Sulfuric Acid Removal Process Evaluation: Long-term Results

Topical Report

Cooperative Agreement No.: DE-FC26-99FT40718

Prepared for:

William W. Aljoe

U.S. Department of Energy
National Energy Technology Laboratory
626 Cochrans Mill Road
Pittsburgh, Pennsylvania 15236

Prepared by:

Gary M. Blythe
Richard McMillan

URS Corporation
9400 Amberglen Boulevard
Austin, Texas 78729

July 3, 2002

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

ABSTRACT

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 project is being co-funded by the U.S. DOE National Energy Technology Laboratory, under Cooperative Agreement DE-FC26-99FT40718, along with EPRI, the American Electric Power Company (AEP), FirstEnergy Corp., the Tennessee Valley Authority, and Dravo Lime, Inc.

Sulfuric acid controls are becoming of increasing interest to power generators with coal-fired units for a number of reasons. Sulfuric acid is a Toxic Release Inventory species and can cause a variety of plant operation problems such as air heater plugging and fouling, back-end corrosion, and plume opacity. These issues will likely be exacerbated with the retrofit of selective catalytic reduction (SCR) for NO_X control on many coal-fired plants, as SCR catalysts are known to further oxidize a portion of the flue gas SO_2 to SO_3.

The project previously tested the effectiveness of furnace injection of four different calcium- and/or magnesium-based alkaline sorbents on full-scale utility boilers. These reagents were tested during four one- to two-week tests conducted on two FirstEnergy Bruce Mansfield Plant (BMP) units. One of the sorbents tested was a magnesium hydroxide byproduct slurry produced from a modified Thiosorbic® Lime wet flue gas desulfurization system. The other three sorbents are available commercially and include dolomite, pressure-hydrated dolomitic lime, and commercial magnesium hydroxide. The dolomite reagent was injected as a dry powder through out-of-service burners, while the other three reagents were injected as slurries through air-atomizing nozzles inserted through the front wall of the upper furnace, either across from the nose of the furnace or across from the pendant superheater tubes.

After completing the four one- to two-week tests, the most promising sorbents were selected for longer-term (approximately 25-day) full-scale tests on two different units. The longer-term tests were conducted to confirm the effectiveness of the sorbents tested over extended operation on two different boilers, and to determine balance-of-plant impacts. The first long-term test was conducted on FirstEnergy's BMP, Unit 3, and the second test was conducted on AEP's Gavin Plant, Unit 1. The Gavin Plant testing provided an opportunity to evelute the effects of sorbent injected into the furnace on SO_3 formed across an operating SCR reactor.

This report presents the results from those long-term tests. The tests determined the effectiveness of injecting commercially available magnesium hydroxide slurry (Gavin Plant) and byproduct magnesium hydroxide slurry (both Gavin Plant and BMP) for sulfuric acid control. The results show that injecting either slurry could achieve up to 70 to 75% overall sulfuric acid removal. At BMP, this overall removal was limited by the need to maintain acceptable electrostatic precipitator (ESP) particulate control performance. At Gavin Plant, the overall sulfuric acid

removal was limited because the furnace injected sorbent was less effective at removing SO_3 formed across the SCR system installed on the unit for NO_X control than at removing SO_3 formed in the furnace.

The long-term tests also determined balance-of-plant impacts from slurry injection during the two tests. These include impacts on boiler back-end temperatures and pressure drops, SCR catalyst properties, ESP performance, removal of other flue gas species, and flue gas opacity. For the most part the balance-of-plant impacts were neutral to positive, although adverse effects on ESP performance became an issue during the BMP test.

CONTENTS

4 RESULTS FROM THE LONG-TERM SLURRY INJECTION TESTS AT AEP'S GAVIN PLANT

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

As part of this DOE co-funded Cooperative Agreement, two longer-term (23-day) sorbent injection tests were conducted at different sites to determine the effects of magnesium-based alkalis injected into the furnace of coal-fired boilers for removing SO_3/sulfuric acid from the flue gas. Summary information and conclusions from each test are discussed below.

Bruce Mansfield Plant (BMP) Results

The first test was conducted at FirstEnergy's BMP Unit 3, using a byproduct magnesium hydroxide (byproduct Mg) slurry. During the 23-day test, the molar ratio of injected sorbent to SO_3 in the economizer outlet gas (as measured prior to sorbent injection) was varied from about 2:1 to 5:1. 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 removed 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, electrical conditions in two of the four ESPs appeared to have been adversely affected by previous dolomite injection testing on Unit 3. Otherwise, higher injection rates and higher sulfuric acid removal levels might have been possible.

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 3 air heater pressure drop or outlet flue gas temperatures, or on economizer outlet gas 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 of gas-phase arsenic from the economizer outlet gas. Effects on SCR catalyst coupons were minimal, mostly ranging from neutral to slightly positive in nature. 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 14th floor of the boiler could achieve 60 to 70% sulfuric acid removal, with greatly reduced plume opacity and only minor impacts on ESP performance. Higher sulfuric acid removal levels might have been possible if two of the four ESPs had been in better electrical condition at the start of the test. No other significant balance of plant impacts were noted, and no multipollutant removal was measured (e.g., no HCl or HF removal).

Gavin Plant Results

The second long-term test was conducted at the AEP Gavin Plant. Both byproduct Mg and commercial magnesium hydroxide (commercial Mg) injection were tested, with two different injection location schemes. This test was significantly different than the BMP test because the Gavin Plant has operating SCR reactors that convert about 1% of the flue gas SO_2 to SO_3. This, combined with the furnace conversion, results in approximately 2.3% overall conversion of the coal sulfur to the SO_3 form, and relatively high flue gas SO_3/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 13th floor of the boiler, and the remainder at the 17th floor, rather than inject all of the slurry at the 17th floor. The 13th floor is just above the nose of the boiler, and the 17th floor is adjacent to the tops of the pendant superheater tubes.

When injecting either sorbent split with 40% going to the 13th floor and 60% going to the 17th floor, 90% of the furnace-formed SO_3 was removed at a $Mg:SO_3$ ratio of about 3.5:1. For injection all on the 17th floor, a $Mg:SO_3$ ratio of about 5:1 was required. These molar ratios are based on the SCR outlet SO_3 concentrations, as measured during baseline Unit 1 operation.

The furnace-injected sorbent was less effective at removing SO_3 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 $Mg:SO_3$ 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_2 to SO_3 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.

The balance of plant effects tracked during the long-term Mg sorbent injection tests at Gavin Plant were, for the most part, minor. ESP electrical conditions may have been adversely affected for the first three fields of the center ESPs, but the downstream fields in these ESPs and all fields of the outer ESPs were unaffected. ESP outlet opacity readings were decreased somewhat by sorbent injection, which is a desirable effect. There was no clear effect of sorbent injection on ESP outlet mass loading. This observation may have been influenced by the fact that an outer ESP rather than a center ESP was measured for performance.

A review of temperature data show that the center economizer outlet duct temperatures increased by approximately 10°F (6°C) over the course of the test, possibly indicating minor fouling of "back pass" surface area in the center of the furnace. Air heater pressure drop data indicate an increase of approximately 0.5 inches H_2O (0.1 kPa) over three weeks of test duration, at full-load operation, on all three air heaters. It is not known how this increase with time compares with normal operation. No effect of sorbent injection was seen on air heater outlet temperatures.

There was no apparent affect of sorbent injection or injection location on slagging tendencies or slag properties on the leading edge of the secondary superheater pendants. Gas sampling results showed no effect of sorbent injection on flue gas HCl or HF concentrations at the ESP outlet, and no effect on vapor-phase arsenic concentrations at the SCR inlet.

1
INTRODUCTION

This document is the long-term test report for the project "Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control." 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 (HCl) and hydrofluoric acid (HF) is also being determined, as is the removal of arsenic, a known poison for NO_X selective catalytic reduction (SCR) catalysts. The project is being co-funded by the U.S. DOE National Energy Technology Laboratory, under Cooperative Agreement DE-FC26-99FT40718, along with EPRI, the American Electric Power Company (AEP), FirstEnergy Corp. (FirstEnergy), the Tennessee Valley Authority, and Dravo Lime, Inc. URS Corporation (formerly Radian International) is the prime contractor.

Background

Sulfuric acid is present in most flue gases from coal combustion because a small percentage of the SO_2 produced from the sulfur in the coal (approximately 0.5 to 1.5%) is further oxidized to form SO_3. The SO_3 combines with flue gas moisture to form vapor-phase or condensed sulfuric acid at temperatures below about 500^oF (260^oC). Throughout this report, the terms "sulfuric acid" and "SO_3" sometimes appear to be used interchangeably. However, the authors recognize that in the furnace and in the flue gas path up to the air heater, the predominant form of sulfur in this oxidation state is vapor-phase SO_3, while downstream of the air heater the predominant form is vapor-phase or condensed sulfuric acid (H_2SO_4).

Besides being a Toxic Release Inventory substance, sulfuric acid in the flue gas can lead to power plant operating problems. These can include boiler air heater plugging and fouling, corrosion in the air heater and downstream, and reduced power plant efficiency if air heater outlet flue gas temperatures are raised to avoid these problems. Also, the formation of a visible plume can be an issue, particularly for plants with wet flue gas desulfurization (FGD) systems. These issues will likely be exacerbated with the retrofit of selective catalytic reduction (SCR) for NO_X control on some coal-fired plants, as SCR catalysts are known to further oxidize a portion of the flue gas SO_2 to SO_3.

Project Overview

The project first tested the effectiveness of furnace injection of four different calcium- and/or magnesium-based alkaline sorbents on full-scale utility boilers. These reagents were tested during four one- to two-week tests conducted on two FirstEnergy Bruce Mansfield Plant (BMP) units. One of the sorbents tested was a magnesium hydroxide byproduct slurry produced from a

modified Thiosorbic® Lime wet flue gas desulfurization system. The other three sorbents are available commercially and include dolomite, pressure-hydrated dolomitic lime, and commercial magnesium hydroxide (commercial Mg). The dolomite was injected as a powder into the furnace of BMP Unit 2, while the other three reagents were injected as slurries into the upper furnace of BMP Unit 3.

After completing the four one- to two-week tests, the most promising sorbents were selected for longer-term (approximately 25-day) full-scale tests. The longer-term tests were conducted to confirm the effectiveness of the sorbents tested over extended operation and to determine balance-of-plant impacts. Two longer-term tests were conducted, one on FirstEnergy's BMP Unit 3 and the second on AEP's Gavin Plant Unit 1. Testing on two different units was desirable because it provided an opportunity to see how well results from one boiler would transfer to another boiler, built by another manufacturer and firing a different bituminous coal. The Gavin Plant testing was also very advantageous because it offered the opportunity to determine the impacts of sorbent injected into the furnace on SO_3 formed across an operating SCR reactor.

Report Organization

This report provides a detailed discussion of technical results from the two longer-term sorbent injection tests, with the first being conducted on BMP Unit 3 and the second on Gavin Plant Unit 1. Results from the short-term tests were presented and discussed in a previous report.[1] Section 2 provides a description of the measurement methods used in conducting the project, and Section 3 presents a description of the host site, and conditions for and results from the long-term byproduct Mg injection test conducted on BMP Unit 3. Section 4 presents similar information from the long-term magnesium hydroxide slurry injection tests on Gavin Plant Unit 1. Section 5 provides a summary and conclusions from the long-term tests.

---

[1] *Sulfuric Acid Removal Process Evaluation: Short-term Results*, EPRI, Palo Alto, CA, U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, Pennsylvania, October 2001. TR1003980.

2
TEST MEASUREMENT METHODS

This section describes the measurement methods used in the conduct of the two long-term furnace sorbent injection tests, at FirstEnergy's BMP and AEP's Gavin Plant. The first subsection describes flue gas measurements, and the second describes slurry and solid sample measurements.

Flue Gas Measurements

H_2SO_4 Vapor by Controlled Condensation

At BMP, SO_3 concentrations at the economizer outlet and sulfuric acid vapor concentrations at the ESP outlet were measured using the CCS method. A diagram of this sulfuric acid vapor train is shown in Figure 2-1. Controlled condensation is generally regarded as the most accurate method for measuring SO_3/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 (138°C), or all locations upstream of the FGD system.

In the CCS method, 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 (288°C) 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 (66°C) 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 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 H_2SO_4 vapor in the flue gas can be calculated.

During the long-term test at Gavin Plant, the CCS measurements were made by a third-party 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.

Protective Housing
for SO$_3$/H$_2$SO$_4$
Condenser

Thermocouple to
Monitor Exit Gas
Temperature

High-Temperature
Oven for Pyrex
Thimble Holder

Probe

3% H$_2$O$_2$
Impingers

Dry Impinger

Temperature
Sensor

Quartz Liner

High-Temperature
Probe Liner

Condenser Cooling
Liquor Inlet

Thermometer

Dual-Temperature
Controller for
Maintaining Probe and
Oven Temperature (550°F)

Condenser
Cooling
Liquor Outlet

Submergible Temperature
Controller and Pump
Combination

Silica Gel
Dessicant

Vacuum
Line

140°F Controlled
Temperature Bath

Temperature
Sensors

Bypass
Valve

Vacuum
Gauge

Orifice

Main
Valve

Orifice
Magnehelic

Dry Gas Meter

Pump

Figure 2-1. Controlled Condensation Sulfuric Acid Vapor Train
Note: 550°F = 288°C.

A diagram of the CCS sulfuric acid vapor train as operated by URS was shown previously in Figure 2-1. Differences in the method as practiced by E.ON Engineering include:

- At the economizer outlet and SCR outlet (700°F [371°C] 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 [182°C] 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 [54°C] 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.

Acid Dew Point

During the long-test at BMP, measurements were periodically made using either an in-situ or a portable acid dew-point meter manufactured by Land Combustion, or both, to determine the acid dew point. These measurements were made at the inlet ducts to the ESPs, where the flue gas temperature is in the range of 280 to 340°F (138 to 171°C). 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. 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.[2] Acid dew-point measurements were used primarily as an indicator of sorbent effectiveness but not directly to quantify performance.

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 sample extraction with an apparatus similar to that used in EPA Method 5. An illustration of the Method 26a train is shown in Figure 2-2. 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_2 and F_2) are dissolved in the third impinger which contains sodium hydroxide. The samples collected are analyzed by ion chromatography (IC) or ion specific electrode. Samples were collected by this method during both the BMP and Gavin Plant long-term tests.

Method 108—Flue Gas Arsenic Content

Arsenic is a known SCR catalyst poison. At economizer exit temperatures (about 700°F [371°C]), 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

---

[2] Pierce, Robert R., "Estimating Acid Dewpoints in Stack Gases," *Chemical Engineering*, April 11, 1977, pp. 125-128.
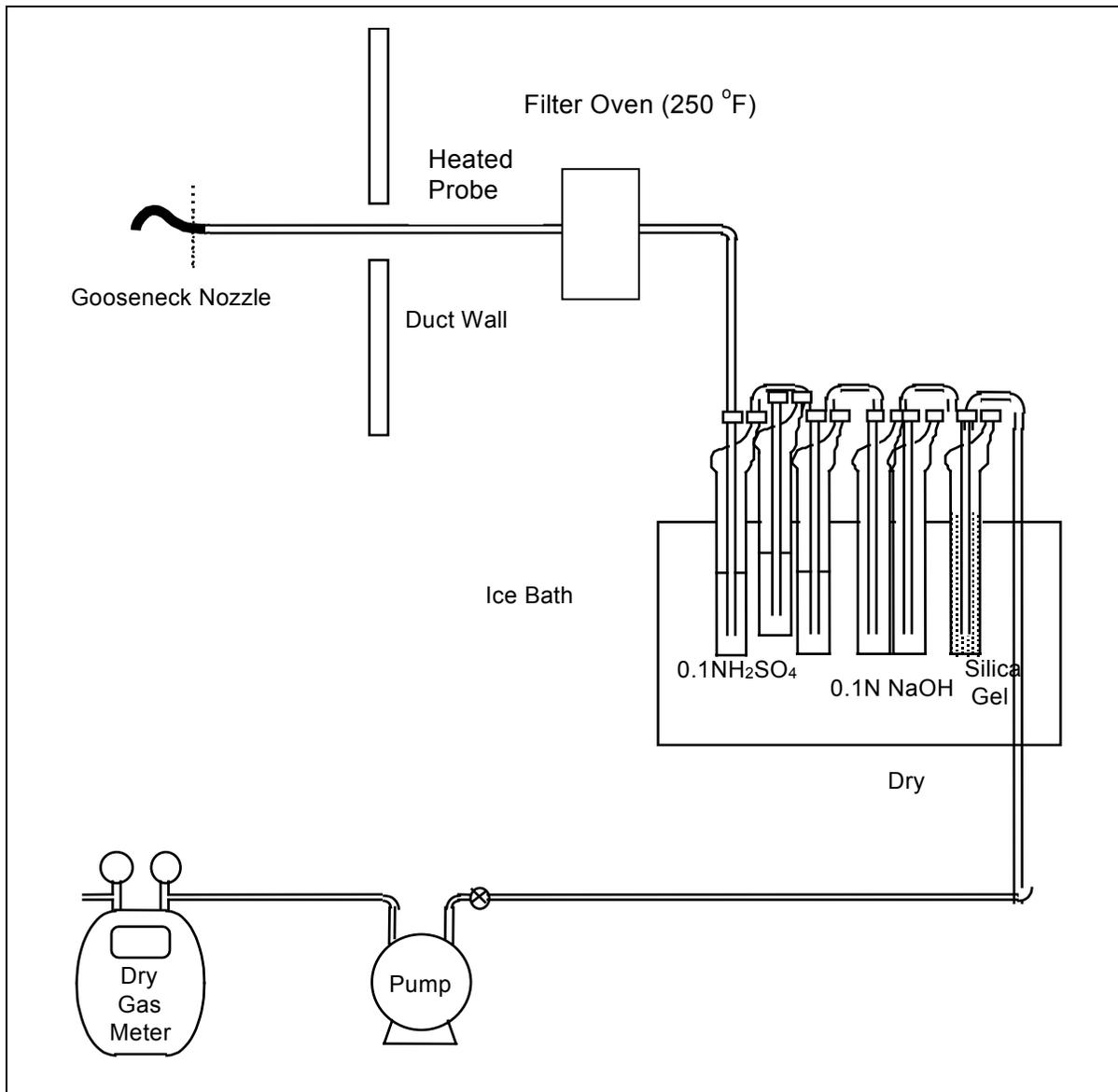
Figure 2-2. EPA Method 5/Method 26a Sampling Train
Note: $250^{\circ}F = 121^{\circ}C$.

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 $250^{\circ}F$ ($121^{\circ}C$). 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 $250^{\circ}F$ ($121^{\circ}C$). Since the temperature of the flue gas at the economizer exit is approximately $700^{\circ}F$ ($371^{\circ}C$), vapor-phase arsenic compounds with dew points between 250 and $700^{\circ}F$ (121 and $371^{\circ}C$) 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 (371°C). The sample was first collected from the flue gas stream isokinetically. An in-stack filter, such as is used in Method 17, 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.

Solid and Slurry Sample Analyses

Fly Ash Samples

Fly ash samples were collected from the ESP hoppers and analyzed for acid-soluble magnesium and sulfate content (predominantly magnesium sulfate formed by the injection of sorbent rather than magnesium in the coal ash). Magnesium analyses were conducted by atomic absorption and sulfate content by ion chromatography.

The magnesium content analyses were used to determine how uniformly the reagents were distributed among the ESP hoppers, and to conduct cursory material balance calculations to ensure that the amounts of reagents injected could be accounted for in the ESP fly ash catch.

Reagent Slurry Samples

Reagent slurries were analyzed for specific gravity and weight percent solids content (gravimetric determination), magnesium content (atomic absorption), and total alkalinity (acid-base titration). The results of these analyses were used to determine the amount of magnesium hydroxide present in the slurries injected into the furnace. The byproduct magnesium hydroxide solids also contain about 30 wt% gypsum ($CaSO_4 \cdot 2H_2O$) as an impurity. A number of these samples were consequently analyzed for calcium content by atomic absorption and sulfate content by ion chromatography.

3
RESULTS OF THE LONG-TERM BYPRODUCT MG INJECTION TEST AT BMP

Results from the baseline and 23-day byproduct Mg injection test on Unit 3 at BMP are presented and discussed in this section. First, the test approach is described, including a description of the host unit and the test equipment. Next, the results of the baseline (no sorbent injection) tests are presented and discussed, then results that quantify the impacts of sorbent injection on Unit 3 sulfuric acid concentrations are discussed. Finally, balance-of-plant issues are discussed, including impacts of sorbent injection on ESP performance, and on removal of HCl, HF, chlorine, fluorine, and arsenic.

Byproduct Mg Slurry Injection Test Description for FirstEnergy's BMP

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 SO_3 control. Various analytical techniques were used to assess the effects of sorbent injection, primarily sampling with the Controlled Condensation System (CCS) method for determining flue gas SO_3 content. To a lesser extent, an acid dew-point meter was used for determining the sulfuric acid dew point (and, indirectly, the concentration of sulfuric acid) of the flue gas. EPA Reference Method 26a was used for determining HCl and HF, as well as chlorine (Cl_2) and fluorine (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. These methods were described in more detail in Section 2.

Impacts on ESP operation were quantified by taking voltage and current data on operating electrical sections of the Unit 3 ESPs. A modified version of EPA Reference Method 17 was used to quantify ESP outlet particulate readings under baseline operation and during sorbent injection. Sorbent and ESP hopper samples were analyzed for magnesium content by acid disolution 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. SCR catalyst coupons were inserted into the economizer outlet flue gas stream at the beginning of sorbent injection, and individual coupons were removed periodically as the test progressed. These coupons were analyzed off site for the impacts of byproduct Mg on catalyst activity. 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 Description

Unit 3 is rated at 800 net MW. It was brought into service in 1980. It has an opposed-wall fired, supercritical boiler rated at approximately 6,415,000 pounds of steam per hour (2,916,00 kg/hr) at 3785 psig (26,100 kPa) and 1005°F (541°C) 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, although the actual coal sulfur can vary over a range from 2.0 to 4.5%. Up to 20% of the fuel blend can be petroleum coke. During the long-term test period on Unit 3, a standard fuel blend averaging 3.5 to 4% sulfur was fired.

