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Project Title: **CORRELATE FLY ASH CAPTURE OF Hg WITH ASH CARBON CONTENT AND FLUE GAS TEMPERATURE**

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ABSTRACT

In reports to Congress, the U.S. Environmental Protection Agency (EPA) has identified potential adverse health effects of mercury (Hg) emissions from coal-fired utilities. It has been determined that approximately one-third (50 tpy) of all U.S. anthropogenic Hg emissions (150-160 tpy) come from coal-fired utilities. Consequently, EPA is considering utility Hg emission regulations, which could have a costly effect on the Illinois coal and utility industries.

Currently, there is no universally accepted Hg control technology for coal-fired utilities. Studies have shown that fly ash can remove Hg, with the extent of removal increasing with an increase in fly ash carbon content and a decrease in flue gas temperature. However, the data base with fly ash is limited. This project was conducted to expand this data base. Variables studied were the fly ash carbon content (2 to 16 wt % C) and flue gas temperature (195 to 325 °F).

The project team used CONSOL's coal combustion pilot plant (1.5 MM Btu/hr). The facility is designed to simulate the operation of an industrial or utility coal-fired boiler. The combustor fired an Illinois coal (CONSOL's Rend Lake Mine) during the test program. Fly ashes obtained from Illinois utility and industrial boilers were injected into the combustor duct and collected in an electrostatic precipitator (ESP). Mercury removals were measured across the duct and ESP. The flue gas temperature was controlled using both humidification with an in-duct atomization nozzle and the pilot plant heat exchanger. The research team used state-of-the-art solid and flue gas mercury sampling/analytical methods to determine mercury removal and speciation.

The research has shown that fly ash can capture a substantial portion of flue gas Hg. Mercury removals ranged from 30-100%. The effect of flue gas temperature on Hg capture varied depending on the amount of carbon (C) in the ash. With the low carbon ashes (2 to 8 wt % C), the Hg removals increased from 30-60% at 270 °F to 80-90% at 200 °F. With the high carbon ash (15 wt % C), Hg removal increased with increasing temperature: from 50-60% at 200 °F to 80% at 320 °F. The variation in temperature effect suggests different Hg capture mechanisms with different C ashes. With the exception of tests at 200 °F, the Hg removals increased with the ash C content. At 200 °F, the Hg removals (88-94%) were essentially constant with 3 wt % to 8 wt % C ashes. At 225, 275, and 325 °F, the removals ranged from 40-50% with 2 wt % C to 95-100% with 12-13 wt % C. The C content of utility boiler fly ash varies widely. A substantial number of boilers produce fly ash with C in the 1-3 wt % range. However, the C content can be as high as 35-40 wt %, depending on boiler type and boiler conditions.

EXECUTIVE SUMMARY

Under the 1990 Clean Air Act Amendments (CAAA), the U.S. Environmental Protection Agency (EPA) conducted a comprehensive study of hazardous air pollutant (HAPs) emissions from coal-fired utility plants. Of the 189 elements or compounds identified as HAPs, the majority were found to be captured with fly ash in particulate collection systems (ESPs, fabric filters). The exceptions are the more volatile elements or compounds which pass through the emissions control equipment and are emitted to the atmosphere. One of these materials is mercury (Hg). EPA¹ claims to have established a plausible link between Hg and adverse health effects. As a result, EPA is considering regulations to limit utility mercury emissions. These regulations could adversely impact Illinois coal use through an increased use of natural gas and/or the use of non-Illinois coals.

Presently, there is no commercially accepted technology for removing Hg from coal-fired utility flue gas. Tests conducted by CONSOL^{2,3} have shown that wet flue gas desulfurization systems remove up to 60% of the flue gas Hg at no extra cost. The majority of boilers do not have wet scrubbers, and must rely on ESPs for flue gas clean-up. These boilers would require dedicated Hg removal techniques. The dedicated Hg removal technologies would increase the cost to burn Illinois coal.

Lab^{4,5} and pilot plant^{6,7} studies have shown that fly ash has the capability to capture Hg; the mercury captured increased as the fly ash carbon content increased and the flue gas temperature decreased. If fly ash (already present in coal-fired flue gas) and flue gas humidification can be used to capture a significant portion of the Hg, this would provide a cost benefit to Illinois utilities, and help preserve Illinois coal markets. To expand the very limited data base on fly ash capture of Hg, CONSOL R&D conducted a Hg removal study in a pilot combustor equipped with flue gas humidification and an electrostatic precipitator. A correlation was developed between Hg removal and: 1) fly ash carbon content and 2) flue gas temperature.

The tests were conducted in CONSOL's 1.5 MM Btu/hr coal-fired combustor. The combustor is designed to simulate the operation of an industrial or utility boiler. For the test program, the combustor fired an Illinois coal (CONSOL's Rend Lake Mine located near Sesser, IL). Fly ashes obtained from Illinois industrial and utility boilers containing different carbon contents were injected into the combustor ductwork and collected in a pilot scale electrostatic precipitator (ESP). The Hg removal was measured across the combustor duct work (with 1.4 to 2.7 seconds flue gas residence time) and across the ESP. An in-duct atomization nozzle and combustor heat exchanger was used to control the flue gas temperature. The flue gas was sampled at the duct inlet and ESP exit to determine Hg removal across the pilot-scale ESP. The flue gas Hg concentration was determined using the Ontario Hydro ASTM Draft Method, which has been determined by DOE, EPRI,⁸ and others⁹ as the best method for determining both total and speciated mercury in flue gas. In addition to flue gas sampling, the injected fly ash and recovered ESP solids from each test were sampled and analyzed to confirm the Hg removals across the duct and ESP.

Various fly ashes obtained from Illinois industrial and utility boilers were evaluated in this study. The unburned carbon content (LOI) of the ash varied from 2-16 wt %. The low carbon represents a normal utility boiler operation, while the high carbon represents a low NOx burner operation. The use of low NOx burners has the disadvantage of generating fly ash with higher LOI, but this type of fly ash can be advantageous for Hg removal. For example, high carbon has a detrimental effect on the pozzolanic quality of fly ash, but can provide more active sites for absorption of Hg. Flue gas temperatures ranging from 195 °F to 325 °F were studied. A temperature of 325 °F is normally found downstream of the air preheater without flue gas humidification. The temperatures less than 325 °F represent varying degrees of flue gas humidification.

The results of this study show that fly ash, along with flue gas temperature reduction, is a potential Hg control technology. Mercury removals from 25-100% were obtained across the duct and ESP of the pilot combustor.

- The effect of flue gas temperature on Hg removal varied depending on the carbon content of the fly ash.

With the relatively low carbon (C) fly ashes (2 to 8 wt %), the duct/ESP Hg removal increased with decreasing flue gas temperature. In general, the removals increased from 30-60 % at 260-270 °F to 85-95% at 200 °F.

With 12 wt % C, the Hg removals (95-100%) were essentially constant over the temperature range of 220 to 320 °F.

With the high C ash (15 wt %), the Hg removal increased with an increase in temperature: 50-60% at 200 °F to 80% at 320 °F. The opposite trend with temperature may suggest a temperature-dependent chemical reaction with the higher C ash.

- With the exception of tests at 200 °F, the Hg removal increased with an increase in fly ash C content.
 - 200 °F: Mercury removals (88-94%) were essentially constant as the C content was increased from 3 wt % to 8 wt %.
 - 220-230 °F: Removals increased from 45% with 2 wt % C to 99% with 13 wt % C.
 - 265-275 °F: Removals increased from 50% with 2 wt % C to 98% with 12 wt % C.
 - 320-325 °F: Removals increased from 40% with 2 wt % C to 95% with 12 wt % C.

Mercury speciation (Ontario Hydro flue gas sampling) results showed that fly ash will capture both oxidized and elemental mercury. As much as 80% of the Hg fraction collected in the potassium chloride (KCl) impingers, assumed to be oxidized Hg, was removed across the duct and ESP. As much as 70% of the Hg⁰ fraction was removed. The removals of oxidized and/or elemental Hg were actually higher than the values presented, since there was also a reduction in the particulate Hg (Hg captured by the sample train filter) from the duct inlet to the ESP exit. The particulate Hg can be oxidized or elemental Hg.

The results of this program show that fly ash, in combination with flue gas temperature reduction, has the capability to remove a substantial portion of flue gas Hg. These results, along with other fly ash studies,⁴⁻⁷ provide the Illinois utility industry with a potential low-cost retrofit Hg control technology, which could be utilized in the event of EPA regulations on coal-fired Hg emissions.

References

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OBJECTIVES

The goal of this project was to determine the mercury reduction due to fly ash flue gas humidification. The majority of Hazardous Air Pollutants (HAPs) derived from coal-fired utilities are captured with fly ash in existing particulate collection equipment (ESPs, fabric filters). The few exceptions include Hg, which, because of its volatility, remains in the vapor state and is found at the exit of the particulate collection devices. Since the Environmental Protection Agency (EPA) has indicated a plausible link between Hg emissions and adverse health effects, Hg emissions from coal-fired utilities may be regulated.

Currently, there is no commercially accepted control technology for coal-fired utilities. Recent studies¹⁻⁴ have shown that fly ash can capture Hg. The capture percentage increases with an increase in fly ash carbon content and a decrease in flue gas temperature. However, the data on fly ash capture of mercury are limited. The objective of this test program was to expand the data base and correlate Hg capture with: 1) fly ash carbon content, and 2) flue gas temperature. The program involved measurement of Hg capture across the duct and ESP of CONSOL's pilot scale (1.5 MM Btu/hr) coal combustion pilot plant. Fly ashes with carbon contents ranging from 2 wt % to 16 wt % were injected into the combustor duct and collected in the ESP. Flue gas temperature was varied between 195 °F and 325 °F. Mercury removal was determined by state-of-the-art flue gas sampling procedures at the duct inlet and at the ESP exit. Fly ash and ESP solids were analyzed to confirm mercury removal.

INTRODUCTION AND BACKGROUND

As a result of the 1990 Clean Air Act Amendments (CAAA), hazardous air pollutants (HAPs) such as Hg may be regulated in the near future. An Hg regulation would be a threat to the Illinois coal industry because additional control costs would make switching to natural gas or Powder River Basin coal a cheaper control option. A technology that minimizes the cost of Hg control can help preserve Illinois coal burn, thereby preserving mining employment.

Tests conducted by CONSOL R&D have shown that wet flue gas desulfurization scrubbers remove up to 60% of the flue gas Hg at no added cost.^{5,6} However, the majority of boilers must rely on ESPs for flue gas clean-up, and would require dedicated mercury control techniques. Supplemental and dedicated controls would increase the cost to burn Illinois coal.

Activated carbon injection has been shown in lab^{7,8} and pilot scale^{3,9} studies to be an effective Hg control technology. However, control costs for this type of technology have been estimated at \geq \$50,000 per lb of Hg removed. Lab,^{1,2} pilot-scale,^{3,4} and full-scale utility^{5,6} studies have shown that fly ash can capture a significant portion of coal-fired flue gas Hg. Preliminary studies have indicated an increase in Hg capture with an increase in fly ash carbon content and a reduction in flue gas temperature. If flue gas humidification and relatively high carbon-containing fly ash can remove a significant portion of the flue gas Hg, the cost benefits to the Illinois utilities could preserve Illinois coal markets. The fly ash-humidification process could provide a mercury removal technology for systems with and without wet scrubbers, and

eliminate the need for fuel switching or blending with non-Illinois coals. The goal of this project was to expand the extremely limited data base on fly ash capture of Hg.

Reduction of flue gas temperature, by humidification or heat exchangers downstream of the air-preheater, presents the possibility of combined emissions control, i.e., removal of both Hg and SO₂. Economics improve for dry sorbent injection SO₂ control as the approach to the flue gas dew point decreases.¹⁰ The beneficial effect of lower temperature, or a closer approach to the dew point, has been seen for Hg control with fly ash or activated carbons.^{3,11} Calcium-based sorbents, such as hydrated lime, have been shown to efficiently capture not only SO₂, but also Hg.^{12,13} The combination of flue gas humidification, duct injection of lime, and utilization of existing fly ash presents a possible process for combined emissions control, and a scenario for minimizing the cost impact of environmental regulation on Illinois coal-fired boilers. The addition of lime would serve to protect ESPs and downstream equipment from corrosion at temperatures below the acid dew point.

The results of this project, along with existing data on fly ash capture of Hg, will provide the Illinois utility industry with valuable information in evaluating the use of fly ash and flue gas humidification as a technology to remove hazardous air pollutants such as Hg.

