

# First-Year Operating Experience from the Greenidge Multi-Pollutant Control Project

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## ABSTRACT

The Greenidge Multi-Pollutant Control Project is being conducted as part of the U.S. Department of Energy's (DOE's) Power Plant Improvement Initiative (PPII) to demonstrate an innovative combination of air pollution control technologies that is well suited for reducing emissions of SO<sub>2</sub>, NO<sub>x</sub>, Hg, acid gases (SO<sub>3</sub>, HCl, and HF), and particulate matter (PM) from the vast existing fleet of smaller coal-fired electric generating units (EGUs). A multi-pollutant control system, which includes combustion modifications, a NO<sub>x</sub>OUT CASCADE<sup>®</sup> hybrid selective non-catalytic reduction (SNCR) / in-duct selective catalytic reduction (SCR) system, and a Turbosorp<sup>®</sup> circulating fluidized bed dry scrubbing system (including a new baghouse), was designed specifically to meet the needs of these smaller EGUs by providing deep emission reductions, low capital costs, small space requirements, applicability to a wide variety of coals, mechanical simplicity, and operational flexibility. The system is being demonstrated at AES Greenidge Unit 4 (Boiler 6), a 107 MWe, 1950s vintage, tangentially-fired, reheat unit that burns mid-to-high sulfur eastern U.S. bituminous coal and can co-fire up to 10% biomass.

The multi-pollutant control system was installed at AES Greenidge Unit 4 in 2006 by Babcock Power Environmental Inc. (BPEI), with a capital cost of < \$350/kW and a footprint of < 0.5 acre. Start-up and commissioning were completed in early 2007. This paper focuses on the experience gained from the first year of operation of the system. Apart from several minor issues with its onsite lime hydration system, the Turbosorp<sup>®</sup> scrubber has operated reliably since start-up and has consistently achieved the project's targeted SO<sub>2</sub> removal efficiency of ≥ 95%. Tests conducted in October 2007 demonstrated the system's ability to achieve 96% SO<sub>2</sub> capture when the unit was firing coal with a sulfur content of 4.7 lb SO<sub>2</sub>/mmBtu, which is substantially greater than typical coal sulfur specifications for dry scrubbers. SO<sub>3</sub> and HCl removal efficiencies of > 95% have frequently been observed during performance testing, and particulate matter emissions have been reduced by more than 98% relative to those achieved by the unit's old electrostatic precipitator (ESP). Moreover, all tests performed to-date have demonstrated 93-99% mercury removal as a co-benefit of the hybrid NO<sub>x</sub> control and Turbosorp<sup>®</sup> systems, without the need for any activated carbon injection (ACI). Most of the operational challenges encountered thus far have involved the hybrid SNCR/SCR system. That system attained its NO<sub>x</sub> emissions target of 0.10 lb/mmBtu during short-term testing, but the plant routinely has had to operate at a slightly higher emission rate (0.10-0.15 lb/mmBtu) in order to attain acceptable combustion characteristics, steam temperatures, and ammonia slip. Operation of the in-duct SCR reactor has also been hampered by large particle ash (LPA), which has forced several outages for catalyst cleaning. An LPA removal system is being implemented to mitigate this problem. The effects of the multi-pollutant control system on the unit's emissions profile, operability, and operating costs are discussed in detail, providing valuable information for generators seeking air emissions control retrofit options for their smaller coal-fired EGUs.

## INTRODUCTION

There are about 420 coal-fired electric generating units in the United States with capacities of 50-300 MW<sub>e</sub> that currently are not equipped with selective catalytic reduction, flue gas desulfurization (FGD), or mercury control systems. These smaller units are a valuable part of the nation's energy infrastructure, constituting almost 60 GW of installed capacity. However, with the onset of the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule

(CAVR), a possible mercury MACT (maximum achievable control technology) standard, and various state environmental actions requiring deep reductions in emissions of SO<sub>2</sub>, NO<sub>x</sub>, and Hg, the continued operation of these units increasingly depends upon the ability to identify viable air pollution control retrofit options for them. The large capital costs and sizable space requirements associated with conventional technologies such as SCR and wet FGD make these technologies unattractive for many smaller units.

The Greenidge Multi-Pollutant Control Project, which is part of the U.S. Department of Energy's Power Plant Improvement Initiative, seeks to demonstrate a solution for these units. As part of the project, an innovative combination of technologies including combustion modifications, a NO<sub>x</sub>OUT CASCADE<sup>®</sup> hybrid SNCR/SCR system, and a Turbosorp<sup>®</sup> circulating fluidized bed dry scrubbing system with baghouse ash recycling and activated carbon injection, were installed on the 107 MW<sub>e</sub> (EIA net winter capacity) AES Greenidge Unit 4 in Dresden, NY. Unit 4 (Boiler 6) is a 1953-vintage, tangentially-fired, balanced draft, reheat unit that fires pulverized eastern U.S. bituminous coal as its primary fuel and can co-fire biomass (waste wood) at up to 10% of its heat input. As such, it is representative of many of the 420 smaller coal-fired units identified above. Before the multi-pollutant control project, the unit was equipped with a separated overfire air (SOFA) system for NO<sub>x</sub> control and an electrostatic precipitator (ESP) for particulate matter control; fuel sulfur content was restricted in order to meet its permitted SO<sub>2</sub> emission rate of 3.8 lb/mmBtu.

