

The Ashworth Gasifier – Combustor **“A Clean “Green Coal” Technology”**

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INTRODUCTION

The Ashworth Gasifier-Combustor™ is a three-stage pulverized coal combustion technique that dramatically reduces the major air pollutants (NO_x, SO₂, Hg and other air metal toxics) associated with coal combustion. Why do we call it a clean “green coal” technology? It removes the real pollutants from coal combustion flue gas. Carbon dioxide (CO₂) is not a pollutant and it clearly is not causing the earth to warm. Coal is the greenest fuel on the planet. CO₂ is essential for life, without it plants would not grow and animals, including man would have no oxygen to breathe.

The Ashworth Gasifier-Combustor test results from the technology demonstration at the Lincoln Developmental Center in Lincoln, Illinois yielded the following results;

- **NO_x emissions down to 0.095 lb/10⁶ Btu**
- **SO₂ reduction of 72% at a Ca/S ratio of 0.85, achieving 85% calcium utilization**
- **99 wt% Carbon conversion**
- **CO emissions of 15 to 30 ppmvd @ 3% O₂**
- **Hg capture in slag/fly ash of 93 to 100 wt%**
Leach tests of slag and fly ash yielded 0 mg Hg/L of leachate
- **Near 100% capture of Sb, As, Ba, Be, Cd, Cr, Co, Cu, Pb, Mo, Ni, Se, Ag, Tl, V, Zn & 80% Mn with slag and fly ash. TCLP tests showed the concentrations of Ag, As, Ba, Cd, Pb, and Se in the leachate were all well below the EPA regulatory limit for both the fly ash and slag**
- **26% Fluorine and 14% Chlorine capture by ash (Ca/S ratio of 0.85)**

The technology promises to be a low cost multi-pollutant reduction technique for pulverized coal-fired units. In the near term, this technique will provide the electric utility industry with a low cost option to reduce acid gas emissions from its small coal-fired units (200 MWe and less). In the long term it should become the Best Available Control Technique (BACT) for coal combustion in new power plants.

NO EMPIRICAL EVIDENCE FOR CO₂ CAUSING GLOBAL WARMING

The empirical data (actual measurements)¹ show that atmospheric CO₂ concentrations have no discernible effect on global temperature, see Figure 1. The land-sea temperature plot shown is data from the United Kingdom's Hadley Climate Research Unit. The average CO₂ plot is from the Mauna Loa Observatory in Hawaii. While CO₂ levels increased some 20 ppmv over the past 10 years, global temperatures did not increase as predicted by the Intergovernmental Panel on Climate Change models - they fell! The earth's temperature from January 1998 to January 2008 cooled around 0.6 °C.

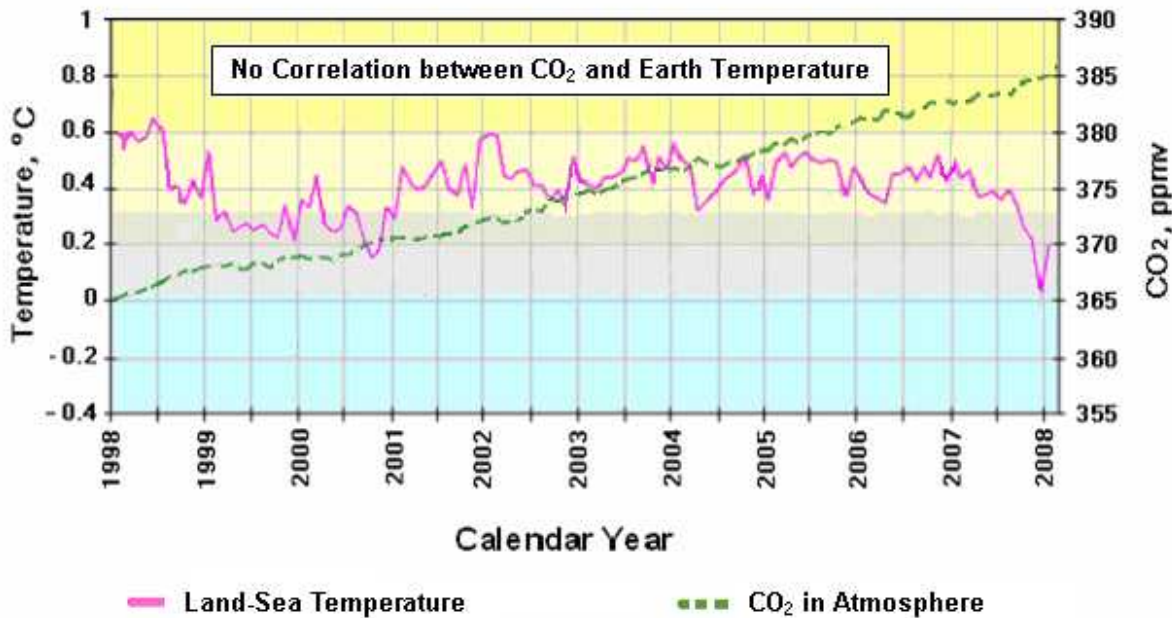


Figure 1. Earth temperature and CO₂ concentration 1998-2008

Man only contributes some 3% of the CO₂ emitted to the atmosphere, nature the rest ². If we were to globally eliminate all man-made CO₂ tomorrow, the concentration would be the same as it was in January 2002. It was some 0.5 °C warmer then than in January 2008. Further, of all CO₂ emitted to the atmosphere, nature absorbs 98.5% of it so nature already has its own built-in mechanism to control the level of CO₂ in the atmosphere.