EXPERIMENTAL PROCEDURES

Combustor Test Facility

CONSOL's 1.5 MM Btu/hr (125 lb/hour coal feed) combustor research facility simulates the operation of a commercial utility or industrial boiler. The unit consists of a pulverized coal feed system, bottom ash pit, firebox, radiant section, nose section, convection section, duct work, and particulate collection systems (ESP and fabric filter). Pulverized coal is fed to four firebox burners using four micro-processor controlled gravimetric feeders. The firebox can be configured to simulate opposed-firing, tangential-firing, or cyclone-firing. The radiant section contains an air-cooled tube array to simulate boiler water walls. From the top of the firebox, the flue gas enters the convection section, which utilizes a water-cooled jacket to reduce flue gas temperature prior to fly ash collection. The convection section consists of nine passes. Each pass is approximately 10.5 ft long, and connected by 180° elbows. A section of ductwork, approximately 35 ft long, connects the convection section to the ESP. The convection section and ductwork are constructed of 8" pipe. Diagrams of the combustion pilot plant and ESP facility are presented in Figures 1 and 2.

A pilot-scale ESP was used for flue gas fly ash collection. The ESP consists of three zones, each zone equipped with two plates and four wires. Each zone is 36" long x 60" high. The total collecting plate area of the three zones is 90 ft². Each zone is equipped with two pneumatic rappers for removing dust from the plates and two pyramidal dust collection hoppers. The ESP is equipped with an ash removal and collection system, consisting of motorized rotary valves underneath the dust hoppers, and an external ash collection cyclone and vacuum source. The ESP is equipped with an outside wall electrical heating system to maintain the desired gas temperature. A detailed diagram of the ESP is presented in Figure 3.

The 35 ft section of ductwork between the convection section and the ESP provides 1.4 to 2.7 seconds gas residence time, depending on coal feed rate, combustion air feed rate, and duct temperature. Mercury removal in this study was measured across this section of the duct plus the ESP. At the end of the first pass of the nine pass convection section (Figure 2), the system is fitted with an enlargement to remove a large percentage of the fly ash coming from the firebox. The ash collection box is employed since many of the combustor test programs are solely concerned with firebox operation (flame characteristics, combustion efficiency, slagging, etc.), and are not concerned with downstream ESP or baghouse particulate removal efficiency. This ash collection box is 9.5" wide x 36" long x 41.5" high (8.2 ft³). The amount of firebox (Illinois coal) ash passing through this enlargement and reaching the duct/ESP section of the facility varied depending on firebox operating conditions (coal and combustion air feed rates). The different LOI fly ashes, obtained from Illinois industrial and utility boilers, were injected downstream of the convection section (into the duct inlet) using a volumetric screw feeder. Consequently, the ashes studied for Hg capture in the duct and ESP were a mixture of firebox and different Illinois ashes. The fly ash feeder was mounted on a floor scale, so the total weight of the ash fed during a given time period was known. The ash was discharged from the feeder into an eductor feeder from which the ash was pneumatically transferred with air through flexible tubing to the duct inlet. The fly ash was injected at a rate that simulated typical flue gas solids loading in a utility boiler (2 to 4 gr/scf). The temperature in the duct and ESP was partially controlled by an atomization nozzle located in the 7th pass of the 9-pass convection section, prior to the duct inlet. The nozzle water pressure was varied to control the amount of water spray. Temperature control was aided by, and often completely controlled by, the water-cooled jackets of the combustor convection passes. The duct and ESP are electrically heat-traced and insulated. There were temperature probes located at various points in the duct and ESP, so the temperature could be monitored and maintained at the desired setting.

Combustor Operating Conditions

It would have been desirable to conduct the entire Hg removal program under constant combustor operating conditions. However, it was necessary to coordinate the ICCI Hg removal program with an on going program regarding boiler corrosion from Illinois coals. The combustor corrosion program involved different firebox conditions of coal firing rate and amount of excess combustion air, as summarized in the following table:

Coal Feed, lb/hr	% Excess Combustion Air	Flue Gas Flow, dscfm
84	7 - 16	211 - 241
84	18 - 23	250
126	1 - 14	320 - 330
126	15 - 25	348 - 350

The Hg removal tests, along with the corresponding firebox conditions and flue gas properties, are presented in detail in Table 1. The flue gas moisture was generally in the 7 to 8 vol % range typical of a coal-fired boiler flue gas. There was a test week (Table 1) when the flue gas moisture was higher (10 to 18 vol %). This was due to a small leak in the cooling jacket of one of the convection passes, resulting in a portion of cooling water entering the flue gas stream.

Hg Removal Test Plan

This study involved the evaluation of coal combustion fly ash for removal of flue gas mercury (Hg). Studies have shown that fly ash has the capability to remove a significant fraction of the Hg in flue gas, with the removal increasing with an increase in ash carbon content and a decrease in flue gas temperature. The study evaluated Hg removal with seven Illinois coal fly ashes containing carbon concentrations between 2% and 16 wt %. The ashes were injected into the combustor ductwork and collected in the ESP. Flue gas temperatures of 195 °F to 325 °F were studied, with the program focusing on four temperatures: 200, 225, 270, and 325 °F.

The tests were conducted in CONSOL's 1.5 MM Btu/hr coal combustion research facility. The combustor fired an Illinois coal (CONSOL's Rend Lake Mine) during the study. The Hg removal was determined across the combustor duct plus electrostatic precipitator (ESP). The research combustor is equipped with an ESP or fabric filter for particulate control. The ESP was chosen for this study, since the majority of utility plants use ESPs. Mercury removal was determined by flue gas sampling at the duct inlet (prior to fly ash injection and flue gas humidification) and at the ESP outlet. Collection and analysis of the feed coal, injected fly ash, and recovered ESP ash were conducted to confirm mercury removals. Standard pitot-tube and particulate measurement (EPA Method 5) tests were conducted in the duct prior to each test day to determine the flue gas flowrate, and the amount of fly ash injection required for a reasonable solids loading. State-of-the-art sampling and analytical procedures were used for the flue gas and solid samples.

Daily Test Plan

Normally two tests were conducted in a 9-10 hour period. A typical test day chronology is outlined below:

<u>Time</u>	<u>Activity</u>
0530-0700	Conduct pitot-tube flue gas velocity measurements Conduct EPA Method 5 flue gas particulate measurements
0700-0900	Prepare flue gas sampling trains Establish nozzle water flows Establish fly ash feed rate Line out duct and ESP at desired temperature Sample feed coal and fly ash feed

- 0900-1030 Conduct gas sampling at duct inlet
 Conduct gas sampling at ESP exit
- 1030-1230 Empty ESP and collect solid samples
 Recover gas sampling solutions
 Prepare flue gas sampling trains
 Change conditions for 2nd test
 Establish nozzle water flows
 Establish fly ash feed rate
 Line out duct and ESP at desired temperature
- 1230-1400 Conduct gas sampling at duct inlet
 Conduct gas sampling at ESP exit
- 1400-1530 Empty ESP and collect solid samples
 Recover gas sampling solutions

Test Materials

The coal burned during the Hg test program was an Illinois coal. The coal was obtained from CONSOL's Rend Lake Mine located near Sesser, IL, Jefferson County. The coal is part of the Herrin (No. 6) Illinois coal seam. The coal, as received, was ground on site to pulverized-coal-fired power generation size using a one ton per hour Williams bowl mill. The coal was stored in twenty ton silos under inert gas until ready for use. The coal was sampled and analyzed using standard ASTM methods. Detailed analyses of the ground coal are presented in Table 2.

The fly ashes evaluated in this study were obtained from three utility boilers and one industrial boiler, all located in Illinois. The coals burned in the boilers were from either the Springfield (No. 5) or Herrin (No. 6) Illinois coal seams. Three 55-gal drums of ash were obtained from each site. The three drums obtained from the utility boilers contained ash taken from three different ESP fields. Taking samples from different fields provided a wider variety in ash carbon contents. The ash obtained from the industrial (stoker) boiler was a mixture of bottom ash, cyclone ash and ESP ash. The industrial boiler ash mix contained a significant amount of large size particles, and consequently required on site grinding to obtain a final product of typical ESP ash size. The utility ESP fly ash did not require grinding. Air drying was conducted on certain fly ashes if it was felt that the surface moisture was high enough to cause feeding problems during the test program. After carbon analysis of the various ground and dry ashes, blending was conducted to obtain seven ash samples with a wide range of carbon contents. Some samples contained ash from a single utility (industrial) site, and others from two different sites. The blending was done using an end-over-end 55-gal drum mixer. After blending, standard sampling/analytical procedures were conducted on each ash sample to ensure a homogeneous feed stock. Detailed analyses of the ash blends used in this study are presented in Table 3.

Sampling Locations, Procedures and Analytical Requirements

The following contains a discussion of all the pilot combustor sampling streams.

1. **Coal Feed to Combustor.** A representative sample of the feed coal was taken from the research combustor's gravimetric feeder tote bin. After standard ASTM riffing and sampling, the coal sample was analyzed for ultimate and proximate analysis, Hg, total Cl, particle size, and major ash elements.
2. **Fly Ash Feed to Duct.** The fly ashes received from Illinois utility and industrial boilers were dried, ground, and blended as described previously. The ash blends were screened through a 10 mesh screen prior to testing to remove foreign particles or agglomerated ash which could plug the ash feeder. A sample of each screened ash blend was taken from the drums using standard ASTM procedure, and analyzed for ultimate and proximate analysis, Hg, particle size, and major ash elements.
3. **ESP Ash.** After each test, rappers were applied to the ESP to remove ash from the wires and plates. The solids in the ESP hoppers were transferred to a 55-gal drum by the ESP ash collection system. After mixing, and sampling, the ashes were analyzed for Hg.
4. **Flue Gas Streams for Hg.** The flue gas was sampled prior to the duct inlet (4th pass of the 9-pass convection section) and at the ESP exit using the Ontario Hydro train. Evaluation of this train by EPA, DOE, EPRI, and others as a method to provide total and Hg speciation data has been promising. In this procedure, gas is extracted from the flue gas stream. The gas is pulled through a heated glass-lined probe and a quartz filter which removes the particulate matter. Total particulate mass loading is obtained from the filter weight gain. Probe and filter temperatures are maintained near the flue gas temperature at the sampling locations, with a minimum temperature of 248 °F. The flue gas exits the filter and is pulled through a series of chilled impingers. The first three impingers are filled with 1.0 N KCl, which preliminary tests indicate collect only the oxidized (ionic) Hg. The fourth impinger contains a 5-8% H₂O₂ solution to scrub out SO₂ to protect the permanganate impingers. This solution is analyzed for Hg, and any Hg found is accounted as elemental Hg. The fifth and sixth impingers contain permanganate solution to collect additional elemental Hg. The seventh impinger contains silica gel to protect the downstream sample pump and gas meter from moisture. The particulate matter and impinger solutions are analyzed by cold vapor atomic absorption.
5. **Flue Gas Streams for Gas Flow and Solids Loading Measurements.** A standard pitot-tube velocity measurement was performed daily to determine the flue gas flow rate. Measurement of the flue gas solids loading was performed daily using EPA Method 5. Both measurements were conducted in the duct between the fly ash injection point and ESP inlet, and were used to determine the fly ash solids loading attributed solely to the burning of an Illinois coal. With this information, the amount of injected fly ash needed for a practical flue gas solids loading could be determined. Carbon analyses were

conducted on EPA Method 5 filter solids to determine the total carbon in the flue gas ash from the firebox.

Analytical and Sampling Facilities

The analytical laboratory used to analyze feed and effluent samples from this program is located at the CONSOL R&D, Library, Pennsylvania facility. The laboratory contains all the necessary state-of-the-art equipment and instrumentation needed for coal and coal-derived product analyses.

The CONSOL R&D Technical Services field test team maintains state-of-the-art EPA-style stack sampling equipment for the measurement of effluents from coal-fired combustion systems.

RESULTS AND DISCUSSION

The combustor coal firing conditions and resulting flue gas conditions are presented in Table 1, the detailed Hg removal test conditions and ESP solids analyses and results are presented in Table 4, and the Hg removal test conditions and Ontario Hydro sampling results are presented in Table 5.

Effect of Coal Firing Rate on Flue Gas Hg Concentration

As mentioned, the Illinois (Rend Lake Mine) coal firing rate was varied during the Hg removal test program. As shown in Table 1, the two firing rates resulted in different flue gas Hg concentrations at the duct inlet section of the pilot ESP. Average weekly inlet Hg concentrations of 1.98 and 3.51 $\mu\text{g}/\text{dry m}^3$ were measured at the low coal feed rate (84 lb/hr), and 4.32 and 4.82 $\mu\text{g}/\text{dry m}^3$ were measured at the high (126 lb/hr) coal feed rate. Based on the Hg content of Rend Lake Mine coal, and assuming 100% evolution of Hg from the firebox, the flue gas Hg concentrations should range from 6.3 to 7.5 $\mu\text{g}/\text{dry m}^3$.

