995.

5. B. Folsom et al., "Three Gas Reburning Field Evaluations: Final Results and Long-term Performance," EPRI/EPA 1995 Joint Symposium on Stationary Combustion NO_x Control, Book 4, Kansas City, Missouri, May 16-19, 1995.

6. G. De Michele et al., "Development and Industrial Application of Oil Reburning for NO_x Emission Control in Utility Boilers," EPRI/EPA 1995 Joint Symposium on Stationary Combustion NO_x Control, Book 4, Kansas City, Missouri, May 16-19, 1995.

7. Energy and Environmental Research Corporation, Vol. 2, "Gas Reburning-Sorbent Injection at Hennepin Unit 1, Illinois Power Company," March 1996.

8. Energy and Environmental Research Corporation, Vol. 3, "Gas Reburning-Sorbent Injection at Edwards Unit 1, Central Illinois Light Company," March 1996.

9. Energy and Environmental Research Corporation, Vol. 4, "Gas Reburning-Sorbent Injection at Lakeside Unit 7, City Water, Light and Power, Springfield, Illinois," March 1996.

10. Energy and Environmental Research Corporation, "Enhancing the Use of Coal by Gas Reburning-Sorbent Injection, Vol. 1, Program Overview: Part A Public Design; Part B - Project Performance and Economics," Final Report, February 1997.

11. Energy and Environmental Research Corporation, "Enhancing the Use of Coal by Gas Reburning-Sorbent Injection, Vol. 5, Guideline Manual," June 1998.

Abbreviations

CCA	Clean Air Act Amendments
CCT	Clean Coal Technology Program
EER	Energy and Environmental Research Corp.
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESEERCO	Empire State Electric Energy Corporation
GR-SI	Gas Reburning-Sorbent Injection
GRI	Gas Research Institute
LNB	low-NO_x burner
NYSEG	New York State Electric and Gas
OFA	Overfire Air
FGR	Flue gas recirculation

Table 1. Results of Long-Term Testing of GR-SI Process at Full Load

Demonstration Location	Hennepin Unit 1	Lakeside Unit 7
Boiler Type	T-fired	Cyclone-Fired
Capacity, MWe (net)	71	33
NO_x Emissions		
Without GR-SI, lb/10^6 Btu (Baseline)	0.75	0.97
With GR-SI, lb/10^6 Btu	0.25	0.39
Average Reduction, %	67	60
Average Gas Heat Input, %	18	23
SO_2 Emissions		
Without GR-SI, lb/10^6 Btu (Baseline)	5.3	5.9
With GR-SI, lb/10^6 Btu	2.5	2.5
Average Reduction, %	53	58
Calcium/Sulfur Molar Ratio	1.6	1.8
Calcium Utilization, %	24	24

Table 2. Properties of Coals Used in GR-SI Tests

Coal Source: Illinois No. 6 Bituminous

Power Plant Location	Hennepin Unit 1	Lakeside Unit 7
Proximate Analysis, wt**%** (as received)		
Fixed Carbon	40.95	38.66
Volatile Matter	35.76	33.62
Moisture	13.11	17.78
Ash	10.18	9.94
Total	100.00	100.00
Ultimate Analysis, wt% (as received)		
Carbon	60.38	56.97
Hydrogen	4.13	4.01
Nitrogen	1.16	1.06
Sulfur	2.96	3.00
Chlorine		--
Oxygen	8.08	7.34
Ash	10.18	9.94
Moisture	13.11	17.78
Total	100.00	100.00
Higher Heating Value, Btu/lb	10,895	10,300

Table 3. Primary Variables in the GR-SI Process

Variable	Major Function	Other Effects
Primary zone air/fuel stoichiometric ratio	Amount of gas reburning fuel	Slagging & increased LOI
Natural gas/coal heat input	NO_x removal	SO_2 & particulates reduction
Reburn zone air/fuel stoichiometric ratio	NO_x removal	Water wall corrosion and OFA
Flue gas recirculation (FGR) rate	Natural gas dispersion	Furnace temperatures
Overfire air (OFA) rate	Fuel burnout	Steam attemperation, boiler & ESP efficiencies
Calcium/sulfur ratio	SO_2 removal	Fouling, ESP performance
Sorbent transport air rate	Sorbent dispersion	Similar to OFA
Sootblowing cycle	Fouling reduction	Tube erosion
Humidification (Hennepin)	ESP performance	Fouling, corrosion

Table 4. Title IV Acid Rain Emissions Limits
lb/10^6 Btu

	Phase I	Phase II
NO_x Emissions		
Compliance Date	January 1, 1996	January 1, 2000
Group 1 Boilers		
Dry Bottom Wall-Fired	0.50	0.46
T-fired	0.45	0.40
Group 2 Boilers		
Wet Bottom Wall-Fired > 65 MWe	NA	0.84
Cyclone-Fired > 155 MWe	NA	0.86
Vertically Fired	NA	0.80
Cell Burner	NA	0.68
Fluidized Bed	NA	Exempt
Stoker	NA	Exempt
SO_2 Emissions		
Compliance Date	January 1, 1995	January 1, 2000
All Boilers > 25 MWe	2.5	1.2

