

# **Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control**

## **Semi-Annual Technical Progress Report**

**April 1, 2001 – September 30, 2001**

**Cooperative Agreement No: DE-FC26-99FT40718**

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## **Abstract**

This document summarizes progress on Cooperative Agreement DE-FC26-99FT40718, Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control, during the time period April 1, 2001 through September 30, 2001. The objective of this project is to demonstrate the use of alkaline reagents injected into the furnace of coal-fired boilers as a means of controlling sulfuric acid emissions. The coincident removal of hydrochloric acid and hydrofluoric acid is also being determined, as is the removal of arsenic, a known poison for NO<sub>x</sub> selective catalytic reduction (SCR) catalysts. EPRI, the Tennessee Valley Authority (TVA), FirstEnergy Corporation, and the Dravo Lime Company are project co-funders. URS Corporation is the prime contractor. During the current period, American Electric Power (AEP) joined the project as an additional co-funder and as a provider of a host site for testing.

This is the fourth reporting period for the subject Cooperative Agreement. During this period, two long-term sorbent injection tests were conducted, one on Unit 3 at FirstEnergy's Bruce Mansfield Plant (BMP) and one on Unit 1 at AEP's Gavin Station. These tests determined the effectiveness of injecting alkaline slurries into the upper furnace of the boiler as a means of controlling sulfuric acid emissions from these units. The alkaline slurries tested included commercially available magnesium hydroxide slurry (Gavin Station), and a byproduct magnesium hydroxide slurry (both Gavin Station and BMP). The tests showed that injecting either the commercial or the byproduct magnesium hydroxide slurry could achieve up to 70 to 75% sulfuric acid removal. At BMP, the overall removal was limited by the need to maintain acceptable electrostatic precipitator (ESP) particulate control performance. At Gavin Station, the overall sulfuric acid removal was limited because the furnace injected sorbent was less effective at removing SO<sub>3</sub> formed across the SCR system installed on the unit for NO<sub>x</sub> control than at removing SO<sub>3</sub> formed in the furnace. Balance of plant impacts, primarily on the ESP particulate control device, were also determined during both tests. These results are presented and discussed in this report.

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## 1.0 INTRODUCTION

This document is the semi-annual Technical Progress Report for the project “Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control,” for the time period April 1, 2001 through September 30, 2001. The objective of this project is to demonstrate the use of alkaline reagents injected into the furnace of coal-fired boilers as a means of controlling sulfuric acid emissions. The coincident removal of hydrochloric acid and hydrofluoric acid is also being determined, as will the removal of arsenic, a known poison for NO<sub>x</sub> selective catalytic reduction (SCR) catalysts. The project is being funded by the U.S. DOE National Energy Technology Laboratory under Cooperative Agreement DE-FC26-99FT40718. EPRI, the Tennessee Valley Authority (TVA), FirstEnergy Corporation, American Electric Power Company (AEP), and the Dravo Lime Company are project co-funders. URS Corporation (formerly Radian International) is the prime contractor.

Sulfuric acid is present in most flue gases from coal combustion because a small percentage of the SO<sub>2</sub> produced from the sulfur in the coal (approximately 0.5% to 1.5%) is further oxidized to form SO<sub>3</sub>. The SO<sub>3</sub> combines with flue gas moisture to form vapor-phase or condensed sulfuric acid at temperatures below 500°F. Because of this temperature effect, in this report sulfur in this oxidation state is generally referred to as “SO<sub>3</sub>” in furnace gas or flue gas upstream of the boiler air heater, and “sulfuric acid” in flue gas downstream of the air heater.

Besides being a Toxic Release Inventory substance and a potential precursor to acid aerosol/condensable emissions from coal-fired boilers, sulfuric acid in the flue gas can lead to boiler air heater plugging and fouling, corrosion in the air heater and downstream, and the formation of a visible plume. These issues will likely be exacerbated with the retrofit of SCR for NO<sub>x</sub> control on some coal-fired plants, as SCR catalysts are known to further oxidize a portion of the flue gas SO<sub>2</sub> to SO<sub>3</sub>.

The project is testing the effectiveness of furnace injection of four different calcium- and/or magnesium-based alkaline sorbents on full-scale utility boilers. These reagents have been tested during four one- to two-week tests conducted on two FirstEnergy Bruce Mansfield Plant (BMP) units. One of the sorbents tested was produced from a wet flue gas desulfurization (FGD) system waste stream, from a system that employs a modified Thiosorbic<sup>®</sup> Lime scrubbing process. The other three sorbents are commercially available.

After completing the four one- to two-week tests, the most promising sorbents have been selected for two longer-term (up to 30-day) full-scale tests. The longer-term tests are being used to confirm the effectiveness of the sorbent tested over extended operation, and to determine balance-of-plant impacts. Two longer-term tests have been conducted, one on FirstEnergy’s BMP Unit 3 and the second on AEP’s Gavin Station Unit 1.

At the completion of the project, it is expected that sufficient full-scale test data will be available to design and implement commercial installations of the sulfuric acid control technologies demonstrated.

The remainder of this report is divided into three sections. Section 2 provides a summary account of progress on the project during the current reporting period, including any problems encountered. Section 3 provides a forecast of plans for the next and future reporting periods, and Section 4 provides a detailed discussion of technical results from the project during the current reporting period.



## **2.0 PROGRESS DURING THE CURRENT REPORTING PERIOD**

### **2.1 Summary of Progress**

The current reporting period, April 1, 2001 through September 30, 2001, is the fourth technical progress reporting period for this project. October 1, 1999 was the start date for this Cooperative Agreement.

In April of this year, plans were underway to conduct a long-term slurry injection test at BMP Unit 3. The sorbent of interest was the byproduct magnesium hydroxide (byproduct Mg) produced at Allegheny Energy's Pleasants Station, but it was not clear that the project budget would be adequate to allow testing for a duration of 30 days. After negotiations with Allegheny Energy over the price of the byproduct Mg and discussions among team members, it was decided that a test duration of nominally 25 days could be conducted, and that this would be an adequate duration to achieve the test objectives.

Prior to conducting the test, a number of upgrades had to be implemented to the slurry injection system, since the required injection rates to treat the whole boiler were anticipated to be higher than the original design values. These included revisions to the air-driven Wilden pumps for transferring slurry from the basement of Unit 3 to the day tank on level 9 to a design that would not "freeze up," and replacing the motors on the Moyno slurry injection pumps with higher rpm, higher horsepower rating motors. Other revisions included minor pipe size upgrades, replacing slurry transfer hoses in bigger diameters, and making additional injection nozzles and lances for the west side of the furnace.

The long-term injection test began the second week of May and continued into the first week of June 2001. The primary measure of the success of the slurry injection tests was the reduction in flue gas SO<sub>3</sub> concentration at the electrostatic precipitator (ESP) B and C outlets, which are nearer the center of the boiler and on the "hot" sides of the air heater outlets. Some SO<sub>3</sub> concentration measurements were made at the beginning of the test and a second series was made at the end of the test. During the period that SO<sub>3</sub> concentrations were not being made, the injection system was typically operated at the highest injection rate that did not result in adverse effects on ESP operation.

After the test was complete, samples collected during the test were chemically analyzed, and data collected were organized, reduced and analyzed. Results from this testing are presented in Section 4 of this Technical Report.

In July, AEP joined the project as a new team member, co-funder, and host site. Their Gavin Station started up new SCR units for NO<sub>x</sub> control on both Unit 1 and Unit 2 (both 1300-MW coal-fired units) in May 1999. As might have been expected, a portion of the SO<sub>2</sub> produced from the high-sulfur coal fired there was oxidized to SO<sub>3</sub> across the SCR catalysts. This conversion essentially doubled the amount of SO<sub>3</sub> in the flue gas going to the units' air heaters, and correspondingly increased sulfuric acid concentrations at the ESP outlet and FGD outlet (stack). The increased sulfuric acid concentrations in the stack flue gas caused greatly increased plume opacity, and appeared to contribute to the occurrence of plume "touch downs" at ground level

near the plant. AEP was interested in joining the project to test magnesium hydroxide injection as a means of controlling stack sulfuric acid concentrations, and TVA agreed to forego testing on one of their units for the opportunity to test sorbent injection on a unit with an operating, full-scale SCR system.

Because the Gavin Station units are considerably larger than the BMP units and with the SCR, the air heater inlet flue gas contained much higher concentrations of  $\text{SO}_3$ , the slurry injection system that was designed for testing at BMP and at a TVA unit was too small. Consequently, AEP contracted with a company that normally conducts their boiler deslagging and chemical cleaning to install and operate a temporary slurry injection system. The temporary slurry injection system consisted of a 1-million-gallon storage tank at the station that was used to store byproduct Mg slurry as it was unloaded from trucks, 21,000-gallon mobile “frac” tanks used as day tanks, and two diesel-driven, 8-inch Moyno pumps used to pump slurry from the ground to the 17<sup>th</sup> floor of the boiler. As in the BMP tests, URS provided injection lances and nozzles, and flexible hoses and pipe manifolds were used to connect the pump discharge to the lances.

Because the supply of byproduct Mg in the quantities that might be required to treat two 1300-MW units was in question, AEP also wanted to test commercial magnesium hydroxide (commercial Mg), so that sorbent was used for a portion of the test. Also, AEP was interested in injecting the slurry lower in the furnace (near the nose of the boiler) to determine whether any benefits might be derived on slagging, whereas the BMP results showed that injection near the top of the furnace was advantageous. Also, the available inspection ports near the nose of the boiler (13<sup>th</sup> floor) were spaced too far apart to ensure good slurry coverage in the furnace, while more ports were available higher in the furnace (17<sup>th</sup> floor, across from the pendant superheat platens). Consequently, most of the testing at AEP involved injecting the slurry at the 17<sup>th</sup> floor level, but during a portion of the test the slurry injection was split, with 40% going to the 13<sup>th</sup> floor and 60% going to the 17<sup>th</sup> floor.

The testing at Gavin Station was conducted from the middle of August through the first week of September. There was relatively little time between when AEP joined the team and when the long-term test at Gavin needed to begin. This is because the SCR systems are intended to operate only during the “NO<sub>x</sub> season” (May 1 through September 30) and the test needed to be completed while the SCR was operating. After the test was complete, samples collected during the test are being chemically analyzed, and data collected were organized, reduced and analyzed. This effort has not yet been completed. Interim results from the testing at Gavin Station are presented in Section 4 of this Technical Report.

One URS subcontract was completed during the current reporting period. Ashworth Engineering designed slurry nozzles specifically for the slurry injection locations on Unit 1 at Gavin Station, and a machine shop in Ohio fabricated the new nozzles. Also, team member AEP implemented two subcontracts. One subcontract was to MPW Industrial Services, Inc., to set up and operate a temporary slurry injection system at Gavin Station. The second subcontract was to E.ON Engineering GmbH, to conduct  $\text{SO}_3$ /sulfuric acid concentration measurements during the long-term test at Gavin Station. This subcontract was required because URS, who conducted these measurements at BMP, did not have staff and equipment available to conduct the measurements at Gavin given the short lead time between AEP joining the test and the required test start date.

Also during the current reporting period, a technical paper summarizing the results of the short-term tests and the first long-term test at BMP was prepared and submitted at the DOE/EPA/EPRI co-sponsored Mega Symposium. Jake Davis of FirstEnergy made the presentation. The symposium was held in the Chicago area the week of August 20-24, 2001.

## **2.2 Problems Encountered**

As might be expected, a variety of problems were encountered during start-up, operation and testing of full-scale sorbent slurry injection systems at two different power plants. However, such problems were for the most part, relatively minor. Some issues and their resolution were described in the previous subsection. Other problems and their eventual resolution are described in Section 4. None were so significant as to require discussion here.

### **3.0 PLANS FOR FUTURE REPORTING PERIODS**

#### **3.1 Plans for Next Reporting Period**

The next reporting period covers the time period October 1, 2001 through March 31, 2002. Since the end date for the Cooperative Agreement is actually February 28, 2002, the next reporting period will actually just cover five months.

During the next reporting period, two technical notes will be prepared and submitted. One technical note will present results from the baseline and short-term sorbent injection tests, and the second will present the results from the two long-term tests, one at BMP and the second at Gavin Station. Also, the final report for the project will be prepared and submitted.

#### **3.2 Prospects for Future Progress**

Any subsequent reporting period would extend beyond the current period of performance of this Cooperative Agreement, which ends February, 2002. Therefore, no progress is anticipated beyond that which is planned for the next reporting period.

## 4.0 TECHNICAL RESULTS

The technical results for the current reporting period (April 1, 2001 through September 30, 2001) are for two longer-term (approximately 25-day) alkaline slurry injection tests. One was conducted on BMP Unit 3, and the second was conducted on AEP's Gavin Station Unit 1. The objective of these tests was to investigate the effectiveness of alkaline sorbents for sulfuric acid control. The tests also evaluated the effects of these sorbents on boiler equipment performance.

The first test evaluated a byproduct magnesium hydroxide [ $\text{Mg}(\text{OH})_2$ ] (byproduct Mg) as a furnace injection sorbent for  $\text{SO}_3$  control. The second, at Gavin Station, evaluated both the byproduct Mg and commercially available magnesium hydroxide (commercial Mg) as furnace injection sorbents for  $\text{SO}_3$  control. The remainder of this section presents and discusses the results from these two tests. The BMP long-term test is discussed in Section 4.1, and the Gavin long-term test in Section 4.2.

### 4.1 Long-term Test on BMP Unit 3

During the long-term test, byproduct Mg slurry was injected into the entire Unit 3 boiler continuously for 23 days, to assess its effectiveness for flue gas  $\text{SO}_3$  control. Various analytical techniques were used to assess the effects of sorbent injection. These primarily included sampling with the Controlled Condensation System (CCS) method for determining flue gas  $\text{SO}_3$  content and, to a lesser extent, an acid dew-point (ADP) meter for determining the sulfuric acid dew point (and, indirectly, the concentration of sulfuric acid) of the flue gas. Daily average  $\text{SO}_2$  concentration measurements were often made coincident with the CCS measurements. EPA Reference Method 26a was used for determining hydrochloric acid (HCl) and hydrofluoric acid (HF), as well as chlorine ( $\text{Cl}_2$ ) and fluorine ( $\text{F}_2$ ) concentrations in the ESP outlet flue gas. A modified version of EPA Method 108 was used to determine flue gas vapor-phase and particulate arsenic concentrations at the economizer outlet.

Impacts on ESP operation were quantified by taking voltage and current data on operating electrical sections of the Unit 3 ESP's. Sorbent and ESP hopper samples were analyzed for magnesium content by acid dissolution followed by atomic absorption analysis. Some sorbent samples were also analyzed for calcium content (atomic absorption) and sulfate content (ion chromatography). All sorbent samples were also analyzed for density and weight percent solids by gravimetric analysis, and for total alkalinity by acid-base titration. Coal samples were collected and analyzed for a variety of parameters according to ASTM protocols. Finally, visual observations were made of boiler furnace and pendant superheater tube surfaces prior to and during sorbent injection, to observe any trends related to slag formation.

Unit 3 is rated at 800 net MW. It has an opposed-wall fired, supercritical boiler rated at approximately 6,415,000 pounds of steam per hour at 3785 psig and 1005°F/1005°F superheat and reheat temperatures. The boiler has 16 burners each on the front and back walls of the furnace. The burners are arranged in four horizontal rows on each wall, with four burners per row. One ball mill pulverizer provides the pulverized fuel for each row. Depending on fuel quality and mill condition, full load can generally be achieved with six of the eight mills in operation (and thus six of eight rows of burners in service).

Unit 3 typically burns a 4% sulfur coal. Coal blends are typically fired, predominantly blends of a McElroy-type coal. The actual coal sulfur can vary over a range from 2.0% to 4.5%. The facility also has permission to burn up to 20% of the fuel as petroleum coke. During the long-term test period, a standard coal blend averaging about 4% sulfur was typically fired.

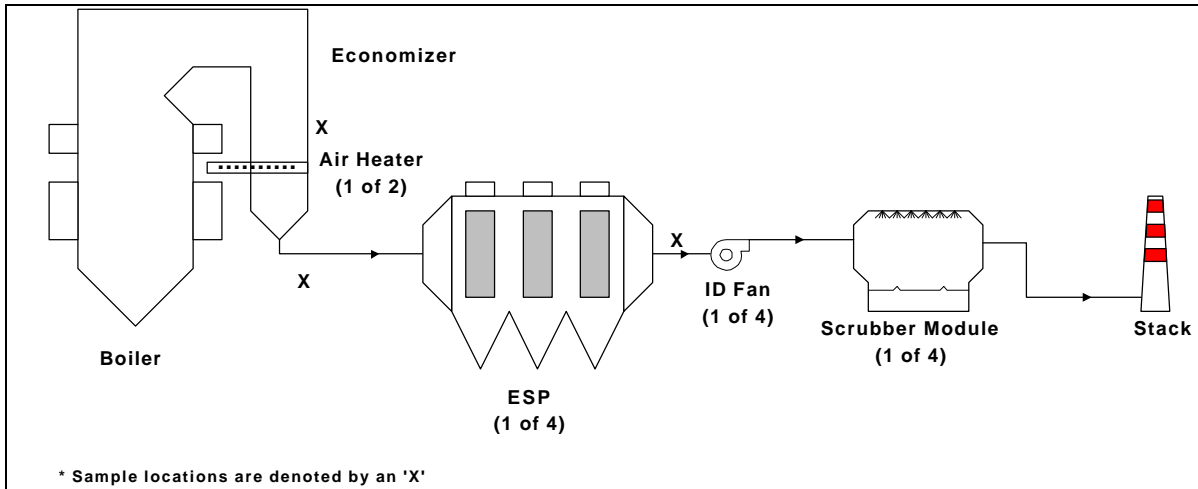
The 800-net-MW unit operates as a swing unit to meet the load demands of the grid. During most of the long-term test, Unit 3 operated at 750 to 860 MW gross load during daylight hours, and 500 to 750 MW gross overnight. The boiler is equipped with two air heaters following the economizer section. The average flue gas temperature at the outlet of the air heaters is controlled to about 320°F due to acid dew point considerations.

Figure 4-1 illustrates the flue gas path for Unit 3, and notes the gas sampling locations used during this test. Flue gas from each of the two air heaters splits into two duct runs, each of which goes to an ESP followed by an induced draft (ID) fan. There are no ties between the four ducts (two per air heater) so when an ID fan is out of service, there is no gas flow through the associated air heater outlet duct and ESP. Correspondingly, the gas flow through the air heater on that side of the boiler is also reduced, although the plant typically tries to bias the gas flow through the operating fans to minimize this effect. Downstream of the ID fans, the flue gas flows to a common plenum, then the gas flow splits to up to five horizontal-gas-flow, FGD system absorber modules (four normally operate at full load). The scrubbers use a magnesium-enhanced, Thiosorbic<sup>®</sup> lime slurry reagent and operate in a natural oxidation mode. The flue gas then goes to a dedicated stack for Unit 3. The flue gas in the stack is saturated at a temperature of about 130°F; no reheat is employed.

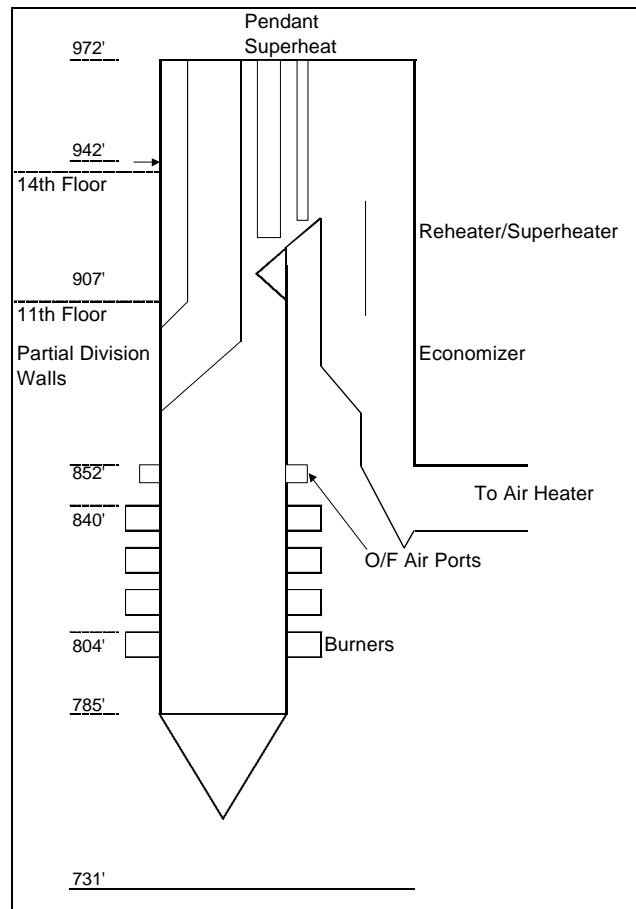
During these tests, injection of sorbent slurries was accomplished through ten air-atomizing nozzles inserted through inspection port openings on the front wall of the boiler. The injection location was at the 14<sup>th</sup> floor of the boiler structure, across from the pendant superheat tubes. The injection levels are illustrated in Figure 4-2.

At the 14<sup>th</sup> floor, there are twelve ports across the face of the boiler. There is a port adjacent to each corner of the boiler along the front wall, then the remaining ports are situated on either side of five partial division walls that are equally spaced across the upper furnace cavity. Figure 4-3 illustrates the twelve potential lance locations. Note, however, that on the 14<sup>th</sup> floor, potential lance location numbers 5 and 8 were blocked by cameras installed in those inspection ports. Consequently, only ten of the twelve potential slurry injection locations could be used.

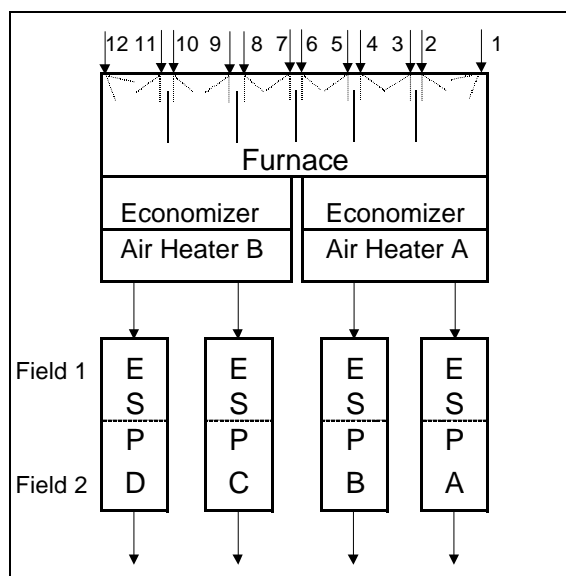
The air-atomizing nozzles were designed by Ashworth Engineering specifically for this application. The proprietary design employs an internal mix configuration, and was designed for relatively low airflow requirements and to achieve a relatively large minimum passage diameter. The air pressure to the nozzles was typically 80 psig.