The lower-than-expected (and variation in) inlet Hg concentration may be attributed to the unique design of the combustor convection section, along with differences in flue gas flows, flue gas velocities, and flue gas temperatures at the two coal firing rates. Flue gas conditions at each coal firing rate are summarized in the following table:

Coal Feed, lb/hr	Flue Gas Flow, dscfm	Flue Gas Velocity, ft/sec	Solids Loading, gr/dscf	Inlet Hg, $\mu\text{g}/\text{dry m}^3$
84	211 to 250	13 to 18	0.3 to 0.6	1.98 to 3.51
126	320 to 350	20 to 25	0.6 to 0.9	4.32 to 4.82

The lower flue gas velocities (low coal firing rate) resulted in lower flue gas temperatures in the convection section of the pilot facility. Inlet Ontario Hydro measurements were made at average

convection pass flue gas temperatures of 710 °F and 770 °F for tests with 84 and 126 lb/hr coal feed, respectively. The temperature of the convection pass duct walls, as a result of the water-cooled jacket, can be as much as 300 °F lower than the flue gas temperature (measured in the center of the 8" duct). Because of the unique configuration of the convection pass (Figure 2), firebox fly ash has a tendency to impact on the 180° bends and drop out of the gas stream. This ash deposition is greater at the lower flue gas velocities. An average of 14% and 27% of the coal fly ash reached the ESP at the low and high coal firing rates, respectively. In a full scale pulverized coal (PC) utility system, 60-70 % of the coal ash would normally reach the ESP. Although speculative, Hg loss could have occurred as a result of this ash deposition and the relatively low wall temperatures in the convection section. Also, each of the nine convection passes is connected by a 180° elbow (Figure 2), which would cause higher gas turbulence and more efficient gas/solid mixing than that found in a normal flue gas duct. Studies have shown that sorbent capture of Hg in a duct is limited by bulk gas mass transport, which can be improved by more turbulent contact between the sorbent and gas.¹² The configuration of the convection passes and the relatively low flue gas velocities are unique to the pilot combustor, and would not be a factor in a coal-fired utility.

Comparison of Ontario Hydro Flue Gas Sampling Results with ESP Ash Analyses

As shown in Figure 4, the majority of the Hg removal, based on recovered ESP ash analyses, are lower than those based on the Ontario Hydro method. This is understandable, because it was not possible to obtain a representative ESP sample during a Hg removal test period. For example, the ESP wires and plates were rapped and the ash removed from the collection hoppers minutes prior to a test, and immediately after conclusion of a test. However, because of the intricate construction of the ESP (Figure 3), it was not possible to completely remove all the ash during the pre-test clean out period. The ash remaining in the ESP at the start of a test was derived from a line-out period without Illinois ash injection; and would generally, because of lower ash solids loading, have a lower Hg concentration than that during an actual Hg removal tests. Also, the line outs generally involved a time period (1 to 3 hours) when the duct/ESP temperature was being reduced to the desired test conditions. With the lower solids loading and higher temperatures during line out, the actual test samples were "contaminated" with lower Hg containing ash. However, the ESP ash results presented in Figure 4 show a significant number of tests with high (50-90%) Hg removal.

The exception was the ESP samples collected during the first week of testing, where Hg removal was higher based on ESP solids analysis. This may have been because the combustor was idle for two weeks for maintenance prior to the start of this test program, and because the Rend Lake Mine coal is extremely high in chlorine (Cl) content. The Cl content was 0.58% (Table 2), versus 0.1 to 0.2% in other Illinois coals evaluated by CONSOL.^{5,6} Activated char evaluation tests conducted for the Illinois State Geological Survey (ISGS) in CONSOL's 500 scfm Air Toxics Control Pilot Plant showed extremely high Hg balances (>200%) when hydrogen chloride (HCl) was first introduced to the synthetic coal-fired flue gas.¹⁴ This was thought to be due to HCl reacting with, and helping remove, Hg deposited on the duct and/or baghouse walls of the pilot plant during previous tests. Mercury balances improved with time, indicating

that an equilibrium had been reached. The same phenomenon may have occurred during the first week of this test program in the combustor.

Since the ESP ash analyses are suspect, the Hg removals discussed in this report are based on the flue gas sampling/analytical results (Ontario Hydro train, Table 5), unless specified otherwise. The % Hg removals were calculated as follows:

$$\% \text{ Hg Removal} = (A - B) \times 100/A$$

where:

A = Average of the flue gas duct inlet Hg concentrations obtained during a week of testing.

B = Flue gas ESP exit Hg concentration from each test.

A weekly average was used as the common inlet Hg concentration, since combustor conditions did not change significantly during a test week (Table 1). An average inlet Hg value reduces the effect of any small analytical experimental error on results. Averaging, however, had an insignificant effect on the results.

Effect of Ash Carbon Content on Hg Capture

The results showing the effect of fly ash carbon content at various temperatures are presented in Figures 5 through 8. In general, the Hg removals increased with increasing ash carbon (C) content. The beneficial effect of carbon content has been observed in other studies with fly ash.^{1,2,4}

At 197 to 203 °F (Figure 5), there was a very small increase in Hg removal (88-94%) obtained by increasing the C content from 3 to 8 wt %. Fly ash with 15 wt % C gave only 56% removal; however, as will be discussed later, the high carbon ash was not as effective at low temperatures.

At 217 to 228 °F (Figure 6), the Hg removal increased from 46% with 2% C to 99% with 13% C. Again, the 15 % C ash gave low removal (52%) at these relatively low temperatures. The Hg removal (33%) was also low with fly ash Blend C. Even though Blend C has a fairly high carbon content of 9.1 wt % (Table 3), it did not appear to be as effective as ashes with lower C contents. This was especially true in tests 7 and 8 (Table 5) where a small amount of low-C firebox ash was present in the flue gas (Table 4). The important influence of the ash from the Illinois coal fired in the pilot combustor will be discussed later. The results with Blend C show that C content is not the only important factor in Hg control. Blend C was one of the coarser ashes studied (Table 3), and it is possible that the larger particle size had a detrimental effect on Hg capture efficiency. Studies with activated carbon have shown the beneficial effect of finer (higher surface area) sorbents.¹¹

At 265 to 276 °F (Figure 7), the Hg removal increased from 49% with 2 wt % C to 98% with 12 wt % C. Again, ash Blend C (9 wt % C) showed very low effectiveness: 27% Hg removal.

At 321 to 325 °F (Figure 8), the Hg removal increased from 38% with 2 wt % C to 97% with 10 wt % C.

Effect of Flue Gas Temperature on Hg Capture

The effect of flue gas temperature on Hg capture in the duct and ESP is presented in Figures 9 through 13. Although there is some data scattering, the results with 2, 4, and 8% carbon ashes (Figures 9, 10, and 11) generally show a beneficial effect of lowering the flue gas temperature, in the range of 200 to 320 °F.

With 2% carbon ash (Figure 9), the duct and ESP Hg removal increased from approximately 40% at 260 °F to 90% at 200 °F. With 4% carbon ash (Figure 10), the duct and ESP Hg removal increased from 50% to 60% at 270 °F to 90% at 200 °F.

With 8% carbon ash (Figure 11), the duct and ESP Hg removal increased from approximately 65% at 270 °F to +90% at 200 °F. The curve in Figure 11 was drawn ignoring the results obtained with ash Blend C. As previously discussed, Blend C showed lower Hg capture efficiency than the other ashes tested in this program.

The increase in Hg capture with a decrease in temperature with the 2 to 8 wt % C ashes may suggest that a physisorption mechanism takes place between the Hg and active carbon sites in the ash. In lab studies with activated carbon, Krishnan¹⁵ shows a possible deactivation or depletion of active sites as the temperature was increased to 140 °C (284 °F). This deactivation also could apply to active sites in fly ash carbon and explain the significant decrease in Hg capture as the flue gas temperature was increased from 200 °F to 270-320 °F.

With the 12% carbon ash (Figure 12), decreasing the temperature from 320 °F to 220 °F had essentially no effect on results. Duct/ESP Hg capture was 99% and 95% at 220 °F and 320 °F, respectively. Although the data are limited, the results with the high carbon (14-15 wt %) ash appear to be different than those seen with the lower carbon (2 to 8 wt %) ashes (Figure 13). The duct/ESP Hg capture increased with temperature: from 50 to 60% at 200 °F to 80% at 320 °F. This behavior with the higher carbon may be due to the carbon form in the ash. Carbon forms differ in their physical and chemical properties due to differences in the arrangement and bonding of the atoms. The high carbon ashes were produced at somewhat different combustion conditions, and, consequently, may contain a different form of carbon than that found in the lower carbon ash. The increase in Hg capture with an increase in flue gas temperature indicates a possible temperature-activated chemical reaction taking place, as compared to a physical absorption with the lower carbon ashes. Unpublished studies in CONSOL R&D's 500 scfm Air Toxics Control pilot plant showed similar behavior with a high carbon (>20 wt %) ash. In these pilot plant studies, the capture of both elemental Hg (Hg⁰) and mercuric chloride (HgCl₂) increased substantially in the duct + fabric filter as the temperature was increased from 150 °F to 300 °F.

This study showed no correlation between flue gas humidification and Hg removal. In most of the tests at the lower flue gas temperatures, the water nozzle was not used. The convection

section cooling jacket was sufficient for maintaining the desired temperature. Additional studies are needed to determine if either water droplets or flue gas temperature reduction using a heat exchanger are the important factors.

Because of the unique configuration of the combustor test facility, as previously discussed, the Hg removals obtained in this program may be somewhat higher than would be obtained in an actual coal-fired utility plant. However, the results presented in Figure 14 show that Hg removals based on ESP ash analysis, which are felt to have a low bias, still show relatively high removals (50-80%) in a significant number of tests. The data, whether based on gas or solids analyses, confirm the results of other studies showing fly ash utilization and flue gas temperature reduction as a potential Hg control technology.

Mercury Speciation and Removal

Mercury (Hg) speciation at the flue gas duct inlet and ESP exit for the four weeks of testing is presented in Figure 15. The data shown represent the average inlet and exit Hg values for each week, as obtained by the Ontario Hydro flue gas sampling method. Mercury collected in the potassium chloride (KCl) impingers is assumed to be the oxidized species. Mercury getting through the KCl and collected in the hydrogen peroxide (H₂O₂) and potassium permanganate (KMnO₄) impingers is assumed to be elemental mercury (Hg⁰). Mercury collected on solids from the probe and filter (particulate Hg) can be either oxidized or elemental mercury.

1. Week 1

During test week 1, the combustor was operated at a low coal feed rate and high excess air (Table 1). The average duct inlet and ESP exit Hg concentrations were 1.95 and 1.18 $\mu\text{g}/\text{dry m}^3$, respectively, for a 39% Hg removal. Most of the removal is reflected in the estimated oxidized Hg species, the predominant species in the flue gas. The inlet and exit oxidized species were 1.59 and 0.94 $\mu\text{g}/\text{m}^3$, respectively (41% removal). The small amount of particulate (filter cake) Hg ($<0.2 \mu\text{g}/\text{m}^3$) in the inlet gas was essentially removed. Operating with high excess air would produce low carbon ash, and consequently, low Hg capture on the filter. Estimated elemental Hg was low ($<0.2 \mu\text{g}/\text{m}^3$) and essentially unchanged from inlet to exit. A high ratio of oxidized Hg to elemental Hg is not surprising in view of the high chlorine content of the feed coal. Mercury emission and control studies have strongly suggested the existence of mercuric chloride (HgCl₂) in flue gas containing hydrogen chloride (HCl) and/or chlorine (Cl₂).^{16,17}

2. Week 2

During week 2, the combustor operated at a high coal feed rate with low excess air (Table 1). The average duct inlet and ESP exit Hg concentrations were 4.34 and 0.13 $\mu\text{g}/\text{m}^3$, respectively (97% Hg removal). A large percentage of the flue gas Hg was particulate Hg, which was essentially 100% removed. Inlet and exit particulate Hg was 3.73 and 0.02 $\mu\text{g}/\text{m}^3$, respectively. Operating with lower excess air would result in less efficient combustion, and more carbon in the fly ash and in the filter solids. Estimated oxidized Hg was low, with 81% being removed:

0.58 and 0.11 $\mu\text{g}/\text{m}^3$ in the inlet and exit flue gas streams, respectively. Essentially no estimated elemental Hg was found in the flue gas.