Figure 3-1 illustrates the flue gas path for Unit 3, and notes the gas sampling locations used during this test. Flue gas from each of two air heaters splits again into two duct runs, each of which goes to an electrostatic precipitator (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 tries to bias the ID fans to equalize the gas flow as much as possible. 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® lime slurry reagent. The flue gas in the stack is saturated at a temperature of about 130°F (54°C); no reheat is employed.
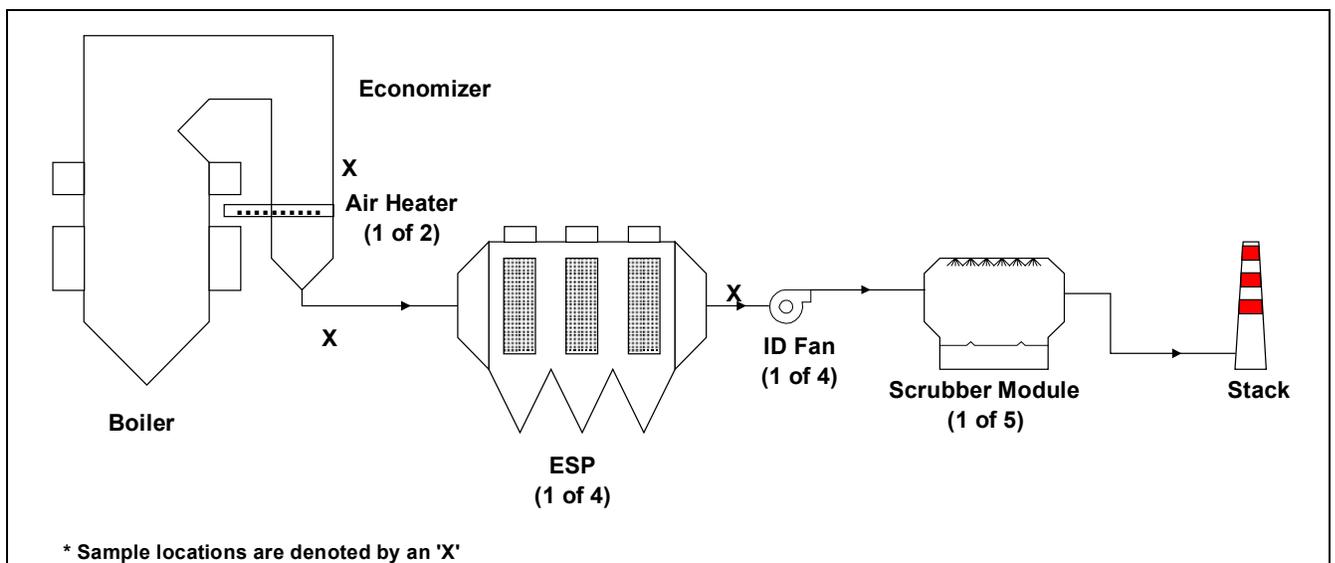
Figure 3-1. Illustration of Flue Gas Path for BMP Unit 3

During these tests, injection of sorbent slurries was accomplished through air-atomizing nozzles inserted through inspection port openings on the front wall of the boiler. The injection location was at the 14th floor of the boiler structure, across from the pendant superheat tubes. The injection levels are illustrated in Figure 3-2.
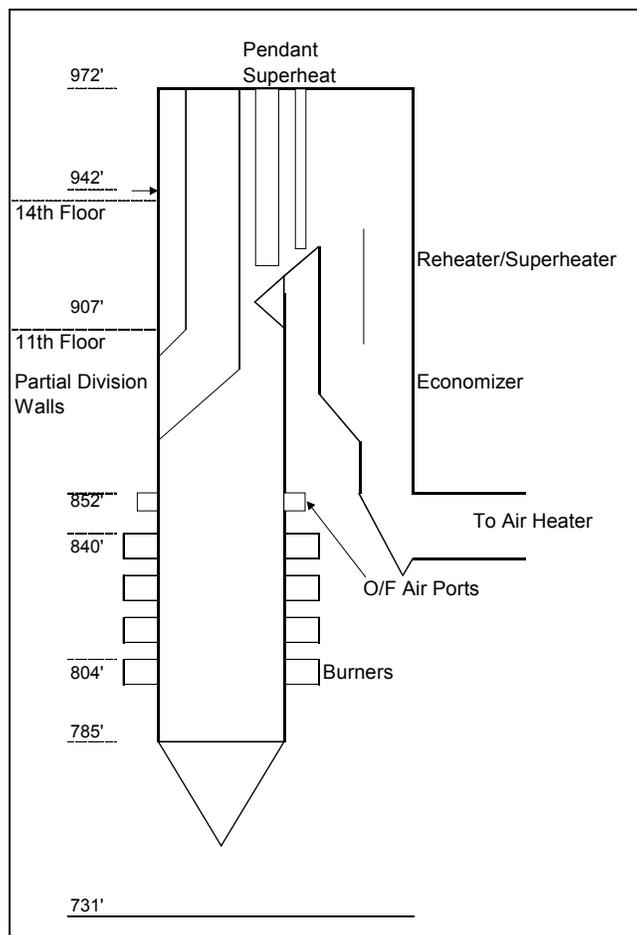
Figure 3-2. Illustration of Slurry Injection Levels for BMP Unit 3

At the 14th 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 3-3 illustrates the twelve potential port/lance locations. However, on the 14th 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 nominally 80 psig (550 kPa).
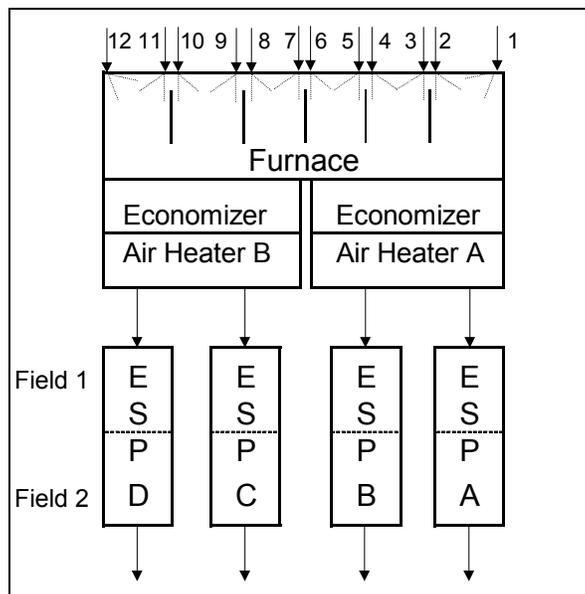
Figure 3-3. Plan View Illustration of Slurry Injection Locations for BMP Unit 3 (location nos. 5 and 8 were not used)

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 11,000-gallon (41-m^3) 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 (3.8-m^3) "day" tank located on the 9th floor of the boiler structure. The day tank level was controlled by a signal from an ultrasonic level indicator on the tank. Relays controlled by this signal 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$_3$ 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 3-3 also illustrates the arrangement of the four ESPs 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 2-3) tends to be cooler and have a lower sulfuric acid 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_3 content in the furnace, where the sorbent was injected.

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, from May 7 through 10. Baseline measurements included CCS runs for SO_3/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, from May 12 through May 14, to assess initial SO_3/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 3-1. During most flue gas testing, the steam generator operated 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. Unit 3 load variations are illustrated later in this section.

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

Date	Time Period for CCS Testing	Hourly Average Unit Load (gross MW)	Average Economizer Exit O_2 (%)	Coal Mills Out of Service	ID Fans Out of Service
Baseline Testing					
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*	-
Byproduct Mg Long-term Testing					
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
End of Test Baseline Repeat (CCS only)					
6/4/01	9:50-12:05	822 - 835	3.4	-	-

* Off line during a portion of the testing period.

Baseline Test Results

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_3/sulfuric acid concentrations at a variety of measurement locations, but additional sampling was conducted for flue gas SO_2, 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 3-2 summarizes the results of CCS measurements made at various locations throughout the flue gas path on Unit 3. Please refer to Figures 3-1 through 3-3 to review how these sample locations are laid out in the gas path. Table 3-2 shows the results of individual measurement runs by date and by location. Figure 3-4 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 3-2. Summary of Flue Gas SO_3/Sulfuric Acid Concentrations Measured for BMP Unit 3 Baseline Testing

Date	Measured SO_3/Sulfuric Acid Concentration, ppmv (dry basis, at actual O_2 conc.)				
	Run 1	**Run 2**	**Run 3**	**Run 4**	**Average**
Economizer B Outlet					
5/7/01	48	51	50	-	50
5/8/01	50	40	45	-	45
5/10/01	40	52	55	-	49
ESP B Inlet/Air Heater A Outlet (Hot Side)					
5/8/01	28	36	33	30	33
ESP C Inlet/Air Heater B Outlet (Hot Side)					
5/7/01	37	-	-	-	-
5/8/01	39	38	39	-	38
ESP A Outlet					
5/8/01	9.8	11	9.2	-	10
ESP B Outlet					
5/7/01	19	22	-	-	21
5/8/01	23	22	26	-	24
5/10/01	33	31	30	31	31
ESP C Outlet					
5/7/01	34	27	-	-	30
5/8/01	29	28	31	-	29
ESP D Outlet					
5/8/01	15	15	15	-	15

When illustrated as averages in Figure 3-4, the results show some side-to-side variation in SO_3 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_3 concentration, and it showed a substantially higher concentration than was measured at this location during previous baseline testing in October 2000 (48 ppm vs.

```
┌─────────────────────────────────────────────┐
│        ┌──────────────────────────┐          │
│        │         Furnace          │          │
│        │ West                East │          │
│        │                          │          │
│        ├────────────┬─────────────┤          │
│        │ Econ Out-48│ Econ Out-NA │          │
│        │Air Heater B│ Air Heater A│          │
│        └──────┬─────┴──────┬──────┘          │
│            38 │         33 │                 │
│        ┌───┐ ┌───┐    ┌───┐ ┌───┐            │
│        │ E │ │ E │    │ E │ │ E │            │
│        │ S │ │ S │    │ S │ │ S │            │
│        │ P │ │ P │    │ P │ │ P │            │
│        │ D │ │ C │    │ B │ │ A │            │
│        └─┬─┘ └─┬─┘    └─┬─┘ └─┬─┘            │
│       15 │  30 │     26 │  10 │              │
│          ▼     ▼        ▼     ▼              │
└─────────────────────────────────────────────┘
```
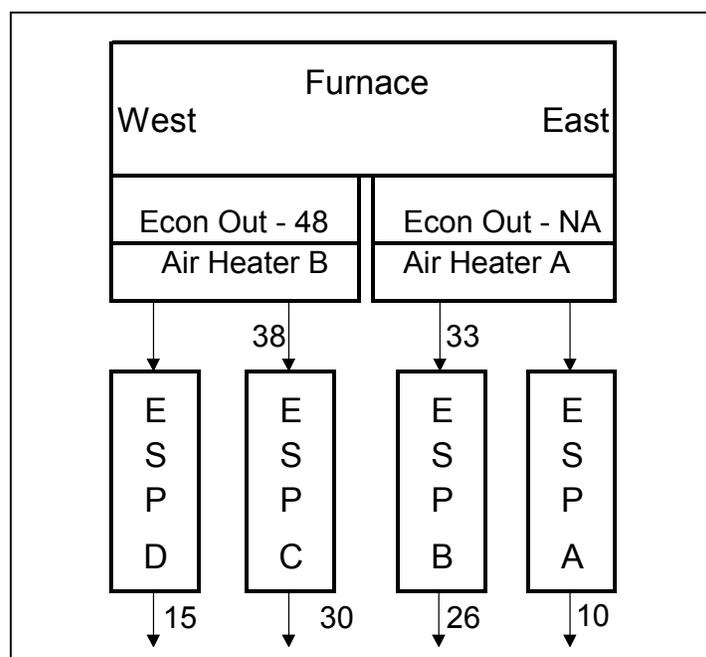
Figure 3-4. Summary of Baseline CCS Measurements at BMP Unit 3 (all values in ppmv [dry basis] SO_3 or sulfuric acid at actual flue gas O_2 concentration)

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_3 removal across the "B" air heater on its "hot" side. Another 21% reduction in SO_3/sulfuric acid concentration is seen across the "B" and "C" ESPs; the same removal percentage is seen across both of these ESPs. 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_3 concentration is seen. Most of this reduction is presumed to occur across the cold side of the air heater.

Throughout this report, SO_3/sulfuric acid removal during sorbent injection is reported as the percent reduction in vapor-phase sulfuric acid 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_3 concentration data in Table 3-2 were used to calculate an average SO_2 to SO_3 conversion percentage for Unit 3, to serve as a basis for reporting sorbent-to-SO_3 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 3-3. These results were used in combustion calculations to calculate the total amount of SO_2 that would be produced from the combustion of these coals, then that value was compared to the measured economizer outlet SO_3 concentrations. For the October 2000 baseline measurements reported in a previous 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_3 production as a function of sulfur in the coal fired.

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

Date Sampled	5/17/01	5/22/01	5/25/01	5/30/01	5/31/01	6/1/01	6/3/01
% 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
HHV (kg-cal/kg)	6,616	6,724	7,105	6,650	6,726	6,793	7,123

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_3, 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 differing 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 time.

Downstream measurements indicated that the SO_3 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_3 concentrations from the east economizer were not measured, it is expected that the conversion of SO_2 to SO_3 would have been lower for that side. Consequently, the value for conversion of SO_2 to SO_3 in the Unit 3 boiler for the long-term test was assumed to be slightly lower than the measured conversion, at 1.5%, for calculating sorbent-to-SO_3 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.

Long-term Test SO₃ 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 Power Station. The Pleasants Station has a modified Dravo Thiosorbic® 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 Generating 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^2/g. The gypsum solids in this slurry most likely have a low specific surface area (less than 5 m^2/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^2/g.

The byproduct slurry was trucked from the Pleasants Station and unloaded into the 11,000-gallon (41-m^3) 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 3-5 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 3-4 and plotted in Figure 3-6. The Mg:SO₃ molar ratios in the table and in Figures 3-5 and 3-6 are based on the amount of Mg(OH)₂ in the byproduct slurry injected, the Unit 3 coal feed rate, ultimate analyses of coal samples for this time period, and an assumed 1.5% conversion of coal sulfur to SO₃, which was derived from the baseline data as described above. The coal ultimate analysis data were summarized in Table 3-3. The results in Table 3-3 showed that the coal quality varied somewhat during the long-term test period, with coal sulfur levels ranging from 3.5 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.

The results plotted in Figure 3-6 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
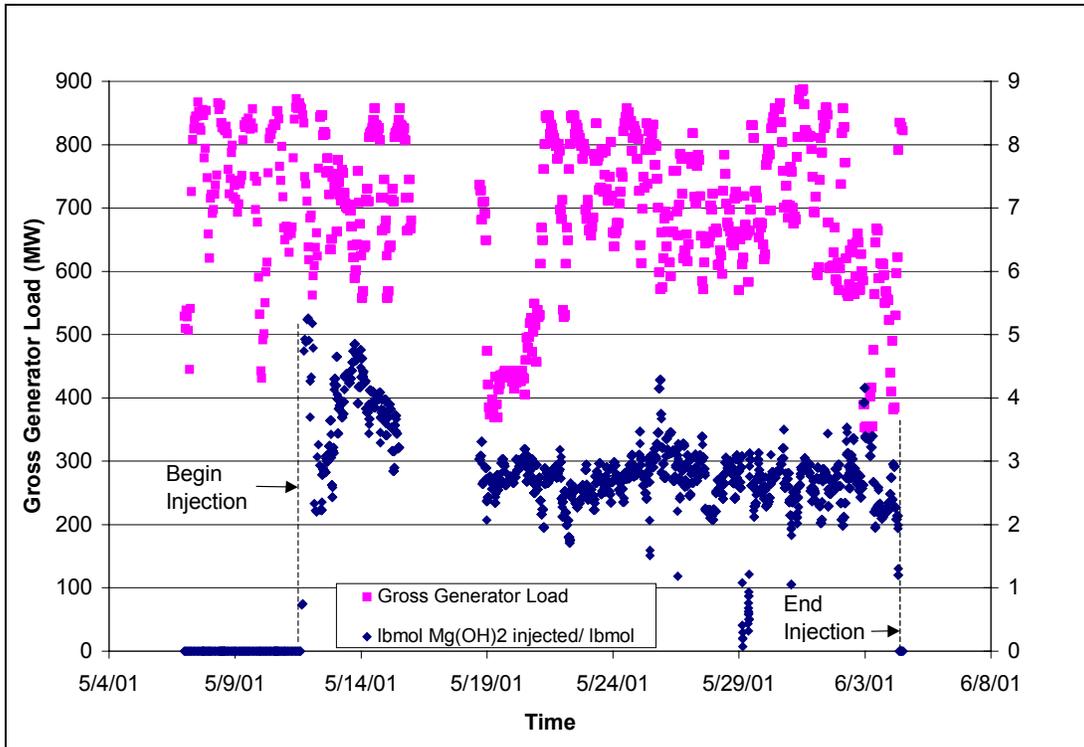
Figure 3-5. BMP Unit 3 Gross Unit Load and Sorbent Injection Rate during Long-term Test
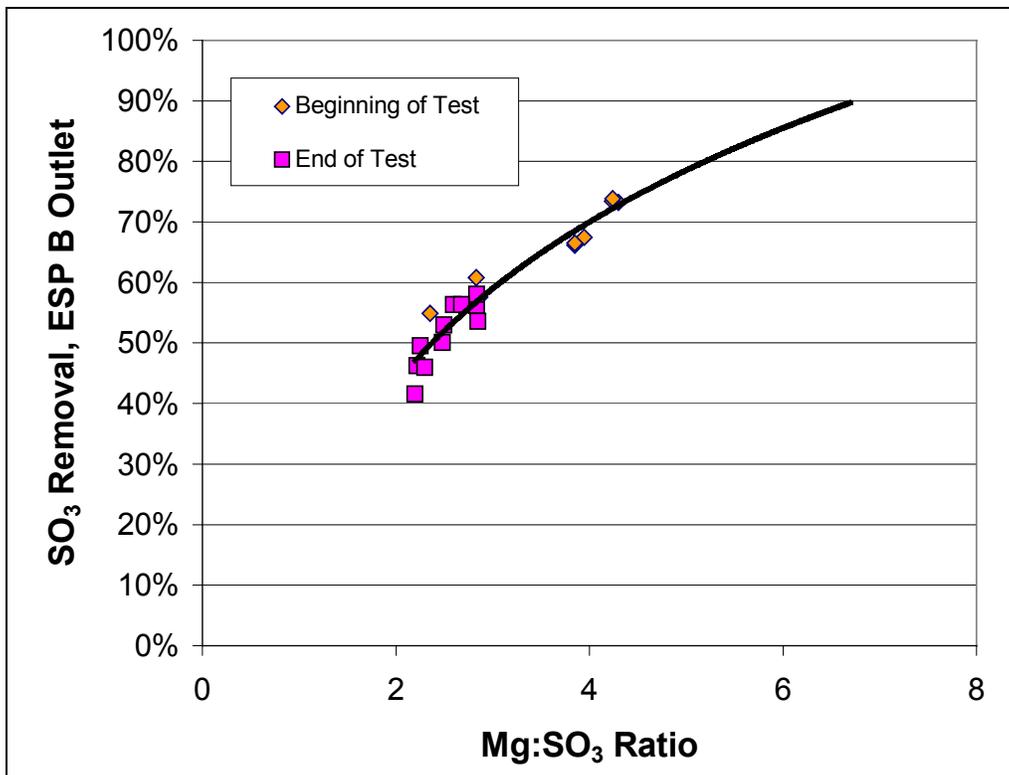
Figure 3-6. Results from the BMP Unit 3 Long-term Byproduct Mg Test (ESP B outlet location)

Table 3-4. Summary of Sulfuric Acid Removal Results from the BMP Unit 3 Long-term Byproduct Mg Test

Date/Time	Mg:SO$_3$ Molar Ratio	Sulfuric Acid Concentration (ppmv, dry basis at actual O$_2$ 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	-

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 3-5 compares ESP B and ESP C data during baseline and injection conditions, corrected to a common 3% O$_2$ 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

Table 3-5. Comparison of BMP Unit 3 ESP B and ESP C Outlet Sulfuric Acid Concentration Data

Time Period	Sulfuric Acid Concentration (ppmv, dry at 3% O_2)	
	ESP B Outlet	ESP C Outlet
Pre-test Baseline	32	40
May 12 (2.8 Mg:SO$_3$)	13	13
May 30 (2.8 Mg:SO$_3$)	17	9.9
After-test Baseline (June 4)	39	14

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.

The results plotted in Figure 3-6 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$_3$ molar ratios were varied from about 2.4 to 4.3 moles magnesium hydroxide injected per mole of SO$_3$ under baseline conditions, while at the end of the test, the ratios were in a 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$_3$ 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.

The data from the beginning and end of the test overlap well for measurements at the same Mg:SO$_3$ ratios. The figure also shows a logarithmic least squares fit of the data for both time periods. One relationship appears to fit the two data sets quite well, with an R^2 value greater than 0.92. The logarithmic relationship shows a reduced slope at higher injection rates and higher overall SO$_3$ removal percentages, as might be expected for a sorbent injection process.

The test data were extrapolated based on the logarithmic 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 3-6. The extrapolation predicts that a Mg:SO$_3$ molar ratio of 6.7:1 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 short-term test results might have over-predicted the Mg:SO$_3$ requirement for the long-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 extrapolation of the long-term test results may be somewhat optimistic in terms of sulfuric acid removal at higher

Mg:SO_3 ratios, as this relationship may flatten further at higher molar ratios and higher overall sulfuric acid removal percentages.

Long-term Test Balance of Plant Effects

Balance of plant effects measured were primarily focused on the impacts of sorbent injection and SO_3/sulfuric acid 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$_3$ Removal on ESP Operation

During the short-term sorbent injection tests on Unit 3, the impacts of sorbent injection and SO_3 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, during the initial baseline and at the end of the long-term test, the impact of sorbent injection and SO_3 removal on ESP outlet particulate loading was quantified by conducting mass loading measurements via EPA Method 17.

The impacts from sorbent injection appear to be predominantly due to the resulting SO_3 removal. Sorbent injection could have adverse effects from the sorbent alone 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. Neither appeared to be a significant effect during the short-term tests. Instead, removal of SO_3 upstream of the ESP was observed to have an adverse effect on the resistivity of the fly ash particles themselves. When the SO_3 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 previous, short-term byproduct Mg test was successful at achieving 90% or greater SO_3 removal as measured at the ESP B outlet. The ESP B inlet SO_3 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 short-term byproduct Mg injection test were summarized in a previous report[3], and showed an adverse effect on ESP performance that appeared to be directly related to the effects of high SO_3 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 11th rather than 14th floor, and high SO_3 removal efficiencies were not seen.

---

[3] *Sulfuric Acid Removal Process Evaluation: Short-term Results*, EPRI, Palo Alto, CA, U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, Pennsylvania, October 2001. TR1003980.

The data from the short-term byproduct Mg test also suggest that the "A" ESP was affected by the byproduct Mg injection to achieve low SO_3 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_3 concentrations are adequate for fly ash conditioning than are required for ESP B. Such a relationship is consistent with theory.

The short-term test results showed that the SO_3 removal resulting from byproduct Mg injection, down to 2 ppm of sulfuric acid vapor 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_3 removal level would be limited by ESP performance. For the long-term test, the injection system operators tried to optimize the slurry injection rate to achieve the maximum level of SO_3 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 sulfuric acid vapor 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) could be 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 3-6, 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. In ESP C, one of the two parallel, first-field electrical sections (CA) appeared to be operating normally, but the other first field (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 first fields (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^3.

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 was 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 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 misaligned plates.

Whatever the reason, it was decided that the impacts of sorbent injection on ESP performance would be best tracked by observing ESP B performance. As discussed previously, ESP A treats

Table 3-6. BMP Unit 3 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^3)
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.

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. The sulfuric acid concentrations likely could have been controlled to lower levels if all four ESPs had been performing well.

Figure 3-7 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 3-7 show that at the beginning of the test, byproduct Mg injection rates were relatively high (Mg:SO$_3$ 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 3-6. 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 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^3. The data in Table 3-4 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 3-7 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^3, primarily out of concern over what the emissions might be from the poorly
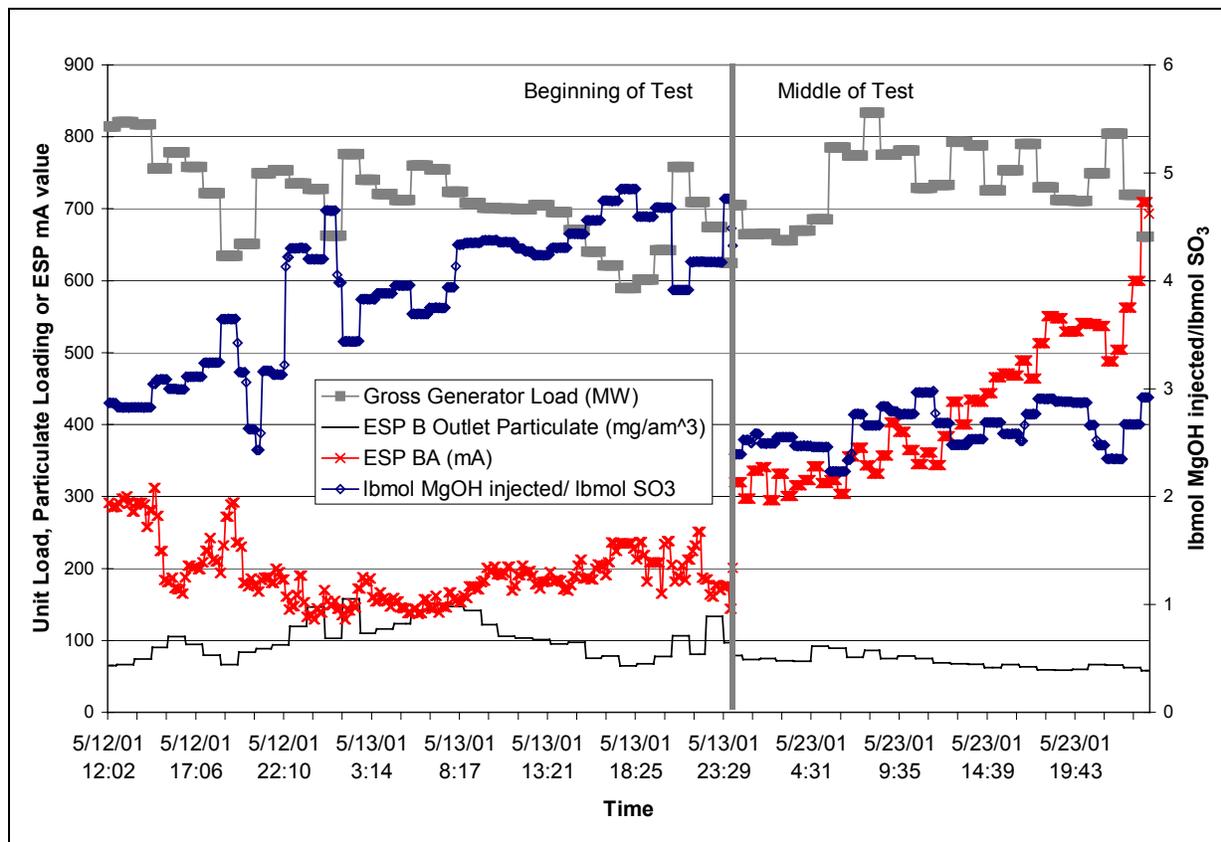
Figure 3-7. Comparison of ESP Electrical Conditions and Outlet Loadings (as indicated by plant opacity monitors) between the Beginning and Middle of the Long-term Test at BMP

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 Figure 3-4 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^3. Although no CCS measurements were made during this period, the sulfuric acid concentration data in Table 3-3 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 3-7 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 currentvalues 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^3. 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 $Mg:SO_3$ 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 the ESP electrical conditions had not been impacted by previous dolomite testing. Higher sulfuric acid removal percentages would most likely have been achievable on a unit equipped with larger ESPs. The specific collection area of the ESPs on Unit 3 are relatively low, about 100 ft^2/kacfm (8.4 m^2/[10^3Nm^3/h]). It was hoped that testing at AEP's Gavin Plant would provide an opportunity to confirm this conjecture. However as described in Section 4, with the SCR in operation at Gavin Plant, the ESP inlet sulfuric acid concentrations were never controlled to as low a concentration as they were at BMP.