**Figure 4-1. Illustration of Flue Gas Path for BMP Unit 3**



**Figure 4-2. Illustration of Slurry Injection Levels**



**Figure 4-3. Plan View Illustration of Slurry Injection Locations  
(nos. 5 and 8 were not used)**

The byproduct Mg sorbent injected into the furnace was delivered to the site in truckload quantities, as slurries containing 15 to 20 wt% solids. Two 10,000-gallon slurry storage tanks were situated in the basement of Unit 3. The tanker trucks unloaded into one or both of these tanks. Between the two tanks, approximately 4 to 5 truckloads could be stored on site. From the storage tanks, one of two air-driven diaphragm pumps was used to transfer slurry up to a 1000-gallon “day” tank located on the 9<sup>th</sup> floor of the boiler structure. The day tank level was controlled by a signal from an ultrasonic level indicator on the day tank. Relays controlled by this signal energized (opened) a solenoid valve on the air supply to the transfer pump on low day tank level, and closed the solenoid valve on high level.

From the day tank, one or both of two Moyno progressing cavity pumps were used to feed slurry to the injection nozzles. The Moyno pumps were equipped with magnetic flow meters at their discharge, and pump speed was modulated to maintain slurry flow rate at a set point. The slurry flow rate set point was adjusted by the URS operator according to the density and purity of the reagent, the Unit 3 load, the expected Unit 3 coal sulfur content, and the desired reagent-to-SO<sub>3</sub> molar ratio. Slurry from the Moyno pumps was fed to a manifold, which in turn distributed slurry to the ten injection nozzles. Plant compressed air was connected to each lance individually, through flexible plant air hoses, to provide atomizing air.

Figure 4-3, mentioned above, also illustrates the arrangement of the four ESP’s relative to the two air heaters. Note that, because of the direction of rotation of the regenerative-type air heaters, the flue gas going to the outboard ESPs (labeled “A” and “D” in Figure 4-3) tends to be cooler and have a lower SO<sub>3</sub> content than the flue gas going to the inboard ESP’s (labeled “B” and “C”). However, no attempt was made to bias the sorbent slurry flow to the nozzles on the inboard side of the air heaters to account for this observed stratification. It was felt that the stratification was caused by the drop in gas temperature across the air heater, and was not reflective of stratification in flue gas SO<sub>3</sub> content in the furnace, where the sorbent was injected.



#### 4.1.1 Unit 3 Operating Conditions

The byproduct Mg long-term test was conducted on Unit 3 over the time period May 11 through June 3, 2001. Baseline (no sorbent injection) measurements were conducted several days prior to the beginning of sorbent injection, over the time period May 7 through 10. Baseline measurements included CCS runs for sulfuric acid concentrations, Method 26a for halogens, and modified Method 108 for arsenic. Several CCS baseline repeat measurements were also made on June 4, about 24 hrs after sorbent injection ended.

During the sorbent injection period, a number of CCS runs were made shortly after injection began, over the time period May 12 through May 14, to assess initial sulfuric removal performance with the byproduct Mg. Towards the end of the test period, from May 30 through June 3, a number of measurements were made by the CCS method, Method 26a, and modified Method 108 to quantify steady state long-term test performance.

Unit 3 operating conditions during these specific test periods are summarized in Table 4-1. During most flue gas testing, the steam generator was at close to full load with one to two pulverizers and burner rows out of service. Unit 3 operating conditions during time periods when byproduct Mg was being injected but no flue gas measurements were made are not shown in the table. However, unit loads were generally in the range of 750 to 860 gross MW during daylight hours on weekdays, and varied over the range of 500 to 750 gross MW overnight and on weekends. One weekend in the middle of the test the unit load was dropped into the range of 350 to 450 gross MW so the two steam condensers could be cleaned, one at a time. Unit 3 load variations are illustrated later in this section.

#### 4.1.2 Test Methods

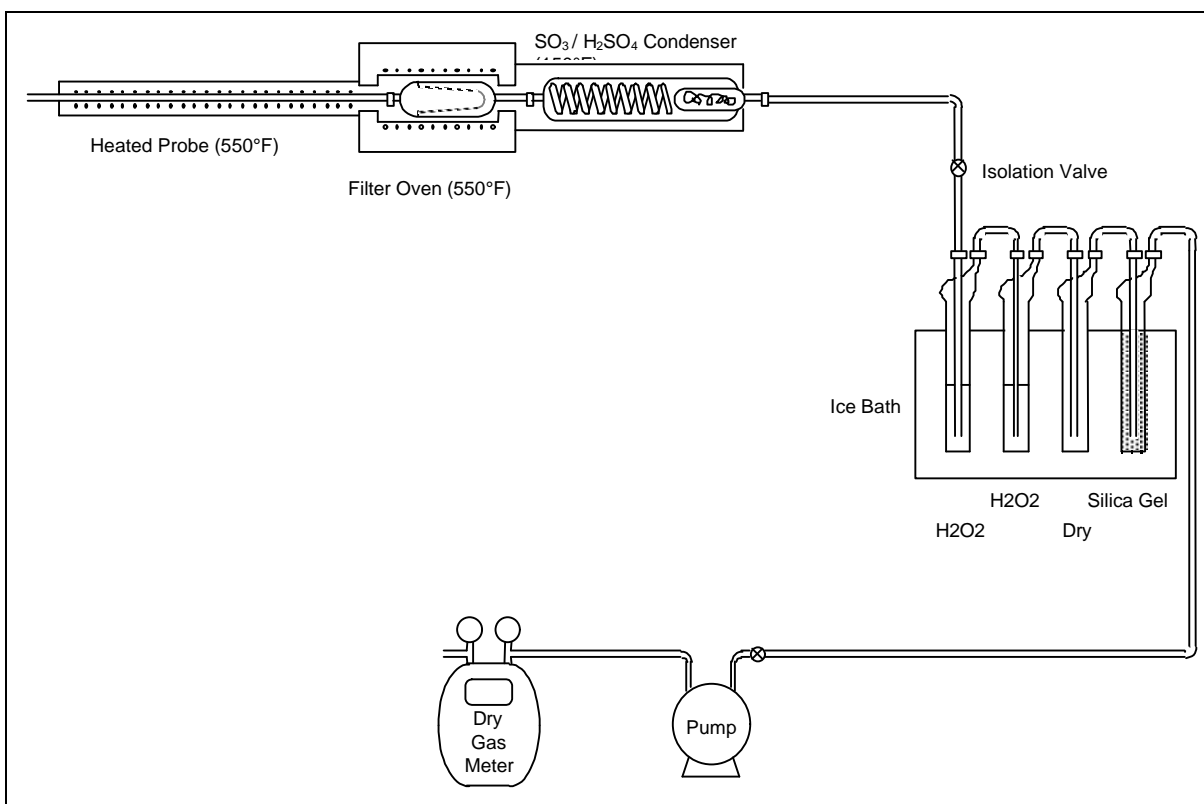
***H<sub>2</sub>SO<sub>4</sub> Vapor by Controlled Condensation.*** Sulfuric acid vapor concentrations were measured at the economizer outlet, air heater outlet, and ESP outlet locations using the controlled condensation system (CCS). A diagram of this sulfuric acid vapor train is shown in Figure 4-4. Controlled condensation is generally regarded as the most accurate method for measuring sulfuric acid vapor concentrations in flue gas, particularly where the flue gas is above the acid dew point. For these units, this would include flue gas temperatures above about 280°F, or all locations upstream of the FGD system.

In the controlled condensation system, a sample of flue gas is pulled from the duct through a heated, quartz-lined probe. Particulate material is removed from the sample using a quartz thimble filter. Both the probe and the filter are maintained at about 550°F to ensure that no sulfuric acid vapor condenses in this part of the sampling system. Next, the filtered flue gas sample passes to a glass condenser that is maintained at a temperature of about 150°F by a circulating water bath. This temperature is well below the acid dew point but above the water dew point. The only material in most flue gases that will condense at this temperature is sulfuric acid vapor. Other acid gases have dew points that are much nearer the water dew point. At the completion of a CCS run, the condenser is removed from the sampling system, and a rinse of the

**Table 4-1. Unit 3 Operating Conditions during Baseline and Long-term Sorbent Injection CCS Testing**

<b>Date</b>	<b>Time Period for CCS Testing</b>	<b>Hourly Average Unit Load (gross MW)</b>	<b>Average Economizer Exit O<sub>2</sub> (%)</b>	<b>Coal Mills Out of Service</b>	<b>ID Fans Out of Service</b>
<b>Baseline Testing:</b>					
5/7/01	17:29-18:52	780-847	3.4-3.8	D	-
5/8//01	9:58-14:28	822-862	3.4	D	-
5/10/01	12:58-17:15	825-854	3.3-3.6	D*	-
<b>Byproduct Mg Long-term Testing:</b>					
5/12/01	10:33-14:14	815-847	3.3-3.4	-	-
5/13/01	11:33-13:59	695-705	3.6-3.7	D, G	-
5/14/01	11:52-14:17	827-858	3.4	D	-
5/30/01	11:15-16:42	836-866	3.4-3.6	-	-
6/1/01	11:15-16:59	605-848	3.4-4.1	D*,E*	-
6/3/01	10:02-13:57	589-668	3.8-4.4	A	D
<b>End of Test Baseline Repeat (CCS only):</b>					
6/4/01	9:50-12:05	822-835	3.4	-	-

\*Off-line during a portion of the testing period



**Figure 4-4. Controlled Condensation Sulfuric Acid Vapor Train**

condenser is analyzed for sulfate content. By measuring the total volume of flue gas pulled through the system and the amount of sulfate in the condenser, the concentration of  $\text{H}_2\text{SO}_4$  vapor in the flue gas can be calculated.

**Acid Dew Point.** During most of the long-term test period, a portable and/or a semi-continuous acid dew-point meter manufactured by Land Combustion were used to determine the acid dew point. These measurements were made at the inlet duct to the B ESP, where the flue gas temperature is approximately 320°F. The acid dew-point measurement can be used to estimate the flue gas content of sulfuric acid. There are several relationships correlating acid dew point to flue gas sulfuric acid concentration, such as those by Verhoff and Banchero.<sup>1</sup> Acid dew-point correlations from different sources are not always in agreement, often yielding results considerably different, especially at high dew points and/or high sulfuric acid concentrations. Acid dew-point measurements were used primarily as an indicator of sorbent effectiveness, but not directly to quantify performance. Consequently the acid dew-point measurement data are not reported herein.

**Method 26a—Hydrogen Halide and Halogen Emissions (chloride and fluoride).** Method 26a is the reference EPA test method for determining hydrogen halide and halogen emissions—hydrochloric and hydrofluoric acids, chlorine and fluorine. This method requires isokinetic

<sup>1</sup> Pierce, Robert R., "Estimating Acid Dewpoints in Stack Gases," *Chemical Engineering*, April 11, 1977, pp 125-128.

sample extraction with an apparatus similar to that used in EPA Method 5. Method 26a is different from Method 5 in that it includes an impinger containing sulfuric acid and an impinger containing sodium hydroxide. With the Method 26a sampling train, a flue gas sample is extracted isokinetically, passes through a heated probe and through a particulate filter contained in a heated oven. Following the particulate filter, the gas sample passes through the impinger train where moisture is removed in the first impinger, hydrogen halides (HCl and HF) are dissolved in the second impinger which contains sulfuric acid, and halogens (Cl<sub>2</sub> and F<sub>2</sub>) are dissolved in the third impinger which contains sodium hydroxide. The samples collected are analyzed by ion chromatography (IC) or ion specific electrode.

**Method 108 – Flue Gas Arsenic Content.** Arsenic is a known SCR catalyst poison. At economizer exit temperatures (about 700°F), arsenic exists in both the vapor and solid phases (i.e., appearing as solid particulate or condensed on fly ash particles). Vapor phase arsenic may have a more pronounced role in catalyst deactivation since the vapor-phase arsenic can diffuse into the catalyst pores. Therefore, knowledge of vapor-phase arsenic concentrations are of value to enable assessment for the potential of catalyst deactivation in coal-fired SCR applications. The standard test method used for measuring arsenic is EPA Method 108. This test method is similar to EPA Method 5, utilizing a heated glass or quartz lined probe to extract a flue gas sample isokinetically and particulate removal by a filter contained in an oven heated to 250°F. Vapor phase arsenic in the sample gas downstream of the filter is collected in an impinger that contains a 0.1 N solution of sodium hydroxide.

This sampling procedure allows for separation between the vapor and solid phases of arsenic only for those arsenic compounds with dew points below approximately 250°F. Since the temperature of the flue gas at the economizer exit is approximately 700°F, vapor phase arsenic compounds with dew points between 250°F and 700°F would condense on the sampling probe or particulate filter. Therefore, the standard method would tend to under-report the amount of vapor-phase arsenic present at the economizer outlet. URS employed an alternative sampling system that should better allow for determination of vapor phase arsenic at 700°F. An in-stack filter such as is used in Method 17, using isokinetic sampling, was used to separate the solid phase from vapor phase arsenic at the actual economizer outlet gas temperature. A quartz probe liner was used downstream of the filter to minimize arsenic adsorption on or reaction with the stainless steel probe surfaces. Therefore, the arsenic removed in the downstream sodium hydroxide impinger should better represent the amount present in the vapor phase in the sample gas at the economizer exit conditions than with the standard method.

Results from the baseline and 23-day byproduct Mg injection test are presented and discussed in the remainder of this section. First, the results of the baseline tests are presented and discussed, then results which quantify the impacts of sorbent injection on Unit 3 sulfuric acid concentrations are discussed. Finally, balance-of-plant issues are discussed, primarily impacts of sorbent injection on ESP performance, and on removal of HCl, HF, chlorine, fluorine, and arsenic.

#### **4.1.3 Baseline Test Results**

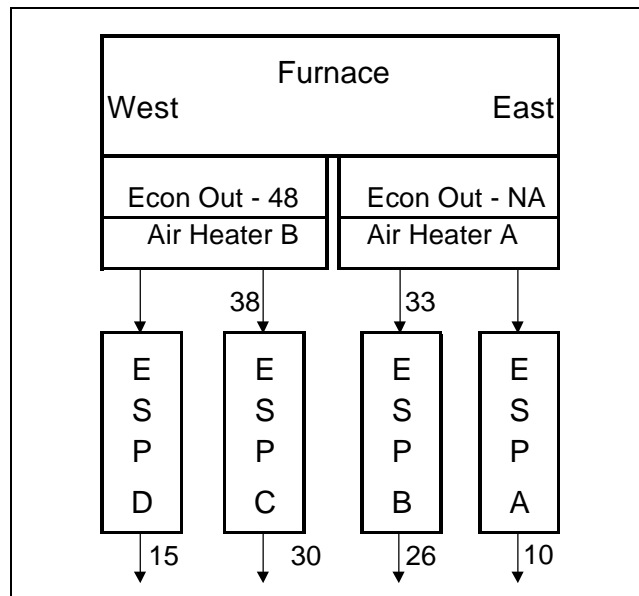
As described earlier, baseline data were collected over several days immediately prior to the initiation of byproduct Mg injection on May 11. The primary objective of these measurements

was to determine baseline (no sorbent injection) SO<sub>3</sub> concentrations at a variety of measurement locations, but additional sampling was conducted for flue gas SO<sub>2</sub>, HCl, HF and halogen gas concentrations, economizer outlet arsenic concentrations, and ESP outlet particulate concentrations. The baseline CCS results are discussed in the following paragraphs, while the results of the other measurements are discussed under Balance of Plant Effects.

Table 4-2 summarizes the results of CCS measurements made at various locations throughout the flue gas path on Unit 3. Please refer to Figures 4-1 through 4-3 to review how these sample locations are laid out in the gas path. Table 4-2 shows the results of individual measurement runs by date and by location. Figure 4-5 summarizes these same data by location, showing the average of all measurements made at a particular location irrespective of sampling date or number of runs.

**Table 4-2. Summary of Flue Gas SO<sub>3</sub> Concentrations Measured for Unit 3 Baseline Testing**

Date	Measured SO <sub>3</sub> Concentration, ppmv (dry basis, at actual O <sub>2</sub> conc.)				
	Run 1	Run 2	Run 3	Run 4	Average
<b>Economizer B Outlet:</b>					
5/7/01	48	51	50	-	50
5/8/01	50	40	45	-	45
5/10/01	40	52	55	-	49
<b>ESP B Inlet/Air Heater A Outlet (Hot Side):</b>					
5/8/01	28	36	33	30	32
<b>ESP C Inlet/Air Heater B Outlet (Hot Side):</b>					
5/7/01	37	-	-	-	-
5/8/01	39	38	39	-	38
<b>ESP A Outlet:</b>					
5/8/01	9.8	11	9.2	-	10
<b>ESP B Outlet:</b>					
5/7/01	19	22	-	-	21
5/8/01	23	22	26	-	24
5/10/01	33	31	30	31	31
<b>ESP C Outlet:</b>					
5/7/01	34	27	-	-	30
5/8/01	29	28	31	-	29
<b>ESP D Outlet:</b>					
5/8/01	15	15	15	-	15



**Figure 4-5. Summary of Baseline CCS Measurements at BMP Unit 3**

When illustrated as averages in Figure 4-5, the results show some side-to-side variation in SO<sub>3</sub> conversion in the furnace and back pass of the boiler, as measured at the “hot” sides of the two air heater outlets, with higher concentrations on the west side of the boiler. Only one economizer outlet was measured for SO<sub>3</sub> concentration, and it showed a substantially higher concentration than was measured at this location during previous baseline testing in October 2000 (48 ppm vs. 28 ppm previously). The current, 48 ppm value represents the average of nine runs conducted over a three-day period, so it appears to be a representative and repeatable value for conditions in early May 2001.

The air heater outlet concentrations measured downstream of this economizer outlet indicate about 20% SO<sub>3</sub> removal across the “B” air heater on its “hot” side. SO<sub>3</sub> does not appear to be removed across either the “B” or “C” ESP’s at a high percentage; on average the removal percentage across these two ESP’s varies from 2 to 6%. The sampling ports for the outlet of the “cold” side of the air heaters and inlets to the “A” and “D” ESP’s are difficult to access on Unit 3, therefore no CCS measurements were made at those locations. However, comparing the west economizer outlet value to the concentrations measured at the outlet of the “D” ESP, a total of 67% reduction in SO<sub>3</sub> concentration is seen. Most of this reduction is presumed to occur across the cold side of the air heater.

Throughout this report, SO<sub>3</sub> removal during sorbent injection is reported as the percent reduction in SO<sub>3</sub> concentration measured at the B ESP outlet for injection versus baseline conditions. It would be possible to calculate a higher percentage by comparing baseline economizer outlet values to ESP outlet values during sorbent injection. However, the latter calculation would overstate the effect of reagent injection, because it would also incorporate the removal across the air heater and ESP that is already seen at baseline (no injection) conditions.

The economizer outlet SO<sub>3</sub> concentration data in Table 4-2 were used to calculate an average SO<sub>2</sub> to SO<sub>3</sub> conversion percentage for Unit 3, to serve as a basis for reporting sorbent-to-SO<sub>3</sub> molar ratios. Seven Unit 3 coal feed samples were collected and analyzed for the long-term test. The ultimate analyses of these coal samples are shown in Table 4-3. These results were used in combustion calculations to calculate the total amount of SO<sub>2</sub> that would be produced from the combustion of these coals, then that value was compared to the measured economizer outlet SO<sub>3</sub> concentrations. For the October 2000 baseline measurements reported in a previous Technical Progress Report, the calculated conversion percentage was 0.9%, which is near the middle of the expected range for bituminous coals in pulverized-coal-fired boilers (approximately 0.5% to 1.5%). For the previous, short-term tests conducted at BMP Unit 3, a “rounded” value of 1% was used to estimate SO<sub>3</sub> production as a function of sulfur in the coal fired.

**Table 4-3. Ultimate Analyses of Coal Samples from the Unit 3 Baseline Test**

<b>Date sampled</b>	<b>5/17/01</b>	<b>5/22/01</b>	<b>5/25/01</b>	<b>5/30/01</b>	<b>5/31/01</b>	<b>6/1/01</b>	<b>6/3/01</b>
% Moisture	6.69	6.86	6.73	7.33	6.49	5.77	5.47
% Carbon	66.52	67.27	67.66	66.39	68.14	68.02	73.71
% Hydrogen	3.99	3.98	3.71	3.98	3.63	4.21	3.35
% Nitrogen	1.19	1.19	1.19	1.21	1.23	1.23	1.31
% Sulfur	3.50	3.79	3.99	3.70	3.64	3.69	4.52
% Ash	12.99	12.24	13.08	11.63	12.44	12.14	9.39
% Oxygen (diff)	5.12	4.67	3.64	5.76	4.43	4.94	2.25
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV (Btu/lb)	11,909	12,103	12,790	11,971	12,107	12,227	12,876

Unfortunately there was not a coal sample available for the days the baseline measurements were made (May 7-10), so the average coal sulfur for all of the long-term test coal samples was used as the basis for calculating this conversion. The May 2001 data for the “B” economizer outlet correspond with a significantly higher 1.6% conversion of the coal sulfur to SO<sub>3</sub>, based on the average of 3.83 wt % sulfur in the seven coal samples. This conversion percentage can be affected by many variables, including excess air levels in the furnace, slag accumulations on heat transfer surfaces, etc. It is not certain why this conversion was higher than had been measured previously in October, 2000, but it could be related to the relative amounts of slagging and fouling of boiler heat transfer amounts during the two test periods. The May test immediately preceded a planned boiler outage, and the boiler heat transfer surfaces had not been cleaned for some period.

Downstream measurements indicated that the SO<sub>3</sub> production was higher on the west side of the furnace (corresponding with the “B” economizer outlet) than on the east side. Although the outlet SO<sub>3</sub> concentrations from the east economizer were not measured, it is expected that the conversion of SO<sub>2</sub> to SO<sub>3</sub> would have been lower for that side. Consequently, the value for conversion of SO<sub>2</sub> to SO<sub>3</sub> in the Unit 3 boiler for the long-term test was assumed to slightly lower than the measured conversion, at 1.5%, for calculating sorbent-to-SO<sub>3</sub> mole ratios. However, it is recognized that the actual percentage at any given time could vary because of the influences of excess air levels and other factors.

#### 4.1.4 Long-term Test SO<sub>3</sub> Removal Results

The long-term slurry injection test at BMP Unit 3 was conducted over the time period May 11 through June 3, 2001, using a byproduct magnesium hydroxide produced at Allegheny Energy's Pleasants Station. The Pleasants Station has a modified Dravo Thiosorbic<sup>®</sup> Lime FGD process that employs magnesium-enhanced scrubbing, with external forced oxidation to produce a gypsum byproduct. The remaining liquor after the gypsum is produced is further processed by lime addition to precipitate a mixture of magnesium hydroxide and gypsum particles. This stream is purified to recover most of the gypsum, and a second byproduct is a slurry that contains a mixture of magnesium hydroxide (about 65% of the solids) and gypsum fines (most of the remaining solids). With the current equipment configuration at the Pleasants Station, this byproduct slurry is produced at about 15 to 20 wt % total suspended solids.