Since carbon dioxide does not cause global warming like many erroneously claim, coal is the greenest fuel we could possibly use. There is more carbon dioxide per million Btu of coal fired than any other fossil fuel. Since nature absorbs most of the CO₂ that is emitted to the atmosphere to increase plant growth and liberate oxygen there is more food and oxygen for an increasing world population.

BACKGROUND OF TECHNOLOGY

The Ashworth Gasifier-Combustor includes two complimentary combustion techniques:

- 1) A two-stage gasification-combustion technology that Florida Power Corporation (FPC) called the CAIRE (Controlled AIR Emissions) Combustor. It reduced both sulfur and nitrogen oxide emissions. This technology is protected under U. S. Patent 5,458,659. ClearStack purchased the rights to the FPC patent in 2008.
- 2) The three-stage gasifier-combustor technology was developed by ClearStack to achieve ultra-low NO_x emissions and to improve sulfur capture. It is currently protected under U. S. Patents 6,085,674 and 6,325,002. Both of these goals were achieved and as a bonus mercury and other air metal toxics were captured in the slag as well in testing of the three stage technique at the Lincoln Development Center (discussed later).

CAIRE Combustor Pilot Unit

The technology is based on the oxygen-fired Rummel molten slag bath gasification technology used in Germany in the 1940's to produce a synthesis gas for ammonia production. The Rummel gasifier, burning German Brown coal with high alkaline ash content, captured 70+% of the coal sulfur in the molten slag that was removed from the gasifier.

FPC demonstrated a 12 million Btu/hr CAIRE gasifier-combustor¹ at the Foster Wheeler Development Center³ in Livingston, New Jersey, see Figure 2. The 1st Stage (gasifier) was run at 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. With the air blown two stage technique, sulfur dioxide (SO₂) reductions of up to 60% and nitrogen oxide (NO_x) emissions of 0.25 lb/million Btu were achieved when firing Eastern Bituminous coal.

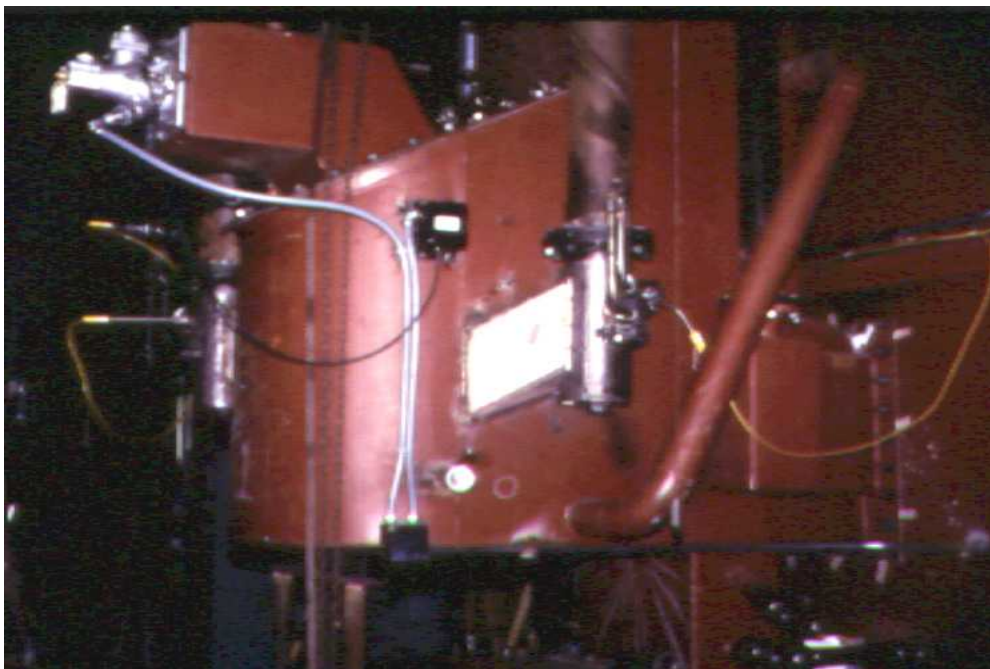


Figure 2. 12 Million Btu/hr pilot unit tested at the Foster Wheeler Development Center.

