Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control

Semi-Annual Technical Progress Report

October 1, 2001 – March 31, 2002

Cooperative Agreement No: DE-FC26-99FT40718

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Disclaimer

Abstract

This document summarizes progress on Cooperative Agreement DE-FC26-99FT40718, Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control, during the time period October 1, 2001 through March 31, 2002. The objective of this project is to demonstrate the use of alkaline reagents injected into the furnace of coal-fired boilers as a means of controlling sulfuric acid emissions. The coincident removal of hydrochloric acid and hydrofluoric acid is also being determined, as is the removal of arsenic, a known poison for NO_X selective catalytic reduction (SCR) catalysts. EPRI, the Tennessee Valley Authority (TVA), FirstEnergy Corporation, American Electric Power (AEP) and the Dravo Lime Company are project co-funders. URS Corporation is the prime contractor.

This is the fifth reporting period for the subject Cooperative Agreement. During the previous (fourth) period, two long-term sorbent injection tests were conducted, one on Unit 3 at FirstEnergy's Bruce Mansfield Plant (BMP) and one on Unit 1 at AEP's Gavin Plant. Those tests determined the effectiveness of injecting alkaline slurries into the upper furnace of the boiler as a means of controlling sulfuric acid emissions from these units. The alkaline slurries tested included commercially available magnesium hydroxide slurry (Gavin Plant) and a byproduct magnesium hydroxide slurry (at both Gavin and BMP). The tests showed that injecting either the commercial or the byproduct magnesium hydroxide slurry could achieve up to 70-75% overall sulfuric acid removal. At BMP, the 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 SO_3 removal results were presented in the previous semi-annual technical progress report (April 1, 2001 through September 30, 2001). During the current reporting period, additional balance of plant impact information was determined for one of the two tests. These additional balance-of-plant results are presented and discussed in this report. There was no other technical progress to report, because all planned testing as part of this project has been completed.

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1.0   INTRODUCTION

This document is the semi-annual Technical Progress Report for the project "Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control," for the time period October 1, 2001 through March 31, 2002. The objective of this project is to demonstrate the use of alkaline reagents injected into the furnace of coal-fired boilers as a means of controlling sulfuric acid emissions. The coincident removal of hydrochloric acid and hydrofluoric acid has also been determined, as has the removal of arsenic, a known poison for NO_X selective catalytic reduction (SCR) catalysts. The project is being funded by the U.S. DOE National Energy Technology Laboratory under Cooperative Agreement DE-FC26-99FT40718. EPRI, the Tennessee Valley Authority (TVA), FirstEnergy Corporation, American Electric Power Company (AEP), and the Dravo Lime Company are project co-funders. URS Corporation (formerly Radian International) is the prime contractor.

Sulfuric acid is present in most flue gases from coal combustion because a small percentage of the SO_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 500^oF. Because of this temperature effect, in this report sulfur in this oxidation state is generally referred to as "SO_3" in furnace gas or flue gas upstream of the boiler air heater and "sulfuric acid" in flue gas downstream of the air heater.

Besides being a Toxic Release Inventory substance and a potential precursor to acid aerosol/condensable emissions from coal-fired boilers, sulfuric acid in the flue gas can lead to boiler air heater plugging and fouling, corrosion in the air heater and downstream, and the formation of a visible plume. These issues will likely be exacerbated with the retrofit of SCR for NO_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.

The project has tested the effectiveness of furnace injection of four different calcium- and/or magnesium-based alkaline sorbents on full-scale utility boilers for SO_3 control. These reagents have been tested during four one- to two-week tests conducted on two FirstEnergy Bruce Mansfield Plant (BMP) units. One of the sorbents tested was produced from a wet flue gas desulfurization (FGD) system waste stream, from a system that employs a modified Thiosorbic$^®$ Lime scrubbing process. The other three sorbents are commercially available.

After completing the four one- to two-week tests, the most promising sorbents were selected for two longer-term (up to 30-day) full-scale tests. The longer-term tests were used to confirm the effectiveness of the sorbent 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.

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

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

2.0 PROGRESS DURING THE CURRENT REPORTING PERIOD

2.1 Summary of Progress

The current reporting period, October 1, 2001 through March 31, 2002, is the fifth technical progress reporting period for this project. October 1, 1999 was the start date for this Cooperative Agreement.

In May of last year, a long-term slurry injection test was conducted at BMP Unit 3. The sorbent was a byproduct magnesium hydroxide (byproduct Mg) produced at Allegheny Energy's Pleasants Power Station. The long-term injection test began the second week of May and continued into the first week of June 2001. The primary measure of the success of the slurry injection tests was the reduction in flue gas SO_3 concentration at the electrostatic precipitator outlets. After the test was complete, samples collected during the test were chemically analyzed, and data collected were organized, reduced, and analyzed. Results from this testing were presented in the previous Technical Report for this project (April 1, 2001 through September 30, 2001).