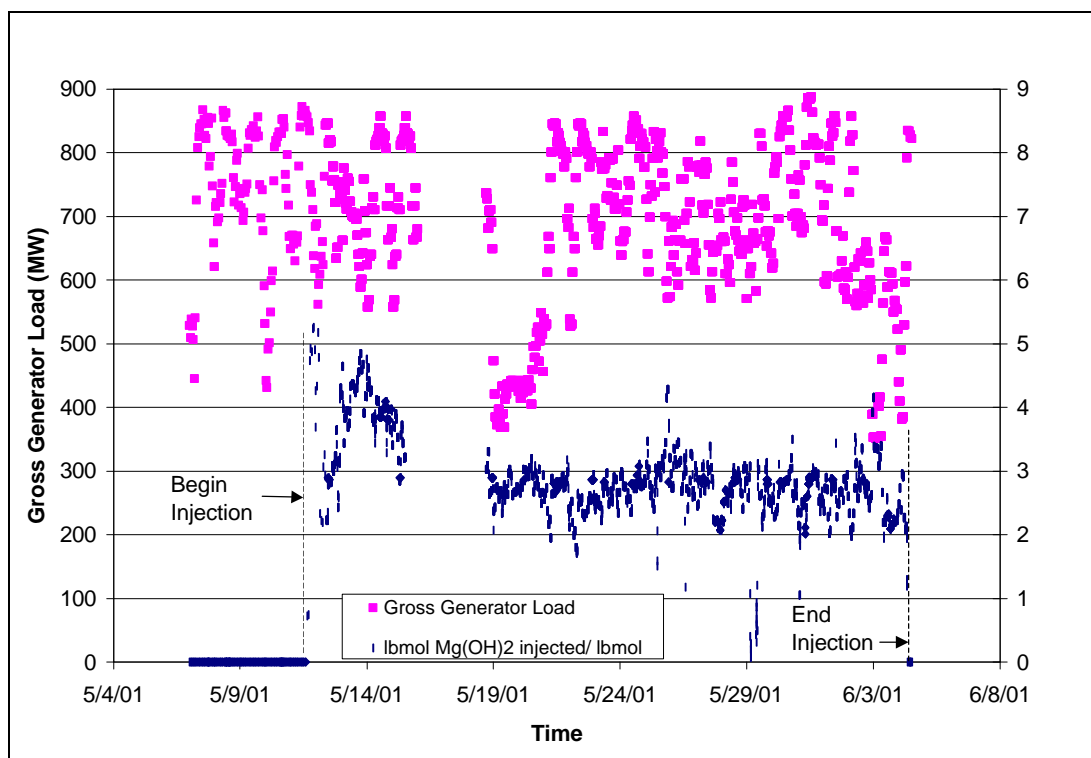
The solids in this slurry average about 4 to 5 microns for a mass mean particle diameter, and have a specific surface area of about 49 to 63 m<sup>2</sup>/g. The gypsum solids in this slurry most likely have a low specific surface area (less than 5 m<sup>2</sup>/g) and contribute very little to the average, so the specific surface area of the magnesium hydroxide in this slurry is probably in the range of 70 to 100 m<sup>2</sup>/g.

The byproduct slurry was trucked from the Pleasants Station and unloaded into the 10,000-gallon storage tanks at BMP Unit 3. Eight to nine truckloads per day were typically required at the slurry injection rates tested.

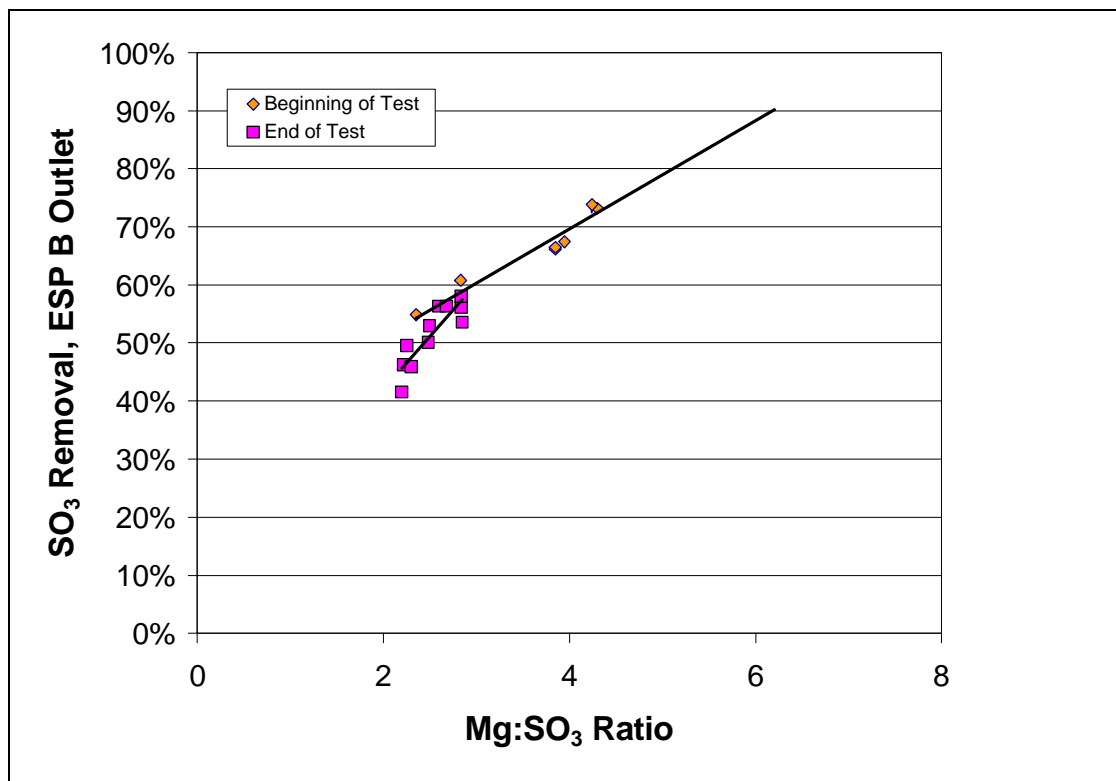
The objectives of the long-term tests were to evaluate the ability to control sulfuric acid emissions, as measured at the ESP outlet, over an extended period of time, and to evaluate balance of plant effects from sorbent injection. Figure 4-6 illustrates the Unit 3 gross load, and the byproduct Mg injection rates over the test duration.

The sulfuric acid removal performance was measured by CCS method sampling only at the beginning (May 12-14) and the end of the long-term test period (May 30-June 3). The sulfuric acid removal results from these two byproduct Mg long-term test periods are summarized in Table 4-4 and plotted in Figure 4-7. The Mg:SO<sub>3</sub> molar ratios in the table and in Figures 4-6 and 4-7 are based on the amount of Mg(OH)<sub>2</sub> in the byproduct slurry injected, the Unit 3 coal feed rate, ultimate analyses of coal samples for this time period, and a factor of 1.5% conversion of coal sulfur to SO<sub>3</sub>, which was derived from the baseline data as described above. The coal ultimate analysis data were summarized in Table 4-3. The results in Table 4-3 showed that the coal quality varied somewhat during the long-term test period, with coal sulfur levels ranging from 3.5 wt % to 4.5 wt %. As mentioned above, the coal sulfur averaged about 3.8 wt % for this test, which is in the range of about 3.5 to 4 wt % for the previous, short-term tests.





**Figure 4-6. Gross Unit Load and Sorbent Injection Rate During Long-term Test**



**Figure 4-7. Results from the Long-term Byproduct Mg Test (ESP B Outlet Location)**

**Table 4-4. Summary of Sulfuric Acid Removal Results from  
Long-term Byproduct Mg Test**

Date/Time	Mg:SO <sub>3</sub> Molar Ratio	SO <sub>3</sub> Concentration (ppmv, dry basis at actual O <sub>2</sub> concentration)			
		ESP A Outlet	ESP B Outlet	ESP C Outlet	ESP D Outlet
5/12/01 10:46	2.4	-	11	11	-
5/12/01 11:52	2.9	-	12	7.3	-
5/12/01 12:57	2.8	-	10	12	-
5/13/01 11:45	4.3	1.9	6.8	-	-
5/13/01 12:31	4.2	2.2	7.0	-	-
5/13/01 13:11	4.2	2.1	7.1	-	-
5/14/01 11:55	3.9	2.7	8.9	-	-
5/14/01 12:40	3.8	3.2	9.9	-	-
5/14/01 13:26	3.8	3.2	9.7	-	-
5/30/01 11:17	2.8	-	13	6.9	-
5/30/01 12:07	2.8	-	13	7.9	-
5/30/01 12:53	2.8	-	15	7.2	-
5/30/01 14:31	2.9	4.7	-	-	4.9
5/30/01 15:16	2.9	4.5	-	-	4.4
5/30/01 16:00	3.0	4.1	-	-	4.2
6/1/01 14:11	2.5	-	14	4.2	-
6/1/01 14:52	2.5	-	15	-	-
6/1/01 15:28	2.6	-	13	5.1	-
6/1/01 16:08	2.7	-	13	2.9	-
6/3/01 10:11	2.3	-	13	4.2	-
6/3/01 10:52	2.2	-	14	6.4	-
6/3/01 11:47	2.2	-	16	3.6	-
6/3/01 12:23	2.3	-	14	5.0	-
6/4/01 10:00	0.0	-	33	12	-
6/4/01 10:30	0.0	-	32	12	-
6/4/01 11:00	0.0	-	33	12	-
6/4/01 11:30	0.0	-	37	12	-

The results plotted in Figure 4-7 are for sulfuric acid removal as measured at the ESP B outlet. The ESP A and ESP D data were not used because the outlet sulfuric acid concentrations from these ESPs are typically much lower than from ESPs B and C, because ESPs A and D take flue gas from the cool side of the air heaters. In the short-term tests previously conducted at BMP Unit 3, where the sorbent injection was just on the east half of the furnace, the ESP B data were always used as an indicator of sorbent performance. With injection across the entire furnace, it was expected that both the ESP B and ESP C data could be used as a measure of sorbent effectiveness. However, the ESP C data from the latter portions of the test appear to be anomalous. The end-of-test ESP C outlet sulfuric acid concentrations were measured to be about half or less of those at the ESP B outlet, both during sorbent injection on May 31 through June 3 and after sorbent injection ceased on June 4.

Table 4-5 compares ESP B and ESP C data during baseline and injection conditions, corrected to a common 3 % O<sub>2</sub> basis to account for any variations in air inleakage from side to side and from the beginning to the end of the test. The data in the table show a dramatic decrease in the values measured at the ESP C outlet at the end of the test, compared both to the ESP C outlet values at the beginning of the test and to the ESP B outlet data at the end. There is no clear explanation for this apparent bias, but it makes the ESP C data suspect. They were therefore not used as a basis for reporting sulfuric acid removal efficiencies.

**Table 4-5. Comparison of ESP B and ESP C  
Outlet Sulfuric Acid Concentration Data**

Time Period	Sulfuric Acid Concentration (ppmv, dry at 3% O <sub>2</sub> )	
	ESP B Outlet	ESP C Outlet
Pre-test Baseline	32	40
May 12 (2.8 Mg:SO <sub>3</sub> )	13	13
May 30 (2.8 Mg:SO <sub>3</sub> )	17	9.9
After-test Baseline (June 4)	39	14

The results plotted in Figure 4-7 show the performance measured at the beginning of the test compared to that measured at the end of the test. At the beginning of the test, the Mg:SO<sub>3</sub> molar ratios were varied from about 2.4 to 4.3 moles magnesium hydroxide injected per mole of SO<sub>3</sub> under baseline conditions, while at the end of the test, the ratios were in a somewhat lower range of 2.2 to 2.9:1. At the end of the test, sorbent injection rates and overall sulfuric acid removal percentages were controlled to lower values to avoid adverse effects on ESP performance (see below). Apparent sulfuric acid removal efficiencies ranged from about 55% to 75% at the beginning of the test, and from about 40% to 60% at the lower Mg:SO<sub>3</sub> ratios at the end of the test. The removal percentages for the beginning of the test are based on the baseline values for ESP B outlet from May 7-10, while the end of test values are based on baseline values from June 4.

In general, the data from the beginning and end of the test overlap well for measurements at the same Mg:SO<sub>3</sub> ratios. The figure also shows linear least squares fits of the data for the two time periods. The two data sets show different slopes, but this may be because the later data includes more results at lower ratios, where the slope between molar ratio for the injected byproduct Mg and baseline SO<sub>3</sub> would be expected to be steeper. At higher injection rates and higher overall SO<sub>3</sub> removal percentages, this relationship would be expected to flatten out.

The beginning-of-test data, which include higher injection rates and higher sorbent molar ratios, were extrapolated based on a linear correlation of the data, to determine what molar ratio would be projected to achieve 90% sulfuric acid removal at the ESP B outlet. This extrapolation is also illustrated in Figure 4-7. The extrapolation predicts that a Mg:SO<sub>3</sub> molar ratio of about 6.5:1 would be required to achieve 90% sulfuric acid removal. This is slightly lower than the value of approximately 7:1 seen in the short-term test results with byproduct Mg injection. However, this is still seen as very good agreement between the two data sets, particularly considering that there are at least two reasons why the long-term test results might be expected to

under-predict the Mg:SO<sub>3</sub> requirement seen in the short-term test results. One is that the short-term tests were conducted on only half of the furnace, and there was evidence that some of the injected sorbent migrated to the other side of the furnace and did not contribute to sulfuric acid removal as measured at the ESP B outlet. The molar ratio requirements measured in the short-term tests may have been overstated for this reason. The other consideration is that the linear extrapolation of the long-term test results may be somewhat optimistic in terms of sulfuric acid removal at higher Mg:SO<sub>3</sub> ratios, as this relationship would be expected to flatten somewhat at higher molar ratios and higher overall sulfuric acid removal percentages.

#### **4.1.5 Long-term Test Balance of Plant Effects**

Balance of plant effects measured were primarily focused on the impacts of sorbent injection and SO<sub>3</sub> removal on ESP performance during the long-term slurry injection tests. However, measurements were also made of halogen species and arsenic concentrations in the Unit 3 flue gas, both during baseline and sorbent injection conditions.

***Impacts of Sorbent Injection and SO<sub>3</sub> Removal on ESP Operation.*** During the short-term sorbent injection tests on Unit 3, the impacts of sorbent injection and SO<sub>3</sub> removal were measured in as many as three different manners. First, the ESP electrical properties were measured, by recording ESP electrical operating conditions (secondary current and voltage and/or power input) for each electrical section during the test. Second, the outputs from the unit's ESP outlet opacity monitors were retrieved from the plant's data archive for these time periods and reviewed. Finally, for during the initial baseline and at the end of the long-term test, the impact of sorbent injection and SO<sub>3</sub> removal on ESP outlet particulate loading was quantified by conducting mass loading measurements via EPA Method 17.

Note that the impacts from sorbent injection appear to be predominantly due to impacts from the resulting SO<sub>3</sub> removal. Sorbent injection could have adverse effects if the sorbent has a higher bulk particle resistivity than the fly ash particles. If the resistivity increases into an undesirable range, the corona current in the ESP fields could be limited to low levels by the onset of sparking, and the ability to charge and collect the particles could be severely limited. Also, the addition of the fine particles represented by the injected sorbent can lead to space charge effects that would lower the resulting corona current at a given applied voltage. This did not appear to be a significant effect during the short-term tests. Instead, removal of SO<sub>3</sub> upstream of the ESP was observed to have an adverse effect on the resistivity of the fly ash particles themselves. When the SO<sub>3</sub> is removed by the sorbent before it has a chance to be adsorbed onto fly ash particles, it can result in greatly increased fly ash resistivity.

The following describes the data collected during the long-term slurry injection tests, and what those data indicate about ESP impacts.

The previous, short-term byproduct Mg test was successful at achieving 90% or greater SO<sub>3</sub> removal as measured at the ESP B outlet. The ESP B inlet SO<sub>3</sub> concentrations were measured to have been lowered into the range of 3 to 4 ppm, and the outlet concentrations to 2 ppm. ESP impacts during the byproduct Mg injection test were summarized in the previous Technical Progress Report, and showed an observed adverse effect on ESP performance that appeared to be directly related to the effects of high SO<sub>3</sub> removal. The observed effect did not appear to be

related to sorbent injection rate per se, as a high injection rate was experienced during the first week of the test with no apparent effect on ESP particulate emissions. The first week's data were for slurry injection at the 11<sup>th</sup> rather than 14<sup>th</sup> floor, and high SO<sub>3</sub> removal efficiencies were not seen.

The data from the short-term byproduct Mg test also suggest that the "A" ESP was also affected by the byproduct Mg injection to achieve low SO<sub>3</sub> concentrations on the east side of the boiler, but to a much lesser extent than ESP B. ESP A is on the side experiencing injection, but showed only a minor effect on outlet particulate levels during this period. This may be because ESP A receives gas from the "cold" side of the air heater, so the flue gas treated is much cooler than that treated in ESP B. These data suggest that at the lower flue gas temperature, much lower SO<sub>3</sub> concentrations are adequate for fly ash conditioning than are required for ESP B. Such a relationship is consistent with theory.

It appears that the SO<sub>3</sub> removal resulting from byproduct Mg injection, down to 2 ppm in the ESP B outlet gas, had a strong, adverse effect on ESP B performance. It became clear that for continued operation on the entire furnace, the injection rate and SO<sub>3</sub> removal level would be limited by ESP performance. For the long-term test, we had to try to optimize the slurry injection rate to achieve the maximum level of SO<sub>3</sub> removal while maintaining acceptable ESP particulate control performance. From the limited data available from the short-term test it was estimated that the "B" and "C" ESP outlet SO<sub>3</sub> concentrations would have to be maintained somewhere in the range of 5 to 8 ppm unless some other form of fly ash resistivity conditioning (e.g., flue gas humidification) was employed.

When the long-term test was begun in early May, it became clear that two of the four ESPs were not performing well. Electrical sections in both the "C" and "D" ESP were operating at very low power input levels even before sorbent injection began. The electrical performance of the four ESPs is summarized in Table 4-6, which shows example readings from a full-load operation period during baseline testing. The data in the table show that in the "A" and "B" ESPs, the first fields typically were operating with secondary current levels of about 700 to 900 mA, and power levels of 30 to 45 kW. While the CA electrical section appeared to be operating normally, the other first field of ESP C, "CC," was operating at a secondary current of only 39 mA and a power input of only 1 kW. In ESP D, the reductions were not as great, but both DA and DC were operating at secondary current levels of about 200 to 300 mA, and power levels of only 10 to 15 kW. ESP outlet particulate loadings (as indicated by the plant opacity monitors) were not available for the "C" and "D" ESPs, but the "A" and "B" ESP outlet loadings were indicating less than 100 mg/aM<sup>3</sup>.

There were two possibilities as to why these two ESPs were operating at reduced power. First, the plant had conducted a dolomite injection test on Unit 3 a week before the long-term test baseline testing began. Dolomite is injected at relatively high rates (e.g., several percent of the total coal feed rate to the boiler) and the calcium oxides and salts produced from this injection are known to have a high bulk resistivity, and to form solids that can be difficult to remove once

**Table 4-6. Baseline ESP Electrical Operating Conditions (May 8, 2001, 8:00 a.m.)**

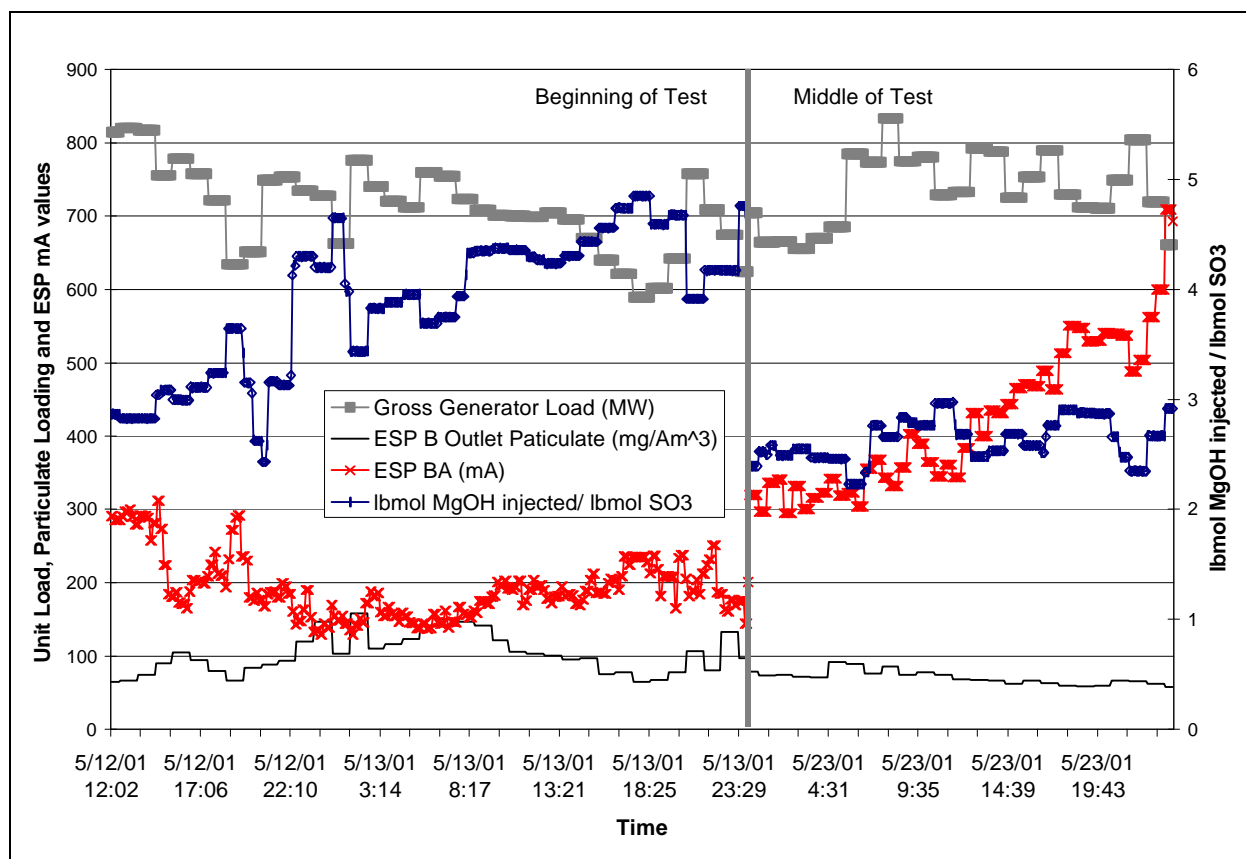
ESP Electrical Section	Secondary Current (mA)	Secondary Voltage (kV)	Power Input (kW)	ESP Outlet Particulate Loading (mg/aM <sup>3</sup> )
AA*	916	49.1	44.5	68.0
AB	600	44.1	36.9	
AC*	853	41.2	35.1	
AD	869	46.9	40.9	
BA*	679	51.8	29.3	83.4
BB	324	51.3	14.7	
BC*	814	48.9	39.8	
BD	624	55.0	34.6	
CA*	671	55.0	36.3	Out of Service
CB	766	53.7	36.6	
CC*	39	32.2	1.0	
CD	498	46.5	21.1	
DA*	213	50.9	9.1	Out of Service
DB	450	43.4	19.9	
DC*	332	44.5	12.8	
DD	173	26.1	5.1	

\*Upstream (first) electrical sections

deposited on metal surfaces. It is possible that half of ESP C and ESP D performance was adversely affected by a build-up of high-resistivity, calcium-based solids on plates and wires in the affected electrical sections. Another possibility is that these sections were adversely affected by mechanical problems such as broken wires or miss-aligned plates.