ASHWORTH GASIFIER-COMBUSTOR TECHNOLOGY

The Ashworth Gasifier is a modification of the FPC “CAIRE” Gasifier. Design modifications were made that improved sulfur capture and further reduced NO_x emissions in a demonstration at the Lincoln Developmental Center in Lincoln, Illinois. 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 oxidation 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 but also eliminates high temperature oxidizing conditions that results in reduced thermal NO_x formation.

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 (NH₃) and hydrogen cyanide (HCN). Figure 3 shows equilibrium concentrations of NO_x, NH₃ and HCN as a function of SR. Therefore, if equilibrium is achieved in the 1st Stage, which pilot plant testing showed happened, there is 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 at 2650 °F that is equivalent to a Low Btu Gas heating value of 120 to 130 Btu/scf.

2nd Stage Reducing Zone

Fuel gas from the 1st Stage enters the furnace at a temperature of some 2650°F. Second stage oxidation takes place here to bring the air: fuel stoichiometric ratio up 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 occur in the lower part of the furnace; see Figure 4.

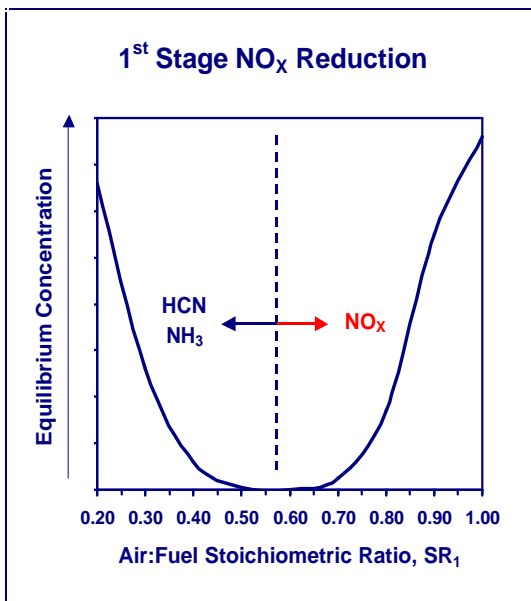


Figure 3. 1st Stage equilibrium concentrations.

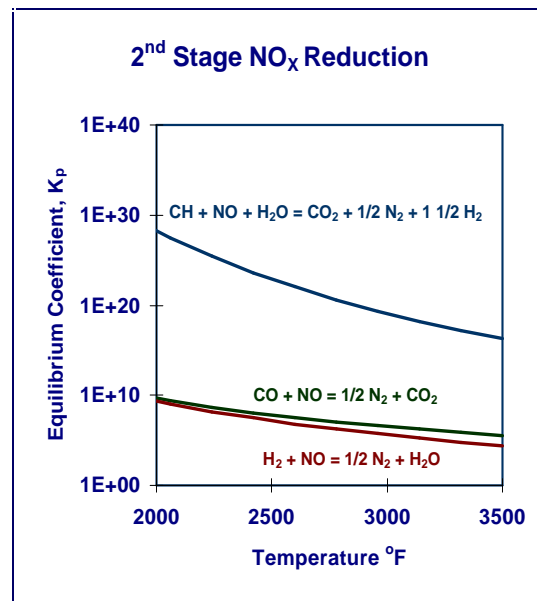


Figure 4. 2nd Stage NO reducing reactions.

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 to reduce NO_x formation and not affect boiler waterwall tube life. Following the second stage oxidation zone, overfire air is added to complete combustion.

3^d 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 at the point where the flue gas temperature is ~2400°F to minimize the formation of thermal NO_x. Thermochemical equilibrium as a function of temperature for the prime thermal NO_x producing reaction is shown in Figure 5. Three-stage kinetic modeling⁴ 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).

The ODF model has been validated against experimental data from several sources. The ODF model was set up for three stages of oxidation. The 1st Stage SR₁ was held at 0.60. The 2nd Stage SR₂ was varied and the 3rd Stage SR₃ was held at a constant 1.14. Two models 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 oxidation could reduce NO_x emissions to less than 0.10 lb NO_x/10⁶ Btu of coal fired. With steam addition that lowers the 2nd Stage temperature, emissions as low as 0.07 lb NO_x/10⁶ Btu could be achieved (see Figure 6). With this technique, if EPA restricts NO_x emissions further (value less than 0.15 lb/10⁶ Btu) low-pressure steam could be added into the first stage to reduce NO_x emissions further.