3. Week 3

During week 3, the combustor operated at a low coal firing rate with low excess air. The average total flue gas Hg concentration was 3.50 and 0.46 $\mu\text{g}/\text{m}^3$ at the inlet and exit, respectively (87% removal). Again, with the low excess air, a large percentage of the flue gas Hg was particulate Hg (55%). The particulate, estimated oxidized Hg, and estimated elemental Hg species all showed significant removals. The particulate Hg was 1.93 and 0.04 $\mu\text{g}/\text{m}^3$ in the inlet and exit, respectively (98% removal). Estimated oxidized Hg in the inlet and exit was 0.94 and 0.22 $\mu\text{g}/\text{m}^3$ (77% removal), and the inlet and exit estimated elemental Hg was 0.63 and 0.20 $\mu\text{g}/\text{m}^3$ (68% removal). It is encouraging to see fly ash removal of elemental Hg. This potentially makes the utilization of fly ash and flue gas humidification a supplemental Hg control technology with wet scrubbers, which have been found remove only the oxidized Hg species.^{5,6}

4. Week 4

During week 4, the combustor operated at a high coal feed rate with high excess air. The inlet and exit flue gas Hg concentrations were 4.83 and 2.23 $\mu\text{g}/\text{m}^3$ at the inlet and exit, respectively (54% removal). With the high excess air, very little particulate Hg was found in the inlet and exit gas streams (0.22 and 0.05 $\mu\text{g}/\text{m}^3$). Both the estimated oxidized and estimated elemental Hg showed significant removals. The inlet and exit oxidized Hg concentration was 2.72 and 1.35 $\mu\text{g}/\text{m}^3$, respectively (50% removal). The inlet and exit elemental Hg concentration was 1.89 and 0.79 $\mu\text{g}/\text{m}^3$, respectively (58% removal). The estimated elemental Hg concentration was higher in week 4 than in week 2, test weeks with high coal feed rate (Table 1, Figure 15). Week 4 testing was conducted with higher excess combustion air, and probably higher NOx concentration in the flue gas. The differences in NOx concentration is not known since the combustor flue gas NOx analyzers were not operating during this test program. Data on the effect of NOx on Hg speciation is essentially non-existent. However, nitric oxide (NO), the primary component of flue gas NOx, can react with and tie up oxidizing agents such as chlorine (Cl).^{18,19} In studies on Hg partitioning in flue gas, Cl has been found to react vigorously with elemental Hg (Hg^0) to form oxidized Hg species such as mercuric chloride (HgCl_2).¹⁷ Additional work on the effect of NOx on Hg speciation is needed.

Effect of Illinois Coal (Firebox) Fly Ash

The Hg removal data indicates that the carbon in the Rend Lake Mine coal fly ash emitted from the firebox had a strong influence on Hg capture. The data presented in Figure 16 is from tests with high (126 lb/hr) coal feed rate. When the firebox ash contained less than 2 wt % carbon, the duct + ESP Hg capture was less than 65%. At conditions where the firebox ash carbon was 9 to 21 wt %, the Hg capture was 90 to 100% (Figure 16 and Tables 4 and 5). This is further illustrated in Figure 17 showing results with three tests with similar total flue gas ash carbon contents (6.1 to 7.3 wt %), but a wide variation in firebox ash carbon (0.4 to 12.9 wt %). The

test with 0.4 wt % carbon in the firebox ash produced a Hg capture of 64%. With 12.9 wt % carbon in the firebox ash, the Hg capture was 96%. The highly reactive nature of the firebox ash may be due to its "freshness". As described previously, the ashes obtained from Illinois coal-firing facilities and injected into the duct went through a preparation process (drying, grinding, blending, etc.). This may have had an adverse effect on the physical and/or chemical reactivity properties of the prepared ashes. It may also be that the firebox ash has other properties that are conducive to Hg capture. It is still not known if properties other than carbon content, such as inorganic composition, play an important role in reactivity to Hg.

The importance of the firebox ash also is demonstrated in the baseline test BL-3 (Table 5). Ontario Hydro flue gas analysis showed 92% Hg removal with 34 wt % C in the firebox ash, in spite of an extremely low ash solids loading (0.9 gr/dscf).

Hg Removal Capacity of Ontario Hydro and EPA Method 5 Filter Solids

Mercury analyses were performed on the filter solids from both the Ontario Hydro Hg sampling train (duct inlet) and the flue gas particulate measurement train (EPA Method 5). In both sampling trains, the filter cake weight and volume of the flue gas sampled were measured. Consequently, the percent of flue gas Hg capture could be calculated. The results showing the percent of Hg captured as a function of the filter solids carbon content are presented for the Ontario Hydro and Method 5 trains in Figures 18 and 19, respectively.

These filters do not simulate the Hg capture mechanism that would take place in a duct and/or ESP. The filters and filter cakes would actually closer simulate a fabric filter where an ash layer coats the fabric filter bags. The results were obtained with just Illinois coal fly ash carried over from the firebox. The duct inlet Ontario Hydro train was prior to the Illinois fly ash injection point, and the EPA Method 5 measurements were made before testing with Illinois ash injection.

The results show the effect of increasing the ash carbon content on Hg capacity of the ash. The flue gas Hg captured on the Ontario Hydro filter solids (Figure 18) was less than 10% with the relatively low carbon (<5 wt %) ash. Increasing the ash carbon content above 5% produced a substantial increase in Hg capture, i.e., Hg removals of 80 to 90% were obtained with 10 to 15% carbon. Increasing the carbon content above 15% had little, if any, additional benefit. With the EPA particulate measurement train (Figure 19), the Hg capture increased from less than 10% with low (<2 wt %) carbon to 100% with 21-22 wt % carbon. The Hg removals shown were obtained at relatively low temperatures. The average filter temperatures for the Ontario Hydro and Method 5 trains were 235 and 213 °F, respectively. The positive effect of low temperature and high fly ash carbon content on Hg capture efficiency has been shown in lab studies with fixed bed reactors,^{1,2} and in pilot scale studies with fabric filters.⁴

The data presented in Figures 18 and 19 are from test periods when the combustor coal feed rate (126 lb/hr), flue gas flow (320 to 350 dscfm), and flue gas Hg concentration (4.2 to 5.3 µg/dry Nm³) were highest (Table 1). Results from test periods with low coal feed rate have not been discussed here because of the small variation in the filter solids carbon content (0.4 to 4.9 wt %).

CONCLUSIONS AND RECOMMENDATIONS

In 1999, CONSOL conducted a study measuring coal-fired flue gas Hg removal with fly ash. The Hg capture was correlated with: 1) fly ash LOI (carbon) content, and 2) flue gas temperature. The test program was conducted using CONSOL's 1.5 MM Btu/hr coal combustion unit, which is designed to simulate the operation of an industrial or utility coal-fired boiler. Mercury removal was measured across the duct and ESP of the test facility. Fly ash carbon contents from 2 wt % to 16 wt %, and flue gas temperatures from 195 °F to 325 °F were studied. Flue gas temperature was controlled by humidification and a heat exchanger. Mercury removal was determined by state-of-the-art mercury sampling methods conducted at the duct inlet and ESP exit.

The test program showed that fly ash, in conjunction with a reduction of flue gas temperature, has the capability to remove a substantial portion of flue gas Hg. Mercury removals from 25% to 100% were obtained, with the removals generally increasing with an increase in fly ash carbon content and a decrease in flue gas temperature. This information provides Illinois utilities with a potential low-cost control option in the event of EPA regulation of coal-fired Hg emissions. This information could prevent fuel switching, and help preserve the Illinois coal mining industry.

Specific conclusions are listed below:

- The effect of flue gas temperature on Hg removal was different depending on the carbon content of the fly ash.
 - With the relatively low carbon (C) fly ashes (2 to 8 wt %), the duct/ESP Hg removal increased with a decrease in flue gas temperature. In general, the removals increased from 30-60 % at 260-270 °F to 85-95% at 200 °F.
 - With 12 wt % C, the Hg removals (95-100%) were essentially constant over the temperature range of 220 to 320 °F.
 - With the high C ash (15 wt %), the Hg removal increased with an increase in temperature: 50-60% at 200 °F to 80% at 320 °F. The opposite trend with temperature may suggest a temperature-dependent chemical reaction with the high C ash.
- With the exception of tests at 200 °F, the Hg removal increased with an increase in fly ash C content.
 - 200 °F: Mercury removals (88-94%) were essentially constant as the C content was increased from 3 wt % to 8 wt %.
 - 220-230 °F: Removals increased from 45% with 2 wt % C to 99% with 13 wt % C.

- 265-275 °F: Removals increased from 50% with 2 wt % C to 98% with 12 wt % C.
- 320-325 °F: Removals increased from 40% with 2 wt % C to 95% with 12 wt % C.
- Mercury speciation data shows substantial fly ash removal of both elemental and oxidized Hg species. Removals of 55 to 70% and 35 to 80% were obtained with elemental and oxidized Hg, respectively. The removal of both Hg species makes this process attractive as a potential supplemental control technology for utility plants with wet scrubbers, or a dedicated technology for plants using either ESPs or fabric filters as emission control devices.

Based on the favorable Hg removals obtained in this program, it is recommended to confirm the results on a larger scale. One option would be to use a flue gas slipstream (~1 MWe equivalent) from a coal-fired utility plant. The test facility would be equipped with flue gas humidification and a pilot scale ESP for fly ash collection. Flue gas temperature and, if possible, fly ash carbon content would be the desired program variables. This configuration would closer simulate a full-scale utility operation and would be useful in scaling up data for design of a full scale Hg control technology with fly ash.

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Table 1
 Combustor Operating Conditions and Flue Gas Properties

Test (a)	Date	Coal Feed, lb/hr	% Excess Air (b)	Flue Gas O ₂ Vol% dry (b)	Flue Gas Hg, $\mu\text{g/dry Nm}^3$ (b)	Flue Gas Flow, dscfm	Flue Gas Solids, gr/dscf (c)	Flue Gas Moisture, Vol. % (b)
PM-1	6/8/99	84.1	25	4.2	-	250	0.3	6.8
PM-2	6/8/99	84.1	25	4.2	-	250	0.3	7.3
BL-1	6/8/99	84.1	23	3.9	2.12	250	0.3	8.1
BL-2	6/8/99	84.1	22	3.8	2.10	250	0.3	7.5
1	6/9/99	84.1	21	3.6	2.38	250	0.3	7.5
2	6/9/99	84.1	22	3.8	1.99	250	0.3	7.2
3	6/9/99	84.1	22	3.8	1.97	250	0.3	7.0
4	6/10/99	84.1	20	3.6	1.89	250	0.3	8.1
5	6/10/99	84.1	21	3.7	2.07	250	0.3	7.1
6	6/10/99	84.1	23	3.9	1.87	250	0.3	6.8
7	6/11/99	84.1	20	3.5	1.40	250	0.3	7.8
8	6/11/99	84.1	18	3.3	1.99	250	0.3	8.2
PM-3	6/15/99	126.1	10	1.9	-	320	0.9	16.4
BL-3	6/15/99	126.1	4	0.8	4.25	320	0.9	18.1
PM-4	6/16/99	126.1	8	1.5	-	320	0.9	11.2
9	6/16/99	126.1	14	2.6	4.29	320	0.9	10.4
10	6/16/99	126.1	6	1.1	4.37	320	0.9	10.4
11	6/16/99	126.1	4	0.8	4.46	320	0.9	10.3
PM-5	6/17/99	126.1	11	2.0	-	323	0.8	11.8
12	6/17/99	126.1	5	1.0	4.23	323	0.8	12.3
13	6/17/99	126.1	5	1.0	4.29	323	0.8	13.0
PM-6	6/18/99	126.1	13	2.5	-	330	0.8	12.7
14	6/18/99	126.1	1	0.2	4.33	330	0.8	12.6
PM-7	6/22/99	84.1	16	2.9	-	211	0.6	10.9
15	6/22/99	84.1	16	2.9	3.10	211	0.6	8.2
PM-8	6/23/99	84.1	21	3.6	-	241	0.4	8.1
16	6/23/99	84.1	11	2.1	3.63	241	0.4	8.1
17	6/23/99	84.1	9	1.7	3.36	241	0.4	8.1
PM-9	6/24/99	84.1	11	2.1	-	228	0.6	7.4
18	6/24/99	84.1	7	1.3	3.53	228	0.6	8.3
19	6/24/99	84.1	8	1.5	3.78	228	0.6	8.7
PM-10	6/25/99	84.1	9	1.7	-	220	0.6	8.0
20	6/25/99	84.1	8	1.6	3.62	220	0.6	8.2
PM-11	7/14/99	126.1	18	3.3	-	348	0.7	8.0
21	7/14/99	126.1	25	4.2	4.69	348	0.7	7.3
22	7/14/99	126.1	21	3.7	5.32	348	0.7	7.1
PM-12	7/15/99	126.1	21	3.7	-	350	0.6	7.3
23	7/15/99	126.1	15	2.7	4.90	350	0.6	8.5
24	7/15/99	126.1	20	3.5	4.36	350	0.6	7.6

(a) PM tests are flue gas particulate measurement tests (EPA Method 5) conducted at ESP inlet.

BL tests are baseline Hg removal tests with just firebox ash -- no Illinois fly ash addition.

The remaining tests are Hg removal tests with Illinois fly ash addition.

(b) Determined by EPA Method 5 at ESP inlet and inlet Ontario Hydro sampling train in the convection pass prior to the duct inlet.

