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ASHWORTH COMBUSTOR DEMONSTRATION

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INTRODUCTION

The Ashworth Combustor™ is a three-stage pulverized coal combustion technique that reduces the major air pollutants (NO_X, SO_2, Hg and other air toxics) associated with coal combustion. A 40 million Btu/hr three-stage combustion system was retrofitted to a coal-fired stoker at the Lincoln Developmental Center in Lincoln, Illinois. A state-of-the-art DeltaV control system was used to control the system and a Continuous Emissions Monitoring System (CEMS) was used to measure SO_2, NO_X, CO, O_2, and Opacity. Testing at the Center was completed in early March 2003. ClearStack Combustion Corporation (ClearStack) is currently negotiating a contract with an electric utility to complete the next phase of development, a demonstration on a 50 MWe tangentially fired unit.

The three-stage combustion technique is very simple. Pulverized coal is fired into a 1st Stage gasifier and lime/limestone is added to capture sulfur. The 1st Stage is fired at a SR of 0.60 to minimize fuel bound NO_X production and to provide the right conditions to capture sulfur and mercury. The 2nd Stage is fired at a SR of 0.90 to preclude NO_X formation in the 2nd Stage (lower boiler furnace). The 3rd Stage of combustion (SR of 1.10 to 1.15) occurs in the upper furnace (OFA) after the gases have cooled to a point that minimizes thermal NO_X production.

The technology promises to be a low cost option for pulverized coal-fired units by reducing SO_2 emissions by some 70% and NO_X emissions to < 0.15lb $NO_X/10^6$ Btu, the level that the U. S. EPA has mandated to come into effect on May 31, 2004. Certain air toxics are also reduced. From ash analyses, the technique appears to achieve near quantitative removal of mercury with the slag/fly ash produced. Also the mercury does not leach from the slag/fly ash. This aspect will be very beneficial to electric utilities in 2007, the year expected for the U.S. EPA to regulate mercury emissions from power plants. With this technology, mercury reduction comes with the system at no added cost.

In the near term, this technique will provide the electric utility industry with a lower cost option to reduce acid gas emissions from smaller coal-fired units (200 MWe and less). In the long term this combustion system should become the Best Available Control Technique (BACT) for coal combustion in new power plants.

ClearStack, the IL Clean Coal Review Board, the IL Department of Commerce and Community Affairs, the IL Development Finance Authority, EPRI, Detroit Edison, Dynegy, Allegheny Energy Supply, and the IL Department of Human Services funded the demonstration. Midrex Technologies Inc. (Midrex) is a ClearStack technology partner responsible for the engineering for commercial applications of the technology. The cost of the demonstration was ~ $4 million.

BACKGROUND OF TECHNOLOGY

The Ashworth Combustor includes two complimentary combustion techniques. A two-stage combustion technology owned by Florida Power Corporation (FPC) that reduces both sulfur and nitrogen oxide emissions. This technology is protected under U. S. Patents 4,395,975, 4,423,702, and 5,458,659. ClearStack has the exclusive worldwide licensing rights to the FPC technology. The second combustion technology, which is owned by ClearStack, is a modification of the air rate introduced into the 2nd Stage and includes the addition of a 3rd Stage of combustion to achieve the ultra-low NO_X emissions that will be required in 2004. It is protected under U. S. Patents 6,085,674 and 6,325,002. The FPC two-stage CAIRE® combustor is an offshoot of coal gasification technology. The 1st Stage is a small coal gasifier, which replaces an existing burner. Excess air is added to complete combustion as the fuel gas from the gasifier enters the furnace. Alkali is added to capture sulfur as CaS in a molten slag mineral complex that flows from the bottom of the 1st Stage gasifier and is water quenched. The CAIRE combustor incorporates certain features of the Rummel molten slag bath gasifier. The Rummel gasifier, burning German Brown coal with a high alkali ash content captured some 70% of the coal sulfur in the molten slag removed from the gasifier.

<u>FPC Pilot Combustor</u>

FPC demonstrated a 12 million Btu/hr two-stage combustor[1] at the Foster Wheeler Development Center in Livingston, New Jersey. The 1st Stage was run with an air: fuel stoichiometric ratio (SR) of approximately 0.60 and the 2nd stage was run with an SR of 1.10 to 1.20. Lime and limestone were fed with the fired pulverized coal to capture sulfur.

Sulfur Capture

For most runs, sulfur reduction was primarily the result of SO_2 being captured by alkaline fly ash. However, at the end of Run #11, when using a hydrated lime that was a finer grind than the limestone previously used, a dramatic increase in sulfur capture (CaS) by the slag was observed. Also, at that time 59 wt% overall coal sulfur was captured. Runs #10 and #11 used the same coal/air nozzles and were set up to run at similar operating conditions, the only difference was that limestone was used in Run #10, and hydrated lime was used in Run #11. The hydrated lime size distribution was 42% minus 200 mesh, while the limestone was 15% minus 200 mesh. In Figure 1, flue gas SO_2 is shown versus time. Steam addition was seen to increase sulfur capture. Increased Ca/S ratios and lower SRs also improved sulfur capture. The finer hydrated lime achieved the best sulfur capture. When using identical particle sizes, limestone and lime should react similarly. We found this to be true in the Lincoln demonstration.

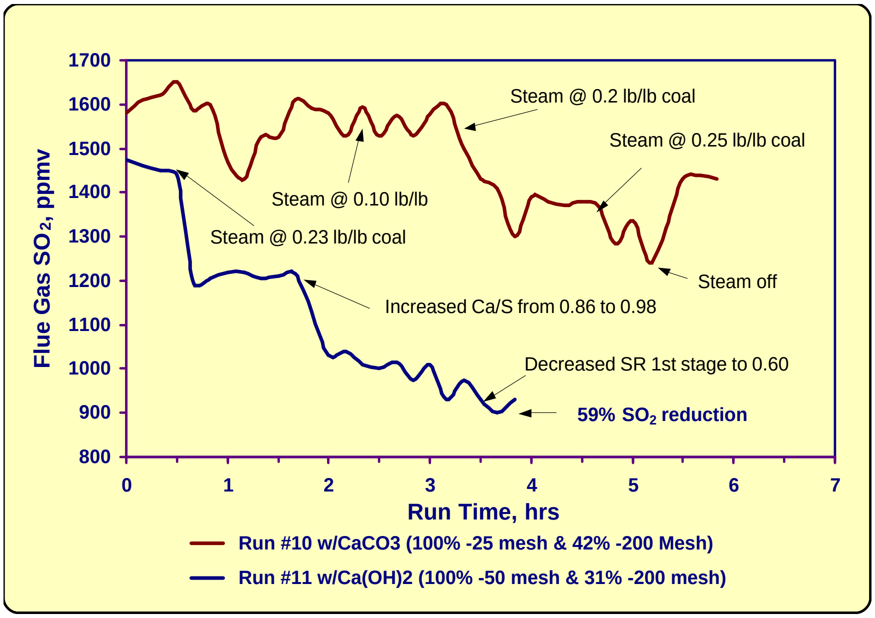

Figure 1. Flue gas SO_2 concentration versus run time.