Last July, AEP joined the project as a new team member, co-funder, and host site. Their Gavin Plant started up new SCR units for NO_X control on both Units 1 and 2 (both 1300-MW coal-fired units) in May 2001. As might have been expected, a portion of the SO_2 produced from the high-sulfur coal fired there was oxidized to SO_3 across the SCR catalysts. This conversion essentially doubled the amount of SO_3 in the flue gas going to the units' air heaters, and correspondingly increased sulfuric acid concentrations at the ESP outlet and FGD outlet (stack). The increased sulfuric acid concentrations in the stack flue gas caused greatly increased plume opacity, and appeared to contribute to the occurrence of plume "touch downs" at ground level near the plant. AEP joined the project to test magnesium hydroxide injection as a means of controlling stack sulfuric acid concentrations, and TVA agreed to forego testing on one of their units for the opportunity to test sorbent injection on a unit with an operating, full-scale SCR system.

Because the supply of byproduct Mg in the quantities required to treat two 1300-MW units was in question, AEP also wanted to test commercial magnesium hydroxide (commercial Mg), so that sorbent was used for a portion of the test. The testing at Gavin Plant was conducted from the middle of August through the first week of September. SO_3 removal results from this test were reported in the previous Technical Progress Report for this project (April 1, 2001 through September 30, 2001).

During the current reporting period, samples collected during the test were chemically analyzed, and data collected were organized, reduced, and analyzed to determine other, balance-of-plant impacts from the Mg injection. Balance-of-plant results from the testing at Gavin Plant are presented in Section 4 of this Technical Report.

One topical report was submitted during the current reporting period, covering the results of the short-term sorbent injection tests conducted at BMP in the fall of 2000 and the spring of 2001. Also during the current period, the project period of performance was extended by four months,

to allow additional time to complete reporting efforts and to allow a presentation to be made at a NETL-sponsored PM$_{2.5}$ conference in April.

2.2   Problems Encountered

There were no problems encountered during the current reporting period of enough significance to require discussion here.

3.0   PLANS FOR FUTURE REPORTING PERIODS

3.1   Plans for Next Reporting Period

The next reporting period would cover the time period April 1, 2002 through September 30, 2002. Since the end date for the Cooperative Agreement is June 30, 2002, the next reporting period will actually just cover three months.

During the next reporting period, one topical report will be prepared and submitted, presenting the results from the two long-term tests, one at BMP and the second at Gavin Plant. Also, the final report for the project will be prepared and submitted. Finally, a poster presentation was made at a NETL-sponsored $PM_{2.5}$ conference in Pittsburgh in early April.

3.2   Prospects for Future Progress

Any subsequent reporting period would extend beyond the current period of performance of this Cooperative Agreement, which ends June 30, 2002. Therefore, no progress is anticipated beyond that planned for the next reporting period.

4.0   TECHNICAL RESULTS

The technical results for the current reporting period (October 1, 2001 through March 31, 2002) are limited to additional results that have become available for two longer-term (approximately 25-day) alkaline slurry injection tests that were conducted during the previous reporting period (April 1, 2001 through September 30, 2001). One test was conducted on BMP Unit 3 in May-June 2001, and the second was conducted on AEP's Gavin Plant Unit 1 in August/September 2001. The objective of these tests was to investigate the effectiveness of furnace injection of alkaline sorbents for sulfuric acid control. The tests also evaluated the effects of these sorbents on boiler equipment performance. The first test evaluated a byproduct magnesium hydroxide [$Mg(OH)_2$] (byproduct Mg) as a furnace injection sorbent for SO_3 control. The second, at Gavin Plant, evaluated both the byproduct Mg and commercially available magnesium hydroxide (commercial Mg) as furnace injection sorbents for SO_3 control.

The remainder of this section presents and discusses additional results from these two tests that have become available during the current reporting period. There is no new information available from the BMP long-term test, as discussed in Section 4.1. Additional information about balance-of-plant impacts from the Gavin long-term test is discussed in Section 4.2.

4.1   Long-term Test on BMP Unit 3

During the long-term test, byproduct Mg slurry was injected into the entire Unit 3 boiler continuously for 23 days, to assess its effectiveness for flue gas SO_3 control.

Various analytical techniques were used to assess the effects of sorbent injection. These primarily included sampling with the Controlled Condensation System (CCS) method for determining flue gas SO_3 content and, to a lesser extent, an acid dew-point (ADP) meter for determining the sulfuric acid dew point (and, indirectly, the concentration of sulfuric acid) of the flue gas. Daily average SO_2 concentration measurements were often made coincident with the CCS measurements. EPA Reference Method 26a was used for determining hydrochloric acid (HCl) and hydrofluoric acid (HF), as well and 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. Impacts on ESP operation were quantified by taking voltage and current data on operating electrical sections of the Unit 3 ESPs. Sorbent and ESP hopper samples were analyzed for magnesium content and sulfate content, for density and weight percent solids, and for total alkalinity. 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.

