DOE/FE-0452

PUBLIC SERVICE COMPANY OF COLORADO

INTEGRATED DRY NO_x/SO_2 EMISSIONS CONTROL SYSTEM

PROJECT PERFORMANCE SUMMARY
CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

APRIL 2003

Public Service Company of Colorado

Integrated Dry NO_x/SO_2 Emissions Control System

Project Performance Summary
Clean Coal Technology Demonstration Program

Environmental Control Devices

Integrated Dry NO_x/SO_2 Emissions Control System

The IDECS project demonstrated the first application of low-NO_x burners and overfire air to a down-fired boiler and provided valuable information on the synergy between selective non-catalytic reduction NO_x control and sodium-based sorbent injection SO_2 control.

Overview

The Integrated Dry NO_x/SO_2 Emissions Control System (IDECS) project demonstrated synergistic application of low-cost nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions control technologies to achieve 80% NO_x reduction and 70% SO_2 reduction in a 100-MWe down-fired boiler.

This project is part of the U.S. Department of Energy's (DOE) Clean Coal Technology Demonstration Program (CCTDP) established to address energy and environmental concerns related to coal use. DOE sought cost-shared partnerships with industry through five nationally competed solicitations to accelerate commercialization of the most promising advanced coal-based power generation and pollution control technologies. The CCTDP, with a combined participant/government value of over five billion dollars, has significantly leveraged federal funding by forging effective partnerships founded on sound principles. For every federal dollar invested, CCTDP participants have invested two dollars. These participants include utilities, technology developers, state governments, and research organizations. The IDECS project presented here was one of 13 selected in May 1989 from 48 proposals submitted in response to the program's third solicitation.

The Public Service Company of Colorado (PSCC) evaluated and successfully demonstrated application of low-NO_x burners (LNBs) with overfire air (OFA) and urea-based selective non-catalytic reduction (SNCR) for NO_x reduction; and dry sorbent injection (DSI), with and without flue-gas humidification (FGH), for SO_2 reduction. Together these technologies comprise IDECS. The project was sited at PSCC's Arapahoe Generating Station Unit No. 4 in Denver, Colorado. Although Unit 4 is a down-fired unit, IDECS results have application to wall-fired and tangentially-fired boilers, which represent over 90% of the coal-fired boiler fleet, because these types of unit may benefit from installing one or more of the technologies in IDECS.

The IDECS project achieved its goals of 70% NO_x and SO_2 removal while producing a dry waste disposable with the fly ash. The project also provided valuable information on the synergistic interaction of IDECS components and effectiveness of IDECS in conjunction with a fabric filter dust collector (FFDC) in removing high percentages of air toxics, including mercury. IDECS offers a low capital cost alternative to selective catalytic reduction (SCR) NO_x control and wet flue-gas desulfurization (FGD) SO_2 control for older, smaller plants both domestically and internationally. IDECS has particular domestic application to units that can use emissions averaging to meet regulated limits.

The Project

The IDECS project was sited at PSCC's Arapahoe Generating Station Unit 4 in Denver, Colorado, which began operation in 1955, and was subsequently used as a load-following unit with a capacity factor of 50 to 60%. When the IDECS project was initiated in 1989, there was no low-cost NO_x/SO_2 emissions control system demonstrated for down-fired boilers. Public Service Company of Colorado (PSCC) proposed demonstrating a combination of existing and emerging technologies that could achieve satisfactory controls on a down-fired unit burning low-sulfur coal.

IDECS was comprised of five technologies: low-NO_x burners (LNBs), overfire air (OFA), urea-based selective noncatalytic reduction (SNCR), dry sorbent injection (DSI), and flue-gas humidification (FGH). However, the combination of the five separate technologies equated to three separate emission control systems for purposes of testing because the LNBs were always used in conjunction with OFA, and FGH was used only with DSI. The three systems — LNB/OFA, SNCR, and DSI with or without FGH — were individually tested using both parametric tests and long-term tests. Individual system tests were followed by testing the technologies as one integrated system. Throughout the demonstration, Unit 4 burned one of two low-sulfur (0.4%) Colorado bituminous coals (Cyprus Yampa Valley and Empire Energy). The properties of these coals are shown in Table 1.

The broad purpose of the project was to assess the integration of a down-fired LNB with urea-based SNCR for NO_x removal and DSI with FGH for SO_2 removal and to examine potential synergies between SNCR and sodium-based DSI. Emission control objectives were 70% removal for both NO_x and SO_2. The test program began in August 1992 and was completed in December 1996, accumulating more than 34,000 hours on the IDECS.