(c) Includes just firebox ash.

Table 2
Analysis of Illinois Coal

As Received Sample	
Moisture, wt %	3.62
Mercury, ppm	0.07
Prox. Analysis (Dry Basis), wt%	
Ash	6.23
Volatile Matter	37.52
Fixed Carbon	56.25
Total Sulfur	1.07
Misc.	
Btu/lb	13553
MAF Btu/lb	14453
Ult. Analysis (Dry Basis), wt%	
Carbon	77.41
Hydrogen	4.91
Nitrogen	1.79
Chlorine	0.58
Total Sulfur	1.07
Ash	6.23
Oxygen (Diff.)	8.01
Ash Elements, wt% of Ash	
SiO ₂	52.72
Al ₂ O ₃	24.07
TiO ₂	1.19
Fe ₂ O ₃	11.84
CaO	2.19
MgO	0.96
Na ₂ O	2.05
K ₂ O	2.29
P ₂ O ₅	0.32
SO ₃	1.56
UND	0.81
Wet Screen, wt%	
+28 mesh	0.0
28 X 48	0.4
48 X 100	4.8
100 X 200	18.9
200 X 325	20.7
- 325 mesh	55.2

Table 3
Analyses of Illinois Fly Ashes

	Fly Ash						
	Blend A	Blend B	Blend C	Blend D	Blend F	Blend G	Blend H
As Received Sample							
Moisture, wt%	0.01	0.25	0.05	0.10	0.63	0.26	0.25
Mercury, ppm	0.19	0.04	0.09	0.11	0.06	0.03	0.05
Prox. Analysis (Dry Basis), wt%							
Ash	97.49	92.89	90.10	81.47	87.19	94.81	89.45
Total Sulfur	0.36	1.01	0.31	0.35	0.70	0.01	0.00
Ult. Analysis (Dry Basis), wt%							
Carbon	2.31	5.17	9.11	16.74	8.75	3.75	9.88
Hydrogen	0.01	0.01	0.01	0.00	0.06	0.05	0.04
Nitrogen	0.01	0.01	0.06	0.15	0.07	0.01	0.04
Total Sulfur	0.36	1.01	0.31	0.35	0.70	0.01	0.00
Ash	97.49	92.89	90.10	81.47	87.19	94.81	89.45
Oxygen (Diff.)	-0.18	0.91	0.41	1.29	3.23	1.37	0.59
Ash Elements, wt% of Ash							
SiO ₂	51.88	42.16	40.25	37.21	44.49	45.96	39.50
Al ₂ O ₃	16.83	16.84	17.48	16.82	16.17	18.24	18.38
TiO ₂	0.88	1.07	0.76	0.67	0.89	1.05	0.73
Fe ₂ O ₃	18.39	19.93	26.59	25.31	16.73	19.09	27.06
CaO	4.87	3.70	1.61	0.90	3.41	3.94	0.99
MgO	0.88	1.17	0.65	0.58	1.00	1.24	0.62
Na ₂ O	1.39	0.52	0.42	0.25	0.95	0.52	0.27
K ₂ O	1.94	3.55	1.60	1.45	2.70	3.61	1.58
P ₂ O ₅	0.19	0.63	0.13	0.09	0.36	0.56	0.10
SO ₃	1.22	2.99	0.89	0.82	2.25	1.80	0.65
UND	1.53	7.44	9.62	15.90	11.05	4.01	10.14
Wet Screen, wt%							
+28 mesh	0.5	-	2.2	6.8	-	-	2.7
28 X 48	1.0	-	3.8	8.1	-	-	3.8
48 X 100	1.7	-	5.2	8.6	-	-	6.2
100 X 200	6.3	-	18.7	20.1	-	-	19.0
200 X 325	11.0	-	22.6	21.4	-	-	23.7
-325 mesh	79.5	-	47.5	35.0	-	-	44.6
Malvern Particle Size, wt% (a)							
+188 micron	0.0	0.0	0.0	0.0	2.7	0.0	0.7
188 X 121	0.0	0.0	0.0	0.5	7.9	0.0	2.5
121 X 66.8	0.2	0.0	16.1	20.2	10.5	1.0	31.1
66.8 X 43.0	4.7	0.0	26.7	26.5	8.5	3.3	27.6
43.0 X 20.5	16.2	8.6	28.6	33.3	17.0	16.4	21.0
20.5 X 11.4	25.1	27.1	15.0	12.0	18.0	28.9	8.8
11.4 X 5.43	31.2	34.5	9.0	5.4	20.3	34.3	5.7
5.43 X 1.93	22.6	29.8	4.6	2.1	15.1	16.1	2.6
- 1.93	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mass Mean Particle Size, micron	9.1	7.6	30.5	35.3	15.7	9.7	47.2

(a) Malvern analysis was run on the -200 mesh fraction for Blends A, C, D, and H.
Malvern analysis was run on the entire ash sample for Blends B and F, and G.

Table 4
Test Conditions and ESP Results

Test No.	Coal Feed, lb/hr	Flue Gas Flow, dscfm	Temp., °F		Fly Ash Blend	Fly Ash		Firebox Ash		ESP Inlet Ash Carbon Content, wt%	Flue Gas Solids Loading, gr/dscf (a)	Hg Capture by Duct/ESP, ng/dry m ³ (b)	% Hg Captured (c)
			Duct (d)	ESP (e)		Carbon, wt%	Carbon, wt%	Carbon, wt%					
1	84	250	278	253	D	6.7	16.7	0.6	0.6	15.3	3.4	2.01	100
2	84	250	227	228	D	6.3	16.7	0.6	0.6	15.2	3.2	1.81	91
3	84	250	192	203	D	5.7	16.7	0.6	0.6	15.1	3.0	1.14	58
4	84	250	284	268	A	7.0	2.3	0.6	0.6	2.2	3.6	1.92	97
5	84	250	220	236	A	6.7	2.3	0.6	0.6	2.2	3.4	2.52	100
6	84	250	194	217	A	6.3	2.3	0.6	0.6	2.1	3.2	1.54	78
7	84	250	272	265	C	5.7	9.1	0.6	0.6	8.2	3.0	1.13	57
8	84	250	228	225	C	6.4	9.1	0.6	0.6	8.3	3.3	1.58	80
9	126	320	352	325	C	6.5	9.1	2.5	21.2	12.5	3.3	3.57	83
10	126	320	277	276	C	6.6	9.1	2.5	21.2	12.4	3.3	3.14	73
11	126	320	235	221	C	5.6	9.1	2.5	21.2	12.8	3.0	2.49	58
12	126	323	335	324	G	5.1	3.7	2.2	12.9	6.5	2.6	3.35	78
13	126	323	275	274	G	6.1	3.7	2.2	12.9	6.1	3.0	3.26	52
14	126	330	334	323	H	6.0	9.8	2.3	9.5	9.7	2.9	3.04	70
15	84	211	197	197	A	4.8	2.3	1.1	4.9	2.8	3.2	2.52	72
16	84	241	229	226	B	4.6	5.2	0.9	1.6	4.6	2.7	1.85	53
17	84	241	196	197	B	5.8	5.2	0.9	1.6	4.7	3.2	2.00	57
18	84	228	233	228	C	5.1	9.1	1.2	3.4	8.0	3.2	1.94	55
19	84	228	200	197	C	4.7	9.1	1.2	3.4	7.9	3.0	2.01	57
20	84	220	338	324	D	6.1	16.7	1.2	2.3	14.4	3.9	1.97	56
21	126	348	335	321	A	6.3	2.3	2.1	1.9	2.2	2.8	0.60	12
22	126	348	272	272	B	6.2	5.2	2.1	1.9	4.4	2.8	0.73	15
23	126	350	228	226	B	6.5	5.2	1.6	0.4	4.3	2.7	0.62	13
24	126	350	273	267	F	7.7	8.7	1.6	0.4	7.3	3.1	1.41	29
BL-1	84	250	-	259	-	0.0	-	0.6	0.6	0.6	0.3	0.11	6
BL-2	84	250	219	225	-	0.0	-	0.6	0.6	0.6	0.3	0.07	4
BL-3	126	322	330	322	-	0.0	-	2.5	34.1	34.1	0.9	1.25	29

(a) Firebox ash + injected Illinois ash.
 (b) Based on mercury analysis of recovered ESP ash.
 (c) (ESP ash Hg x 100)/(Ontario Hydro inlet Hg)
 (d) TC location - 15 ft prior to ESP inlet.
 (e) Average of ESP inlet and exit temperature.

Table 5
Results of Ontario Hydro Sampling

Test No.	Combustor Test Conditions				Ontario Hydro Sampling Location				Gas Hg Concentration, ug/dry m ³						Total Gas Hg, ug/m ³		% Hg Removed
	Flue Gas Flow dscfm	ESP Temp., °F	ESP Inlet Ash Carbon, wt%	Flue Gas Solids Loading, gr/dscf	Hydro Sampling Location	Filter	Probe & Filter Rinse	KCl	H ₂ O	KMnO ₄	KMnO ₄ Rinse	Dry	Wet				
1	250	253	15.3	3.4	Duct Inlet	0.40	0.00	1.91	0.00	0.00	0.00	0.07	2.38	2.20			
1					ESP Exit	0.03	0.03	3.40	0.00	0.00	0.00	0.03	3.49	3.24	0		
2	250	228	15.2	3.2	Duct Inlet	0.15	0.00	1.72	0.00	0.11	0.00	0.01	1.99	1.86			
2					ESP Exit	0.02	0.00	0.87	0.00	0.00	0.00	0.08	0.97	0.88	52		
3	250	203	15.1	3.0	Duct Inlet	0.15	0.00	1.77	0.00	0.00	0.00	0.05	1.97	1.83			
3					ESP Exit	0.02	0.00	0.86	0.00	0.00	0.00	0.00	0.88	0.80	56		
4	250	268	2.2	3.6	Duct Inlet	0.16	0.00	1.64	0.00	0.09	0.00	0.00	1.89	1.73			
4					ESP Exit	0.02	0.00	0.99	0.00	0.00	0.00	0.00	1.01	0.94	49		
5	250	236	2.2	3.4	Duct Inlet	0.17	0.00	1.51	0.35	0.00	0.00	0.04	2.07	1.92			
5					ESP Exit	0.02	0.00	0.98	0.20	0.00	0.00	0.00	1.20	1.09	42		
6	250	217	2.1	3.2	Duct Inlet	0.11	0.00	1.58	0.17	0.00	0.00	0.01	1.87	1.74			
6					ESP Exit	0.02	0.00	0.86	0.14	0.05	0.00	0.00	1.07	0.98	46		
7	250	265	8.2	3.0	Duct Inlet	0.11	0.00	0.99	0.28	0.02	0.00	0.00	1.40	1.29			
7					ESP Exit	0.02	0.00	1.02	0.23	0.17	0.00	0.00	1.44	1.33	27		
8	250	225	8.3	3.3	Duct Inlet	0.13	0.00	1.56	0.15	0.15	0.00	0.00	1.99	1.83			
8					ESP Exit	0.02	0.00	0.97	0.36	0.00	0.00	0.00	1.35	1.23	33		
9	320	325	12.5	3.3	Duct Inlet	3.61	0.20	0.48	0.00	0.00	0.00	0.00	4.29	3.84			
9					ESP Exit	0.01	0.00	0.20	0.00	0.00	0.00	0.00	0.21	0.20	95		
10	320	276	12.4	3.3	Duct Inlet	3.73	0.08	0.56	0.00	0.00	0.00	0.00	4.37	3.92			
10					ESP Exit	0.01	0.00	0.06	0.00	0.00	0.00	0.00	0.07	0.06	98		
11	320	221	12.8	3.0	Duct Inlet	2.81	0.30	1.31	0.00	0.00	0.00	0.04	4.46	4.00			
11					ESP Exit	0.02	0.00	0.04	0.00	0.00	0.00	0.00	0.06	0.05	99		
12	323	324	6.5	2.6	Duct Inlet	3.61	0.10	0.47	0.05	0.00	0.00	0.00	4.23	3.71			
12					ESP Exit	0.01	0.00	0.16	0.00	0.00	0.00	0.00	0.17	0.15	96		
13	323	274	6.1	3.0	Duct Inlet	3.55	0.43	0.31	0.00	0.00	0.00	0.00	4.29	3.73			
13					ESP Exit	0.02	0.00	0.14	0.00	0.00	0.00	0.00	0.16	0.14	96		
14	330	323	9.7	2.9	Duct Inlet	3.87	0.06	0.34	0.06	0.00	0.00	0.00	4.33	3.78			
14					ESP Exit	0.06	0.00	0.07	0.00	0.00	0.00	0.00	0.13	0.12	97		

