A Review of DOE/NETL's Advanced NOx Control Technology R&D Program for Coal-Fired Power Plants

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INTRODUCTION

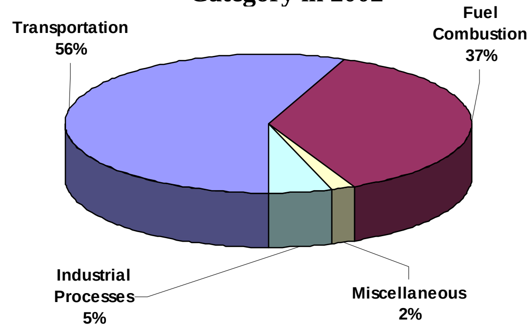
The environmental performance of the United States' fleet of coal-fired boilers has steadily improved since passage of the 1990 Clean Air Act Amendments (CAAA). Missions of sulfur dioxide (SO_2), nitrogen oxide (NOx), particulate matter (PM) have been significantly reduced. NOx emissions have been reduced by 29%, while coal use has increased almost 30%. However, further restrictions on emissions from power plants have been proposed in response to issues such as mercury, acid rain, ground-level ozone, nitrification of aquatic ecosystems, ambient fine particulate matter, and visibility impairment (regional haze). For example, the EPA's recently proposed Clean Air Interstate Rule is intended to significantly reduce both NOx and SO_2 emissions. In addition, several multi-pollutant bills have been offered in Congress, including the Clear Skies Act, to further control power plant emissions.

In response to these environmental challenges, the U.S. Department of Energy Office of Fossil Energy's National Energy Technology Laboratory (DOE/NETL) is carrying out a comprehensive, integrated research and development (R&D) effort under its Innovations for Existing Plants (IEP) Program. The overall goal of the IEP Program is to continue to enhance the efficiency and environmental performance of the existing fleet of fossil-fuel-fired power systems that represent more than 320 gigawatts of generating capacity as well as apply these concepts to advanced power systems. An important component of the program is the R&D of advanced NOx control technologies. This effort focuses primarily on systems capable of controlling NOx emissions to a level of 0.15 lb/MMBtu by 2006 and 0.10 lb/MMBtu by 2010, while achieving a levelized cost savings of at least 25% compared to state-of-the-art SCR control technology. The research also provides an improved understanding of the impact of these advanced technologies on related issues such as unburned carbon, waterwall wastage, and mercury speciation and capture. The IEP portfolio of NOx control technology R&D projects encompasses laboratory studies, modeling, and pre-commercial demonstration full-scale testing. The success of the projects is intimately tied to key collaborations and partnerships with industry, federal, state, and local agencies, and the academic and research communities. This paper will provide an update on the status of these projects covering Rich Reagent Injection, ultra-low-NOx burners (LNB), selective non-catalytic reduction (SNCR), enhanced-oxygen combustion, and methane de-NOx.

BACKGROUND

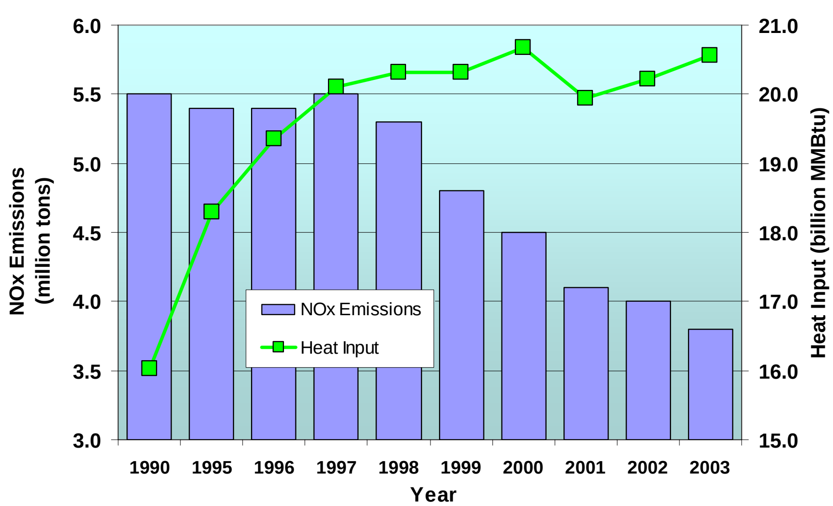
Nitrogen oxide is a general term used to describe a group of gases that contain varying amounts of nitrogen and oxygen. NOx forms at high temperatures during fossil fuel combustion. The primary sources of NOx emissions in the United States are motor vehicles, power plants, and other commercial, industrial, and residential sources that burn fossil fuels. Direct NOx emissions from these sources include nitrogen dioxide (NO_2), nitrous oxide (N_2O), and nitric oxide (NO).[a] NOx emissions can also react with other compounds in the atmosphere to form secondary products that includes ozone (O_3), nitric acid (HNO_3), and nitrate particles. As shown in Figure 1, fuel combustion sources contributed 37% of total U.S. NOx emissions of approximately 22 million tons in 2002.[1]

Figure 1 - U.S. NOx Emissions by Source Category in 2002



NOx emissions from U.S. coal-fired power plants subject to EPA's Title IV acid rain program were approximately 3.8 million tons in 2003, representing about 18% of total U.S. NOx emissions.[2] As a result of implementation of various Clean Air Act regulatory requirements, NOx emissions in 2003 from U.S. coal-fired power plants were approximately 31% less than in 1990 despite a 29% increase in total generation as measured by thermal heat input. Figure 2 presents the trend in annual NOx emissions from U.S. coal-fired power plants from 1990 through 2003.[2]

Figure 2 - NOx Emissions Trend for U.S. Coal-Fired Power Plants



[a] NOx emission inventories are expressed in terms of equivalent weight of NO_2.

Health and Environmental Impacts of NOx Emissions

The EPA has established national ambient air quality standards (NAAQS) for six major pollutants (known as criteria pollutants) under the Clean Air Act: NO_2, O_3, sulfur dioxide (SO_2), particulate matter (PM), carbon monoxide (CO), and lead (Pb). The purpose of these standards is to protect public health and welfare. NOx emissions from coal-fired power plants and other man-made sources can contribute directly or indirectly to three of these criteria pollutants: NO_2, O_3, and PM. The emission of NOx to the atmosphere has been associated with the following health and environmental impacts.[3]

Nitrogen Dioxide − Human exposure to excessive concentrations of NO_2 can lead to respiratory problems. However, average NO_2 concentrations in the U.S. are well below the NAAQS and therefore do not represent a current public health or environmental concern.

Acid Rain − NOx and SO_2 can form acidic compounds ("acid rain") through reactions with water and oxidants in the atmosphere. Studies have shown that the low pH associated with the acid rain can be harmful to plant and aquatic life.

Ground-level Ozone − NOx can react with volatile organic compounds in the presence of heat and sunlight to form ground-level ozone. Ozone can trigger respiratory problems in sensitive individuals such as children, the elderly, and asthmatics.

Fine Particulate Matter − NOx can react with ammonia, moisture, and other compounds in the atmosphere to form secondary fine particulate matter that may adversely impact human cardio-pulmonary functions.

Visibility Impairment − Nitrogen dioxide gas and secondary fine particulate matter nitrates can block the transmission of light leading to reduced visibility known as regional haze.

Water Quality Deterioration − The deposition of nitrogen compounds in and around bodies of water has been linked to "eutrophication" – an over-enrichment of nutrients that can deplete the oxygen content of lakes and rivers and result in a reduction of fish and shellfish populations. The deposition of atmospheric NOx has been identified as a primary source of nitrogen in the Chesapeake Bay in addition to fertilizer and animal waste run-off from agricultural lands. EPA has proposed using the Clean Water Act as a mechanism to further reduce NOx emissions near sensitive waters.

Global Warming − One compound of NOx, nitrous oxide, is a greenhouse gas that has been associated with contributing to global warming.

Existing and Future NOx Regulatory Requirements

Because of the health and environmental impacts associated with NOx emissions, coal-fired power plants will continue to be subject to progressively more stringent NOx regulations in the near future. The 1990 Clean Air Act Amendments (CAAA) contains several provisions that required coal-fired power plants to significantly reduce NOx emissions over the past ten years. However, there are several other CAAA provisions and recently introduced multi-pollutant control legislative proposals that are likely to require additional NOx emission reductions over the next ten years. The following is a summary of these existing and potential future NOx emission control requirements.

New Source Performance Standards and New Source Review. New coal-fired power plants are required to meet both New Source Performance Standards (NSPS) and New Source Review (NSR) NOx emission requirements. Additionally, existing sources that undergo a major modification are also subject to NSR. The NOx NSPS for coal-fired plants built after August 17, 1971 and prior to July 9, 1997 ranges from 0.5 to 0.8 lb/MMBtu depending on coal rank and the date construction was commenced. The NOx NSPS was recently changed to a generation output-based standard of 1.6 lb/MWh (approximately equivalent to 0.15 lb/MMBtu at a heat rate of 10,500 Btu/kWh) for new coal-fired plants that commenced construction after July 9, 1997. However, the NOx NSR requirements are established on a case-by-case basis by the state environmental agency during the permitting process for a new plant and are likely to be much more stringent than NSPS. Under NSR, a new plant is required to install either Best Available Control Technology (BACT) if located in an ozone National Ambient Air Quality Standard (NAAQS) attainment area, or Lowest Achievable Emission Rate (LAER) technology if located in an ozone NAAQS nonattainment area. Recent state BACT/LAER determinations have established NOx emission rate limits for new coal-fired plants between 0.05 and 0.10 lb/MMBtu and required the installation of LNB and SCR.[4]

Title IV Acid Rain Program. The Title IV acid rain program of the 1990 CAAA consists of a two-phase strategy to reduce SO_2 and NOx emissions from coal-fired power plants. The Title IV NOx program was implemented through unit-specific NOx emission rate limits based on the type of boiler/burner configuration. However, plants also had the option to comply under a multi-unit NOx emissions averaging plan or could petition for an alternative emission limitation (AEL). The overall goal was to reduce NOx emissions from approximately 1,000 coal-fired power plant boilers by 2 million tons below the 1980 baseline emissions of about 6 million tons.