All of the above results have been previously reported. The reader is referred to the previous Technical Progress Report for this project (April 1, 2001 through September 30, 2001) for details of BMP Unit 3, test descriptions, SO_3 removal results, and balance-of-plant impacts. No new information related to this testing has become available for reporting during the current reporting period.

4.2 Long-term Test on AEP's Gavin Plant, Unit 1

The long-term test at Gavin Plant was significant because it provided the opportunity to measure the effectiveness of sorbent injection into the furnace at removing SO_3 formed in the furnace as well as that formed across the SCR catalyst. During the long-term test, two different sorbents, a byproduct Mg slurry and a commercially available magnesium hydroxide (commercial Mg) slurry were injected into the entire Unit 1 boiler over a total of 23 days. Analytical techniques used to assess the effects of sorbent injection primarily included sampling with a modified Controlled Condensation System (CCS) method to determining flue gas SO_3 content, during baseline and then injection conditions. These SO_3 removal results were presented previously. The reader is referred to the previous Technical Progress Report for this project (April 1, 2001 through September 30, 2001) for details of Gavin Plant Unit 1, test descriptions, and SO_3 removal results.

EPA Reference Method 26a was used for determining hydrochloric acid (HCl) and hydrofluoric acid (HF), as well and 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. Impacts on ESP operation were quantified by taking voltage and current data on operating electrical sections of the Unit 1 ESP's, and by measuring ESP outlet flue gas particulate loading by EPA Method 17. Sorbent and ESP hopper samples were analyzed for magnesium content and sulfate content. Sorbent samples were also analyzed for density and weight percent solids, and for total alkalinity. 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, and boiler slag samples were collected and analyzed, to observe any trends related to slag formation. The results of all of these additional measurements have become available during the current reporting period, and are reported below.

4.2.1 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 hydrochloric acid 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 4-1. 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 dissolution 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 the base fly ash.

The acid soluble magnesium data presented in Table 4-1 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 (center ESP) magnesium concentrations were typically higher than in the ESP 11 and ESP 31 (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 later samples, the ESP ash samples may not have been representative of injection conditions at the time the ash samples were collected.

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.

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

Sample ID	Mg:SO₃ Mole Ratio Injected	Measured Magnesium Content		Estimated 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 (a.m.)	5.07	4.88		2.75	4.78	27%	49%
8/31/01 21 Upper	4:1 (a.m.)	5.61	4.89		2.85	4.36	26%	45%
8/31/01 31 Upper	4:1 (a.m.)	5.66	5.06		2.63	4.53	23%	45%
8/31/01 11 Lower	4:1 (a.m.)	4.33	3.76	4.0	2.40	3.73	28%	50%
8/31/01 21 Lower	4:1 (a.m.)	5.37	4.94		2.90	4.84	27%	49%
8/31/01 31 Lower	4:1 (a.m.)	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%

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.

4.2.2   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 Bruce Mansfield results presented previously, 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.

4.2.2.1   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 then plotted. The data plots were reviewed to determine if Mg sorbent injection into the furnace had a discernable effect on ESP operation.

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 4-1. 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 4-1, 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.
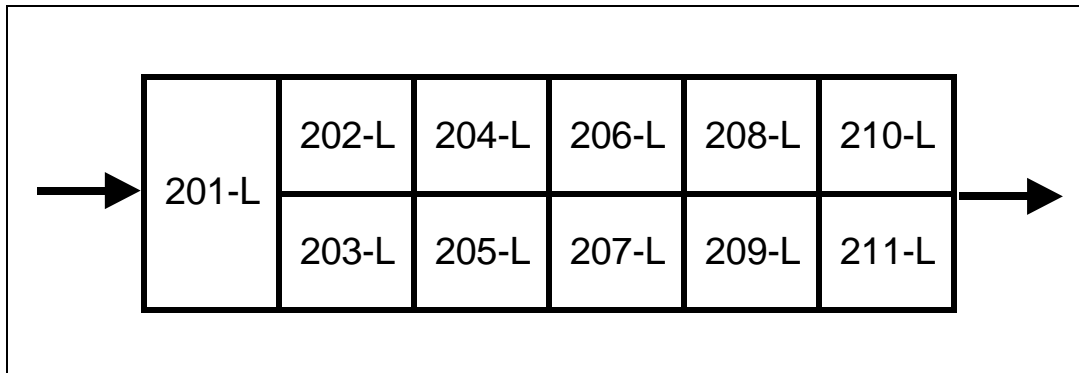
Figure 4-1. Schematic of Electrical Sections in One of Six ESPs at Gavin Plant

