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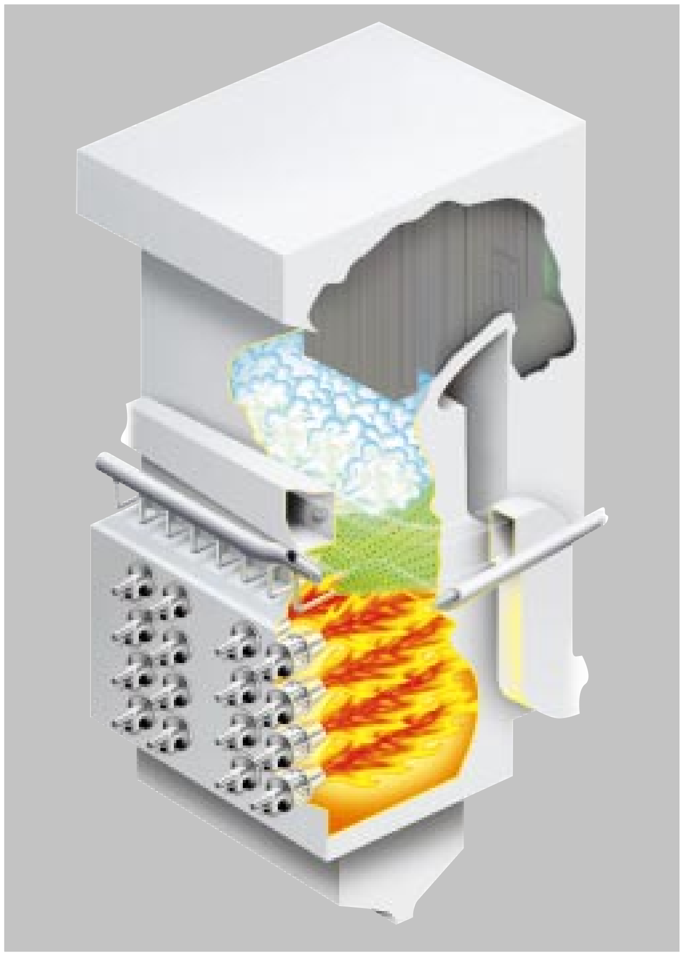
CLEAN COAL TECHNOLOGY



Reburning Technologies for the Control of Nitrogen Oxides Emissions from Coal-Fired Boilers

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A report on three projects conducted under separate cooperative agreements between:

The U.S. Department of Energy and
- The Babcock & Wilcox Company
- Energy and Environmental Research Corporation
- New York State Electric & Gas Corporation

Cover image: Schematic of reburning technology

Source: Energy and Environmental Research Corporation

CLEAN COAL TECHNOLOGY

Reburning Technologies for the Control of Nitrogen Oxides Emissions from Coal-Fired Boilers

Executive Summary

The Clean Coal Technology (CCT) Demonstration Program is a government and industry co-funded effort to demonstrate a new generation of innovative coal utilization processes in a series of "showcase" facilities built across the country. These projects are carried out on a scale sufficiently large to demonstrate commercial worthiness and to generate data for design, construction, operation, and technical/economic evaluation of full-scale commercial applications.

The goal of the CCT Program is to furnish the U.S. energy marketplace with a number of advanced, more efficient coal-based technologies meeting strict environmental standards. These technologies will mitigate the economic and environmental impediments that limit the full utilization of coal as a continuing viable energy resource.

To achieve this goal, beginning in 1985, a multiphased effort consisting of five separate solicitations was administered by the U.S. Department of Energy's (DOE) Federal Energy Technology Center (FETC). Projects selected through these solicitations have demonstrated technology options with the potential to meet the needs of energy markets while satisfying relevant environmental requirements.

Part of this program is the demonstration of reburning technologies on existing coal-fired utility boilers to reduce emissions of nitrogen oxides (NOx). NOx is an acid rain precursor and a contributor to the formation of ground-level ozone, which is a health hazard and a major component of smog. NOx emissions are regulated under the provisions of the 1990 Clean Air Act Amendments (CAAA).

In applying reburning to a coal-fired boiler, the furnace is subdivided into three zones: (1) the primary combustion zone, where the bulk of the coal is burned with relatively low levels of excess air (NOx is formed in this zone); (2) the reburn zone, where 10% to 30% of the total heat is provided as reburn fuel and where, under reducing conditions, NOx is converted to molecular nitrogen; and (3) the burnout zone, where overfire air is injected to complete burnout of the remaining combustibles.

This report discusses three CCT reburning projects:

- *Coal Reburning for Cyclone Boiler NOx Control* was tested by The Babcock & Wilcox Company on a 110-MWe (gross) cyclone boiler at Wisconsin Power & Light Company's Nelson Dewey plant in Cassville, Wisconsin. The objective was to demonstrate 50% or greater NOx reduction. This goal was achieved, using both bituminous and subbituminous coals. The technology was effective at turndown ratios of 66% and 63%, respectively. Process flexibility was excellent.
- *Gas Reburning-Low-NOx Burners (GR-LNB)* was tested by Energy and Environmental Research Corporation on a 158-MWe (net) wall-fired boiler at Public Service Company of Colorado's Cherokee Station near Denver, Colorado. The objective was to attain 70% reduction of NOx emissions. Low-NOx burners (LNBs) alone reduced NOx emissions by only 37%, which was less than the target level of 45%. As a result, the GR-LNB combination, which achieved 66% NOx reduction, fell slightly short of the target. However, the 70% target reduction was achieved in short-term testing. No significant adverse impacts on boiler performance were found. A turndown ratio of 50% was achieved.
- *Micronized Coal Reburning* was tested by New York State Electric & Gas Corporation (NYSEG) on a 50-MWe equivalent industrial cyclone boiler at the Kodak Park steam plant, Rochester, New York, and at a 150-MWe (net) tangentially fired boiler at NYSEG's Milliken Station in Lansing, New York. This project was aimed at improving coal reburning by further size reduction of the reburn coal. The project achieved 57% NOx emissions reduction at Kodak Park and 28% reduction in conjunction with LNBs at Milliken.

For a 110-MWe cyclone boiler, the estimated capital cost of coal reburning is $66/kW, and the levelized cost is $1,075/ton of NOx removed. For GR-LNB installed on a 300-MWe wall-fired boiler with 12.5% natural gas reburn heat input, the estimated capital cost is $26/kW, and the levelized cost is $1,187/ton, assuming that natural gas is available on-site. Cost estimates for micronized coal reburning are not yet available. The economics presented in this report have been provided by the technology suppliers and are not on the same basis, such as plant capacity and financial parameters. Therefore, they cannot be directly compared.

A number of reburn retrofits have been demonstrated or are operating on a commercial scale on coal-fired boilers in the U.S., and several others are on order. In light of increasingly stringent environmental regulations, the potential U.S. market for reburning appears to be significant, particularly in combination with other NOx emissions control technologies.

Reburning Technologies for the Control of Nitrogen Oxides Emissions from Coal-Fired Boilers

Background

The Clean Coal Technology (CCT) Demonstration Program, sponsored by the U.S. Department of Energy (DOE), is a government and industry co-funded technology development effort conducted since 1985 to demonstrate a new generation of innovative coal-utilization processes.

The CCT Program involves a series of “showcase” projects, conducted on a scale sufficiently large to demonstrate commercial worthiness and generate data for design, construction, operation, and economic/technical evaluation of full-scale commercial applications. The goal of the CCT Program is to furnish the U.S. energy marketplace with advanced, more efficient coal-based technologies meeting strict environmental standards. These technologies will mitigate some of the economic and environmental impediments that inhibit the full utilization of coal as an energy source.

Concurrent with the development of the CCT Program by DOE, the U.S. Environmental Protection Agency (EPA) has promulgated regulations, under the 1990 Clean Air Act Amendments (CAAA), controlling emissions from a variety of stationary sources, including coal-fired boilers.

The CCT Program has opened a channel to policy-making bodies by providing data from cutting-edge technologies to aid in formulating regulatory decisions. For example, results from several CCT projects have been provided to EPA to help establish achievable nitrogen oxides (NO and NO_2, collectively referred to as NOx) emissions targets for coal-fired boilers subject to CAAA.

Under the CCT Program, the three projects discussed in this report were undertaken to evaluate the performance and economics of reburning technologies for reducing NOx emissions from coal-fired boilers.

Milliken Station (left); Nelson Dewey Station (top); Cherokee Station (right).

NOx Emissions Standards

History

The Clean Air Act of 1970 established a major role for the federal government in regulating air quality. The act was further extended by amendments in 1977 and, most recently, in 1990. The 1990 CAAA is one of the most complex and comprehensive pieces of environmental legislation ever written. It authorizes EPA to establish standards for a number of atmospheric pollutants, including sulfur dioxide (SO_2) and NOx.

Two major portions of the CAAA relevant to NOx control are Title I and Title IV. Title I establishes National Ambient Air Quality Standards (NAAQS) for six criteria pollutants, including ozone, while Title IV addresses controls for specific types of boilers, including stationary coal-fired utility power plants. Title IV is often referred to as the Acid Rain Program.

Title IV uses a two-phase NOx control strategy. Effective January 1, 1996, Phase I established regulations for Group 1 boilers: dry-bottom, wall-fired boilers and tangentially fired (T-fired) boilers. In Phase II, which begins on January 1, 2000, lower emissions limits are set for certain Group 1 boilers, and regulations are established for Group 2 boilers, which include cell-burner, cyclone, wet-bottom wall-fired, and other types of coal-fired boilers.

Stationary Source NOx Regulations Under CAAA

NOx emissions are generated primarily from transportation, electric utility, and other industrial sources. NOx is reported to contribute to a variety of environmental problems, including acid rain and acidification of aquatic systems, ground-level ozone and smog formation, and visibility degradation. For these reasons, NOx emissions are regulated by various levels of government throughout the country.

Ozone Nonattainment

Title I of the CAAA requires the states to apply the same requirements to major stationary sources of NOx as are applied to major stationary sources of volatile organic compounds (VOCs). In general, these new NOx provisions require: (1) existing major stationary sources to apply reasonably available control technologies (RACT); (2) new or modified major stationary sources to offset their new emissions and install controls representing the lowest achievable emissions rate (LAER); and (3) each state with an ozone nonattainment region to develop a State Implementation Plan (SIP) that, in most cases, includes reductions in stationary source NOx emissions beyond those required by the RACT provisions of Title I.