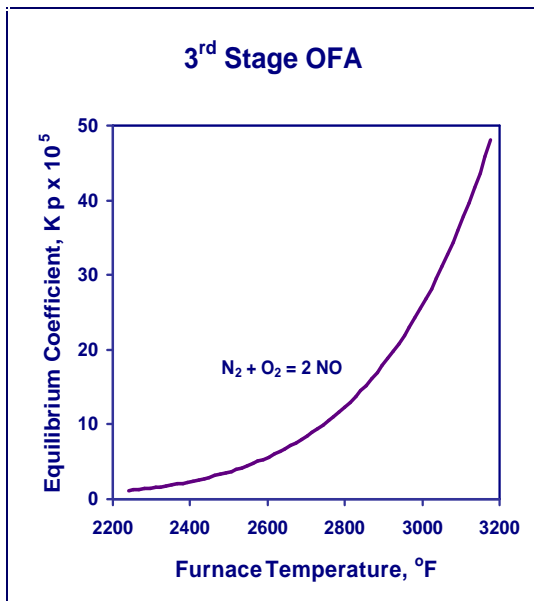


Figure 5. 3rd Stage NO equilibrium.

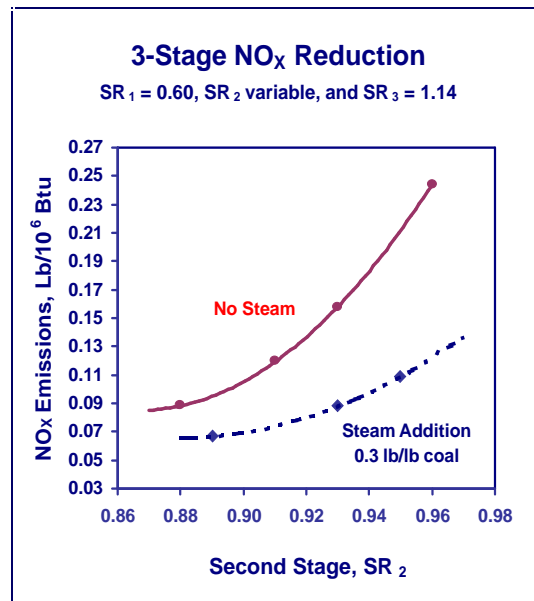
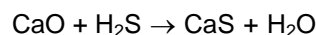


Figure 6. 3-Stage NO_x emissions.

Sulfur Capture

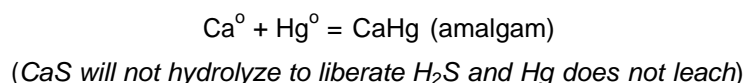
Limestone is added with low alkaline ash coal to capture sulfur, mercury and other air metal toxics in the slag produced. The reaction to capture sulfur is as follows:



The thermochemical equilibrium for sulfur capture of sulfur dioxide in an oxidizing environment and hydrogen sulfide capture in a reducing environment with calcium oxide is shown in Figure 7. As shown, the capture of sulfur in a reducing environment as hydrogen sulfide at 2600 °F is much more favored than the capture of sulfur in an oxidizing environment as sulfur dioxide at 1500 °F (fluidized bed combustion).

Mercury Capture

It is believed that the mercury gets tied up as an amalgam in the molten slag. Once an amalgam with calcium occurs it is very difficult to separate the two elements. Evidence for this is shown by the fact that the mercury once captured, does not leach from the slag.