Participant
Public Service Company of Colorado

Additional Team Members
Electric Power Research Institute—cofunder
Stone and Webster Engineering Corp.—engineering support
The Babcock & Wilcox Company—burner and humification technology supplier
Fossil Energy Research Corporation—operational tester
Western Research Institute—fly ash evaluator
Colorado School of Mines—bench-scale test support
NOELL, Inc.—SNCR technology supplier

Location
Denver, Denver County, CO (Public Service Company of Colorado's Arapahoe Station, Unit No. 4)

Technology
The Babcock & Wilcox Company's DRB-XCL® low-NO_x burners with OFA, NOELL's urea-based SNCR system, and dry sorbent injection with and without humidification

Plant Capacity/Production
100 MWe

Coal
Colorado bituminous, 0.4% sulfur

Demonstration Duration
August 1992–December 1996

Project Funding

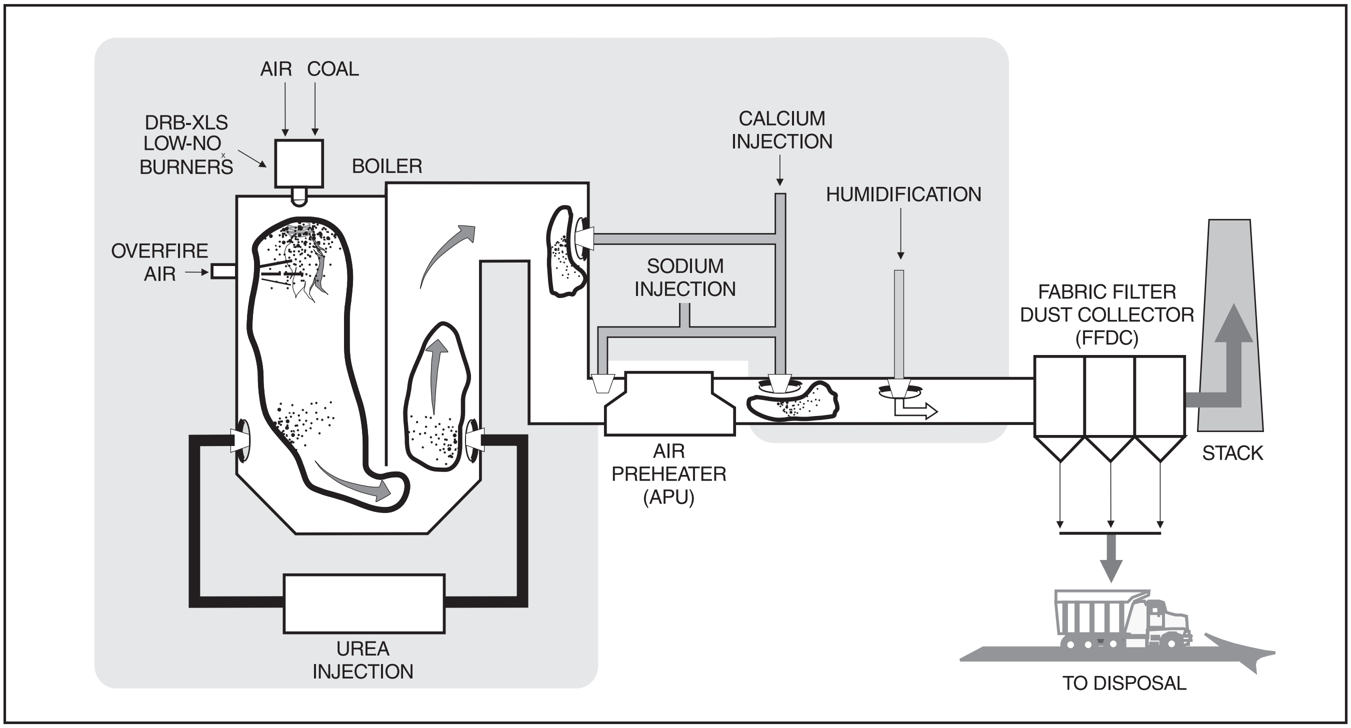
Total project cost	$ 26,165,306	100%
DOE	13,082,653	50
Participant	13,082,653	50

DRB-XCL is a registered trademark of The Babcock & Wilcox Company.

Table 1. Properties of Colorado Low-Sulfur Bituminous Test Coals

Proximate Analysis, % by weight	Cyprus Yampa	Empire Energy
Moisture	10.6	13.2
Volatile Matter	34.1	33.8
Fixed Carbon	45.7	45.0
Ash	9.6	8.0
Ultimate Analysis, % by weight dry		
Carbon	70.3	70.9
Hydrogen	5.0	5.2
Nitrogen	1.8	1.5
Sulfur	0.4	0.4
Oxygen	11.8	12.8
Ash	10.7	9.2
Heating Value, Btu/lb (as received)	11,050	10,600

THE TECHNOLOGY



Twelve Babcock & Wilcox (B&W) Dual-Register Burner–Axially-Controlled (DRB-XCL®) LNBs replaced 12 existing burners on the boiler roof and were modified to accommodate down-fired versus conventional horizontal service. The LNBs control NO_x by staging combustion, keeping air/fuel ratios relatively low, particularly in the early stages of combustion. This process lowers flame temperatures, reducing thermal NO_x, and reduces conversion of nitrogen in the coal to NO_x. Three separate Babcock & Wilcox dual-zone NO_x ports (OFA ports) were installed on each side of the furnace (six total) approximately 20 feet below the boiler roof. The dual zone feature provides air axially and along the furnace wall to ensure effective mixing with the flue gas. These ports complement the LNBs by injecting up to 25% of the secondary air (at full load) downstream of the LNBs to complete combustion in a cooler zone, which reduces thermal NO_x, allows the LNBs to operate at desired low air/fuel ratios, and keeps carbon monoxide (CO) and carbon burnout under control.