More recently, EPA has attributed part of the problem with nonattainment to long range transport of ozone and its precursors, NOx and VOCs. To address these transported pollutants, EPA has adopted a regional approach by promulgating an Ozone Transport Rule that requires 22 states and the District of Columbia to amend their SIPs under CAAA to lower NOx emissions levels during the "summer" (May through September) ozone season.

EPA's rule sets statewide NOx emissions budgets, which include budget components for the electric power industry and certain industrial stationary sources. These sources are required to make large NOx emissions reductions to decrease the movement of significant amounts of ozone from one region of the country to another. The target NOx emissions limit for utility boilers is 0.15 lb/million Btu.

Coal-Fired Boiler NOx Emissions Limits (Title IV), lb/million Btu

	Phase I	Phase II
Implementation Date	Jan. 1, 1996	Jan. 1, 2000
Group 1 Boilers		
Dry-Bottom, Wall-Fired	0.50	0.46
Tangentially 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

Acid Rain

Title IV of the CAAA focuses on a particular set of NOx-emitting sources–coal-fired electric utility plants–and uses a two-phase strategy to reduce emissions. Phase I of the program has reduced NOx emissions in the United States by over 400,000 tons/year. These reductions were achieved by the installation of low-NOx burner technology on dry-bottom, wall-fired boilers and tangentially fired (T-fired) boilers (Group 1).

In Phase II, which begins in the year 2000, EPA has established lower emissions limits for Group 1 boilers and established limits for Group 2 boilers. Group 2 boilers include those applying cell-burner technology, cyclone boilers, wet-bottom boilers, and other types of coal-fired boilers.

The statute requires that emissions control costs for Group 2 boilers be comparable to costs for Phase I, Group 1 boilers. The regulations allow for emissions averaging in which the emissions levels established by EPA are applied to an entire group of boilers owned or operated by a single company. It is projected that the more stringent Phase II limits will result in an additional NOx reduction of 820,000 tons/year.

Ozone Formation

When NOx and volatile organic compounds (VOCs) enter the atmosphere, they react in the presence of sunlight to form ground-level ozone, which is a major ingredient of smog. The revised NAAQS for ozone is 0.08 ppm (eight-hour average). Many urban areas do not meet this standard and are classified as nonattainment, and a large number of power plants are situated within these nonattainment areas. Nonattainment status is attributable not only to locally released NOx emissions but also to significant amounts of ozone and ozone precursors (NOx and VOCs) transported by wind over a wide geographical region.

To address regional pollutant transport, EPA has issued a rule under Title I of the CAAA governing NOx emissions from electric power plants and other large stationary boilers in an area consisting of 22 Eastern states and the District of Columbia. To meet the ground-level ozone NAAQS in that area, EPA projects an average NOx emissions rate for electric power plants of 0.15 lb/million Btu during the five-month (May through September) "summer" ozone season.

How NOx Is Formed in a Boiler

Most of the NOx formed during the combustion process is the result of two oxidation mechanisms: (1) reaction of nitrogen in the combustion air with excess oxygen at elevated temperatures, referred to as thermal NOx; and (2) oxidation of nitrogen that is chemically bound in the coal, referred to as fuel NOx. In addition, minor amounts of NOx, referred to as prompt NOx, are formed early in the combustion process through complex interactions of molecular nitrogen with hydrocarbon free radicals to form reduced nitrogen species that are then oxidized to NOx.

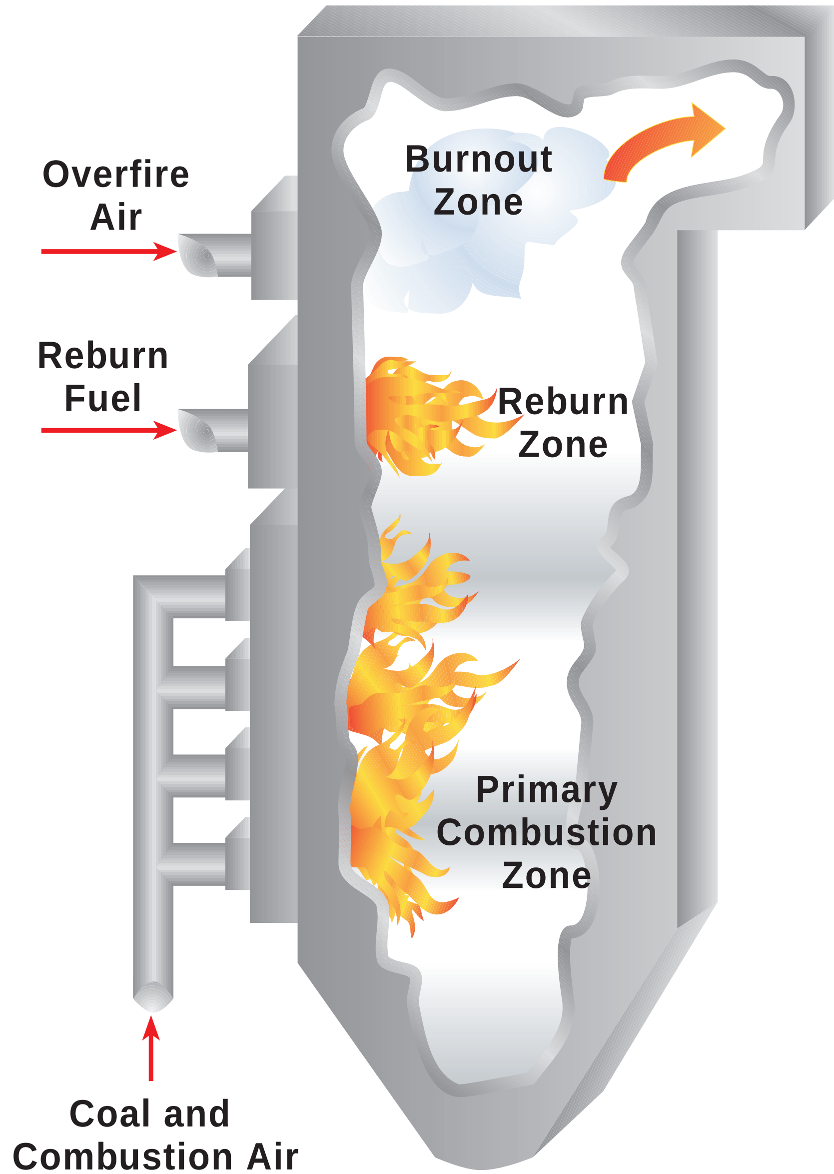
For most coal-fired units, thermal NOx typically represents about 25% and fuel NOx about 75% of the total NOx formed. However, for cyclones and other boilers that operate at very high temperatures, the ratio is different, and thermal NOx can be considerably higher than fuel NOx.

The quantity of thermal NOx formed depends primarily on the "three t's" of combustion: temperature, time, and turbulence. In other words, flame temperature, the residence time at temperature, and the degree of fuel/air mixing, along with the nitrogen content of the coal and the quantity of excess air used for combustion, determine NOx levels in the flue gas. Combustion modifications delay the mixing of fuel and air, thereby reducing temperature and initial turbulence, which minimizes NOx formation.

NOx Control Technologies

Techniques for reducing NOx emissions from fossil-fuel-fired boilers can be classified into two fundamentally different categories: combustion controls and post-combustion controls. Combustion controls reduce NOx formation during the combustion process, while post-combustion controls reduce NOx after it has been formed.

Combustion controls include low-NOx burners (LNBs), reburning, overfire air (OFA), flue gas recirculation (FGR), and operational modifications. Post-combustion controls include selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR). The primary technology currently used for NOx reduction to meet Title IV standards is combustion modification using LNBs, often in combination with OFA.



Schematic of reburning technology.

The Reburning Process

History

Reburning, or the staged introduction of fuel into a combustion device, is based on laboratory-scale studies in the early 1970's by Wendt and Sternling of Shell Development Company. The first commercial-scale application of this technology to control NOx emissions was installed in Japan during the same decade.

Subsequently, commercial-scale testing was conducted in the U.S. and Europe, mainly on electric utility boilers, but also to some extent on municipal waste incinerators. At present, natural gas, coal, and fuel oil (in Italy) reburning applications are in operation. The majority of the commercial installations in the U.S. use natural gas as the reburn fuel, but either natural gas, oil, or coal can achieve about 50-60% NOx reduction without adversely affecting boiler operations.

Process Description

Reburning involves the staged addition of fuel into two combustion zones: (1) the primary combustion zone where coal is fired; and (2) the reburn zone where additional fuel (the reburn fuel) is added to create a reducing (oxygen deficient) condition to convert the NOx produced in the primary zone to molecular nitrogen (N_2) and water. Above the reburn zone is a burnout zone in which OFA is added to complete the combustion. Each zone has a unique stoichiometric air ratio (the ratio of the air used to that theoretically required for complete combustion) as determined by the flows of primary fuel, burner air, reburn fuel, and OFA.

Primary Combustion Zone

Coal is fired under normal to low excess air conditions at a rate corresponding to 70-

90% of the total heat input. The amount of NOx created in this zone is reduced by about 10% because less coal is fired (lower production of fuel NOx), the heat release rate is lower (lower production of thermal NOx) and, generally, the excess air level to the burners is reduced (a lower oxygen concentration results in lower NOx).

Reburn Zone

Reburn fuel injection creates a reducing region within which the reburn fuel molecules break down to hydrocarbon fragments (CH, CH_2, etc.) that react with NOx, producing reduced nitrogen species (mainly N_2). The optimum reburn zone stoichiometric ratio is 0.85-0.95. This is achieved by injecting reburn fuel at a rate corresponding to 10-30% of the total heat input, depending on the primary zone excess air level. The lower the primary combustion zone excess air, the lower the reburn fuel requirement. Introduction of FGR through the reburn fuel injectors may also be employed to increase the momentum of the injected reburn fuel to improve furnace penetration and mixing. Because recirculated flue gas has a low oxygen content, FGR has only a minor impact on the reburn zone fuel requirement and the burnout zone air rate.