NO_X Reduction

The NO_X emissions for two-stage combustion were low (0.25lb $NO_X/10^6$ Btu), considering that no special design provisions were included in the 2nd Stage to reduce production of thermal NO_X. As seen in Figure 2, the lower the 2nd Stage excess air, the lower the NO_X emissions.

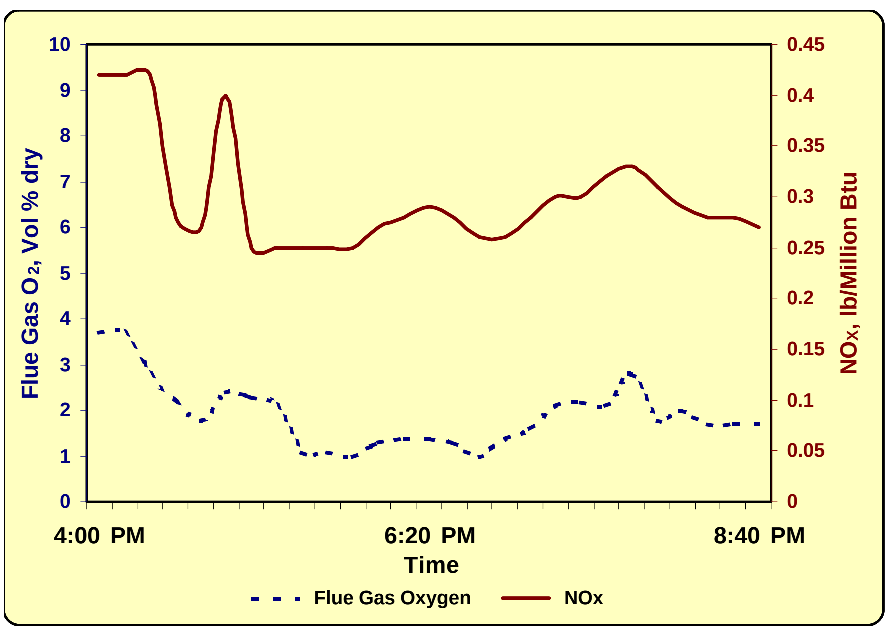

Figure 2. NO_X emissions reduction as a function of 2nd Stage flue gas oxygen.

Combustion Efficiency

Combustion efficiency was 98.7%. This was very good taking into account that design improvements could be used in the second combustion stage. Further, the pilot boiler was a water-jacketed vessel and the flue gas was cooled faster than would occur in a typical boiler.

ASHWORTH COMBUSTOR TECHNOLOGY

The Ashworth Combustor 1st Stage is a modified design of the CAIRE combustor. Features were incorporated to increase sulfur capture in the molten slag and further reduce NO_X emissions. These design changes had to do with the mode of firing, residence time in the 1st Stage, the rate and mode of secondary air firing, the residence time in the 2nd Stage and the addition of a 3rd Stage of combustion air.

NO_X Reduction Mechanisms

This three-stage combustion technology is an improved technique for the reduction of NO_X. It precludes the formation of nitrogen oxides from fuel bound nitrogen in the 1st Stage like the FPC combustor but also eliminates high temperature oxidizing conditions that reduce thermal NO_X formation. The reduction of nitrogen oxides using combustion techniques only, is fairly simple once one understands the reaction mechanisms and combustion gas flow patterns required to yield low NO_X. Implementation in the field to achieve the desired conditions may be a little difficult but the science is very straightforward.

1st Stage Gasification

The 1st Stage is operated at a SR of about 0.60. This SR is best for eliminating fuel bound NO_X and the NO_X precursors, ammonia (NH_3) and hydrogen cyanide (HCN). Figure 3 shows equilibrium concentrations of NO_X, NH_3 and HCN as a function of SR. Therefore, if equilibrium is achieved in the 1st Stage, which pilot plant testing showed does happen at 2600 ^{o}F, there will be no fuel bound NO_X formed. The fuel gas produced in the 1st Stage gasification zone has a heating value of 60 to 65 Btu/scf and this gas enters the 2nd Stage oxidation zone.

2nd Stage Reducing Zone

Fuel gas from the 1st Stage enters the furnace at a temperature of 2600°F to 2800^{o}F. Second stage oxidation takes place here to bring the air: fuel stoichiometric ratio from 0.60 to 0.90. Nitric oxide (NO) formation (most prominent form of NO_X formed in pulverized coal-fired boilers) is minimized by the various reducing reactions that will occur in the lower part of the furnace; see Figure 4. The 2nd Stage lower furnace zone at an SR of 0.90 yields a concentration of 3% CO which is a slightly reducing gas condition that does not affect boiler waterwall tube life. The 2nd Stage SR is similar to that used in Reburn technology, another three-stage technique for reducing NO_X emissions.