A urea-based SNCR system was installed for further NO_x reduction. SNCR involves the injection of a nitrogen-containing chemical, typically urea ($(NH_2)_2CO$) or ammonia, into the combustion products at a point where the temperature is 1,600–2,100 °F. In this temperature range and in the presence of oxygen, the chemical reacts selectively with NO_x to form nitrogen (N_2) and water. Performance of SNCR systems depends strongly on furnace geometry, temperature profile, and mixing, as well as less important factors. Furnace geometry is important, because there must be sufficient residence time within the correct temperature window. As shown in Figure 1, if the temperature is too low, the injected chemical does not react with NO_x, resulting in excessive emissions of ammonia. If the temperature is too high, the chemical reacts directly with oxygen to form additional NO_x. Mixing is important, because if the injected chemical does not mix uniformly, then both incomplete reaction and excessive ammonia slip will result.

The initially installed SNCR consisted of two levels of injectors with 10 injectors at each level. Subsequently, to adjust to a drop in boiler temperature induced by the LNBs, NOELL Advanced Retractable Injection Lances (ARIL) were installed at two unused sootblower ports in the higher temperature regions of the furnace. Each lance was nominally 4 inches in diameter and approximately 20 feet in length with a single row of nine injection nozzles. Each injection nozzle consisted of a fixed air orifice and a replaceable liquid orifice. The ability to change orifices allowed for not only removal and cleaning but also adjustment of the injection pattern along the length of the lance to compensate for any significant maldistributions of flue gas velocity, temperature, or baseline NO_x concentration. One of the key features of the ARIL system was its ability to rotate, thus providing a high degree of flexibility in optimizing SNCR performance.

A DSI SO_2 control system was installed that could inject either calcium- or sodium-based reagents into the flue gas between the air preheater unit (APU) and the FFDC, and inject calcium-based sorbent into the economizer. Provision was subsequently made to inject sorbent just prior to the APU. The reagent used for calcium-based DSI was slaked or hydrated lime ($Ca(OH)_2$). The reagent used for sodium-based DSI was nachcolite, a naturally-occurring sodium bicarbonate ($NaHCO_3$), and trona, a naturally occurring sodium sesquicarbonate ($Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$). Sorbent is ground in a pulverizer to 90% passing 400 mesh and the piping connects to a splitter on top of the duct. Each splitter separates the flow into six streams which feed six injectors. The 12 injectors, which inject sorbent in the direction of flue-gas flow, form a two by six grid in the duct. The injectors from the two systems alternate to allow even distribution of sorbent regardless of whether one or both systems are operating.

An FGH system designed by B&W was installed along with the post-APU DSI to provide humidification needed for the calcium-based sorbent to react effectively with SO_2 at the relatively low temperature (about 300 °F). The FGH provided a capability of achieving 20 °F approach-to-saturation temperature. The system, located approximately 100 feet ahead of the FFDC, incorporated 84 "I-Jet" nozzles that can inject up to 80 gal/min into the flue gas ductwork. Dual-fluid "I-Jet" nozzles use high-pressure air to atomize the injected water to ensure that it is completely evaporated before it reaches the particulate control device. A 12 thermocouple array located just in front of the FFDC controlled the amount of water injected. The water injection lances were interspersed with the DSI lances. Shield air was supplied to help prevent deposition of solids on the nozzles, and a rapper helped remove any solids that collected.

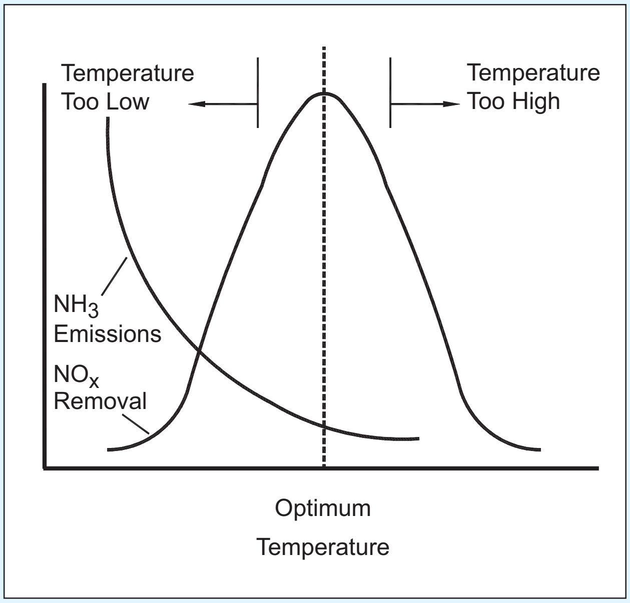
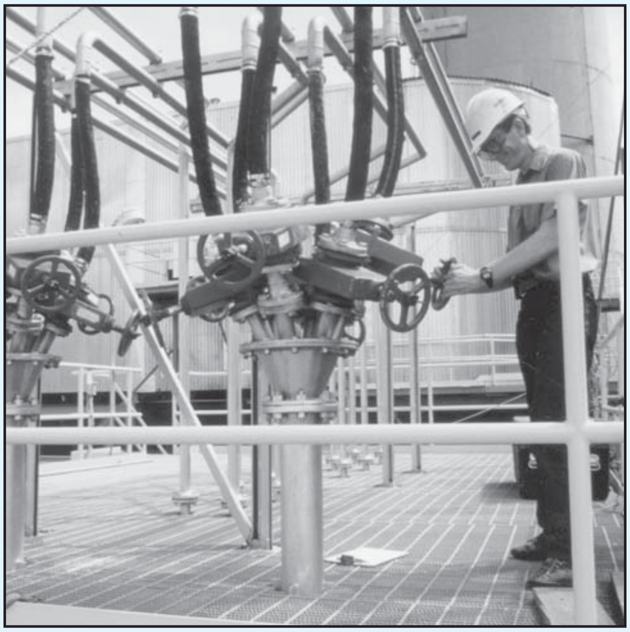