Effects of Sorbent Injection and SO₃ Removal on ESP Outlet Particulate Loading

ESP outlet particulate loadings were measured by a modified 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 3-7.

Table 3-7. Summary of Method 17 Results for BMP Unit 3

Date	Run	Unit Load (gross MW)	Sampling Location	Mass Loading (grains/DSCF)	Emission Rate (lb/MMBtu)
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
Baseline Average				**0.027**	**0.057**
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
Daily Average				0.014	0.030
Injection Average				**0.018**	**0.038**

Note: 1 grain/dscf = 2.46 g/Nm^3.

It should be noted that the measurements were not all made at the same measurement location, as shown in the table. The method was modified in that some runs were made at single points of representative flue gas velocity rather than conducting full-duct traverses as is called for in the method. 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 C, 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 ESP's A and B, 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 3-7 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.

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 HCl and chlorine, HF 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 3-8. Flue gas concentration data in Table 3-8 show that the baseline HCl concentration averaged about 22 ppm, while the 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 and fluorine 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 3-8. Summary of Method 26a Data for BMP Unit 3

Date	Run	Flue Gas Concentration Data				Mass Balance Data					
		Hydrogen Halides		Halogens			Cl_2 in Flue Gas, lb/hr	Cl_2 Mass Closure, %	F_2 in Coal, lb/hr	F_2 in Flue Gas, lb/hr	F_2 Mass Closure, %
		HCl, ppmv	HF, ppmv	Cl_2, ppmv	F_2, ppmv	Cl_2 in Coal, lb/hr					
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
Baseline Ave:		**21.7**	**11.0**	**2.4**	**0.27**	**265**	**271**	**102**	**49.0**	**63.4**	**129**
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
Injection Ave:		**26.6**	**13.1**	**0.31**	**0.01**	**249**	**242**	**97**	**43.8**	**62.3**	**142**
Apparent Removal, %:		**-23**	**-19**	**87**	**96**						

* 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.

Note: 1 lb/hr = 0.454 kg/hr.

The concentration data values in Table 3-8 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 and fluorine 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 3-8 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 suggest it is 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 for 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 ±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 (371°C) 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 rather than using an out-of-stack Method 5 filter at 250°F (121°C). The latter would only allow arsenic that is in the gas phase at 250°F (121°C) to pass through the filter to the impingers for measurement, while the modified method was intended to allow arsenic in the gas phase at 700°F (371°C) to pass through. The results of these measurements are summarized in Table 3-9. 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 3-9 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

Table 3-9. BMP Unit 3 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
Baseline Average		**0.310**	**0.0002**	**0.311**
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
Injection Average		**0.233**	**0.0021**	**0.235**

measurements showed less than 0.1% of the total arsenic present in the gas phase. The gas-phase measurements correspond 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 almost 1%) and an order of magnitude higher gas-phase arsenic concentration (2 ppb dry basis). This is opposite the expected effect. The total arsenic concentrations measured (vapor plus particulate) were slightly lower during the sorbent injection period than during baseline.

Table 3-10 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 appears to have happened based on the data presented in Table 3-9. Arsenic concentration measurements on SCR catalyst coupons from this test period suggest that this sampling result is erroneous. The coupon results are discussed later in this section.

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 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

Table 3-10. BMP Unit 3 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
Baseline Average		**2.67**	**5.36**	**201**
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
Injection Average		**2.78**	**3.70**	**133**

* Based on average arsenic analysis of all coal samples submitted, 4.4 ppm as received.
** Based on arsenic analysis for the 5/31/01coal sample, 5.6 ppm as received (6 ppm dry basis).
Note: lb/hr = 0.454 kg/hr.

due to sulfuric acid deposition on the baskets. The pressure drop data are illustrated in Figure 3-8, while the temperature data are plotted in Figure 3-9. The pressure drop data do not show a significant change in the relationship between air heater flue gas 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_2O 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 3-9 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^oF (6^oC), from about 320^oF (160^oC) at the beginning to 310^oF (154^oC) at the end of the sorbent injection test, in spite of the fact that the preheat on the air going to the air heater increased by a couple of degrees over this period (not shown in Figure 3-9). This may be an indicator of improved air heater heat transfer performance resulting from lower inlet SO_3 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 3-10. 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, in spite of the furnace exit gas temperatures trending upward by about 30^oF (17^oC) over the same period.
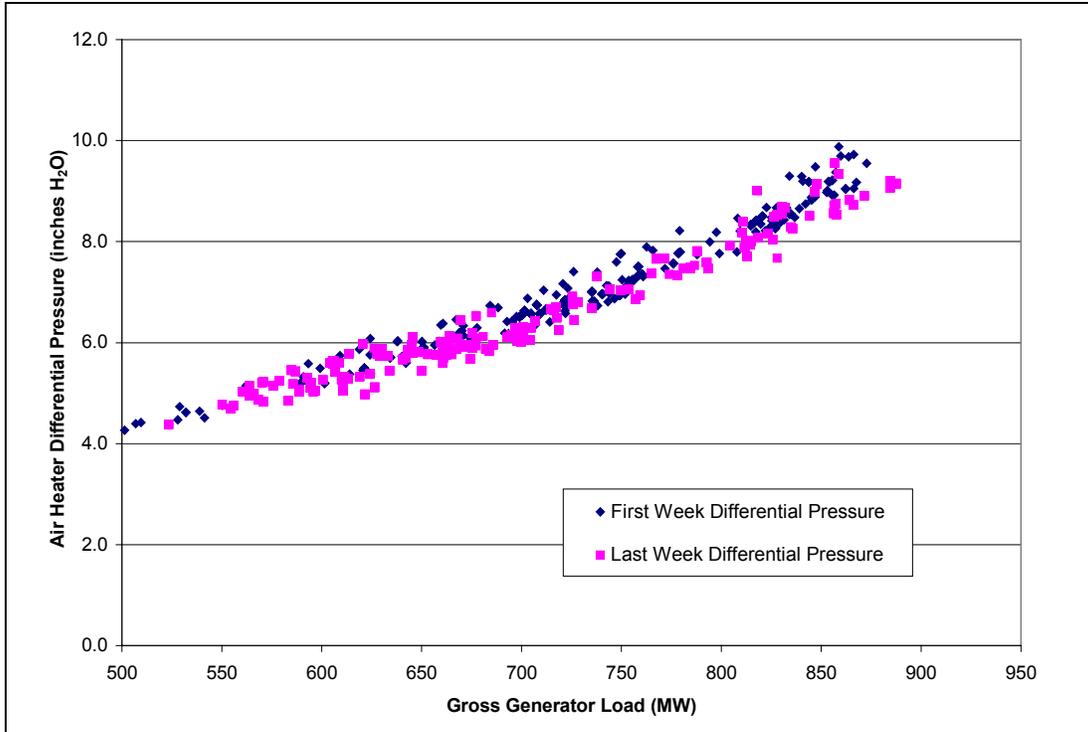
Figure 3-8. Comparison of BMP Unit 3 Air Heater Pressure Drop Before and After Long-term Test
Note: 1 inch H_2O = 0.25 kPa.
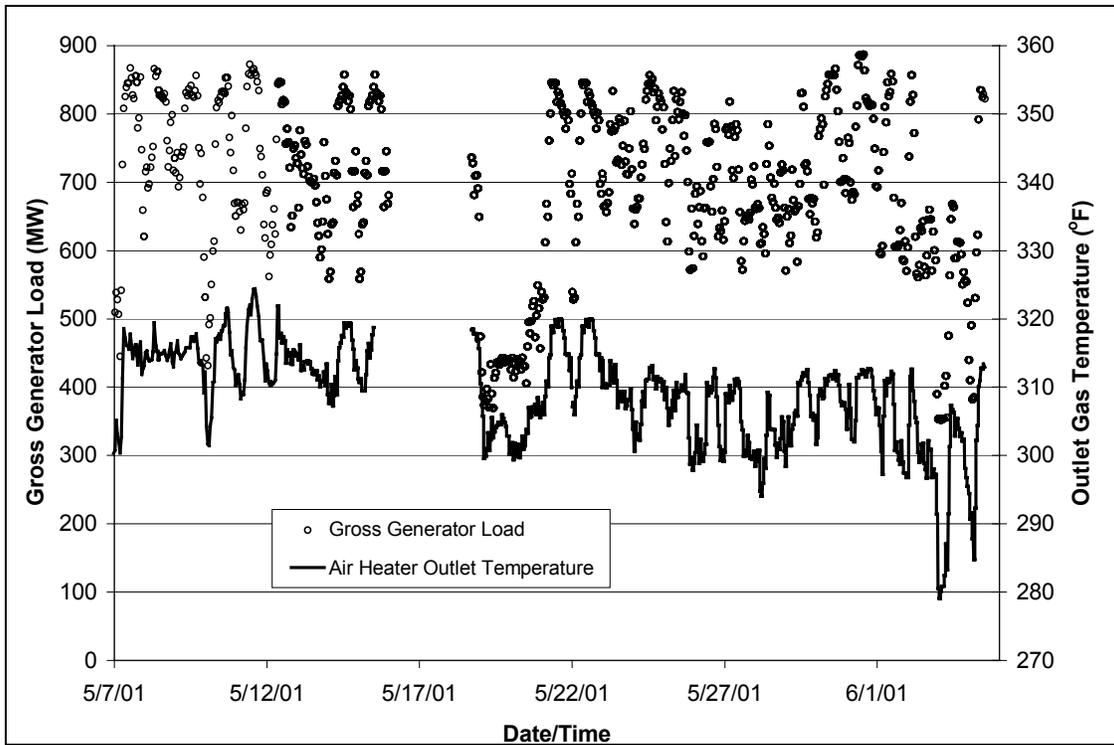
Figure 3-9. BMP Unit 3 Air Heater Outlet Temperature Trends during Long-term Test
Note: (°F - 32)/1.8 = (°C).
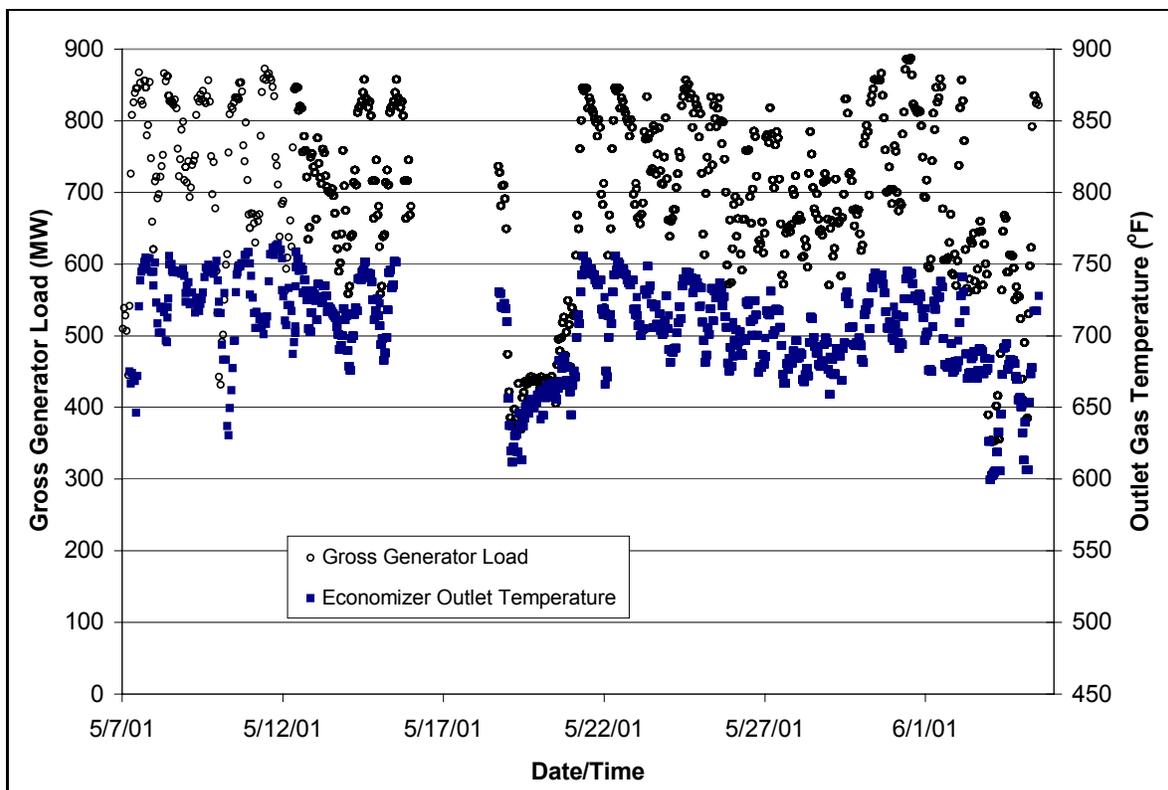
Figure 3-10. Effects of Sorbent Injection on BMP Unit 3 Economizer Outlet Gas Temperatures
Note: (°F - 32)/1.8 = (°C).

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 (1100°C) 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.

Effect of Byproduct Mg on SCR Catalyst Coupons

At the beginning of the long-term tests at BMP, a number of SCR catalyst coupons provided by an SCR catalyst vendor, Babcock-Hitachi K.K., were inserted into the economizer outlet duct to be removed at prescribed time intervals as the test progressed. These coupons were recovered at the prescribed times and analyzed for a number of chemical and physical parameters as described below in an effort to predict the effects of byproduct Mg injection in the furnace on a downstream SCR system.

There were concerns that these coupon results would not be an accurate predictor of full-scale effects for a number of reasons including the relatively short duration of the byproduct Mg injection test (about 550 hours) versus SCR catalyst life. Also, the coupons were installed and exposed at duct velocities (50 to 60 ft/sec [15 to 18 m/s]) versus typical SCR operating velocity (about 13 to 17 ft/sec [4 to 5 m/s]), which could cause metals to penetrate further into catalyst pores. Finally, the small size of the coupons meant that edge effects could overstate effects that might be seen on full-length catalyst beds. In spite of these concerns, it was felt that collecting this information might at least indicate any major trends. Based on the results described below, it would have been desirable to have byproduct Mg injection coupons exposed for greater periods of time, but the concerns about duct velocity and coupon size do not appear to have influenced the results.

The coupons were inserted into a common area of the economizer outlet duct shortly after byproduct Mg injection began on May 11, 2001. Coupons were pulled on May 15 (101.5 hrs), May 20 (221.5 hrs), and May 31 (485.5 hrs) or after nominally 100, 200, and 500 hours of byproduct Mg testing. These coupons were shipped to Babcock-Hitachi and analyzed for the following parameters:

- Catalyst activity – the NO_x reduction activity of each catalyst coupon was measured with a micro-reactor under standardized test conditions;

- Physical properties – specific surface area was measured by the B.E.T. method, and pore volume was measured by the mercury adsorption method; and

- Chemical composition – the chemical composition of the catalyst surface was measured semi-quantitatively by x-ray fluorescence (14 metals plus chlorine and sulfate), and quantitative analyses were conducted on digested samples for 10 metals plus chlorine and sulfate.

The results of these analyses are presented below and compared to previous results for baseline (no sorbent injection) coupons from BMP Unit 3.

Catalyst Activity

Figure 3-11 compares the NO_x reduction results for the catalyst coupons from the byproduct Mg test to results for baseline (no injection) samples from the same exposure periods. In both sets of coupons the loss of activity with time is very gradual. There does not appear to be any difference in the rate of activity loss for the baseline versus the byproduct Mg test coupons.
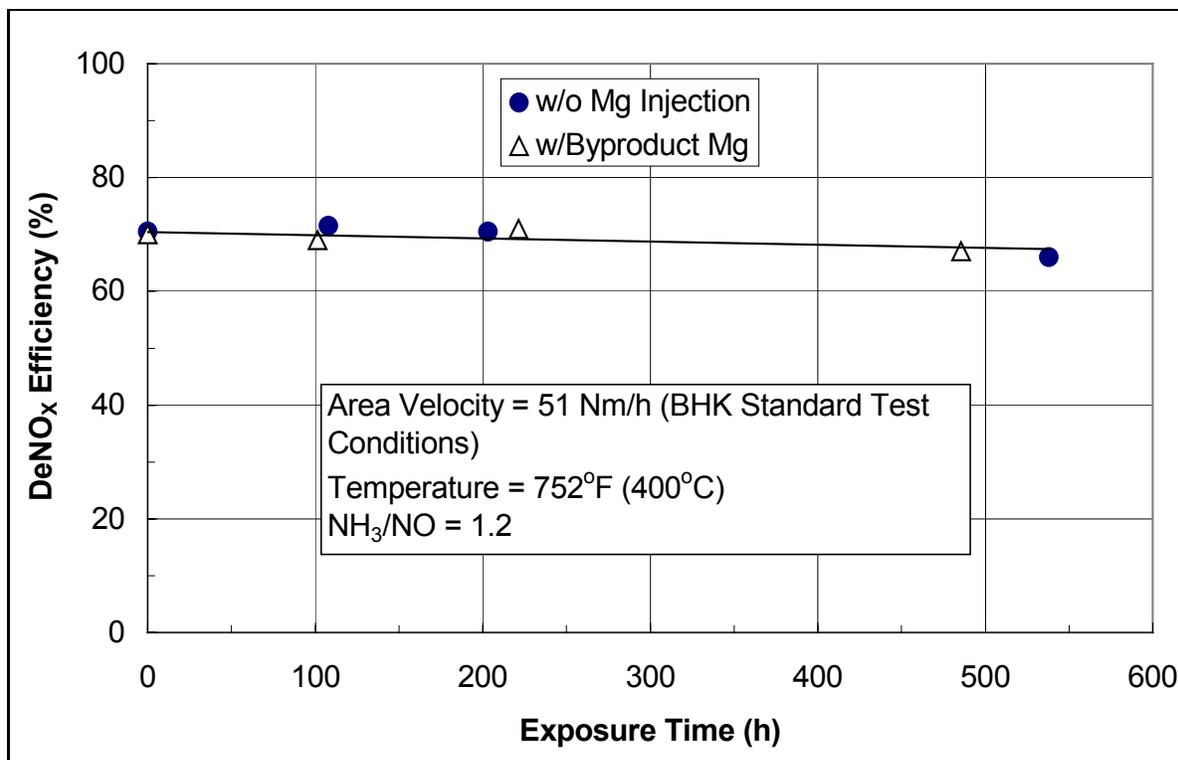
Figure 3-11. Catalyst Coupon NO$_X$ Reduction Activity for Baseline and Byproduct Mg Tests Versus Flue Gas Exposure Time, BMP Unit 3

Physical Properties

Table 3-11 summarizes the results of the physical property measurements. The surface area and pore volume results are presented in relative terms compared to unexposed coupons since the actual values for these two parameters are considered proprietary. The results show some loss in specific surface area under both conditions but somewhat less surface area loss for the byproduct Mg injection test coupons than the baseline (no injection) coupons at 200 and 500 hours. The byproduct Mg injection coupons showed slightly greater specific surface area loss at 100 hours, which may be an anomaly. Reduced specific surface area loss at longer duration is considered a desirable outcome because loss of surface area can ultimately lead to activity loss. The relative pore volume results show very similar values for both the baseline and byproduct Mg injection test coupons, with very little loss of pore volume in either.

Table 3-11. Summary of BMP Unit 3 Catalyst Coupon Physical Property Measurements

Time of Flue Gas Exposure	Relative Specific Surface Area		Relative Pore Volume	
	Baseline	Byproduct Mg Injection	Baseline	Byproduct Mg Injection
Unused Coupon	1.00	1.00	1.00	1.00
100 hours	0.92	0.89	1.00	1.01
200 hours	0.91	0.97	0.99	1.01
500 hours	0.91	0.97	0.98	0.99

Chemical Composition Results

Results of the semi-quantitative and quantitative chemical analyses are summarized in Tables 3-12 and 3-13, respectively. Again, data are shown for varied flue gas exposure times for both baseline coupons and coupons from the byproduct Mg injection test.

Table 3-12. Summary of Semi-quantitative (Surface) Chemical Analyses on BMP Unit 3 Catalyst Coupons

Coupon Type	Unused	Baseline (without Injection)			With Byproduct Mg Injection		
Flue Gas Exposure Duration	0 h	100 h	200 h	500 h	101.5 h	221.5 h	485.5 h
Chemical Composition (wt%)							
Na_2O	0.025	0.038	0.051	0.083	0.048	0.056	0.080
MgO	-	0.066	0.069	0.12	0.28	0.18	0.24
Al_2O_3	2.7	3.5	3.8	4.9	5.1	4.8	5.2
SiO_2	7.4	9.1	9.5	11	14	14	16
P_2O_5	0.16	0.18	0.18	0.27	0.19	0.22	0.17
SO_3	-	1.3	1.4	1.9	3.3	2.2	3.0
Cl	0.042	0.038	0.041	0.023	0.045	0.042	0.041
K_2O	Trace	0.062	0.053	0.064	0.11	0.082	0.084
CaO	0.033	0.17	0.14	0.22	0.35	0.27	0.45
Cr_2O_3	0.17	0.13	0.15	0.12	0.21	0.62	0.24
Fe_2O_3	0.094	0.64	0.81	0.66	1.2	2.3	1.2
NiO	-	0.011	Trace	Trace	0.015	0.012	0.016
As_2O_3	-	0.13	0.24	0.62	Trace	0.026	0.037
SrO	-	-	-	Trace	Trace	Trace	Trace
ZrO_2	0.065	0.068	0.056	0.62	0.048	0.025	0.050
Nb_2O_5	0.16	0.16	0.15	0.16	0.12	0.15	0.11

Table 3-13. Results of Quantitative (Bulk) Chemical Analyses of BMP Unit 3 Catalyst Coupons

Coupon Type	Unused	Baseline (without Injection)			With Byproduct Mg Injection		
Flue Gas Exposure Duration	0 h	100 h	200 h	500 h	101.5 h	221.5 h	485.5 h
Chemical Composition (wt%, except where noted)							
Na_2O	0.03	0.032	0.036	0.042	0.031	0.031	0.035
MgO	0.033	0.033	0.033	0.033	0.022	0.022	0.020
Al_2O_3	7.16	7.29	7.26	6.80	7.63	7.82	7.41
SiO_2	12.66	13.60	13.33	12.17	13.58	13.43	12.96
P_2O_5	0.052	0.060	0.056	0.074	0.023	0.046	0.046
SO_3	0.17	0.76	0.80	0.84	1.27	1.07	0.91
Cl	0.009	0.006	0.008	0.007	0.009	0.007	0.005
K_2O	0.0024	0.014	0.020	0.031	0.014	0.016	0.017
CaO	0.024	0.042	0.049	0.073	0.055	0.046	0.038
Fe_2O_3	0.043	0.19	0.29	0.27	0.200	0.172	0.114
As_2O_3	0.026	0.066	0.13	0.24	<0.013	<0.013	0.013
V_2O_5*	Base	NR**	NR**	NR**	+4%	+6%	+8%

* Percent difference in concentration from unused catalyst.
**Not reported.

The results of the semi-quantitative surface analyses in Table 3-12 show the following trends:

- Accumulation of sodium (Na), potassium (K), calcium, magnesium, iron (Fe), phosphorus (P), sulfur, silicon (Si) and aluminum (Al) was apparent in both types of coupons;

  – Of these species, calcium, magnesium, iron, sulfur, and silicon accumulations were clearly greater on the byproduct Mg test coupons,

  – The increased calcium, magnesium, and sulfur accumulations are most likely due to the byproduct Mg injection ($Mg(OH)_2$ and $CaSO_4 \cdot 2H_2O$), but still the increases were relatively small, and

  – The iron and silicon increases are most likely from fly ash;

- Accumulation of arsenic (As) was apparent in the baseline coupons, but not in the byproduct Mg test coupons;

  – This may indicate that the byproduct Mg reduced vapor phase arsenic concentrations, and

  – Reduced arsenic accumulation on the catalyst surface is seen as a positive impact, since arsenic is a known SCR catalyst poison.