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 4-2 and 4-3, 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.
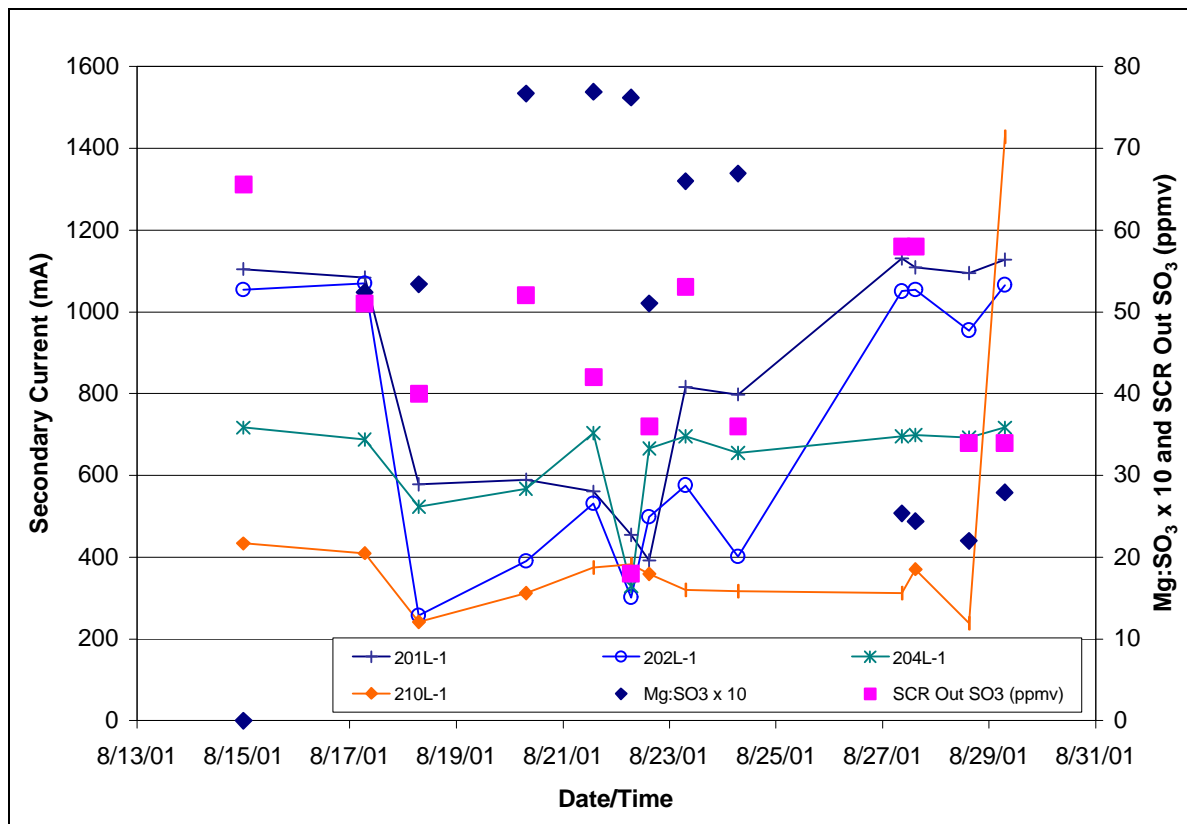
Figure 4-2. Electrical Conditions in ESP 2-L (center, lower) during the Long-term Sorbent Injection Test
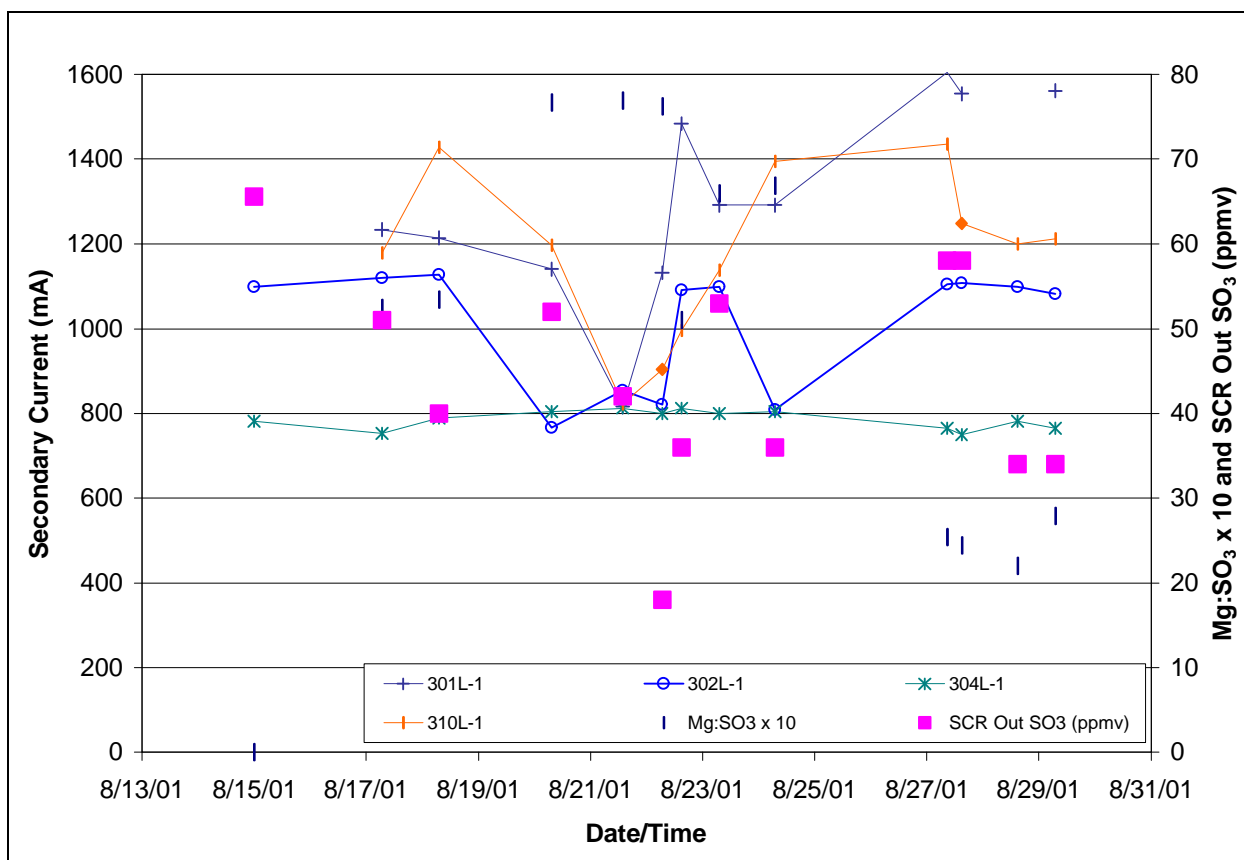
Figure 4-3. Electrical Conditions in ESP 3-L (Outside, Lower) during the Long-term Sorbent Injection Test