Whatever reason, it was decided that the impacts of sorbent injection on ESP performance would be best tracked by observing ESP B performance. ESP A treats flue gas from the cold side of the air heater outlet, and short-term test results showed that it was much less affected by sorbent injection and sulfuric acid removal than ESP B. However, it was also decided that injection rates should also be controlled to avoid excessive particulate emissions from the already poorly performing “C” and “D” ESPs. Thus, the injection rate and sulfuric acid removal performance might have to be controlled to lower levels than if all four ESPs were performing well.

Figure 4-8 illustrates typical conditions for ESP B at the beginning of sorbent injection, and about midway through the test. End-of-test data were not plotted because only individual “snapshot” values were available for ESP electrical conditions, which were not conducive to producing trend plots. The data in Figure 4-8 show that at the beginning of the test, byproduct Mg injection rates were relatively high (Mg:SO<sub>3</sub> molar ratios approximately 4:1 to 5:1), and electrical section BA secondary currents were in the range of 150 to 300 mA. These secondary currents are less than half the baseline value, as shown in Table 4-6. The reduced secondary currents, and ultimately reduced power input, are most likely due to higher resistivity in the particulate matter entering the ESP, since approximately three-fourths of the sulfuric acid was



**Figure 4-8. Comparison of ESP Electrical and Outlet Loading Conditions between the Beginning and Middle of the Long-term Test**

being removed from the flue gas by sorbent injection. The data in the figure also show that the ESP B outlet particulate loadings were somewhat higher than during baseline, in the range of approximately 75 to 150 mg/aM<sup>3</sup>. The data in Table 4-4 show that over this time period, ESP B outlet sulfuric acid concentrations were in the range of 7 to 10 ppm, which represents approximately 75% removal of flue gas sulfuric acid.

The right side of Figure 4-8 shows comparable data from the middle period of the long-term test. The plant had concerns about the ESP B outlet particulate loading indications increasing above 100 mg/aM<sup>3</sup>, primarily out of concern over what the emissions might be from the poorly performing ESP C. Consequently, the sorbent injection rate was decreased to a molar ratio between 2.5:1 and 3:1 for the remainder of the test. The data plotted on the right side of 4-8 show that decreasing the sorbent injection rate into this range raised the BA secondary current values into the range of 300 to 600 mA with the unit at high load (>700 gross MW) and lowered the ESP B outlet particulate loading indications into the range of 60 to 90 mg/aM<sup>3</sup>. Although no CCS measurements were made during this period, the sulfuric acid concentration data in Table 4-4 indicate that the ESP B outlet concentrations would be in the range of 10 to 15 ppm, corresponding to about 55 to 70% sulfuric acid removal.

The ESP B performance remained much the same as is illustrated in the right side of Figure 4-8 through the end of the test. For example, on May 30 the gross unit load was in the range of 850

to 870 MW, the byproduct Mg injection ratio was about 2.9:1, and the BA secondary current values were in the range of 400 to 500 mA. The ESP B outlet particulate loading indications were in the range of 50 to 70 mg/aM<sup>3</sup>. The ESP B outlet sulfuric acid concentrations were measured at 13 to 15 ppm during this time period.

These data indicate that sorbent injection to achieve sulfuric acid removal did have a tendency to reduce the input power levels achievable in the well-performing ESP B, most likely due to increased resistivity of the particulate matter as sulfuric acid was removed from the ESP inlet flue gas. After initial concerns about ESP performance early in the test, the Mg:SO<sub>3</sub> molar ratio was lowered into the range of 2.5:1 to 3:1 for the remainder of the test, and acceptable ESP performance was observed for the remainder of the test. This injection resulted in ESP B outlet sulfuric acid concentrations in the range of 10 to 15 ppm, corresponding to about 55% to 70% relative to baseline values. It may have been possible to inject at higher molar ratios and achieve higher sulfuric acid removal efficiencies if all four ESPs had been in good operating condition with respect to electrical conditions, though.

***Effects of Sorbent Injection and SO<sub>3</sub> Removal on ESP Outlet Particulate Loading.*** ESP outlet particulate loadings were measured by EPA Method 17 during baseline operation at the beginning of May, and at the end of the long-term test in late May/early June. The results of ESP outlet particulate loading measurements are summarized in Table 4-7.

It should be noted that the measurements were not all made at the same measurement location, as shown in the table. At the beginning of the baseline measurements, the outlets of ESPs B and C were traversed on each run, collecting samples from a nine-point traverse of the outlet duct of each ESP. Because of concern over the operation of ESP B, as discussed above, it was decided to collect a sample from the outlet of ESP B only on the third day. This third run was conducted at a single point of representative gas flow at the outlet of ESP B. As can be seen from the results in the Table, this third run showed considerably lower mass loading results, which suggests that the mass loadings on the first two runs were biased by poor performance on ESP C.

At the end of the sorbent injection period, it was decided that the best indicator of ESP performance would be to traverse the outlets of ESPs B and C, as this traverse would indicate mass loadings from the half of the plant that appeared to have well-performing ESPs. While this decision resulted in making measurements that probably best represented ESP performance after over 20 days of sorbent injection, it made comparison with baseline measurements difficult since they were made at a different location.

The end-of-test results in Table 4-7 show that at full load (May 31) ESP A and B outlet mass loadings were about 0.02 gr/dscf, with calculated mass loadings of approximately 0.04 lb/MM Btu. These values are lower than the ESP B and C baseline traverse values, but above the ESP B baseline single-point loading. It is not possible to make a quantitative evaluation of the impact of sorbent injection on outlet loadings from ESP A and ESP B from these data. However, it is clear that ESPs A and B were still performing well after 20 days of continuous sorbent injection and sulfuric acid removal upstream.



**Table 4-7. Summary of Method 17 Results**

<b>Date</b>	<b>Run</b>	<b>Unit Load (gross MW)</b>	<b>Sampling Location</b>	<b>Mass Loading (grains/DSCF)</b>	<b>Emission Rate (lb/MMBtu)</b>
5/9/01	1	825-834	ESP B & C Outlet Traverse	0.030	0.065
5/9/01	2	750-827	ESP B & C Outlet Traverse	0.047	0.101
5/10/01	3	825	ESP B Outlet, Point C2	0.002	0.004
<b>Baseline Average:</b>				<b>0.027</b>	<b>0.057</b>
5/31/01	1	864-888	ESP A & B Outlet Traverse	0.023	0.049
5/31/01	2	818-823	ESP A & B Outlet Traverse	0.022	0.047
5/31/01	3	815	ESP A & B Outlet Traverse	0.018	0.039
Daily Average:				0.021	0.042
6/2/01	1	629	ESP A & B Outlet Traverse	0.014	0.030
6/2/01	2	564-576	ESP A & B Outlet Traverse	0.014	0.030
6/2/01	3	593-645	ESP A & B Outlet Traverse	0.014	0.030
<b>Daily Average:</b>				0.014	0.030
<b>Injection Average:</b>				<b>0.018</b>	<b>0.038</b>

**Flue Gas Halogen Species Concentrations.** Method 26a sampling was employed during the baseline and at the end of the sorbent injection period to measure the effects of sorbent injection on the concentrations of flue gas halogen species at the ESP B outlet location. Species measured included hydrochloric acid and chlorine, hydrofluoric acid and fluorine. The objective of making these measurements was to determine if any of these species would be effectively removed from the flue gas by the injected slurry sorbent. Baseline measurements were also made in October 2000 immediately prior to short-term slurry injection tests, but no corresponding measurements were made during sorbent injection during those short-term tests.

The results of the recent long-term test measurements are summarized in Table 4-8. Flue gas concentration data in Table 4-8 show that the baseline hydrochloric acid (HCl) concentration averaged about 22 ppm, while the hydrofluoric acid (HF) concentration averaged 11 ppm. Both of these values are in the typical range for bituminous coals, but are lower than the baseline concentrations measured in October 2000 (36 ppm and 14 ppm, respectively). The chlorine (Cl<sub>2</sub>) and fluorine (F<sub>2</sub>) concentrations were measured to be much lower, at 2.4 ppm and 0.3 ppm, respectively. These values are higher than the concentrations measured last October (0.6 ppm and 0.05 ppm, respectively).

Table 4-8. Summary of Method 26a

Date	Run	Flue Gas Concentration Data				Mass Balance Data					
		Hydrogen Halides		Halogens		Chlorine in Coal, lb/hr	Chlorine in Flue Gas, lb/hr	Chlorine Mass Closure, %	Fluorine in Coal, lb/hr	Fluorine in Flue Gas, lb/hr	Fluorine Mass Closure, %
		HCl, ppmv	HF, ppmv	Cl <sub>2</sub> , ppmv	F <sub>2</sub> , ppmv						
5/9/01	1	26.5	10.8	1.1	0.08	254*	282	111	46.9*	57.7	123
5/10/01	2	19.0	10.9	3.2	0.33	268*	263	98	49.5*	64.1	129
5/10/01	3	19.5	11.3	2.9	0.39	274*	268	98	50.6*	68.4	135
<b>Baseline Ave:</b>		<b>21.7</b>	<b>11.0</b>	<b>2.4</b>	<b>0.27</b>	<b>265</b>	<b>271</b>	<b>102</b>	<b>49.0</b>	<b>63.4</b>	<b>129</b>
5/31/01	1	27.1	12.5	0.20	0.01	317**	284	90	49.5**	69.3	140
5/31/01	2	27.0	13.9	0.40	0.01	302**	273	90	53.6**	72.9	136
6/2/01	1	25.7	13.2	0.31	0.02	218*	223	102	40.3*	60.1	149
6/2/01	2	26.5	13.0	0.35	0.01	202*	213	105	37.3*	54.7	147
6/2/01	3	26.7	12.7	0.25	0.01	205*	217	106	38.0*	54.5	143
<b>Injection Ave:</b>		<b>26.6</b>	<b>13.1</b>	<b>0.31</b>	<b>0.01</b>	<b>249</b>	<b>242</b>	<b>97</b>	<b>43.8</b>	<b>62.3</b>	<b>142</b>
<b>Apparent Removal, %:</b>		<b>-23</b>	<b>-19</b>	<b>87</b>	<b>96</b>						

\* Based on an average value of 436 ppm Cl and 81 ppm F (as received basis) from four coal analyses.

\*\* Based on a values of 505 ppm Cl and 90 ppm F (as received basis) for a coal sample from this date.

The concentration data values in Table 4-8 during sorbent injection show that the HCl and HF concentrations actually increased during sorbent injection, to about 26 ppm and 13 ppm, respectively. However, this increase appears to be due to an increase in the average coal chlorine and fluorine content rather than reflecting an adverse affect from sorbent injection. This is seen in the mass balance data in the table, as discussed in the next paragraph. It is also possible that there were chlorides and fluorides in the byproduct Mg injected, as this material is an FGD byproduct and FGD systems typically remove HCl and HF from the flue gas at high efficiency.

The concentration data for chlorine (Cl<sub>2</sub>) and fluorine (F<sub>2</sub>) during sorbent injection indicate high removal of these species from the flue gas relative to the baseline values (87 and 96%, respectively). However, these species were measured to represent only a small percentage of the chlorine- and fluorine-containing species in the flue gas, so this apparent removal is relatively inconsequential compared to the amounts of HCl and HF that remained.

Mass balance data summarized in Table 4-8 show very good agreement between the average measured flue gas chlorine species concentrations and the corresponding coal chlorine measurements. The mass balances closed within approximately 3%, on average, meaning that the amount of chlorine-containing species measured in the flue gas agreed well with the amount coming in with the coal. These good mass balance closures make appear unlikely that the byproduct Mg introduced a significant amount of chlorides into the flue gas. Note that the mass balance data for the baseline period and for June 2 are based on average coal chloride analyses on four samples that did not correspond with the actual sampling dates as coal samples were not available for those specific dates. For the May 31 Method 26a sampling a coal sample was available. However, this did not appear to impact the mass balance closures appreciably, all of the individual daily closures were still very good at  $\pm 11\%$ .

The fluorine mass balances do not close as well as the chlorine balances. On average, the amount accounted for in the flue gas was approximately 30 to 40% more than was apparent in the coal. Based on previous URS experience, we expect that the bias is most likely in the coal fluorine concentration analyses.

***Arsenic Concentrations.*** Flue gas arsenic concentrations were measured by a modified version of EPA Method 108 that was intended to better reflect gas-phase concentrations at the 700°F flue gas temperatures at the economizer outlet location. The method was modified to use an in-stack filter to remove particulate matter from the gas sample than using an out-of-stack Method 5 filter at 250°F. The latter would only allow arsenic that is in the gas phase at 250°F to pass through the filter to the impingers for measurement, while the modified method was intended to allow that in the gas phase at 700°F to pass through. The results of these measurements are summarized in Table 4-9. In the table, the amount of arsenic in the particulate phase is expressed as an equivalent amount in ppmv as if it were still in the gas phase.

The data in Table 4-9 show that under baseline conditions, the vast majority of the arsenic present in the flue gas at the economizer outlet is already precipitated into the solid phase, the measurements showed less than 0.1% of the total arsenic present in the gas phase. The gas phase measurements corresponds to about 0.2 ppb (dry basis). Surprisingly, the samples collected during sorbent injection showed a higher percentage of the total arsenic present in the gas phase

**Table 4-9. Economizer Outlet Flue Gas and Particulate Phase Arsenic Concentrations Measured by Modified Method 108**

Sampling Date	Run	Arsenic Concentration, ppmv (dry basis)		
		Solid Phase (equivalent flue gas concentration)	Gas Phase	Total
5/9/01	1	0.354	0.0000	0.354
5/9/01	2	0.449	0.0001	0.450
5/10/01	3	0.216	0.0003	0.217
5/10/01	4	0.222	0.0004	0.223
<b>Baseline Average:</b>		<b>0.310</b>	<b>0.0002</b>	<b>0.311</b>
5/31/01	1	0.244	0.0022	0.246
5/31/01	2	0.251	0.0026	0.253
5/31/01	3	0.258	0.0035	0.262
6/2/01	1	0.219	0.0015	0.220
6/2/01	2	0.216	0.0014	0.217
6/2/01	3	0.211	0.0016	0.213
<b>Injection Average:</b>		<b>0.233</b>	<b>0.0021</b>	<b>0.235</b>

(almost 1%) and an order of magnitude higher gas phase arsenic concentration (2 ppb dry basis). This is directionally opposite the expected effect. The total arsenic concentrations (vapor plus particulate) were slightly lower during the sorbent injection period than during baseline.

Table 4-10 summarizes the results of arsenic mass balance calculations for these two periods. The calculated arsenic balance closures were not very close, with the arsenic in the flue gas measurements corresponding to twice that in the coal during baseline. However, there were no baseline samples available for the actual dates of this sampling, so the coal arsenic concentration used for this calculation was an average from four samples over the test period. For the sampling effort on 5/31/01, there was a corresponding coal sample for that day, and the mass balance closure for that day was much better, within 25% on average.

Because the measured gas phase arsenic concentrations were extremely low, and the arsenic mass balances did not close very well, no firm conclusions can be made about the effect of sorbent injection on gas phase arsenic concentrations at the economizer outlet. There is not an obvious explanation for why the concentrations went up, as would appear to have happened based on the data presented in Table 4-9.

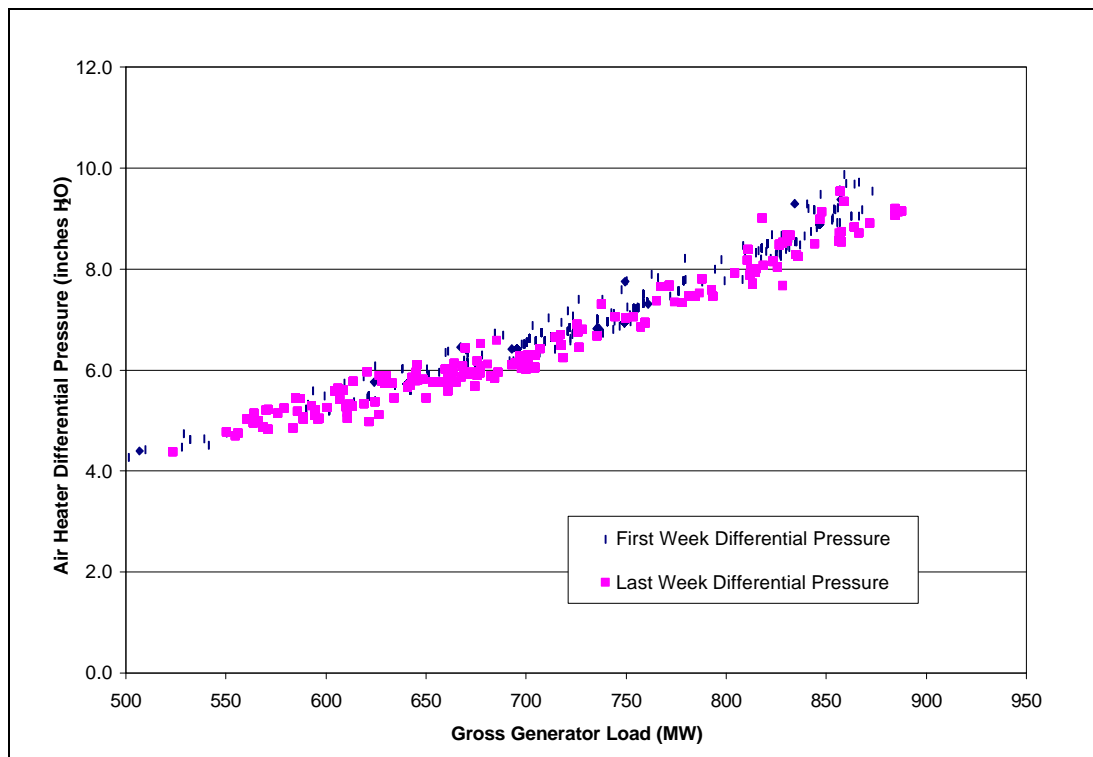
**Air Heater Impacts.** Plant process data were analyzed to determine if any longer-term impacts of sorbent injection on the air heater were apparent, either on pressure drop or outlet temperature. Increased in pressure drop and/or outlet temperature might be an indicator of a buildup of injected solids on the air heater baskets, while a decrease in either might be an indicator of a decrease of solids buildup due to sulfuric acid deposition on the baskets. The pressure drop data are illustrated in Figure 4-9, while the temperature data are plotted in Figure 4-10. The pressure drop data do not show a significant change in the relationship between air heater flue gas

**Table 4-10. Arsenic Mass Balance Summary**

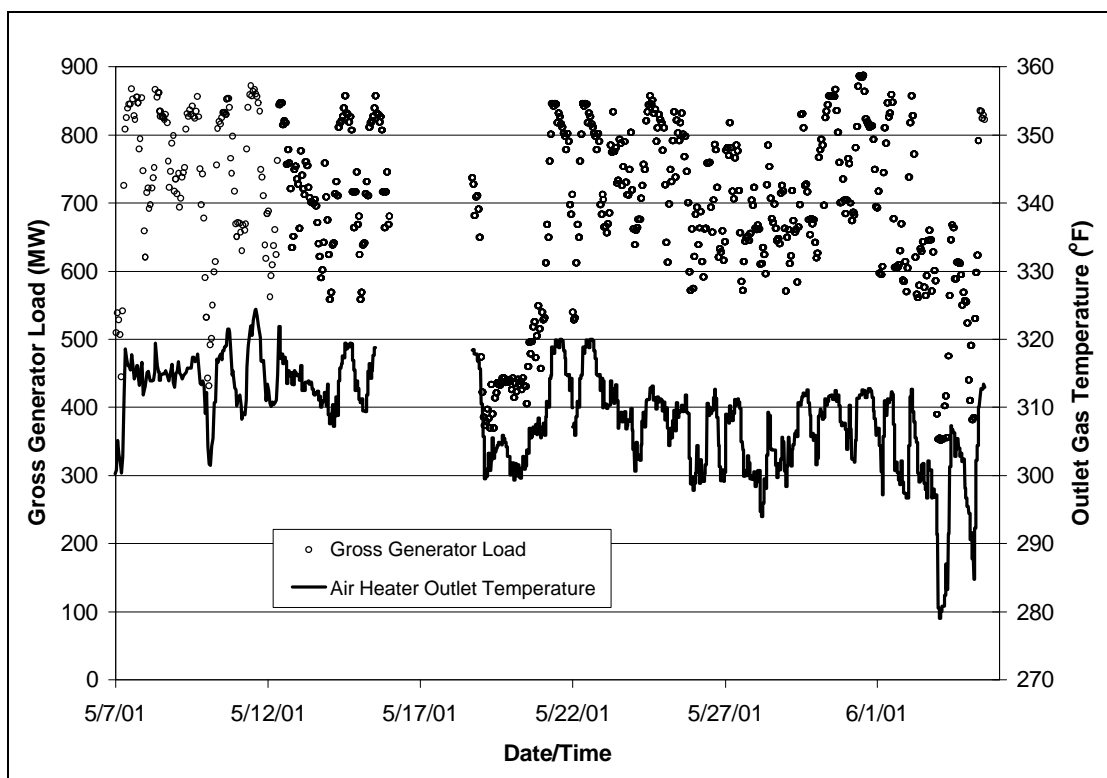
Date	Test	Arsenic in Coal (lb/hr)	Arsenic in Flue Gas (lb/hr)	Apparent Closure (%)
5/9/01	1	2.59*	5.93	229
5/9/01	2	2.69*	7.81	291
5/10/01	3	2.67*	3.76	141
5/10/01	4	2.72*	3.94	145
<b>Baseline Average:</b>		<b>2.67</b>	<b>5.36</b>	<b>201</b>
5/31/01	1	3.63**	4.38	121
5/31/01	2	3.41**	4.27	125
5/31/01	3	3.34**	4.29	129
6/2/01	1	2.20*	3.26	149
6/2/01	2	2.02*	3.00	149
6/2/01	3	2.07*	2.99	144
<b>Injection Average:</b>		<b>2.78</b>	<b>3.70</b>	<b>133</b>

\* Based on average arsenic analysis of all coal samples submitted, 4.4 ppm as received.

\*\* Based on arsenic analysis for 5/31/01 coal sample, 5.6 ppm as received (6 ppm dry basis).