Phase I of the Title IV program started January 1, 1996 for two boiler types – dry-bottom, wall-fired boilers and tangentially-fired boilers (known as Group 1 boilers).[b] The Title IV Phase I, Group 1 dry-bottom, wall-fired boilers were required to meet a 0.50 lbs NOx/MMBtu emission limit, while tangential-fired boilers were limited to 0.45 lbs NOx/MMBtu. These emission limits were based on application of LNB technology available at that time. NOx emission limits for other boiler/burner configurations were not established under Phase I due to lack of cost-effective commercially available control technologies.

Phase II of the Title IV program started January 1, 2000. EPA determined that more effective LNB technology was available to establish more stringent standards for the Group 1 boilers not regulated under Phase I. Also, Phase II established limitations for other boiler/burner configurations, known as Group 2 boilers (cell burner boilers, cyclones, vertically-fired boilers,

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[b] Group 1 boilers were classified as Phase I- or Phase II-affected under the Title IV NOx program based on their designation under the Title IV SO_2 program.

and wet bottom boilers), based on technologies that were considered comparable in cost to LNB. The Title IV NOx emission limits are shown in Table 1.

Table 1– Title IV NOx Emission Limits

Boiler Type	NOx Emission Limit (lb/MMBtu)	
	Phase I	Phase II
Group 1 Boilers		
Wall-fired, dry bottom	0.50	0.46
Tangential-fired	0.45	0.40
Group 2 Boilers		
Cell-burner	NA	0.68
Cyclone	NA	0.86
Vertically-fired	NA	0.80
Wall-fired, wet bottom	NA	0.84

Title I NOx RACT. Under Title I of the 1990 CAAA, coal-fired power plants located in one-hour ozone NAAQS nonattainment areas were required to install NOx Reasonably Available Control Technology (NOx RACT) by May 1995. By definition, NOx RACT was presumed to require the installation of LNB and overfire air (OFA). NOx RACT emission limits for individual plants were determined by the state environmental agencies through a permitting process.

Northeast Ozone Transport Region. In November 1994 states located in the Northeast Ozone Transport Region (OTR) agreed to a three phase plan to implement additional power plant NOx reductions beyond Title IV requirements as a means to achieve attainment with the one-hour average ozone NAAQS.[c] The goal was to reduce OTR power plant NOx emissions during the five-month (May through September) summer ozone season from the 1990 baseline of 473,000 tons to 141,000 tons by 2003. Phase I required power plants to install NOx RACT by May 1995 as already required under Title I of the 1990 CAAA. Similar to the Title IV SO_2 acid rain program, the Phase II reductions were implemented using a NOx allowance cap-and-trade program beginning May 1999. Power plants located in the outer zone of the OTR were required to reduce their ozone season NOx emissions equivalent to the less stringent of an emission rate

[c] The OTR member states include Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Maryland, Delaware, Virginia, and the District of Columbia. Virginia elected not to adopt the OTR NOx reduction plan.

of 0.2 lb/MMBtu or a 55% reduction from their 1990 baseline NOx emissions. Likewise, power plants located in the inner zone of the OTR were required to reduce ozone season NOx emissions equivalent to an emission rate of 0.2 lb/MMBtu or a 65% reduction. Phase III was to include a similar 0.15 lb/MMBtu or 75% reduction requirement effective May 2003. However, due to EPA's promulgation of the ozone transport NOx SIP call rule discussed below, it was unnecessary for the OTR to implement the Phase III reductions.

NOx SIP Call Rule. The inability of the OTR states to achieve attainment with the one-hour average ozone NAAQS led to the EPA's regulation of long range NOx transport from power plants in the Northeast, Midwest and Southeast U.S. through the NOx state implementation plan rule (known as the NOx SIP call rule) that was published in October 1998. The EPA determined that 21 states and the District of Columbia were all contributing significantly to ozone levels in downwind states.[d] As a result, these states were required to develop corresponding NOx SIP call regulations to reduce power plant NOx emissions to an equivalent average emission rate of 0.15 lb/MMBtu during the ozone season. The ensuing state-developed NOx SIP call rules became effective in May 2003 for eight Northeastern states and the District of Columbia and May 2004 for the remaining NOx SIP call affected states with the exception of Georgia and Missouri, which must comply by May 2005. The states are implementing the power plant NOx reductions through a market-based NOx allowance cap-and-trade program similar to the EPA's Title IV acid rain SO_2 allowance program. Under the NOx SIP call, power plants must surrender one NOx allowance for every ton of NOx emissions during the ozone season. The states allocate a prorated share of NOx allowances to each power plant that is calculated using a historical baseline period heat input and emission rate of 0.15 lb/MMBtu. Power plants then have the option to either reduce their NOx emissions to the level of their NOx allowance allocation or acquire additional NOx allowances from other plants that over comply. It has been estimated that approximately 100 GW of SCR will have been installed by U.S. coal-fired power plants for compliance with the NOx SIP call.[5]

Regional Haze Rule. In July 1999 the EPA published a regional haze regulation to improve visibility in national parks and wilderness areas. Visibility impairment occurs as a result of fine particles and gases in the atmosphere. Further reductions of power plant emissions of NOx and SO_2 are likely to be targeted as compliance strategies. The rule includes an overall goal of achieving pristine visibility within 60 years. The states are required to develop control plans to demonstrate reasonable progress toward that goal and to update those plans every 10 years. The EPA has encouraged states to participate in multi-state regional planning organizations (RPO) in order to share technical resources and coordinate their implementation plans. The regional haze rule requires the installation of best available retrofit technology (BART) for existing pre-NSPS power plants that were placed into operation between 1962 and 1977. The BART provision could require the installation of SCR controls on these plants for control of NOx emissions. According to EPA, states are required to identify BART sources and submit implementation

[d] The NOx SIP call states include Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, and West Virginia. Only portions of Alabama, Georgia, Michigan, and Missouri are subject to NOx reductions under the NOx SIP call rule.

plans by January 2008. Implementation of BART NOx controls would then occur between 2014 and 2018.

Title I Revisions to Ozone and Particulate Matter NAAQS. In July 1997 the EPA promulgated revisions to the ozone and particulate matter NAAQS. The ozone NAAQS was revised from 120 parts per billion (ppb) averaged over one hour to 80 ppb averaged over eight hours. The particulate matter (PM) NAAQS was revised to include a new standard for "fine" particulate matter sized less than 2.5 microns in diameter ($PM_{2.5}$). The previous PM NAAQS, based on particles sized less than 10 microns in diameter (PM_{10}), was retained. The new $PM_{2.5}$ NAAQS includes an annual standard of 15 microgram per cubic meter and a 24-hour standard of 65 ug/m^3. Based on a review of ambient air pollution monitoring data, EPA has recently published nonattainment designations for both the 8-hour ozone and $PM_{2.5}$ NAAQS for many areas of the United States. States with nonattainment areas are now required to develop state implementation plans (SIP) that include appropriate emissions control regulations that are necessary for these areas to achieve attainment with the revised NAAQS. Since NOx emissions from coal-fired power plants can be a significant precursor to atmospheric formation of both ozone and $PM_{2.5}$, additional state regulation of these emissions will be necessary. The EPA's Clean Air Interstate Rule, discussed below, is intended to achieve the majority of the required NOx emission reductions. However, it may be necessary for some states to require even more stringent NOx controls in order to achieve attainment.

Clean Air Interstate Rule. On January 30, 2004, the U.S. EPA proposed the Clean Air Interstate rule (CAIR)[e] for the control of SO_2 and NOx emissions from fossil-fuel fired power plants located in 29 states and the District of Columbia.[f] The proposed emission reductions are intended to assist the Eastern U.S. in achieving compliance with the fine particulate matter and eight-hour average ozone NAAQS. A supplemental proposal published on June 10, 2004 provided additional details on a proposed market-based allowance cap-and-trade program for states to implement the proposed SO_2 and NOx emission reductions. The EPA plans to issue a final rule in March 2005.

The proposed emission reductions would be implemented in two phases, with a Phase I compliance date of January 1, 2010, and a Phase II compliance date of January 1, 2015. The SO_2 and NOx region-wide emissions and caps are shown in Table 2. The SO_2 emission caps were calculated as percent reductions from the total number of Title IV, Phase II allowances currently allocated to sources in the affected states - a 50% reduction for 2010 and 65% reduction for 2015. The NOx emission caps were calculated using emission rates of 0.15 lb/MMBtu for 2010 and 0.125 lb/MMBtu for 2015 multiplied by a historical baseline period heat input for each affected state. The proposed SO_2 and NOx emission reductions in CAIR are similar to those contained in the Administration's proposed Clear Skies Act of 2003 (see below) with two notable exceptions. First, CAIR covers only the Eastern U.S. compared to the nation-wide

[e] The proposed rule was originally titled the Interstate Air Quality rule. However, EPA now refers to this rule as the Clean Air Interstate Rule – CAIR.