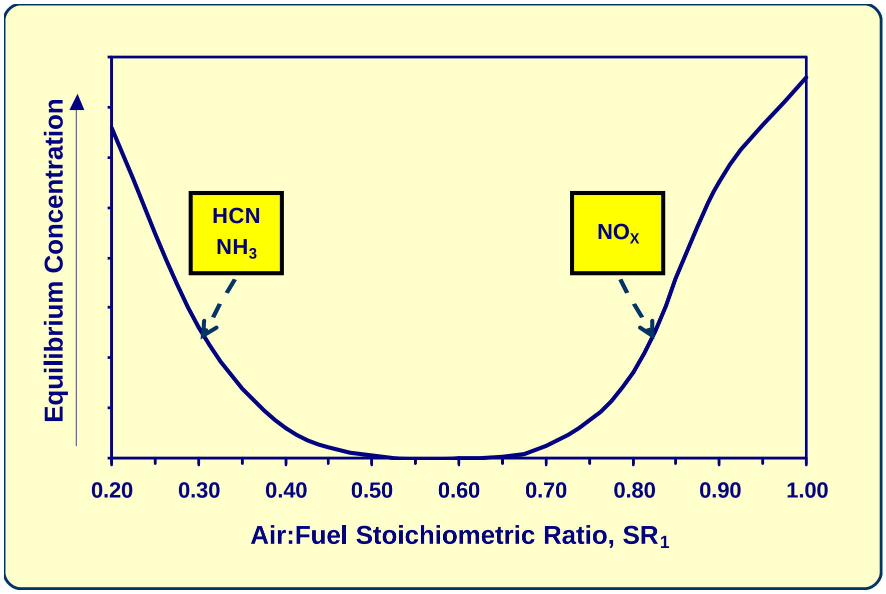

Figure 3. 1st Stage HCN, NH_3 and NO_X relative equilibrium concentrations.

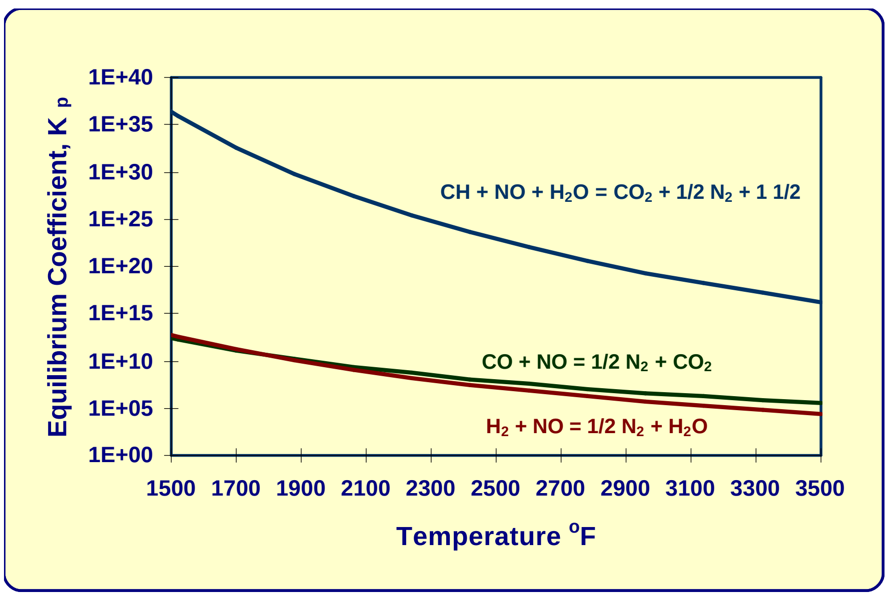

Figure 4. 2nd Stage NO reducing reactions.

With the Reburn technique, NO_X is formed from burners run at excess air conditions that the Reburn Zone then has to reduce to diatomic nitrogen (N_2). Following the Reburn Zone, overfire air is also added to complete combustion. Reburn is oxidizing - reducing - oxidizing and the Ashworth Combustor is reducing - reducing - oxidizing. The best NO_X emission levels that Reburn technology alone can achieve is in the range[2] of 0.25 to 0.30lb/10^6 Btu compared with the Ashworth Combustor of 0.15lb/10^6 Btu and less.

3rd Stage Combustion (OFA) Zone

Third stage air (OFA) is added in the upper furnace to complete the combustion process, increasing the SR from 0.90 up to an SR of 1.10 to 1.20. The OFA is injected into the upper furnace at the point where the flue gas temperature has been cooled (~2400°F) to a point that minimizes the formation of thermal NO_X. The thermochemical equilibrium as a function of temperature for the prime thermal NO_X producing reaction is shown in Figure 5.

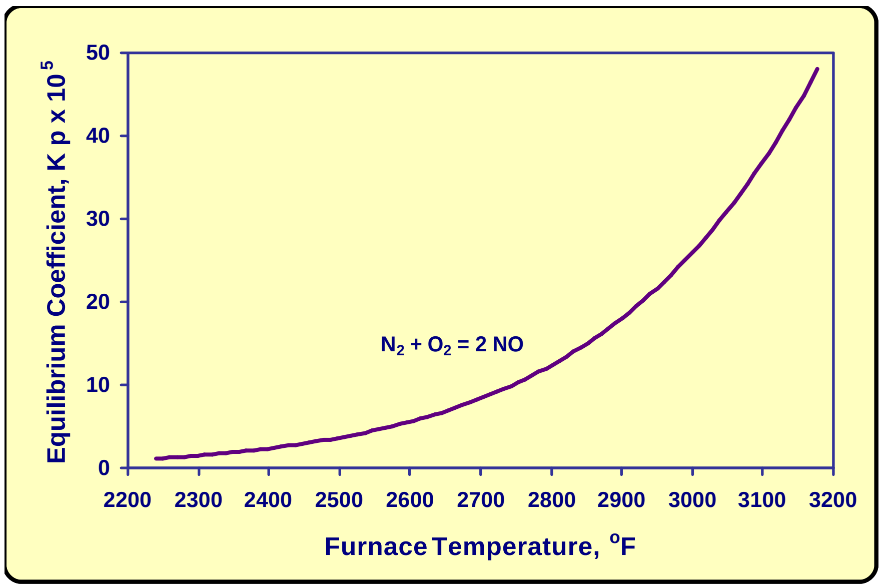

Figure 5. 3rd Stage NO formation thermochemical equilibrium.

Three-stage kinetic modeling[3] was completed by GE-EER for ClearStack. A One Dimensional Flame (ODF) kinetics model developed in a FORTRAN computer code was used. ODF treats the combustion system as a series of one-dimensional reactors. Each reactor may be perfectly mixed (well-stirred) or unmixed (plug flow). Each ODF reactor may also be assigned a variety of thermodynamic characteristics, including adiabatic, isothermal, or specified profiles of temperature or heat flux, and/or pressure. The flexibility in model setup allows for many different chemical processes to be simulated in a wide variety of environments. The ODF model has been validated against experimental data from several sources; applications include flame zone modeling, Reburn, reagent injection and industrial process reactors. The ODF model was set up for three stages of combustion. The 1st Stage SR_1 was held at 0.60. The 2nd Stage SR_2 was varied and the 3rd Stage SR_3 was held at a constant 1.14. Two modeling series were run, one that included steam addition to the 1st Stage and one that did not. In both cases, modeling predictions showed that three-stage combustion could reduce NO_X emissions to less than 0.10lb $NO_X/10^6$ Btu of coal fired. With steam addition that lowers the 2nd Stage temperature, emissions as low as 0.07lb $NO_X/10^6$ Btu could be achieved (see Figure 6). With this technique, if EPA restricts NO_X emissions further (value less than 0.15lb/10^6 Btu) the utility boiler owner could add low-pressure steam into the first stage to reduce NO_X emissions further.