Burnout Zone

OFA is injected downstream of the reburn zone to complete combustion. OFA is typically 20% of the total air flow with an overall excess air level of 15-25% being usual. The OFA injection rate is optimized for each specific application to minimize carbon monoxide emissions and unburned carbon in the fly ash. Thermal NOx formation in the burnout zone is small because of the lower temperature.

Depending on the nature of the reburn fuel used, various boiler retrofits are required. In all cases, the boiler needs to be equipped with fuel injection in the reburn zone, and FGR may also be added. OFA ports are also needed for the burnout zone. If natural gas is used as the reburn fuel, a pipeline extension to the site may be required.

If the reburn fuel is coal, additional coal handling and pulverizing equipment may have to be installed. For example, cyclone boilers are fired with coarse crushed coal, which needs to be reduced to smaller particle sizes to be an effective reburn fuel. Similarly, micronized coal, which was tested as the reburn fuel in one of the CCT projects described in this report, requires special size-reduction equipment.

Comparison of Reburning with Post-Combustion Control Technologies

Reburning involves combustion modification. Competing technologies for coal-fired boiler NOx control are post-combustion processes such as SCR and SNCR. SNCR operates in a fashion that has some of the characteristics of reburning. In SNCR, instead of generating the NOx-reducing species from the decomposition of fuel, as is done in reburning, the reducing agent (typically ammonia or urea) is injected into the furnace above the combustion zone, where it reduces the NOx to nitrogen and water. NOx reduction efficiency for SNCR may be in the same range as that for reburning, but efficiency varies with boiler capacity, furnace configuration, etc.

SCR, in which the NOx reduction is carried out over a catalyst, has the capability of greater NOx reduction but is more expensive than SNCR. SCR, like reburning, is applicable to virtually any type of power generation or industrial boiler.

Clean Coal Technology Reburning Demonstration Projects

This report discusses three CCT demonstration projects:

- Demonstration of Coal Reburning for Cyclone Boiler NOx Control
- Evaluation of Gas Reburning and Low-NOx Burners on a Wall-Fired Boiler
- Micronized Coal Reburning Demonstration for NOx Control

All three of these projects involve reburning for reducing NOx emissions from utility boilers. The goal of these projects was to demonstrate the technical feasibility and evaluate the economic potential of reburning under three different boiler configurations.

These projects were designed to confirm pilot plant results and to generate the data necessary for scale-up of the technology to commercial applications, as well as to resolve those technical issues that could not be adequately addressed by engineering studies. The work reported here has helped establish reburning as a viable technology for NOx control.

NOx Reduction Technologies

NOx reduction technologies can be grouped into two broad categories: combustion modifications and post-combustion processes. Some of the more important NOx control approaches are briefly discussed below.

Combustion Modifications

Low-NOx Burners – LNBs are designed to control the mixing of fuel and air so as to achieve staged combustion. This results in a lower maximum flame temperature and a reduced oxygen concentration during some phases of combustion, thus resulting in both lower thermal NOx and lower fuel NOx production.

Overfire Air – Overfire air (OFA) is air that is injected into the furnace above the normal combustion zone. OFA is generally used in conjunction with operating the burners at a lower-than-normal air-to-fuel ratio, which reduces NOx formation. The OFA is then added to achieve complete combustion. OFA is frequently used in conjunction with LNBs.

Reburning – With reburning, part of the boiler heat input (typically 10-30%) is added in a separate reburn zone, where fuel-rich conditions lead to the reduction of NOx formed in the normal combustion zone. OFA is injected above the reburn zone to complete combustion. Thus, with reburn there are three zones in the furnace: (1) a combustion zone with a normal to slightly below normal air-to-fuel ratio; (2) a reburn zone, where added fuel results in a fuel-rich, reducing condition; and (3) a burnout zone, where OFA leads to completion of combustion. Coal, oil, and gas can all be used as the reburn fuel.

Flue Gas Recirculation – FGR, in which part of the flue gas is recirculated to the furnace, can be used to modify conditions in the combustion zone (lowering the temperature and reducing the oxygen concentration) to reduce NOx formation. Another use for FGR is as a carrier to inject fuel into the reburn zone to increase penetration and mixing.

Operational Modifications – These involve changing certain boiler operational parameters to create conditions in the furnace that will lower NOx production. Examples are burners-out-of-service (BOOS), low excess air (LEA), and biased firing (BF). In BOOS, selected burners are removed from service by stopping fuel flow, but air flow is maintained to create staged combustion in the furnace. LEA involves operating at the lowest possible excess air level while maintaining good combustion, and BF involves injecting more fuel to some burners (typically the lower burners) while reducing fuel to other burners (typically the upper burners) to create staged combustion conditions in the furnace.

Post-Combustion Processes

Selective Noncatalytic Reduction – In SNCR a reducing agent (typically ammonia or urea) is injected into the furnace above the combustion zone, where it reacts with NOx to form nitrogen gas and water vapor, thus reducing NOx emissions. The critical factors in applying SNCR are sufficient residence time in the appropriate temperature range and even distribution and mixing of the reducing agent across the full furnace cross section.

Selective Catalytic Reduction – In SCR a catalyst vessel is installed downstream of the furnace. Ammonia is injected into the flue gas before it passes over the fixed-bed catalyst. The catalyst promotes a reaction between NOx and ammonia to form nitrogen and water. NOx reductions as high as 90% are achievable, but careful design and operation are necessary to keep ammonia emissions (referred to as ammonia slip) to a concentration of a few ppm.

Hybrid Process – SNCR and SCR can be used in conjunction with each other with some synergistic benefits. Also, both processes can be used in conjunction with LNBs.

Aerial view of Nelson Dewey Station.

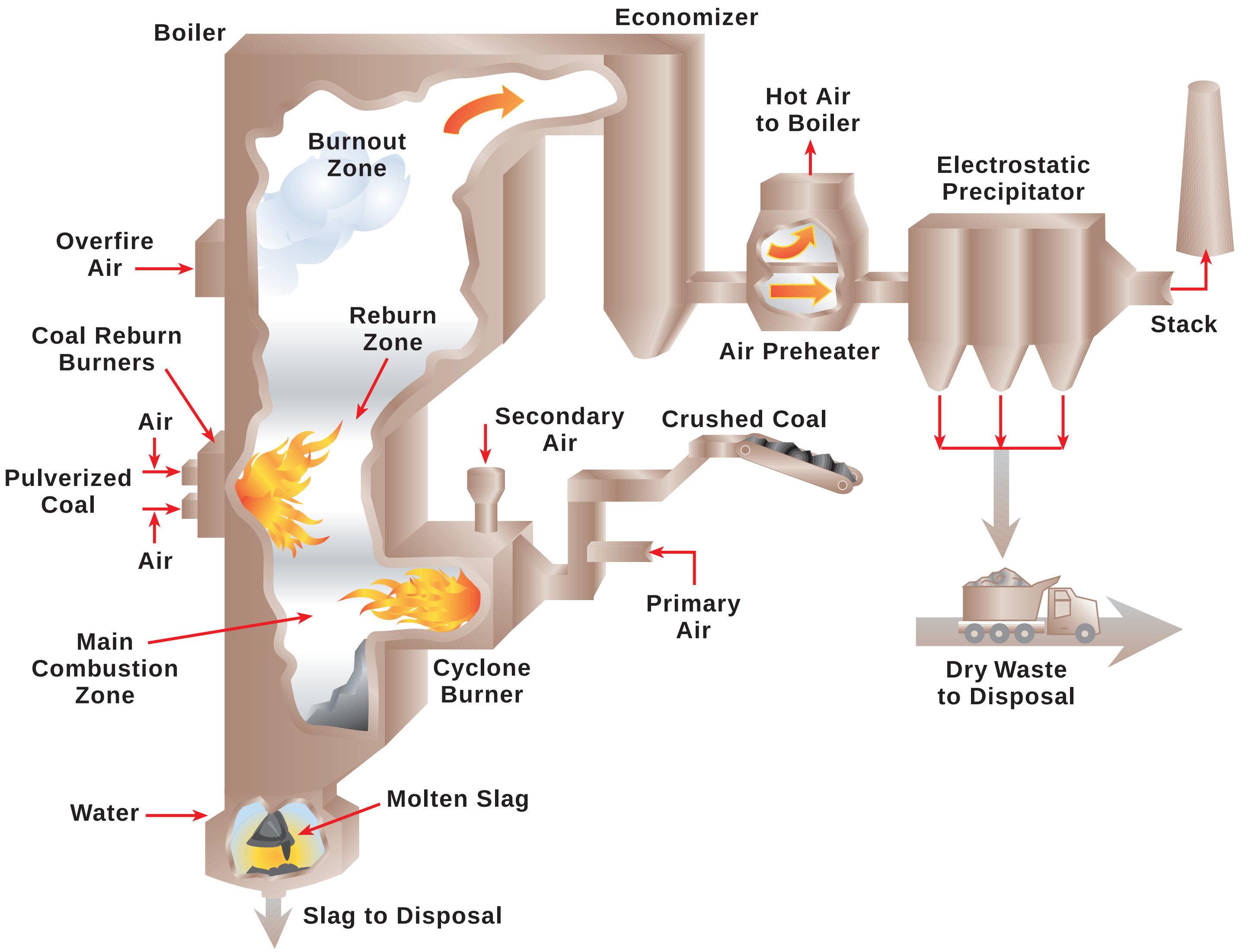
Demonstration of Coal Reburning for Cyclone Boiler NOx Control

Project Description

Coal reburning for cyclone boiler NOx control was selected during Round II of DOE's CCT Program. In April 1990, The Babcock & Wilcox Company (B&W) entered into an agreement with DOE to conduct this project. The project site was Wisconsin Power & Light's (WP&L) 110-MWe (gross) cyclone-fired Nelson Dewey Unit 2 (Cassville, Wisconsin). WP&L served as co-funder and host. The tests were conducted by B&W. Sargent and Lundy engineered the coal handling equipment. Additional team members and co-funders were the Electric Power Research Institute (EPRI), the Illinois Department of Energy and Natural Resources, and 14 electric utility owner/operators of cyclone boilers. DOE provided 46% of the total project cost of $13.6 million.