Table 5 (Continued)
Results of Ontario Hydro Sampling

Test No.	Combustor Test Conditions				Ontario Hydro Sampling Location				Gas Hg Concentration, ug/dry m ³				Total Gas Hg, ug/m ³		% Hg Removed
	Flue Gas Flow dscfm	ESP Temp., °F	ESP Inlet Ash Carbon, Content, wt%	Flue Gas Solids Loading, gr/dscf	Location	Filter	Probe & Filter Rinse	KCl	H ₂ O	KMNO ₄	KMNO ₄ Rinse	Dry	Wet		
15	211	197	2.8	3.2	Duct Inlet	1.48	0.11	0.65	0.00	0.77	0.09	3.10	2.85	88	
15					ESP Exit	0.01	0.04	0.16	0.00	0.15	0.05	0.41	0.38		
16	241	226	4.6	2.7	Duct Inlet	2.13	0.05	0.85	0.00	0.54	0.06	3.63	3.34	86	
16					ESP Exit	0.01	0.02	0.20	0.00	0.19	0.05	0.47	0.44		
17	241	197	4.7	3.2	Duct Inlet	1.81	0.05	0.93	0.00	0.50	0.07	3.36	3.09	91	
17					ESP Exit	0.01	0.04	0.12	0.00	0.07	0.09	0.33	0.30		
18	228	228	8.0	3.2	Duct Inlet	1.98	0.07	0.95	0.00	0.37	0.16	3.53	3.23	82	
18					ESP Exit	0.03	0.04	0.36	0.00	0.14	0.04	0.61	0.57		
19	228	197	7.9	3.0	Duct Inlet	2.80	0.05	0.63	0.00	0.21	0.09	3.78	3.45	94	
19					ESP Exit	0.02	0.03	0.06	0.00	0.09	0.01	0.21	0.20		
20	220	324	14.4	3.9	Duct Inlet	1.03	0.01	1.64	0.00	0.90	0.04	3.62	3.33	79	
20					ESP Exit	0.01	0.00	0.39	0.00	0.24	0.10	0.74	0.69		
21	348	321	2.2	2.8	Duct Inlet	0.03	0.00	2.99	0.00	1.64	0.03	4.69	4.35	38	
21					ESP Exit	0.03	0.00	2.08	0.00	0.83	0.03	2.97	2.75		
22	348	272	4.4	2.8	Duct Inlet	0.43	0.03	2.64	0.00	2.14	0.08	5.32	4.94	56	
22					ESP Exit	0.02	0.01	1.02	0.17	0.87	0.03	2.12	1.98		
23	350	226	4.3	2.7	Duct Inlet	0.22	0.00	3.01	0.00	1.63	0.04	4.90	4.48	57	
23					ESP Exit	0.02	0.00	1.29	0.00	0.72	0.03	2.06	1.90		
24	350	267	7.3	3.1	Duct Inlet	0.16	0.00	2.22	0.00	1.90	0.08	4.36	4.03	64	
24					ESP Exit	0.02	0.08	1.01	0.00	0.63	0.00	1.74	1.62		
BL-1	250	259	0.6	0.3	Duct Inlet	0.60	0.00	1.41	0.00	0.00	0.11	2.12	1.95	50	
BL-1					ESP Exit	0.03	0.00	1.04	0.00	0.00	0.00	1.07	0.99		
BL-2	250	225	0.6	0.3	Duct Inlet	0.19	0.00	1.86	0.00	0.00	0.05	2.10	1.94	41	
BL-2					ESP Exit	0.03	0.00	1.07	0.00	0.00	0.08	1.18	1.08		
BL-3	320	322	34.1	0.9	Duct Inlet	3.80	0.17	0.24	0.00	0.00	0.04	4.25	3.48	92	
BL-3					ESP Exit	0.04	0.00	0.34	0.00	0.00	0.00	0.38	0.32		

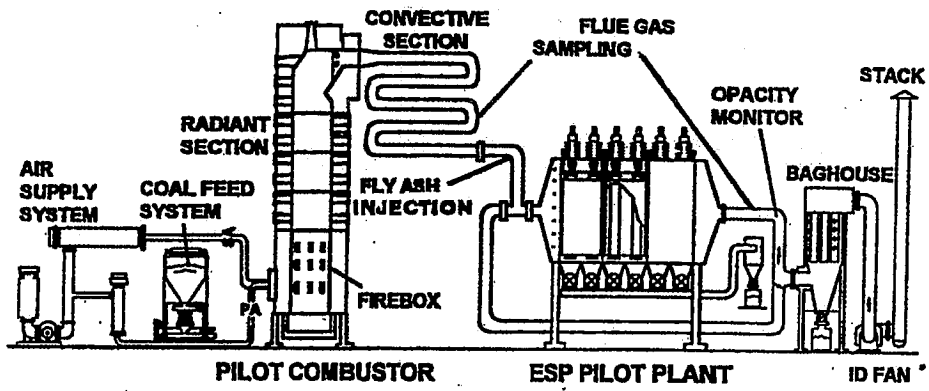


Figure 1. The CONSOL Combustion and ESP Pilot Plant Facility.

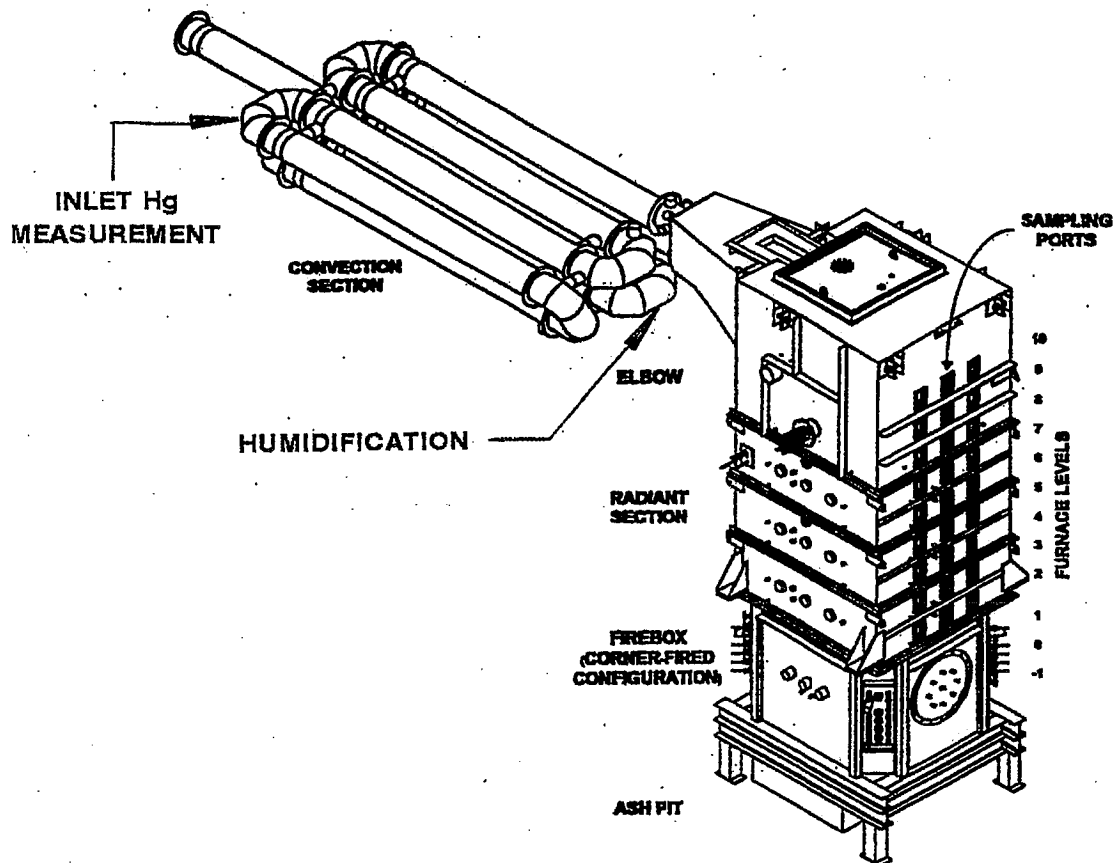


Figure 2. The CONSOL Combustion Pilot Plant.

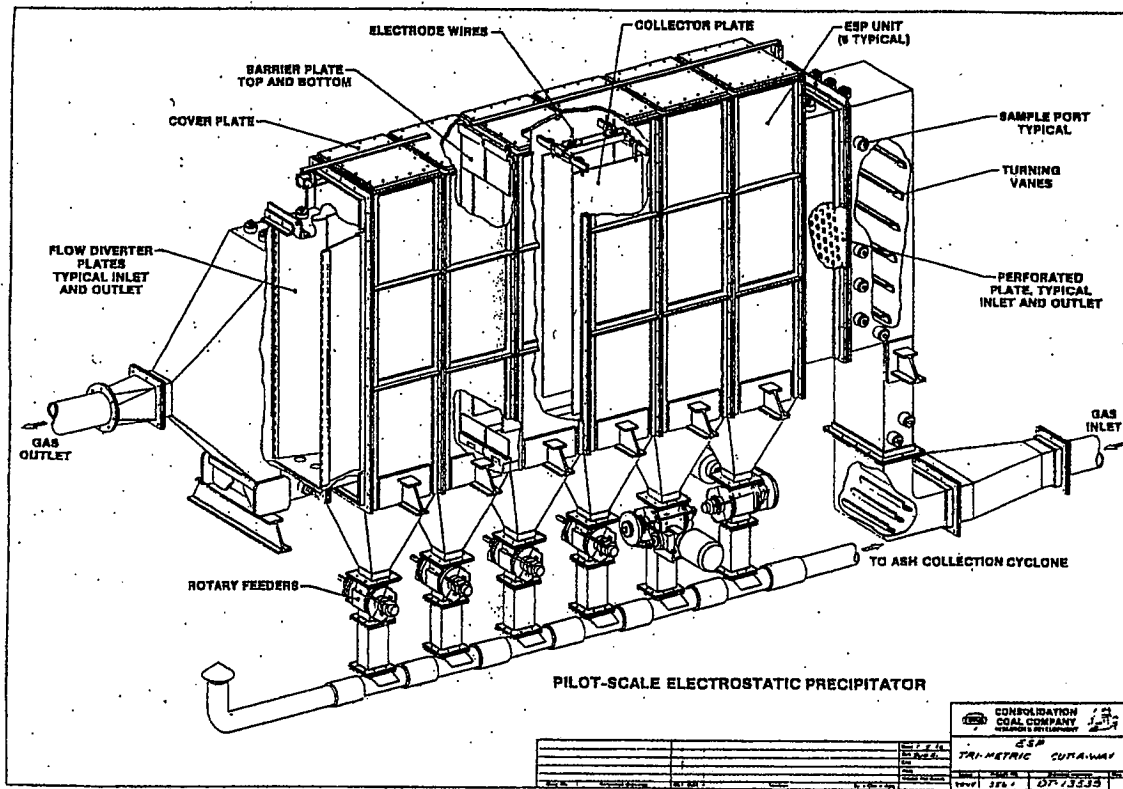


Figure 3. Trimetric Cut-Away of the Pilot Scale ESP.

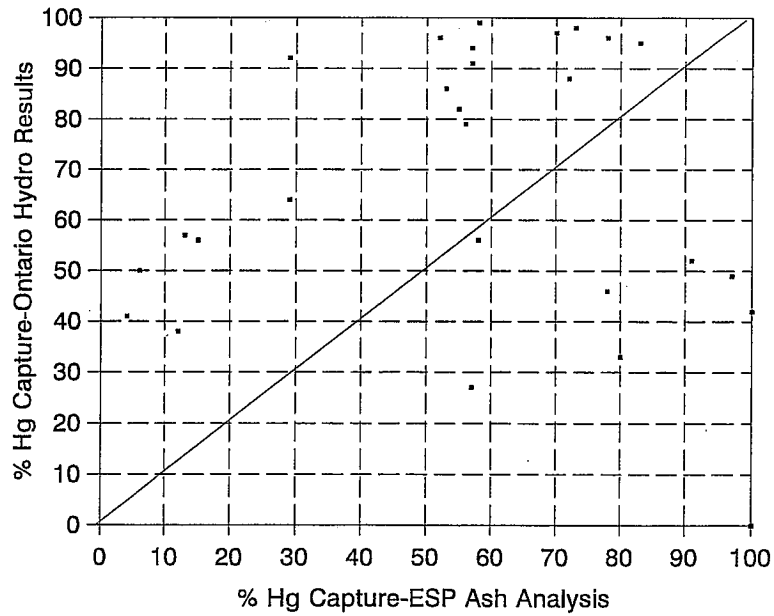


Figure 4. Data Confirmation – Ontario Hydro Results vs. ESP Ash Analysis.