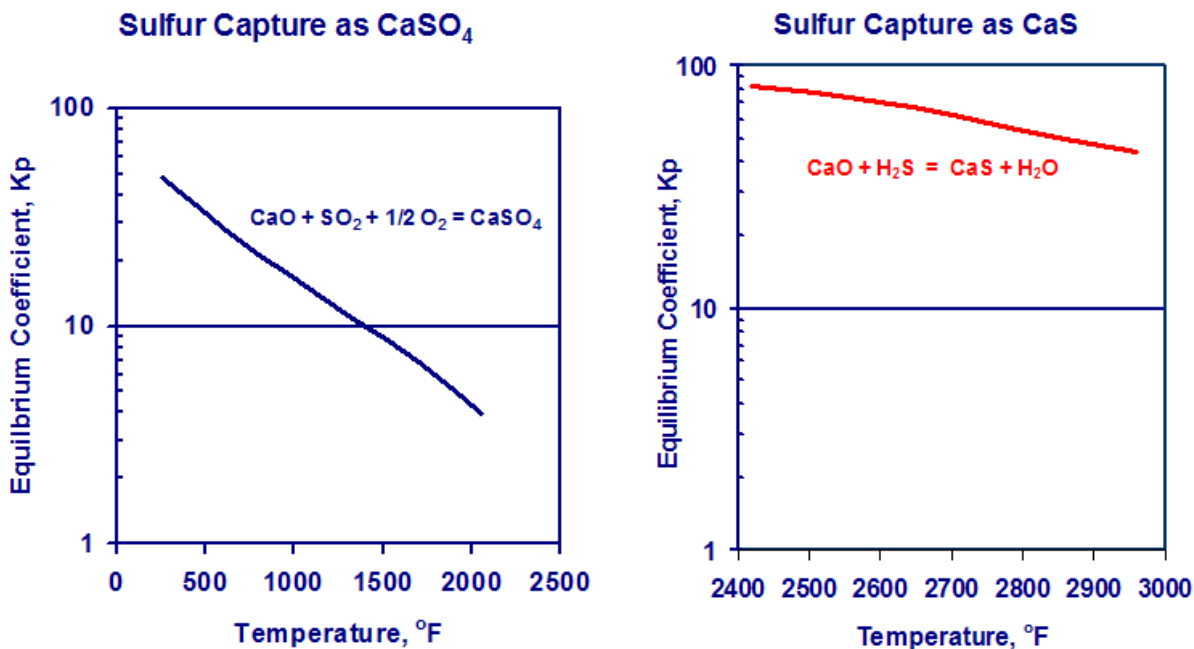


Figure 7. Equilibrium coefficients for sulfur capture in oxidizing and reducing atmospheres.

Potential Increase in Boiler Performance

Assuming one per cent of coal sulfur goes to SO_3^- in a conventional boiler, when using a 3-wt% sulfur coal it would yield 30 ppmv of SO_3 . In limestone furnace injection tests by others⁵, although only 50% of the SO_2 was removed 90% of the SO_3^- was removed. Assuming 90% of the SO_3^- is removed with the gasifier-combustor, the acid dew point would drop from 298°F to 256°F. This would allow an enlargement of the air preheaters to recover more heat from the boiler flue gas and increase overall efficiency by around 1.0%.

Further, the gasification-combustion system can be operated with as low as 10% excess air rather than the 15 - 20% usually required for good combustion. This would improve boiler performance by 0.5% through reduction of stack gas heat losses. So for a unit having a heat rate of 10,000 Btu/kWhr, after an Ashworth Gasifier retrofit the heat rate would be 9850 Btu/kWhr.

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 can no longer do that due to high carbon content. With the Ashworth Gasifier the high carbon conversion of the old excess air burners returns to provide a fly ash with 5-wt% carbon or less.

Coal-fired cyclone boiler slag is currently being used as a wear-resistant component in surface coatings of asphalt in road paving. Finer-sized slag can be used as blasting grit and is commonly used for coating roofing shingles. The gasifier bottom slag, low in carbon (<1.0%), appears to be ideal for those applications as well.

LINCOLN DEVELOPMENTAL CENTER DEMONSTRATION

The Ashworth Gasifier-Combustor demonstration ⁶ took place at the Illinois Department of Human Services, Lincoln Developmental Center in Lincoln, IL. The boiler house there consists of three boilers, Units #1 and #3 are coal-fired stoker boilers and Unit #2 was a coal-fired stoker that was converted to natural gas. The Center seldom used the gas-fired unit due to the high price of natural gas compared to coal. Unit #2 was therefore selected as the host boiler for the retrofit (see Figure 8).



Figure 8. Ashworth (40×10^6 Btu/hr) Gasifier-Combustor System.

The retrofit consisted of installing a water jacketed gasifier, a second stage partial oxidization unit and an overfire air system, 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 was 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.

Pulverized coal (70% minus 200 mesh) and limestone (80% minus 200 mesh) was fired into the slagging gasifier 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 9) for disposal to a conventional landfill.

Second stage air was added to the hot fuel gas (equivalent to 120-130 Btu/scf in energy content) 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 10) for particulate removal and then to an atmospheric stack.



Figure 9. Gasifier Slag to Roll-Off Container.



Figure 10. Baghouse.

Test Results at Lincoln

The gasifier was designed for 40 million Btu/hr coal heat input, but the steam requirement was only half of that. This was because the facility was shut down just before startup. Even at half load the facility would run out of boiler makeup water in around 4 hours 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.

The gasifier 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 problem we did experience with the gasifier operation was that the slag tap would sometimes plug. It was found that the 1st Stage was not hot enough at an SR of 0.60 due to the limit on feed throughput. We found that when the 1st Stage temperature was maintained at 2600 °F and up, the slag plugging problem went away.

The gasifier design modifications were successful in increasing sulfur capture and reducing NO_x emissions compared to the FPC CAIRE combustor. A CEMS unit was used to measure nitrogen oxides, sulfur dioxide, carbon monoxide and oxygen.

NO_x Emissions

Nitrogen oxides (NO_x) emissions were as low as 0.095 lb/10⁶ Btu (68 ppmv @ 3 vol % O₂ dry) with coal firing using the three-stage combustion technique. The unit is gas capable and when firing natural gas only at similar conditions, NO_x emissions were 0.048 lb/10⁶ Btu (44 ppmv @ 3 vol % O₂ dry).

SO₂ Emissions

Sulfur dioxide (SO₂) emissions were reduced to 1.70 lb/10⁶ Btu for a high sulfur Illinois coal that yields uncontrolled SO₂ emissions of 6.14 lb SO₂/10⁶ Btu - a 72 % reduction. This reduction was achieved with a limestone Ca/S ratio of 0.85 providing for 85% utilization of the calcium injected.