Figure 1. Temperature Window for the SNCR Process



The sodium-based sorbent injection piping for the flue gas ductwork on Unit No. 4 at Arapahoe Station

Results Summary

Environmental

- DRB-XCL® burners with minimum OFA reduced NO_x emissions by more than 61% over the load range of 80–100 MWe. With maximum OFA (32% of total secondary air at 50 MWe to 24% at 80 MWe and above), NO_x reduction was 62–69% across the load range of 50- to 110-MWe.
- DRB-XCL® burners with maximum OFA maintained CO below baseline emission levels, reaching a maximum of 50 ppm.
- The SNCR system, using both stationary and retractable injection lances in the furnace, provided NO_x removal of 30–50% at an ammonia slip of 10 parts per million (ppm), thus increasing performance of the total NO_x control system to greater than 80% NO_x reduction. The retractable ARIL system increased NO_x emission reduction at low loads (below 70 MWe) from 11% to 35–52%.
- Hydrated lime injection into the boiler economizer at 950–1,150 °F reduced SO_2 emissions by 5–10%; and hydrated lime injection into the FFDC duct reduced SO_2 emissions by 28–40% at a normalized stoichiometric ratio (NSR) of 2.0 and 25–30 °F approach-to-saturation temperature.
- A 70% SO_2 removal was achieved by injecting sodium bicarbonate before the APU (650 °F) at an NSR of 1.0; and by injecting sodium sesquicarbonate after the APU (220–280 °F) at an NSR of 1.9.
- At 70% SO_2 removal, both sodium-based sorbents reduced NO_x emissions by approximately 10%.
- Integration of SNCR and sodium-based DSI decreased the level of unwanted nitrogen dioxide emissions by 50% and, in turn, DSI decreased the level of ammonia slip that would occur with SNCR alone.
- IDECS with the FFDC successfully removed 96.9–98.6% of trace metal emissions and 67.5–93.7% of the mercury.

Operational

- LNB/OFA maintained unburned carbon at essentially baseline levels.
- DRB-XCL® burners resulted in an approximately 200 °F decrease in furnace exit gas temperature, which impacted the amount of excess air required to maintain steam temperature at reduced load.
- Temperature differential between the top and bottom surfaces of the ARIL caused the lances to bend downward 12–18 inches, making insertion and removal difficult.

Economic

- Total estimated capital costs for IDECS applied to a 100-MWe boiler are \$195/kW. Fixed operating costs are estimated at \$0.32 million/year and variable operating costs at \$1.49 million/year. Estimated levelized costs are \$1,358/ton of NO_x plus SO_2, or 9.7 mills/kWh (current 1994\$s) and \$1,044/ton of NO_x plus SO_2, or 7.4 mills/kWh (constant 1994\$s)

Environmental Performance

The IDECS project complied with all applicable federal and state air, water, and solid waste regulations and no problem areas were identified concerning environmental regulation or permit conditions due to the operation of the project. Environmental results from the test program are summarized below.

LNB/OFA. The testing of the LNB/OFA system — 12 DRB-XCL® burners and 6 B&W Dual-Zone NO_x ports — was performed in two phases, parametric testing and long-term testing. Parametric testing was conducted by controlling boiler load, number of mills in service, excess air levels, and LNB and OFA control settings. Long-term testing was conducted under normal load-following operations.

The results of LNB/OFA parametric testing are shown in Figure 2. The OFAs must operate with the LNBs to keep the OFA ports cool. Thus, parametric testing was conducted with minimum OFA and maximum OFA. Minimum OFA represents 15% of total secondary air. Maximum OFA varies as boiler load, air flow, and fan pressure change. Maximum OFA varied from 32% of total secondary air at a load of 50 MWe to 24% at 80 MWe and above. The LNB/OFA system using minimum OFA reduced NO_x emissions from 61–64% in the 80–100-MWe load range. At maximum OFA, the LNB/OFA system reduced NO_x emissions 61–69% in the 50–100-MWe load range.

Maximum OFA kept CO levels lower than the original burners, holding CO levels to a maximum of 50 ppm, as shown in Figure 3. However, the LNBs required higher than baseline excess air to maintain adequate steam temperature and to stay below 50 ppm CO at boiler loads below 100 MWe.

During long-term testing, the NO_x emissions were 10–20% (30–60 ppm) higher than the parametric tests. These increased NO_x emissions were attributed to higher oxygen (O_2) levels (1.0–1.5% higher) experienced during normal load-following conditions. The NO_x levels increased by about 40 ppm for each percent increase in O_2 levels.