**Figure 4-9. Comparison of Air Heater Pressure Drop Before and After Long-term Test**

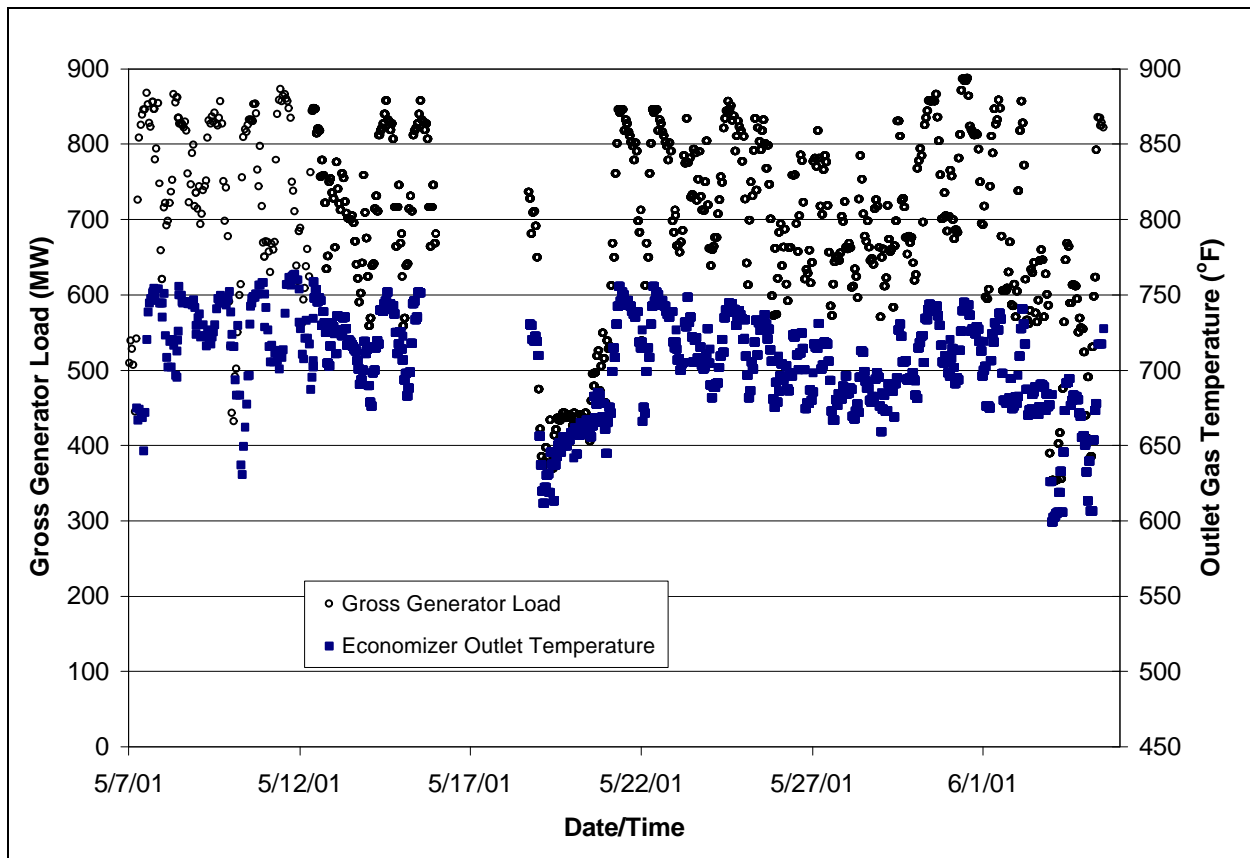


**Figure 4-10. Air Heater Outlet Temperature Trends during Long-term Test**

differential pressure between the first week of the test period (predominantly baseline operation) and the last week of sorbent injection. Actually, least-squares fits of the data (not plotted) show a slightly lower pressure drop at high load in the end-of-test data (about 0.3 in H<sub>2</sub>O lower at 850 gross MW), which may indicate the air heater “cleaning up” slightly over the duration of the test. Again, this small difference is not considered significant.

The air heater outlet flue gas temperature trends plotted in Figure 4-10 for the duration of the sorbent injection test (May 11 through June 3) similarly do not show any adverse impacts of sorbent injection. Actually, the full-load outlet gas temperatures dropped by about 10°F, from about 320°F at the beginning to 310°F at the end of the sorbent injection test. This may be an indicator of improved air heater heat transfer performance resulting from lower inlet SO<sub>3</sub> concentrations.

Economizer outlet temperature trends were also plotted to determine whether there were any adverse effects of sorbent injection on heat transfer in the back pass of the boiler. These data are plotted in Figure 4-11. As do the air heater outlet temperature data, the economizer outlet flue gas temperatures do not show any adverse effects of sorbent injection. If anything, the full-load economizer outlet gas temperatures trended down slightly (indicating improved heat transfer) over the course of the test.



**Figure 4-11. Effects of Sorbent Injection on Economizer Outlet Gas Temperatures**

***Effects of Sorbent Injection on Slagging in the Upper Furnace.*** Throughout the long-term test, a FirstEnergy engineer made daily observations of the amount of slag apparent on the front surface of the pendant, secondary superheater tubes. Over the course of the long-term test, these observations were tracked to determine, at least subjectively, if the byproduct Mg injection had any effect on slagging in the upper furnace. Magnesium is known to be a slag modifier in coal-fired furnaces under some conditions, helping to produce friable slag deposits that are more readily removed with soot blowers. However, the byproduct Mg was injected relatively high in the furnace, and it was not clear whether adding the magnesium this high in the furnace and at furnace gas temperatures of 2000°F or less would have any impacts on the slag.

At the beginning of the test, the pendant superheat tubes were relatively clean, probably reflective of a high-quality coal blend having been fired recently. Over the long-term test period, their cleanliness degraded somewhat. However, even at the end of the test, the pendant superheater tubes had only a light slag buildup and still were considered relatively clean. Within the accuracy of these qualitative observations, it can only be concluded that the sorbent injection had no measurable impact on slagging in the upper furnace.

***Effects of Sorbent Injection on Stack Gas Opacity.*** One objective of sorbent injection to removal sulfuric acid from the flue gas is to reduce the opacity of the stack flue gas. Sulfuric acid

in the flue gas condenses as a submicron-diameter acid mist at the inlet to wet scrubbers, and the acid mist is very efficient in scattering light, which causes elevated stack gas opacity. The stack gas opacity was not measured directly, as there was no one certified for EPA Method 9 (visual opacity) at the plant. However, to the untrained eye, the stack gas opacity was greatly reduced throughout the long-term test period compared to baseline opacity.

#### **4.2 Long-term Test on AEP's Gavin Station, Unit 1**

The long-term test at Gavin Station was significant because it provided the opportunity to measure the effectiveness from sorbent injection into the furnace at removing  $\text{SO}_3$  formed in the furnace as well as that formed across the SCR catalyst. During the long-term test, two different sorbents, a byproduct Mg slurry and a commercially available magnesium hydroxide (commercial Mg) slurry were injected into the entire Unit 1 boiler for a total of 23 days. Analytical techniques used to assess the effects of sorbent injection primarily included sampling with a modified Controlled Condensation System (CCS) method to determining flue gas  $\text{SO}_3$  content, during baseline and then injection conditions.

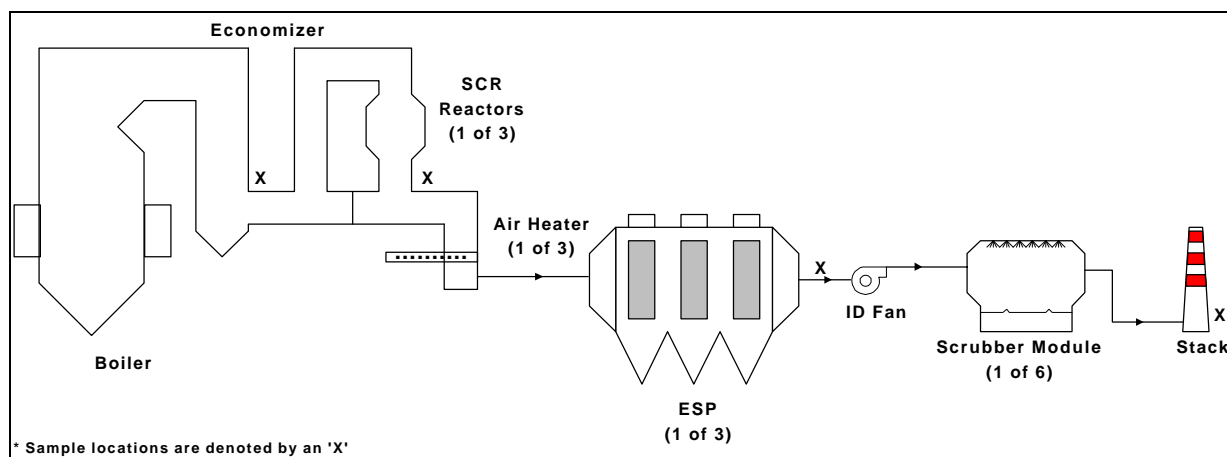
EPA Reference Method 26a was used for determining hydrochloric acid (HCl) and hydrofluoric acid (HF), as well as chlorine ( $\text{Cl}_2$ ) and fluorine ( $\text{F}_2$ ) concentrations in the ESP outlet flue gas. A modified version of EPA Method 108 was used to determine flue gas vapor-phase and particulate arsenic concentrations at the economizer outlet. However, the results of these additional measurements are not yet available for reporting.

Impacts on ESP operation were quantified by taking voltage and current data on operating electrical sections of the Unit 1 ESP's, and by measuring ESP outlet flue gas particulate loading by EPA Method 17. Sorbent and ESP hopper samples were analyzed for magnesium content by acid dissolution followed by atomic absorption analysis. Some sorbent samples were also analyzed for calcium content (atomic absorption) and sulfate content (ion chromatography). All sorbent samples were also analyzed for density and weight percent solids by gravimetric analysis, and for total alkalinity by acid-base titration. Coal samples were collected and analyzed for a variety of parameters according to ASTM protocols. Finally, visual observations were made of boiler furnace and pendant superheater tube surfaces prior to and during sorbent injection, to observe any trends related to slag formation.

Unit 1 is rated at 1300 net MW. It has an opposed-wall-fired boiler that typically burns a 3.5 to 4% sulfur coal. The unit typically operates as a base-loaded unit, operating at reduced load only during overnight hours, in response to reduced load demands from the grid. During most of the long-term test, Unit 1 typically operated at 1320 to 1390 MW gross load from 8:00 a.m. until midnight, but at reduced loads of 1000 to 1200 gross MW overnight.

Figure 4-12 illustrates the flue gas path for Unit 1, and notes the gas sampling locations used during this test. Flue gas from the economizer splits into three gas paths. Each gas path goes to an SCR reactor. Ammonia is fed to each of the three SCR reactors from an ammonia-on-demand system to achieve 90%  $\text{NO}_x$  reduction. Also, about 1 to 1.5% of the flue gas  $\text{SO}_2$  is further oxidized to  $\text{SO}_3$  across the catalyst bed in each reactor. From the SCR reactors, the flue gas flows to three air heaters. The average flue gas temperature at the outlet of the air heaters is controlled to about 350 to 360°F due to acid dew point considerations. The outlet gas from each of the three





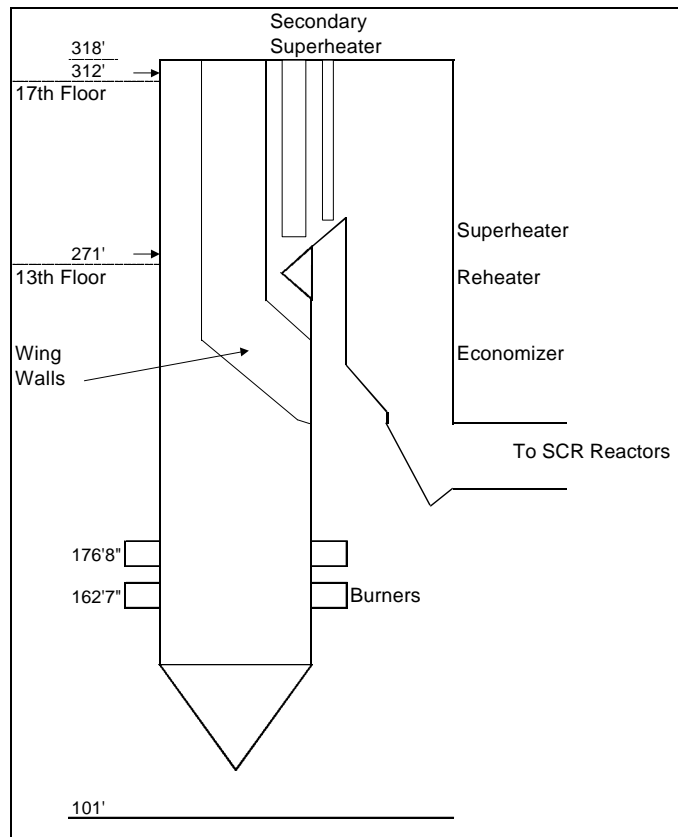
**Figure 4-12. Illustration of Flue Gas Path for Gavin Unit 1**

air heaters then goes to an ESP followed by ID fans. Downstream of the ID fans, the flue gas flows through up to six countercurrent FGD spray/tray absorber modules (five normally operate at full load). The FGD system uses a magnesium-enhanced, Thiosorbic<sup>®</sup> lime slurry reagent and operates in a natural oxidation mode to produce a calcium sulfite hemihydrate byproduct. The flue gas then goes to a dedicated stack for Unit 1. The flue gas in the stack is saturated at a temperature of about 130°F; no reheat is employed.

During these tests, injection of sorbent slurries was accomplished through air-atomizing nozzles inserted through inspection port openings and/or through ports installed in man doors on the front wall and front corners of the boiler. During most of the testing, the injection location was at the 17<sup>th</sup> floor of the boiler structure, across from the pendant superheat tubes. For a portion of the test, 40% of the total slurry flow was fed lower in the furnace, just above the nose of the boiler at the 13<sup>th</sup> floor of the boiler structure. The remaining 60% was injected through the nozzles at the 17<sup>th</sup> floor. The injection levels are illustrated in Figure 4-13.

At the 17<sup>th</sup> floor, there are eight man doors almost evenly spaced across the front face of the boiler. There is also a man door on each side wall at this level, near the corners where the side walls intersect with the front wall. The plant installed 4-inch pipe in each of these ten man doors, angled downward at 45 degrees, to serve as ports for slurry injection into the furnace. Figure 4-14 illustrates these ten lance locations.

The plant was interested in testing slurry injection lower in the furnace, where the furnace gas temperatures might be high enough that ash slagging properties could be modified by magnesium addition. The boiler has a series of five inspection ports along the front wall at the 13<sup>th</sup> floor, just above the nose of the boiler. There are also inspection ports on each of the side walls at the 13<sup>th</sup> floor, very near the corners where the side walls intersect with the front wall. This provided locations for up to seven nozzle lances at the 13<sup>th</sup> floor level. However, it was expected that the seven nozzle lance locations would not be adequate to inject the entire slurry flow (up to 165 gpm) and still use nozzles small enough to achieve good atomization, while providing good slurry coverage across the furnace cross section. The latter is exacerbated by the fact that the Unit 1 furnace is 110 feet wide and 51 feet deep, and by the fact that the inspection

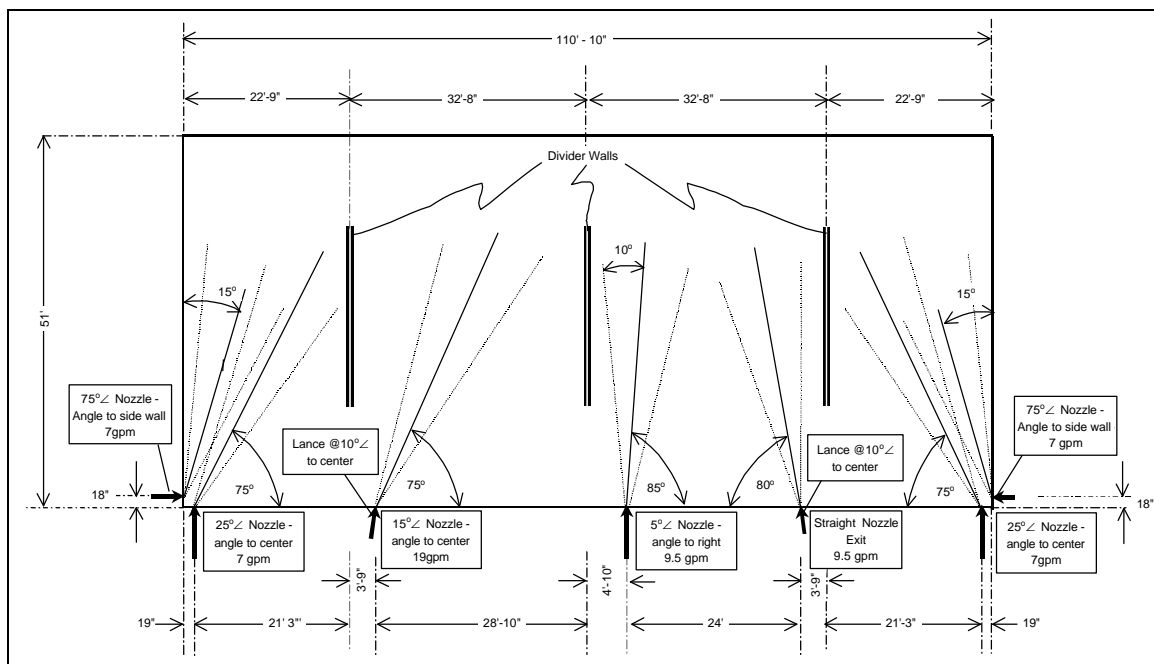
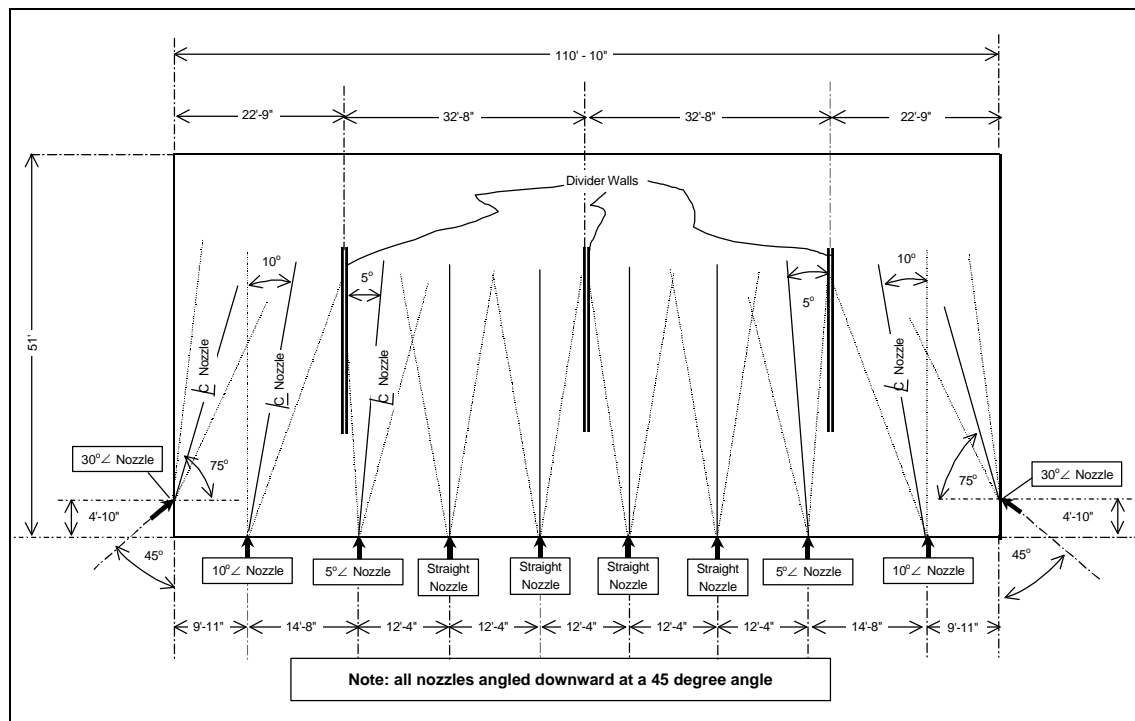


**Figure 4-13. Illustration of Slurry Injection Levels**

ports on the front wall at the 13<sup>th</sup> floor are not equally spaced. The ports range from 24 ft apart to 33.7 ft apart. For this reason it was decided to test with only a portion of the slurry (40%) added at the lower level. Figure 4-15 illustrates the nozzle lance locations at the 13<sup>th</sup> floor level.

The air-atomizing nozzles were designed by Ashworth Engineering specifically for this application. The proprietary design employs an internal mix configuration, and was designed for relatively low air flow requirements and to achieve a relatively large minimum passage diameter. The air pressure to the nozzles was typically 80 psig, although under some conditions lower air pressures were encountered.

The slurry handling and injection system used for the short-term and long-term tests at BMP was too small for the testing at Gavin, because of the larger unit size (1300 vs. 800 net MW) and because the SO<sub>3</sub> concentrations were higher at Gavin downstream of the SCR system. A temporary slurry injection system was set up at the plant and operated by MPW Industrial Services. The byproduct Mg sorbent was delivered to the site by truck as a slurry containing 15 to 20 wt% solids. A 1-million-gallon chemical cleaning storage tank at the station was used to store byproduct Mg slurry. A relatively large storage tank was required to allow building an inventory at the site, because the planned injection rates were greater than the byproduct slurry could be produced at Allegheny Energy's Pleasants Station. The large storage tank was not agitated, but a centrifugal pump was used to provide a small amount of recirculation of the slurry in the tank.



From the storage tank, a gasoline-engine-powered centrifugal pump was used to intermittently fill two 21,000-gallon “day” tanks located on the ground outside of the Unit 1 boiler house. The two tanks were hydraulically connected to serve as one 42,000-gallon tank. A temporary run of PVC pipe connected the gasoline-engine-driven pump with the two “day” tanks. The day tanks also were not agitated. The day tank level was controlled by MPW personnel, who started and stopped the gasoline-engine-driven pump as needed to maintain level.

From the day tanks, one or both of two eight-inch, diesel-engine-driven Moyno progressing cavity pumps were used to feed slurry to the injection nozzles. The Moyno pumps were equipped with a turbine flow meter at their common discharge header, and the diesel engine speed was modulated to adjust and control slurry flow rate. The slurry flow rate was adjusted by the MPW operator to achieve a desired value calculated from the density and purity of the reagent, the Unit 1 load, the expected Unit 1 coal sulfur content, and the desired reagent-to-SO<sub>3</sub> molar ratio. Slurry from the Moyno pumps was fed through 3-inch flexible hose up to the 17<sup>th</sup> floor to a manifold, which in turn distributed slurry to the ten lances and injection nozzles. When also injecting at the 13<sup>th</sup> floor, a portion of the flow was split off at the 13<sup>th</sup> floor through a second turbine meter and manifold, to the seven lances and nozzles at that level.

For the commercial Mg testing, the Dow magnesium hydroxide was delivered to the site by truck as a 58-wt% slurry. This slurry was stored at the site in three additional 21,000-gallon storage tanks. These tanks did not normally require agitation, because the 58-wt% slurry settles very slowly. During the commercial Mg test period, the 58-wt% slurry was pumped from the storage tanks to one of the day tanks, where it was diluted with plant water to a lower solids content. From the day tanks, the diluted slurry was pumped to the lances and nozzles as described above. Also, as mentioned above, the day tanks were not agitated. A recirculation pump was used in an effort to keep the solids in the diluted slurry suspended. However, the recirculation pumping rate did not prove to be adequate to keep the solids in the diluted slurry suspended, so the commercial Mg tests were plagued with varying solids content in the injected slurry.