[f] The CAIR rule states include Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

coverage of Clear Skies. Secondly, the second-phase implementation of CAIR begins earlier than Clear Skies – 2015 versus 2018.

Table 2 – Proposed CAIR SO_2 and NOx Region-Wide EGU Emissions and Caps

	2002 Emissions (million tons)	Phase I - 2010		Phase II - 2015	
		Cap (million tons)	% Reduction from 2002 Emissions	Cap (million tons)	% Reduction from 2002 Emissions
SO_2	9.4	3.9	59% (50% per Title IV)	2.7	71% (65% per Title IV)
NOx	3.7	1.6	57%	1.3	65%

The states will be responsible for the allocation of NOx allowances to sources under the CAIR NOx cap-and-trade program. Similar to the NOx SIP call rule, each affected source must hold and surrender a sufficient number of allowances to cover its emissions each year. However, CAIR requires year-round compliance with the proposed NOx reductions, while the existing NOx SIP call rule requires compliance only during the ozone season. EPA estimates that SCR would be installed on an additional 46 GW of existing power plant capacity by 2015 to meet compliance with CAIR.[6] As a result, EPA projects a total of 171 GW of SCR capacity would be installed nation-wide by 2015.

Multipollutant Control Legislation. In the past several years, the Administration and Congressional members have proposed legislation for multiple pollutant control that would limit emissions of SO_2, NOx, mercury, and in some cases CO_2 from fossil-fueled power plants. At this time, enactment of such legislation is uncertain.

The May 17, 2001, National Energy Policy Report recommended the President direct the EPA to work with Congress to propose multipollutant control legislation "that would establish a flexible, market-based program to significantly reduce and cap emissions of SO_2, NOx, and mercury from electric power generators." Subsequently, on February 14, 2002, the Bush Administration announced its Clear Skies Initiative (CSI) multipollutant control proposal. The CSI proposal would require significant emission reductions of SO_2, NOx, and mercury implemented in two phases using an allowance-based cap-and-trade program. The CSI proposal requires a reduction in NOx emissions equivalent to an approximately 59% reduction below 2001 baseline levels beginning in 2008 and a 67% reduction beginning in 2018.[7] The Clear Skies Act legislation to adopt CSI as an amendment to the CAA was originally introduced in both the U.S. House and Senate in July 2002. The Clear Skies Act was not enacted in 2002 or 2003, but was re-introduced in the Senate in January 2005 as S. 131 by Senators James Inhofe (R-OK) and George Voinovich (R-OH).

In addition to the Clear Skies Act, alternative CAA amendments were introduced in the 108th Congress. Of those alternatives, the two that have received the most attention are S. 556 - The Clean Power Act of 2003 (Sen. Jeffords, I-NH) and S. 843 - The Clean Air Planning Act of 2003 (Sen. Carper, D-DE). The three legislative proposals are significantly different on matters such as compliance methods, targets, deadlines, and regional definitions. Additionally, both the Clean

Power Act and the Clean Air Planning Act regulate CO_2 to some degree. Table 3 provides a summary of annual NOx emission caps under each proposed Act. Under the Clear Skies Act, the country is split into two regions, the western region has a 0.72 million ton NOx cap and the eastern region has a 1.47 million ton NOx cap beginning in 2008. In 2016, the eastern NOx cap is further reduced to 1.07 million tons.[8,9]

Table 3 - Summary of U.S. NOx Emission Caps Under Proposed Multipollutant Legislation

Proposed Legislation	Annual NOx Emission Caps, million tons			
	2008	2009	2013	2016
Clear Skies Act of 2005	2.19	--	--	1.79
Clean Air Planning Act of 2003	--	1.87	1.7	--
Clean Power Act of 2003	--	1.51	--	--

State-Specific NOx Emission Reduction Regulations. In addition to complying with the national and regional NOx requirements discussed above, several states have also implemented NOx emission reduction regulations that apply to coal-fired power plants. Three recent examples of state NOx regulatory actions are New York[10], North Carolina[11], and Texas[12]. In August 2004, New York adopted emergency regulations that require additional NOx and SO_2 reductions to address concerns with acid deposition. The New York NOx regulation basically extends the ozone season NOx SIP call reductions to a year-round basis beginning October 2004. In 2002, North Carolina enacted legislation known as the Clean Smokestacks Act that requires coal-fired power plants to reduce annual NOx emissions by 77% from their 1998 baseline beginning in 2009. The impetus for the North Carolina legislation was to address local concerns with acid rain, ozone, and visibility. In December 2002, Texas adopted revisions to its SIP for the 8-county Houston/Galveston area that requires coal-fired power plants to reduce NOx emissions by 88% from their 1997 baseline emissions to help the area achieve attainment with the one-hour average ozone NAAQS. The reductions are being phased in between April 2003 and April 2007 and being implemented through a NOx allowance cap-and-trade program. The NOx reductions are rather stringent and equate to a 0.045 lb/MMBtu NOx emission rate for tangential-fired boilers and 0.05 lb/MMBtu for wall-fired boilers.

NOx Emissions from Coal-Fired Power Plants

Coal consists of both organic and inorganic matter. In the high-temperature environment during and after the combustion process, the components of coal and air are physically and chemically transformed into a suite of products. One of the products is NOx, which can be formed by (1) nitrogen and oxygen in the combustion air reacting at high temperature to produce "*thermal NOx*" and (2) fuel-bound nitrogen reacting with the combustion air to produce *"fuel NOx."* The amount of NOx formed depends on numerous factors including flame temperature, nitrogen content of the coal, combustion excess air, residence time, and degree of mixing. For most coal-fired units, thermal NOx typically represents about 20% and fuel NOx about 80% of the total NOx formed. However, for cyclones and other boilers that operate at very high temperatures, thermal NOx can be considerably higher than fuel NOx. In addition, minor amounts of 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 later oxidized to NOx, referred to as *"prompt NOx."* The quantity of thermal NOx formed depends primarily on the "three T's"of combustion: temperature, time, and turbulence. Thus 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.

NOx Control Technologies

There are a number of NOx control technologies that have been developed over the last 15 years for application on coal-fired power plants. These NOx control technologies can be grouped into two broad categories: combustion modifications and post-combustion processes. Combustion modifications manage the mixing of fuel and air, thereby reducing temperature and initial turbulence, which minimizes NOx formation in the boiler. Post-combustion control relies on various chemical processes to convert the NOx formed in the boiler to inert nitrogen. In addition to NOx control processes, more sophisticated combustion control systems using neural networks are being developed to further reduce NOx emissions while optimizing overall boiler performance. Some of the more important NOx control technologies are briefly discussed below.

Combustion Modifications

Low NOx Burners − LNB are designed to control the mixing of fuel and air to achieve what amounts to staged combustion. This staged combustion reduces both flame temperature and oxygen concentration during some phases of combustion that lowers both thermal NOx and fuel NOx production. Based on a recent analysis, EPA estimated average NOx reduction ranges from 35% to 45% for tangential- and wall-fired boilers equipped with LNB. Sub-bituminous-fired plants tend to operate at a higher NOx removal efficiency than bituminous-fired plants. The estimated capital costs for LNB are estimated to be $9/kW for tangential-fired boilers and $17/kW for wall-fired boilers (1999$).[13]

Overfire Air − OFA is air that is injected into the furnace above the normal combustion zone. Generally when OFA is employed, the burners are operated at a lower than normal air-to-fuel ratio that reduces NOx formation. OFA, which is frequently used in conjunction with LNBs, completes the combustion process at a lower temperature. Average NOx reduction ranges from 50% to 65% for tangential- and wall-fired boilers equipped with LNB and OFA. The estimated capital costs for LNB and OFA are estimated to be $13 to $15/kW for tangential-fired boilers and $23/kW for wall-fired boilers (1999$).

Reburning − In the reburning process, part of the boiler fuel input (typically 10-25%) is added in a separate reburn zone. The fuel-rich reducing conditions in this zone 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 an approximately normal air-to-fuel ratio; (2) a reburn zone, where added fuel results in a fuel-rich condition; and (3) a burnout zone, where OFA completes the combustion. Coal, oil, or gas can be used as the reburn fuel. Average NOx reduction ranges from 25% to 65% depending on the percentage of reburn fuel heat input. The estimated capital costs range from \$5 to \$30/kW for gas reburn and \$30 to \$60/kW for coal reburn (2000\$).[14,15,16]

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. FGR is also used as a carrier to inject fuel into a reburn zone to increase penetration and mixing.

Operational Modifications − Changing certain boiler operational parameters can create conditions in the furnace that will lower NOx production. Examples include 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 airflow is maintained to create staged combustion in the furnace. LEA involves operating at the lowest possible excess air level without interfering with 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. Depending on boiler specific operating conditions, operational modifications could lead to a slight increase or decrease in the plant's operations and maintenance cost.