The project goal was to achieve 50% or greater NOx reduction at full load by reburning with the same coal as the primary fuel, with no substantial adverse impact on other emissions or on boiler reliability, operability, and steam production rate. Adding coal reburning to Unit 2 required the installation of four B&W S-type reburn burners, four B&W dual zone OFA ports, and a B&W MPS-67 pulverizer and primary air fan plus the necessary ducting, dampers, and monitors. Modifications were also made to the control system. Coals burned during the test were Illinois Basin (Lamar) bituminous (1.15% sulfur, 1.24% nitrogen) and Powder River Basin (PRB) subbituminous (0.27% sulfur, 0.55% nitrogen).

When reburning is being used, the cyclone burners operate within their normal, noncorrosive, oxidizing conditions, thereby minimizing any adverse effects on combustor and boiler performance. The 110-MWe boiler is a size that is representative of a significant fraction of the population of cyclone units.



Flow diagram of coal reburning on a cyclone boiler.

Results

At Nelson Dewey Unit 2, NOx emissions reductions exceeding 50% were achieved using both Lamar bituminous and PRB subbituminous coals. Switching part of the load from the cyclone burners to the reburn burners eliminated the need for derating the boiler, normally required for boilers feeding lower heat content subbituminous coal and having limited coal feed capacity.

Excellent process flexibility was demonstrated. The boiler operated successfully at load levels as low as 37 MWe (a turndown ratio of 66%) with bituminous coal and 41 MWe (a turndown ratio of 63%) with subbituminous coal. It was found that accurate and responsive control of both fuel and air flow rates into the different operating zones of the boiler was required.

For optimum NOx control, effective in-furnace mixing of the gases from the cyclone and reburning burners is essential. This was predicted by mathematical modeling, which proved to be an extremely useful process design tool. Measured NOx emissions with bituminous coal at full load were reduced from the baseline level of 0.82 lb/million Btu to 0.39 lb/million Btu, a reduction of 52%. Percentage reductions were somewhat poorer at reduced load levels, and slightly better emissions reductions were achieved with the subbituminous coal.

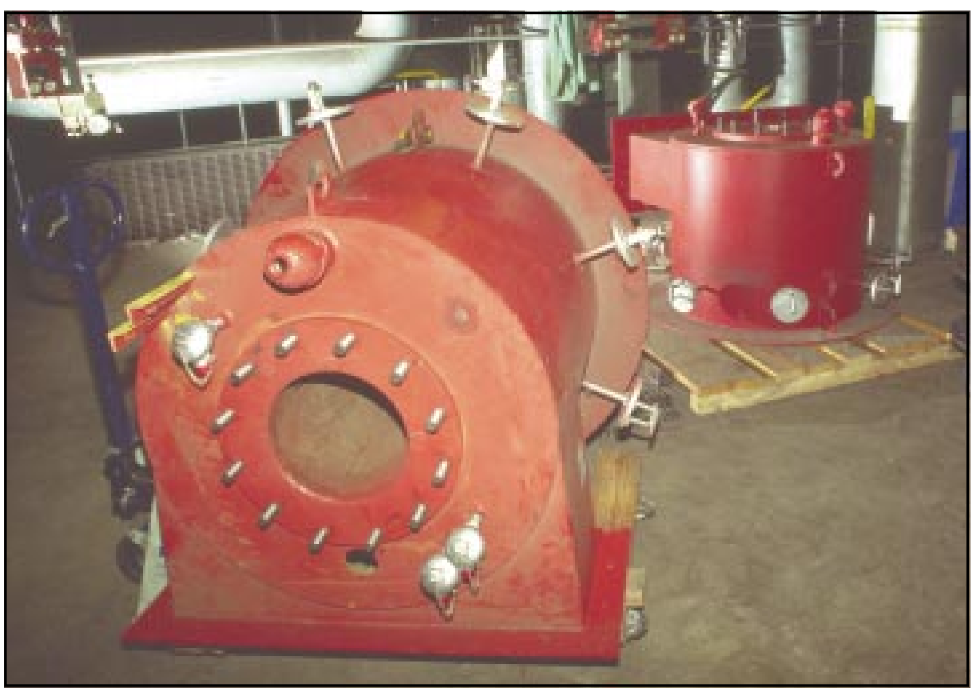
The two most important operating variables for effective NOx control were found to be the stoichiometric ratio in the reburn zone (optimum was in the range of 0.85-0.95) and the use of FGR. The use of FGR was vital to providing necessary burner cooling, flame penetration, and mixing, while maintaining the reburn zone stoichiometric ratio.

No significant adverse boiler impacts were found. Only a slight reduction in boiler efficiency (<1.5%) resulted from coal reburning compared with baseline operation, and the furnace exit flue gas temperature was not compromised by reburning. Under long-term reburn operating conditions, there was no impact on slagging, fouling, tube wall corrosion rate, surface cleanliness, or spray flow requirements for superheat and reheat steam temperature control. Particulate collection efficiency remained the same with subbituminous coal and actually improved slightly with bituminous coal.

Costs

Cost estimates by B&W for commercial implementation of coal reburning technology are based on two sizes of cyclone boilers, with 50% NOx reduction for each size. For a 110-MWe (gross) power plant, the same size as Nelson Dewey Unit 2, total capital is $66/kW. This figure decreases to $43/kW at a capacity of 605 MWe. Ten-year levelized costs (current dollars) are 2.4 mills/kWh at 110 MWe and 1.6 mills/kWh at 605 MWe. The corresponding costs are $1,075/ton of NOx removed at 110 MWe and $408/ton at 605 MWe. Site-specific factors, such as the type of boiler, will affect the economics.

Coal pulverizer with associated feed and distribution piping.



Coal reburn burner on floor awaiting installation.

Chemistry of the Reburning Process

The following equations are not intended to be exact but only approximate representations of the complex, free-radical reactions that occur during reburning.

Primary Combustion Zone (Low to normal excess air; stoichiometric ratio of 1.1-1.2) – The major reactions occurring in the primary combustion zone are fuel combustion and NOx formation.

Main Fuel + O_2 —> CO_2 + CO + H_2O + Other Species

N(fuel) + O_2 —> NOx

N_2(air) + O_2 —> NOx

Reburn Zone (Fuel rich; stoichiometric ratio of 0.85-0.95) – The chemistry in the reburn zone is very complex. NOx reacts with hydrocarbon free radicals to form reduced nitrogen species which, in turn, react with additional NOx to form nitrogen gas.

Reburn Fuel —> CH_x + Other Species

CH_x + NOx —> •CN + •NH_2 + H_2O

NOx + •NH_2 —> N_2 + H_2O

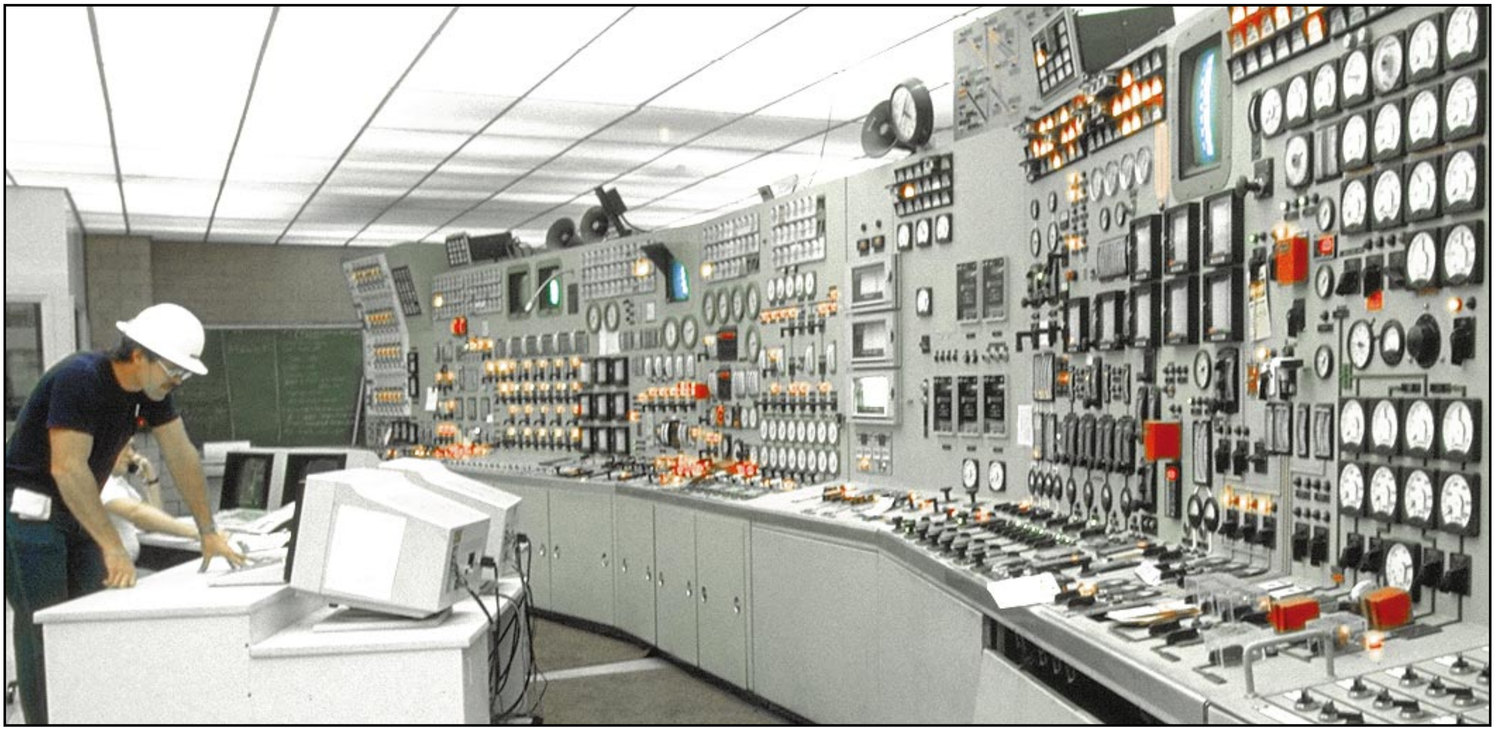
NOx + •CN —> N_2 + CO

NOx + CO —> N_2 + CO_2

Burnout Zone (Normal excess air; stoichiometric ratio of 1.20-1.25) – The main function of the burnout zone is to complete combustion of the fuel. However, any unreacted reduced nitrogen compounds may be reoxidized to NOx. This latter effect is normally small, and the overall result of reburning is a reduction in NOx emissions.