SNCR. The SNCR system underwent both parametric and long-term testing. Parametric test variables examined included boiler load, SNCR injection location, reagent used (urea, converted urea, and ammonia), SNCR re-

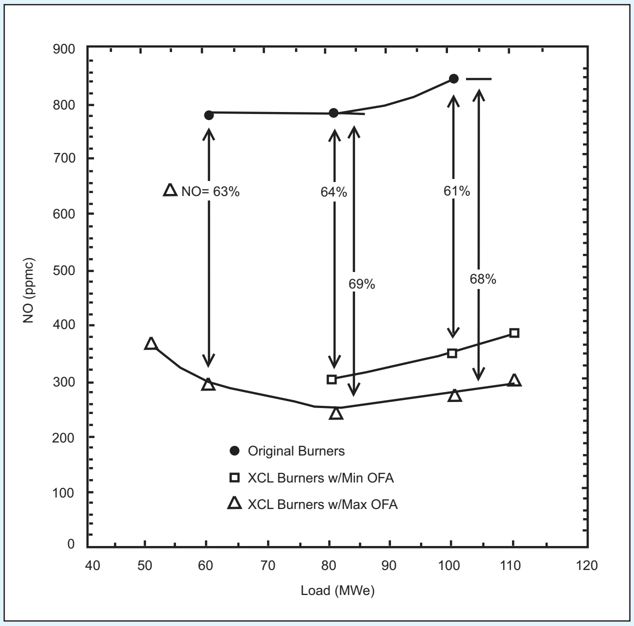


Figure 2. Boiler Load Parametric Testing of LNB/OFA System

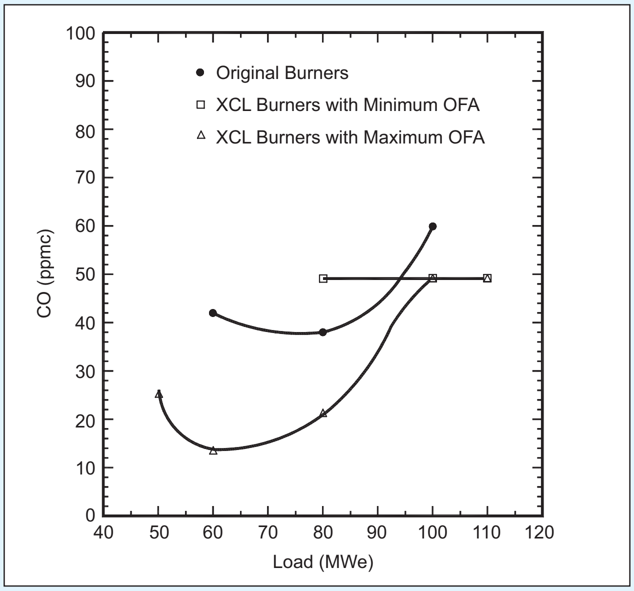


Figure 3. CO Emissions During Parametric Testing

agent injection rate, DSI sodium sorbent injection rate, and ash chemistry.

Boiler load was the predominant factor in determining the flue gas temperature at SNCR injection locations and therefore had the greatest effect on system performance. The original two-row SNCR injector design proved relatively ineffective because one row of injectors was in a region where the flue gas temperature was too low for effective operation. This situation was exacerbated by a 200 °F boiler temperature drop resulting from LNB/OFA installation. At 60-MWe, NO_x removal was limited to about 11% with an ammonia slip of 10 ppm. Use of ammonia in lieu of urea improved the NO_x removal at low loads due primarily to avoiding the urea decomposition step, which requires heat. As a result, a urea converter was installed. However, installation of the ARIL retractable lance system in the appropriate temperature regime was required to bring SNCR performance up to an acceptable level. With the ARIL system, NO_x reduction increased from 11% to 35–52% at loads below 70 MWe. The ability to follow the temperature window by rotating the lances proved to be an important feature in optimizing performance. As a result, the SNCR system achieved NO_x removals of 30–50% (at an ammonia slip limited to 10 ppm at the FFDC inlet) over the normal load range of the boiler. The 30–50% reduction applies to the reduced NO_x levels achieved by the LNB/OFA system, bringing total NO_x emission reductions to greater than 80%.

It was observed that urea injection produced a substantial amount of nitrous oxide (N_2O), an undesirable greenhouse gas, making N_2O as much as 29–35% of the overall NO_x subject to removal. By converting the urea to ammonia prior to injection, N_2O levels dropped to 3–8% of the overall NO_x subject to removal.

The amount of ammonia adsorbed on the fly ash in the baghouse depended upon the fly-ash chemistry. With SNCR operation alone, conditions producing 10 ppm NH_3 slip resulted in ash ammonia concentrations of 100–200 ppm by weight, which did not cause any problems with odor or ash disposal. As discussed later, this was not the case when sodium was present.

DSI/FGH. DSI testing examined two sodium-based sorbents — sodium sesquicarbonate and sodium bicarbonate — and hydrated lime. Objectives of the sodium-based dry sorbent test program extended beyond SO_2 removal to evaluating the effects on NO_x removal and NO_2 emissions. Variables investigated included sorbent type, boiler load, injection location, sorbent particle size, humidification/approach-to-saturation temperature, and NSR. NSR is a molar ratio of sorbent to SO_2 that has a value of one for the theoretical removal of all SO_2. For calcium-based sorbents only one mole of calcium is needed to remove one mole of sulfur, whereas two moles of sodium are needed. Percent utilization is defined as the ratio of percent SO_2 removal divided by NSR.