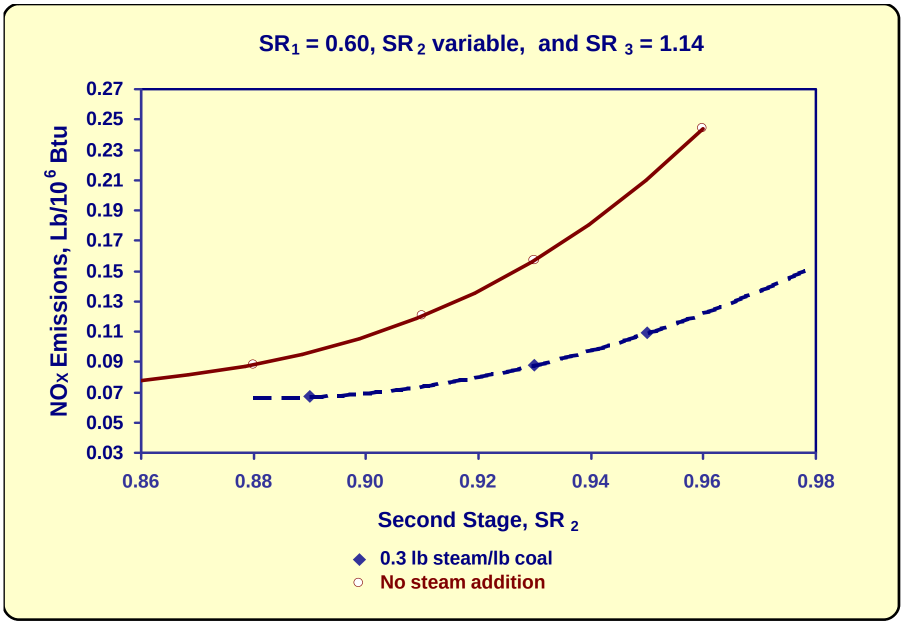

Figure 6. Three Stage Kinetic Modeling NO_X emissions prediction.

Acid Aerosols and Air Toxics

Since limestone is added with the coal, acid aerosols sulfur trioxide (SO_3), hydrochloric acid (HCl), and hydrofluoric acid (HF) will also be reduced. Testing of the ash, discussed later, has shown a dramatic capture of mercury.

Increase in Boiler Performance

Assuming one per cent of coal sulfur goes to SO_3 in a conventional boiler, using a 3-wt% sulfur coal would yield 30 ppmv of SO_3. In limestone furnace injection tests by others, although only 50% of the SO_2 was removed, 90% of the SO_3 was removed. Assuming that 90% of the SO_3 is removed with the combustor, the acid dew point would drop from 298°F to 256°F. This would allow an enlargement of air preheaters to recover more heat from boiler flue gas and increase overall efficiency by around 1.0%. Further, it is believed that the combustion system can be operated with as low as 10% excess air rather than the 15 - 20% usually required for low CO emissions and high carbon conversion. This would improve boiler performance by 0.5% through reduction of stack gas heat losses.

Saleable By-Products

Since the advent of low NO_X burners, many coal-fired power plants that once sold their fly ash to the cement industry could no longer do that due to high carbon content. With the Ashworth Combustor the high carbon conversion of the old excess air burners returns to provide a fly ash with 5-wt% carbon or less. The bottom slag, low in carbon (<1.0%), appears to be ideal for asphalt shingle manufacture.

LINCOLN DEVELOPMENTAL CENTER DEMONSTRATION

The Ashworth Combustor demonstration[4] took place at the Illinois Department of Human Services, Lincoln Developmental Center in Lincoln, IL. The Center's boiler house has three nominal 40,000 lb/hr boilers but usually produce no more than 18,000 lb/hr of steam. Units #1 and #3 are coal-fired stoker boilers and Unit #2 is a coal-fired stoker that was converted to natural gas. The Center seldom used the gas-fired unit due to the high price of purchased natural gas compared to coal. Unit #2 was therefore selected as the host boiler for the retrofit (see Figure 7). The retrofit consisted of installing a water-jacketed two-stage combustor; a coal feed system that includes a pulverizer, a limestone storage and feed system, a slag quench and removal system, an overfire air (OFA) system, an air pre-heater and a baghouse.

A state-of-the-art DeltaV control system was used to control the combustion system, an Allen Bradley system is being used to control the baghouse and a Continuous Emissions Monitoring System (CEMS) was used to measure SO_2, NO_X, CO, O_2, and Opacity.

Figure 7. Ashworth 40 x 10^6 Btu/hr 3-Stage Combustion System.

Pulverized coal (70% minus 200 mesh) and limestone (80% minus 200 mesh) was fired into the slagging combustor at an air rate to maintain a SR of about 0.60. The slag flowed through a tap in the center of the combustor into a water-quench drag tank. The ash was de-watered and then conveyed to a roll-off container (see Figure 8) for disposal to a conventional landfill. Like cyclone slag, commercially the slag could be used in the manufacture of asphalt shingles. Second stage air was added to the fuel gas (~60 Btu/scf) from the combustor as it entered the boiler furnace to bring the SR up to 0.90. In the upper furnace, overfire air (OFA) was added to complete the combustion process. Flue gas from the boiler flowed to a baghouse (see Figure 9) for particulate removal and then to an atmospheric stack.

Figure 8. 1st Stage Combustor Slag to Roll-Off Container.

Figure 9. Baghouse.