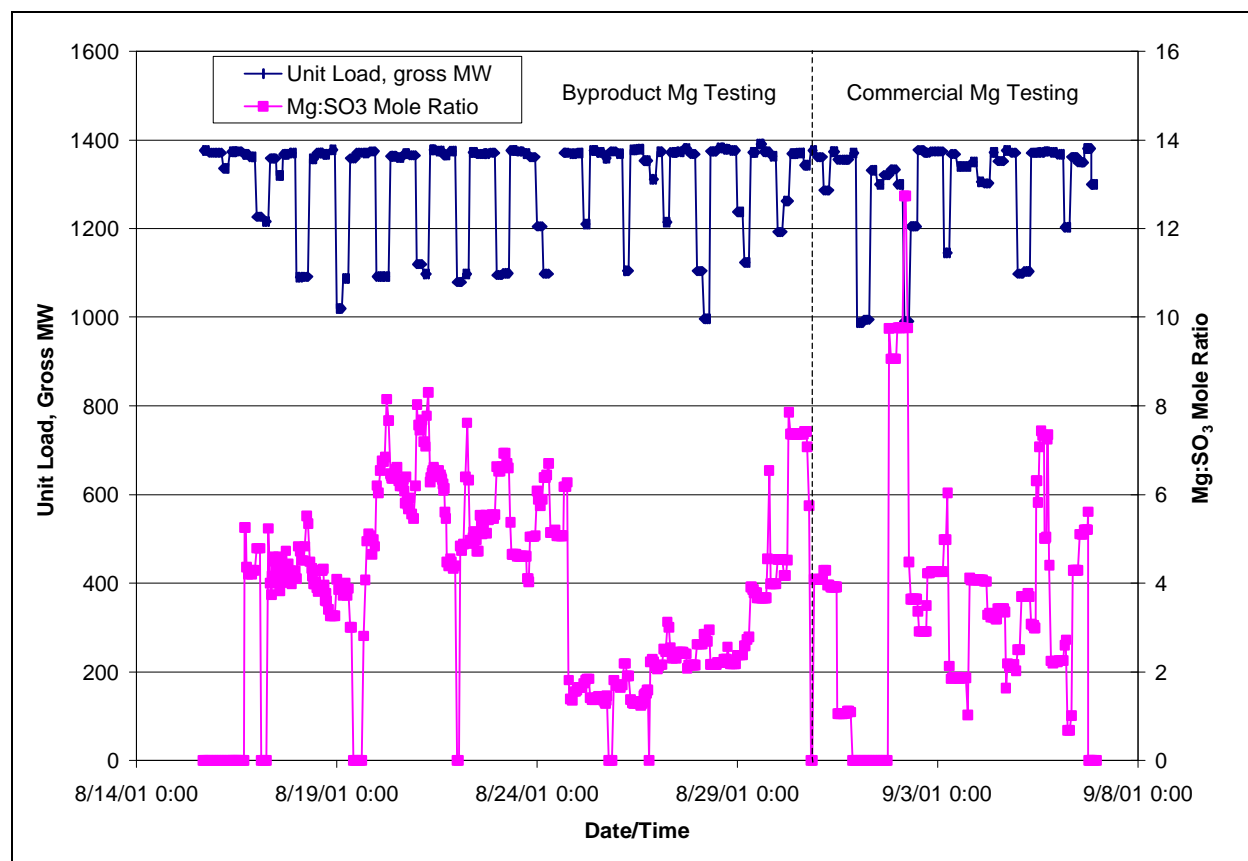
The plant compressed air system did not have sufficient capacity to provide atomizing air to all 17 nozzles. The plant installed four electric-motor-driven compressors for the duration of this test. These compressors fed air through flexible hoses to a receiver tank on the 16<sup>th</sup> floor of the boiler. Air from the receiver tank was connected to each lance individually, through flexible plant air hoses, to provide atomizing air.

#### **4.2.1 Unit 1 Operating Conditions**

The byproduct Mg long-term test was conducted on Unit 1 over the time period August 16 through September 7, 2001. Baseline (no sorbent injection) measurements for sulfuric acid concentration were conducted using a modified CCS method several days prior to the beginning of sorbent injection, over the time period August 14 through 16. During the sorbent injection period, modified CCS runs were made on a six-day-per-week basis to assess sulfuric acid removal performance with the byproduct Mg and commercial Mg reagents. Typically, no CCS measurements were made on Sundays, although sorbent injection continued around the clock seven days a week with few interruptions.

Additional measurements were made late in the injection period, including Method 17 for ESP outlet mass loading, Method 26a for halogen concentrations, and modified Method 108 for arsenic concentrations. Baseline measurements were also made using these methods on September 8, after sorbent injection ended.

Unit 1 load and sorbent injection rates during the long test period are summarized in Figure 4-16. During most flue gas testing, from about 9:00 a.m. through 6:00 p.m. Mondays through Saturdays, the steam generator was generally at close to full load, at 1320 to 1390 gross MW. Unit loads often dropped into the range of 1000 to 1200 gross MW after midnight but before 8:00 a.m., but the unit was typically at full load for at least an hour before flue gas sampling began.



**Figure 4-16. Unit 1 Operating Conditions during Long-term Sorbent Injection Testing**

## 4.2.2 Test Methods

Test methods during the long-term test at Gavin Station were typically the same as were used in the long-term test conducted previously at BMP. One significant difference was the CCS measurements, which were made by a third-part organization, E.ON Engineering GmbH from Germany, under contract to AEP. The methods and equipment they use are somewhat different than how the CCS method is practiced in the U.S. The differences in the methods used are

described below. However, the differences are not thought to significantly bias the results of one method versus the other.

A diagram of the CCS sulfuric acid vapor train as operated by URS was shown previously in Figure 4-4. Differences in the method as practiced by E.ON Engineering include:

- At the economizer outlet and SCR outlet (700°F gas) the sampling probe is not heated, but operates at or near the flue gas temperature.
- A heated thimble is not used to separate particulate matter from the sample gas; instead, a quartz wool plug at the stack end of the probe is used to effect this separation; this plug is replaced for every measurement run.
- An impinger train is not used to remove acid gases and dry the sample gas before the pump and dry gas meter; instead a Teflon-lined wet pump and wet test meter are used to handle the wet, acidic gas.
- For sampling at the ESP outlet (360°F gas), the probe is controlled to the actual duct/sample gas temperature; a small sampling ESP is used to collect acid mist from the sample gas; the remaining gas goes to the sulfuric acid condenser; both the ESP catch and the condenser catch are titrated to allow determination of the split between acid mist and sulfuric acid vapor in the sample gas.
- For sampling at the stack (130°F gas), the probe is controlled to the actual stack/sample gas temperature; a small sampling ESP is used to collect acid mist from the sample gas; the remaining gas goes directly to the pump and wet test meter; the ESP catch is titrated to allow determination of the amount of acid mist in the sample gas.

#### **4.2.3 Baseline Test Results**

As mentioned earlier, baseline data were collected August 14-16, immediately prior to the initiation of byproduct Mg injection late in the afternoon of August 16. The primary objective of these measurements was to determine baseline (no sorbent injection) SO<sub>3</sub> concentrations at a variety of measurement locations. The baseline CCS results are discussed in the following paragraphs.

Table 4-11 summarizes the results of CCS measurements made at various locations throughout the flue gas path on Gavin Unit 1. Please refer to Figure 4-13 to review how these sample locations are laid out in the gas path. Table 4-11 shows the results of individual measurement runs by date and by location.

**Table 4-11. Summary of Flue Gas SO<sub>3</sub> Concentrations Measured for Unit 1  
Baseline Testing**

Date	Measured SO <sub>3</sub> Concentration, ppmv (dry basis, corrected to 3% O <sub>2</sub> conc.)				
	Run 1	Run 2	Run 3	Run 4	Average
<b>Economizer Outlet:</b>					
8/15/01 a.m.	41	42	33	33	-
8/15/01 a.m. (cont'd)	34	-	-	-	37
<b>SCR Reactor Outlet:</b>					
8/14/01 p.m.	61	59	-	-	60
8/15/01 a.m.	66	65	68	-	66
8/15/01 p.m.	55	60	74	71	-
8/15/01 p.m. (cont'd)	69	62	-	-	66
8/16/01 a.m.	79	76	57	59	-
8/16/01 a.m. (cont'd)	53	57	-	-	64
Average (8/15-8/16)	-	-	-	-	65
<b>ESP Outlet:</b>					
8/14/01 p.m.	36	37	-	-	37
8/15/01 p.m.	46	58	56	-	53
8/16/01 a.m.	54	56	55	-	55
Average (8/15-8/16)	-	-	-	-	54
<b>Stack:</b>					
8/14/01 p.m.	31	31	-	-	31
8/15/01 a.m.	54	51	53	-	53
8/15/01 p.m.	35	49	49	51	46
8/16/01 a.m.	43	47	46	47	-
8/16/01 a.m. (cont'd)	49	-	-	-	46
Average (8/15-8/16)	-	-	-	-	48

The baseline values from August 14 appear to be lower than the values measured on August 15 and 16. This may be because the plant was switching from a lower sulfur coal being fired as an interim measure to control plume “touch downs” after the SCR retrofit, to the normal high-sulfur coal for the sorbent injection tests. The measurements on August 14 may have reflected a small percentage of the lower sulfur coal remaining in the fuel burned. For this reason, only the measurements from August 15 and 16 have been used to calculate baseline averages. These average values show 37 ppm of SO<sub>3</sub> at the economizer outlet, 65 ppm at the SCR outlet (an increase because of SO<sub>2</sub> to SO<sub>3</sub> oxidation across the SCR catalyst), 54 ppm at the ESP outlet, and 48 ppm at the stack. Throughout this report, SO<sub>3</sub> removal during sorbent injection is reported as the percent reduction in SO<sub>3</sub> concentration at a given location, for injection versus baseline conditions. The preceding values were used in those calculations.

The SCR outlet SO<sub>3</sub> concentration data in Table 4-11 were used to calculate an average SO<sub>2</sub> to SO<sub>3</sub> conversion percentage for Unit 1, to serve as a basis for reporting sorbent-to-SO<sub>3</sub> molar ratios. Daily Unit 1 coal feed samples were collected and analyzed for the long-term test. The proximate analyses of these coal samples are shown in Table 4-12. These results were used in combustion calculations to calculate the total amount of SO<sub>2</sub> that would be produced from the

**Table 4-12. Ultimate Analyses of Coal Samples from the Gavin Unit 1  
Long-term Test**

<b>Date/Time (Beginning of Sample Collection Period)</b>	<b>Moisture, wt% as received</b>	<b>Ash, wt% as received</b>	<b>Sulfur, wt% as received</b>	<b>HHV, BTU/lb</b>
8/16/01 06:00	8.78	12.36	3.58	11,385
8/16/01 18:00	7.49	11.48	3.62	11,753
8/17/01 06:00	8.09	11.84	3.16	11,594
8/17/01 18:00	8.33	11.75	3.54	11,529
8/18/01 06:00	8.89	11.94	3.23	11,412
8/18/01 18:00	8.69	12.68	3.54	11,369
8/19/01 06:00	-	-	-	-
8/19/01 18:00	7.06	11.41	3.81	11,966
8/20/01 06:00	6.08	10.02	3.20	12,520
8/20/01 18:00	7.32	10.84	3.48	11,969
8/21/01 06:00	8.54	11.51	3.22	11,580
8/21/01 18:00	8.86	12.35	3.83	11,350
8/22/01 06:00	10.05	11.46	3.41	11,268
8/22/01 18:00	8.89	11.66	3.68	11,477
8/23/01 06:00	8.82	11.78	3.64	11,403
8/23/01 18:00	7.19	10.74	4.09	12,089
8/24/01 06:00	9.84	13.18	3.90	11,091
8/24/01 18:00	6.70	10.67	3.84	12,240
8/25/01 06:00	8.83	12.39	3.77	11,313
8/25/01 18:00	8.17	12.11	3.75	11,620
8/26/01 06:00	6.62	10.36	4.44	12,199
8/26/01 18:00	7.21	10.05	4.25	12,141
8/27/01 06:00	9.10	11.65	3.33	11,501
8/27/01 18:00	8.85	12.08	3.70	11,420
8/28/01 06:00	8.68	12.39	3.93	11,441
8/28/01 18:00	7.97	11.28	3.94	11,691
8/29/01 06:00	8.96	12.26	3.72	11,316
8/29/01 18:00	8.32	11.90	3.70	11,543
8/30/01 06:00	9.87	13.14	3.42	11,070
8/30/01 18:00	8.97	12.23	3.59	11,338
8/31/01 06:00	9.19	13.04	3.88	11,159
8/31/01 18:00	10.01	13.01	3.70	10,986
9/1/01 06:00	10.58	12.13	3.59	11,087
9/1/01 18:00	9.32	10.75	2.39	11,667
9/2/01 06:00	8.21	10.75	3.12	11,935
9/2/01 18:00	7.33	10.59	2.58	12,088
9/3/01 06:00	7.60	11.85	2.13	11,895
9/3/01 18:00	8.39	11.99	3.85	11,536
9/4/01 06:00	7.52	9.99	4.73	12,155



**Table 4-12. Ultimate Analyses of Coal Samples from the Gavin Unit 1  
Long-term Test (continued)**

<b>Date/Time (Beginning of Sample Collection Period)</b>	<b>Moisture, wt% as received</b>	<b>Ash, wt% as received</b>	<b>Sulfur, wt% as received</b>	<b>HHV, BTU/lb</b>
9/4/01 18:00	9.22	11.37	4.00	11,424
9/5/01 06:00	8.66	13.43	3.93	11,042
9/5/01 18:00	-	-	-	-
9/6/01 06:00	9.28	3.72	3.72	11,156
9/6/01 18:00	9.61	3.45	3.45	11,120
9/7/01 06:00	9.89	13.07	3.73	11,042
9/7/01 18:00	8.87	12.27	3.70	11,389
9/8/01 06:00	7.54	11.24	4.23	11,901
<b>Test Period Average</b>	8.50	11.79	3.62	11,559

combustion of these coals, then that value was compared to the measured economizer/SCR outlet SO<sub>3</sub> concentrations. The economizer outlet and SCR outlet concentrations correspond to approximately 1.3% conversion of SO<sub>2</sub> to SO<sub>3</sub> in the furnace, and another 1.0% conversion of SO<sub>2</sub> to SO<sub>3</sub> across the SCR catalyst.

Downstream measurements indicated that the sulfuric acid removal across the air heater and ESP was only about 17% (11 ppm) and the removal across the FGD system was about 11% (6 ppm). Both of these values are relatively low compared to what has been measured at other bituminous coal plants. The relatively low sulfuric acid removal across the air heater (in combination with the ESP) is most likely reflective of the high air heater exit temperature (about 360°F), which was elevated to reduce the dropout of sulfuric acid on air heater baskets. The relatively low removal across the ESP (in combination with the air heater) is most likely reflective of the high overall sulfuric acid concentration. A portion of the sulfuric acid would be expected to adsorb to fly ash particles and to be collected in the ESP. However, the percentage removed by this mechanism is limited, being primarily a function of the surface area of fly ash in the flue gas (i.e., a fixed mass of acid adsorbed per unit surface area) and the flue gas temperature. With a high concentration of sulfuric acid in the flue gas and with the higher air heater exit temperature adversely affecting adsorption, the percentage of the flue gas that can be removed by this mechanism is limited. The relatively low sulfuric acid removal percentage across the FGD system is thought to be a function of the high inlet concentration, and the low liquid to gas ratio (21 gal/ACF) in the magnesium-enhanced lime absorber.

#### **4.2.4 Long-term Test SO<sub>3</sub> Removal Results**

The long-term slurry injection test at Gavin Unit 1 was conducted over the time period August 16 through September 7, 2001. A byproduct magnesium hydroxide produced at Allegheny Energy's Pleasants Station as tested through the evening of August 30, and a commercially available magnesium hydroxide produced by the Dow Chemical Company was tested from August 31 through September 7.

As described earlier, the Pleasants Station has a modified Dravo Thiosorbic<sup>®</sup> Lime FGD process that employs magnesium-enhanced scrubbing, with external forced oxidation to produce a gypsum byproduct. The remaining liquor after the gypsum is produced is further processed by lime addition to precipitate a mixture of magnesium hydroxide and gypsum particles. With the current equipment configuration at the Pleasants Station, this byproduct slurry is produced at about 15 to 20 wt % total suspended solids.

The commercial Mg is produced by Dow at a plant in Leddington, Michigan, and shipped as a 58 wt% slurry. Although the byproduct Mg was the reagent of choice for the long-term test at BMP, the commercial Mg was tested at Gavin Station for two reasons. One was that the commercial Mg was never tested at the more favorable 14<sup>th</sup> floor injection location at BMP, and it remained uncertain how the performance of the commercial Mg would compare to that of the byproduct Mg if they were each injected higher in the furnace. The second reason is that the Gavin Station was looking for a near-term approach for lowering their stack gas sulfuric acid mist concentrations, and it was uncertain whether a sufficient quantity of byproduct Mg would be available, particularly to treat two units at Gavin (2600 net MW of generating capacity). The commercial Mg, if proven effective, could provide a second source of reagent for furnace injection.

The objectives of the long-term tests were to evaluate the ability to control sulfuric acid emissions, as measured at the ESP outlet, over an extended period of time, and to evaluate balance of plant effects from sorbent injection. The sulfuric acid removal performance was measured almost daily by a modified CCS sampling method throughout the long-term test period.

The results from sorbent injection testing at Gavin plant are more complicated to interpret than the previous BMP results, because at Gavin SO<sub>3</sub> was produced in both the furnace and in the downstream SCR reactor. Also, because this was the first sorbent injection test conducted under these conditions, a range of Mg:SO<sub>3</sub> ratios had to be tested to evaluate each of the two sorbents. The plant's desire to test injection at the 17<sup>th</sup> floor level versus injection split between the 13<sup>th</sup> and 17<sup>th</sup> floor added another variable to be evaluated. Consequently, the long-term test essentially became a full factorial evaluation of three variables (Mg:SO<sub>3</sub> ratio, reagent, and injection level).

Furthermore, the organization conducting the modified CCS measurements for SO<sub>3</sub>/sulfuric acid concentration measurements, E.ON Engineering, had staff on site adequate to allow simultaneous sampling of three of the four locations of interest (economizer outlet, SCR outlet, ESP outlet, and stack). The plant was most interested in tracking the economizer outlet and SCR outlet locations, and wanted these two locations to be sampled during each measurement effort. Thus, the third of the simultaneous measurement locations was split about 50% each between the ESP outlet and stack locations. This represents a limitation on the usefulness of the CCS data. Because the furnace injected sorbent continues to react with flue gas SO<sub>3</sub>/sulfuric acid downstream of the SCR outlet, the ESP outlet concentrations represent the best measure of sorbent effectiveness, but these concentrations are only available for half of the measurements.

Throughout this discussion, the Mg:SO<sub>3</sub> molar ratios in tables and figures are based on the measured amount of magnesium hydroxide in the byproduct or commercial Mg slurry injected, the slurry feed rate, the Unit 1 coal feed rate, sulfur content analyses of coal samples for this time period, and a factor of 2.3% conversion of coal sulfur to SO<sub>3</sub> at the SCR outlet location. This factor was derived from the baseline SO<sub>3</sub> concentration data as described above, and is the sum of the observed conversion in the furnace (1.3% and SCR reactors (1.0%). Note that this basis is different than in the previously reported BMP results, where the Mg:SO<sub>3</sub> molar ratios are based only on the SO<sub>3</sub> conversion in the furnace.

The amount of magnesium hydroxide in the slurry fed was determined by analyzing samples of the injected slurry (typically two per day) for wt% solids content, density, magnesium content in the solids, and total alkalinity in the slurry. The coal sulfur data were summarized in Table 4-12, and were based on daily composite sample analyses conducted by AEP's coal laboratory. The reagent slurry feed rate was based on the MPW turbine meter installed at the Moyno pump outlet and logged on an hourly basis by MPW personnel. The flow meter readings were divided by a correction factor of 1.1 based on flow meter calibrations conducted by URS personnel at the beginning of the test period. Finally, the coal feed rate data were recorded by Gavin Station control room operators from plant instrumentation.

There are some limitations in the accuracy of these values. The biggest source of error is most likely the magnesium hydroxide content values for the commercial Mg slurries. As described earlier, the commercial Mg was diluted from 58 wt% in the day tanks, which were not agitated. Once diluted, the commercial Mg slurry tended to settle in the unagitated tanks. The Moyno pump suction lines pulled from the bottom of the tank, where the solids tended to settle. Thus, when starting on a fresh tank, the wt% solids level tended to be higher than the target value, and as the inventory in the tank became depleted, the wt% solids level tended to be lower than the target value. This variation was not adequately captured in just two slurry samples per day, as the tanks were filled and emptied several times a day. Thus, the Mg:SO<sub>3</sub> values for the commercial Mg tests are of questionable accuracy. Another significant data quality issue is just how representative SO<sub>3</sub>/sulfuric acid concentration data taken at a single measurement point with 2-meter or 3-meter-length probes are of the total flue gas flow in a plant of this size. For example, the stack internal diameter is 42 ft (12.8 m).

The results in are summarized in Table 4-13. Selected results are also plotted in Figures 4-17 through 4-23.

As mentioned earlier, it is a bit more difficult to portray the sorbent inject results from Gavin Station because of the SO<sub>2</sub> to SO<sub>3</sub> conversion that occurs across the SCR reactors. We have plotted SO<sub>3</sub> removal percentages as measured at two locations, the economizer outlet and the ESP outlet.