Air + CH_x + CO —> CO_2 + H_2O

•CN + •NH_2 + O_2 —> NOx + CO_2 + H_2O



Power plant control room.

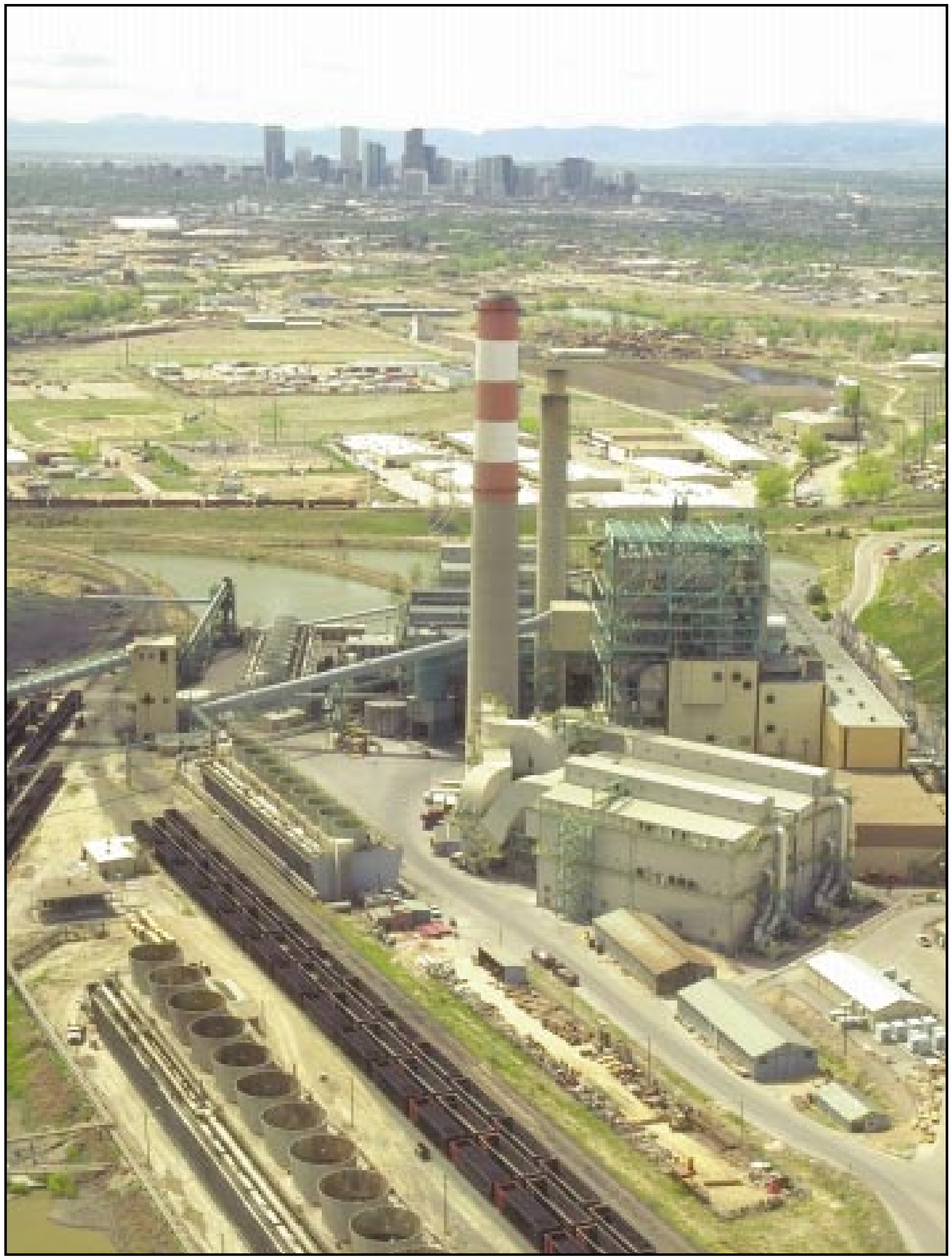
Evaluation of Gas Reburning and Low-NOx Burners on a Wall-Fired Boiler

Project Description

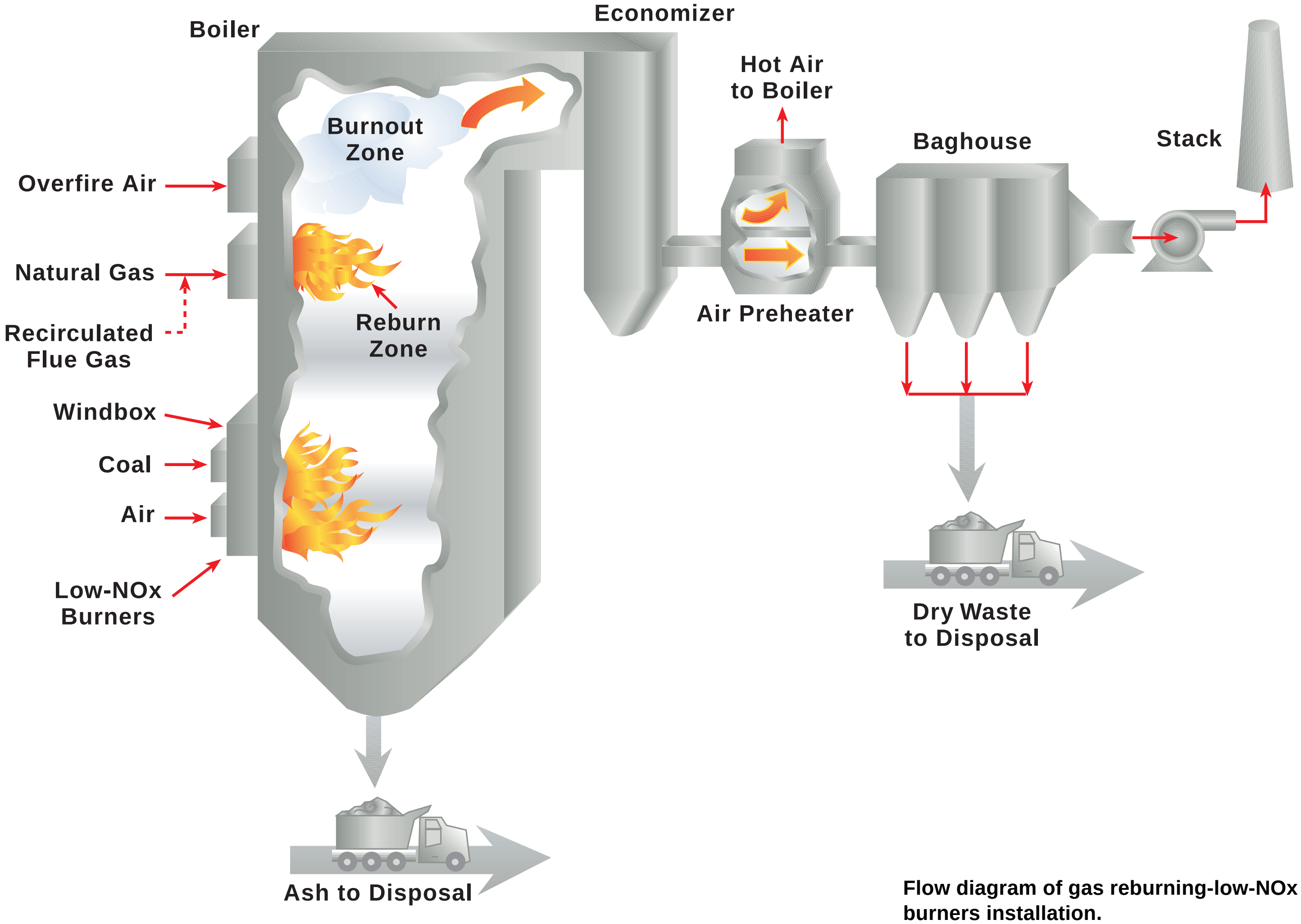
This project was selected during Round III of DOE's CCT Program. In October 1990 Energy and Environmental Research Corporation (EER) signed an agreement with DOE to conduct this project. Gas reburning coupled with low-NOx burners (GR-LNB) was tested at Public Service Company of Colorado's (PSCo) 158-MWe (net) wall-fired Cherokee Unit 3 near Denver, Colorado. PSCo served as co-funder and host. EER and Foster Wheeler Energy Corporation were the technology suppliers, and testing was conducted by EER. Additional team members and co-funders were the Gas Research Institute (GRI), Colorado Interstate Gas Company, and EPRI. DOE provided 50% of the total project cost of $17.8 million.

The existing 16 burners on Unit 3 were replaced by Foster Wheeler Controlled Flow/Split Flame LNBs. These burners employ dual combustion-air registers, allowing control of air distribution at the burner and providing independent control of the ignition zone and flame shape. The gas reburning system retrofit involved routing natural gas to 16 boiler penetrations (eight on the front wall and eight on the rear wall), installing a flue gas recirculation fan, installing a multiclone dust collector to remove particulates and protect the fan, and connecting the equipment with the ductwork. The OFA system involved installing an OFA fan and ductwork from the secondary air system to six front-wall injection nozzles. The control system was also modified.

During the first test series, it was found that FGR had little effect on NOx reduction. Therefore, part way through the demonstration, the FGR system was removed. At the same time, the natural gas injectors were replaced by high-velocity injectors, which made greater use of the available natural gas pressure. Also, the OFA ports were modified to provide higher jet momentum, air swirl capability, and velocity control. This provided improved lateral coverage and turbulence in mixing with unburned fuel. After these modifications, the system was referred to as Second Generation GR-LNB.



Aerial view of Cherokee Station with Denver skyline in background.



Flow diagram of gas reburning-low-NOx burners installation.