The quantitative (bulk coupon) analysis results in Table 3-13 showed following tendencies:

- Both types of coupons showed accumulations of sodium, sulfur, potassium, calcium, and iron;

- Of those species, for the longest duration (500-h) samples only sulfur accumulations were higher in the byproduct Mg coupons;

- Neither set of coupons showed magnesium concentration increases.

- The byproduct Mg test coupons showed accumulation of aluminum and silicon (fly ash components), but the baseline samples did not;

- As shown in the XRF analysis results, there was little or no accumulation of arsenic compared to that in the baseline samples; and

- Small increases in vanadium (V) concentration were observed for the byproduct Mg test coupons. The actual concentration results are not shown, nor are the baseline sample results, because this information is considered proprietary.

Conclusions from SCR Coupon Evaluations

According to these analysis results, over a period of 500 hours the activity decrease tendency in the catalyst coupons from the byproduct Mg test at BMP Unit 3 was similar to baseline test results. Physical property changes in the two samples sets were also similar, although the surface area decrease tendency was slightly less in the byproduct Mg test coupons. These results suggest that over the period evaluated, the byproduct Mg injection had little or no impact on the SCR catalyst coupons.

However, two items were noted in the chemical analyses of the coupons that may forecast longer-term impacts of byproduct Mg injection. First, the accumulation of arsenic on the catalyst coupons was apparently less during the byproduct Mg tests than during baseline operation. This is a potential benefit from byproduct Mg injection, as arsenic is a known SCR catalyst poison. Thus, catalyst life could be extended with byproduct Mg injection compared to operation without sorbent injection.

However, an increase in vanadium content was observed over the duration of the byproduct Mg test, while no increase was seen in the baseline coupons. This suggests that SO_2 to SO_3 conversion across the SCR catalyst might increase with operating time, since vanadium is a known SO_2 oxidation catalyst. Such an increase, if realized, would be counterproductive to byproduct Mg injection in the furnace to lower flue gas SO_3/sulfuric acid concentrations.

Effects of Sorbent Injection on Stack Gas Opacity

One objective of sorbent injection to remove sulfuric acid 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, qualitatively the stack gas opacity was greatly reduced throughout the long-term test period compared to baseline opacity.

4
RESULTS FROM THE LONG-TERM SLURRY INJECTION TESTS AT AEP'S GAVIN PLANT

Results from the baseline and 23-day test of byproduct Mg injection at AEP's Gavin Plant, Unit 1, are presented and discussed in this section. First, a test description is provided, then the results of the baseline testing on this unit are presented and discussed. Next, results which quantify the impacts of sorbent injection on Unit 1 SO_3/sulfuric acid concentrations are discussed. Finally, balance-of-plant issues are discussed, including impacts of sorbent injection on ESP performance, and on removal of HCl, HF, chlorine, fluorine, and arsenic.

Mg Reagent Slurry Injection Test Description for AEP's Gavin Unit 1

A long-term test was conducted on the entire boiler at Gavin Plant Unit 1 (1300 MW) for a total of 23 days, to assess the effectiveness of furnace injection of magnesium-based sorbents for flue gas SO_3 control. The long-term test at Gavin Plant was significant because it provided the opportunity to measure the effectiveness of sorbent injection at removing SO_3 formed in the furnace, as well as that formed across the SCR catalyst. Two different sorbents, a byproduct Mg slurry and a commercially available magnesium hydroxide (commercial Mg) slurry were tested.

Analytical techniques used to assess the effects of sorbent injection primarily included sampling with a modified CCS method to determine flue gas SO_3 content during baseline and then injection conditions. EPA Reference Method 26a was used for determining HCl and HF, as well and chlorine and fluorine 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 1 ESP's, and by measuring ESP outlet flue gas particulate loading by a modified EPA Method 17. Sorbent and ESP hopper samples were analyzed for magnesium content. 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, and a few slag samples were collected and analyzed.

Unit 1 Description

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 generally 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 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 4-1 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% NO_X reduction. Also, about 1% of the flue gas SO_2 is further oxidized to 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 360ºF (177 to 182ºC) due to acid dew point considerations. The outlet gas from each of the three air heaters then goes to either an upper or lower ESP (one of six total) 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® 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 130ºF (54ºC); no reheat is employed.
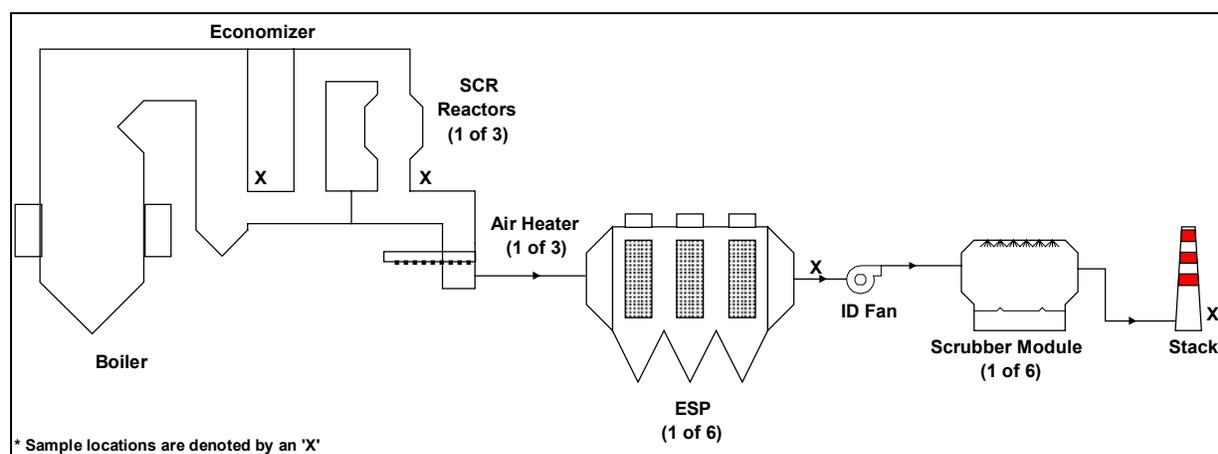
Figure 4-1. Illustration of Flue Gas Path for Gavin Unit 1

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 17th 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 13th floor of the boiler structure. The remaining 60% was injected through the nozzles at the 17th floor. The injection levels are illustrated in Figure 4-2.

4-2
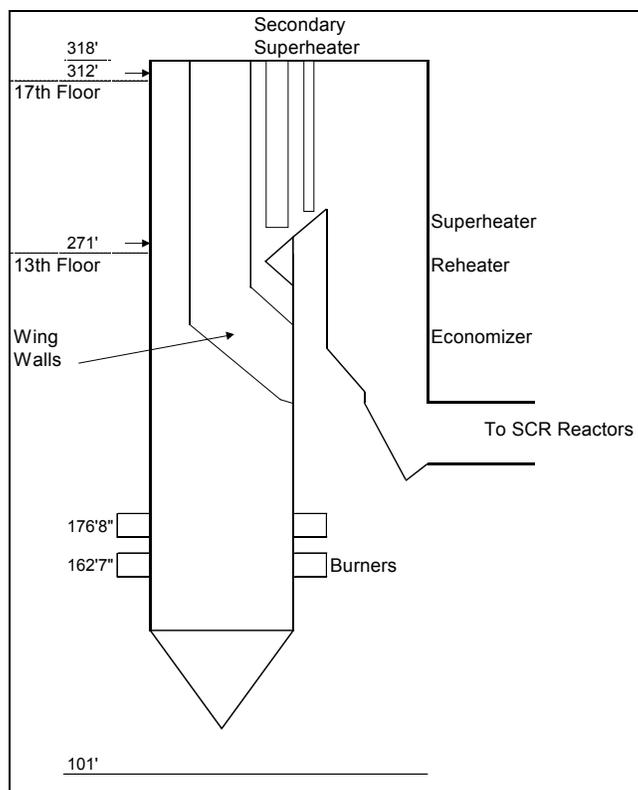
Figure 4-2. Illustration of Slurry Injection Levels for Gavin Unit 1
Note: 1 ft = 0.305 m.

At the17[th] 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 (10-cm) pipe in each of these ten man doors, angled downward at 45 degrees, to serve as ports for slurry injection into the furnace. Figure 4-3 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 13th floor, just above the nose of the boiler. There are also inspection ports on each of the side walls at the 13th 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 13th 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 [625 l/min]) 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 (33.5 by 15.5 m), and by the fact that the inspection ports on the front wall at the 13th floor are not equally spaced**.** The ports range from 24 feet apart to 33.7 feet apart (7.3 m to 10.3 m). For this reason, it was decided to test with only a portion of the slurry (40%) added at the lower level. Figure 4-4 illustrates the nozzle lance locations at the 13th floor level.
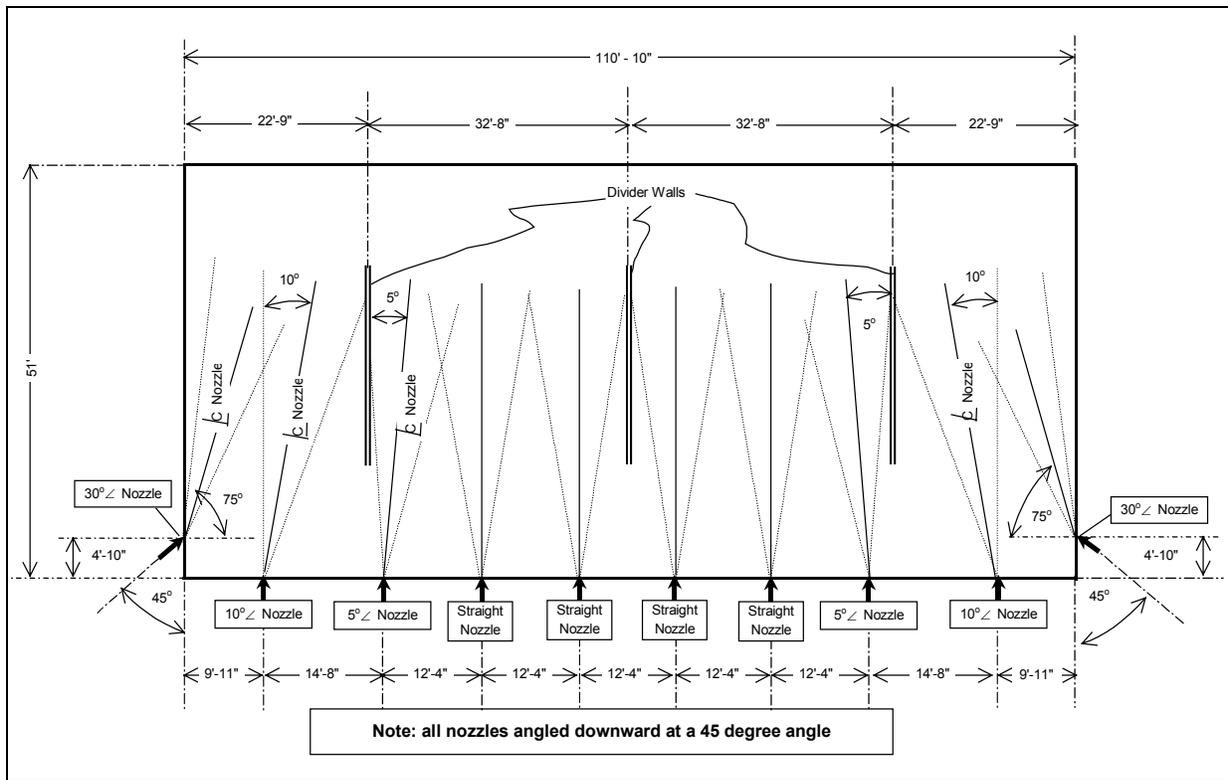
Figure 4-3. Plan View Illustration of Slurry Injection Nozzle Locations at the 17th Floor of Gavin Unit 1
Note: 1 ft = 0.305 m.

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 (550 kPa), 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_3 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 (3800-m^3) 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 Power 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 (80-m^3) "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 (160-m^3) tank. A temporary run of PVC pipe connected the gasoline-engine-driven pump with the two "day"

4-4
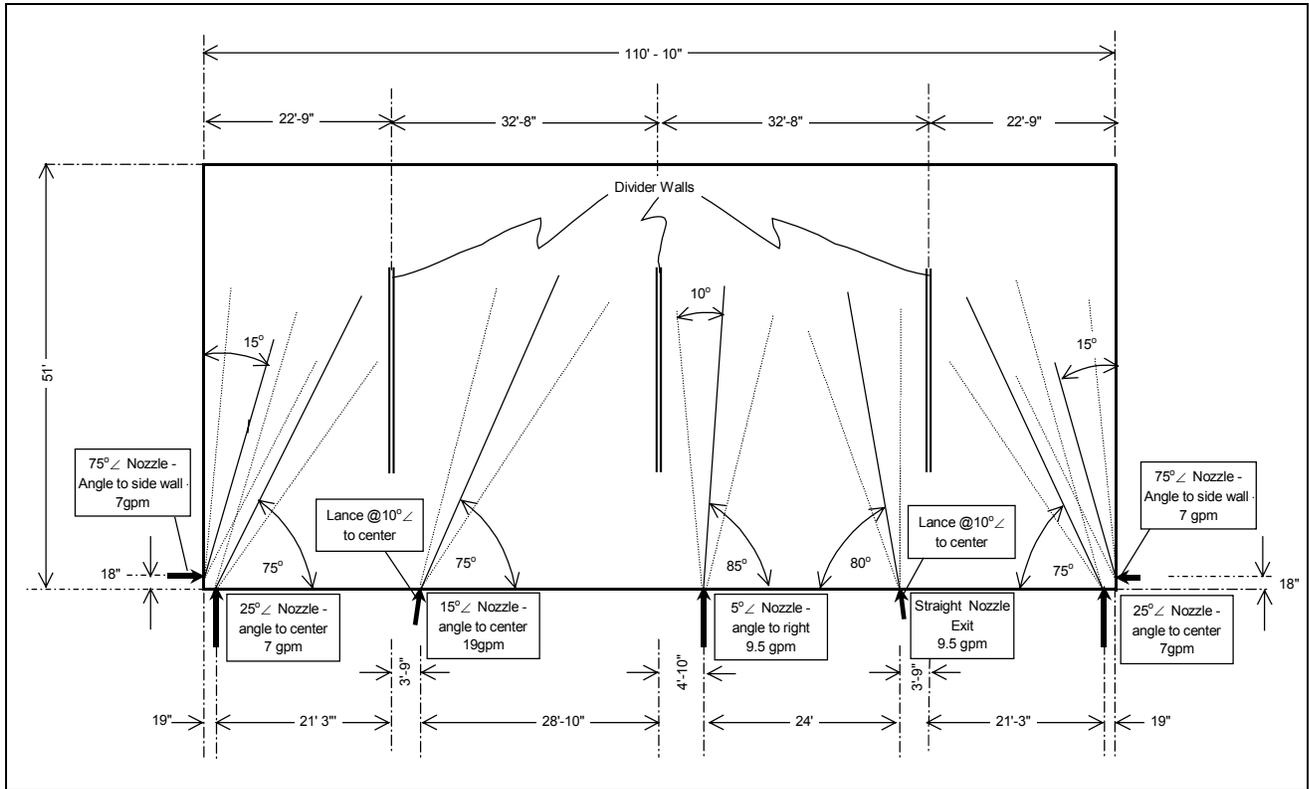
Figure 4-4. Plan View Illustration of Slurry Injection Nozzle Locations at the 13th Floor of Gavin Unit 1
Note: 1 gpm = 3.8 l/min, 1 ft = 0.305 m.

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 (20-cm), 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_3 molar ratio. Slurry from the Moyno pumps was fed through 3-inch flexible hose up to the 17th floor to a manifold, which in turn distributed slurry to the ten lances and injection nozzles. When also injecting at the 13th floor, a portion of the flow was split off at the 13th 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 (80-m^3) 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 21,000-gallon (80-m^3) tanks, where it was diluted with plant water to a lower solids content. From this tank, the diluted slurry was pumped to the lances and nozzles as described above. Also, as mentioned above, the 21,000-gallon (80-m^3) 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 16th floor of the boiler. Air from the receiver tank was connected to each lance individually, through flexible plant air hoses, to provide atomizing air.

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, from 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 modified 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 4-5. 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.

Baseline Test Results

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_3 concentrations at a variety of measurement locations. The baseline CCS results are discussed in the following paragraphs.

Table 4-1 summarizes the results of CCS measurements made at various locations throughout the flue gas path on Gavin Unit 1. Please refer to Figure 4-1 to review how these sample locations are laid out in the gas path. Table 4-1 shows the results of individual measurement runs by date and by location.
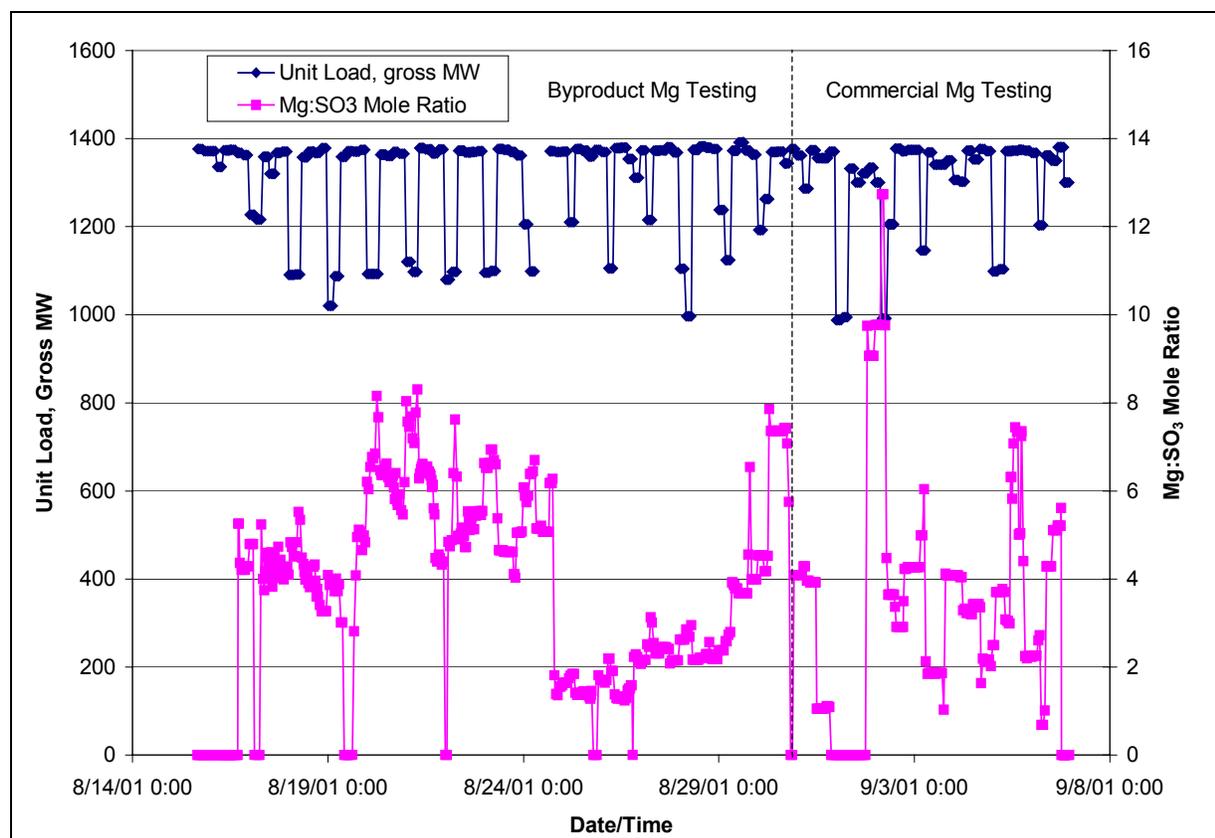
Figure 4-5. Gavin Unit 1 Operating Conditions during Long-term Sorbent Injection Testing

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_3 at the economizer outlet, 65 ppm at the SCR outlet (an increase because of SO_2 to SO_3 oxidation across the SCR catalyst), 54 ppm at the ESP outlet, and 48 ppm at the stack. Throughout this report, SO_3 removal during sorbent injection is reported as the percent reduction in SO_3 concentration at a given location, for injection versus baseline conditions. The preceding values were used in those calculations.

The SCR outlet SO_3 concentration data in Table 4-1 were used to calculate an average SO_2 to SO_3 conversion percentage for Unit 1, to serve as a basis for reporting sorbent-to-SO_3 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 4-2. These results were used in combustion calculations to calculate the total amount of SO_2 that would be produced from the combustion of these coals, then that value was compared to the measured economizer/SCR outlet SO_3 concentrations. The economizer outlet and SCR outlet concentrations correspond to approximately 1.3% conversion of SO_2 to SO_3 in the furnace, and an additional 1.0% conversion of SO_2 to SO_3 across the SCR catalyst.

Table 4-1. Summary of Flue Gas SO₃ Concentrations Measured for Gavin Unit 1 Baseline Testing

Date	Measured SO$_3$ Concentration, ppmv (dry basis, corrected to 3% O$_2$ concentration)				
	Run 1	**Run 2**	**Run 3**	**Run 4**	**Average**
Economizer Outlet					
8/15/01 a.m.	41	42	33	33	-
8/15/01 a.m. (cont'd)	34	-	-	-	37
SCR Reactor Outlet					
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
ESP Outlet					
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
Stack					
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

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 [182°C]), 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.

Table 4-2. Proximate Analyses of Coal Samples from the Gavin Unit 1 Long-term Test

Date/Time (beginning of sample collection period)	Moisture, wt% as Received	Ash, wt% as Received	Sulfur, wt% as Received	HHV, BTU/lb
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
9/4/01 18:00	9.22	11.37	4.00	11,424

Table 4-2. Proximate Analyses of Coal Samples from the Gavin Unit 1 Long-term Test (continued)

Date/Time (beginning of sample collection period)	Moisture, wt% as Received	Ash, wt% as Received	Sulfur, wt% as Received	HHV, BTU/lb
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
Test Period Average	8.50	11.79	3.62	11,559

Note: 12,000 Btu/lb = 6667 kg-cal/kg.

Long-term Test SO$_3$ 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 Power Station was 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 Power Station has a modified Dravo Thiosorbic® 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 Pleasants, 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 Plant for two reasons. One was that the commercial Mg was never tested at the more favorable 14th 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 it were similarly injected higher in the furnace. The second reason is that the Gavin Plant 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_3 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 $Mg:SO_3$ ratios had to be tested to evaluate each of the two sorbents. The plant's desire to test injection at the 17th floor level versus injection split between the 13th and 17th floor added another variable to be evaluated. Consequently, the long-term test essentially became a full factorial evaluation of three variables ($Mg:SO_3$ ratio, reagent, and injection level).

Furthermore, the organization conducting the modified CCS measurements for SO_3/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_3/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 $Mg:SO_3$ 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_3 at the SCR outlet location. This factor was derived from the baseline SO_3 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 $Mg:SO_3$ molar ratios are based only on the SO_3 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 4-2, 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 Plant 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$_3$ values for the commercial Mg tests are of questionable accuracy. Another significant data quality issue is just how representative SO$_3$/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 feet (12.8 m).

The results are summarized in Table 4-3. Selected results are also plotted in Figures 4-6 through 4-12.