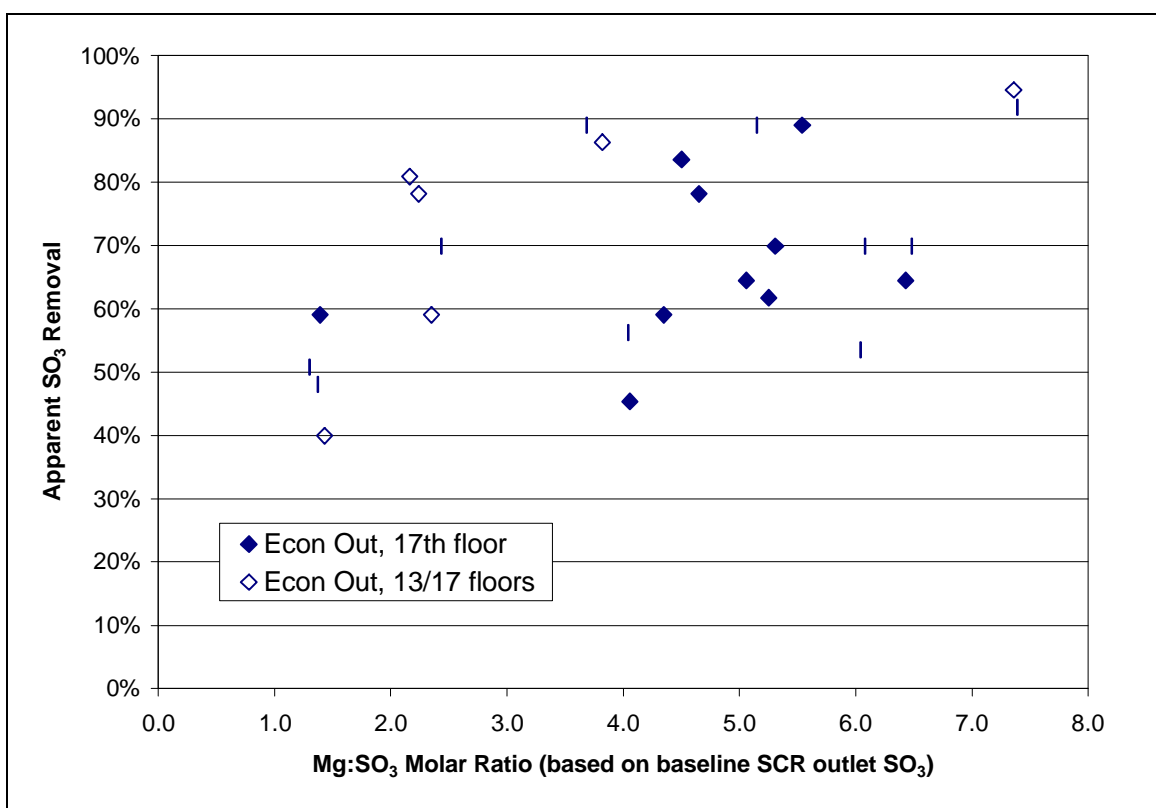
Figure 4-17 shows the economizer outlet data for the byproduct Mg test period. Data are plotted for injection at the 17<sup>th</sup> floor location only, and for injection split between the 13<sup>th</sup> and 17<sup>th</sup> floor. The removal of SO<sub>3</sub> formed in the furnace appears to be more effective when injecting at two levels than when injecting all of the slurry at the 17<sup>th</sup> floor. It is not clear whether this is a residence time effect, a slurry droplet distribution effect, or a droplet size effect (finer

**Table 4-13. Summary of Sulfuric Acid Removal Results from  
Gavin Long-term Mg Injection Test**

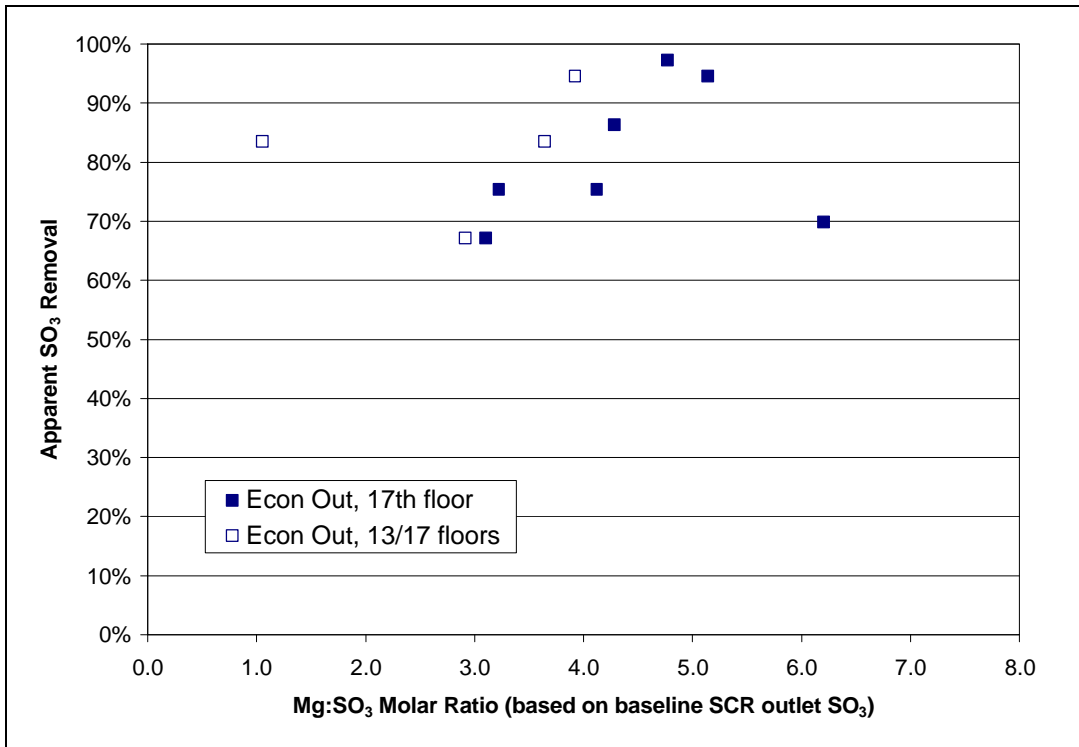
Date/Time	Sorbent (Mg Source)	Injection Location (Floor)	Mg:SO <sub>3</sub> Molar Ratio	Average SO <sub>3</sub> Concentration (ppmv, dry basis at 3% O <sub>2</sub> concentration)			
				Econo- mizer Outlet	SCR Reactor Outlet	ESP Outlet	Stack
Baseline Average	None	None	0.0	37	65	54	48
8/16/01 p.m.	Byproduct	17	5.3	14	43	-	36
8/17/01 a.m.	Byproduct	17	4.4	15	50	-	32
8/17/01 p.m.	Byproduct	17	4.3	-	45	30	36
8/18/01 a.m.	Byproduct	17	4.1	20	43	-	29
8/18/01 p.m.	Byproduct	17	4.0	16	40	22	29
8/20/01 a.m.	Byproduct	17	6.4	13	45	25	-
8/20/01 p.m.	Byproduct	17	6.1	11	39	18	-
8/21/01 a.m.	Byproduct	17	6.5	11	37	18	-
8/21/01 p.m.	Byproduct	17	6.0	17	38	22	-
8/22/01 a.m.	Byproduct	17	5.1	13	30	-	17
8/22/01 p.m.	Byproduct	17	5.3	11	34	22	-
8/23/01 a.m.	Byproduct	17	4.7	8		-	22
8/23/01 p.m.	Byproduct	17	4.5	6	41	26	-
8/24/01 a.m.	Byproduct	17	5.2	4	32	20	-
8/24/01 p.m.	Byproduct	17	5.5	4	24	-	13
8/25/01 a.m.	Byproduct	17	1.4	15	50	34	-
8/25/01 p.m.	Byproduct	17	1.4	19	54	-	33
8/26/01 a.m.	Byproduct	13/17	1.3	18	65	37	-
8/26/01 p.m.	Byproduct	13/17	1.4	22	61	-	40
8/27/01 a.m.	Byproduct	13/17	2.4	15	63	37	-
8/27/01 p.m.	Byproduct	13/17	2.4	11	58	-	31
8/28/01 a.m.	Byproduct	13/17	2.2	7	45	27	-
8/28/01 p.m.	Byproduct	13/17	2.2	8	45	-	26
8/29/01 a.m.	Byproduct	13/17	3.8	5	40	24	-
8/29/01 p.m.	Byproduct	13/17	3.7	4	40	-	23
8/30/01 a.m.	Byproduct	13/17	7.4	2	35	18	-
8/30/01 p.m.	Byproduct	13/17	7.4	3	33	-	18
8/31/01 a.m.	Commercial	13/17	3.9	2	24	9	-
8/31/01 p.m.	Commercial	13/17	1.1	6	37	-	17
9/2/01 a.m.	Commercial	13/17	3.6	6	34	21	-
9/2/02 p.m.	Commercial	13/17	2.9	12	42	31	-
9/4/01 a.m.	Commercial	17	3.2	9	53	31	-
9/4/01 p.m.	Commercial	17	3.1	12	61	-	33

**Table 4-13. Summary of Sulfuric Acid Removal Results from  
Gavin Long-term Mg Injection Test (continued)**

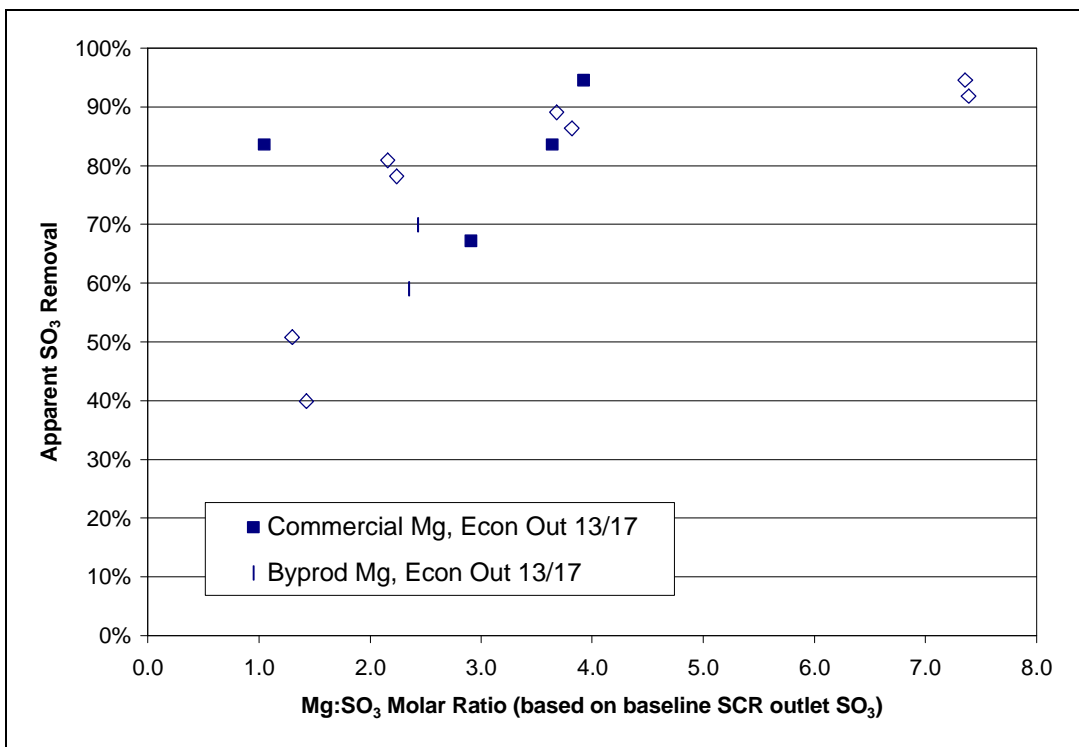
Date/Time	Sorbent (Mg Source)	Injection Location (Floor)	Mg:SO <sub>3</sub> Molar Ratio	Average SO <sub>3</sub> Concentration (ppmv, dry basis at 3% O <sub>2</sub> concentration)			
				Econo- mizer Outlet	SCR Reactor Outlet	ESP Outlet	Stack
Baseline Average	None	None	0.0	37	65	54	48
9/5/01 a.m.	Commercial	17	4.1	9	54	34	-
9/5/01 p.m.	Commercial	17	6.2	11	41	27	-
9/6/01 a.m.	Commercial	17	4.3	5	46	26	-
9/6/01 p.m.	Commercial	17	5.1	2	41	-	-
9/7/01 a.m.	Commercial	17	4.8	1	33	-	-



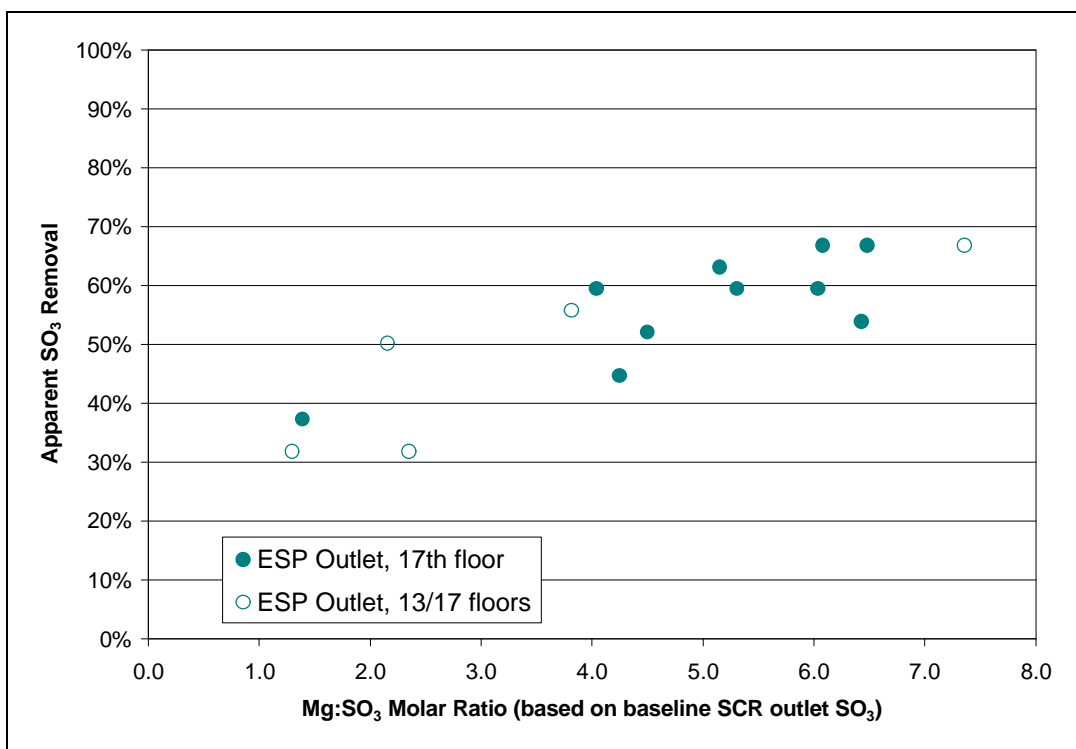
**Figure 4-17. Results from the Byproduct Mg Injection Test Period  
(Economizer Outlet Location)**



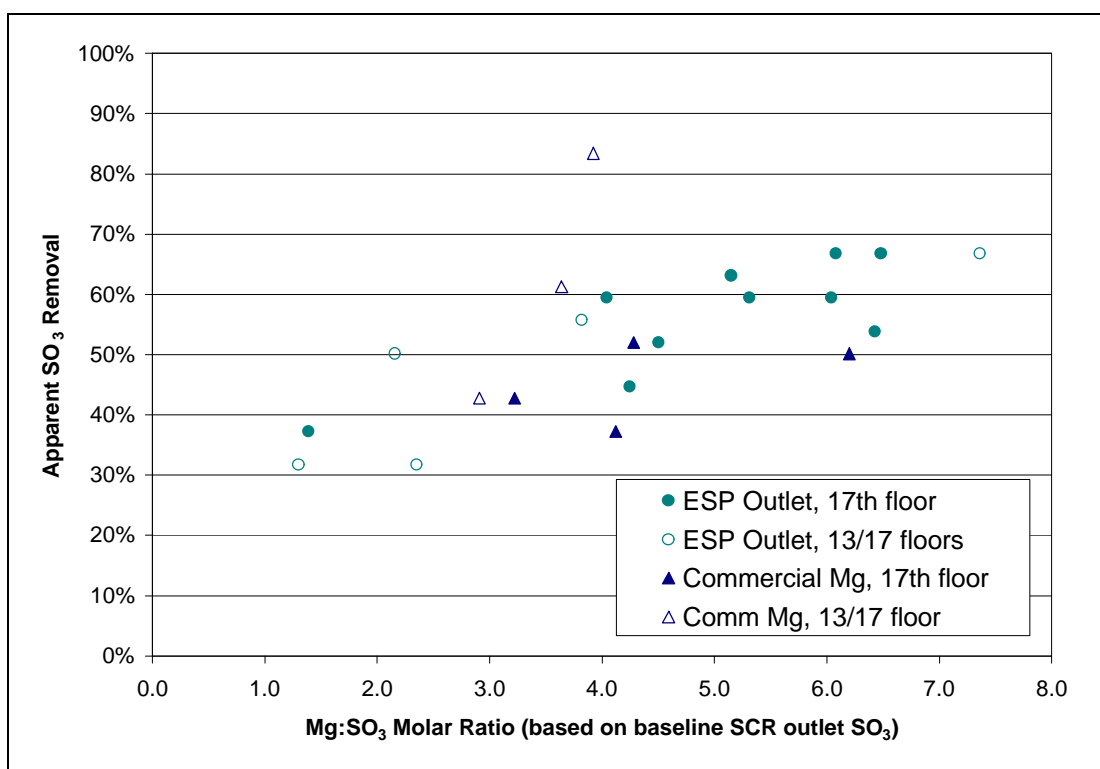
**Figure 4-18. Results from the Long-term Commercial Mg Injection Test Period (Economizer Outlet Location)**



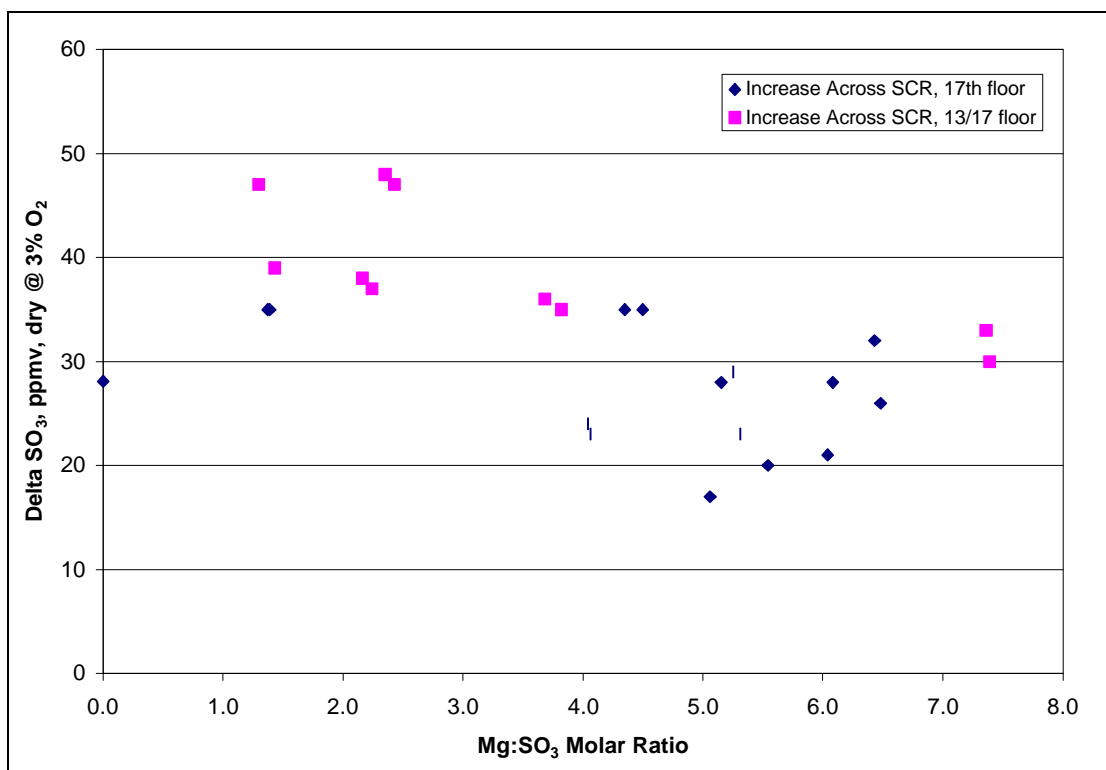
**Figure 4-19. Comparison of Byproduct Mg and Commercial Mg Sorbent Performance (Economizer Outlet Location)**



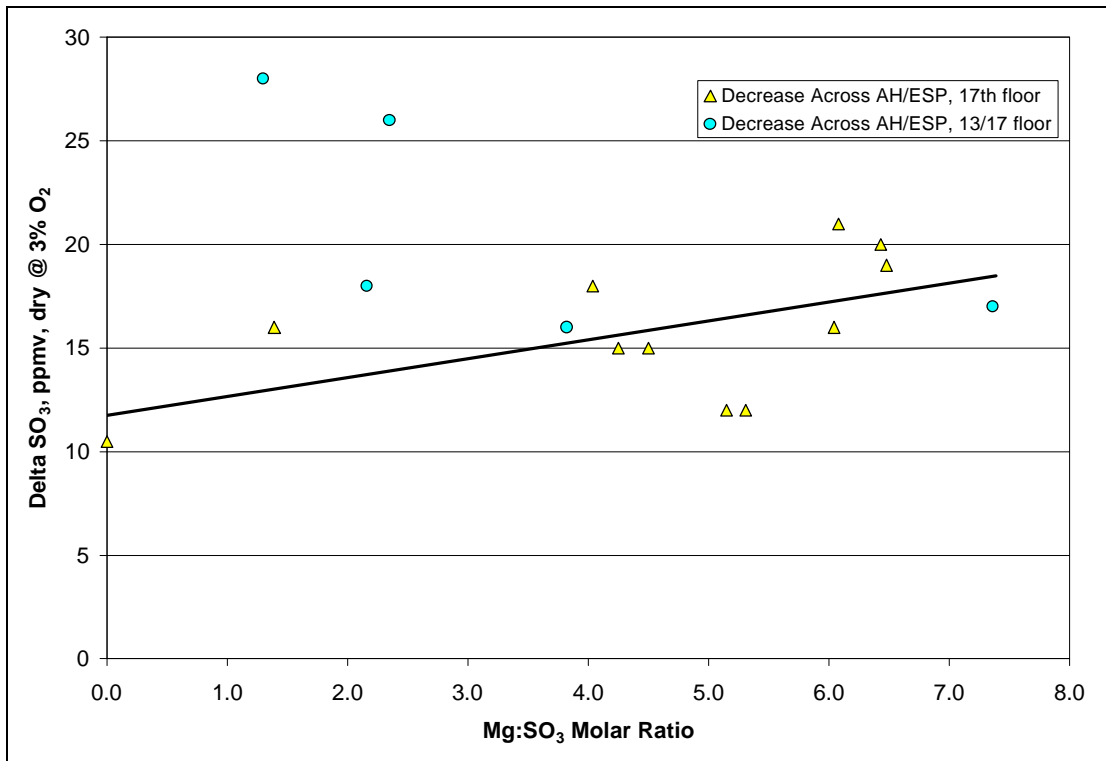
**Figure 4-20. Results from the Byproduct Mg Injection Test Period (ESP Outlet Location)**



**Figure 4-21. Results from the Commercial Mg Injection Test Period Compared to Byproduct Mg Injection Results (ESP Outlet Location)**



**Figure 4-22. Comparison of SO<sub>3</sub> Concentration Changes Across the SCR Reactors (Byproduct Mg Injection)**



**Figure 4-23. Comparison of SO<sub>3</sub> Concentration Changes Across the Air Heaters and ESPs (Byproduct Mg Injection)**



atomization with more nozzles in service and higher air/slurry mass ratios at each nozzle). Much of the data for the 17<sup>th</sup> floor injection are early in the test period, during initial boiler “conditioning” and during a period where the slurry distribution into the furnace was being optimized. Initially, too much SO<sub>3</sub> removal was occurring in the center gas path from the furnace and less from the outer gas paths. Even taking the best performance for injection at the 17<sup>th</sup> floor only, it appears that 90% removal of the SO<sub>3</sub> formed in the furnace was removed at a Mg:SO<sub>3</sub> mole ratio of about 5:1, whereas with injection at both levels only about 3.5:1 was required. Remember that these mole ratios are based on SO<sub>3</sub> concentrations as measured at the SCR outlet. To put these mole ratios on a furnace basis only, they should be multiplied by about 1.75.