Post-Combustion Processes

Selective Catalytic Reduction − In SCR, a catalyst vessel is installed downstream of the furnace. Ammonia (NH_3) is injected into the flue gas before it passes over the fixed-bed catalyst. The catalyst promotes a reaction between NOx and NH_3 to form nitrogen and water vapor. NOx reductions as high as 90% are achievable, but careful design and operation, such as control of the reagent dosage and assuring good mixing, are necessary to keep NH_3 emissions (referred to as NH_3 slip) to a concentration of a few ppm. The capital costs for SCR can vary greatly due to site specific retrofit requirements. In a recent survey of 45 SCR installations, the capital cost ranged from \$60 to over \$150/kW. For plants in the 400 to 599 MW size range, the average capital cost was \$103/kW.[17] SCR O&M costs can also vary greatly due to reagent feed rate and catalyst replacement frequency. EPA's current estimate for a 500 MW plant is 0.54 \$/kW-yr (equivalent to 0.06 mills/kWh) fixed O&M and 0.55 mills/kWh variable O&M (1999\$).

Selective Noncatalytic Reduction − In SNCR, a reducing agent (typically NH_3 or urea) is injected into the furnace above the combustion zone, where it reacts with NOx as in the case of SCR. Critical factors in applying SNCR are sufficient residence time in the appropriate temperature range and uniform distribution and mixing of the reducing agent across the full furnace cross section. SNCR average NOx reduction ranges from 20% to 50% and the estimated capital costs range from \$10 to \$20/kW. SNCR O&M costs vary with reagent usage based on the level of NOx reduction and range from 0.5 to 1.5 mills/kWh (1999\$).[14,18]

Balance-of-Plant Impacts

Unfortunately, the implementation of NOx control technologies at a coal-fired power plant can have adverse operational and maintenance balance-of-plant impacts that can decrease plant efficiency and/or availability. The impacts are a result of changed combustion conditions in the furnace, changed products of combustion, and the addition of chemical reagents. These impacts can include incomplete coal combustion, boiler tube corrosion, air heater pluggage, deterioration in electrostatic precipitator performance, fly ash contamination, and excessive NH_3 and sulfur trioxide (SO_3) emissions. The magnitude and severity of these balance-of-plant impacts at a particular plant is dependent on boiler design and coal properties, as well as the specific design and operating conditions of the NOx control technology. However, there is at least one beneficial balance-of-plant impact – SCR catalyst oxidation of mercury. The following is a brief summary of some of these potential balance-of-plant impacts:

Incomplete Coal Combustion – The staged combustion associated with LNB operation can result in a 2 to 5 percentage point increase in unburned carbon levels (measured as loss-on-ignition, or LOI), particularly for plants burning bituminous coal. Improving air-coal flow balance for both the mills and burners and increasing coal fineness can reduce LOI levels in LNB applications.

Boiler Tube Corrosion – The staged combustion associated with LNB operation can result in a local reducing atmosphere (low oxygen concentration) under ash deposits along portions of the furnace waterwall that accelerates boiler tube corrosion, particularly for plants burning high-sulfur bituminous coal. The tubes can be protected from excessive corrosion through application of metal cladding or weld overlays.

Air Heater Pluggage – Excessive ammonia slip from either SNCR or SCR operation can react with SO_3 in the combustion flue gas to form ammonium bisulfate and/or ammonium sulfate salts that can result in air heater pluggage.[19]

Deterioration in ESP Performance – Excessive LOI levels in the fly ash captured in the ESP can lower ash resistivity that can result in ash re-entrainment and subsequent opacity spiking during collection plate cleaning.

Fly Ash Contamination – Excessive LOI levels in the fly ash captured in the ESP can prohibit the utilization of the ash as a substitute for Portland cement in concrete. The unburned carbon adsorbs the air entraining admixtures (AEA) which are added to concrete to facilitate workability and improve freeze/thaw characteristics. In addition, excessive ammonia slip adsorbed on the ash can cause a nuisance odor if the ash is wetted during subsequent handling, transport, disposal, or utilization applications.

Excess Ammonia Emissions – State environmental agencies typically establish maximum ammonia emission rates during the permitting process required for installation and operation of SNCR and SCR NOx controls. Therefore, excess ammonia emissions could result in violations of the plant's operating permit.

Excess Sulfur Trioxide Emissions – Recent operating experience with SCRs at some plants burning high-sulfur bituminous coal have indicated a problem with excessive SO_3 emissions.[20] The SCR catalyst converts a small portion (approximately 1%) of SO_2 to SO_3. The decrease in flue gas temperature across the air heater condenses the SO_3 and forms sulfuric acid (H_2SO_4)

droplets that are visible as a blue plume upon discharge to the atmosphere. Several power plants have been testing various chemical additives to adsorb the SO_3/H_2SO_4 prior to discharge.

Mercury Oxidation Across SCR Catalyst – Recent testing with SCRs at plants burning bituminous coal have indicated the catalyst converts a significant portion of the elemental mercury in the flue gas to an oxidized form of mercury that can be more readily captured in downstream air pollution control devices.[21] This co-benefit could be significant for plants equipped with a wet flue gas desulfurization (wet FGD) system.

DOE/NETL INNOVATIONS FOR EXISTING PLANTS PROGRAM

A comprehensive, integrated environmental R&D program is being carried out under the DOE Office of Fossil Energy's IEP program. The program, which is managed by DOE/NETL, encompasses both in-house and contracted research on advanced, low-cost environmental control systems and ancillary science and technologies that can help the existing fleet of coal-based power plants meet current and future environmental requirements. The program also provides high-quality scientific information on present and emerging environmental issues for use in regulatory and policy decision making. The research directly supports the Administration's CSI and the May 2001 National Energy Policy recommendations concerning the environmental performance of coal-based power systems.

The IEP portfolio includes bench-scale through field-scale R&D related to the control of mercury, NOx, particulate matter, and acid gas emissions from power plants, as well as research in the area of ambient air quality, atmospheric chemistry, and solid by-products. Furthermore, the program recognizes the importance of emerging water-related issues and their relationship with reliable and efficient power plant operations. Partnership and collaboration with industry, Federal and state agencies, research organizations, academia, and non-government organizations are key to the success of the program. Additional information on DOE/NETL's IEP program can be found at: http://www.netl.doe.gov/coal/E&WR/index.html.

ADVANCED NOx CONTROL TECHNOLOGY R&D ACTIVITIES

DOE/NETL has been at the forefront of conducting advanced NOx control technology R&D for coal-fired power plants. The success of achieving the required Title IV acid rain program NOx reductions can be attributed largely to the adoption of LNB technology by the utility industry. The LNBs that are currently installed in 75% of the nation's coal-fired power plants are a direct result of the DOE/NETL Clean Coal Technology Program's government–industry partnerships.[22]

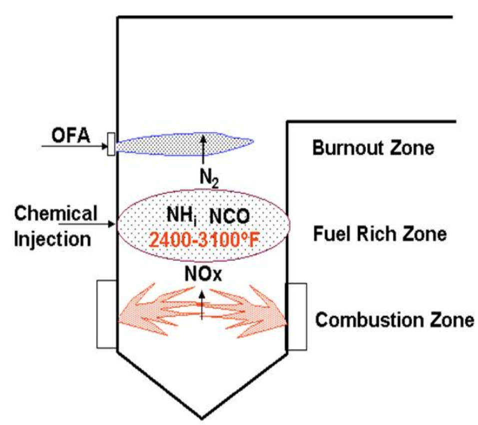
The continuing ratcheting down of NOx emissions by new regulations will require some power plant emission rates to be reduced well beyond 0.15 lb/MMBtu. To meet these requirements, power producers will need to retrofit existing boilers with additional NOx control technologies, some of which will adversely impact plant efficiency and performance. The new NOx control requirements demand an increase in R&D, capital, and operating expenditures from power plants to implement and come at an inopportune time for an industry that has been adversely impacted financially by deregulation and the associated capital market pressures, aging facilities, homeland security, in addition to other ever-expanding environmental control requirements.

In response to this challenge, DOE/NETL is partnering with industry and academia through the IEP Program to conduct advanced NOx control technology R&D.[23] The specific performance target is to develop combustion control technologies for existing plants with a NOx emission rate of 0.15 lb/MMBtu by 2006 and 0.10 lb/MMBtu by 2010, while achieving a levelized cost savings of at least 25% compared to state-of-the-art SCR control technology. A long-range goal is to further develop a combination of advanced combustion and SCR control technologies to achieve a NOx emission rate of 0.01 lb/MMBtu by 2020. However, in a cap-and-trade allowance-based regulatory program, it is realized that low cost NOx control technologies that do not achieve the target emission rates can still have a prominent role as a compliance strategy. Further, the technologies under development are: (1) to have negligible impact on balance-of-plant issues, (2) applicable to a wide range of boiler types and configurations, and (3) capable of maintaining performance over a wide range of feed coals and operating conditions. The research portfolio includes advanced combustion controls, advanced flue gas treatment, and integrated control systems. Additional information on DOE/NETL's advanced NOx emissions control activities can be found at: http://www.netl.doe.gov/coal/E&WR/nox/index.html. The following sections include brief summaries of several current DOE/NETL advanced NOx control technology R&D projects.

Rich Reagent Injection for Cyclone Burners

Reaction Engineering International (REI) has conducted optimization studies of EPRI's, Rich Reagent Injection (RRI) process for NOx reduction on cyclone burners.[24,25] Cyclone burners create an intense flame that melts the ash to form slag. The high temperature generated by this burner results in relatively high uncontrolled NOx emissions, typically exceeding 1.2 lb/MMBtu. RRI uses a nitrogen-containing additive, such as ammonia or urea, to non-catalytically reduce NOx in the lower furnace. A schematic of the RRI process is shown in Figure 3. Full-scale field-testing of RRI has been successfully completed at Conectiv's 138 MW B.L. England Unit 1 and AmerenUE's 500 MW Sioux Unit 1.