CO Emissions

With coal firing only, carbon monoxide (CO) emissions were 15 - 30 ppmv @ 3 vol % O₂ dry compared to natural gas firing at similar conditions of 10 - 20 ppmv @ 3 vol % O₂ dry.

Carbon Conversion

The carbon conversion achieved was 99 wt. %. Carbon in the gasifier slag was 0.1 to 0.2-wt % and carbon in the fly ash was less than 5 wt %. The three-stage combustion technique yields a light gray fly ash like that obtained prior to the advent of low NO_x burners. Low NO_x burners yield carbon in fly ash that in many cases are in the 10 – 15 wt % range, making it unsuitable for cement manufacture. Activated carbon injection for mercury control also makes fly ash unsuitable for making cement.

Mercury Reduction

The Detroit Edison Fuel laboratory analyzed all of the solids streams entering and exiting the Ashworth Combustor system. Mercury reduction has been surprisingly high (93 to 100%) based on solids analyses. Here is the run data when 93.6% of the mercury was captured. In addition, what is also impressive is that the mercury captured does not leach when using the Toxicity Characteristic Leaching Procedure (TCLP).

<u>Hg In:</u>	Coal	=	0.075	ppmw Hg
	Limestone	=	0.03	ppmw Hg
<u>Hg Out:</u> Slag		=	4.69	ppmw Hg
	Fly Ash	=	0.02	ppmw Hg

93.6 wt% reduction

Standard Leach (TCLP) Tests:

Slag = 0 mg/l Hg, Fly Ash = 0 mg/l Hg

Other Air Toxics and Halides Reductions

From trace element analyses of other metal toxics in the slag and fly ash it looks as though nearly all of the antimony, arsenic, barium, beryllium, cadmium, cobalt, chromium, copper, lead, molybdenum, nickel, selenium, silver and vanadium are captured and around 80% of the manganese. The toxicity characteristic leaching procedure (TCLP) tests showed the regulated concentrations of Ag, As, Ba, Cd, Pb, and Se in the leachate were all well below the EPA regulatory limit for both the fly ash and slag. Laboratory analyses performed on the fly ash also showed 26% fluoride capture and 14% chloride capture by the fly ash with a Ca/S ratio of 0.85. With higher Ca/S ratios halide capture should increase.

Renewable Energy Use

The EPRI Biomass Interest Group (BIG) provided funds to the project because of its interest in using slagging gasifiers to increase the percentage of biomass that can be fired into a boiler. Some of the reactive alkalis (Na, K) in biomass 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 it could replace some 10 -15% of the coal, thus conserving our fossil fuel resources and help a utility meet proposed renewable energy standards.

RETROFIT APPLICATION

ClearStack, with PROMECON USA, Alstom Power, Sargent & Lundy, and United Conveyor completed an engineering assessment ⁷ of retrofitting the Ashworth Gasifier-Combustor to the Ameren Energy Generating (AEG) Hutsonville Boiler #6, Unit #4 (77 MWe). The purpose of the engineering assessment was to determine if the Ashworth Gasifier-Combustor technique could be physically retrofit to the boiler and if so what boiler performance impacts would result.

Boiler #6 is a Combustion Engineering tangentially fired boiler, producing 1500 psig/1005 °F superheated steam with a gross heat rate of 10,000 Btu/kWhr. It is a natural circulation boiler that has both superheat and reheat. The boiler feeds a GE steam turbine generator. Boiler #6 has three Raymond 573 coal pulverizers and the pulverized coal is air swept to three burner levels located on all four corners of the boiler furnace. It has a Westinghouse Distributive Control System (DCS) that can be modified to run the three-stage combustion system. Each unit has a Continuous Emissions Monitoring system (CEMS).

Physical Retrofit

The right rear corner of the boiler furnace was very congested so it was decided to evaluate three-corner firing with the Ashworth Gasifiers. Alstom completed Computational Fluid Dynamic (CFD) modeling based on three-corner firing and found that the tangential swirl, although skewed somewhat was still established in the furnace and would yield a viable firing configuration.

Temperatures

The temperatures in the furnace would be a little different. Since the combustors are water-cooled and remove heat external to the boiler, the flue gas entering the convective passes reduces by 65-70 °F below the baseline modeling case. However, if the 2nd and 3rd stage air entries of the Ashworth combustor are designed to be tiltable the fireball can be raised up to increase the exit temperature. Modeling was completed based on firing the same Illinois Bituminous coal for both the gasifier and baseline cases

Heat Flux

Several differences were noted between the base case and the gasifier case. The lower section of the furnace (the hopper) has significantly less heat flux with the gasifier operation. This is primarily due to the location of the gasifiers shifted upward relative the current windbox. The coal particles in the base case circulate in the hopper and burn with combustion air, while for the gasifier; the particles leaving the gasifier are essentially carbon free. The gasifier, compared to baseline, shows a higher flux in the firing zone where the hot gases enter the furnace cavity. However, the heat absorption per wall is similar.