Table 4-3. Summary of Sulfuric Acid Removal Results from Gavin Unit 1 Long-term Mg Injection Test

Date/Time	Sorbent (Mg Source)	Injection Location (Floor)	Mg:SO$_3$ Molar Ratio	Average SO$_3$ Concentration (ppmv, dry basis at 3% O$_2$ concentration)			
				Economizer 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	-

4-12

Table 4-3. Summary of Sulfuric Acid Removal Results from Gavin Unit 1 Long-term Mg Injection Test (continued)

Date/Time	Sorbent (Mg Source)	Injection Location (Floor)	Mg:SO$_3$ Molar Ratio	Average SO$_3$ Concentration (ppmv, dry basis at 3% O$_2$ concentration)			
				Economizer Outlet	SCR Reactor Outlet	ESP Outlet	Stack
9/4/01 a.m.	Commercial	17	3.2	9	53	31	-
9/4/01 p.m.	Commercial	17	3.1	12	61	-	33
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	-	-
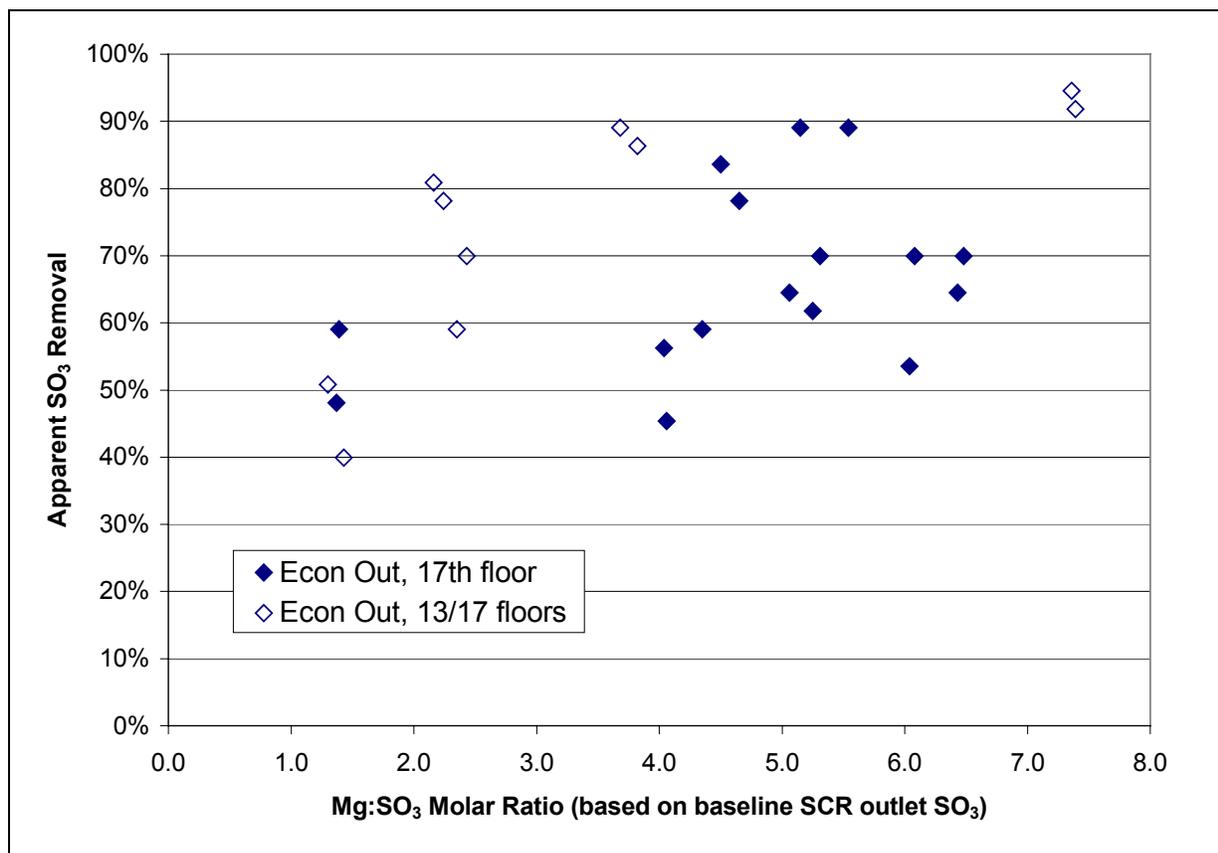
Figure 4-6. Results from the Gavin Unit 1 Byproduct Mg Injection Test Period (economizer outlet location)
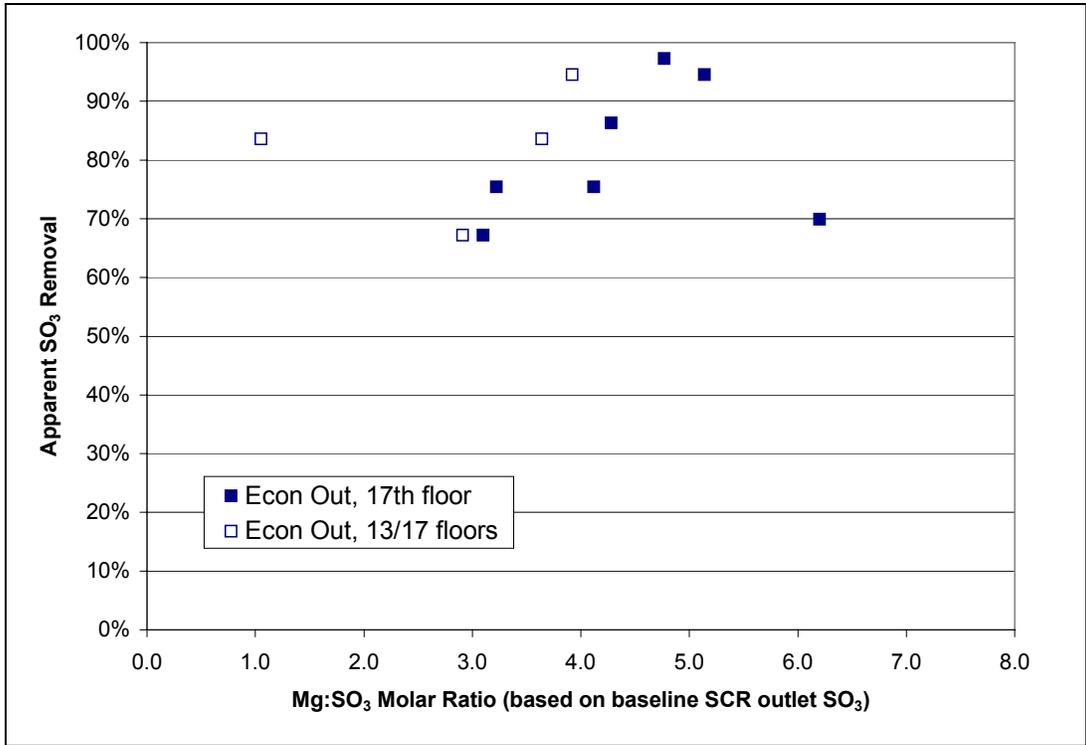
Figure 4-7. Results from the Gavin Unit 1 Long-term Commercial Mg Injection Test Period (economizer outlet location)
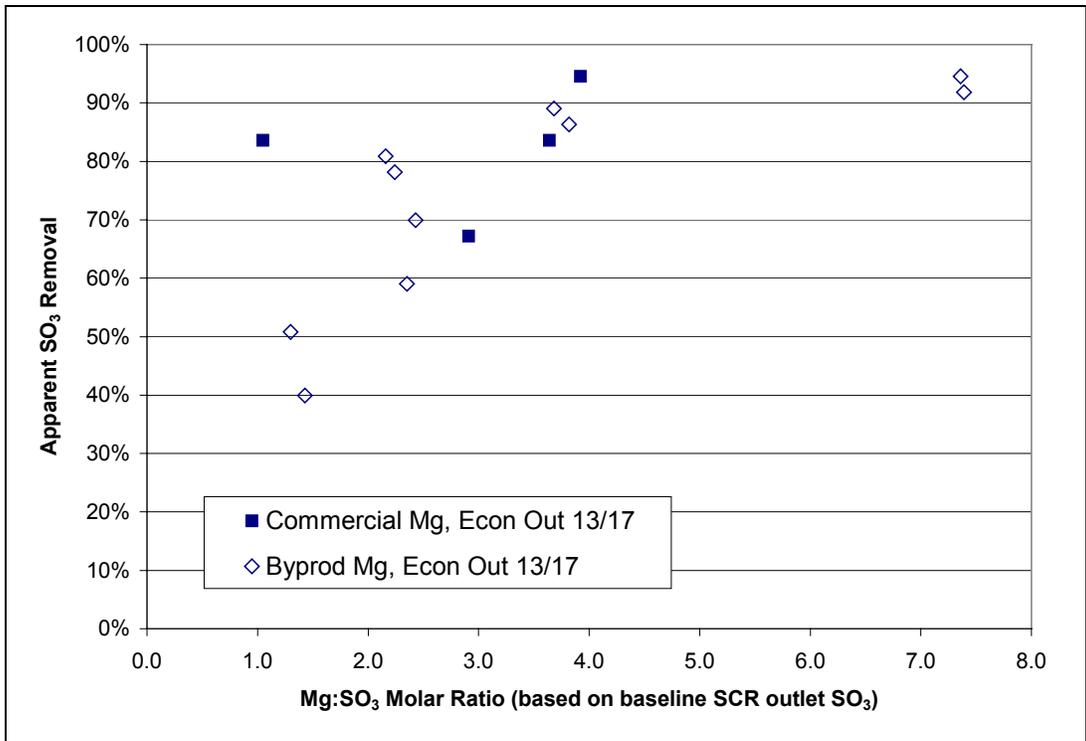
Figure 4-8. Comparison of Byproduct Mg and Commercial Mg Sorbent Performance for Gavin Unit 1 (economizer outlet location)
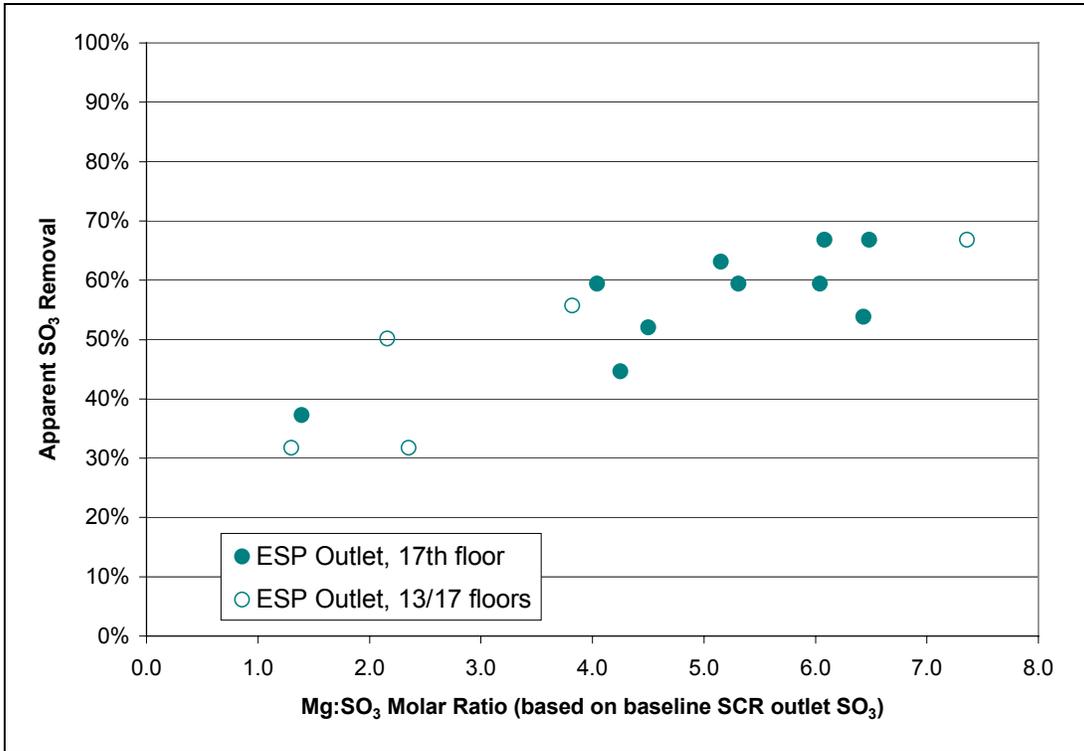
Figure 4-9. Results from the Gavin Unit 1 Byproduct Mg Injection Test Period (ESP outlet location)
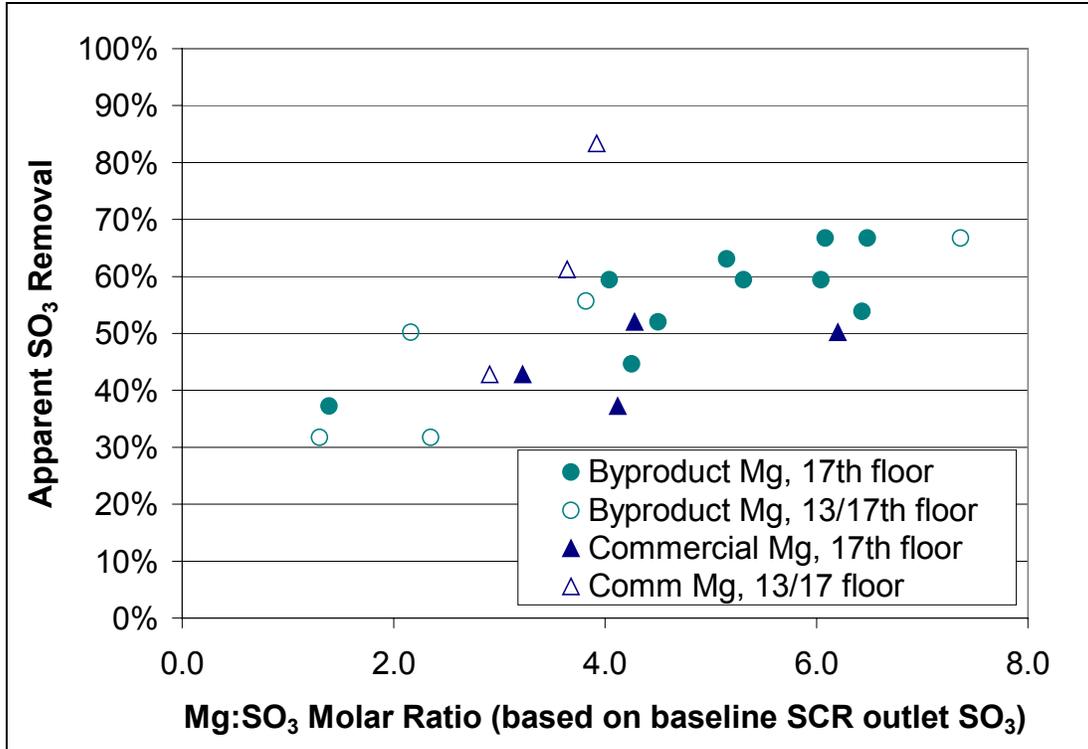
Figure 4-10. Results from the Gavin Unit 1 Commercial Mg Injection Test Period Compared to Byproduct Mg Injection Results (ESP outlet location)

4-15
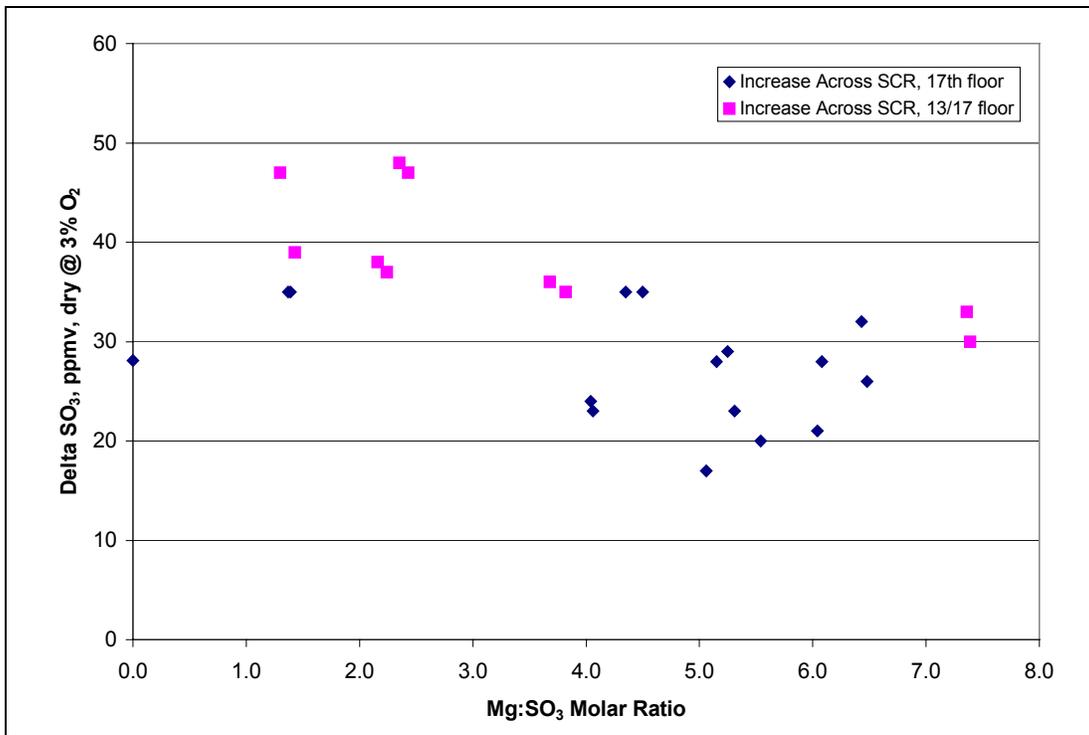
Figure 4-11. Comparison of SO₃ Concentration Changes across the Gavin Unit 1 SCR Reactors (byproduct Mg injection)
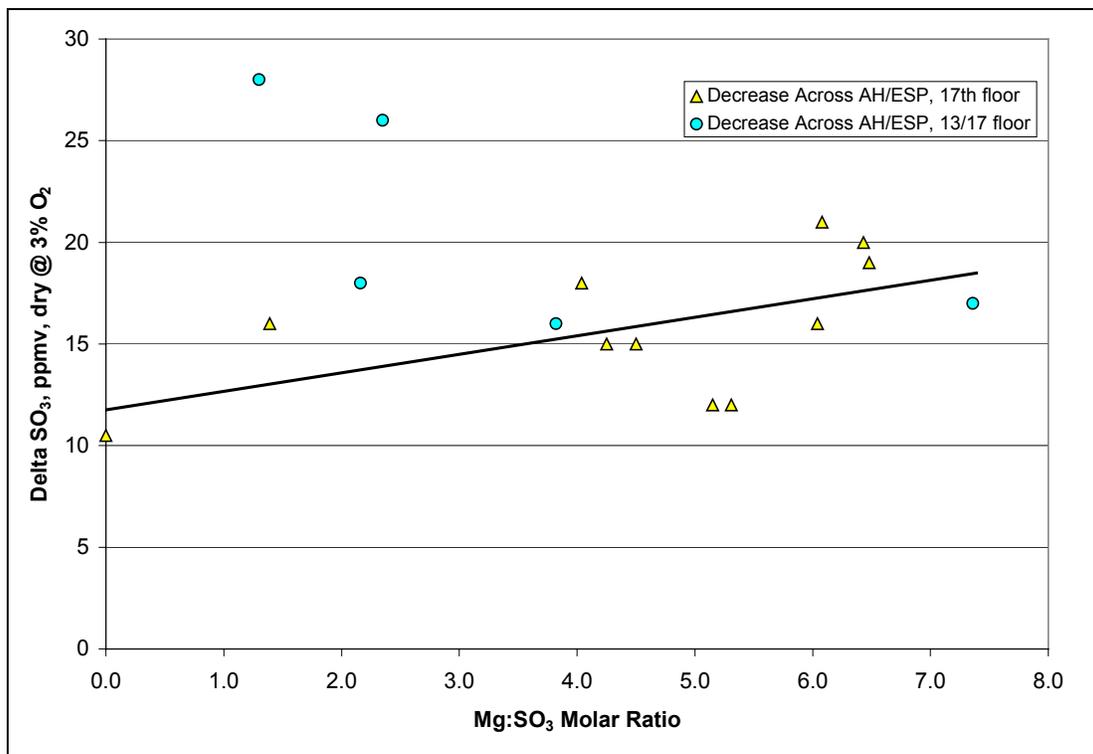
Figure 4-12. Comparison of SO₃ Concentration Changes across the Gavin Unit 1 Air Heaters and ESPs (byproduct Mg injection)

As mentioned earlier, it is a bit more difficult to portray the sorbent inject results from Gavin Plant because of the SO_2 to SO_3 conversion that occurs across the SCR reactors. We have plotted SO_3 removal percentages as measured at two locations, the economizer outlet and the ESP outlet.

Figure 4-6 shows the economizer outlet data for the byproduct Mg test period. Data are plotted for injection at the 17th floor location only, and for injection split between the 13th and 17th floor. The removal of SO_3 formed in the furnace appears to be more effective when injecting at two levels than when injecting all of the slurry at the 17th floor. It is not clear whether this is a residence time effect, a slurry droplet distribution effect, or a droplet size effect (finer atomization with more nozzles in service and higher air/slurry mass ratios at each nozzle). Much of the data for the 17th 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_3 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 17th floor only, it appears that 90% removal of the SO_3 formed in the furnace was removed at a $Mg:SO_3$ 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_3 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 4-7 shows results of economizer outlet sampling during the commercial Mg test period. The results in the figure are similar to those in Figure 4-8. 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_3 can be achieved at a $Mg:SO_3$ molar ratio of about 3.5:1 to 4:1 when injecting on the 13th and 17th floors, and about 4.5:1 to 5:1 when injecting only on the 17th floor. Figure 4-8 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 $Mg:SO_3$ molar ratios.

Figure 4-9 shows sulfuric acid removal percentages measured at the ESP outlet location for the byproduct Mg test period, for injection at the 17th floor versus injection at both floors. When measured at the ESP outlet, which takes into account the SO_3 produced across the SCR reactors and SO_3/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_3/sulfuric acid removal at a $Mg:SO_3$ 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 4-10 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 4-6 through 4-10 do not clearly illustrate the effects of sorbent added in the furnace on the SO_3 formed across the SCR reactors. Figure 4-11 is an attempt to illustrate this effect. In Figure 4-11, the SO_3 concentration increase measured across the SCR is plotted versus $Mg:SO_3$ ratio for the byproduct Mg test period, both for injection at the

17th floor and for injection split between the 13th and 17th floors. The data do not show a clear effect of sorbent injection on this increase. For injection at the 17th 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 $Mg:SO_3$ ratio increases.

For injection split between the 13th and 17th floor with byproduct Mg, the results plotted in Figure 4-11 do show a reduced SO_3 concentration increase as the $Mg:SO_3$ molar ratio increases from 1:1 to 7:1. However, the values at a 1:1 ratio (39 to 47 ppm) are significantly higher than the baseline increase (28 ppm), so even the reduced values at a 7:1 ratio (30 to 33 ppm) are higher than the baseline increase (28 ppm). The commercial Mg data are not plotted, but they show no clear trends.

The data plotted in Figure 4-11 show that sorbent injection in the furnace did not measurably affect the conversion of SO_2 in the flue gas to SO_3 across the SCR reactors, although scatter in the data made it difficult to note any trends. Another possible effect of sorbent injection in the furnace on SO_3 formed across the SCR reactors could be increased removal of that SO_3 as the flue gas passes through the air heaters and ESPs. Figure 4-12 is a plot of data that illustrate this effect. The plot shows the drop in SO_3/sulfuric acid concentration from the SCR outlet to the ESP outlet, for the byproduct Mg test period. The results in the figure shows that for sorbent injection at the 17th floor, this drop in concentration becomes more significant as the $Mg:SO_3$ ratio increases. The line in the figure represents a linear least squares fit of these data. This drop in SO_3/sulfuric acid concentration increases from about 11 ppm at baseline conditions to about 20 ppm at a $Mg:SO_3$ molar ratio of 6:1, although there is considerable scatter in the data. The commercial Mg data are not plotted, but also show considerable scatter.

Based on a review of the SO_3/sulfuric acid concentration data in Figures 4-6 through 4-12, it can be concluded that byproduct Mg or commercial Mg sorbents injected into the furnace can remove a high percentage of the SO_3 formed in the furnace. However, the furnace-injected sorbents have only a modest effect on SO_3 formed across the SCR reactors. The data show no clear trend for any impact of the injected sorbent on the conversion of SO_2 to SO_3 across the SCR reactors. There appears to be a weak trend for increased removal of SO_3 formed in the SCR across the air heater and ESP at higher sorbent injection rates, though.

Long-term Test Balance of Plant Effects

A variety of balance of plant effects were measured during the long-term test period at Gavin Plant, to determine the impacts of sorbent injection and SO_3 removal on ESP ash characteristics and ESP performance, and effects on air heater performance, SCR pressure drop, and furnace slagging conditions. Measurements were also made of halogen species and arsenic concentrations in the Unit 1 flue gas, both during baseline and sorbent injection conditions, to determine whether the injected Mg sorbents lowered gas-phase concentrations of these species.

ESP Ash Samples—Magnesium and Sulfate Content

Samples were collected from the ESP hoppers at regular intervals throughout the long-term test for a variety of reasons. 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 could be accounted for in the fly ash catch. Total magnesium and sulfate analyses were also conducted to determine how the injected magnesium sorbents would impact fly ash quality for potential byproduct sales**.**

Fly ash samples were analyzed in two manners. First, the results of a relatively mild digestion of the samples in a HCl solution were analyzed to determine the "acid soluble" content of magnesium and sulfate in the ash samples. This procedure should readily dissolve magnesium sulfate resulting from byproduct or commercial Mg injection and removal of flue gas SO_3, but might not dissolve a high percentage of the magnesium and/or 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 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 property impacts.

The results from these analyses are summarized in Table 4-4. 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 byproduct or commercial Mg injection rates.