The Greenidge Project is being conducted by a team including CONSOL Energy Inc. Research & Development as prime contractor (responsible for project administration, performance testing, and reporting), AES Greenidge LLC as host site owner (responsible for site management, permitting, and operation of the multi-pollutant control system), and Babcock Power Environmental Inc. as engineering, procurement, and construction (EPC) contractor. The NO<sub>x</sub>OUT CASCADE<sup>®</sup> technology was supplied by Fuel Tech, and the Turbosorp<sup>®</sup> technology was supplied by BPEI and Austrian Energy and Environment. All funding for the project is being provided by the U.S. DOE, through its National Energy Technology Laboratory, and by AES Greenidge. The overall goal of the Greenidge Project is to show that the multi-pollutant control system being demonstrated, which had a capital cost of less than \$350/kW and occupies a less-than 0.5-acre footprint for the AES Greenidge Unit 4 application, can achieve full-load NO<sub>x</sub> emissions of ≤ 0.10 lb/mmBtu, reduce SO<sub>2</sub> and acid gas (SO<sub>3</sub>, HCl, and HF) emissions by ≥ 95%, and reduce Hg emissions by ≥ 90%, while the unit is firing 2-4% sulfur eastern U.S. bituminous coal and co-firing up to 10% biomass.

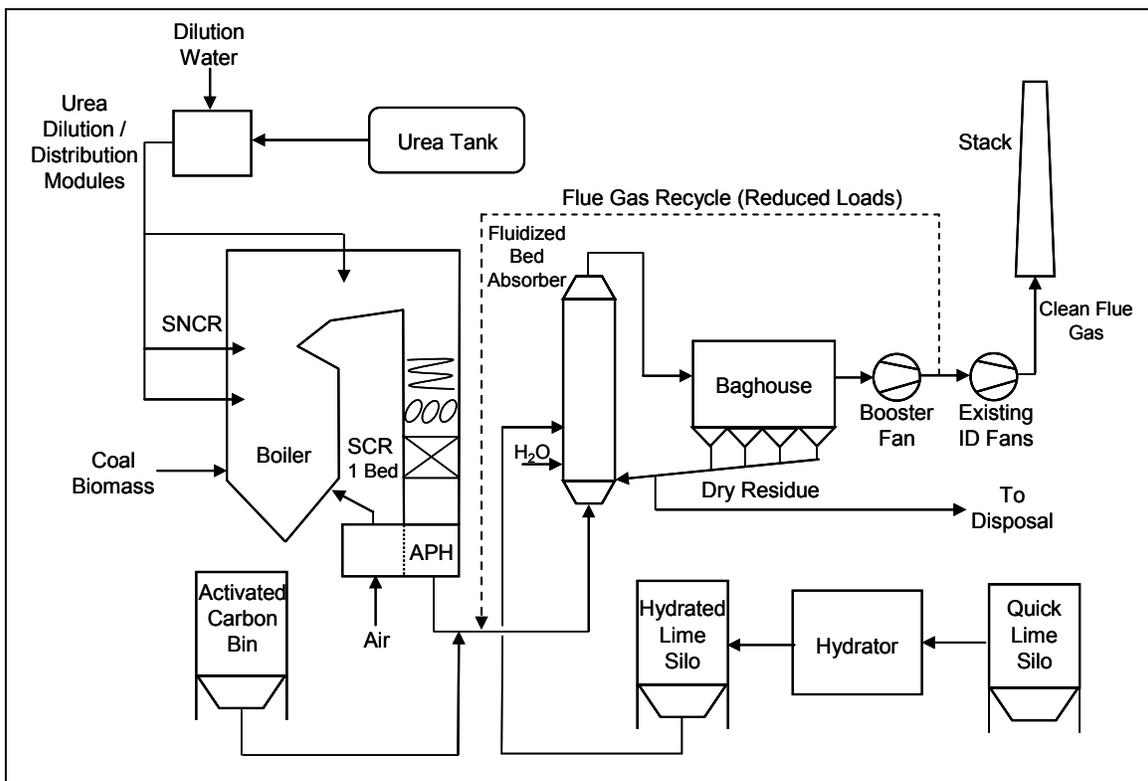
Start-up and commissioning of the multi-pollutant control system at AES Greenidge were completed in early 2007, and the system has now operated commercially for more than one year. This paper focuses on the experience gained during that first year of operation. The effects of the multi-pollutant control system on the unit's emissions profile, operability, and operating costs are discussed in detail, providing valuable information for evaluating the applicability of the multi-pollutant control system to the large fleet of smaller existing coal-fired units.

## **MULTI-POLLUTANT CONTROL SYSTEM DESIGN**

Figure 1 presents a schematic of the process that is being demonstrated as part of the Greenidge Multi-Pollutant Control Project. The multi-pollutant control process was designed to achieve deep emission reductions, approaching those that can be achieved by a conventional full-scale SCR and wet FGD, but with lower capital costs and smaller space requirements than would be required for those conventional technologies. It was also designed to be applicable to a wide variety of coals, including high-sulfur coals, as more than 80% of the 420 candidate units referenced above are located east of the Mississippi River where high-sulfur coals are a likely fuel source. Finally, the process is designed for low maintenance requirements, consistent with the staffing levels at smaller plants, and for operational flexibility, including turndown capabilities for units that routinely cycle load in response to electricity demand. The design for AES Greenidge Unit 4 is based on the use of a 2.9%-sulfur bituminous coal, co-fired with up to 10% waste wood, and on a baseline full-load NO<sub>x</sub> emission rate of ~ 0.30 lb/mmBtu prior to the installation of the new combustion modifications.