The project goal was to reduce NOx emissions by 70% by the combined use of LNBs and GR. Tests were performed on the GR system by varying operational control parameters to assess the effect on boiler emissions, completeness of combustion, thermal efficiency, and heat rate. A long-term testing program was performed to evaluate the consistency of system operations, assess the impact of long-term operation on the boiler, gain experience in operating GR-LNB in a normal load-following environment, and develop a database for use in subsequent applications. The coal burned during this demonstration was a Western bituminous coal with a sulfur content of 0.45% and a nitrogen content of 1.5%.

Results

The use of LNBs by themselves (without GR) reduced NOx emissions from the 0.73 lb/million Btu baseline level to 0.46 lb/million Btu, a 37% reduction. This performance, however, fell short of the targeted value of 45% NOx reduction and had an adverse impact on the overall performance of the combined GR-LNB technology. NOx emissions for first-generation GR-LNB, at 18% gas heat input, were lowered to an average of 0.25 lb/million Btu, an overall reduction of 65%, slightly poorer than the targeted value. Second-generation GR-LNB (no FGR) achieved 64% NOx reduction at 13% gas heat input. In short-term tests, both first- and second-generation GR-LNB were able to meet the target level of 70% reduction in NOx emissions.

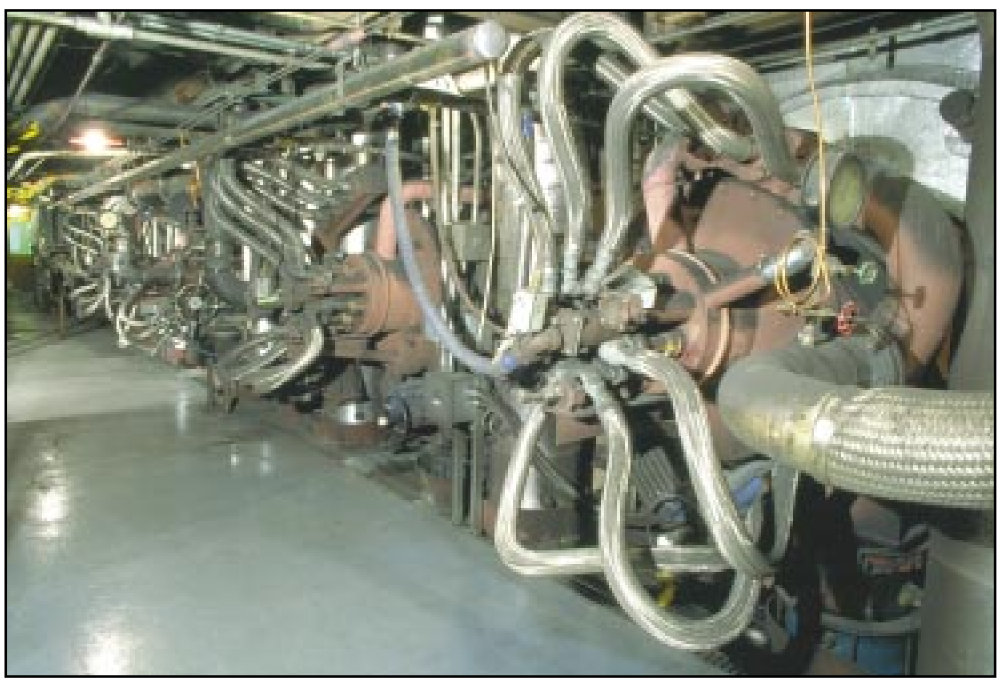
The use of natural gas reduced SO_2 and particulate emissions in direct proportion to the gas heat input. GR-LNB had only a minor impact on the boiler. Boiler efficiency decreased by about 1% during gas reburning because of the increased moisture in the flue gas resulting from natural gas combustion. There was no measurable tube erosion, and only small amounts of slagging occurred. There was no reduction in the efficiency of flyash collection at the baghouse. After completion of the GR-LNB project, the host site has continued to operate the LNB system. The gas reburn system has been retained by the host utility but is not operated at present because current NOx emissions requirements can be met using LNBs alone. Gas reburning can be used in the future if needed to meet more stringent regulations, although at somewhat higher operating cost.

Costs

Preliminary economics were developed by EER for a GR-LNB retrofit to a hypothetical 300-MWe wall-fired boiler burning 3.0 wt% sulfur coal with a 10,000 Btu/kWh heat rate, a capacity factor of 65%, and 12.5% of the heat input by natural gas, which was assumed to be available on-site. The capital cost is \$26/kW, of which GR contributes \$12/kW and the LNBs contribute \$14/kW.

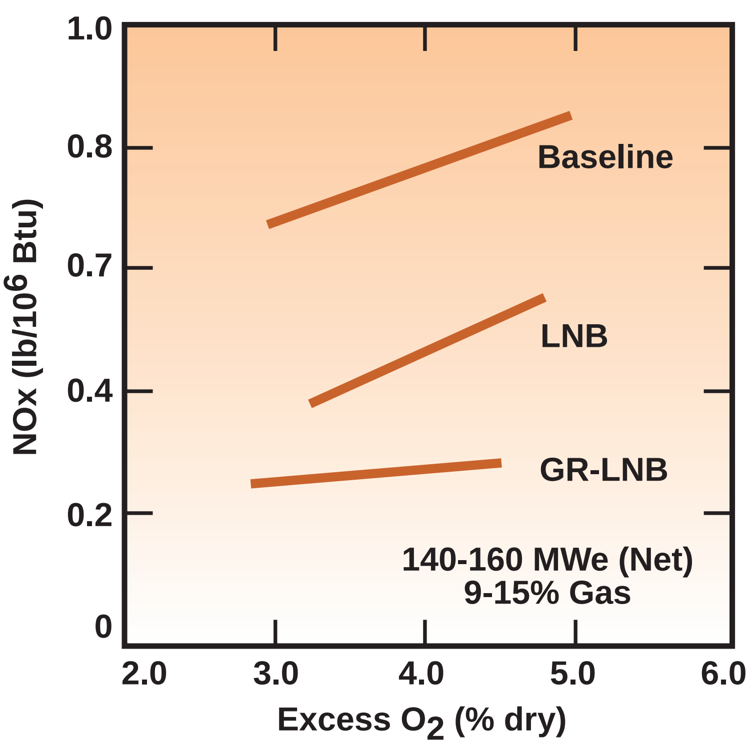
The cost differential between gas and coal is assumed to be \$1.00/million Btu. The amount of fuel fired is increased by 0.8%, compared with baseline operation, to account for the slight loss in overall boiler efficiency. Based on these assumptions, the levelized cost is \$908/ton of NOx removed (constant dollar basis). These economics do not include an allowance for reduced SO_2 emissions resulting from the substitution of natural gas (containing no sulfur) for a portion of the coal feed. The reduction in SO_2 emissions may result in credits on the SO_2 emissions trading market, which would lower the levelized cost of NOx reduction.

Installation of low-NOx burner.



View of low-NOx burners after installation.

Kodak Park.



NOx reduction data from Cherokee Station.

Micronized Coal Reburning Demonstration for NO_x Control

Project Description

The micronized coal reburning project was selected during Round IV of DOE's CCT Program, and in August 1997, New York State Electric & Gas Corporation (NYSEG) entered into an agreement with DOE to conduct the project. The project was conducted at two sites: NYSEG's Milliken Unit 1 (Lansing, New York), a 150-MWe (net) T-fired boiler, where NYSEG was host and co-funder; and Kodak Park Unit 15 (Rochester, New York), a 50-MWe equivalent cyclone-fired industrial boiler, where Eastman Kodak Company was host and co-funder. Energy and Environmental Research Corporation provided the reburn system design. Consolidation Coal Company, now known as CONSOL, provided coal sample testing, and the New York State Electric Research and Development Authority and the Empire State Electric Energy Research Corporation were co-funders. DOE provided 29% of the total project cost of $8.7 million.

With gas reburning, the differential cost of gas over coal is the largest component of the cost of NOx reduction. When coal is used as the reburn fuel, this differential is zero. Thus, coal reburning has the potential for significantly lower NOx control cost than gas reburning. The challenge with coal reburning is to achieve aequate combustion of the reburn coal in the oxygen deficient, short residence time reburn zone. This project demonstrates micronized coal reburning, where the reburn coal is finely ground to 85% below 325 mesh. The small coal particles have greatly increased surface area which increases the rate of combustion, allowing coal

Milliken Station, located in the Finger Lakes Region of New York State.

reburning to be applied in units with limited reburn zone residence time.