Figure 3 - Rich Reagent Injection Process Schematic



At Conectiv's B.L. England Unit 1, prior installation of OFA and SNCR had reduced uncontrolled NOx emissions from 1.2 lb/MMBtu to 0.35 lb/MMBtu. REI's *GLACIER* computational fluid dynamics (CFD) combustion simulation software was used to design the RRI system. A summary of the RRI test results are shown in Figure 4. Field-testing confirmed modeling predictions and demonstrated that the RRI system alone could achieve 25-30% NOx reduction beyond OFA levels with less than 1 ppm ammonia slip and that the inclusion of SNCR could achieve an additional 35% NOx reduction to 0.25 lb/MMBtu with less than 5 ppm NH_3 slip.

Figure 4 - RRI Test Results at B.L. England Unit 1

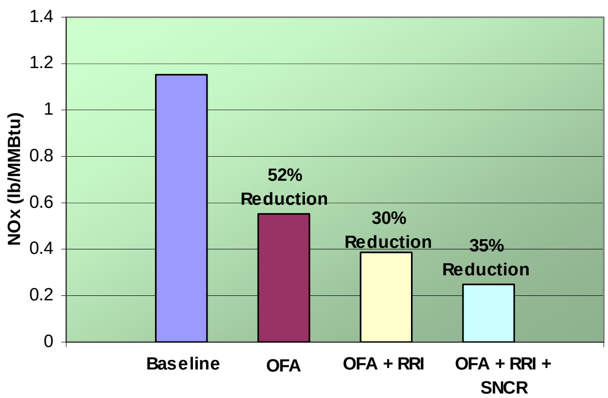
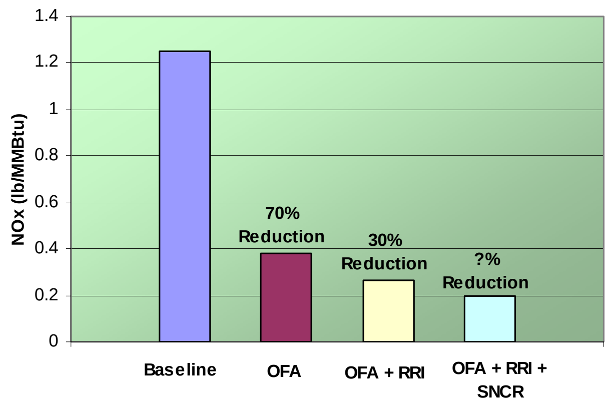


Figure 5 - RRI Test Results at Sioux Unit 1



The objective of the testing at AmerenUE's Sioux Unit 1 was to determine whether similar performance could be obtained with RRI in a significantly larger unit. A summary of the RRI test results are shown in Figure 5. The field test results were found to be consistent with the CFD model predictions. Both showed that NOx reductions of 30% from full load baseline emissions of 0.38 lb/MMBtu with OFA to 0.27 lb/MMBtu were achievable with RRI. These reductions were achieved with no predicted or measurable ammonia slip. Modeling of this unit also suggests that NOx reductions could be improved through modification of FGR operation, reduction of lower furnace stoichiometry or utilization of SNCR. Although the target emissions of 0.15 lb/MMBtu were ambitious for this style of burner, these results are substantial when compared to the Title IV NOx limit of 0.86 lb/MMBtu for cyclone-fired boilers. These units, which account for only 8% of the US generating capacity, emit nearly 12% of the coal-fired NOx emissions.

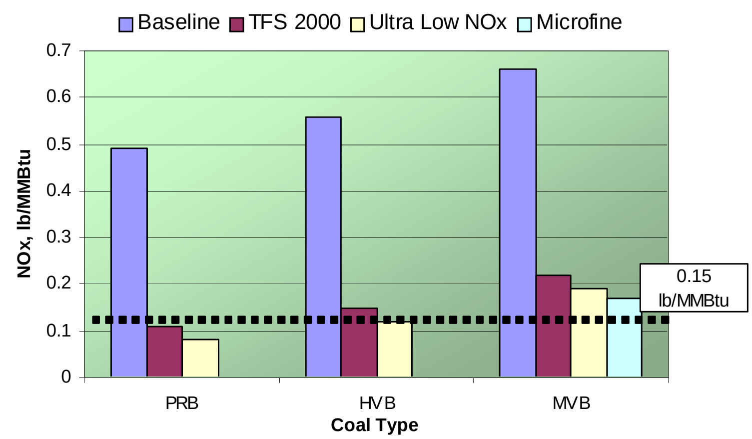
Low NOx Firing System for Tangential Boilers

ALSTOM Power Inc. recently completed a comprehensive pilot-scale study to develop retrofit NOx control technology for tangential boilers to achieve less than 0.15 lb/MMBtu NOx firing bituminous coal and 0.10 lb/MMBtu NOx firing subbituminous coal at a cost that is at least 25% less than SCR technology.[26,27] ALSTOM's TFS 2000™ low NOx firing system served as a basis for comparison to other low NOx systems evaluated and was the foundation upon which refinements were made to further improve NOx emissions and related combustion performance.

Three coals, ranging from a very reactive subbituminous Powder River Basin coal (PRB) to a moderately reactive Midwestern high volatile bituminous coal (HVB) to a less reactive Eastern medium volatile bituminous coal (MVB), were evaluated using a large, 50-60 MMBtu/hr, pilot-scale boiler. Among the technologies evaluated were finer coal grinding, oxidative pyrolysis burners, windbox auxiliary air optimization, and various burner zone firing arrangements in concert with overfire air. Other technologies, such as an advanced boiler control system, coal and airflow balancing, and a Carbon Burn Out combustor, were also evaluated.

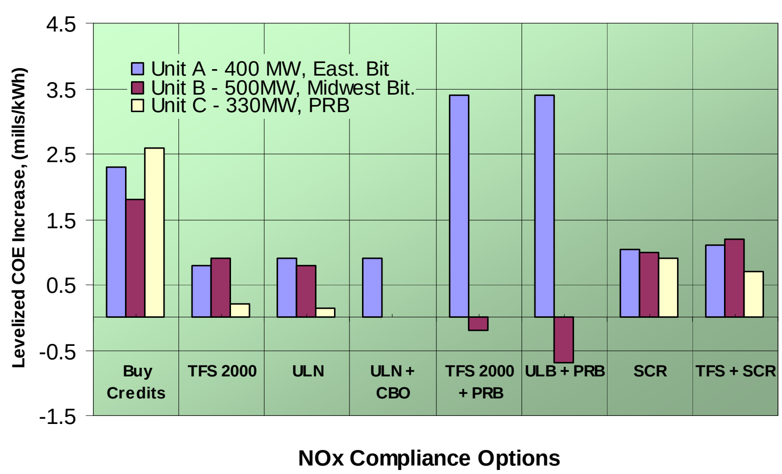
Pilot-scale testing of the three test coals showed that both NOx and combustion performance are a strong function of coal properties. As shown in Figure 6, the most reactive coal, PRB, showed the lowest NOx emission rate, followed by the moderately reactive HVB, and least reactive MVB coals. The combination of firing system modifications resulting in the lowest NOx emissions is referred to as the Ultra Low NOx (ULN) integrated system. In general, firing system modifications that reduce NOx emissions can also result in higher levels of unburned carbon in the fly ash and increased levels of carbon monoxide (CO). The PRB coal showed the lowest combustibles in the flue gas, followed by the HVB and MVB coals. When both NOx emission rate and combustion efficiency performance were evaluated, the standard TFS 2000 system gave the best results for the HVB and MVB coals and the ULN system gave the best results on the PRB coal. Many of the firing system components developed in this project have been applied to the TFS 2000 firing system, resulting in improved NOx emissions without significantly affecting the unburned carbon levels. To date, 19 commercial boilers firing PRB coal that utilize aspects of the technologies demonstrated in this project are achieving NOx emissions at or below 0.15 lb/MMBtu.

Figure 6 - ALSTOM Pilot-Scale Test Results



An engineering systems and economic analysis was performed to evaluate various NOx reduction options including the commercially-available TFS 2000 system, the ULN system developed in this project, and SCR. The various NOx reduction alternatives were evaluated as retrofit options for three tangential boilers. These include: (1) a 400 MW boiler on the East coast firing an Eastern bituminous

Figure 7 - ALSTOM Cost Analysis



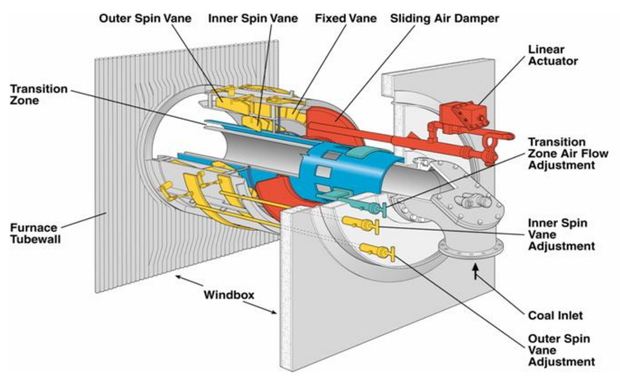
compliance coal, (2) a 500 MW boiler in the Midwest firing a Midwestern bituminous coal, and (3) a 330 MW boiler in the West firing a PRB subbituminous coal. The objective was to evaluate the economics of various NOx reduction options to gain insight into the optimum NOx reduction strategy for different pulverized coal (PC) fired units.