In Figures 4-2 and 4-3, 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 (mA) 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 of any of the three SCR reactors, and hence may not have been measured immediately upstream of the ESP for which data were plotted.

The plot for the outer ESP (Figure 4-3) 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 4-2) appears to show a more significant effect. The milliamp values are in general lower than in the outer ESP (Figure 4-3), 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.

4.2.2.2   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 a 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 caused by 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 4-4 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 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.
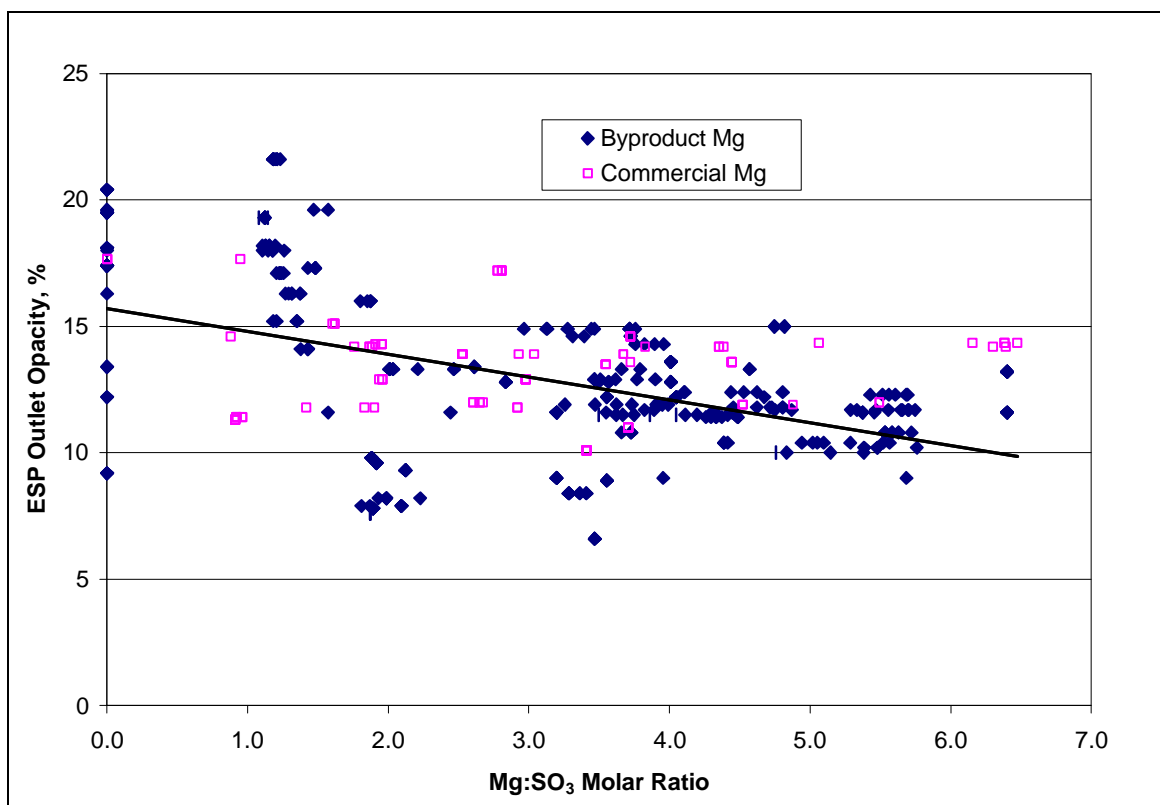
Figure 4-4. ESP Outlet Opacity versus Sorbent Injection Rate during the Long-term Test at Gavin Plant

4.2.2.3   Effects on ESP Outlet Particulate Loading

ESP outlet particulate loading measurements were conducted at the end of the long-term test period, first under sorbent injection conditions then under "baseline" conditions with no sorbent injection. Conditions during the sampling runs are summarized in Table 4-2.