Test Results at Lincoln

The Ashworth Combustor demonstration took place at the Illinois Department of Human Services, Lincoln Developmental Center in Lincoln, IL. The combustor was first run on coal on June 26, 2002 and testing lasted until March 6, 2003. Coal was fired for some 50 hours over 23 days of operation. Operating the combustor at the facility for long periods of time was impossible; it could be operated for around 4 hours maximum each day. The reason for this was that the number of residents at the Lincoln

Development Center was first reduced and then all were eventually moved out and the buildings boarded up. The temperature in the buildings was kept at 60^oF and steam for the laundry was not required. The combustor was designed for 40 million Btu/hr coal heat input, but the steam requirement was less than half of that. Even at half load the facility would run out of boiler makeup water because steam had to be vented through the roof to increase the load to a point (20 million Btu/hr) where the combustor could be operated for a short period of time.

The combustor itself was very easy to operate after going through the typical start-up problems. One could switch from gas to coal and back without any trouble. Initially, a troublesome problem we did experience with the combustor operation was that the slag tap would plug. Many modifications were made to improve slag tapping but the answer was eventually found and was very simple; the 1st Stage was not hot enough at an SR of 0.60 due to the limit on feed throughput. It was found that if the 1st Stage temperature was maintained at 2600 ^oF and up there was very little problem with slag tapping. Potential slag tapping problems is why cyclone units are always run at near capacity to maintain high temperatures.

Coal and Limestone

The coal used for testing at the Lincoln Development Center came from Turris Mine, and Illinois #5 seam coal. The ultimate analysis, heating value and ash compositions are shown in Table 1.

TABLE 1. TURRIS MINE COAL AND ASH COMPOSITION

Ultimate Analysis:		**Ash Analysis:**	
Composition	**Wt%**	**Composition**	**Wt%**
Carbon	57.89	SiO_2	52.85
Hydrogen	4.03	Al_2O_3	13.99
Oxygen	7.88	TiO_2	0.75
Nitrogen	1.15	Fe_2O_3	19.79
Sulfur	3.26	CaO	4.89
Moisture	16.06	MgO	0.69
Ash	9.73	Na_2O	1.28
Total	100.00	K_2O	1.64
		P_2O_5	0.11
Higher Heating Value = 10,609 Btu/lb		SrO	0.02
		BaO	0.05
Coal combustion for this sample with no		MnO_2	0.05
sulfur capture: 6.14 lb $SO_2/10^6$Btu		SO_3	3.89
		Total	100.00

Limestone is used to flux the slag and capture sulfur and mercury, see Table 2 for the limestone used at Lincoln. It is a high calcite limestone that was trucked to the site by Mississippi Lime. For most of the runs limestone was added at a rate to yield a Ca/S weight ratio of 0.85.

TABLE 2. LIMESTONE SIZE DISTRIBUTION AND ANALYSES

Size Distribution	Wt%	Composition	Wt%
Passing 35 Mesh (500 microns)	100.0	$CaCO_3$	97.8 to 98.9
Passing 60 Mesh (250 microns)	99.5 to 99.9	$CaSO_4$	0.06 to 0.12
Passing 100 Mesh (150 microns)	95.0 to 97.0	$MgCO_3$	0.40 to 0.95
Passing 200 Mesh (75 microns)	75.0 to 85.5	SiO_2	0.35 to 0.90
Passing 325 Mesh (45 microns)	58.0 to 73.0	Al_2O_3	0.11 to 0.34
		Fe_2O_3	0.04 to 0.10
Bulk Dry Density	**Lb/ft^3**	H_2O	0.02 to 0.08
(Based on degree of compaction)	56 to 104	P_2O_5	0.006 to 0.009
		MnO	0.0010 to 0.0024

SO_2 Emissions

SO_2 emissions were reduced to 1.7lb/10^6 Btu for a coal that yielded uncontrolled SO_2 emissions of 6.14 lb SO_2/10^6 Btu - a 72% reduction. This reduction was achieved with a limestone Ca/S ratio of 0.85. It is significant that this 1st Stage gasifier performed better that the FPC pilot gasifier, achieving over 70% reduction with limestone at a Ca/S ratio of 0.85 compared to 59% in the pilot gasifier with calcium hydroxide at a Ca/S ratio of 0.98. This was very significant since limestone is about one-tenth of the cost of hydrated lime. It is also easier to pneumatically transport and less hazardous to handle.

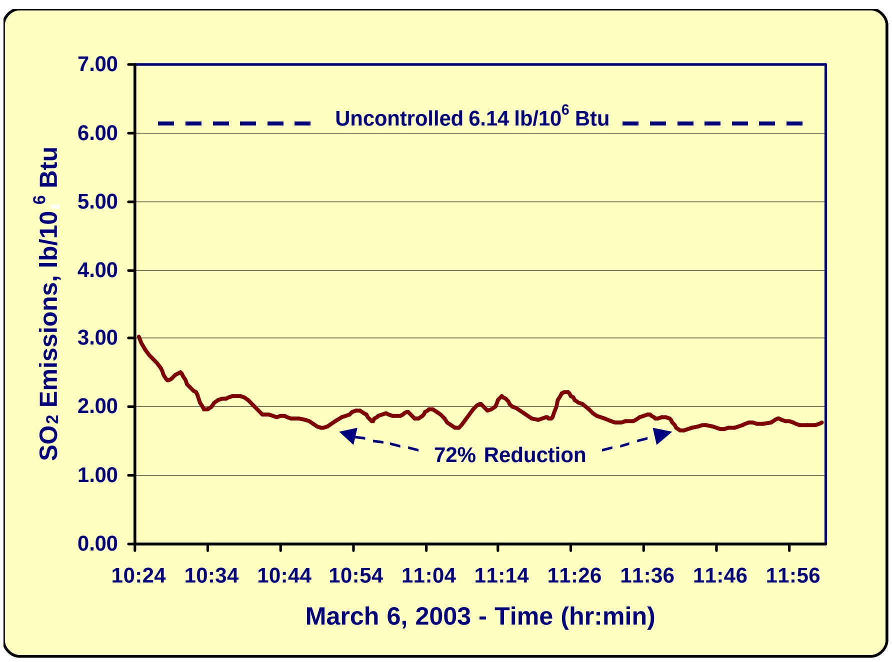

Figure 10. SO_2 reduction at Lincoln.

NO_X Emissions

NO_X emissions were as low as 0.095lb/10^6 Btu (68 ppmv @ 3 vol% O_2 dry) with coal using the three-stage combustion technique. The unit is gas capable and when firing natural gas at similar conditions, NO_X emissions were 0.048lb/10^6 Btu (44 ppmv @ 3 vol% O_2 dry).