Results from this economic analysis are shown in Figure 7. Switching to a PRB coal, in concert with installation of either a TFS 2000 or ULN system, was the most cost effective option (75-80% less than the cost of an SCR) if the cost of shipping the PRB coal to a particular site was not prohibitive. However, it was recognized that the optimum NOx reduction strategy is unit, site, and system specific.

Integrated Low NOx Burners and SNCR for Wall-Fired Boilers

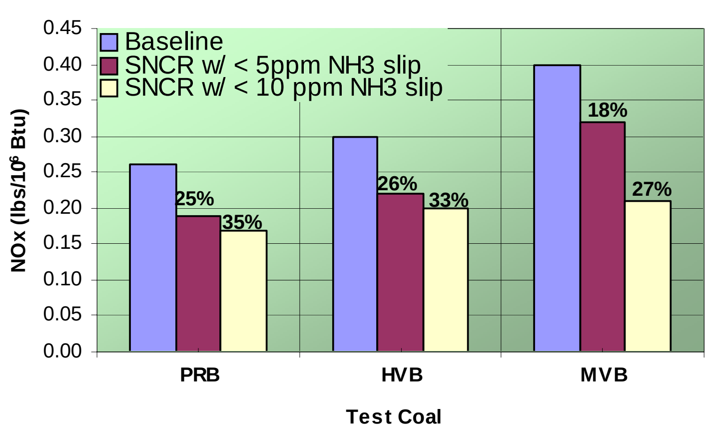
McDermott Technology, Inc. (MTI), the Babcock & Wilcox Company (B&W), and Fuel Tech teamed together to investigate an integrated solution for NOx control.[28,29] The system was comprised of B&W's DRB-4Z™ LNB technology (Figure 8) and Fuel Tech's NOxOUT®, a urea-based SNCR technology. Large-scale testing was conducted using a 100-MMBtu/hr pilot-scale combustor that simulates the conditions of large coal-fired boilers. The test facility is equipped with one near full-scale burner, is constructed with water walls, and is insulated with refractory to simulate the thermal conditions of the middle row burner in a full-scale boiler.

Figure 8 – B&W's DRB-4Z Low NOx Burner



A wide range of coals were tested including: Spring Creek, a PRB western subbituminous coal; Pittsburgh #8, a high volatile bituminous coal; and Middle Kittanning, a medium volatile bituminous coal. As shown in Figure 9, the DRB-4Z™ burner alone without air staging achieved NOx emissions of 0.26 lb/MMBtu for the PRB coal, 0.30 lb/MMBtu for the Pittsburgh #8, and 0.40 lb/MMBtu for the Middle Kittanning coal. The NOx variations with fuel can be explained with the fuel's fixed

Figure 9 - B&W DRB-4Z and SNCR Full-Load Test Results



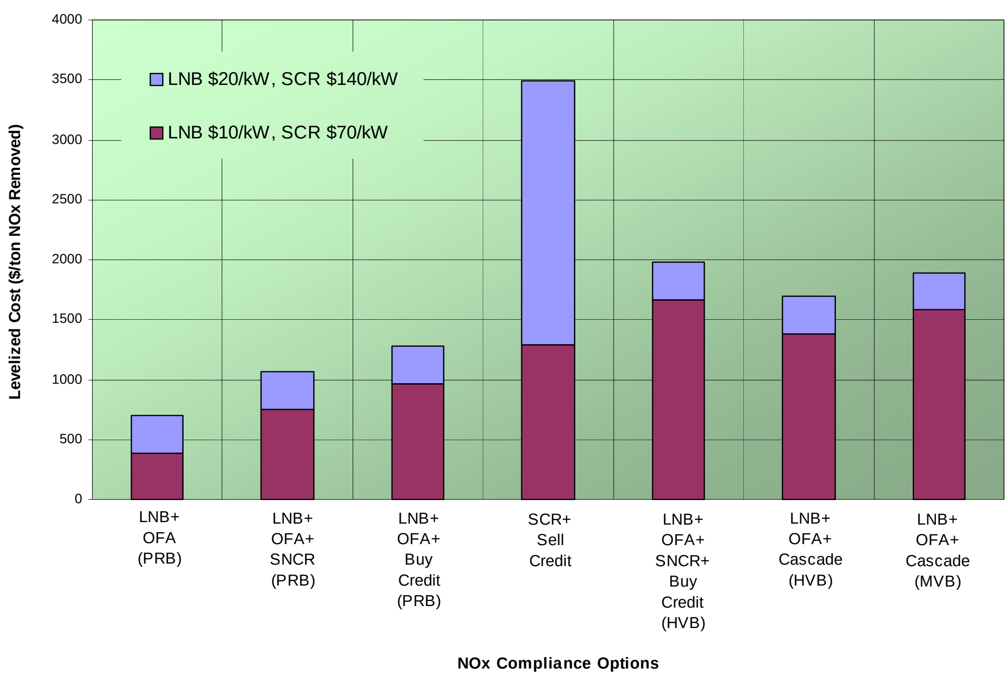
carbon over volatile matter ratio (FC/VM) and fuel nitrogen content. Fuel FC/VM ratios for Spring Creek, Pittsburgh #8, and Middle Kittanning were 1.26, 1.19, and 2.38 respectively. In addition, the lower fuel nitrogen and higher moisture content of the Spring Creek coal reduced the overall NOx emissions.

The baseline DRB-4Z™ NOx levels at full load were reduced by the SNCR system (configured with wall injectors only) to 0.19 lb/MMBtu (25% reduction) for Spring Creek, 0.22 lb/MMBtu (26% reduction) for Pittsburgh No. 8, and 0.32 lb/MMBtu (18% reduction) for Middle Kittanning coal. These data indicate that a nominal 25% additional NOx reduction is feasible using SNCR while firing PRB and eastern high volatile coals with a baseline NOx of 0.2 to 0.3 lb/MMBtu when the NH_3 slip is limited to less than 5 ppm. Higher NOx reductions were possible when the ammonia slip was between 5 to 10 ppm. For units firing coals with lower volatile content such as Middle Kittanning, the higher boiler gas temperatures could limit the SNCR NOx reduction to 15-20%.

To further investigate more favorable conditions of the layered technology, additional testing was conducted using the Spring Creek coal in a boiler configuration which included the use of staged combustion with OFA and a multiple nozzle lance in front of the superheater tubes of the convective pass for more conducive temperatures for urea injection. At the optimum conditions, the baseline NOx emission rate of 0.094 lb/MMBtu was reduced to 0.071 lb/MMBtu. This SNCR reduction of 25% was achieved with an ammonia slip of 6 ppm.

The cost effectiveness of various NOx control options for a reference 500 MWe wall-fired boiler are shown in Figure 10. Three integrated NOx control options were considered in this evaluation with the goal of reducing the baseline emissions from 0.5 to 0.15 lb/MMBtu. The SCR-only scenario represents the base case for comparing with the costs of other cases.

Figure 10 – B&W NOx Control Cost Estimates



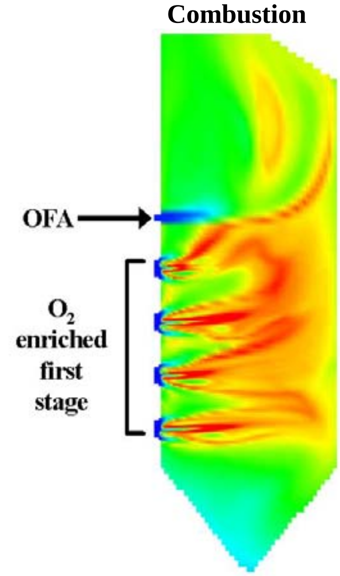
The LNB in combination with OFA was considered a potential technology for boilers using PRB coal. The LNB/OFA plus NOxOUT® was considered when burner NOx level reached 0.2 lb/MMBtu. Also, Fuel Tech investigated the NOxOUT Cascade® for cases with high reagent injection rates (burner NOx @ 0.3 lb/MMBtu) where ammonia slip can be reduced with a catalyst. In some of the pilot-scale tests, the SNCR system was forced to slip 10-20 ppm ammonia. There was no catalyst available in the pilot-scale combustor to promote reaction between ammonia and NOx, which is the basis for the NOxOUT Cascade® technology. For the purpose of this economic analysis, the NOxOUT Cascade® NOx reduction was estimated based on Fuel Tech's experience. The economic analysis normalized the costs to an emission rate of 0.15 lb/MMBtu based on the buying and selling of NOx allowances at a value of $4,000 per ton.

The analysis shows that the DRB-4Z™ LNB in combination with OFA has the lowest levelized cost, 70% to 80% less than SCR. Since LNB are more cost-effective on a $/ton of NOx basis than SNCR or SCR technologies in general, there is a great incentive for using them in combination with post-combustion NOx control methods. LNB/OFA plus the NOxOUT® combination cost is $752 to $1066 per ton of NOx removed when the baseline burner emissions are 0.20 lb/MMBtu, which is 40% to 70% lower than the SCR cost of $1,287 to $3,489 per ton of NOx. The NOxOUT Cascade® levelized cost is close to the lower range of SCR due its lower capital cost. It has been assumed that the catalyst can be placed in-duct and a separate reactor is not necessary. It should be mentioned that these costs are site specific and the results may vary from unit to unit.

Oxygen-Enhanced Combustion

Praxair, Inc. and its partners have developed a novel oxygen-based technology that can reduce NOx emissions from PC-fired boilers, while improving combustion characteristics such as loss-on-ignition (LOI).[30,31] This novel technology replaces a small fraction of the combustion air with oxygen as shown in Figure 11. In order to support this concept, Praxair is also developing an oxygen transport membrane (OTM) process that uses pressurized ceramic membranes for separation of oxygen from air.