Table 4-2. Unit 1 Operating Conditions during ESP Outlet Particulate Loading Measurements

Date/Time	Unit Load (gross MW)	Sorbent	Flow Rate (gpm)	Mg:SO₃ (mole ratio)
9/6/01 11:50	1350	Commercial Mg	155	4.3
9/6/01 14:43	1350	Commercial Mg	185	5.1
9/7/01 13:43	NA	Commercial Mg	150-175	~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, 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 4-3. 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-ft probe, meaning that the maximum effective probe length was about 10 feet. Consequently, by default, the ESP outlet measurements were made at the north-side port, 10 feet 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 4-3 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. However, it is possible that this is could be coincidental, and due to effects such as run-to-run variation or operational variations such as the rapping of the last field of the ESP during this measurement.

Table 4-3. Summary of Method 17 Results

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
Particulate Concentration (gr/dscf)	0.019	0.024	0.012	-	0.018
Particulate Concentration, O_2 Corrected (gr/dscf @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
Particulate Concentration (gr/dscf)	0.005	0.004	0.006	-	0.005
Particulate Concentration, O_2 Corrected (gr/dscf @7% O_2)	0.004	0.004	0.005	-	0.004
Particulate Emissions (lb/MM Btu)	0.008	0.008	0.011	-	0.009

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, because the velocity was 23% lower during baseline, this could have resulted in lower re-entrainment losses from the ESP.

In summary, the results reported in Table 4-3 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.

4.2.3 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 hydrochloric acid, chlorine, hydrofluoric acid, and fluorine. The objective of making these measurements was to determine if any of these species would be effectively removed from the flue gas by the injected slurry sorbent.

The results of these measurements are summarized in Table 4-4. Flue gas concentration data in the table show that the baseline hydrochloric acid (HCl) concentration averaged about 42 ppm while the hydrofluoric acid (HF) concentration averaged 13 ppm. Both of these values are in the typical range for bituminous coals. The chlorine (Cl_2) and fluorine (F_2) concentrations were measured to be much lower at 7.8 ppm and 0.6 ppm, respectively.

The data in Table 4-4 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 4-4 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 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 that the commercial Mg introduced a significant amount of chlorides into the flue gas, as might have been suggested by the flue gas concentration data.

Table 4-4. Summary of Method 26a Results

Date	Run	Flue Gas Concentration Data				Mass Balance Data					
		Hydrogen Halides		Halogens		Chlorine in Coal, lb/hr	Chlorine in Flue Gas, lb/hr	Chlorine Mass Closure, %	Fluorine in Coal, lb/hr	Fluorine in Flue Gas, lb/hr	Fluorine Mass Closure, %
		HCl, ppmv	HF, ppmv	Cl$_2$, ppmv	F$_2$, ppmv						
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).

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 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 was 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) 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 F_2 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 Cl_2 and F_2 at Gavin is inconsistent with the Bruce Mansfield results, where high removal percentages were observed. However, since the Cl_2 and F_2 represent a small percentage of the halogens in the flue gas, this difference is of little consequence.

4.2.4 Arsenic Concentrations

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

Table 4-5. 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
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**

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.

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 4-6 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.

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.

Table 4-6. 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).

4.2.5 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 4-5, while the air heater outlet flue gas temperature data are plotted in Figure 4-6.

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 in. H_2O at the beginning of the test to about 6.0 to 6.5 in. H_2O 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 4-6 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) 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 significance.