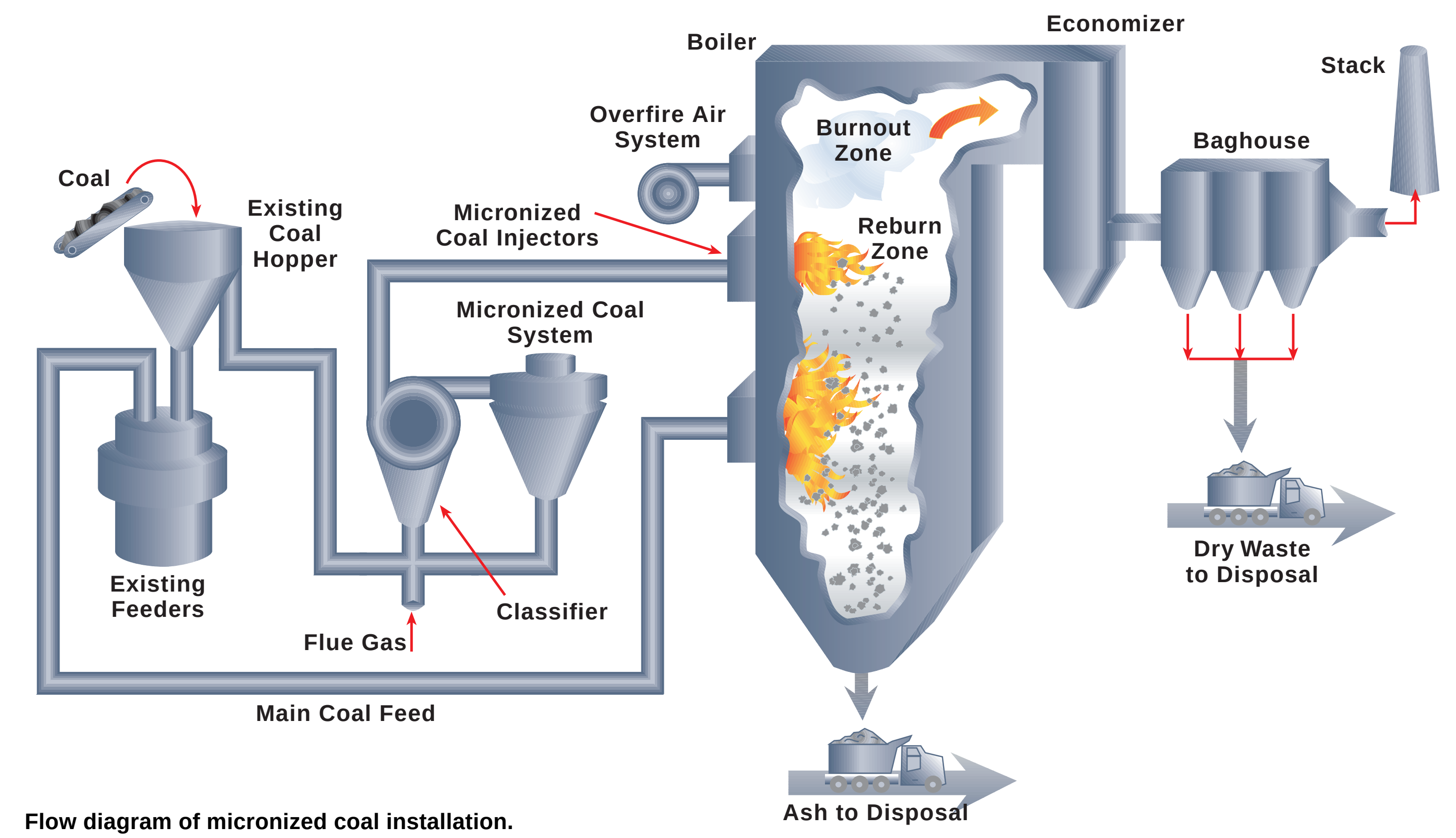
The prime objective of this two-site project was to demonstrate improvements in coal reburning for NOx emissions control by further particle size reduction of the reburn coal. The project goal was to achieve 25-30% NOx reduction on the T-fired unit and at least 50% reduction on the cyclone unit. Testing at both sites began in April 1997 and was completed in 1998. Low-volatile Pittsburgh seam coal (3.2% sulfur and 1.5% nitrogen at Milliken, and 2.2% sulfur and 1.6% nitrogen at Kodak) was fired at both test sites.

Milliken Implementation and Results

At Milliken, the existing ABB Low-NOx Concentric Firing System™ (LNCFS-III), which includes both close coupled and separated OFA ports, was used for the reburn project. Pulverized coal is provided by four DB Riley MPS 150 mills with dynamic classifiers. With LNCFS-III there are four levels of burners, and each mill serves one burner level. When using reburning, the top-level burner nozzles were used to feed the reburn fuel into the upper part of the furnace. To simulate and test a reburn application, the lower three coal elevations were biased to carry approximately 80% of the fuel required for full load, with the top burner supplying the remaining fuel. The speed of the dynamic classifier serving the mill feeding the top burners was increased to provide the micronized fuel. It was decided that full conversion to micronized coal would not be cost effective.

A primary objective at Milliken was to determine the minimum NOx level attainable while maintaining marketable fly ash production (fly ash having less than 4.5% carbon). Variables studied at Milliken include boiler load, reburn coal fineness, oxygen level at the economizer, percent reburn fuel, main burner tilt, and OFA tilt.

Micronized coal reburning with 14% reburn fuel reduced NOx emissions from the 0.35 lb/million Btu baseline level to 0.25 lb/million Btu, a 28% reduction, which was within the target range. The unburned carbon-in-ash, also referred to as loss-on-ignition (LOI), was maintained under 4%. During testing, it was found that excess air is the single most important parameter that affects NOx emissions, higher excess air resulting in higher NOx, but lower LOI. Increasing coal fineness improved NOx emissions only marginally, but lowered LOI. Increasing the percent reburn fuel slightly decreased NOx, but increased LOI.



Flow diagram of micronized coal installation.

MicroMill™ and classifier.

Kodak Implementation and Results

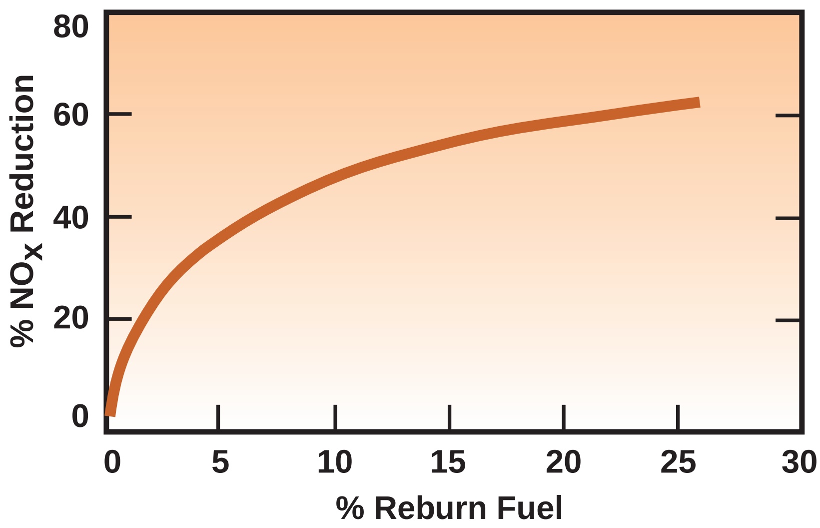
At Kodak, the micronized reburn system was designed by EER using a combination of analytical and empirical techniques, augmented by EER's extensive reburning database. The reburn fuel and overfire air (OFA) injection components were designed with a high degree of flexibility to allow for field optimization to accommodate the complex furnace flow patterns in the cyclone boiler. The micronized coal reburn fuel was provided by a Fuller MicroMill™ system that produces micronized coal with a particle size of approximately 20 microns, about one third the diameter of normal pulverized coal. To maximize NOx reduction, the reburn fuel was injected with flue gas as the carrier instead of air. The flue gas was extracted downstream of the electrostatic precipitator (ESP) and boosted by a single fan.

Two MicroMills™ were installed in parallel to provide the capacity necessary for high reburn rates, the second mill serving as a spare at lower reburn rates. The micronized coal was introduced into the reburn zone by means of eight injectors, six on the rear wall and one on each of the side walls. The optimization variables included the number of injectors, swirl, and velocity. OFA was injected through four injectors on the front wall, utilizing EER's second generation, dual-concentric OFA design which provided for variable injection velocity and swirl. The optimization tests showed that best performance was achieved at conditions close to EER's design point. A new boiler control system was also installed.

The demonstration showed excellent NOx reduction performance. The target

Demonstration and/or Operating Reburn Installations on Coal-Fired Boilers in the United States

Location (Retrofit Date) Boiler Type	Owner/ Operator	Capacity, MWe (net)	Reburn Heat, %	NOx Emissions, lb/million Btu		NOx Reduction, %
				Uncon-trolled	Con-trolled	
Gas Reburning						
Hennepin (1991) Tangential	Illinois Power	71	18	0.75	0.25	67
Lakeside (1993) Cyclone	Springfield Water, Light & Power	33	23	0.97	0.39	60
Cherokee (1993) Wall	Public Service of Colorado	158	18	0.73 (w/o LNB)	0.27	63
Greenidge (1996) Tangential	New York State Electric & Gas	100	10	0.50	0.25	50
Kodak Park (1995) Cyclone	Eastman Kodak	69 (equiv)	20	1.25	0.56	56
Kodak Park (1998) Cyclone	Eastman Kodak	50 (equiv)	14	1.20	0.51	58
Kodak Park (1999) Cyclone	Eastman Kodak	50 (equiv)	13	1.20	0.51	58
Crane (1998) Tangential	Baltimore Gas & Electric	200	Not available	Not available	Not available	Not available
Coal Reburning						
Nelson Dewey (1991) Cyclone	Wisconsin Power & Light	100	25-30	0.82	0.39	52
Milliken (1997) Tangential Micronized Coal	New York State Electric & Gas	150	14	0.35 (with LNB)	0.25	28
Kodak Park (1997) Cyclone Micronized Coal	Eastman Kodak	50 (equiv)	17	1.36	0.59	57



Performance of demonstration and commercial reburning units.

was to reduce NOx to less than 0.60 lb/million Btu from a baseline of 1.25 lb/million Btu, a 52% reduction. Although the actual baseline was higher than expected (1.45 lb/million Btu), the NOx emissions target of 0.60 lb/million Btu was achieved with 17% reburn fuel, a 59% reduction. At greater reburn fuel rates, NOx reduction was even greater. These results are comparable to the NOx reduction achieved with gas reburning systems. As expected, LOI increased with the reburn system in operation; LOI was 35 to 45% during full load, compared with the baseline level of 10-12%.

Some mechanical problems were encountered during the demonstration, including plugging of the coal handling system feeding the MicroMill™, vibration and blade wear on the mills, erosion of the classifiers, and corrosion due to low temperature flue gas when the reburn system was out of service. In spite of these problems, successful operation was achieved.

Costs

The installed cost of a micronized coal reburning system exceeds that of gas reburning, principally due to the cost of the coal milling system. However, since there is no reburn fuel cost differential, operating costs are much lower.

Conclusions

The three projects described in this report clearly show that reburning is an effective NOx control option for coal-fired boilers, either alone or in combination with other emissions control technologies. This is reinforced by the results of an earlier NOx control CCT demonstration project, Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (GR-SI) at Illinois Power's Hennepin Plant (see CCT Topical Report Number 3), as well as by commercial projects involving reburning, both in the U.S. and abroad.

Reburning can reduce NOx emissions from coal-fired boilers by up to 50-60%, depending on various factors such as the baseline emissions level, furnace characteristics, and the fraction of heat input supplied by the reburn fuel. The most important process variable is the stoichiometric ratio in the fuel-rich reburn zone. The optimum value for this ratio is in the range of 0.85-0.95, which is achieved by 10-30% reburn heat input.