As shown in Figure 4, boiler load had little, if any effect on SO_2 removal. SO_2 removals of 70% were achieved with sodium bicarbonate at an NSR of 1.0 while sodium sesquicarbonate required an NSR of 1.9 for the same removal efficiency. The sodium bicarbonate was injected before the APU at 650 °F to correct for slow response times in reaching steady-state conditions. The sodium sesquicarbonate was injected after the APU at 220–280 °F, but had equal effect when injected before the APU.

Particle size proved to be a major factor influencing SO_2 removal efficiency for sodium sesquicarbonate, ranging from 28% at a 28 microns mean particle diameter to 48% at a 15 microns mean particle diameter (both measurements at an NSR of 0.9). SO_2 removal efficiency with sodium bicarbonate showed less dependence on particle size. Humidification at a 60 °F approach-to-saturation temperature increased sodium sesquicarbonate SO_2 removal efficiency by 20% at an NSR of 2.0, but had little effect at an NSR of 1.0.

Both sodium sorbents reduced NO_x emissions by approximately 10% at injection levels comparable to 70% SO_2 removal, but oxidized nitric oxide (NO) to nitrogen dioxide (NO_2), an undesirable compound that produces a brownish-orange gas. However, sodium sesquicarbonate produces only half as much NO_2 as sodium bicarbonate at comparable SO_2 removal efficiencies.

Hydrated lime achieved only 5–10% SO_2 removal when injected into the economizer at 950–1,150 °F and an NSR of 2.0. This performance was attributed in large part to poor sorbent distribution. Humidification failed to significantly improve the performance. Hydrated lime injection downstream of the APU at a 25–30 °F approach-to-saturation temperature and NSR of 2.0 achieved only 28–40% SO_2 removal, far short of the 50% target.

SNCR/DSI Synergy. Operation of the SNCR with sodium-based DSI reduced by approximately 50% the NO_2 emissions that occur with sodium-based DSI alone. Sodium-based DSI reduces ammonia slip by an estimated 50% by inducing precipitation onto the fly ash. At 8 ppm ammonia slip, fly ash ammonia ranged from 400–700 ppm versus 100–200 ppm with SNCR alone. Adjusting ammonia slip to 4 ppm returned fly ash ammonia levels to 100–200 ppm.

Air Toxics. The IDECS project included a comprehensive investigation into many potential air-toxic emissions. Four separate air-toxics tests were completed: (1) LNB combustion, (2) SNCR, (3) DSI using calcium-based reagent, and (4) DSI using sodium-based reagent. Tests show that the use of a FFDC for particulate control was very effective for controlling nearly all air-toxic emissions. Overall particulate removal was greater than 99.9%, and trace-metal-emission removal ranged from 96.9–98.6%. Mercury removal across the FFDC was 67.5% with dry sodium-based DSI, 77.9%, with SNCR, and 93.7% with calcium-based DSI/FGH. Test results indicated the following regarding mercury removal: humidification had a positive effect, primarily through cooling; sodium had no effect; and relatively high levels of carbon in the fly ash contributed greatly to mercury vapor deposition.

Operational Performance

The Arapahoe Unit No. 4 operated more than 34,000 hours with the combustion modifications in place. The availability factor during the period was over 91%.

LNB/OFA. The new LNBs resulted in an approximately 200 °F decrease in furnace exit temperature, which required more excess air than baseline to maintain steam temperature at low loads. This temperature drop also impacted the SNCR system by reducing the temperature to below optimum for SNCR performance at the originally designed injection points.

Unburned carbon levels, or loss-on-ignition (LOI), essentially remained the same between the new and original burners, except at a load of 50 MWe. The high LOI at this low load was attributed to a more uneven distribution of coal and a coarser coal grind as the number of mills in service dropped from three to two.

SNCR. The ARIL lances proved to be effective NO_x control devices, but experienced some operational problems. A large differential heating pattern between opposite sides of the lance caused a differential in thermal expansion and bending of the lance. After 30 minutes of exposure, the ARIL lance bent approximately 12–18 inches in the direction opposite flue gas impingement, making insertion and retraction difficult. The problem was partially resolved by adding cooling slots at the end of the lance. An alternative lance design provided by

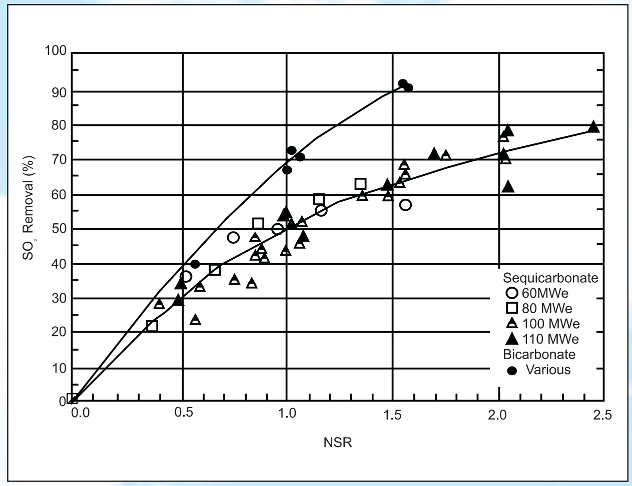
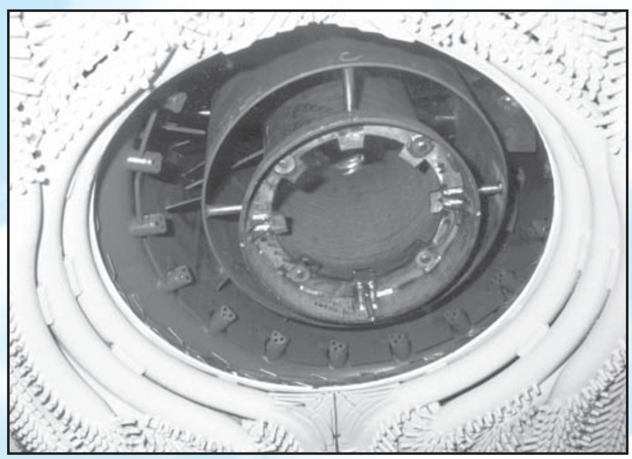