Comparison of results for the two sample digestion techniques for the baseline (no sorbent injection) samples shows that very little of the magnesium in the fly ash was dissolved by the acid disolution, but virtually all of the sulfate was. This suggests that in the base fly ash, most of the magnesium is tied up in relatively insoluble mineral complexes, most likely formed in the furnace, whereas most of the sulfate is present as SO_3/sulfuric acid that adsorbed to the fly ash in the back end of the plant. This result indicates that the acid-soluble magnesium is, in fact, made up almost entirely of the injected reagent and includes very little magnesium from base fly ash.

The acid soluble magnesium data presented in Table 4-4 show that there was significant variability in the distribution of injected magnesium in the ESP hoppers. In particular, the data from early in the test supports observations from early in the test period that the middle of the furnace was seeing higher SO_3 removal levels, and presumably higher dosages of byproduct Mg in the flue gas. The ESP 21 (upper and lower, center ESP) magnesium concentrations were typically higher than in the ESP 11 and ESP 31 (upper and lower, outer ESPs) samples. Later in the test period this was less evident, presumably because of efforts to improve sorbent distribution across the furnace.

A 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 (9/4 and 9/6) where injection ratios were being changed more rapidly. For these days the ESP ash samples may not have been representative of injection conditions at the time they were collected.

Table 4-4. Magnesium and Sulfate Concentrations in Fly Ash Samples from Gavin Unit 1

Sample ID	Mg:SO₃ Mole Ratio Injected (based on SCR Outlet SO₃)	Measured Magnesium Content		Est. Mg Content from Material Balance, wt% as MgO	Measured Sulfate Content		Observed Mg Utilization	
		Total Mg Content, wt% as MgO	Acid Soluble Mg Content, wt% as MgO		Total Sulfate Content, wt% as SO₃	Acid Soluble Sulfate Content, wt% as SO₃	Based on Total Mg & Sulfate Content, mole%	Based on Acid Soluble Mg & Sulfate Content, mole%
8/16/01 11 Lower	0 (Baseline)	0.71	0.07		0.83	0.76	58%	>100%
8/16/01 21 Lower	0 (Baseline)	0.61	0.07	0	1.00	0.88	82%	>100%
8/16/01 31 Lower	0 (Baseline)	0.65	0.07		0.95	0.93	74%	>100%
8/21/01 11 Upper	6:1	4.23	4.16		2.95	2.76	35%	33%
8/21/01 21 Upper	6:1	3.70	5.42		2.75	3.49	37%	32%
8/21/01 31 Upper	6:1	6.00	5.39		4.50	4.05	38%	38%
8/21/01 11 Lower	6:1	4.93	4.39	5.8	2.90	2.72	30%	31%
8/21/01 21 Lower	6:1	6.58	4.35		2.75	2.63	21%	31%
8/21/01 31 Lower	6:1	5.95	5.74		4.28	4.13	36%	36%
8/24/01 11 Upper	5:1	3.71	3.33		2.95	2.74	40%	41%
8/24/01 21 Upper	5:1	4.46	4.43		3.20	3.14	36%	36%
8/24/01 31 Upper	5:1	4.13	3.76		3.03	2.78	37%	37%
8/24/01 11 Lower	5:1	4.41	4.15	5.0	2.78	2.64	32%	32%
8/24/01 21 Lower	5:1	5.16	4.73		3.35	3.21	33%	34%
8/24/01 31 Lower	5:1	3.12	2.69		2.68	2.49	43%	47%
8/28/01 11 Upper	2:1	2.99	2.24		2.38	2.01	40%	45%
8/28/01 21 Upper	2:1	3.83	3.28		2.78	2.50	36%	38%
8/28/01 31 Upper	2:1	1.54	0.78		1.28	1.15	42%	74%
8/28/01 11 Lower	2:1	1.94	1.56	2.5	1.78	1.72	46%	55%
8/28/01 21 Lower	2:1	4.56	3.75		3.05	5.06	34%	68%
8/28/01 31 Lower	2:1	3.95	2.34		2.28	3.44	29%	74%
8/31/01 11 Upper	4:1	5.07	4.88		2.75	4.78	27%	49%
8/31/01 21 Upper	4:1	5.61	4.89		2.85	4.36	26%	45%
8/31/01 31 Upper	4:1	5.66	5.06		2.63	4.53	23%	45%
8/31/01 11 Lower	4:1	4.33	3.76	4.0	2.40	3.73	28%	50%
8/31/01 21 Lower	4:1	5.37	4.94		2.90	4.84	27%	49%
8/31/01 31 Lower	4:1	6.43	5.71		2.68	2.36	21%	21%
9/4/01 11 Upper	3:1	3.03	2.42		1.73	1.64	29%	34%
9/4/01 21 Upper	3:1	3.08	2.59		1.93	1.78	31%	35%
9/4/01 31 Upper	3:1	2.62	2.19		2.05	1.91	39%	44%
9/4/01 11 Lower	3:1	1.81	1.16	5.0	1.63	1.34	45%	58%
9/4/01 21 Lower	3:1	2.90	3.12		1.93	1.82	33%	29%
9/4/01 31 Lower	3:1	2.42	2.09		1.95	1.83	41%	44%
9/6/01 11 Upper	4:1	1.87	1.31		1.43	1.31	38%	50%
9/6/01 21 Upper	4:1	2.77	2.47		2.08	1.88	38%	38%
9/6/01 31 Upper	4:1	3.15	2.82		1.95	1.70	31%	30%
9/6/01 11 Lower	4:1	1.81	1.28	4.3	1.43	1.29	40%	51%
9/6/01 21 Lower	4:1	2.79	2.21		1.70	1.52	31%	35%
9/6/01 31 Lower	4:1	2.90	2.65		1.80	1.66	31%	31%

For the injection test samples, the sulfate concentrations measured were typically higher than would have been predicted base on SO_3/sulfuric acid removal data. The sulfate content values were used along with the MgO concentrations to calculate an apparent magnesium utilization value for each sample and digestion type, as shown in the last two columns of the table. The removal data would have predicted utilization values in the range of 10 to 15% at higher $Mg:SO_3$ ratios (5:1 and greater) and in the range of 15 to 25% at low $Mg:SO_3$ ratios (2:1 or less). The measured utilization values were typically in the range of 20 to 40%, even at the higher injection ratios, which suggest that the injected Mg sorbents were also removing some SO_2. Competition between SO_2 and SO_3 may have limited sorbent effectiveness for SO_3 removal.

The total Mg analyses show that at the highest injection rates, the fly ash contained between 5 and 6 wt% magnesium as MgO, while at the lower injection rates the magnesium content was in the range of 2 to 3 wt% as MgO. The total sulfate content analyses show sulfate levels between 3 and 4 wt% as SO_3 at the higher injection rates, and less than 2 wt% at the lower injection rates. The impacts of these magnesium and sulfate levels in the fly ash on ash sales would depend on the intended ash reuse.

Effects of Sorbent Injection on ESP Operation

During the long-term Mg sorbent injection tests on Unit 1, the impacts of sorbent injection and SO_3 removal on ESP operation were measured in three different manners. First, the ESP electrical properties were measured, by recording ESP electrical operating conditions (secondary current and voltage) for each electrical section periodically during the test. Second, the output from the unit's ESP outlet opacity monitor for these time periods was monitored and reviewed. Finally, at the end of the Mg injection test period and during a subsequent period of baseline operation, the impact of sorbent injection and SO_3 removal on ESP outlet particulate loading was quantified by conducting mass loading measurements via a modified version of EPA Method 17.

As noted in the Bruce Mansfield results in Section 3, the impacts from sorbent injection appear to be predominantly due to the resulting SO_3 removal rather than from the presence of the sorbent material itself. When the SO_3 is removed by the sorbent before it has a chance to be adsorbed onto fly ash particles, it can result in increased fly ash resistivity. Because of the conversion of SO_2 to SO_3 across the SCR system at Gavin Unit 1, and the observation that Mg injected in the furnace was only marginally effective at removing SO_3 formed in the SCR, little impact of sorbent injection on ESP performance was expected. The following describes the data collected during the long-term slurry injection tests, and what those data indicate about ESP impacts.

Electrical Conditions

The ESP data from Gavin plant are not regularly recorded, either electronically or on plant log sheets. For the purposes of this test, ESP secondary current and voltage values were manually recorded once or twice daily during most of the long-term test period. These data were in turn entered into a spreadsheet, along with date, time, sorbent injection rate, and flue gas SO_3 concentration data, and plotted. The data plots were reviewed to determine if Mg sorbent injection into the furnace had a discernable effect on ESP operation.

As described earlier, there are six separate ESPs on each unit at Gavin Plant. From the outlet of each of the three air heaters, flue gas flow splits vertically to an upper and a lower ESP; there is an upper and a lower ESP for each of three gas paths. Each ESP has eleven electrical sections, laid out as illustrated in Figure 4-13. One electrical section spans the entire width of each ESP for the first field, then for the subsequent fields there are two parallel electrical sections for each field. As illustrated in Figure 4-13, the flue gas on one side of an ESP (in this example, the lower ESP on the middle gas path) would go from section 201-L to 202-L, then 204-L, 206-L, 208-L and 210-L in series. Down the other side of that same ESP, the gas flow would be from 201-L to 203-L, 205-L, 207-L, 209-L and 211-L.

| 201-L | 202-L | 204-L | 206-L | 208-L | 210-L |
| | 203-L | 205-L | 207-L | 209-L | 211-L |
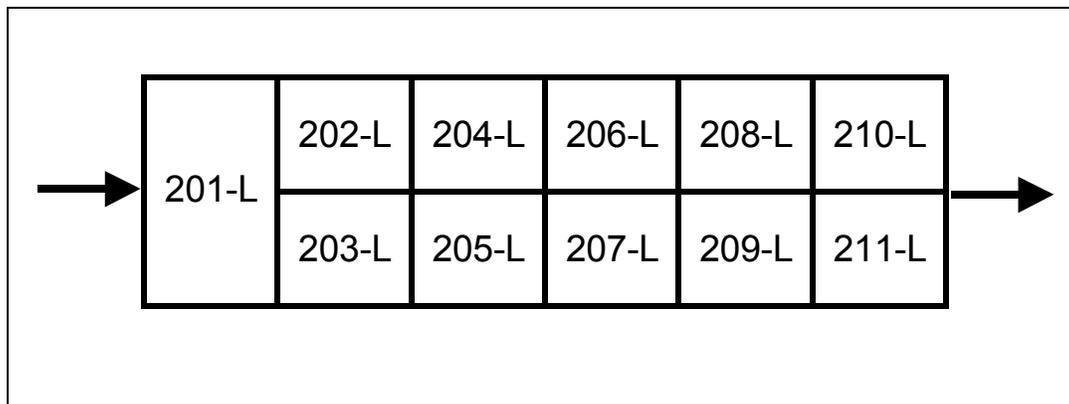
Figure 4-13. Schematic of Electrical Sections in One of Six ESPs at Gavin Plant Unit 1

The effects of Mg sorbent injection for SO_3 control during the long-term test are illustrated for two of the six ESPs: a middle ESP (2xx-lower) and an outside ESP (3xx-lower), in Figures 4-14 and 4-15, respectively. Both center and outside ESP data are illustrated because during the long-term test, there was evidence that the injected sorbent was more concentrated in the center gas path than in the outside gas paths, seen as lower SO_3 concentrations measured at the center economizer outlet. Thus, it was anticipated that a center ESP might see more effects from sorbent injection than an outside ESP.

In Figures 4-14 and 4-15, the secondary current values are plotted as a function of time for the first field, second, third and sixth (last field) on one side of each ESP. The first field would be expected to show the greatest impact of sorbent injection, and the sixth field should show the least. Note that each data point plotted represents an instantaneous value recorded by Gavin Plant operators at a given time. In the figure, the individual points for each electrical section are connected with lines, as a means of visually tracking the changes in milliamp readings from one time to the next. However, the lines do not portray the variation in these values between the discrete data points; they only connect one point for a given electrical section to the next.

Also plotted in the figures are the Mg:SO_3 molar injection ratio at the time the ESP electrical conditions were recorded, and any corresponding SCR outlet SO_3 concentrations measured at approximately the same time. ESP inlet SO_3 concentrations (actually present there as vapor-phase H_2SO_4) were not measured during this program, so the SCR outlet values are plotted as a relative indicator. Note that the SCR outlet values plotted may have been measured at the outlet
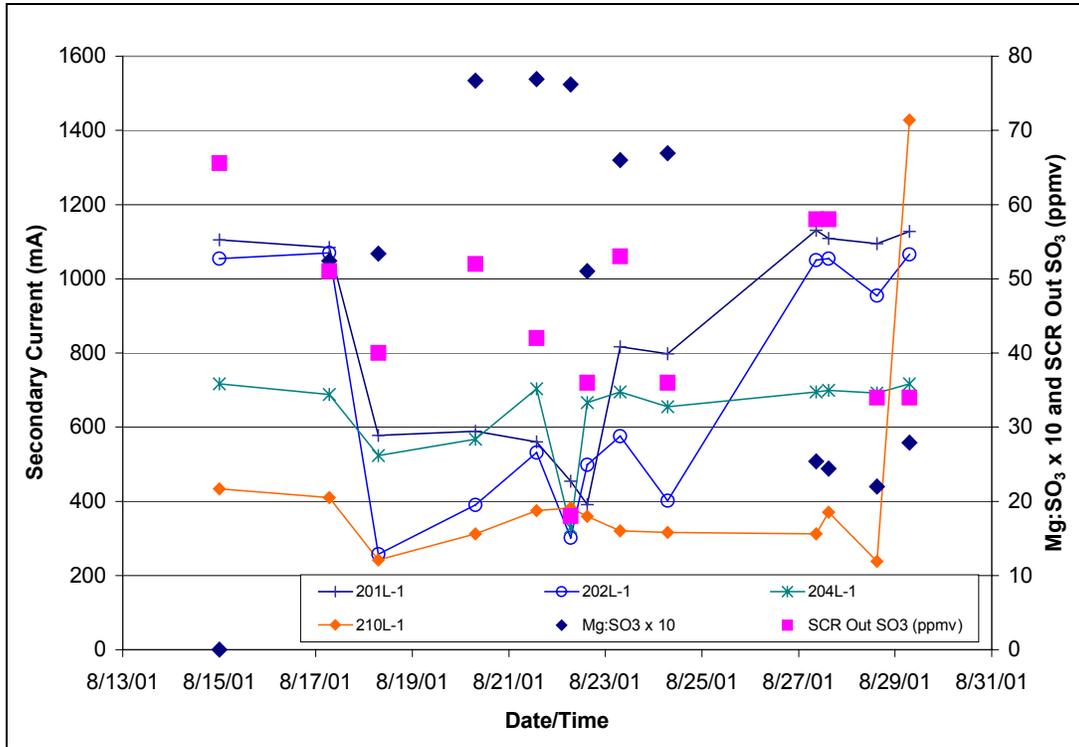
Figure 4-14. Electrical Conditions in ESP 2-L (center, lower) during the Long-term Sorbent Injection Test at Gavin Unit 1
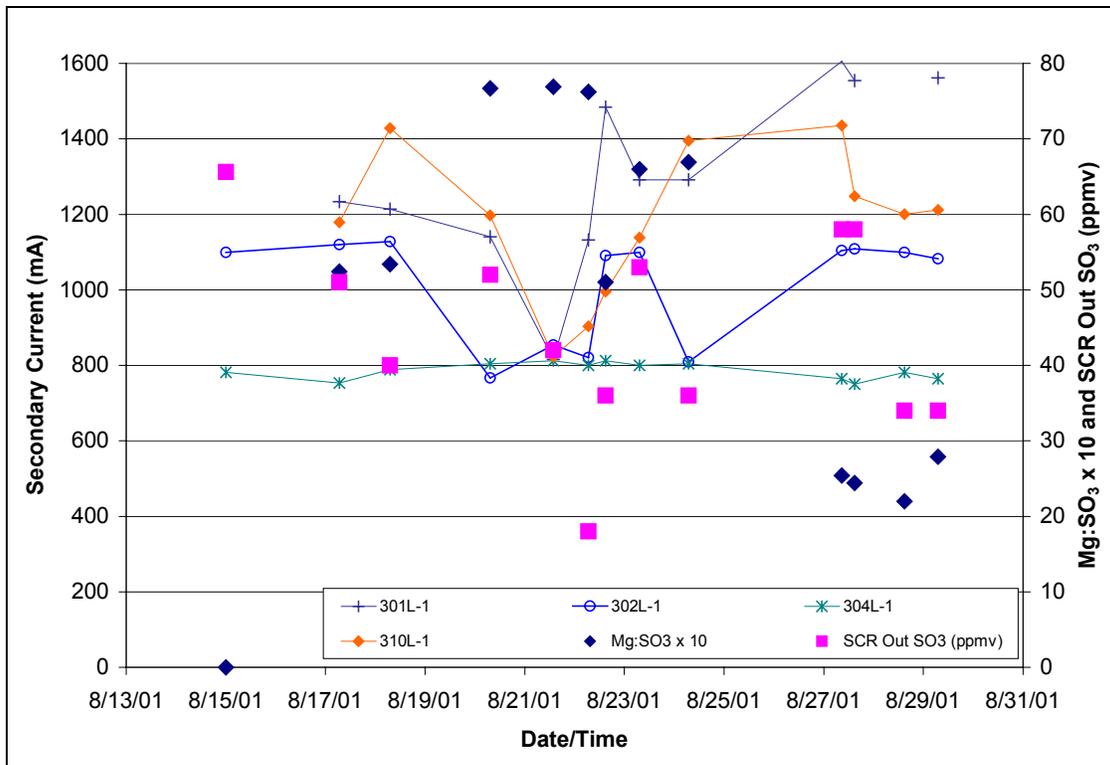
Figure 4-15. Electrical Conditions in ESP 3-L (outside, lower) during the Long-term Sorbent Injection Test at Gavin Unit 1

of any of the three SCR reactors, and hence may not have been measured immediately upstream of the ESP for which data are plotted.

The plot for the outer ESP (Figure 4-15) shows that Mg sorbent injection into the furnace for SO_3 control had little impact on ESP electrical properties. For the first field (301-L) through the last field (310-L), the secondary current values remained at relatively high values (800 to 1600 mA) throughout the test period.

The plot for the middle ESP (Figure 4-14) appears to show a more significant effect. The milliamp values are in general lower than in the outer ESP (Figure 4-15), ranging from as low as 200 mA to as high at 1400 mA. The readings are reduced for the first two fields (201-L and 202-L) during the middle periods of the data plotted, from about 8/18 through 8/24. In general, this time period corresponds with the highest byproduct Mg injection rates. This suggests that byproduct Mg injection in the furnace adversely affected ESP electrical properties. Such an adverse effect could be due to reduced SO_3 concentrations in the ESP inlet gas (increased ash resistivity), space charge effects from the fine byproduct Mg particles in the flue gas, or the presence of high-resistivity gypsum particles introduced with the byproduct. However, there does not seem to be a one-to-one correlation between injection rate and the apparent suppression of secondary currents. The strongest evidence that byproduct Mg injection is the cause of reduced current levels in the first fields is seen the morning of 8/22, when the SCR outlet SO_3 was measured at a low value of 18 ppm and the secondary currents to the first three fields were obviously suppressed.

It is possible that the center ESPs were affected by sorbent injection while the outside ESPs were not. As mentioned earlier, there was evidence that the Mg sorbent injected into the furnace tended to concentrate in the center gas path, in that the center economizer outlet SO_3 concentrations were typically lower than those measured in the two outer economizer outlet ducts. If this was the case, it is possible that the center ESPs saw adverse effects on electrical properties due to lower flue gas SO_3 concentrations, space charge effects and/or elevated concentrations of high-resistivity gypsum fines in the flue gas. The lowest SCR outlet SO_3 concentration measured during sorbent injection was 18 ppm, measured the morning of 8/22. Even considering some dropout of SO_3 across the air heater, this still should have been an ample amount of SO_3 in the flue gas to produce an acceptable ash resistivity. It therefore seems more likely that any adverse effects on ESP electrical properties would have been due to space charge effects or the presence of high-resistivity gypsum fines.

Whatever the case, it appears that the ESPs at Gavin were large enough to recover from the effects of reduced power levels in the first fields. As discussed below, neither the ESP outlet opacity values nor particulate loading values indicated increased particulate emissions during sorbent injection.

Effects on ESP Outlet Opacity Measurements

A portion of the measured opacity in the ESP outlet flue gas during SCR operation at Gavin Plant is attributed to the production of an acid aerosol mist at the "cold" surfaces of the air heaters and/or at cold spots in the ductwork or ESPs. This sub-micron-diameter mist, once

formed, is presumably not removed efficiently by the Gavin ESPs, and the presence of this mist at the ESP outlet apparently contributes several percentage points to the flue gas opacity measured there. E.ON Engineering measured 3 to 5 ppm of entrained acid mist in the flue gas at the ESP outlet under baseline conditions. A reduction in SO_3 concentration at the air heater and downstream, such as during sorbent injection, would also lower the acid dew point of the flue gas, and thus would eliminate or greatly reduce the production of sub-micron-diameter acid mist at these locations. Such reductions could also lower the in-duct opacity as measured at the ESP outlet.

The in-duct opacity as measured at the ESP outlet duct should not be confused with the stack gas opacity. The ESP outlet opacity measurement primarily reflects opacity due to particulate matter that is not removed from the flue gas in the ESP. As described above, sub-micron-diameter acid mist, representing the condensation of a small percentage of the sulfuric acid in the flue gas, can also contribute to the values measured at this location. The ESP outlet opacity is usually monitored continuously with an in-duct transmissometer. At the stack gas exit location on units with FGD, all of the sulfuric acid remaining in the flue gas is present as an sub-micron-diameter acid mist, having been condensed when the flue gas was quenched at the FGD inlet. The visible stack plume opacity on a unit that fires a high-sulfur coal and that has an operating SCR and FGD system is typically dominated by light scattering by this sub-micron-diameter acid mist. It is possible that sorbent injection for SO_3 control could have opposing effects on these two opacity values. A primary objective of SO_3 control is to lower the stack plume opacity, by reducing the amount of sulfuric acid mist present in the stack gas. However, it is possible that the ESP outlet opacity could be increased by sorbent injection for SO_3 control due to increased particle penetration because of adverse effects such as space charges from the small particles injected or increased fly ash resistivity when the flue gas SO_3 is removed.

When byproduct Mg injection first began the afternoon of 8/16, a downward trend was immediately observed on the ESP outlet (in-duct) opacity measurements. The Unit 1 opacity monitor reading dropped from about 18 to 20% prior to injection down to 10 to 12% within a couple of hours. This was presumably due to a reduction in flue gas SO_3 concentration and sulfuric acid dew point, and a corresponding reduction in the acid mist content of the ESP outlet gas. Measurements by E.ON Engineering confirmed that the acid mist content of the flue gas at the ESP outlet was virtually eliminated during sorbent injection. This was seen as an immediate, positive result from sorbent injection. However, there was a question as to whether the ESP outlet opacity would remain lower even at higher sorbent injection rates. That is, would space charge effects and/or increased fly ash resistivity ultimately limit ESP efficiency, and lead to increasing particulate emissions and opacity at this measurement location?