Long-term testing has shown only minor impacts on boiler equipment and operations. There is a small loss in boiler efficiency, particularly when gas is used as the reburn fuel, due to the increased moisture content of the flue gas when gas is fired.

With coal reburning, other emissions are not significantly affected. With natural gas reburning, emissions of sulfur oxides and particulates are reduced in direct proportion to the fraction of heat supplied by natural gas, and carbon dioxide emissions are somewhat reduced, because of the higher hydrogen content of natural gas compared to coal.

In terms of NOx reduction performance, natural gas and coal appear to be about equally effective reburn fuels, and the choice between them will be based on relative capital and operating costs.

Market Potential

Reburning is applicable to all types of coal-fired boilers, including the major types of firing systems used in electric power generation and industrial steam production, specifically wall-fired, T-fired, cyclone, and stoker units. A significant feature of reburning is that it can be used on cyclone boilers, whose design features do not lend themselves to being retrofitted with LNBs.

Reburning can be used as an alternative to LNBs or in combination with LNBs to meet Title IV NOx emissions regulations. A large potential market for reburning is the boilers subject to more stringent controls under Title I of the CAAA. Illustrative of this market are the boilers covered under EPA's September 1998 Rule for Reducing Regional Transport of Ground-Level Ozone. As discussed previously, this rule requires 22 states and DC to submit revised State Implementation Plans to ensure that emissions are sufficiently reduced to mitigate transport of ozone and NOx across state boundaries in the Eastern half of the United States.

All boilers in this region, as well as those located in other ozone nonattainment areas across the U.S., are potential candidates for retrofit reburning applications. While reburning alone cannot meet the stringent NOx emissions requirements associated with Title I, reburning can be used along with LNBs to reduce the load on post-combustion technologies such as SCR.

Canada geese feeding in shadow of power plant stack.

Economics

Whether natural gas or coal is used as the reburn fuel is a decision based largely on economics. Factors that affect the comparison are: (a) the cost differential between gas and coal; (b) the capital and operating costs of pulverizers and other coal-handling equipment required for coal reburning; (c) the availability of natural gas at the site; (d) the relative impacts of coal and gas reburning on boiler efficiency; and (e) the possibility of generating credits from decreased emissions of SO_2 when burning natural gas.

Although a comparison between these technologies is highly site specific, in general the capital cost of coal reburning is higher than that of gas reburning, primarily because of the cost of the pulverizers and ancillary equipment required for coal reburning, particularly with cyclone-fired boilers, which utilize coarse coal. However, for some boilers firing pulverized coal, it may be possible to adjust the existing pulverizers to achieve a sufficiently fine particle size for the reburn coal. If natural gas is not available at the site, the cost of installing a supply line from the nearest pipeline to the power plant may make the capital cost of gas reburning higher than that of coal reburning.

As opposed to capital costs, which tend to be higher for coal reburning, operating costs tend to be higher with gas reburning because of the gas/coal fuel price differential. At present, coal is significantly cheaper than gas per unit of heat content, and this price differential is expected to increase over the next 15 years.

FGR has been used in both coal and gas reburning, primarily as a carrier for the reburn fuel to improve its penetration and mixing in the reburn zone. By redesigning the gas injectors, it was possible to eliminate the use of FGR in the GR-LNB project. The need for FGR has to be examined on a case-by-case basis, and, if it can be avoided, costs will be reduced.

Farming country near Nelson Dewey Station.

Commercial Applications of Reburning Technology

A number of owner/operator hosts have continued to operate their reburn facilities after the completion of the CCT test programs at their plants. These installations on coal-fired boilers include the GR retrofits at Hennepin and Lakeside from the earlier GR-SI CCT project, and the coal reburning retrofit at Nelson Dewey.

In addition, GR has been installed by EER at NYSEG's Greenidge Station, the Tennessee Valley Authority's (TVA) Allen Plant, and at Baltimore Gas and Electric (BG&E) Company's Crane Station. GR has also been installed on an oil/gas-fired boiler at Long Island Lighting Company's Barrett Station. Options with EER to retrofit gas reburning installations on other units have been exercised or are pending with BG&E and TVA. B&W has installed gas reburn at Kodak's second power plant, with design co-funding provided by GRI. Internationally, Scottish Power has installed gas reburning at Longannet. At more than 600 MWe, this is the largest installation to date.

Award

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 gas reburning into a viable and commercial emissions control option for utility and industrial power generation boilers.

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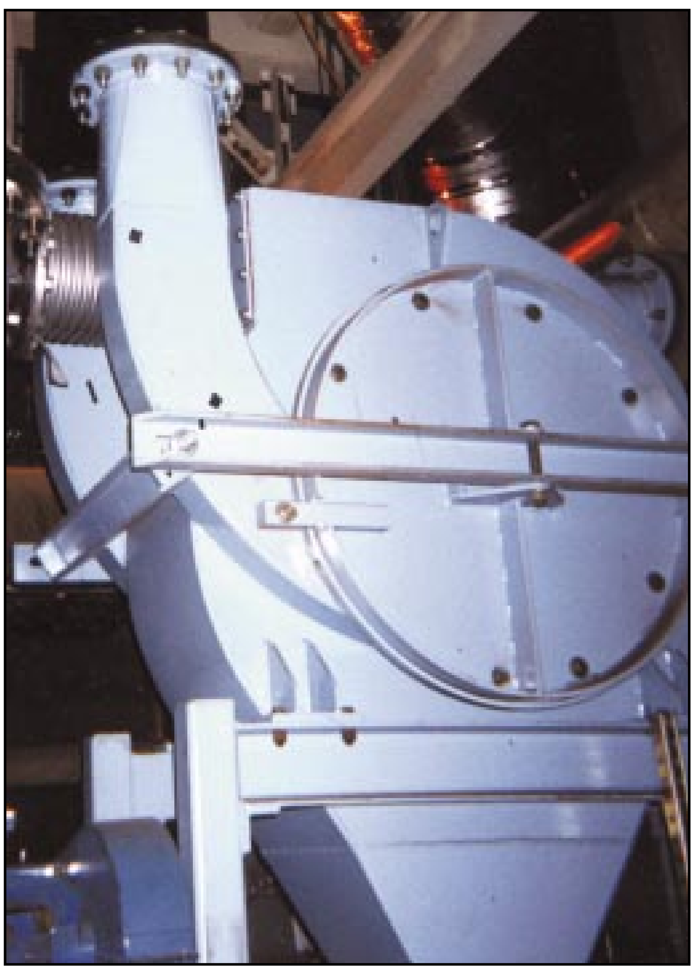

Classifier at Kodak Park.

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Gas reburn installation on Cherokee Unit 3.

The Clean Coal Technology Program

The Clean Coal Technology (CCT) Program is a unique partnership between the federal government and industry that has as its primary goal the successful introduction of new clean coal utilization technologies into the energy marketplace. With its roots in the acid rain debate of the 1980s, the program is on the verge of meeting its early objective of broadening the range of technological solutions available to eliminate acid rain concerns associated with coal use. Moreover, the program has evolved and has been expanded to address the need for new, high-efficiency power-generating technologies that will allow coal to continue to be a fuel option well into the 21st century.

Begun in 1985 and expanded in 1987 consistent with the recommendation of the U.S. and Canadian Special Envoys on Acid Rain, the program has been implemented through a series of five nationwide competitive solicitations. Each solicitation has been associated with specific government funding and program objectives. After five solicitations, the CCT Program comprises a total of 40 projects located in 18 states with a capital investment value of nearly $6 billion. DOE's share of the total project costs is about $2 billion, or approximately 34 percent of the total. The projects' industrial participants (i.e., the non-DOE participants) are providing the remainder—nearly $4 billion.

Clean coal technologies being demonstrated under the CCT Program are establishing a technology base that will enable the nation to meet more stringent energy and environmental goals. Most of the demonstrations are being conducted at commercial scale, in actual user environments, and under circumstances typical of commercial operations. These features allow the potential of the technologies to be evaluated in their intended commercial applications. Each application addresses one of the following four market sectors:

- Advanced electric power generation
- Environmental control devices
- Coal processing for clean fuels
- Industrial applications

Given its programmatic success, the CCT Program serves as a model for other cooperative government/industry programs aimed at introducing new technologies into the commercial marketplace.

Coal unloading facility.

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List of Acronyms and Abbreviations

ABB ..... Asea Brown Boveri
BF ..... Biased firing
BOOS ..... Burners-out-of-service
Btu ..... British thermal unit
B&W ..... The Babcock and Wilcox Company
BG&E ..... Baltimore Gas and Electric Company
CAAA ..... Clean Air Act Amendments of 1990
CCT ..... Clean Coal Technology
CO_2 ..... Carbon dioxide
DOE ..... U.S. Department of Energy
EER ..... Energy and Environmental Research Corporation
EPA ..... U.S. Environmental Protection Agency
EPRI ..... Electric Power Research Institute
ESP ..... Electrostatic precipitator
FETC ..... Federal Energy Technology Center
FGR ..... Flue gas recirculation
FWEC ..... Foster Wheeler Energy Corporation
GR ..... Gas reburning
GRI ..... Gas Research Institute
GR-LNB ..... Gas reburning-low-NOx burners
GR-SI ..... Gas reburning-sorbent injection
kW ..... kilowatt
kWh ..... kilowatt hour
LAER ..... Lowest achievable emissions rate
LEA ..... Low excess air
LNBs ..... Low-NOx burners
LNCFS ..... Low-NOx Concentric Firing System™
LOI ..... Loss on ignition
MWe ..... Megawatts of electric power
NAAQS ..... National Ambient Air Quality Standards
NOx ..... Nitrogen oxides
NYSEG ..... New York State Electric & Gas Corporation
OFA ..... Overfire air
ppm ..... parts per million
PRB ..... Powder River Basin
PSCo ..... Public Service Company of Colorado
RACT ..... Reasonably available control technology
SCR ..... Selective catalytic reduction
SI ..... Sorbent injection
SIP ..... State Implementation Plan
SNCR ..... Selective noncatalytic reduction
SO_2 ..... Sulfur dioxide
TVA ..... Tennessee Valley Authority
VOCs ..... Volatile organic compounds