Gasifier-Boiler Integration

Two solutions were found for integrating the gasifier cooling water into the boiler water circulation system. One was to by-pass the last extraction steam boiler feedwater (BFW) heater and use the gasifier waterwalls to heat up the water. The extraction steam, by going through the steam turbine and not the BFW heater would increase power out, raising the capacity of Unit #4 by some 4%; the heat rate however would increase by around 120 Btu/kWhr. The other method was to pass the water from the economizer outlet through the gasifier waterwalls before going into the steam drum. With this case there would be little change in capacity or heat rate.

Swirl Vortex

Despite only three gasifiers being located on the furnace, not four, the flow vortex characteristic of the tangential firing was established. The velocity of the jets entering the furnace for the baseline case is near the 200 ft/s level, while the gasifier case has velocities above that level. The Separated Over Fire Air (SOFA) jets for the gasifier case provide a useful centering action to the flow.

NO_x Emissions

Using NO_x prediction tools, NO_x emissions for the baseline case and gasifier case were generated. The physical models enabled prediction of NO_x from thermal, prompt and fuel mechanisms. The baseline NO_x calculations were based on a 20% excess air level. For these NO_x calculations, it was assumed that nitrogen was evolved proportionally in the devolatilization and char combustion phases. The NO_x concentrations comparison for the base case and gasifier case is shown in Figure 11.

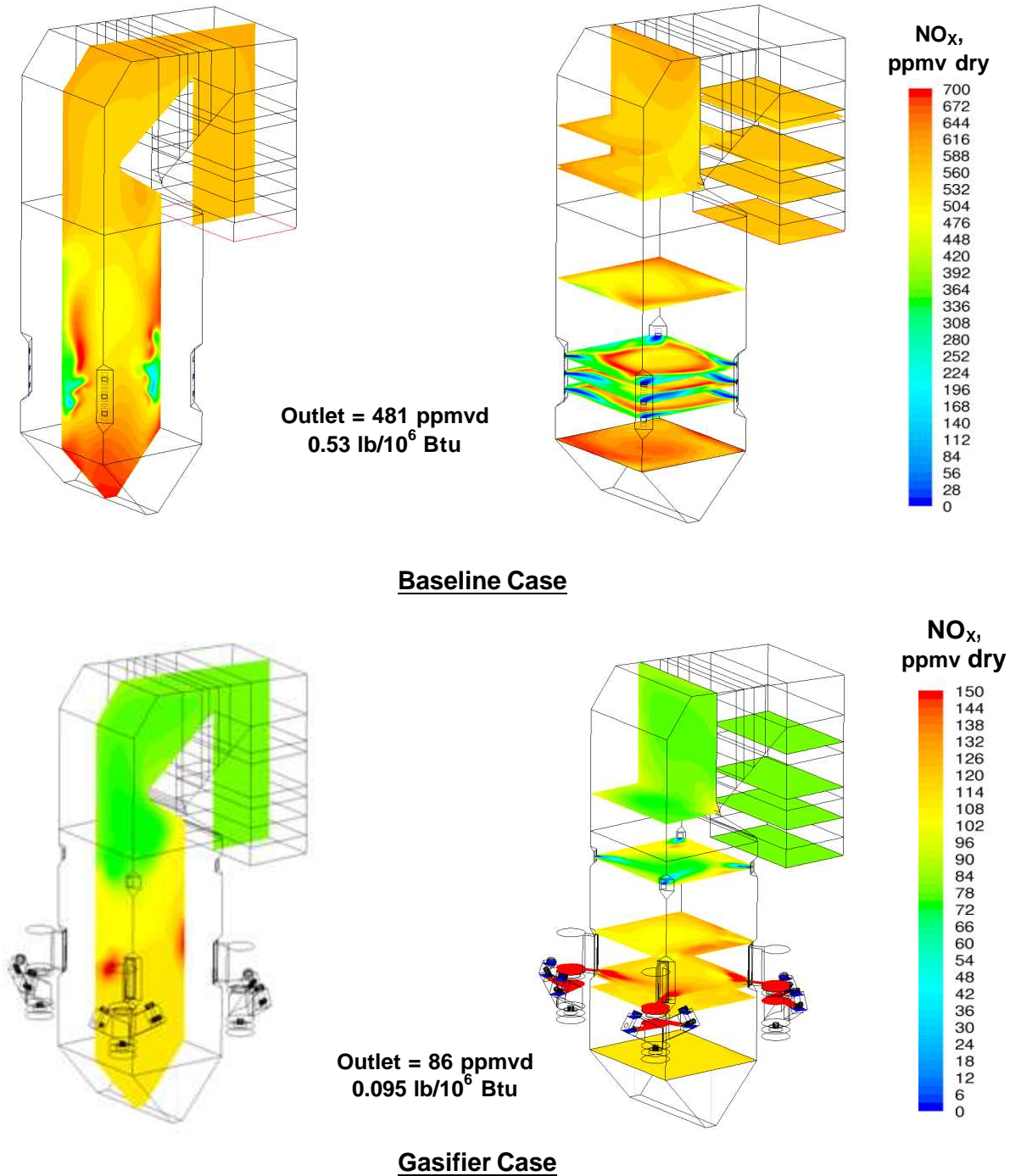


Figure 11. Nitrogen oxide emissions comparison.