The data plotted in Figure 4-16 address this issue. The data plotted show ESP outlet opacity versus injected $Mg:SO_3$ molar ratio, for Unit 1 operation at full load (>1350 gross MW), over the duration of the test program. The byproduct Mg and commercial Mg test data are shown individually. The results plotted in the figure show that during baseline operation, the ESP outlet opacity values were typically in the range of 16 to 20%. When injecting either sorbent at $Mg:SO_3$ molar ratios of 3 or greater, all of the ESP outlet opacity values were in the range of 15% or lower. There was no trend for increasing opacity at higher injection rates. Thus, these data illustrate that the injection of either sorbent resulted in measurable reductions in ESP outlet opacity, and that these reductions were consistent over the duration of the long-term test. This
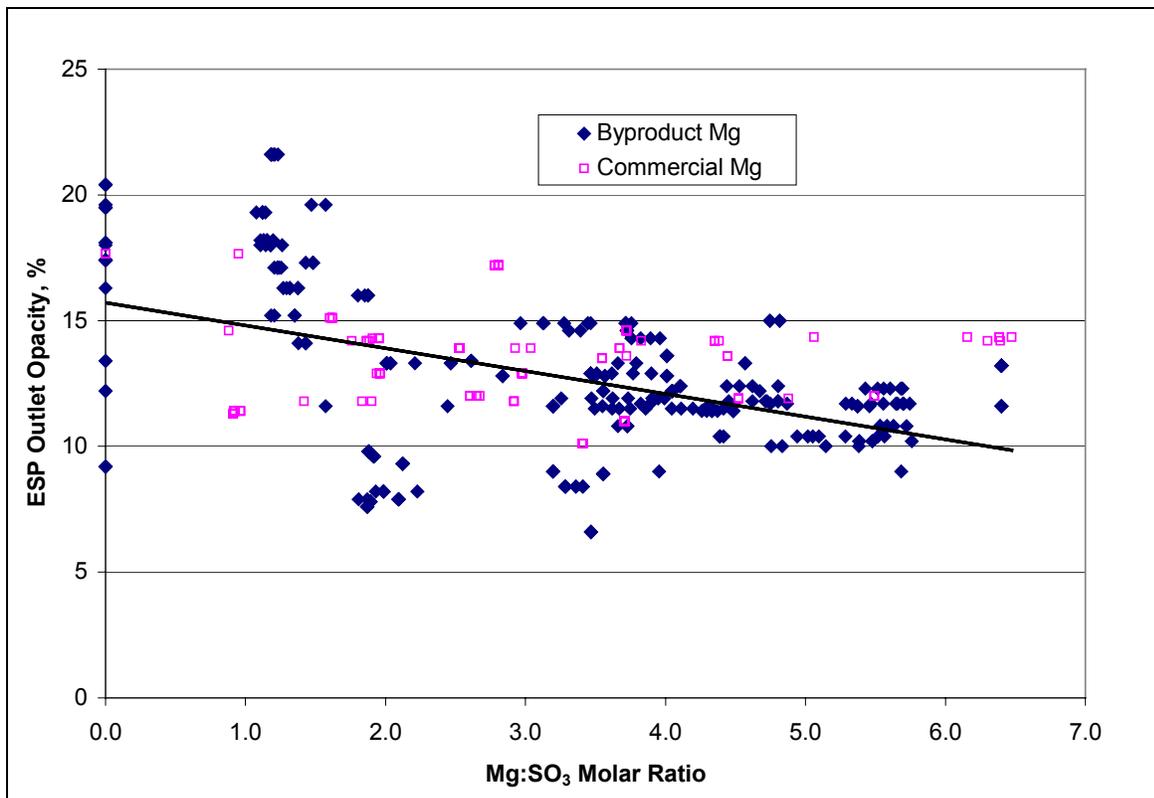
Figure 4-16. ESP Outlet Opacity Versus Sorbent Injection Rate during the Long-term Test at Gavin Plant Unit 1

indicates a positive impact on opacity due to the removal of the small fraction of acid mist present under baseline (no sorbent injection) conditions, and no significant adverse effect from increased space charges or ash resistivity.

Effects on ESP Outlet Particulate Loading

ESP outlet particulate loading measurements were conducted at the end of the test period, first under sorbent injection conditions, and then under "baseline" conditions with no sorbent injection. Conditions during the sampling runs are summarized in Table 4-5.

Table 4-5. Gavin Unit 1 Operating Conditions during ESP Outlet Particulate Loading Measurements

Date/Time	Unit Load (gross MW)	Sorbent	Flow Rate (gpm [l/min])	Mg:SO$_3$ (mole ratio)
9/6/01 11:50	1350	Commercial Mg	155 [587[	4.3
9/6/01 14:43	1350	Commercial Mg	185 [701]	5.1
9/7/01 13:43	NA	Commercial Mg	150-175 [569-663]	~4.8
9/8/01 02:19	NA	None	0	0
9/8/01 03:42	NA	None	0	0
9/8/01 05:30	NA	None	0	0

Because the injection test had officially "stopped" as of the afternoon of September 7, URS did not receive copies of operator log sheets showing Unit 1 gross load for the sampling conducted on September 7 and September 8. Based on pitot tube differential pressure readings during the sampling events, the load was most likely about 1350 to 1370 gross MW during the ESP outlet sampling on September 7, and in the range of 950 to 1150 gross MW during the baseline, early morning sampling runs on September 8. The lower load conditions may have biased the baseline measurements somewhat, since the flue gas velocities the ESP outlet were approximately 70 to 80% of the values during sorbent injection and full load. Lower flue gas velocities through the ESP would tend to improve particulate collection due to corresponding increases in specific collection area and reduced re-entrainment losses at the lower gas velocity. Most of the sampling runs for sorbent injection conditions were conducted during slurry injection rates of 140 to 185 gpm (531 to 701 l/min), with corresponding Mg:SO$_3$ mole ratios of 4:1 to 5:1 (based on magnesium hydroxide concentrations in the injected slurry and baseline SCR outlet SO$_3$ concentrations).

The end-of-test results are shown in Table 4-6. As mentioned previously, the particulate loading measurements were not conducted rigorously by the reference method, and thus do not represent compliance measurements. The primary variation from the reference method is that the samples were collected at a single point of representative gas flow rather than by conducting a full traverse at the sampling location. For the ESP outlet, there was little choice as to where the sampling could be conducted. There were ports available on the side of the ESP outlet duct at the north end of the plant and at the south end, and a limited number of ports on the top of the outlet ducts. However, the port on the south side of the outlet duct was being used by another contractor, E.ON Engineering, to conduct sulfuric acid concentration measurements. The ports on the top of the outlet duct were difficult to access with the Method 17 probe and equipment, and these ports were needed to conduct other measurements by URS during the same time period. This left the north-side port as the only viable location for conducting the ESP outlet Method 17 measurements. Because it was known that the intent was not to rigorously apply the reference methods, the probe brought to the site was the longest that would readily fit in URS' truck, rather than making provisions to ship a longer probe. This was a 12-foot (3.7-m) probe, meaning that the maximum effective probe length was about 10 feet (3 m). Consequently, by default, the ESP outlet measurements were made at the north-side port, 10 feet (3 m) in from the side wall.

One limitation of this sampling location was that it measured the outlet mass loading from an outside ESP rather than a center ESP. The electrical properties review discussed above indicated that the center ESPs were the only ones that may have been adversely affected by sorbent injection. If the outlet particulate loading from the center ESPs was increased due to the suppression of secondary voltages and currents in the first several fields, these measurements would not have reflected any such increase.

The results in Table 4-6 show that all of the ESP outlet mass concentrations and calculated emission rates were well within the plant's permitted values. There are two apparent trends in the data. One is that during sorbent injection, the highest measured emission rate corresponded with the highest furnace sorbent injection rate, as might be expected (see the data in Table 4-5). However, it is possible that this is could be coincidental, and due to effects such as run-to-run

Table 4-6. Summary of Method 17 Results for Gavin Unit 1

Run Number	1	2	3	4	Average
During Sorbent Injection					
Date	9/6/01	9/6/01	9/7/01	-	-
Time Start	11:50	14:43	13:43	-	-
Meter Volume (dscf)	28.260	29.187	28.549	-	28.666
Average Stack Temperature (^{o}F)	343	348	338	-	343
Static Pressure (in H_2O)	-15	-15	-15	-	-15
Flue Gas % O_2	5.0	5.0	5.0	-	5.0
Average Gas Velocity (ft/s)	82.0	79.4	78.9	-	80.1
Filter Weight Gain (g)	0.0300	0.0411	0.0213	-	0.0308
PNR Weight Gain (g)	0.0044	0.0043	0.0009	-	0.0032
Calculated Results					
Particulate Concentration (gr/dscf)	0.019	0.024	0.012	-	0.018
Particulate Concentration, O_2 Corrected (gr/dscf at 7% O_2)	0.017	0.021	0.011	-	0.016
Particulate Emissions (lb/MM Btu)	0.035	0.044	0.022	-	0.034
Baseline (no sorbent injection)					
Date	9/8/01	9/8/01	9/8/01	-	-
Time Start	02:19	03:44	05:30	-	-
Meter Volume (dscf)	41.964	55.452	50.205	-	49.207
Average Stack Temperature (^{o}F)	302	308	327	-	312
Static Pressure (in H_2O)	-15	-15	-15	-	-15
Flue Gas % O_2	5.0	5.0	5.0	-	5.0
Average Gas Velocity (ft/s)	57.6	60.0	66.3	-	61.3
Filter Weight Gain (g)	0.0125	0.0142	0.0182	-	0.0149
PNR Weight Gain (g)	0.0000	0.0010	0.0010	-	0.0007
Calculated Results					
Particulate Concentration (gr/dscf)	0.005	0.004	0.006	-	0.005
Particulate Concentration, O_2 Corrected (gr/dscf at 7% O_2)	0.004	0.004	0.005	-	0.004
Particulate Emissions (lb/MM Btu)	0.008	0.008	0.011	-	0.009

Note: 1 gr/dscf = 2.46 g/Nm^3, 1 dscf = 0.0264 Nm^3, 1 inch H_2O = 0.25 kPa, 1 ft/s = 0.305 m/s, (^{o}F - 32)/1.8 = ^{o}C.

variation or operational variations such as the rapping of the last field of the ESP during this measurement.

The other apparent trend in the data is that the baseline emissions rates were measured to be less than a third of the rate measured during sorbent injection. However, this observation is confounded by unit load. This is apparent in the flue gas velocity measurements, where the baseline gas velocities averaged only 77% of the velocity during the sorbent injection measurements. It is possible that the difference in velocity alone could account for the differences in mass emissions rates measured, due to the ESP specific collection area being approximately 30% higher during the baseline measurements. Also, the velocity being 23% lower during baseline could have resulted in lower re-entrainment losses from the ESP.

In summary, the results reported in Table 4-6 do not show a detrimental effect of sorbent injection on particulate emissions rates from Unit 1. All of the measured values were well below the permitted values for this unit. Observed variations between measured emissions rates during and after sorbent injection may be related to the lower unit load during the baseline measurements, and may be unrelated to sorbent injection. However, this lack of effect of sorbent

injection may have been influenced by the fact that it was the outlet gas from one of the outside ESPs rather than a center ESP that was sampled.

Flue Gas Halogen Species Concentrations

Method 26a sampling was employed 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 outlet location. After sorbent injection was curtailed, "baseline" (no sorbent injection) samples were also collected. The sampling times and the unit conditions were approximately the same as those summarized above for the particulate loading measurements. Species measured included HCl, chlorine, HF, 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.

The results of these measurements are summarized in Table 4-7. Flue gas concentration data in the table show that the baseline HCl concentration averaged about 42 ppm while the HF concentration averaged 13 ppm. Both of these values are in the typical range for bituminous coals. The chlorine and fluorine concentrations were measured to be much lower, at 7.8 ppm and 0.6 ppm, respectively.

The data in Table 4-7 show that HCl concentrations were higher during sorbent injection than during the baseline measurements, averaging 66 ppm compared to 42 ppm during baseline. The HF concentrations were about the same during the two measurement periods. The increased HCl concentrations during sorbent injection appear to be due to increased coal chlorine content rather than reflecting an adverse affect from sorbent injection. The mass balance data in the table show that virtually all of the chlorine measured in the flue gas during sorbent injection can be attributed to chlorine in the coal fired.

The concentration data for chlorine and fluorine during sorbent injection indicate a small removal percentage relative to the baseline values (2 and 34%, respectively). These species were measured to represent only a small fraction of the chlorine- and fluorine-containing species in the flue gas, though, so this apparent removal is relatively inconsequential compared to the amounts of halogen species that remained.

Mass balance data summarized in Table 4-7 show very good agreement between the average measured flue gas chlorine species concentrations and the corresponding coal chlorine measurements during the sorbent injection period, as mentioned above, but poorer agreement during the subsequent baseline testing. During the injection period, the mass balances closed within less than 1% 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 it appear unlikely the commercial Mg introduced a significant amount of chlorides into the flue gas, as might have been suggested by the flue gas concentration data.

The mass balances for the baseline period show poorer closure. The chlorine in the coal accounted for much more total chlorine than was measured in the flue gas; the chlorine-containing species in the flue gas only accounted for 64% of that in the coal. However, the mass balance data for the baseline period are based on average coal chloride analyses from the three

Table 4-7. Summary of Method 26a Results for Gavin Unit 1

| Date | Run | Flue Gas Concentration Data | | | | Mass Balance Data | | | | | |
| | | Hydrogen Halides | | Halogens | | | | | | | |
		HCl, ppmv	HF, ppmv	Cl_2, ppmv	F_2, ppmv	Cl_2 in Coal, lb/hr	Cl_2 in Flue Gas, lb/hr	Cl_2 Mass Closure, %	F_2 in Coal, lb/hr	F_2 in Flue Gas, lb/hr	F_2 Mass Closure, %
9/8/01	1	37.1	13.5	6.8	0.28	950*	535	56	93.0*	89.8	97
9/8/01	2	46.9	13.7	9.5	0.61	1070*	774	72	105*	105	101
9/8/01	3	42.4	12.8	7.0	0.82	1096*	694	63	107*	103	96
Baseline Ave:		**42.1**	**13.3**	**7.8**	**0.57**	**1038**	**668**	**64**	**102**	**99.3**	**98**
9/5/01	1	76.5	12.6	5.9	0.58	1341**	1239	92	122**	106	87
9/6/01	2	74.2	12.0	4.7	0.23	945**	1199	127	113**	99.5	88
9/6/01	3	62.1	8.8	12.4	0.39	945**	1132	120	113*	74.6	66
9/7/01	4	50.9	11.1	7.3	0.31	1250**	887	71	113*	93.5	83
Injection Ave:		**65.9**	**11.1**	**7.6**	**0.38**	**1120**	**1161**	**100**	**115**	**93.4**	**81**
Apparent Removal, %:		**-57**	**17**	**2**	**34**						

* Based on an average of values for Cl and F for 9/5, 9/6, and 9/7 coal analyses, as stated below; coal sample for 9/8 was not available.

** Based on values of 1208 ppm, 836 ppm and 1111 ppm Cl (as received basis) for coal samples from 9/5, 9/6, and 9/7, respectively. Corresponding F values were 110 ppm, 100 ppm, and 100 ppm, respectively (as received basis).

Note: 1 lb/hr = 0.454 kg/hr.

prior days' samples; no coal sample was taken on the baseline sampling date (9/8/01). It is quite possible that the poor mass balance closure for 9/8 is a result of the actual coal chlorine concentrations being lower than the average for the three previous days. Those three samples showed considerable variability in coal chlorine content, with the lowest value (836 ppm on an as-received basis) being only 69% of the highest value (1208 ppm). The flue gas chlorine concentrations during the baseline measurement period would correspond with a coal chlorine content of about 700 ppm (as-received basis).

The fluorine mass balances close reasonably well for both measurement periods. On average, the amount accounted for in the flue gas was just 2% less than was apparent in the coal during the baseline measurements, and 19% lower during the injection test period. The lower recovery during the injection period could possibly be a result of the removal of HF and fluorine by the injected sorbent, although the Bruce Mansfield results did not indicate significant overall removal of fluorine-containing gas species. More likely this just represents experimental error in the gas sampling and analyses and/or in collecting representative coal samples and analyzing them for fluorine content at these relatively low (~100 ppm) levels.

In general, the Method 26a results show little or no removal of halogen species from the flue gas during sorbent injection. The observation that little or no HCl or HF was removed is consistent with results from Bruce Mansfield, but the low removals of chlorine and fluorine at Gavin is inconsistent with the Bruce Mansfield results, where high removal percentages were observed. However, since the chlorine and fluorine represent a small percentage of the halogens in the flue gas, this difference is of little consequence.

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 (371°C) 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 rather than using an out-of-stack Method 5 filter at 250°F (121°C). The latter, which is specified as part of Method 108, would only allow arsenic that is in the gas phase at 250°F (121°C) 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 (371°C) to pass through. The results of these measurements are summarized in Table 4-8. 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 4-8 show that under baseline conditions, the majority of the arsenic in the flue gas at the economizer outlet was already present in the solid phase; an average of 97% of the total arsenic was present in the particulate and only 3% in the gas phase. The gas-phase measurements correspond to an average of less than 9 ppb (dry basis) of arsenic in the flue gas. However, the measured gas-phase concentrations were highly variable, ranging from less than 0.2 ppb to 36 ppb. It is not clear whether this represents a true fluctuation in the gas-phase arsenic concentrations or merely sampling and analytical variability.

Table 4-8. Gavin Unit 1 Economizer Outlet Flue Gas and Particulate-Phase Arsenic Concentrations Measured by Modified Method 108

		Arsenic Concentration, ppmv (dry basis)		
Sampling Date	Run	Solid Phase (equivalent flue gas concentration)	Gas Phase	Total
9/8/01	1	0.248	<0.0002	0.248
9/8/01	2	0.267	0.0036	0.270
9/8/01	3	0.268	0.0230	0.291
Baseline Average		**0.261**	**0.0089**	**0.270**
9/5/01	1	0.225	0.0118	0.237
9/6/01	2	0.143	0.0339	0.177
9/6/01	3	0.325	<0.0002	0.325
9/7/01	4	0.452	<0.0015	0.452
Injection Average		**0.286**	**0.0114**	**0.298**

The averages for samples collected during sorbent injection showed a similar low percentage of the total arsenic present in the gas phase (an average of 3 to 4%), and similar gas-phase arsenic concentrations (11 ppb dry basis). As in the baseline measurements, the gas-phase arsenic concentrations measured during sorbent injection varied widely, from less than 0.2 ppb to 34 ppb.

Table 4-9 summarizes the results of arsenic mass balance calculations for these two periods. The calculated arsenic balance closures were not very close, with the average for arsenic in the flue gas measurements corresponding to twice that in the coal during both the baseline and sorbent injection sampling periods. However, there were no coal samples available for the actual date of the baseline sampling, so the coal arsenic concentration used for this calculation was an average from the three previous daily coal samples. Note that the Bruce Mansfield long-term test results similarly showed poor mass balance closures, with the gas and particulate results averaging about double the amount of arsenic accounted for in the coal. It is not clear whether these poor closures represent a sampling problem for the coal or flue gas, an analytical problem for arsenic in the coal or flue gas samples, or some combination of errors in all of these.

Table 4-9. Gavin Unit 1 Arsenic Mass Balance Summary

Date	Test	Arsenic in Coal (lb/hr)	Arsenic in Flue Gas (lb/hr)	Apparent Closure (%)
9/8/01	1	3.7*	7.2	200
9/8/01	2	3.5*	7.5	210
9/8/01	3	4.3*	9.9	230
Baseline Average		**3.8**	**8.2**	**210**
9/5/01	1	3.9**	7.2	180
9/6/01	2	5.1**	5.7	110
9/6/01	3	5.1**	10.4	200
9/7/01	4	3.1*	14.6	470
Injection Average		**4.3**	**9.5**	**220**

* Based on average arsenic analysis of coal samples for 9/5 through 9/7; 3.6 ppm (as received basis).
** Based on daily arsenic analyses of coal samples for 9/5 through 9/7; 3.7 ppm, 4.5 ppm and 2.7 ppm, respectively (as received basis).
Note: 1 lb/hr = 0.454 kg/hr.

Because the measured gas-phase arsenic concentrations were quite low and widely variable from run to run, 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. However, at face value the results do not indicate that the commercial magnesium hydroxide sorbent injected into the furnace had a measurable impact on gas-phase arsenic concentrations.

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. Increases 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 indicate reduced solids buildup due to sulfuric acid deposition on the baskets. The air heater pressure drop data are illustrated in Figure 4-17, while the air heater outlet flue gas temperature data are plotted in Figure 4-18.
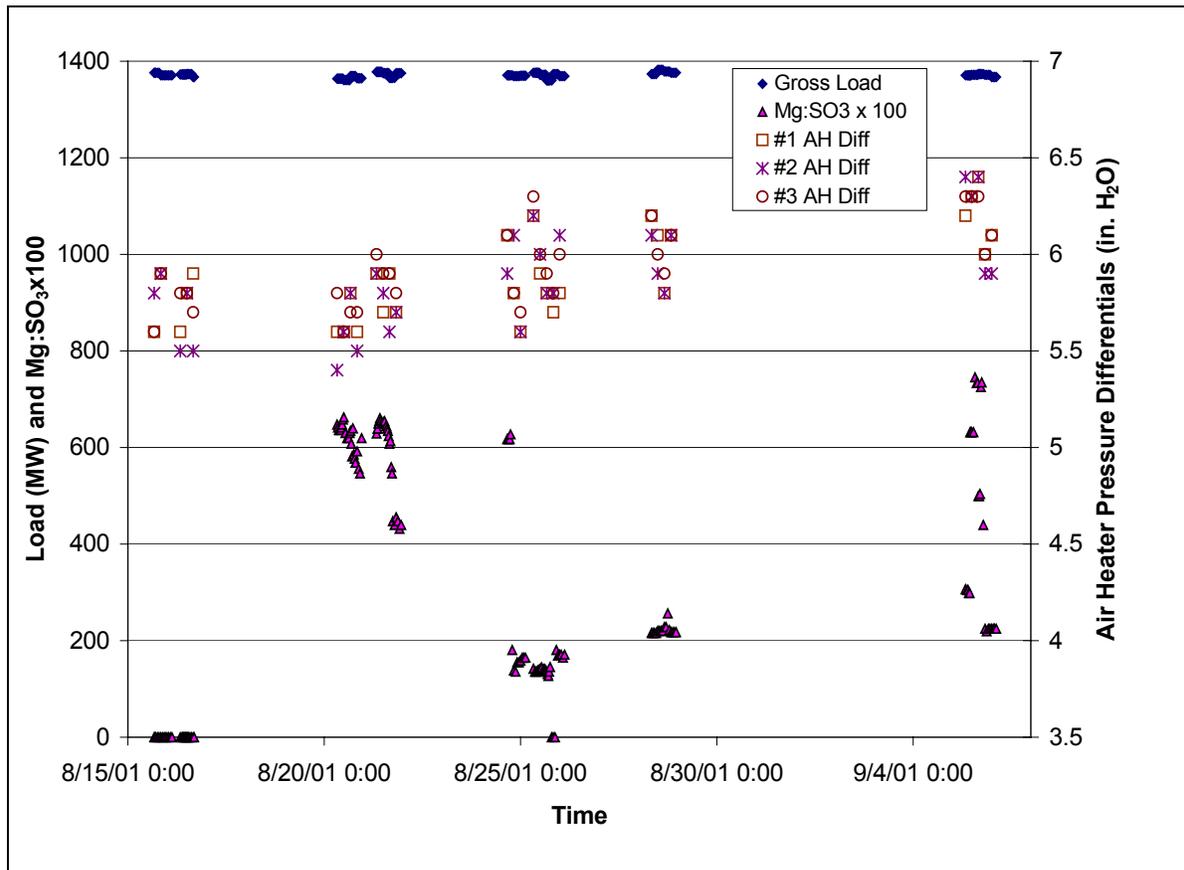

Figure 4-17. Air Heater Pressure Drop at Full Load (>1360 gross MW) during the Long-term Test at Gavin Plant Unit 1
Note: 1 inch H_2O = 0.25 kPa.
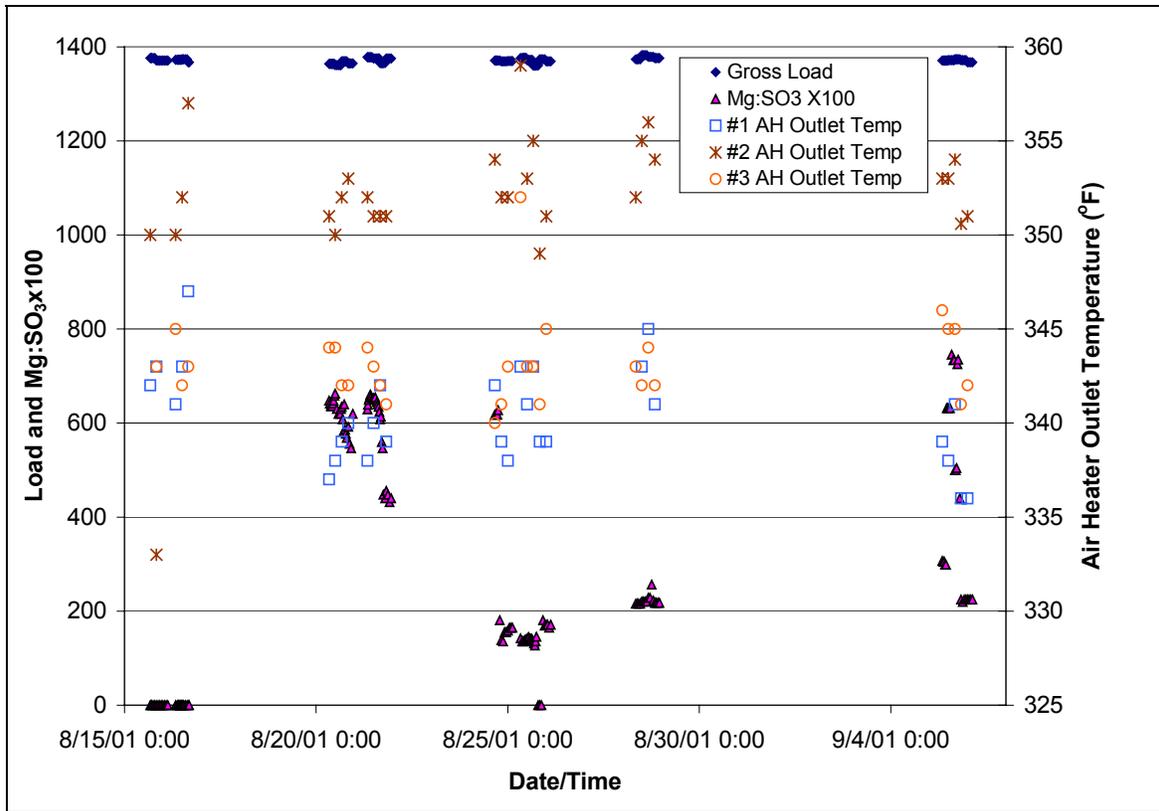
Figure 4-18. Air Heater Outlet Temperature at Full Load (>1360 gross MW) during the Long-term Test at Gavin Plant Unit 1
Note: (°F - 32)/1.8 = (°C).