NO<sub>x</sub> control is the first step in the process and is accomplished using urea-based, in-furnace SNCR followed by a single-bed SCR reactor that is installed in a modified section of the ductwork between the unit's economizer and its two air heaters. The SCR process is fed exclusively by ammonia slip from the SNCR process. Static mixers located just upstream of the SCR are used to homogenize the velocity, temperature, and composition of the flue gas to promote optimal ammonia utilization and NO<sub>x</sub> reduction across the relatively small SCR catalyst, which consists of a single layer that is ~ 1.3 meters deep. Because the SCR reactor is able to consume ammonia slip

(typically a limiting factor in SNCR design), the upstream SNCR system can operate at lower temperatures than a stand-alone SNCR system would, resulting in improved urea utilization and greater NO<sub>x</sub> removal by the SNCR system, as well as sufficient NH<sub>3</sub> slip to permit additional NO<sub>x</sub> reduction via SCR. The hybrid NO<sub>x</sub> control system at AES Greenidge Unit 4 also includes combustion modifications (low-NO<sub>x</sub> burners and SOFA) to achieve further reductions in NO<sub>x</sub> emissions and to improve the performance of the hybrid SNCR/SCR system. Hence, the system is designed to achieve a full-load NO<sub>x</sub> emission rate of ≤ 0.10 lb/mmBtu by combining the combustion modifications, which are designed to produce NO<sub>x</sub> emissions of 0.25 lb/mmBtu, the SNCR, which is designed to reduce NO<sub>x</sub> by ~ 42% to 0.144 lb/mmBtu, and the SCR, which is designed to further reduce NO<sub>x</sub> by ≥ 30% to ≤ 0.10 lb/mmBtu. The SNCR system at AES Greenidge includes three levels of urea injection. At high generator loads, urea is injected into the mid- and low-temperature zones to maximize NO<sub>x</sub> removal and generate ammonia slip for the SCR reactor. At generator loads that produce economizer outlet temperatures below the minimum operating temperature for the SCR reactor, urea injection into the lowest-temperature zone is discontinued; however, urea continues to be injected into one or both of the mid- and high-temperature zones until the minimum SNCR operating temperature is reached, resulting in continued NO<sub>x</sub> removal of 20-25% via SNCR. Below the minimum SNCR operating temperature, NO<sub>x</sub> emissions continue to be controlled by the unit's low-NO<sub>x</sub> combustion system.



**Figure 1.** Schematic of the multi-pollutant control process being demonstrated at AES Greenidge Unit 4.

Emissions of SO<sub>2</sub> and other acid gases are reduced by ≥ 95% in the Turbosorp® circulating fluidized bed dry scrubber system, which is installed downstream of the air heaters. In the Turbosorp® system, water and dry hydrated lime (Ca(OH)<sub>2</sub>), which is produced from pebble lime in an onsite hydrator installed as part of the project, are injected separately into a fluidized bed absorber. There, the flue gas is evaporatively cooled to within 45 °F of its adiabatic saturation temperature and brought into intimate contact with the hydrated lime reagent in a fast fluidized bed. The basic hydrated lime reacts with the acidic constituents of the flue gas (i.e., SO<sub>2</sub>, SO<sub>3</sub>, HCl, and HF) to form dry solid products (i.e., CaSO<sub>3</sub>, CaSO<sub>4</sub>, CaCl<sub>2</sub>, CaF<sub>2</sub>), which are separated from the flue gas in a new eight-compartment pulse jet baghouse. More than 95% of the collected solids are recycled to the absorber via air slides in order to maximize pollutant removal and lime utilization. As shown in Figure 1, a flue gas recycle system is also included to provide sufficient flue gas flow to maintain a fluidized bed in the absorber at low-load operation. A new booster fan, which was installed upstream of the unit's existing induced-draft fans to overcome the pressure drop created by the installation of the in-duct SCR, fluidized bed absorber, and baghouse, provides the

motive force for flue gas recycle. The booster fan accounts for a majority of the multi-pollutant control system's parasitic power requirement, which totals about 1.6% of the net electric output of AES Greenidge Unit 4.

Because water and dry hydrated lime are injected separately into the Turbosorp<sup>®</sup> absorber vessel, the Ca(OH)<sub>2</sub> injection rate is controlled solely by the SO<sub>2</sub> loading in the flue gas and by the desired SO<sub>2</sub> emission reduction, without being limited by the flue gas temperature or moisture content. As a result, the Turbosorp<sup>®</sup> system affords greater flexibility than a spray dryer for achieving deep emission reductions from a wide range of fuels, including high-sulfur coals. Moreover, the high solids recycle rate from the baghouse to the absorber vessel promotes efficient sorbent utilization in the Turbosorp<sup>®</sup> system. The projected calcium-to-sulfur (Ca/S) molar ratio for the design fuel (4.0 lb SO<sub>2</sub> / mmBtu) is 1.6-1.7, based on moles of inlet SO<sub>2</sub>. Finally, unlike wet FGD systems and spray dryers, the Turbosorp<sup>®</sup> system does not require slurry handling. This is expected to result in reduced maintenance requirements relative to the alternative technologies.