Figure 4. Effect of NSR on SO_2 Removal for Injection of Sodium Sesquicarbonate Before the FFDC



Tip of the roof-mounted DRB-XCL® LNB installed on Unit 4 at Arapahoe Station

Diamond Power Specialty Company (a division of B&W) was tested and found to have less bending due to evaporative cooling, but its NO_x reduction and ammonia slip performance dropped relative to the ARIL system. Additional development was deemed to be needed to produce a commercial retractable lance system. SNCR slightly reduced boiler efficiency due to the water produced from its application.

DSI/FGH. During the operation of the DSI system with calcium hydroxide and FGH under load-following conditions, the FFDC pressure drop significantly increased. This condition resulted from buildup of a hard ash cake on the fabric bags that could not be cleaned under normal reverse-air cleaning. The FGH system caused the heavy ash cake, but it was not determined whether the problem was due to operation at 30 °F approach-to-saturation temperature or an excursion caused by a rapid decrease in load.

When the SNCR and dry sodium systems were operated concurrently, an ammonia odor problem was encountered around the ash silo. Reducing the ammonia slip set points to the range of 4–5 ppm reduced the ammonia concentration in the fly ash to the 100–200 ppm range, but the odor persisted. It was found that the problem was related to the rapid change in pH due to the presence of sodium in the ash. The rapid development of the high pH level and the attendant release of the ammonia vapor appear to be related to the wetting of the fly ash necessary to minimize fugitive dust emissions during transportation and handling. This problem was resolved by transporting the ash in enclosed tanker trucks, and by not adding water at the site. The presence of sodium and ammonia in the fly ash precludes its use as a concrete additive.

Economic Performance

The IDECS has application primarily to smaller boilers. Consequently, economics for a commercial installation of IDECS was based on the Arapahoe Unit 4, but the estimate assumes that the demonstrated technologies are mature and incorporate experience gained from earlier installations. The retrofitted unit is a 100-MWe down-fired boiler with a 65% capacity factor, having baseline emissions of 1.15 lb/10^6 Btu for NO_x and 0.66 lb/10^6 Btu for SO_2. Target emission reductions are 79% for NO_x and 70% for SO_2. With all costs in 1994 dollars, the estimated capital costs are $129/kW for LNB/OFA, $41/kW for SNCR, and $25/kW for sodium bicarbonate based DSI (calcium-based DSI is more costly and less efficient than sodium-based DSI), bringing the total capital cost to $195/kW for the integrated system. Estimates for fixed operating costs are $0.32 million/year and for variable operating costs are $1.49 million/year, for a total operating cost of $1.8 million/year. Levelized costs are $1,358/ton of NO_x plus SO_2 removed on a current dollar basis and $1,044/ton on a constant dollar basis. Busbar costs are 9.7 mills/kWh on a current dollar basis and 7.4 mills/kWh on a constant dollar basis. The details of the capital and operating costs are shown in Tables 2, 3, and 4, respectively. A limestone forced oxidation (LSFO) scrubber and SCR retrofit of the

Table 2. Capital Costs for a 100 MW Unit[a]

	Low-NO_x Combustion System	SNCR	Sodium-Based DSI	Calcium-based DSI Plus Flue Gas Humidification	Integrated
	$/kW	$/kW	$/kW	$/kW	$/kW
Installed Equipment Cost	66.55	27.32	16.81	31.31	110.68
Process Contingency	6.65	2.73	1.68	3.13	11.06
Total Process Capital	73.20	30.05	18.49	34.44	121.74
Engineering and Home Office	7.32	3.00	1.85	3.44	12.17
Project Contingency	4.03	1.65	1.02	1.90	6.70
Total Plant Investment	84.55	34.70	21.36	39.78	140.61
Royalty Allowance	0.37	0.15	0.10	0.20	0.62
Preproduction Costs	0.03	0.22	0.45	0.40	0.70
Inventory Capital	0.00	0.74	1.72	1.40	2.46
Subtotal Capital	84.95	35.81	23.63	41.78	144.39
Cost of Construction Downtime	43.68	5.46	1.56	1.60	50.70
Total Capital Requirement	128.63	41.27	25.19	43.38	195.09

[a] Costs in 1994 dollars and based on a 65% operating factor and 0.4% sulfur coal.