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 4-7. 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 over the entire period. For the middle flue gas path (the inlet to air heater 2), it does appear that the
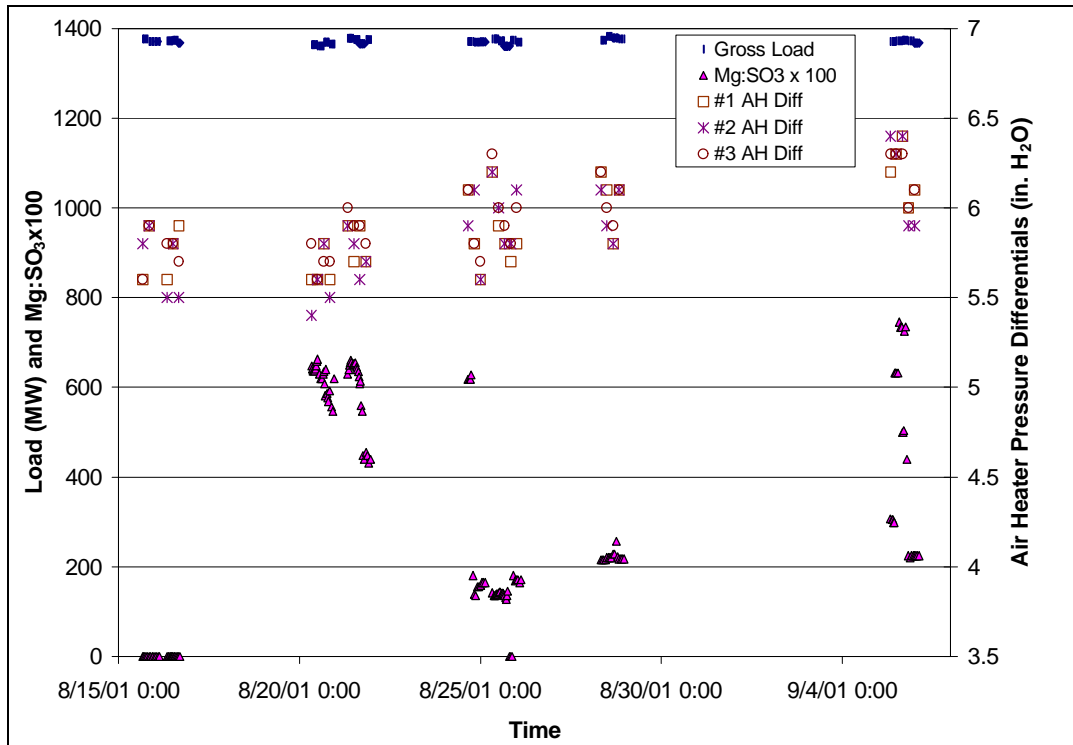
Figure 4-5. Air Heater Pressure Drop at Full Load (>1360 gross MW) during the Long-term Test at Gavin Plant
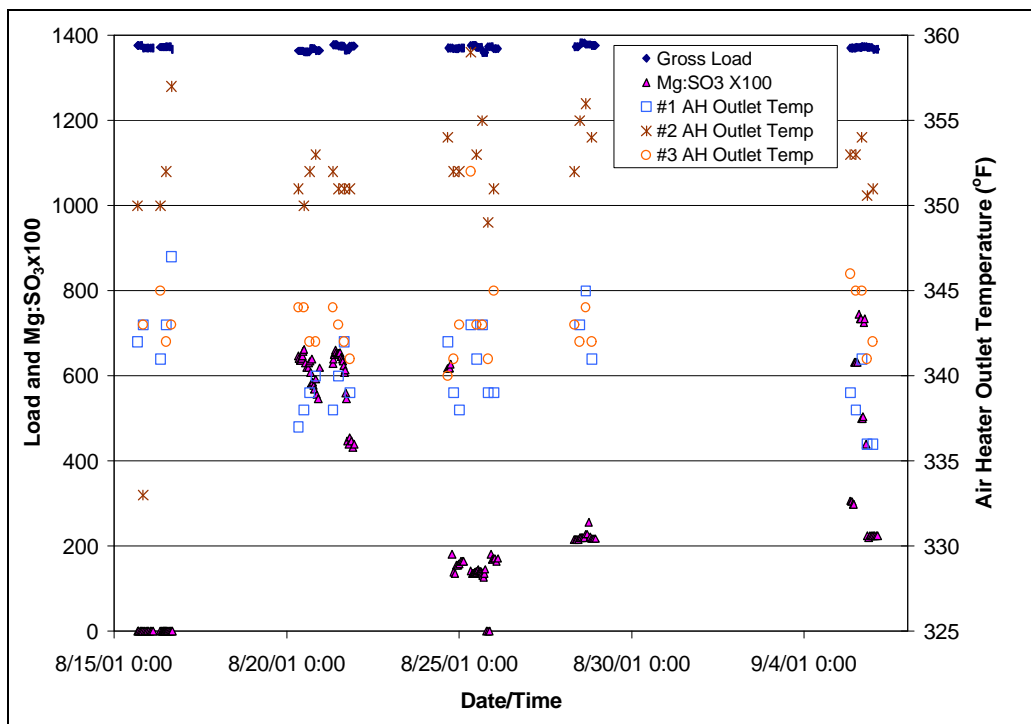