Mercury control in the multi-pollutant control system is accomplished via the co-benefits afforded by the combustion modifications, in-duct SCR, circulating fluidized bed dry scrubber, and baghouse, as well as by injection of activated carbon just upstream of the scrubber as required. From a mercury control perspective, the Greenidge multi-pollutant control process is similar to a conventional air pollution control configuration comprising an SCR, spray dryer, and baghouse. Measurements have demonstrated that this configuration, when applied to plants firing bituminous coals, achieves a high level of mercury removal (i.e., 89-99%) without the need for any mercury-specific control technology. This high level of removal likely results from a combination of factors, including the conversion of elemental mercury (Hg<sup>0</sup>) to oxidized mercury (Hg<sup>2+</sup>) across the SCR catalyst, the removal of Hg<sup>2+</sup> (a Lewis acid) and SO<sub>3</sub> (which can interfere with Hg adsorption on carbon particles) by moistened, basic Ca(OH)<sub>2</sub> particles in the scrubber, and the removal of Hg<sup>2+</sup> and possibly some Hg<sup>0</sup> via adsorption onto carbon-containing fly ash and Ca(OH)<sub>2</sub> at low temperatures in the baghouse, which facilitates contact between gaseous mercury and carbon or other sorbent contained in the dust cake that accumulates on its numerous filter bags. The Greenidge multi-pollutant control process includes all of these components, and hence, it might be expected that its combination of an in-duct SCR, Ca(OH)<sub>2</sub>-based scrubber, and baghouse would result in high mercury removals without any activated carbon injection when applied to bituminous coal-fired units. The combustion modifications also contribute to Hg removal by increasing the unburned carbon content of the fly ash, thereby improving its capacity for Hg capture. In addition, the multi-pollutant control system includes an activated carbon injection system installed upstream of the Turbosorp<sup>®</sup> absorber vessel. Relative to simple duct injection, very effective utilization of the activated carbon and high mercury capture are expected to result from the high solids recycle ratio, long solids residence time, and low temperature (~160 °F) provided by the circulating fluidized bed dry scrubber and baghouse.

Figures 2 and 3 present photographs of the in-duct SCR reactor and Turbosorp<sup>®</sup> system, respectively, at AES Greenidge Unit 4. The SCR reactor is installed in a modified section of ductwork between the unit's economizer and air heaters, and it fits within the existing boiler building in a space with horizontal dimensions of 52 ft by 27 ft and a vertical height of 23 ft. (The cross section of the reactor is 45 ft by 14 ft). Because of this compact reactor design, the hybrid SNCR/SCR system avoids many of the capital costs associated with the multi-bed reactor, structural support steel, foundations, and new ductwork runs required for a conventional stand-alone SCR system. The arrangement of the circulating fluidized bed dry scrubber, baghouse, and associated equipment is also compact. As shown in Figure 3, the various pieces of equipment are vertically tiered to permit gravity-assisted transport of solids where possible, and as a result, the entire installation at AES Greenidge requires only ~ 0.4 acre of land. Unlike a wet FGD system, the Turbosorp<sup>®</sup> system does not produce a saturated flue gas, and therefore it is constructed from carbon steel and does not entail the installation of a new corrosion-resistant stack. These factors, coupled with the mechanical simplicity of the Turbosorp<sup>®</sup> system relative to a wet FGD system, contribute to its comparatively lower capital costs.

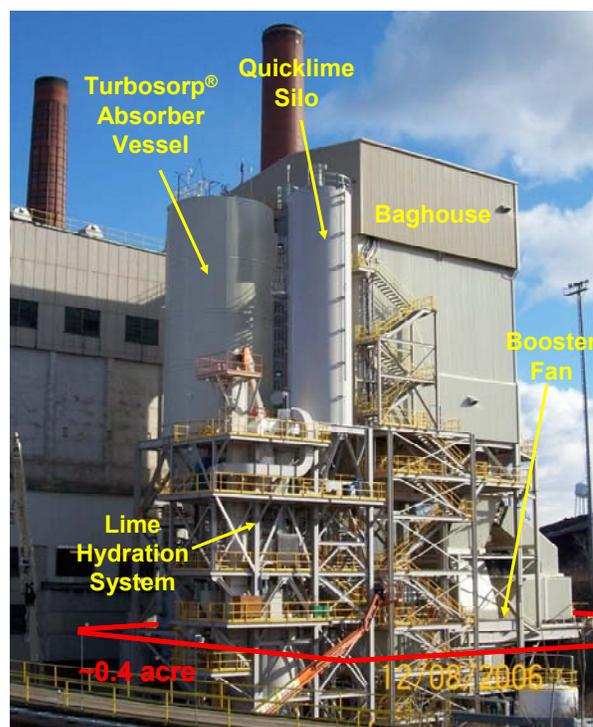
## PERFORMANCE TESTING RESULTS

Guarantee testing of the multi-pollutant control system at AES Greenidge Unit 4 was conducted on March 28-30 and May 1-4, 2007, shortly after start-up and commissioning of the system were completed. During the guarantee test periods, Unit 4 operated at or near full load and fired eastern U.S. bituminous coals containing 2.4-3.2% sulfur. Table 1 summarizes the performance targets and guarantee testing results for NO<sub>x</sub>, SO<sub>2</sub>, Hg, SO<sub>3</sub>, HCl, and HF. As shown in the table, the system demonstrated attainment of its performance targets for each of these species during short-term testing. (HF concentrations were below the detection limit at both the inlet and

outlet of the Turbosorp<sup>®</sup> system, preventing the calculation of a removal efficiency for HF). Additional performance testing results from the first year of operation are discussed in the subsections below.