The pressure drop data show a trend for increasing pressure differential across all three of the air heaters over the course of the test, from an average of about 5.5 to 6.0 inches H_2O (1.4 to 1.5 kPa) at the beginning of the test to about 6.0 to 6.5 inches H_2O (1.5 to 1.6 kPa) about three weeks later. The authors do not know if this represents a normal trend for this unit or whether this represents a change in the pressure drop increase over time.

The air heater outlet flue gas temperature trends plotted in Figure 4-18 for the duration of the sorbent injection test do not show any clear trends. The outlet flue gas temperatures from each of the three air heaters remained approximately the same (plus or minus 5°F [2.8°C]) throughout this time period. It is likely that the air heater outlet temperature was controlled by the flow of steam used to pre-heat the air flowing through the other side of the air heater, so this lack of a trend may not have any signficance.

Economizer outlet temperature trends were also plotted to determine whether there were any apparent adverse effects of sorbent injection on heat transfer in the back pass of the boiler. These data are plotted in Figure 4-19. There is quite a bit of scatter in these data, so trends are difficult to observe. On the "outside" flue gas paths (the inlets to air heaters 1 and 3), no trend is discernable; most of the full-load temperature data fall in the range of 680 to 690°F (360 to 366°C) over the entire period. For the middle flue gas path (the inlet to air heater 2), it does appear that the economizer outlet flue gas temperature increased with time, from about 680 to

4-34
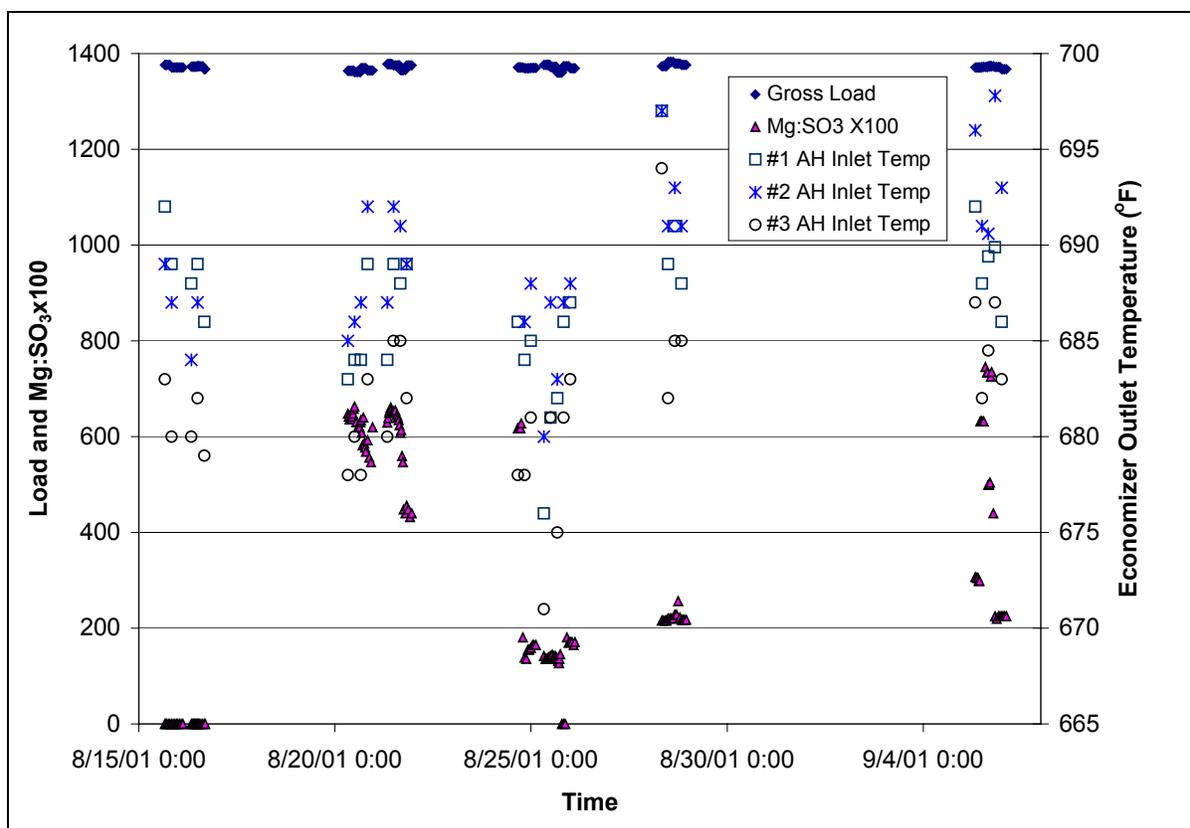
Figure 4-19. Effects of Sorbent Injection on Economizer Outlet Gas Temperatures at Gavin Unit 1

690°F (360 to 366°C) at the beginning of the test to about of 690 to 700°F (366 to 371°C) at the end. This suggests that the middle gas path was seeing more effects from the injected sorbent than the outer gas paths, which is consistent with other observations during the long-term testing. For example, during early testing with the byproduct Mg reagent, lower SO_3 concentrations were measured at the economizer outlet at the middle gas path than at the outer gas paths, suggesting a biasing of the injected solids toward the center of the furnace. Also, the ESP electrical property data showed that the middle gas path was the only one of the three where injected solids may have adversely affected the performance of the first few ESP electrical sections.

Effects of Sorbent Injection 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. When injecting the Mg sorbents near the top of the furnace at the 17th floor, it was expected that magnesium addition this high in the furnace, presumably at furnace gas temperatures of 2000°F (1100°C) or less, would not have any impacts on the slag. However, for a portion of the long-term test, 40% of the Mg sorbents were added at a 13th floor location and the remainder at the 17th floor. The 13th floor injection level is adjacent to the nose of the boiler, where the furnace gases are near the ash fusion temperature, and it was speculated that adding a portion of the Mg at this level could modify observed slag properties and accumulation.

Impacts on slag formation were documented in two manners. First, throughout the long-term test, Gavin plant operators made daily observations of the amount of slag apparent on the front surface of the pendant, secondary superheater tubes. These observations were made visually through 3-inch inspection ports on the sides of the furnace. The observations were tracked over the test duration to determine, at least subjectively, if byproduct Mg or commercial Mg injection had an effect on slagging in the upper furnace, or if injecting part of the material on the 13th floor rather than all on the 17th floor made a difference.

A second manner was to analyze grab samples of the slag, collected through the same 3-inch diameter observation ports on each side of the secondary superheater. These samples were collected on two baseline days and five days during sorbent injection. The sampling device was a steel cup welded to the end of an approximately 10-foot-long (3.0-m) steel rod. Samples were scraped off the secondary superheater tube walls, trapped in the cup and extracted from the furnace through the open port. Samples representing the baseline period (8/15), byproduct Mg injection at the 17th floor level (8/21) and byproduct Mg injection at both the 13th and 17th floor levels (8/28) were selected for chemical analyses. Baseline samples were taken through view ports at the 15th and 17th floor levels, while the samples representing sorbent injection were taken at the 14th and 17th floor levels. Samples were taken from only one side of the furnace on most dates, but were taken from both sides on 8/28. The results of chemical analyses of these slag samples are summarized in Table 4-10.

Table 4-10. Chemical Analyses of Slag Grab Samples from Gavin Unit 1 (all values in wt%, dry basis)

Sample No.	01-2232	01-2233	01-2234	01-2235	01-2236	01-2237	01-2238	01-2239
Date	8/15/01	8/15/01	8/21/01	8/21/01	8/28/01	8/28/01	8/28/01	8/28/01
Conditions	Baseline	Baseline	Byproduct Mg	Byproduct Mg	Byproduct Mg	Byproduct Mg	Byproduct Mg	Byproduct Mg
Sample location	17th floor	15th floor	17th floor	14th floor	17th floor/ left	17th floor/ right	14th floor/ left	14th floor/ right
LOI (1100°C)	0.09	0.67	0.95	+0.22	0.90	0.48	+0.87	+1.69
CaO	2.58	2.95	3.38	2.15	3.29	2.88	1.91	1.88
MgO	0.68	0.61	5.49	0.78	5.02	3.70	0.78	0.78
SiO_2	45.33	38.09	39.71	41.49	39.94	42.88	47.46	45.34
Al_2O_3	22.78	19.91	19.33	20.01	18.77	20.61	22.28	21.29
Fe_2O_3	29.97	37.32	30.52	34.88	32.22	26.89	27.79	30.45
Na_2O	0.48	0.34	0.42	0.43	0.41	0.37	0.39	0.46
K_2O	1.51	1.21	1.31	1.39	1.33	1.49	1.65	1.56
S	0.09	0.31	0.42	0.09	0.39	0.23	0.03	0.02

A summary of the operators' slag observations is attached in Appendix A as Table A-1. Generally, slag thickness observed at the 17th floor varied from less than 1 to 6 inches (3 to 15 cm), depending on the soot blower schedule. The thickness observed from the 14th, 15th, and 16th floor view ports varied from 2 to 6 inches (5 to 15 cm) toward the sides of the furnace, and up to 8 to 10 inches (20 to 25 cm) near the center, again depending on the soot blower schedule. The deposits at the 17th floor level were typically described as "dry," while the slag observed at the 14th through 16th floor levels was often described as "tacky." A review of the operator comments

summarized in Table A-1 shows no clear trends linking sorbent type, rate or injection location with slag conditions or accumulations.

The slag deposit samples retrieved from the 17th floor view ports were all "dry" in appearance; large pieces were very friable and only weakly agglomerated. In contrast, and most likely due to the furnace gas higher temperatures, samples from the 14th and 15th floors were "wet" or plastic, meaning they were semi- molten and "tacky" and presumably more likely to stick to the superheater tubes. However, the unit operators observed that the soot blowers were able to remove these deposits during their regular schedule. The following summarizes the chemical analysis results for these samples.

17th Floor Samples

As seen in the chemical analyses (Table 4-10), the MgO content in the slag samples increased to well above the baseline value in both of the samples from the injection period. The baseline sample measured 0.61% MgO, which increased to 5.49% when feeding 120 gpm of byproduct Mg to the 17th floor on 8/21. When feeding about the same rate on 8/28 but split 40:60 to the 13th and 17th floors, the MgO contents in the slag samples were 5.02% (left side) and 3.70% (right side). However, the observed increase in MgO content was likely of little benefit at this location, since the flue gas temperatures were presumably already well below the ash fusion temperature. Thus, the MgO was not likely incorporated into the ash chemistry and would not have been expected to improve slag qualities.

14th and 15th Floor Samples

Very little increase in MgO content was seen in the samples collected from these locations, even for the samples from 8/28 where byproduct Mg was being injected on the 13th floor. Thus, it appears that the byproduct Mg did not appreciably alter slag chemistry in an area of the furnace where it might have helped. It was hoped that byproduct Mg injection on the 13th floor would help "dry up" the tacky deposits at the 14th and 15th floor levels and cause them to be more friable and easier to remove. Easier slag removal would allow operation at lower excess air levels and thus improve boiler efficiency.

Within the accuracy of these qualitative observations, it can only be concluded that sorbent injection had no measurable impact on slagging in the upper furnace. No favorable trends were noted either in the boiler operator notes or in the chemical analyses of slag samples.

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 measured by an AEP employee certified for EPA Method 9 (visual opacity), when possible. However, on many test days the ability to make opacity readings was limited by atmospheric conditions that were not conducive

to visual determinations. In particular, the close proximity of the Unit 2 stack, with untreated flue gas, to the Unit 1 stack resulted in the two plumes mixing before the water vapor plume dissipated. This often made it impossible to read the visual opacity for Unit 1 alone.

The results of the Method 9 reading have not been reported by AEP due to regulatory issues related to the Unit 1 plume opacity. Qualitatively, the plume opacity was greatly reduced during both the byproduct Mg and commercial Mg test periods.

A
GAVIN PLANT SLAG OBSERVATIONS

Table A-1. Summary of Operator Visual Observations of Slag Conditions at Gavin Unit 1

Date/ Time (EST)	Load (gross MW)	Excess Air to Furnace (%)	Reagent Type	$Mg(OH)_2$ Flow to 13th Floor (% of total)	lbmol $Mg(OH)_2$ Injected/ lbmol SO_3	Slag Conditions	Slag Depth (inches)
8/16/01 10:30	1373	21.5	None	0	0.00	dry	1-5"
8/16/01 11:00	1373	21.5	None	0	0.00	dry	1-3"
8/16/01 15:00	1374	21	None	0	0.00	dry	1-5"
8/16/01 16:00	1367	19.5	Byprod. Mg	0	2.84	dry	1-3"
8/16/01 18:00	1367	19.5	Byprod. Mg	0	4.36	dry	1-4"
8/16/01 20:00	1363	20.3	Byprod. Mg	0	4.29	dry	1-4"
8/17/01 3:00	1227	20	Byprod. Mg	0	0.00	dry	1-3"
8/17/01 10:30	1359	21.5	Byprod. Mg	0	4.54	dry	1-6"
8/17/01 16:00	1367	21	Byprod. Mg	0	4.02	dry	
8/17/01 19:00	1367	21	Byprod. Mg	0	4.44	little tacky	1-6"
8/17/01 23:00	1370	21.5	Byprod. Mg	0	4.27	little tacky	1-6"
8/18/01 3:00	1090	22.5	Byprod. Mg	0	4.51		
8/18/01 8:00	1358	23	Byprod. Mg	0	4.48	dry	1-4"
8/18/01 13:00	1370	21.5	Byprod. Mg	0	3.81	dry	1-4", toward middle 6"
8/18/01 17:00	1367	22.15	Byprod. Mg	0	3.60	dry	elev 17: 1-3", elev 14-16: 4-6", 8-10" toward middle
8/18/01 21:00	1378	20	Byprod. Mg	0	3.26	dry, little tacky	1-3" normal, some spots 1-6" little tacky
8/19/01 1:00	1020	20	Byprod. Mg	0	3.86	mostly normal	1-3" normal, some spots 1-6" little tacky
8/19/01 5:00	1087	22	Byprod. Mg	0	4.01	mostly normal	1-3" normal, some spots 1-6" little tacky
8/19/01 8:00	1359	22.5	Byprod. Mg	0	3.00	dry	elev 17: 1-3", elev 14-16: 4-6", 8-10" toward middle
8/19/01 12:45	1371	19	Byprod. Mg	0	0.00	dry	elev 17: 1-3", elev 14-16: 4-6", 8-10" toward middle
8/19/01 17:00	1370	21	Byprod. Mg	0	4.08	normal	1-6" heaviest in middle
8/19/01 21:00	1374	20	Byprod. Mg	0	4.65	normal	1-6" some spots a little tacky

Table A-1. Summary of Operator Visual Observations of Slag Conditions at Gavin Unit 1 (continued)

Date/ Time (EST)	Load (gross MW)	Excess Air to Furnace (%)	Reagent Type	Mg(OH)$_2$ Flow to 13th Floor (% of total)	lbmol Mg(OH)$_2$ Injected/ lbmol SO$_3$	Slag Conditions	Slag Depth (inches)
8/20/01 1:00	1092	21	Byprod. Mg	0	6.04	normal	1-6" 14 & 15 elev. a little tacky
8/20/01 5:00	1092	20	Byprod. Mg	0	6.84	normal	1-6" 14 & 15 elev. a little tacky
8/20/01 8:00	1364	20	Byprod. Mg	0	6.47	normal	1-6" heavier in middle
8/20/01 12:30	1361	20	Byprod. Mg	0		normal	1-6" heavier in middle
8/20/01 17:00	1369	20	Byprod. Mg	0	5.81	normal	1-6" heavier in middle
8/20/01 20:00	1365	19.5	Byprod. Mg	0	5.92	dry	1-4"
8/21/01 5:00	1097	20	Byprod. Mg	0	7.08	dry	1-4", light white coating on tubes.
8/21/01 14:00	1375	18	Byprod. Mg	0	6.45	dry	1-3", possibly little tacky on back of 15
8/21/01 22:00	1375	20	Byprod. Mg	0	4.32	dry	1-3"
8/22/01 1:00	1080	21	Byprod. Mg	0	0.00	normal	1-3"
8/22/01 8:00	1372	22	Byprod. Mg	0	4.98	dry	1-3" possibly little tacky on back of 14&15
8/22/01 20:00	1371	21	Byprod. Mg	0	5.46	dry	1-3"
8/23/01 6:00	1099	22	Byprod. Mg	0	6.70	dry	1-4"
8/23/01 10:30	1376	20	Byprod. Mg	0	4.65	dry	1-2" on 17th, 14th elevation slightly tacky, 2-4"
8/23/01 20:00	1362	19	Byprod. Mg	0	5.05	dry	1-4"
8/24/01 4:00	1098	23.5	Byprod. Mg	0	6.38	dry	1-4"
8/24/01 16:00	1371	21	Byprod. Mg	0	6.18	dry	1-4"
8/24/01 18:00	1371	21	Byprod. Mg	0	6.27		
8/24/01 21:00	1369	21	Byprod. Mg	0	1.36	dry	1-4" some heavy spots toward middle
8/25/01 8:00	1376	19	Byprod. Mg	0	1.42	patchy	2-8"
8/25/01 11:00	1376	19	Byprod. Mg	0	1.39	tacky	2-6" tacky on 14th floor

Table A-1. Summary of Operator Visual Observations of Slag Conditions at Gavin Unit 1 (continued)

Date/ Time (EST)	Load (gross MW)	Excess Air to Furnace (%)	Reagent Type	Mg(OH)$_2$ Flow to 13th Floor (% of total)	lbmol Mg(OH)$_2$ Injected/ lbmol SO$_3$	Slag Conditions	Slag Depth (inches)
8/25/01 20:00	1374	19	Byprod. Mg	0	0.00	dry and patchy	2-6"
8/26/01 9:00	1378	19	Byprod. Mg	0	1.30	little patchy	2-5", better than on 8/25
8/26/01 14:00	1379	18	Byprod. Mg	40	1.24	little patchy	2-5" little patchy on 15th
8/26/01 23:00	1311	20	Byprod. Mg	40	2.14	dry and patchy	2-6", heaviest in middle
8/27/01 8:00	1372	18	Byprod. Mg	40	2.54	dry and patchy	2-5", patchy on 15
8/27/01 14:00	1373	20	Byprod. Mg	40	2.44	patchy, sticky	2-8", sticky on 14th
8/27/01 20:00	1368	17	Byprod. Mg	40	2.15	dry, tacky	dry on 16th and 17th (0-3"), tacky on 14th (1-4")
8/28/01 4:00	996	23	Byprod. Mg	40	2.85	dryer	0-2", finished blowing slag at time
8/28/01 9:00	1374	20	Byprod. Mg	40	2.16	dry, tacky	0-6", tacky on 14th
8/28/01 15:00	1382	19	Byprod. Mg	40	2.20	normal to tacky	0-6", tacky on 14th
8/28/01 20:00	1376	19.5	Byprod. Mg	40	2.18	normal to sticky	0-3", 17-14 light; lower elevations appear sticky
8/29/01 5:00	1124	21.5	Byprod. Mg	40	2.58	dry	0-2"
8/29/01 9:00	1372	23	Byprod. Mg	40	3.86	dry, tacky	0-6", bit tacky on 14th
8/29/01 14:00	1391	21	Byprod. Mg	40	3.68	dry, tacky	some spots 1-8" still a bit tacky
8/29/01 17:00	1373	19	Byprod. Mg	40	3.68	dry, tacky	14th: 1-7" tacky, 15th: dry, 1-1.5"
8/29/01 20:00	1364	18.5	Byprod. Mg	40	3.99	dry, tacky	0-3" tacky on 15th and RS of 14th, slag formation middle of 15
8/30/01 4:00	1263	20	Byprod. Mg	40	4.18	dry, little tacky	mostly dry (0-2"), tacky in 15th and RS of 14th (0-8")
8/30/01 12:00	1370	19	Byprod. Mg	40	7.36	dry, little tacky	0-3", on 14th elev 1-6" still tacky
8/30/01 16:30	1344	19	Byprod. Mg	40	7.43	dry, little tacky	1-6", on 14th elev 1-8" still tacky
8/30/01 23:00	1376	18	Byprod. Mg	40	4.09	dryer	17-15: 0-3", 14: 1-8", little dryer, 13: large clinker

Table A-1. Summary of Operator Visual Observations of Slag Conditions at Gavin Unit 1 (continued)

Date/ Time (EST)	Load (gross MW)	Excess Air to Furnace (%)	Reagent Type	Mg(OH)$_2$ Flow to 13th Floor (% of total)	lbmol Mg(OH)$_2$ Injected/ lbmol SO$_3$	Slag Conditions	Slag Depth (inches)
8/31/01 5:00	1286	22	Byprod. Mg	40	4.28	dryer	17-15: 0-3", 14: 1-6", much dryer, 13: large clinker
8/31/01 12:00	1356	19	Comm'l. Mg	40	1.05	dry, little tacky	1-6", 14th 1-6" still tacky
8/31/01 17:00	1356	19	Comm'l. Mg	40	1.06	dry, little tacky	1-6", 14th 1-8" still tacky
8/31/01 21:00	1370	19	Comm'l. Mg	40	0.00	dry, little tacky	17-15, dry 0-6", 14th L dry 2-4", 14th R still little tacky 2-5"
9/1/01 5:00	994	26	Comm'l. Mg	40	0.00	dry	0-5"
9/1/01 8:00	1332	20	Comm'l. Mg	40	0.00	dry	0-3"
9/1/01 16:00	1321	22	Comm'l. Mg	40	0.00	dry, sticky	0-3", on 14th 2-6" and sticky
9/1/01 22:00	1334	21	Comm'l. Mg	40	9.06	dry, little tacky	0-4", 1-6" on 14th and little tacky
9/2/01 5:00	991	25	Comm'l. Mg	40	12.73	dry	0-4"
9/2/01 10:00	1205	25	Comm'l. Mg	40	3.64	dry	
9/2/01 16:00	1371	21	Comm'l. Mg	40	2.91	dry	
9/2/01 22:00	1374	22	Comm'l. Mg	40	4.26	dry	0-3"
9/3/01 4:00	1146	23	Comm'l. Mg	40	4.98	dry	0-3"
9/3/01 9:00	1368	21	Comm'l. Mg	40	1.86	dry	0-3", buildup in reheater
9/3/01 16:00	1341	20	Comm'l. Mg	40	1.86	dry	0-3", buildup in reheater
9/3/01 21:00	1351	19	Comm'l. Mg	40	4.08	tacky	2-3"
9/4/01 4:00	1302	21	Comm'l. Mg	40	4.04	dry, little tacky	2-3", little tacky on 14th floor
9/4/01 8:00	1372	20	Comm'l. Mg	0	3.23	dry, little tacky	2-4", little tacky and heavier toward middle of 15-16
9/4/01 14:00	1353	21	Comm'l. Mg	0	3.42	dry	2-4", heavier toward middle 15-16
9/5/01 23:00	1372	22	Comm'l. Mg	0	2.25	tacky	2-5"
9/6/01 5:00	1203	20	Comm'l. Mg	0	2.72	tacky	2-5"

Table A-1. Summary of Operator Visual Observations of Slag Conditions at Gavin Unit 1 (continued)

Date/ Time (EST)	Load (gross MW)	Excess Air to Furnace (%)	Reagent Type	Mg(OH)₂ Flow to 13th Floor (% of total)	lbmol Mg(OH)₂ Injected/ lbmol SO₃	Slag Conditions	Slag Depth (inches)
9/6/01 14:00	1350	19.5	Comm'l. Mg	0	5.11	dry	1-6"
9/6/01 23:00	1300	20	Comm'l. Mg	0	na	dry	0-4"
9/7/01 3:00	na	na	Comm'l. Mg	0	na	dry	0-4"
9/7/01 12:00	na	na	Comm'l. Mg	0	na	dry	2-6"
9/7/01 17:00	na	na	Comm'l. Mg	0	na	dry	some buildup, few clinkers
9/7/01 20:00	na	na	Comm'l. Mg	0	na	dry	0-4"

na – data not available.