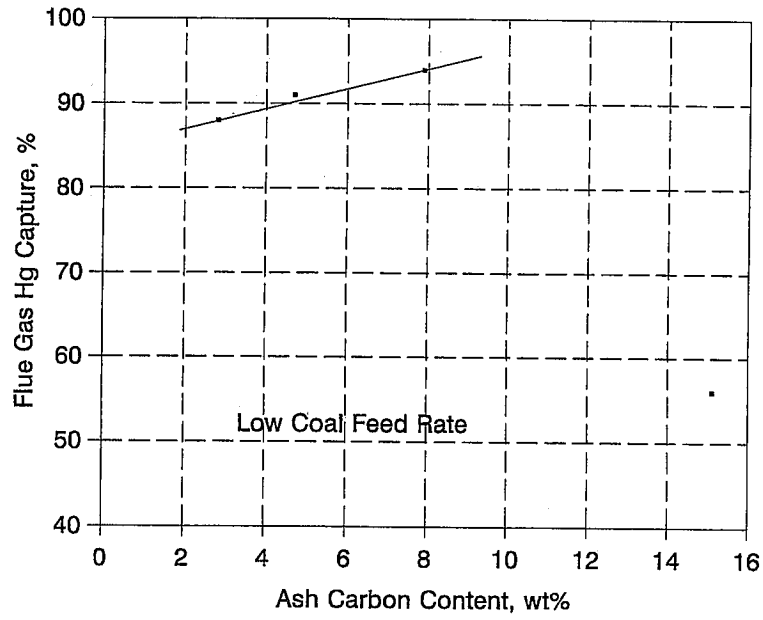


Figure 5. Hg Capture as a Function of Ash Carbon Content (197-203 °F).

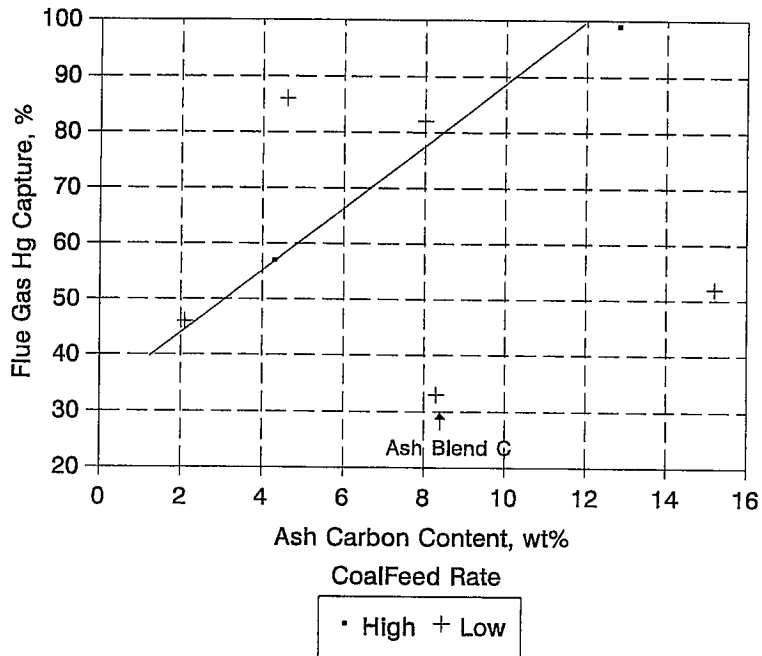


Figure 6. Hg Capture as a Function of Ash Carbon Content (217-228 °F).

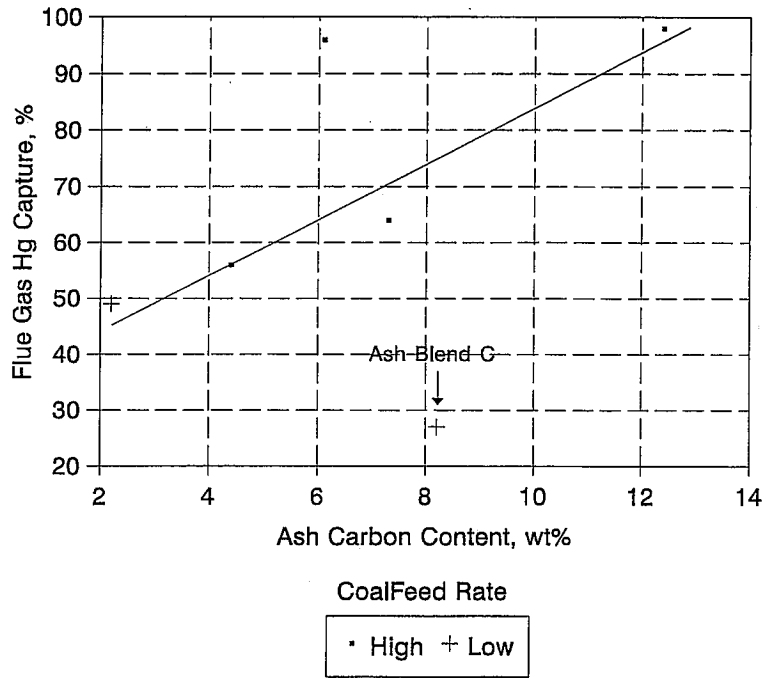


Figure 7. Hg Capture as a Function of Ash Carbon Content (265-276 °F).

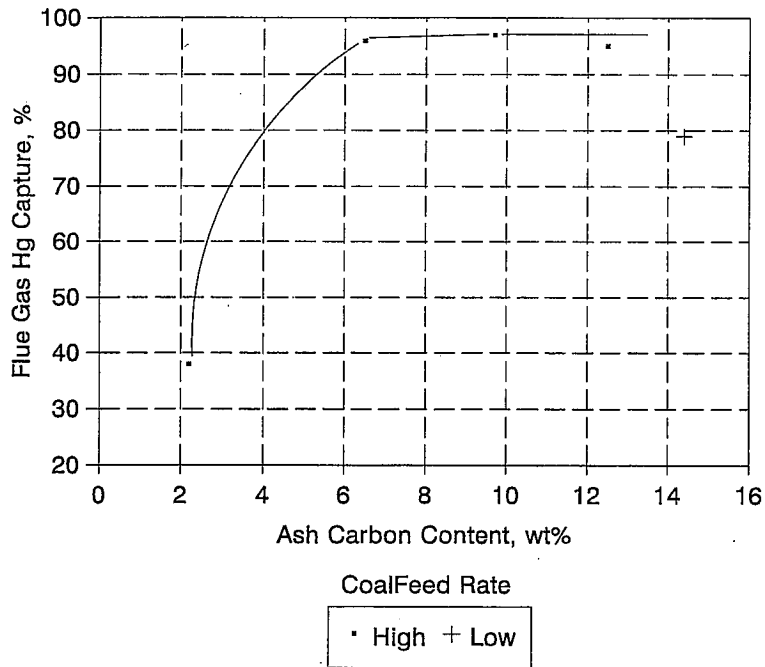


Figure 8. Hg Capture as a Function of Ash Carbon Content (321-325 °F).

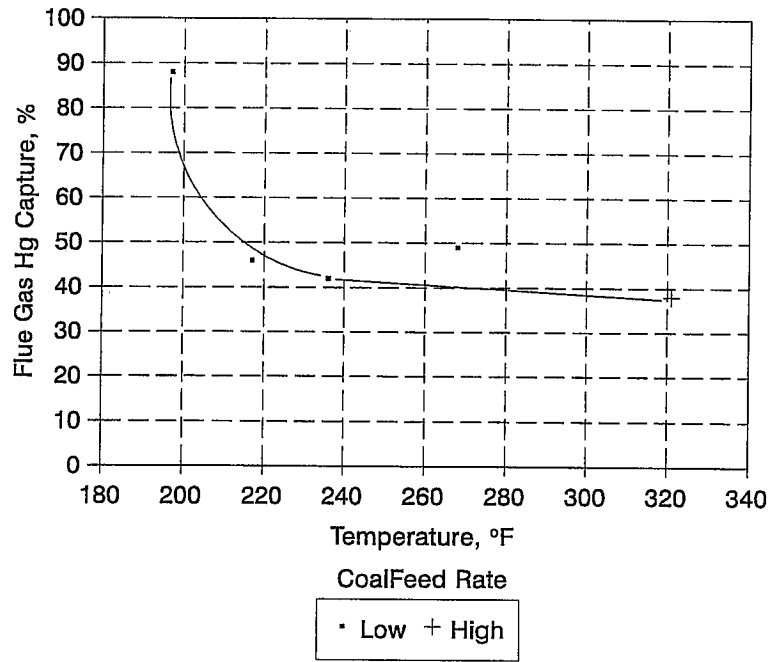


Figure 9. Hg Capture as a Function of Temperature (2.1 to 2.8% Carbon Ash).

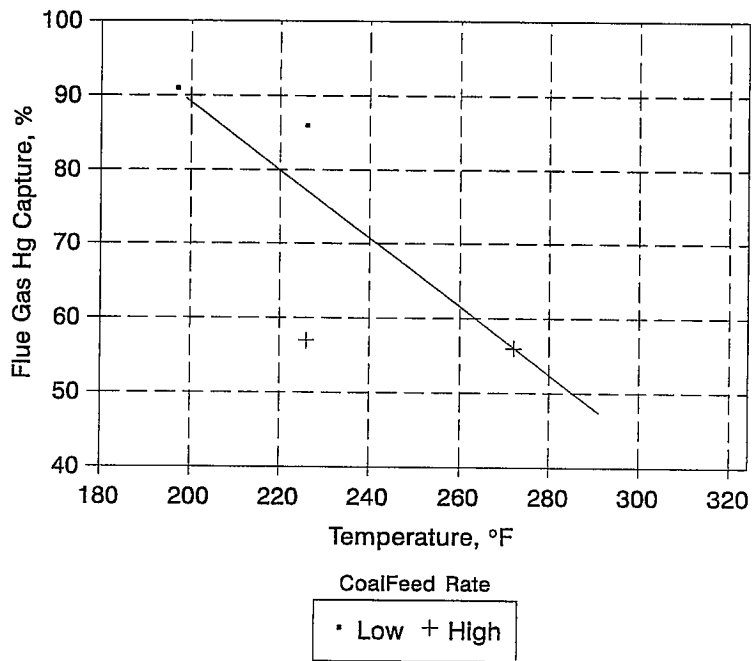


Figure 10. Hg Capture as a Function of Temperature (4.3 to 4.7% Carbon Ash).

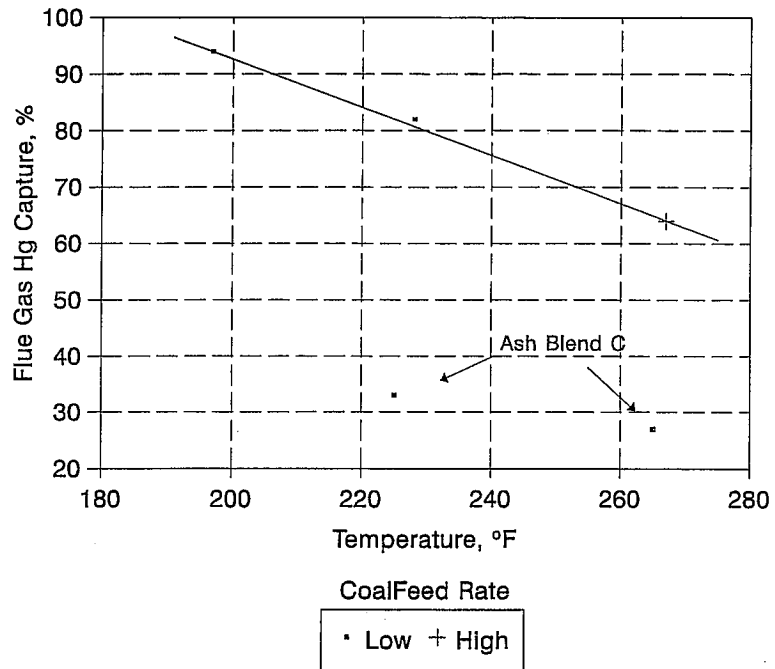


Figure 11. Hg Capture as a Function of Temperature (7.3 to 8.3% Carbon Ash).

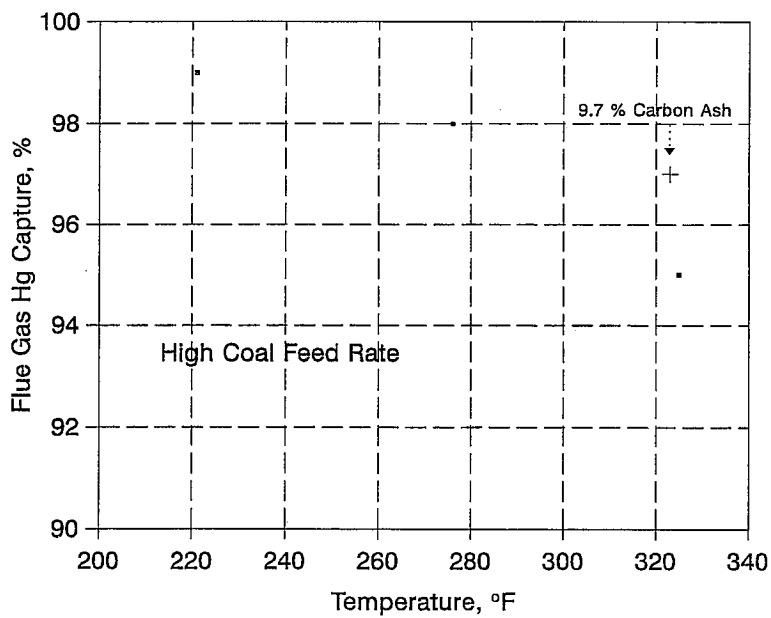


Figure 12. Hg Capture as a Function of Temperature (12.4 to 12.8% Carbon Ash).