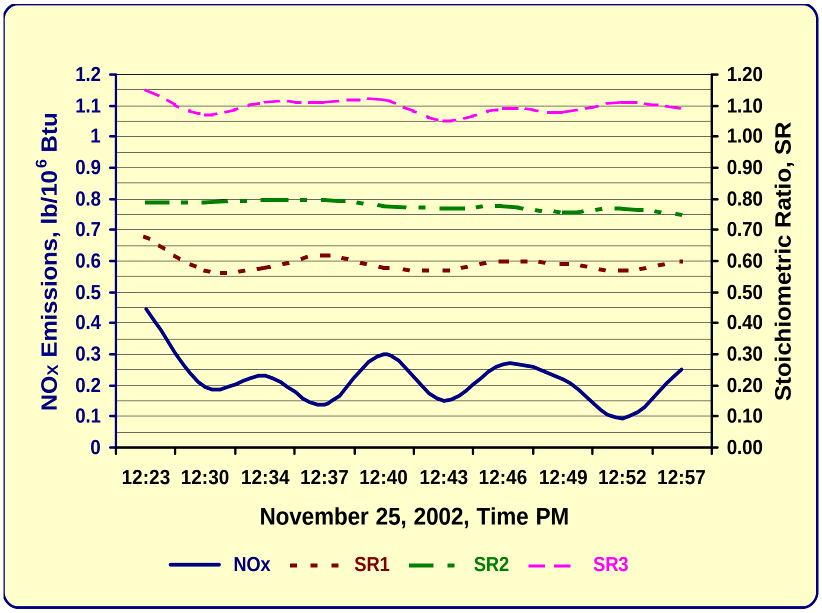

Figure 11. NO_X Reduction at Lincoln – 11/25/02

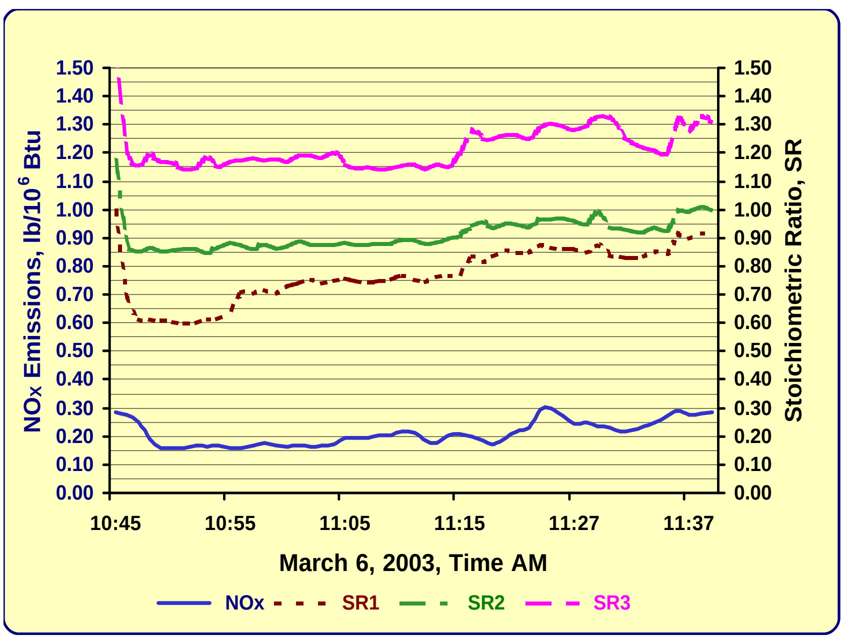

Figure 12. NO_X emissions at Lincoln – 3/06/03

On the November 25th run the weigh belt feeder cycled the actual coal feed due to the weigh roller being 50 thousandths out of round and that is the reason for the undulating data. Even so, a low NO_X level of 0.095lb/10^6 Btu was achieved. During the March 6th run one can see how the air: fuel stoichiometry affects NO_X production. SR_1 had to keep being increased to keep the temperature up to 2600 °F in the 1st Stage. Another problem that affected the NO_X emissions was that too much air was being sucked into the boiler and the more oxygen around the higher the NO_X. When the 1st Stage SR was 0.60 the NO_X emissions were a little over 0.15lb/10^6 Btu. On electric utility boilers that are better maintained regarding air leakage and where the combustors can be run at near capacity, NO_X emissions should be well under 0.15lb/10^6 Btu.

CO Emissions and Carbon Conversion

With coal firing only, carbon monoxide (CO) emissions were 15 - 30 ppmv @ 3 vol% O_2 dry compared to natural gas firing at similar conditions of 10 - 20 ppmv @ 3 vol% O_2 dry. The carbon conversion was around 99 wt%. Carbon in the quenched molten slag from the combustor was 0.1 - 0.2 wt% and carbon in fly ash was 5 wt%. On larger units where not as much tramp air enters the boiler, carbon conversion should be even higher. The three-stage combustion technique yields a light gray fly ash like that obtained prior to the advent of low NO_X burners.

Mercury Reduction

The Detroit Edison Fuel laboratory analyzed all of the solids streams entering and exiting the system. Although a stack test has not been run yet, mercury reduction has been surprisingly high based on solids analyses (Table 3). ClearStack filed for a patent on this Hg reduction technique.

TABLE 3. MERCURY CAPTURE on 12/18/02

Material:	**Rate, lb/hr**	**Hg, ppmw**	**Hg, lb/hr**	**Capture, wt%**
Input:				
Coal	1669.7	0.089	0.00014860	
Limestone	96.5	0.030	0.00000289	
Total	**1766.2**		**0.00015149**	
Output:				
Slag	38.9	2.60	0.00010110	66.7
Fly Ash	156.5	0.26	0.00004069	26.9
Total	**195.4**		**0.00014179**	**93.6**

In addition, the captured mercury does not leach. When DTE ran leachate tests on the slag and fly ash no mercury was leached from either sample. Other air toxics were also reduced.

Other Air Toxics and Halides Reductions

From trace element analyses of other air toxics in the slag and fly ash it looks as though all of the barium, beryllium, cobalt, copper, lead, molybdenum, nickel, selenium, silver and vanadium are captured and around 80% of the manganese. Laboratory analyses performed on the fly ash for the March 6th run also showed 26% fluoride capture and 14% chloride capture with the fly ash with a Ca/S ratio of 0.85. With higher Ca/S ratios capture should increase.