Figure 4-18 shows results of economizer outlet sampling during the commercial Mg test period. The results in the figure are similar to those in Figure 4-19. Ignoring outlier data points (most likely caused by non-representative wt% solids levels in commercial Mg slurry samples analyzed), it appears that 90% removal of furnace formed SO<sub>3</sub> can be achieved at a Mg:SO<sub>3</sub> molar ratio of about 3.5:1 when injecting on the 13<sup>th</sup> and 17<sup>th</sup> floors, and about 4.5:1 to 5:1 when injecting only on the 17<sup>th</sup> floor. Figure 4-19 compares the results for the byproduct Mg and commercial Mg for injection at both levels, as measured at the economizer outlet. As described above, most of the data points in the figure show similar performance for the two reagent types when compared at similar Mg:SO<sub>3</sub> molar ratios.

Figure 4-20 shows sulfuric acid removal percentages measured at the ESP outlet location for the byproduct Mg test period, for injection at the 17<sup>th</sup> floor versus injection at both floors. When measured at the ESP outlet, which takes into account the SO<sub>3</sub> produced across the SCR reactors and SO<sub>3</sub>/sulfuric acid removed across the air heater and ESP, there appears to be little difference in performance between the two injection location modes. Both sets of data show about 60% overall SO<sub>3</sub>/sulfuric acid removal at a Mg:SO<sub>3</sub> ratio of 5:1, with overall removal percentages between 65% and 70% possible at higher ratios. These highest removal percentages correspond with ESP outlet sulfuric acid concentrations in the range of approximately 18 to 22 ppm.

Figure 4-21 shows the same data, but with the corresponding data from the commercial Mg injection test period added. Discounting a couple of apparent outlier data points, it appears that there is little difference between the two reagents when compared for performance at the ESP outlet location.

The percent removal plots shown in Figures 4-17 through 4-21 do not clearly illustrate the effects of sorbent added in the furnace on the SO<sub>3</sub> formed across the SCR reactors. Figure 4-22 is an attempt to illustrate this effect. In Figure 4-22, the SO<sub>3</sub> concentration increase measured across the SCR is plotted versus Mg:SO<sub>3</sub> ratio for the byproduct Mg test period, both for injection at the 17<sup>th</sup> floor and for injection split between the 13<sup>th</sup> and 17<sup>th</sup> floors. The data do not show a clear effect of sorbent injection on this increase. For injection at the 17<sup>th</sup> floor, the increase across the SCR varies from 17 ppm to 35 ppm (versus a baseline average of 28 ppm) with no clear trend for a reduced increase as the Mg:SO<sub>3</sub> ratio increases.

For injection split between the 13<sup>th</sup> and 17<sup>th</sup> floor with byproduct Mg, the results plotted in Figure 4-22 do show a reduced increase as the Mg:SO<sub>3</sub> molar ratio increases from 1:1 to 7:1. However, the values at a 1:1 ratio are significantly higher than the baseline increase (39 to 47

ppm vs. 28 ppm at baseline), so even the reduced values at a 7:1 ratio are higher than the baseline increase (30 to 33 ppm vs. 28 ppm). The commercial Mg data are not plotted, but they also show no clear trends.

The data plotted in Figure 4-22 show that sorbent injection in the furnace did not measurably affect the conversion of  $\text{SO}_2$  in the flue gas to  $\text{SO}_3$  across the SCR reactors, although scatter in the data could have made it difficult to note any trends. Another possible effect of sorbent injection in the furnace on  $\text{SO}_3$  formed across the SCR reactors could be increased removal of that  $\text{SO}_3$  as the flue gas passes through the air heaters and ESPs. Figure 4-23 is a plot of data that illustrate this effect. The plot shows the drop in  $\text{SO}_3$ /sulfuric acid concentration from the SCR outlet to the ESP outlet, for the byproduct Mg test period. The results in the figure show that for sorbent injection at the 17<sup>th</sup> floor, this drop in concentration becomes more significant as the Mg: $\text{SO}_3$  ratio increases. The line in the figure represents a linear least squares fit of these data. This drop in  $\text{SO}_3$ /sulfuric acid concentration increases from about 11 ppm at baseline conditions to about 20 ppm at a Mg: $\text{SO}_3$  molar ratio of 6:1, although there is considerable scatter in the data. The commercial Mg data are not plotted, but show considerable scatter.

Based on a review of the  $\text{SO}_3$ /sulfuric acid concentration data in Figures 4-17 through 4-23, it can be concluded that byproduct Mg or commercial Mg sorbents injected into the furnace can remove a high percentage of the  $\text{SO}_3$  formed in the furnace. However, the furnace-injected sorbents have only a modest effect on  $\text{SO}_3$  formed across the SCR reactors. The data show no clear trend for any impact of the injected sorbent on the conversion of  $\text{SO}_2$  to  $\text{SO}_3$  across the SCR reactors. There appears to be a weak trend for increased removal of  $\text{SO}_3$  formed in the SCR across the air heater and ESP at higher sorbent injection rates, though.

#### 4.2.5 Long-term Test Balance of Plant Effects

Balance of plant effects measured were primarily focused on the impacts of sorbent injection and  $\text{SO}_3$  removal on ESP performance. ESP impacts included outlet particulate loading measurements, and impacts on the ESP ash analyses. Measurements were also made of halogen species and arsenic concentrations in the Unit 3 flue gas, both during baseline and sorbent injection conditions, but these results are not yet available.

***ESP Ash Samples – Magnesium and Sulfate Content.*** Samples were collected from the ESP hoppers at regular intervals throughout the long-term test. The objective of collecting the samples was threefold. First, magnesium analyses on the ash samples would provide a measure of how well the sorbent was distributed across the furnace; a good distribution should result in relatively even magnesium concentrations in the samples collected from the various ESP hoppers at a given time. Second, the magnesium analysis results also provide the opportunity to conduct cursory magnesium mass balances, to see if the amount of magnesium injected can be accounted for in the fly ash catch. Finally, magnesium and sulfate analyses were conducted to determine how the injected magnesium sorbents would impact fly ash byproduct sales qualities.

Fly ash samples were analyzed in two manners. First, the results of a relatively mild digestion of the samples in a hydrochloric acid solution were analyzed to determine the “acid soluble” content of magnesium and sulfate in the ash samples. This mild dissolution should readily

dissolve magnesium sulfate resulting from byproduct or commercial Mg injection and removal of flue gas SO<sub>3</sub>, but should not dissolve a high percentage of the magnesium and sulfate content of the base fly ash. These analysis results should be most useful for determining magnesium injection distribution and for conducting magnesium balances.

The second type of analysis was conducted on a more severe hydrofluoric acid digestion of the ash samples. This digestion and subsequent analyses should provide the total magnesium and sulfate content in the samples, including that in the base fly ash and that in injected magnesium compounds. The results of these analyses are most suitable for determining fly ash sales properties.

To date only the results of the milder hydrochloric acid dissolution and analyses are available. These results are summarized in Table 4-14. Also shown in the table are estimated magnesium content based on a cursory material balance calculation, assuming that 75% of the coal ash ends up as fly ash, and based on the injected Mg:SO<sub>3</sub> ratios. Two things are evident from the data presented in Table 4-14. One is that there was significant variability in the distribution of injected magnesium in the ESP hoppers. The data from earlier in the test supports observations from early in the test period that the middle of the furnace was seeing higher SO<sub>3</sub> removal levels, and presumably higher dosages of byproduct Mg in the flue gas. The ESP 21 magnesium concentrations were typically higher than in the ESP 11 and ESP 31 samples. Later in the test period this was less evident, presumably because of efforts to improve sorbent distribution across the furnace. The second observation is that the measured magnesium content in the ash samples was typically near the estimate based on material balances, except for the samples near the end of the test where injection ratios were being changed more rapidly. For the later samples the ESP ash samples may not have been representative of injection conditions at the time the ash samples were collected.

***ESP Outlet Particulate Loading.*** The effects of sorbent injection on ESP performance was determined by conducting ESP outlet mass loading measurements by the EPA Method 17 procedure, except the mass loading was determined by isokinetic sampling at a representative point in the flue gas duct rather than conducting a full outlet duct traverse. This sampling was conducted during sorbent injection, towards the end of the long-term test period, then a “baseline” sample was collected after sorbent injection had ceased. The results of this sampling are summarized in Table 4-15.

The results in Table 4-15 show acceptably low particulate loadings and emissions rates at the point sampled, under both sorbent injection and baseline operation. Actually, the baseline sampling results show lower loadings and emissions rates than during sorbent injection, by approximately a factor of three. However, this result is confounded by the fact that the “baseline” samples had to be collected during “off” hours, mostly while the unit was operating at reduced load. Reduced load operation allowed the ESP to operate at a higher effective specific collection area, which would tend to improve particulate control performance. These sampling times were required because the plant wanted to continue sorbent injection during daylight hours after the test program had ended, to realize the observed benefits of sorbent injection on plume opacity.

**Table 4-14. Magnesium and Sulfate Concentrations in Fly Ash Samples**

<b>Sample ID</b>	<b>Mg:SO<sub>3</sub> Mole Ratio Injected</b>	<b>Measured Magnesium Content, wt%</b>	<b>Estimated Magnesium Content from Material Balance, wt%</b>	<b>Measured Sulfate Content, wt%</b>
8/16/01 11 Lower	0 (Baseline)	0.04	0	0.91
8/16/01 21 Lower	0 (Baseline)	0.04		1.06
8/16/01 31 Lower	0 (Baseline)	0.04		1.12
8/21/01 11 Upper	6:1	2.51	3.5	3.31
8/21/01 21 Upper	6:1	3.27		4.19
8/21/01 31 Upper	6:1	3.25		4.86
8/21/01 11 Lower	6:1	2.65		3.26
8/21/01 21 Lower	6:1	2.62		3.16
8/21/01 31 Lower	6:1	3.46		4.96
8/24/01 11 Upper	5:1	2.01	3.0	3.29
8/24/01 21 Upper	5:1	2.67		3.77
8/24/01 31 Upper	5:1	2.27		3.34
8/24/01 11 Lower	5:1	2.50		3.17
8/24/01 21 Lower	5:1	2.85		3.85
8/24/01 31 Lower	5:1	1.62		2.99
8/28/01 11 Upper	2:1	1.35	1.5	2.41
8/28/01 21 Upper	2:1	1.98		3.00
8/28/01 31 Upper	2:1	0.47		1.38
8/28/01 11 Lower	2:1	0.94		2.06
8/28/01 21 Lower	2:1	2.26		6.07
8/28/01 31 Lower	2:1	1.41		4.13
8/31/01 11 Upper	4:1 (a.m.)	2.94	2.4	5.73
8/31/01 21 Upper	4:1 (a.m.)	2.95		5.23
8/31/01 31 Upper	4:1 (a.m.)	3.05		5.43
8/31/01 11 Lower	4:1 (a.m.)	2.27		4.48
8/31/01 21 Lower	4:1 (a.m.)	2.98		5.81
8/31/01 31 Lower	4:1 (a.m.)	3.44		2.83
9/4/01 11 Upper	3:1	1.46	3.0	1.97
9/4/01 21 Upper	3:1	1.56		2.13
9/4/01 31 Upper	3:1	1.32		2.29
9/4/01 11 Lower	3:1	0.70		1.61
9/4/01 21 Lower	3:1	1.88		2.18
9/4/01 31 Lower	3:1	1.26		2.19
9/6/01 11 Upper	4:1	0.79	2.6	1.57
9/6/01 21 Upper	4:1	1.49		2.26
9/6/01 31 Upper	4:1	1.70		2.04
9/6/01 11 Lower	4:1	0.77		1.55
9/6/01 21 Lower	4:1	1.33		1.82
9/6/01 31 Lower	4:1	1.60		1.99

**Table 4-15. Results of ESP Outlet Mass Loading Measurements**

<b>Sample Date</b>	<b>Sample Time</b>	<b>Outlet Loading (gr/dscf)</b>	<b>Outlet Emissions Rate (lb/MM Btu)</b>
Sorbent Injection Sampling:			
9/6/01	11:50	0.019	0.035
9/6/01	14:43	0.024	0.044
9/7/01	13:43	0.012	0.022
Average	-	0.018	0.034
Baseline Sampling:			
9/8/01	02:19	0.005	0.008
9/8/01	03:44	0.004	0.008
9/8/01	17:30	0.006	0.011
Average	-	0.005	0.009

Because of this confounding effect, it is not possible to use these data to directly quantify the effect of sorbent injection on ESP particulate control performance. However, it is clear that the ESP performance was quite acceptable during the sorbent injection period.

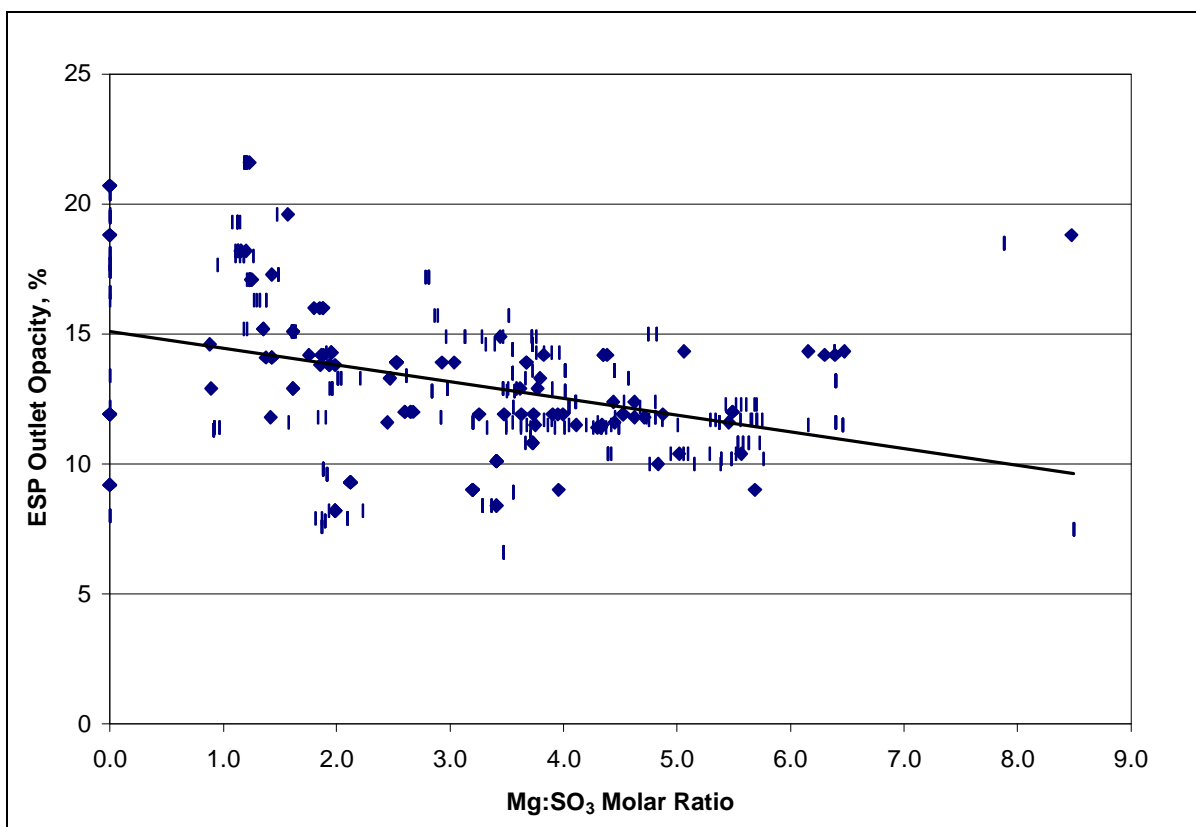
**Effects on Plume Opacity.** The plant had an engineer on site that read the plume opacity according to the procedures of EPA Method 9, when possible. The ability to read plume opacity was often limited by atmospheric conditions, particularly because the stack for the adjacent Unit 2 at Gavin Station is very close to the stack for Unit 1, and the plumes commonly co-mingle. The stack opacity reading data have not yet been reported to URS. These data should become available during the next reporting period. Qualitatively, it was observed that sorbent injection into the furnace greatly decreased the plume opacity from Unit 1.

Another opacity issue concerns the plant's in-duct opacity monitor readings, which measure flue gas opacity at the ESP outlet location. For plants that have wet scrubbers, the flue gas opacity is typically measured upstream of the scrubber because opacity monitors do not work well in wet gas streams. Plume opacity due to sulfuric acid mist is typically only an issue downstream of the wet scrubber, as the acid mist forms when the flue gas is quenched below the acid dew point at the wet scrubber wet/dry interface. In-duct opacity monitors situated at the ESP outlet thus do not detect this opacity. However, at Gavin Station, because of the very high sulfuric acid concentrations in the flue gas downstream of the SCR reactors, the ESP outlet flue gas is actually below the acid dew point, and some acid mist is present in the flue gas at the ESP outlet. E.ON Engineering measured 3 to 5 ppm of entrained acid mist in the flue gas at the ESP outlet under baseline conditions. Apparently because of this entrained acid mist, Gavin Station typically measures elevated in-duct opacity values.

The injection of magnesium alkali slurries into the furnace was observed to be effective at removing this acid mist under most conditions, presumably because even a moderate amount of sulfuric acid removal would elevate the acid dew point above the ESP outlet flue gas temperature. E.ON Engineering typically did not measure any acid mist content in the ESP outlet gas during sorbent injection periods. In fact, the first day that sorbent injection began, the afternoon of August 16, the Unit 1 opacity monitor measured a sharp decrease in opacity soon

after injection began, from about 18 to 20% prior to injection, down to 10 to 12% within a couple of hours.

The plant opacity monitor readings were plotted as a function of injected sorbent Mg:SO<sub>3</sub> ratio. The data for periods of full-load operation (greater than 1300 gross MW) are illustrated in Figure 4-24. The data in the figure show a consistent trend for lower in-duct opacity during sorbent injection. Baseline (no injection) values fall in the range of approximately 16 to 21%, while for injection ratios greater than 3:1, the values are almost entirely in the range of 10 to 15%.



**Figure 4-24. Effect of Sorbent Injection on Opacity as Measured in the ESP Outlet Duct, for Full-Load Operation (>1300 gross MW)**

### 4.3 Summary and Conclusions

During the current reporting period, longer-term (approximately 25-day) sorbent injection tests were conducted at two different sites to determine the effects of magnesium-based alkalis injected into the furnace of coal-fired boilers for removing SO<sub>3</sub>/sulfuric acid from the flue gas. A summary and conclusions from each test are discussed below.

#### 4.3.1 Bruce Mansfield Results

The first test was conducted at FirstEnergy's BMP Unit 3, using byproduct Mg slurry. Over the 23-day injection period, the molar ratio of injected sorbent to SO<sub>3</sub> in the economizer outlet gas

(as measured under baseline conditions) was varied from about 2:1 to 5:1. The corresponding sulfuric acid removal efficiencies, as measured at the ESP B outlet, varied from about 40 to 75%. The amounts of sorbent injected and sulfuric acid removal were generally limited by ESP performance. As the sulfuric acid removal increased, the power to the ESP electrical fields generally decreased, and ESP outlet opacity increased, presumably due to increases in fly ash resistivity resulting from the upstream sulfuric acid removal. However, at the beginning of the test, two of the four ESPs on Unit 3 were not performing well with respect to electrical conditions. Higher injection rates and higher sulfuric acid removal levels may have been possible with four well-performing ESPs.

The stack plume opacity was not measured during the long-term test period. However, qualitative observations noted greatly reduced plume opacity.

No significant effect of sorbent injection was noted on Unit 1 air heater pressure drop or outlet flue gas temperatures, or economizer outlet temperatures. Manual flue gas measurements by EPA Method 17 did not detect a significant impact on ESP outlet particulate mass loadings. Similarly, measurements by applicable EPA reference methods did not detect any measurable removal of gas phase HCl or HF from the ESP outlet flue gas, or gas phase arsenic from the economizer outlet gas. Finally, no significant effect was noted on boiler slagging tendencies during the test period.

In summary, the long-term test showed that byproduct Mg injection at the 14<sup>th</sup> floor of the boiler could be implemented to achieve 60 to 70% sulfuric acid removal, with greatly reduced plume opacity and at most minor impacts on ESP performance. Higher sulfuric acid removal levels may have been possible if the ESP had been in better electrical condition at the start of the test. No significant balance of plant impacts were noted, and no multipollutant removal was measured (e.g., no HCl or HF removal).

#### **4.3.2 Gavin Station Results**

The second long-term test was conducted at the AEP Gavin Station. Both byproduct Mg and commercial Mg injection were tested, with two different injection location schemes. This test was significantly different than the BMP test because the Gavin Station has operating SCR reactors that convert about 1% of the flue gas SO<sub>2</sub> to SO<sub>3</sub>. This, combined with the furnace conversion, results in approximately 2.3% overall conversion of the coal sulfur to the SO<sub>3</sub> form, and relatively high flue gas SO<sub>3</sub>/sulfuric acid concentrations.

There was no clear difference between the performance of the byproduct Mg slurry and the commercial Mg slurry purchased from the Dow Chemical Company, when the two were compared at equal magnesium hydroxide injection rates. The test results did indicate that for this boiler, it was more effective to inject about 40% of the sorbent slurry at the 13<sup>th</sup> floor of the boiler, and the remainder at the 17<sup>th</sup> floor, rather than inject all of the slurry at the 17<sup>th</sup> floor. The 13<sup>th</sup> floor is just above the nose of the boiler, and the 17<sup>th</sup> floor is adjacent to the tops of the pendant superheater tubes.

When injecting either sorbent split with 40% going to the 13<sup>th</sup> floor and 60% going to the 17<sup>th</sup> floor, 90% of the furnace-formed SO<sub>3</sub> was removed at a Mg:SO<sub>3</sub> ratio of about 3.5:1. For injection all on the 17<sup>th</sup> floor, a Mg:SO<sub>3</sub> ratio of about 5:1 was required. These molar ratios are based on the SCR outlet SO<sub>3</sub> concentrations, as measured during baseline Unit 1 operation.

The furnace-injected sorbent was less effective at removing SO<sub>3</sub> formed across the SCR catalyst. When measured at the ESP outlet, downstream of the SCR reactors and air heaters, the overall sulfuric acid removal was only 70% at a Mg:SO<sub>3</sub> molar ratio of 5:1, with the maximum removal observed being about 78% at a molar ratio of about 6:1 to 7:1. The data show no clear reduction in the conversion of SO<sub>2</sub> to SO<sub>3</sub> across the SCR reactors during sorbent injection, and only a modest increase in sulfuric acid removal across the air heaters and ESP compared to baseline removal.

Most of the balance of plant information is not yet available for reporting. However, it was noted qualitatively that the sorbent injection significantly reduced the plume opacity from Unit 1, and measurably lowered the opacity measured in duct at the ESP outlet. ESP outlet particulate emissions remained low during the sorbent injection period.