**Figure 2.** Photograph of the in-duct SCR reactor at AES Greenidge Unit 4.



**Figure 3.** Photograph of the Turbosorp<sup>®</sup> system at AES Greenidge Unit 4.

**Table 1.** Summary of guarantee testing results for the multi-pollutant control system at AES Greenidge Unit 4. All measured performance results represent the average of multiple valid test runs.

Parameter	Performance Target	Measured Performance	Date	Measurement Method
NO <sub>x</sub> emission rate	≤ 0.10 lb/mmBtu	0.10 lb/mmBtu	03/28/07	Stack CEM
SO <sub>2</sub> removal	≥ 95%	96%	03/29/07	Stack CEM (outlet), EPA Method 6C (inlet)
Hg removal	≥ 90%	≥ 95% <sup>a</sup>	03/28/07	Ontario Hydro
Without ACI		≥ 94% <sup>a</sup>	03/30/07	Ontario Hydro
With ACI				
SO <sub>3</sub> removal	≥ 95%	97%	05/02/07	Controlled Condensation
HCl removal	≥ 95%	97%	05/04/07	EPA Method 26A
HF removal	≥ 95%	Indeterminate <sup>b</sup>	05/04/07	EPA Method 26A

<sup>a</sup>Stack concentration was less than the method detection limit for all tests. <sup>b</sup>Concentrations at both the air heater outlet and stack were less than the method detection limit, preventing the calculation of a removal efficiency.

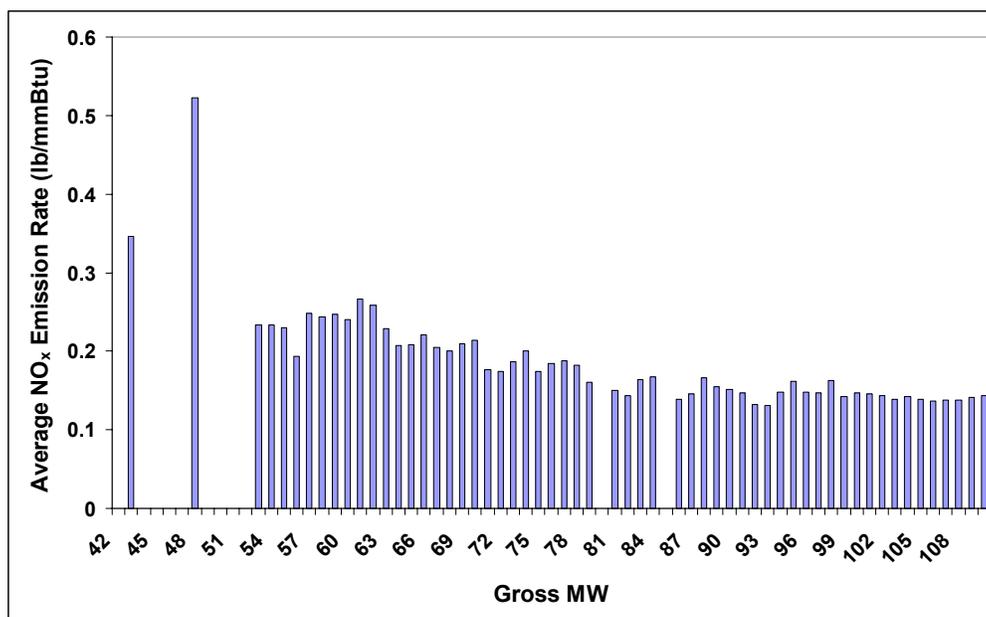
## Oxides of Nitrogen

As shown in Table 1, the hybrid NO<sub>x</sub> control system at AES Greenidge Unit 4 achieved an average full-load NO<sub>x</sub> emission rate of 0.10 lb/mmBtu during short-term testing on March 28, 2007, thereby satisfying its performance target for NO<sub>x</sub> emissions. Urea consumption by the hybrid SNCR/SCR system averaged 49 gal/h during the test period, which equates to a normalized stoichiometric ratio (NSR = 2 x moles of urea ÷ moles of inlet NO<sub>x</sub>) of approximately 1.35, assuming the design NO<sub>x</sub> rate of 0.25 lb/mmBtu leaving the combustion system.

Although the performance target of 0.10 lb/mmBtu was demonstrated during guarantee testing, the plant has been unable to achieve this emission rate in the long term while also maintaining acceptable combustion characteristics, sufficiently high steam temperatures, and sufficiently low ammonia slip for routine operation.