NA = Not applicable

Table 5. Summary of Performance and Cost Data - Gas Reburning
1996 Dollars

Coal Properties	Units	Value
Higher heating value (HHV)	Btu/lb	12,000
Power Plant Attributes With Controls		
Plant capacity, net	MWe	300
Power produced, net	10^9 kWh/yr	1.71
Capacity factor	%	65
Coal fed	10^6 tons/yr	0.68
NO_x Emissions Control Data		
Removal efficiency	%	67.0
Emissions without GR	lb/10^6 Btu	1.30
Emissions with GR	lb/10^6 Btu	0.43
NO_x removed	tons/yr	7,439
Total Capital Requirement	$/kW	17

	Levelization Factor [a]	mills/kWh	$/ton NO_x removed
Levelized Cost, Current $			
Capital charge	0.160	0.47	109
Fixed O&M	1.314	0.22	51
Variable O&M	1.314	2.99	687
Total		3.68	847
SO_2 credits ($95/ton)	1.314	(0.58)	(133)
Total with SO_2 credits		3.10	714
Levelized Cost, Constant $			
Capital charge	0.124	0.37	84
Fixed O&M	1.000	0.17	39
Variable O&M	1.000	2.28	523
Total		2.82	646
SO_2 credits ($95/ton)	1.000	(0.44)	(101)
Total with SO_2 credits		2.38	545

a Levelization based on 15-year project life, 38% tax rate, 4% inflation, and the following capital structure: 50% debt @ 8.5% return, 15% preferred stock @ 7.0% return, and 35% common stock @ 7.5% return.

Table 6. Summary of Performance and Cost Data - Sorbent Injection

1996 Dollars

Coal Properties	Units	Value
Higher heating value (HHV)	Btu/lb	12,000
Sulfur content	Wt%	3.0
Power Plant Attributes With Controls		
Plant capacity, net	MWe	300
Power produced, net	10^9 kWh/yr	1.71
Capacity factor	%	65
Coal fed	10^6 tons/yr	0.68
SO_2 Emissions Control Data		
Removal efficiency	%	45.0
Emissions without SI	lb/10^6 Btu	4.80 [a]
Emissions with SI	lb/10^6 Btu	2.64
SO_2 removed	tons/yr	18,654
Total Capital Requirement	$/kW	13

	Levelization Factor [b]	mills/kWh	$/ton SO_2 removed
Levelized Cost, Current $			
Capital charge	0.160	0.36	33
Fixed O&M	1.314	0.19	20
Variable O&M	1.314	6.44	589
Total		6.99	642
Levelized Cost, Constant $			
Capital charge	0.124	0.28	26
Fixed O&M	1.000	0.14	15
Variable O&M	1.000	4.90	448
Total		5.32	489

____

a Assumes 95% conversion of S to SO_2 in boiler.

b Levelization based on 15-year project life, 38% tax rate, 4% inflation, and the following capital structure: 50% debt @ 8.5% return, 15% preferred stock @ 7.0% return, and 35% common stock @ 7.5% return.