Figure 4-6. Air Heater Outlet Temperature at Full Load (>1360 gross MW) during the Long-term Test at Gavin Plant
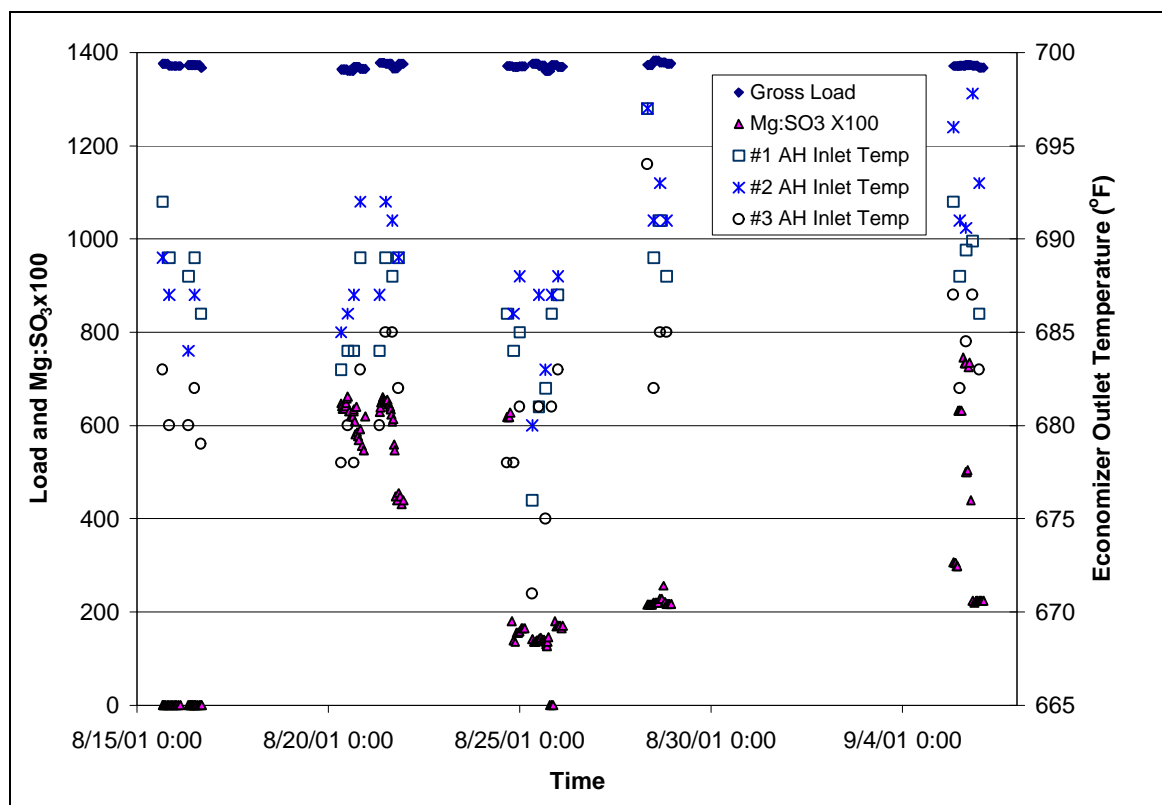
Figure 4-7. Effects of Sorbent Injection on Economizer Outlet Gas Temperatures

economizer outlet flue gas temperature increased with time, from about 680 to 690°F at the beginning of the test to about of 690 to 700°F 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.

4.2.6   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 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 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 4-7.

Table 4-7. Chemical Analyses of Slag Grab Samples (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
Condition	Baseline	Baseline	By-product Mg	By-product Mg	By-product Mg	By-product Mg	By-product Mg	By-product 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 ^{o}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

Generally, slag thickness observed at the 17th floor varied from less than 1 inch to 6 inches, depending on the soot blower schedule. The thickness observed from the 14th, 15th, and 16th floor view ports varied from 2 to 6 inches toward the sides of the furnace, and up to 8 to 10 inches near the center, again, depending on the soot blower schedule. The deposits at the 17th floor level were typically described by the plant operators as "dry," while the slag observed at the 14th through 16th floor levels was often described as "tacky." A review of the operator comments

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 sootblowers were able to remove these deposits during their regular schedule. The following summarizes the chemical analysis results for these samples.

4.2.6.1   17th Floor Samples

As seen in the chemical analyses (Table 4-21), 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.

4.2.6.2   14th/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.

4.2.7   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 sub-micron-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 readings have not been reported by AEP due to regulatory issues related to the Unit 1 plume. Qualitatively, the plume opacity was greatly reduced during both the byproduct Mg and commercial Mg injection periods.

4.3   Summary and Conclusions

During the current reporting period, additional balance-of-plant impact results became available from a previous, long-term (23-day) sorbent injection test conducted at AEP's Gavin Plant. The test was conducted to determine the effects of magnesium-based alkalis injected into the furnace for removing SO_3/sulfuric acid from the flue gas. A summary and conclusions from these new test results are discussed below.

4.3.1   Gavin Station Results

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 fields of the center ESPs, but the downstream fields in these ESPs and all fields of the four 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^oF 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 over approximately 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 pendents. 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. The most dramatic, positive effect of Mg sorbent injection into the furnace for SO_3 control was a substantial reduction in plume visibility from Unit 1.