During the guarantee test period, the unit experienced flame attachments that damaged several burners, forcing plant personnel to reduce the aggressiveness of low-NO<sub>x</sub> firing. The NO<sub>x</sub> control problems have been exacerbated by the accumulation of large particle ash (LPA) in the in-duct SCR reactor, which contributes to decreased NO<sub>x</sub> removal efficiency and increased ammonia slip from the reactor. (See the discussion under the Operating and Maintenance Experience section below). As a result, the unit has generally operated with high-load NO<sub>x</sub> emissions of 0.10-0.15 lb/mmBtu since the guarantee testing period. Its permitted NO<sub>x</sub> emission rate is 0.15 lb/mmBtu for gross generator loads above 68 MW. The permitted emission rate increases to 0.28 lb/mmBtu when the gross generator load is between 53 and 68 MW and to 0.35 lb/mmBtu when the gross generator load is between 43 and 52 MW, consistent with the turndown strategy for the hybrid NO<sub>x</sub> control system.

Figure 4 shows average NO<sub>x</sub> emissions from AES Greenidge Unit 4 as a function of gross generator load during January 2008. A freshly cleaned catalyst layer was installed in the in-duct SCR reactor in late December 2007; hence, NO<sub>x</sub> emissions during January were minimally influenced by LPA in the catalyst. The overall average NO<sub>x</sub> emission rate (weighted by heat input) during the month was 0.15 lb/mmBtu, and the average NO<sub>x</sub> emission rate for gross generator loads above 68 MW was 0.14 lb/mmBtu. This NO<sub>x</sub> emission profile is typical of that observed at AES Greenidge Unit 4 during the first year of operation of the multi-pollutant control system.



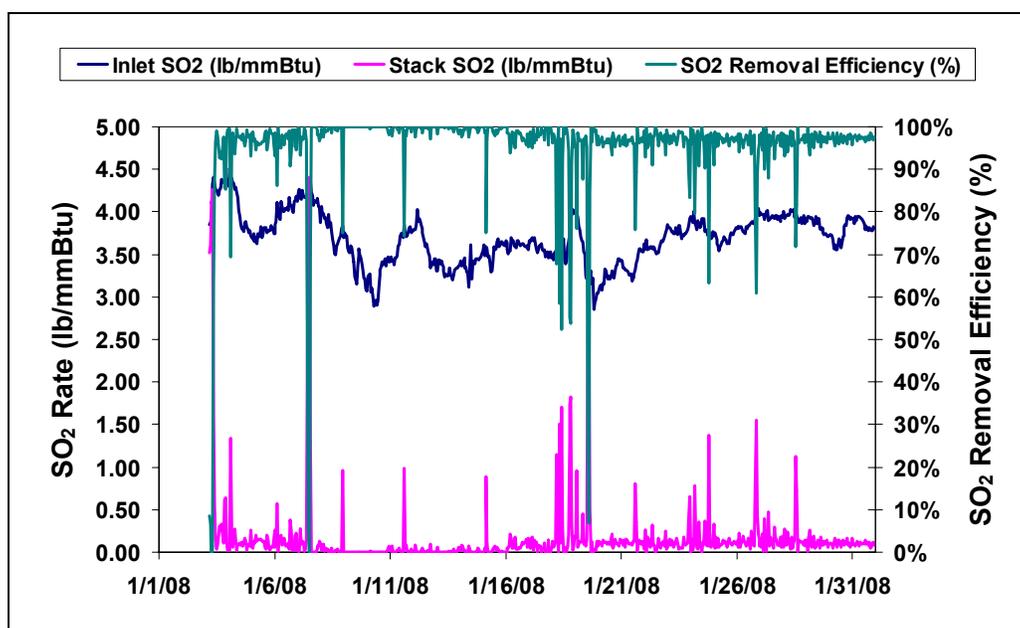
**Figure 4.** NO<sub>x</sub> emissions from AES Greenidge Unit 4 as a function of gross generator load during January 2008. Data were obtained from the unit's stack CEM.

## Sulfur Dioxide

During its first year of operation, the Turbosorp<sup>®</sup> circulating fluidized bed dry scrubber system at AES Greenidge Unit 4 has consistently met or exceeded its performance target of  $\geq 95\%$  SO<sub>2</sub> removal. To exemplify the longer-term SO<sub>2</sub> removal performance of the system, Figure 5 shows the hourly SO<sub>2</sub> rate measured at the inlet and outlet of the Turbosorp<sup>®</sup> system during January 2008, as well as the hourly SO<sub>2</sub> removal percentages calculated from these data. Hourly average inlet SO<sub>2</sub> rates ranged from 2.86 to 4.52 lb/mmBtu during the month. Overall, the Turbosorp<sup>®</sup> system reduced SO<sub>2</sub> emissions from 3.69 lb/mmBtu to 0.14 lb/mmBtu in January, resulting in a removal efficiency of 96.2%. As illustrated in Figure 5, removal efficiencies greater than 99% were observed during a number of one-hour periods.