CO_2 Reduction

The EPRI Biomass Interest Group (BIG) provided some funds to the project because of its interest in using slagging combustors to increase the percentage of biomass that can be fired into a boiler. Some of the reactive alkalis (Na, K) will be removed in the bottom slag and what carries over with the fly ash will be in a mineral complex that is less corrosive to boiler tube walls. With this technology if biomass is available, CO_2 emissions could be reduced by at least 10 %. Biomass CO_2 is not counted as an addition to the ecosystem.

50 MWe DEMONSTRATION

ClearStack has a signed a memorandum of understanding with a major electric utility to complete a retrofit to a 50 MWe tangential unit. Work has now ensued to secure funding for the project. Midrex developed a three-dimensional view of a tangentially fired boiler retrofit (Figure 13) based on the design chose to retrofit the unit. There will be no tube wall penetrations required with this design as four 1st Stage gasifiers will be placed on each corner of the boiler.

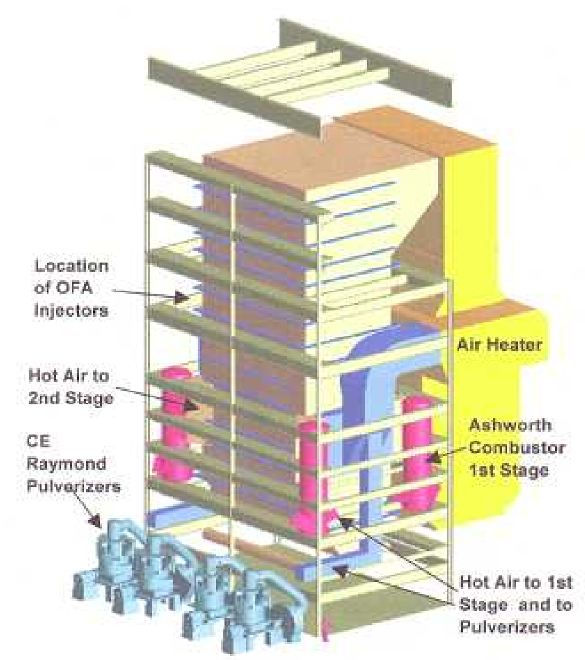

Figure 13. Tangentially fired boiler retrofit.

ECONOMIC COMPARISON WITH SCR

An economic comparison was developed for a 109 MWe tangentially fired boiler Ashworth Combustor retrofit compared to a Selective Catalytic Reduction (SCR) system. In Table 4 the capital (Midrex) and operating (ClearStack) cost estimate for the combustor retrofit is shown. The capital cost is estimated at $10,036,740 that equates to $92/kWe. The annual gross operating cost for NO_X reduction is estimated at $1,867,470 or $1544/ton based on a reduction from 0.45 to 0.15lb NO_X/million Btu. When taking a credit for reducing SO_2 based on an allowance selling price of $172/ton, the net annual operating cost is reduced to $750,817 or $621/kWe. In Table 5 the capital and operating costs for a 109 MWe tangentially fired boiler retrofitted with a SCR unit is shown. A detailed cost estimate for a 600 MWe SCR unit, completed by an engineer-constructor, was factored to develop the cost for the 100 MWe SCR unit. The capital cost was estimated at $14,682,457 or $135/KWe. Operating costs were based on the same level of NO_X reduction and operating capacity as that used for the combustor retrofit. The annual operating cost was estimated at $3,087,157 or $2552/ton of NO_X removed.

Figure 14 compares the annual cost of the Ashworth Combustor compared to a SCR retrofit after mercury regulations come into effect. Assuming a 90% mercury reduction, 53 lb of mercury per year for the 109 MWe unit would need to be removed based on a mercury concentration in the coal of 0.08 ppmw. The U. S. Department of Energy[5] estimates a cost of $30,000 to $70,000 to remove one pound of mercury. The median of the DOE range ($50,000) was chosen for the cost comparison. Since the combustor removes mercury, after restrictions are in place there would be almost a $5 million difference in annual operating cost (includes payback of capital). The Ashworth Combustor would cost $750,000 and the SCR plus mercury control would cost $5.74 million. This translates to an additional 0.1 ¢/kWhr for the combustor and an additional cost of 0.75 ¢/kWhr for SCR.

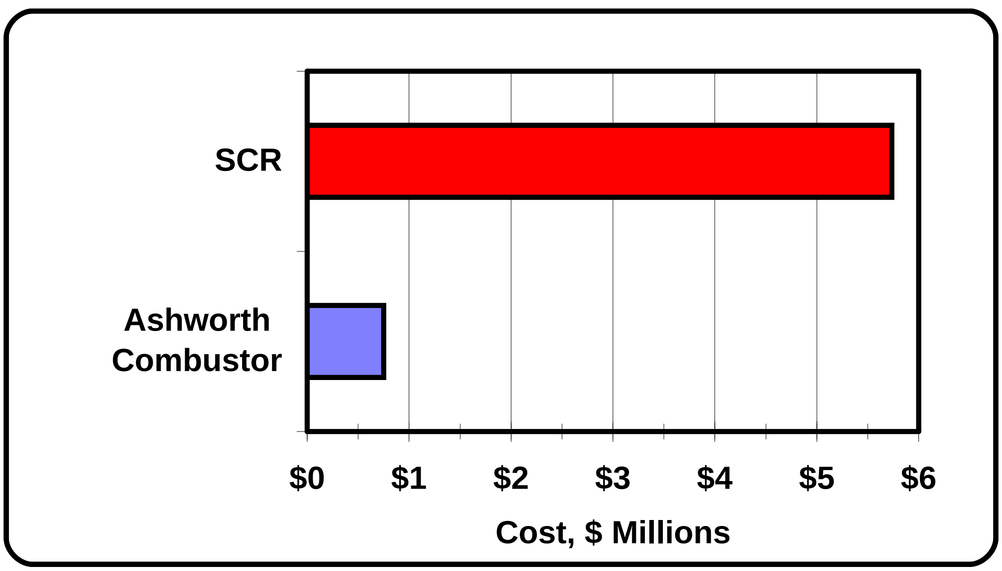

Figure 14. Annual operating cost comparison.