Figure 11 - Praxair Oxygen-Enhanced Staged Combustion



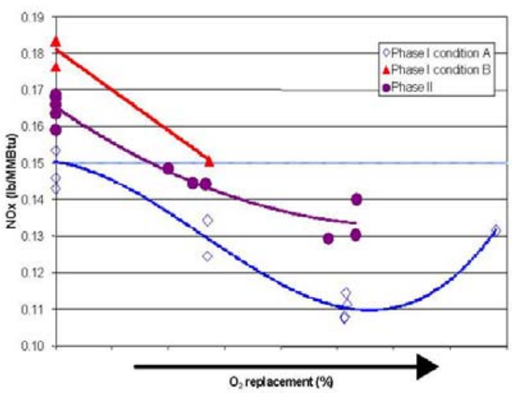
Testing was conducted using ALSTOM Power's pilot-scale combustion facility. The experiments were designed to demonstrate that the concept of oxygen-enhanced low NOx combustion could meet the emissions target of 0.15 lb/MMBtu with minimal impact on CO emissions and furnace performance. The pilot-scale test facility is a water-cooled tunnel furnace designed to test burners up to 50 MMBtu/hr firing rate with time-temperature histories similar to full-scale PC-fired boilers. The test facility has two locations for separated over-fire air (SOFA) injection. An ALSTOM commercially-available wall-fired LNB was used in these experiments.

The burner was designed for a firing rate of 26 MMBtu/hr and was typically fired at 24 MMBtu/hr for these tests.

Illinois No. 6 bituminous coal was used during the initial Phase I-A tests. These tests were performed to shake down the furnace and to obtain baseline NOx data for this facility, burner, and coal combination. A series of experiments were then performed to evaluate the effect of oxygen addition on NOx emissions.

An eastern bituminous coal, Mingo Logan, was then used in Phase I-B to evaluate both the effect of a lower volatile coal and the effect of oxygen addition method. During Phase II, selected experiments were repeated with the Illinois No. 6 coal. As shown in Figure 12, data from the Illinois No. 6 experiments show that even when the baseline (air only) emissions are very low, oxygen addition can drive the NOx emissions even lower. The overall data further show that the reductions are relatively independent of the initial NOx concentration. Data from the Mingo Logan experiments show that the concept works even with the lower volatile coal, and that the technique in injecting the oxygen has a large impact on NOx reduction.

Figure 12 - Praxair Oxygen-Enhanced Combustion Test Results

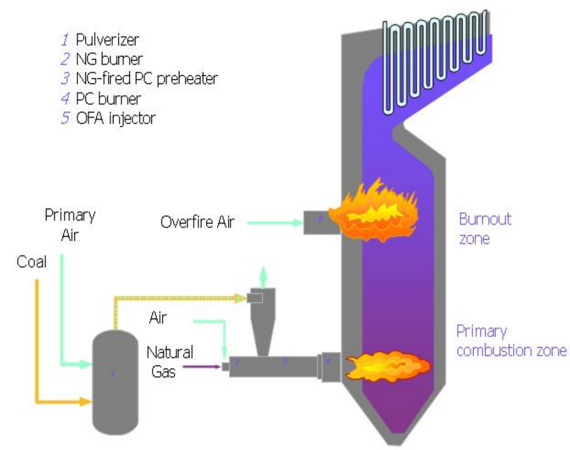


In addition to the reduction in NOx, benefits can be achieved in the areas of reduced LOI and opacity, increased boiler efficiency, and reduced fan limits. Subsequent testing at two utility boilers, City Utilities' James River Unit 3 and Northeast Utilities' Mt. Tom Generating Station, has demonstrated these benefits of the technology while decreasing NOx emissions. Preliminary economic analysis indicates that cost savings of 40-50% can be realized when compared to SCR.

Methane De-NOx

The METHANE de-NOX® NOx reduction process for PC-fired boilers is being developed by the Gas Technology Institute (GTI) to provide a cost-effective, combustion-based alternative to SCR.[32, 33] GTI's METHANE de-NOx reburn technology is combined with a coal-preheating approach developed for PC-fired boilers by the All-Russian Thermal Engineering Institute (VTI). The METHANE de-NOx technology combines several NOx reduction strategies into an integrated system, including a novel burner design using natural gas-fired coal preheating, and internal and external combustion staging in the primary and secondary combustion zones. Figure 13 provides a schematic of the METHANE de-NOx process. The technology consists of a burner modification that preheats coal to elevated temperatures (up to 1500°F) prior to combustion. The natural gas-fired coal preheat combustor releases coal volatiles, including fuel-bound nitrogen compounds, into a controlled reducing environment, which reduces the coal-derived nitrogen compounds to molecular N_2. The preheated coal is converted to a mixture of char and gaseous volatile matter, which is then fired through the main burner into the boiler furnace. The quantity of natural gas fuel required for coal preheating is in the range of 3 to 5% of the total burner heat input.

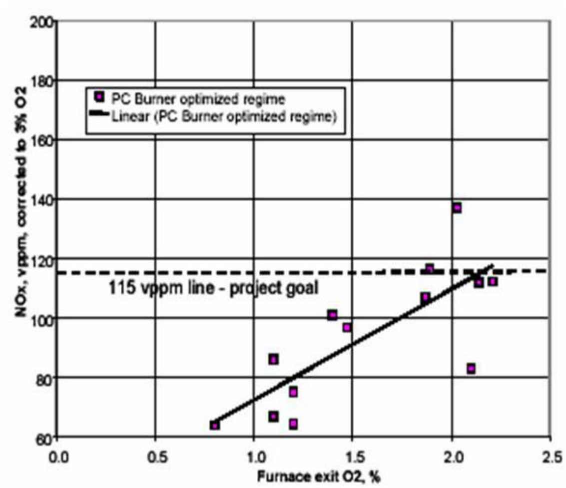
Figure 13 - GTI METHANE de-NOx Process Schematic



GTI and VTI were joined in the project by Babcock Power Inc. (BPI), which provided commercial burner design expertise and testing facilities for 3- and 100-MMBtu/hr preheat burner prototypes. Initial PRB coal testing of a 3-MMBtu/hr pilot system demonstrated that the coal preheat process has a significant effect on final NOx formation in the coal burner. Based on CFD modeling, modifications to both the pilot-scale gas-fired combustor and the coal burner led to NOx levels below 100 ppmv with CO in the range of 35-112 ppmv without any furnace air staging when firing PRB coal. See Figure 14.

Initial small pilot-scale testing with a bituminous coal resulted in deposition and plugging by caked material on the inside of the gas combustor. A series of modifications to the combustor configuration and operation have been developed and tested. One of these approaches was successful in sustaining operation with the bituminous coal up to 85% of the targeted fuel input, although some deposition and LOI issues remained. While not measured under steady-state operating conditions, NOx results from the bituminous coal tests were promising, with NOx levels approaching 100 ppmv with 6% oxygen in the flue gas at the furnace exit. These NOx results indicate that even greater NOx reduction is possible than that achieved with the PRB coal tested. As a result of the pronounced wall-effects of the small burner and its relationship to the wall deposition, it was determined that resolution of this problem would be better addressed in the 100-MMBtu/hr combustor which is tentatively scheduled to be conducted in 2005.

Figure 14 - GTI METHANE de-NOx Test Results



Dense Phase Reburn Combustion System

Wiley & Associates conducted full-scale field-testing of a Dense Phase Reburn Combustion System (DPRCS).[34] DPRCS controls combustion stoichiometry from the bottom to the top of the furnace using dense phase injection of micronized coal at a particle size of 80% minus 325 mesh. The testing was conducted at CP&L's 150 MW Cape Fear Unit No. 5 that burns a low sulfur bituminous coal in a tangentially-fired furnace. The DPRCS was used in conjunction with Mobotec's rotating overfire air (ROFA^{TM}) and ROTAMIX^{TM} systems. Baseline NOx emission rates with the ROFA system ranged from 0.17 to 0.26 lb/MMBtu. During DPRCS testing the micronized coal feed rate averaged 13% of total fuel input and the unit operated at approximately 75% capacity. Tests were conducted with micronized coal injection at four elevations ranging from the lower furnace to below the ROFA injection level in the upper furnace. NOx control performance during the DPRCS testing was mixed depending on injection location. Injection below the ROFA resulted in a 14% increase in the NOx emission rate. Various combinations of DPRCS injection points from the bottom to top coal burner elevations resulted in NOx emission rate reductions ranging from 10% to 30%.

In addition to the reburn studies, furnace sorbent injection (FSI), using finely powdered limestone and Trona, was examined in combination with the NOx reduction capabilities of the ROFA to achieve SO_2 and mercury reductions with relatively low capital and operating costs. These two sorbents were chosen to compare the impact of calcium carbonate versus sodium carbonate in a highly reactive environment. Significant SO_2 reductions of 69% were achieved with Trona and 64% with limestone. Mercury reductions of 89% were achieved with limestone and 67% with Trona. However, slagging in the superheater section was a major operational concern and will need to be addressed by more frequent soot blowing in future applications.