The economics of the Turbosorp<sup>®</sup> process depend strongly on the amount of hydrated lime required to achieve a given level of SO<sub>2</sub> removal. Figure 6 shows Ca/S molar ratios (based on inlet SO<sub>2</sub>) determined during six days of process performance testing in October 2007. Scrubber operating conditions were varied over the course of these six days. The ratios were calculated from the pebble lime feed rate, change in hydrated lime silo level, and SO<sub>2</sub> concentration measured at the scrubber inlet, and they also were determined independently by chemically analyzing samples of the product ash produced by the Turbosorp<sup>®</sup> system. As shown in Figure 6, the ratios

determined from the product ash analysis exhibited less variability than those computed from process data, likely owing to the long residence time of solids in the system. The process-data-based Ca/S ratios are likely more reflective of day-to-day variations in hydrated lime consumption, although they are susceptible to several sources of measurement error. Nevertheless, these Ca/S ratios generally varied according to expectation during the six days depicted in Figure 6. Higher Ca/S molar ratios were required if the inlet SO<sub>2</sub> concentration, scrubber outlet temperature, or desired SO<sub>2</sub> removal efficiency increased. Process conditions on October 9 and 10 were very similar to the design specification for AES Greenidge Unit 4; the average Ca/S molar ratio computed from process data on these days was 1.7, consistent with the projected range of 1.6-1.7 cited earlier in this paper. The data presented in Figure 6 also illustrate the capability of the Turbosorp<sup>®</sup> system for treating flue gases from high-sulfur coals. On October 2 and 5, the system achieved 96 – 97% SO<sub>2</sub> removal efficiency when the inlet SO<sub>2</sub> rate was 4.5 – 4.7 lb SO<sub>2</sub>/ mmBtu, although this required a somewhat larger Ca/S molar ratio of 2.0 – 2.2.



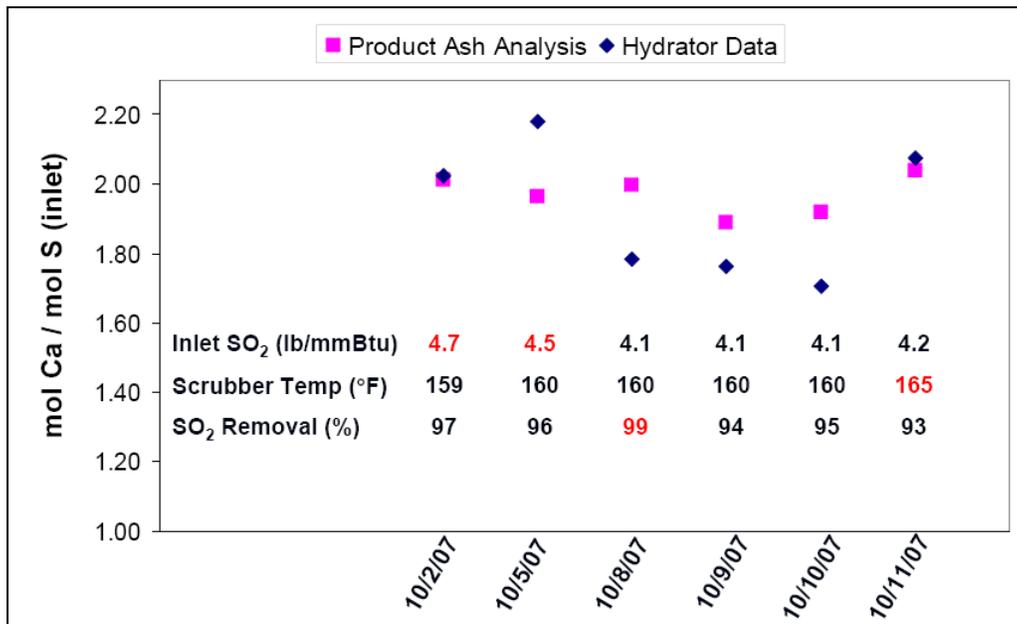
**Figure 5.** Hourly SO<sub>2</sub> measurements at the Turbosorp<sup>®</sup> inlet and stack and hourly SO<sub>2</sub> removal efficiency across the Turbosorp<sup>®</sup> system at AES Greenidge Unit 4 during January 2008. Data were obtained from the unit's air heater outlet SO<sub>2</sub> monitor and stack CEM.

## Mercury

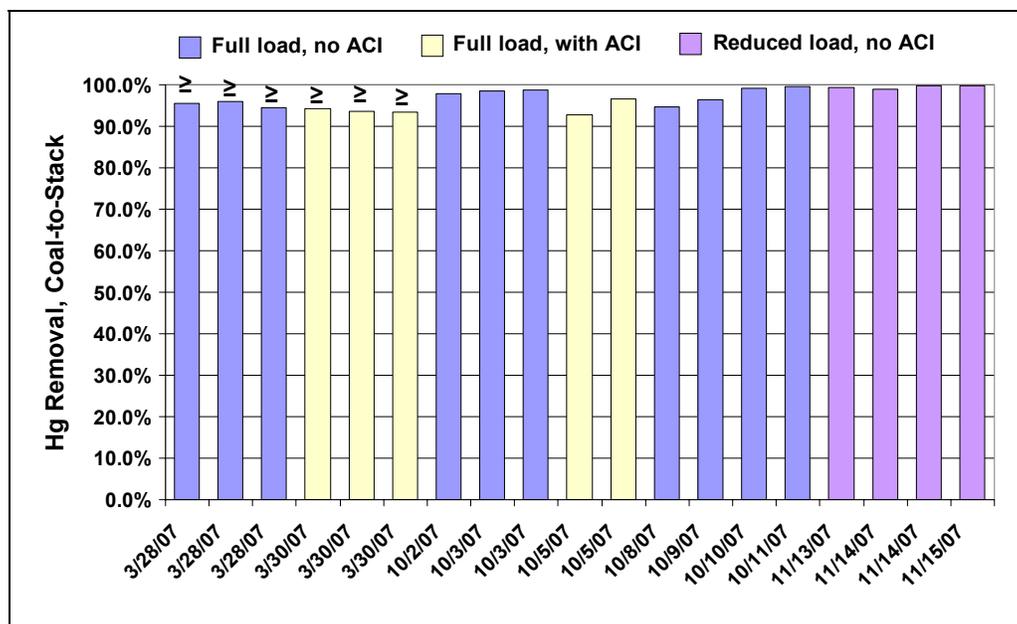
Figure 7 presents the results of all valid mercury tests that were performed at AES Greenidge Unit 4 between March 28 and November 15, 2007. For each test, Hg concentrations at the stack were determined using the Ontario Hydro method (ASTM D 6784-02), and Hg concentrations in the coal were determined by ASTM D 6722. For the guarantee tests on March 28 and 30, the Ontario Hydro samples were analyzed for Hg using cold vapor atomic absorption spectroscopy (CVAAS), and all Hg concentrations at the stack were below the method detection limit. To improve the detection limit, cold vapor atomic fluorescence spectroscopy was employed for all subsequent tests. Hg was detected at the stack for each of these tests, although concentrations were very low. A mercury material balance was performed to verify the validity of each test; material balance closures (Hg out / Hg in) ranged from 80-121% for the tests shown in Figure 7, with an average closure of 105%.