TABLE 4. ASHWORTH COMBUSTOR CAPITAL AND OPERATING COSTS

Capital Cost

Category	Cost	Cost/kWe
Major Equipment	$3,661,248	$33.6
Construction Labor	$2,011,442	$18.5
Construction Indirects	$781,000	$7.2
Engineering/Procurement	$1,531,000	$14.0
Project Management/Owners Costs	$558,125	$5.1
Freight	$109,800	$1.0
Taxes	$183,062	$1.7
ClearStack Licensing Fee	$436,000	$4.0
Startup and Field Services	$183,062	$1.7
Subtotal	$9,454,740	$86.7
Contingency	$582,000	$5.3
Total Plant Investment	**$10,036,740**	$92.1

Projected Annual Incremental Operating Costs[1]

	Annual Rate	Cost/Unit	Cost/ Yr	Cost/Ton NO_x[2]
Raw Material:				
Limestone[3]	8,622 ton	$10.15 /ton	$87,514	$72
Fixed Charges @ 12% TPI			$1,204,409	$996
Labor:[4]				
Maintenance @ 60% of 2% of TPI			$120,441	$100
Supervision @ 20% of Maintenance Labor			$24,088	$20
Supplies:				
Maintenance @ 40% of 2% of TPI			$80,294	$66
Admin. and Gen. Ovhd. (30% of total labor)			$36,132	$30
ClearStack Annual Licensing Fee (10 years)			$43,600	$36
Insurance and Taxes (2.7% of TPI)			$270,992	$224
Total Operating Costs			**$1,867,470**	**$1,544**
SO_2 Allowance Credit @ $172/ton[5]	6,492 ton	$172 /ton	($1,116,653)	($923)
Net Operating Savings			**$750,817**	**$621**

1 109 MWe(gross) @ 80% capacity factor and a 10,557 Btu/kWh gross heat rate

2 NOx reduction based on baseline value of 0.45 lb NOx/10^6 Btu reduced to 0.15 lb NOx/10^6 Btu (removal of 0.3 lb/million Btu)

3 Based on 1.53 wt % S coal (2.80 lb SO_2/10^6 Btu) with limestone added to meet the SO_2 limit of 1.2 lb/10^6 Btu (Ca/S =0.85)
Rock dust price at mine $4.15/ton plus assumed 60 miles at $0.10/ton-mile

4 No incremental operating labor

5 1.61 lb SO_2 removed per million Btu of coal fired. EPA 2003 auction price @ $172/ton

TABLE 5. SCR CAPITAL AND OPERATING COSTS

Capital Cost

Category	Cost	Cost/kWe
Major Equipment (including Initial Catalyst Charge)	$5,961,739	$54.7
Construction Labor	$2,100,285	$19.3
Construction Indirects	$1,675,749	$15.4
Engineering	$2,503,930	$23.0
Project Management/Owners Costs	$894,261	$8.2
Freight	$178,852	$1.6
Taxes	$298,087	$2.7
Startup	$238,470	$2.2
Subtotal	$13,851,374	$127.1
Contingency	$831,082	$7.6
Total Plant Investment (TPI)	**$14,682,457**	**$134.7**

Projected Annual Incremental Operating Costs[1]

	Annual Use		Cost/Unit		Cost/ Yr	Cost/Ton NO_x Removed[2]
Utilities:						
Electricity[3]	509,809	kWh	$0.03	/kWh	$15,294	$13
Catalyst & Chemicals:						
SCR Catalyst[4]	1,000	cu. ft.	$396	/cu. ft.	$395,882	$327
Anhydrous Ammonia[5]	137	ton	$430	/ton	$58,876	$49
Catalyst Disposal	1,000	cu. ft.	$9	/cu. ft.	$9,343	$8
Fixed Charges @ 12% TPI					$1,761,895	$1,457
Labor:[6]						
Maintenance @ 60% of 2% of TPI (less initial catalyst charge)					$176,189	$146
Supervision @ 20% of Maintenance Labor					$35,238	$29
Supplies:						
Maintenance @ 40% of 2% of TPI (less initial catalyst charge)					$111,159	$92
Admin. and Gen. Ovhd. (60% of total labor)					$126,856	$105
Insurance and Taxes (2.7% of TPI)					$396,426	$328
Total Operating Costs					**$3,087,157**	**$2,552**

1 109 MWe @ 80% capacity factor and 10,557 Btu/kWh gross heat rate
2 NOx reduction based on baseline value of 0.45 lb NOx/10^6 Btu reduced to 0.15 lb NOx/10^6 Btu
3 Auxiliary power cost assumed at $0.03/kWhr
4 Catalyst use based on 32,000 hrs before all initial catalyst has been replaced (Southern Energy Inc. Power-Gen 97 paper)
Cost of catalyst $396/cu. Ft. from OTAG publication
5 Anhydrous ammonia price (June 2002 - Ridgetown College publication, Ontario Canada)
6 Assumed no incremental operating labor

CONCLUSION

The Ashworth Combustor is a very promising coal combustion technology because it reduces multi-pollutants (NO_X, SO_2, Hg, halides and other air toxics). Further, unlike SCR it reduces the sulfur trioxide (SO_3) emissions that create opacity (bluish-white haze) and acid rain problems. It also does not require noxious chemicals (NH_3), as does SCR.

This staged combustion technology in the near term has its best application to coal-fired power plant units of 200 MWe and less, units that are uneconomical for the addition of Selective Catalytic Reduction plus Wet Scrubbers. It will be especially beneficial for electric utilities using the "bubble concept" to meet environmental regulations. The "bubble concept" is a control technique allowed by Federal and State Environmental Protection Agencies that allows the utility to treat its power generation units as an aggregate rather than as individual units. This allows utilities to over comply on large units so that the smaller units emissions can be increased. This stage combustion technique will reduce NO_X emissions to below the 2004 US EPA mandated limits for the Ozone Transport Region. Also sulfur dioxide emissions are reduced that will allow many utilities to use lower cost near-by high sulfur coal.

Further, the U.S. EPA announced that it would propose mercury regulations[6] by 12/25/2003 and issue final regulations by 12/15/2004. It is expected that the enforcement will start in 2007. When these regulations come into effect, power plants retrofitted with the combustor will not have to be burdened again with a costly addition to reduce mercury emissions since it is an inherent feature of the technology.

References:

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3. *NO_X Kinetic Modeling Report*, Energy and Environmental Research Corporation, October 23, 1998.
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