New DOE/NETL IEP NOx R&D Projects

As the NOx control technologies currently under development move toward demonstration and commercialization, the NOx program targets are reevaluated and redefined. In light of the proposed EPA CAIR rule and Congressional multi-pollutant legislation, DOE/NETL issued a solicitation in early 2004 to target even lower NOx emissions for existing boilers. As a result, five new NOx R&D projects were announced in November 2004 and will be completed over the next three years. The challenge will be to develop cost-effective NOx control technologies for the smaller, older, less efficient facilities that are not easy candidates for the current state-of-the-art SCR controls because of space constraints and the reluctance of owners to invest large capital expenditures in the aging plants. These facilities, with a generating capacity of 300 MW or less, comprise 66% of the boilers in the U.S. and have an average age of 38 years as compared to the remainder of the fleet with an average age of 24 years. The benefits of this program will be realized by both the existing fleet and new capacity as the targeted NOx control technologies are adopted. The following is a brief description of the new projects:

Enhanced Combustion Low NOx Pulverized Coal Burner - ALSTOM will develop an enhanced combustion, low NOx pulverized coal burner. The objective is to optimize combustion via control of near-burner time, temperature, turbulence, and stoichiometry. Candidate low NOx burner components for testing include up to four (4) enhanced ignition coal nozzle tips and internal and external air and fuel separators. These components will be integrated into ALSTOM's latest generation of the TFS 2000 firing system that includes enhancements developed in the recently completed "Low NOx Firing System for Tangential Boilers" project discussed previously. The enhanced low NOx burner is designed to achieve an emission rate of less than 0.15 lb/MBtu and have minimal balance-of-plant impacts while burning a high-volatile bituminous coal. The project includes CFD modeling and large pilot-scale testing to provide the information to design a full-scale version of the enhanced low-NOx burner.

Advanced In-Furnace NOx Control for Wall- and Cyclone-Fired Boilers - Babcock & Wilcox will develop and demonstrate an advanced NOx control technology capable of achieving an emission rate of 0.10 lb/MBtu while burning high-volatile bituminous coal. The NOx control technology is based on a "layered" strategy that combines deep air staging, continuous corrosion monitoring, advanced combustion-control enhancements, and a proprietary combustion technique using oxygen injection. Wall- and cyclone-fired pilot-scale testing will be used to evaluate the oxygen injection process. Results from the pilot-scale testing will be used to design and prepare a cost estimate for a full-scale version of the technology.

In Situ Device for Real-Time Catalyst Deactivation Measurements in Full-Scale SCR Systems - Fossil Energy Research Corporation (FERCo) will demonstrate the use of an in situ catalyst deactivation measurement device to reduce SCR operating costs through optimized catalyst management. FERCo will develop an *in situ* device to collect real-time SCR performance data by continuously measuring catalyst activity. As the data is collected, it will be analyzed by an existing catalyst management software program. The results of this analysis will provide information on boiler operating conditions that negatively impacts catalyst activity and a means to optimize the catalyst replacement schedule. Testing will be conducted at a Southern Company coal-fired power plant equipped with a SCR.

Cyclone Boiler Field Testing of Advanced Layered NOx Control Technology - Reaction Engineering International (REI) will conduct CFD modeling and full-scale field testing to evaluate a technology known as Advanced Layered Technology Application (ALTA) to achieve a NOx emission rate of near 0.10 lb/MBtu in a cyclone boiler. ALTA combines deep staging from overfire air, Rich Reagent Injection (RRI), and a novel SNCR approach. Testing will also evaluate potential balance-of-plant impacts such as the amount of unburned carbon in the ash, slag tapping, waterwall corrosion, ammonia slip, and heat distribution. Testing will be conducted at AmerenUE's 500 MW Sioux Station. This project is a follow-up to the recently completed "Rich Reagent Injection for Cyclone Burners" project discussed previously. For this new project, the cyclone burner barrel stoichiometry will be further reduced from 0.95 to 0.85.

Pilot-Scale Demonstration of Advanced Layered NOx Control Technology for Coal-Fired Boilers - REI will develop and verify the performance of the ALTA NOx control technology for wall-fired boiler applications to achieve an emission rate of less than 0.15 lb/MBtu. The burner will be designed for complete near-burner combustion, rather than traditional staged-combustion. The objective of the burner design is to achieve homogeneity of the combustion products in the boiler. Not only does this create ideal conditions for combustion-related control of NOx, it also results in a stoichiometry and temperature distribution above the burners that is ideal for the chemistry involved in Rich Reagent Injection. REI will conduct CFD modeling and pilot-scale testing to optimize the near-burner combustion system and reagent injection.

Market Potential for Advanced NOx Combustion Control Technologies

As mentioned previously, the specific performance target of the IEP's NOx R&D activity is to develop combustion control technologies for existing plants with a NOx emission rate of 0.15 lb/MMBtu by 2006 and 0.10 lb/MMBtu by 2010, while achieving a levelized cost savings of at least 25% compared to SCR control technology. The technologies currently under development, such as the ultra-low NOx combustion systems, oxygen-enhanced combustion, and rich reagent injection described above, are close to meeting the DOE/NETL R&D goals for 2006 and further development is likely to achieve those goals as well as the R&D goals for 2010.

Coal-fired power plant operators have a number of options available for compliance with market-based allowance cap-and-trade regulatory programs such as the existing NOx SIP call, the proposed Clean Air Interstate Rule, and the proposed Clear Skies Act. Under a cap-and-trade program, power plants have the option to either install additional NOx controls to reduce their emissions to the level of their NOx allowance allocation or not install controls and instead acquire additional NOx allowances from other plants that elect to over comply. Likewise, plants can install additional controls that don't reduce emissions to the level of their NOx allowance allocation and acquire the allowance shortfall from other plants. As a result, low cost NOx control technologies that do not achieve the target emission rates can still have a prominent role as a compliance strategy. For an individual power plant, the decision on whether to install controls or purchase allowances is based primarily on the incremental cost of the available alternative NOx control technologies, measured as cost per ton of NOx reduction, compared to the market price of NOx allowances.

The projected cost and performance for the advanced NOx combustion control technologies were used by DOE/NETL to estimate NOx control costs measured on a levelized cost per ton of NOx removed basis. The NOx control cost for these technologies tends to fall between traditional LNB and SCR. A preliminary evaluation of alternative compliance options to meet the NOx reduction requirements of the proposed Clear Skies Act was conducted for the entire existing 300 GW fleet of U.S. coal-fired power plants. This assessment showed a U.S. market potential for approximately 150 GW of advanced NOx combustion control technologies that could cost-effectively replace 75 GW of new SCR controls resulting in levelized annual cost savings of over $700 million per year.

Other DOE/NETL Program NOx Control Technology R&D Projects

In addition to the IEP program, there are several other NOx control technology R&D projects currently sponsored under other DOE/NETL programs, such as the Advanced Power, Clean Coal Technology, Power Plant Improvement Initiative, and Clean Coal Power Initiative programs. Table 4 includes a listing of some of these projects. Additional information on these projects can

be found on the DOE/NETL's Strategic Center for Coal website or the DOE Fossil Energy website at:
http://www.netl.doe.gov/coal/
http://www.fossil.energy.gov/programs/projectdatabase/index.html.

Table 4 - Other DOE/NETL Program NOx R&D Projects

Program	Title	Lead Company
Advanced Power	Engineering Development of Advanced Coal-Fired Low-Emission Boiler System	Riley Power
Advanced Power	Development of Hybrid Advanced NOx Control for Detroit Edison River Rouge 3	TIAX
Advanced Power	Ammonia-Free NOx Control System	Foster Wheeler
Clean Coal Technology	Combustion Initiative for Innovative Cost-Effective NOx Reduction	Alliant Energy
Clean Coal Technology	Advanced Wall-Fired Combustion Techniques for the Reduction of NOx Project	Southern Company
Power Plant Improvement Initiative	Achieving NSPS Emission Standards Through Integration of Low-NOx Burners with an Optimization Plan for Boiler Combustion	Sunflower Electric Power
Power Plant Improvement Initiative	Neural Network Sootblower Optimization Project	Tampa Electric Company
Clean Coal Power Initiative	Demonstration of Integrated Optimization Software at the Baldwin Energy Complex	NeuCo, Inc.

SUMMARY

While our knowledge of the formation and capture of NOx from coal-fired power plants has greatly advanced over the past decade and a half, many challenges remain. As the Nation moves toward ever-tightening regulation of NOx emissions from the electric power sector, it is critical that research continues to address these challenges. In response, DOE/NETL is continuing to partner with industry and other key stakeholders in carrying out a comprehensive advanced NOx control technology R&D program. This effort is focused on (1) enhancing the NOx capture performance of existing technologies and (2) developing advanced control concepts to achieve high levels of NOx removal at costs considerably lower than current SCR technology. The cost and performance of the advanced NOx combustion control technologies currently being developed under the IEP program are close to meeting the DOE/NETL R&D goals for 2006 and further development is likely to achieve those goals, as well as the R&D goals for 2010. A preliminary DOE/NETL assessment shows a U.S. market potential for approximately 150 GW of advanced NOx combustion control technologies that could cost-effectively replace 75 GW of new SCR controls that would be required for compliance with the proposed Clear Skies Act. DOE/NETL is committed to continue its comprehensive NOx control technology research program to improve performance and reduce costs to enable the existing fleet of coal-fired power plants to reliably and cost effectively comply with future NOx control regulations, while also providing the scientific and technical knowledge needed to help craft sound regulatory policy.

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DISCLAIMER

References in this article to any specific commercial product or service are to facilitate understanding and do not imply endorsement by the U.S. Department of Energy.

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