Under identical conditions, the gasifier case produced 86 ppmvd of NO (0.095lb NO_x/10⁶ Btu) on a volume-dry basis. This compares to 481 ppmvd or 0.53 lb NO_x/10⁶ Btu for the base case. The Alstom modeling was very close to that projected by the Energy and Environmental Research Corporation model.

Carbon Monoxide

With staged oxidation there is ~3vol% CO in the zone below the SOFA level to prohibit NO_x formation. In the upper furnace at the SOFA level, the CO levels drop rapidly from the mixing of excess air and final burnout for the gasifier case. The baseline case yielded around 100 ppmv of CO. The gasifier case showed CO levels in the single digit range (7-8 ppmv @ 3% O₂). This CO level is about the same as exhaled human breath when compared at the same oxygen level.

Oxygen Distribution

The base case has zones about the perimeter exceeding 12% oxygen, while the gasifier case has essentially no O₂ in the mid-furnace zone, except for the slot air adjacent to the sides of the gasifier outlets. The SOFA air jets mix very well with the furnace gases and result in very uniform O₂ levels at the economizer outlet. In fact, O₂ distribution was more uniform for the gasifier than the baseline case, where remnants of the radial stratification remained in the backpass.

ECONOMIC COMPARISON W/SCR PLUS WET SCRUBBER PLUS HG REMOVAL

An economic comparison of the Ashworth Gasifier-Combustor retrofit compared to a Selective Catalytic Reduction (SCR) system plus a sulfur dioxide Wet Scrubber (WS) plus an activated carbon system with bromine added (AC-Br) for mercury removal was completed. The AC-Br works better when using electrostatic precipitators than activated carbon without bromine. A 180 MWe coal-fired boiler was used as the basis for the retrofits. The SCR + WS + AC-Br combination was designed to match the environmental performance of the Ashworth Gasifier-Combustor, 72% sulfur removal, NO_x reduction to 0.10 lb/million Btu and mercury reduction of 90+%. The capital and operating costs were based on \$2008 U.S. dollars, see Table 1 below. The cost of limestone used was \$25/ton, anhydrous ammonia \$680/ton⁸ and bromated activated carbon \$1/lb⁹.

TABLE 1. 180 MWe APPLICATION COST COMPARISON

Technology	Capital Cost	Incremental Operating Cost/Yr
Ashworth Gasifier	\$24,150,000	\$5,195,000
Selective Catalytic Reduction	\$30,610,000	\$6,290,000
SO ₂ Wet Scrubber	\$32,450,000	\$8,230,000
Hg Carbon Injection	\$1,500,000	\$1,510,000
Total	\$64,560,000	\$16,030,000

The multi-pollutant reduction Ashworth Gasifier-Combustor is seen to be some 38% of the capital cost and 33% of the operating cost compared to the SCR + WS + AC-Br technologies. This analysis does not include any credit for other air metal toxics that are removed by the gasifier. The Ashworth gasifier-Combustor also allows a utility to sell its fly ash to the cement industry while activated carbon injection eliminates that option.

CONCLUSION

If you call carbon dioxide a pollutant, you might as well call oxygen a pollutant. Increased CO₂ increases plant growth and oxygen in the atmosphere which is a good thing for an ever growing world population. The Ashworth Gasifier-Combustor is a clean “green coal” technology because it reduces multi-pollutants (NO_x, SO₂, Hg, halides and other air toxics) associated with coal combustion. If we remove the real pollutants then coal is the greenest fuel we can use.

Unlike SCR the Ashworth Gasifier-Combustor reduces rather than increases sulfur trioxide (SO₃) emissions that create opacity (bluish-white haze) and acid rain problems. It also does not require noxious chemicals (NH₃), as does SCR. There are no vapor plumes as seen with wet scrubbers. Further, it does not increase the net heat rate of the unit like selective catalytic reduction and wet scrubbers do because of increased auxiliary power requirements resulting from increased pressure drops through the system.

This staged gasifier-combustor 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 plus Activated Carbon injection. Sulfur dioxide emissions are significantly reduced with the Ashworth Gasifier and that will allow many utilities to use lower cost near-by high sulfur coal.

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