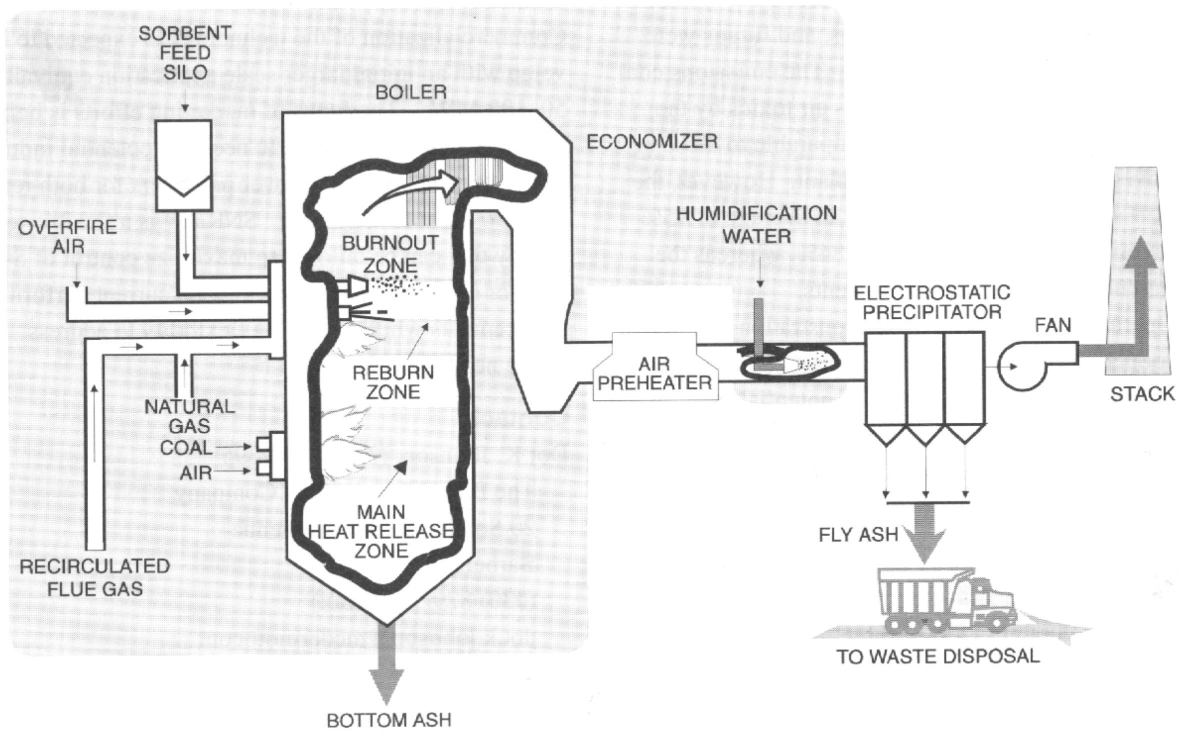

Figure 1 Schematic Flow Diagram of Gas Reburn-Sorbent Injection

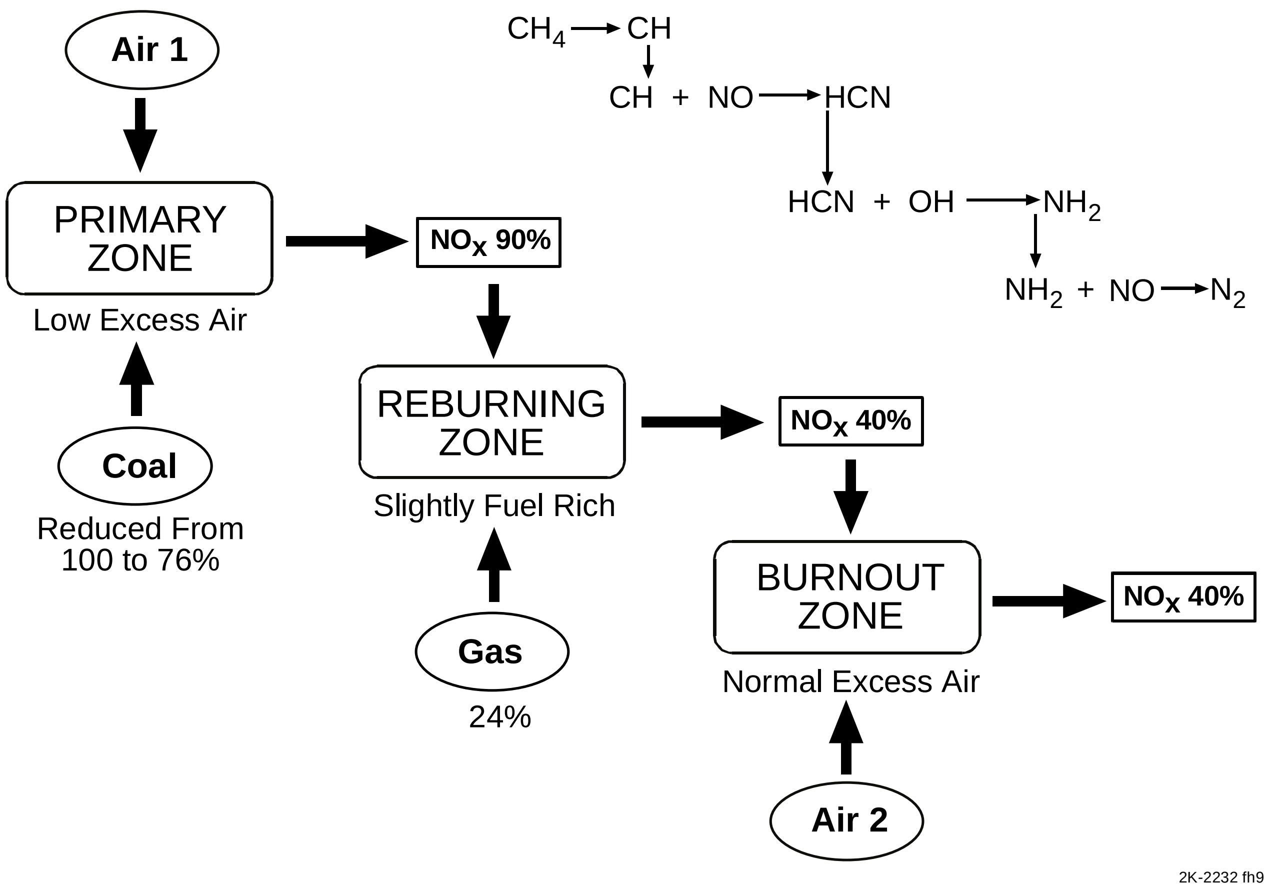

Figure 2 Schematic Flow Diagram of Gas Reburn