TABLE 3. OPERATING COSTS FOR A 100 MW UNIT[a]

	Low-NO_x Combustion System	SNCR	Sodium-Based DSI Bicarbonate	Sodium-Based DSI Sesquicarbonate	Calcium-Based DSI Plus Flue Gas Humidification	Integrated
	$\$10^3$/yr	$\$10^3$/yr	$\$10^3$/yr	$\$10^3$/yr	$\$10^3$/yr	$\$10^3$/yr
Fixed O&M Costs						
Operating Labor	0.0	33.6	33.6	33.6	33.6	67.2
Maintenance Labor	29.3	24.0	29.6	29.6	55.4	82.9
Maintenance Material	43.9	36.1	44.4	44.4	83.0	124.4
Administration/Support Labor	8.8	17.3	19.0	19.0	26.7	45.1
Fixed Costs	82.0	111.0	126.6	126.6	198.7	319.6
Variable Operating Costs						
Urea	0.0	365.6	0.0	0.0	0.0	365.6
Sorbent	0.0	0.0	956.2	854.2	464.7	956.2
Water	0.0	1.8	0.0	0.0	0.2	1.8
Waste Disposal	0.0	0.0	68.2	122.7	63.5	68.2
Electric Power	0.3	80.6	20.6	20.6	322.8	101.5
Variable Costs	0.3	448.0	1045.0	997.5	851.2	1493.3
Total O&M Cost	82.3	559.0	1171.6	1124.1	1049.9	1812.9

[a] Costs in 1994 dollars and based on a 65% operating factor and 0.4% sulfur coal.

same unit would have a total capital cost of \$394/kW and current levelized costs of \$4,136/ton of NO_x plus SO_2 removed and 19.40 mills/kWh.

For other size units with the same baseline emissions and reduction targets, the total estimated capital costs for IDECS ranged from \$125–281/kW for capacities ranging from 300–50 MWe, respectively. Comparably, limestone forced oxidation (LSFO) scrubber and SCR capital costs ranged from \$270–474/kW for the same size range. On a levelized cost (current dollar) basis, the IDECS costs vary from 12.43–7.03 mills/kWh (\$1,746–987/ton of SO_2 and NO_x removed) compared to wet scrubber and SCR levelized costs of 23.34–12.67 mills/kWh (\$4,974–2,701/ton of SO_2 and NO_x removed) based on 0.4% sulfur coal. The integrated system is most efficient on smaller, low-sulfur coal units. As size and sulfur content increase, the cost advantages decrease.

TABLE 4. LEVELIZED COSTS OF POWER FOR A 100 MW UNIT[a]

	Low-NO_x Combustion System	SNCR	Sodium-Based DSI	Calcium-based DSI Plus Flue Gas Humidification	Integrated
Levelized Cost of Power, mills/kWh	Constant \$	Constant \$	Constant \$	Constant \$	Constant \$
Capital Charge	2.80	0.90	0.55	0.94	4.25
Fixed O&M Cost	0.14	0.20	0.22	0.35	0.56
Variable Operating Cost	0.00	0.79	1.83	1.50	2.62
Total Cost	2.94	1.89	2.60	2.79	7.43
Levelized Cost, \$/ton NO_x/SO_2 Removed Basis	NO_x	NO_x	SO_2	SO_2	NO_x+SO_2
Capital Charge	711	1066	235	942	597
Fixed O&M Cost	37	231	95	347	79
Variable Operating Cost	0	935	785	1493	369
Total Cost	748	2232	1115	2782	1044

[a] Costs in 1994 dollars and based on a 65% operating factor and 0.4% sulfur coal.

Commercial Applications

The IDECS was developed to meet the site-specific requirements of some of the more difficult boiler emission-control situations. A market analysis indicated that 65 down-fired boilers, totaling 6,400 MWe, and 29 wet bottom boilers, totaling 3,800 MWe, could be candidates for the IDECS. Because of their age and design, these units generate high levels of NO_x, and because of lack of plot area, they are difficult to retrofit with existing SO_2 removal technologies. The plants also tend to be relatively small. As a result of these considerations, utilities will be reluctant to make major capital investments in these units. Many utilities are considering fuel switching or retirement; however, IDECS provides an economic alternative that can extend plant life. A broader secondary market also exists that would benefit from installing one or more of the technologies in the IDECS.

In summary, IDECS offers the following advantages:

- Up to 80% NO_x and 70% SO_2 reductions at half the cost of a LSFO scrubber/SCR installation and 70% lower cost per ton of reduced emissions than a LSFO scrubber/SCR installation for smaller boilers and low sulfur coal applications;
- Minimal land area required for retrofit along with flexibility in locating equipment;
- Short outage required for installation;
- Application to a number of units regardless of boiler type and particulate collection device;
- No additional solid waste stream; and
- Synergy of components reduces the negative effects of the individual technologies.

The recent trend, however, is toward technologies that provide maximum emissions removal capabilities, rather than selection of technologies that achieve lower removals, but at a more economical cost. This trend may limit the market for IDECS. Nevertheless, there are still a number of units that would benefit from IDECS, especially units that can use emissions averaging to meet emissions limits.

The LNBs remain in operation at Arapahoe Station Unit No. 4. The remaining components of the IDECS remain available for use as required. At the time of this report, PSCC, as developer and patent holder on the SNCR/sodium-based DSI technology, was studying the potential for installing all or part of the IDECS on a number of its units. B&W, as a large market share holder in the environmental control industry, was exposing potential customers to IDECS when site-specific needs warranted its consideration.

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