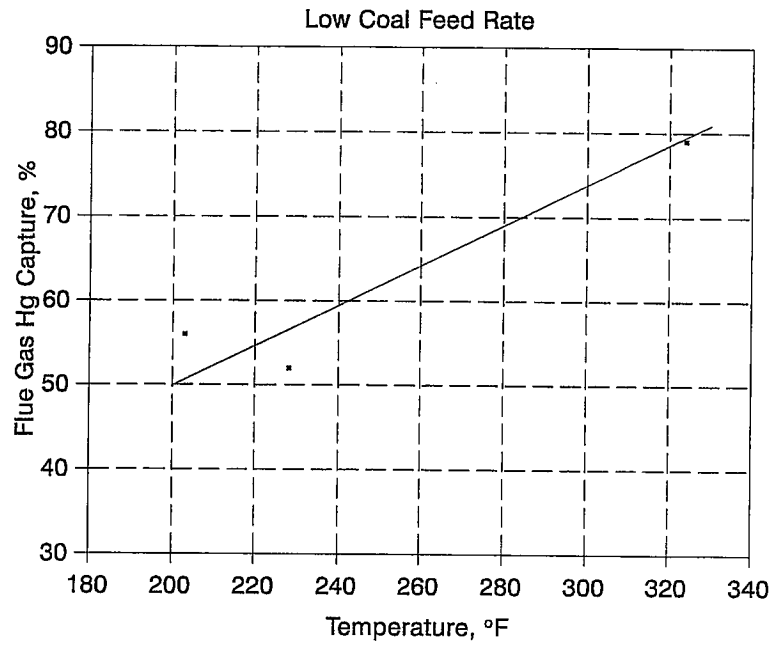


Figure 13. Hg Capture as a Function of Temperature (14.4 to 15.3% Carbon Ash).

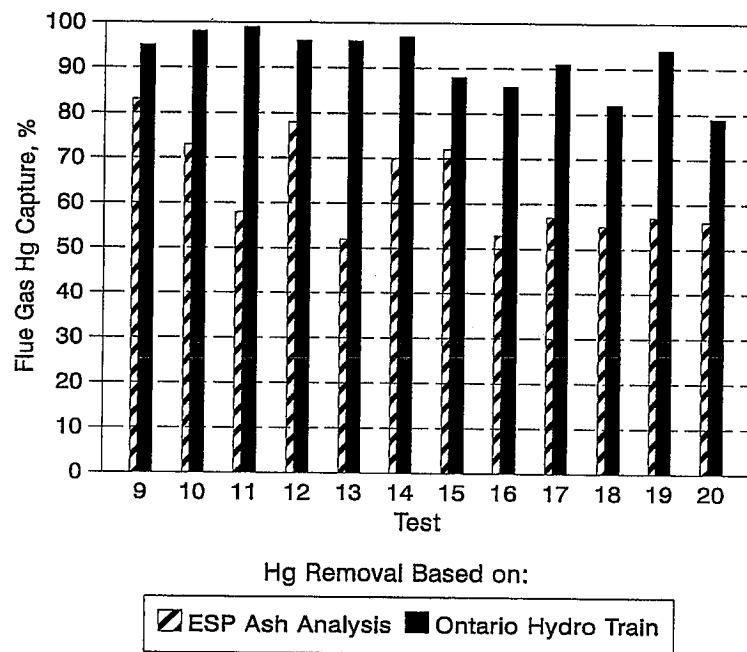


Figure 14. Comparison of Gas Sampling and Solids Analysis.

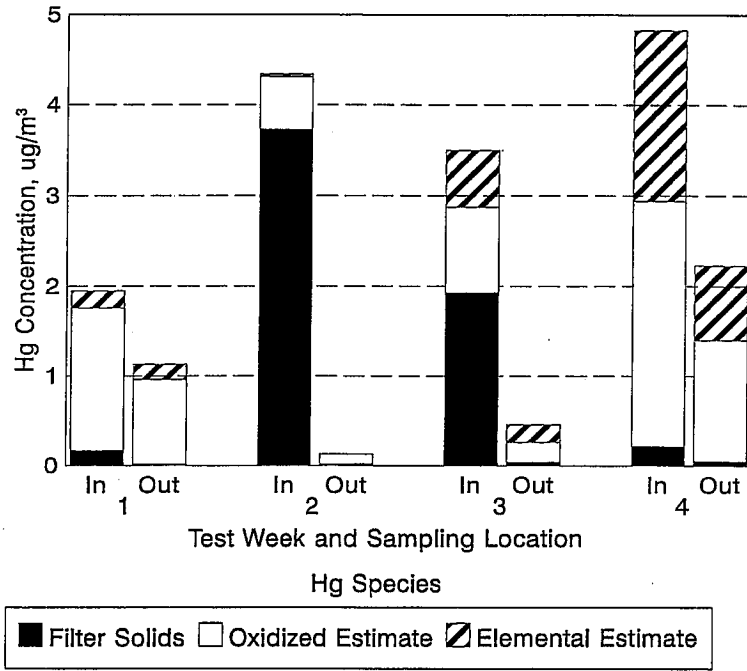


Figure 15. Flue Gas Hg Speciation at the Duct Inlet and ESP Exit.

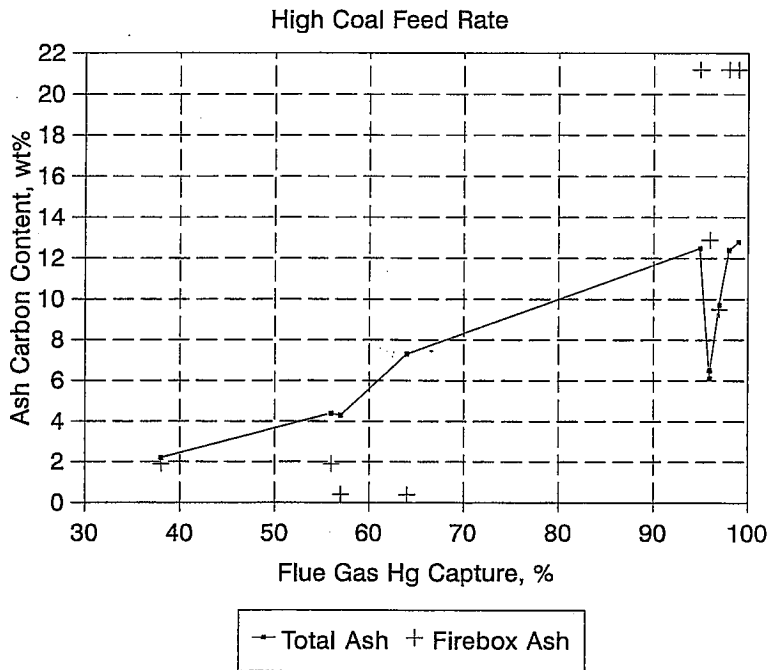


Figure 16. Duct + ESP Hg Capture, Function of Illinois Coal and Total Ash Carbon.

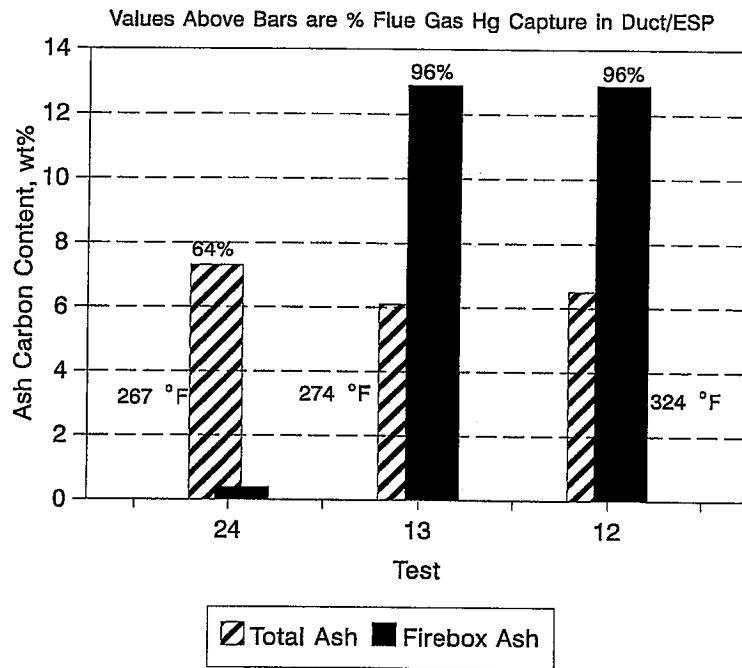


Figure 17. Hg Capture as a Function of Firebox Ash.

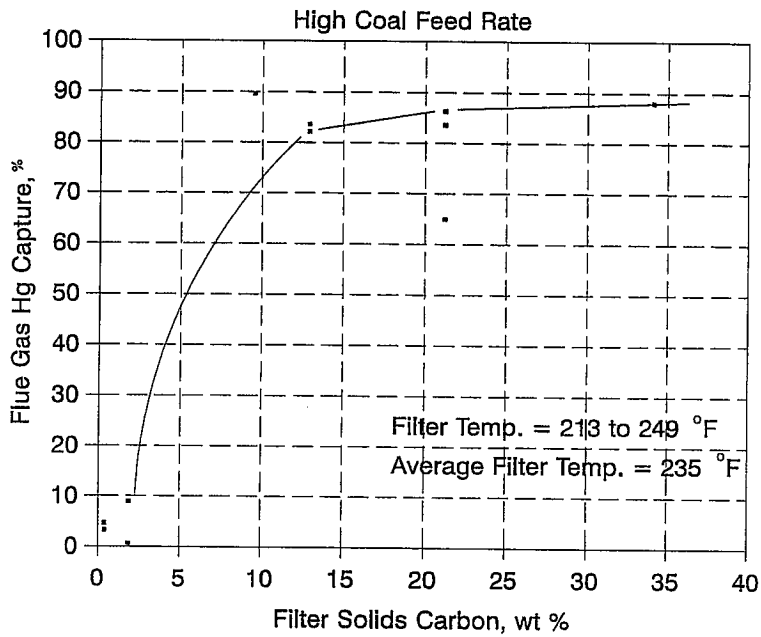


Figure 18. Hg Capture by Filter Solids - Ontario Hydro Method.
Sampling Location: Duct Inlet

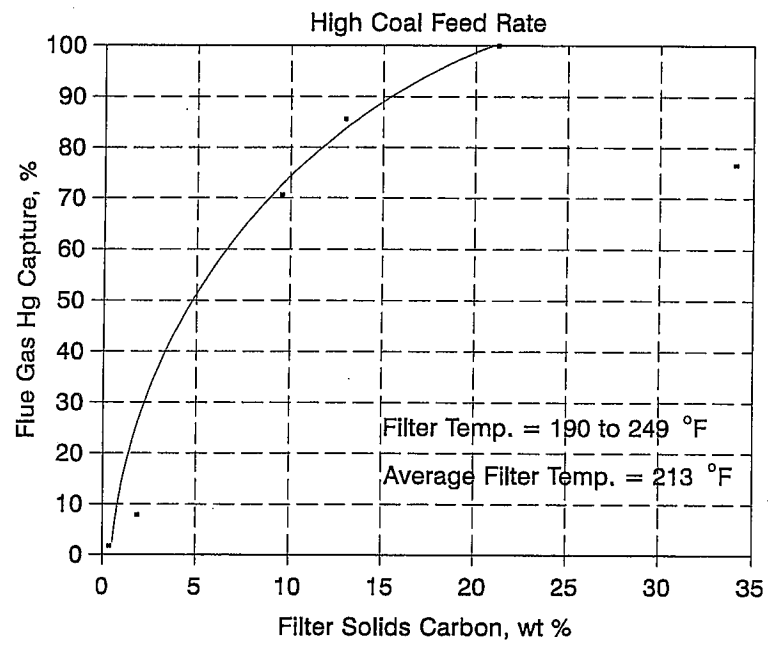


Figure 19. Hg Capture by Filter Solids - EPA Method 5.
Sampling Location: ESP Inlet.