As shown in Table 1, the project's target for coal-to-stack Hg removal efficiency is 90%. All 19 Hg measurements performed between March 28 and November 15 surpassed this target. The coal-to-stack Hg removal efficiencies observed during these tests ranged from 92.8 – 99.8%. Moreover, 14 of the 19 tests were conducted without any activated carbon injection, and all of these exhibited > 90% removal efficiency. (The activated carbon injection rate during the five tests that included ACI was approximately 3 lb/mmacf). During all of the test periods, AES Greenidge Unit 4 fired typical eastern U.S. bituminous coals containing 6.4 – 13.7 lb Hg / TBtu, 3.7 – 4.9 lb SO<sub>2</sub> / mmBtu, and 0.07 – 0.11 % (w/w, dry) Cl. The gross generator load during the reduced-load tests on November 13-15 ranged from 56 to 84 MW; during the other 15 tests, the unit operated between 105 and 109 MW<sub>gross</sub>. The SO<sub>2</sub> removal efficiency across the Turbosorp<sup>®</sup> system varied from 92.9% to 99.0% during the nineteen tests, and

the temperature at the outlet of the fluidized bed absorber varied from 158.6 to 165.2 °F. AES Greenidge Unit 4 produces fly ash with appreciable amounts of unburned carbon. The fly ash carbon content ranged from 9.2 to 25.3% over the course of the 19 Hg tests, likely contributing to the high Hg removal efficiencies that were observed.



**Figure 6.** Calcium-to-sulfur molar ratios computed during six days of process performance testing of the Turbosorp<sup>®</sup> system in October 2007. Ratios were determined both from chemical analysis of scrubber product ash and from process (hydrator) data. Relevant process conditions are also noted.



**Figure 7.** Summary of coal-to-stack Hg removal efficiencies, March-November, 2007.

The average coal-to-stack Hg removal efficiency measured during the 15 full-load tests shown in Figure 7 is ≥ 96%. This represents a more-than 94% reduction over the baseline Hg removal efficiency of 30% measured at AES Greenidge Unit 4 in November 2004, prior to the installation of the multi-pollutant control system. Five additional Hg tests have been conducted at AES Greenidge since November 15, 2007. Material balances are not

yet complete for these tests; hence, they are not included in Figure 7. However, each showed > 95% Hg removal efficiency on the basis of preliminary results.

## Acid Gases

Table 2 summarizes the SO<sub>3</sub>, HCl, and HF concentrations and removal efficiencies that have been measured at AES Greenidge Unit 4 since the installation of the multi-pollutant control system. All SO<sub>3</sub> measurements were conducted using the controlled condensation method, and all HCl and HF measurements were conducted using U.S. EPA Method 26A.

**Table 2.** Summary of results from SO<sub>3</sub>, HCl, and HF testing performed at AES Greenidge Unit 4 between March 29, 2007, and March 13, 2008.

Analyte	Number of Tests	Concentration at Turbosorp <sup>®</sup> Inlet, ppmvd @ 3% O <sub>2</sub> Mean (Range)	Concentration at Stack, ppmvd @ 3% O <sub>2</sub> Mean (Range)	Removal Efficiency, % Mean (Range)
SO <sub>3</sub>	21	11.8 (4.7 - 28.7)	0.7 (0.2 - 1.7)	92.1 (78.8 - 97.4)
HCl	13	38.0 (29.0 - 48.6)	1.4 (0.3 - 2.8)	96.2 (92.2 - 99.1)
HF <sup>a</sup>	9	1.45 (0.87 - 2.07)	<0.17 (<0.15 - <0.20)	>86.9 (>76.7 - >92.0)

<sup>a</sup>Only includes measurements for which the HF concentration at the Turbosorp<sup>®</sup> inlet was above the method detection limit. The inlet HF concentration was below the method detection limit for 5 additional tests.

As shown in Table 1, the Turbosorp<sup>®</sup> system exceeded its performance target for SO<sub>3</sub> removal efficiency (≥ 95%) during guarantee testing on May 2, 2007. The average SO<sub>3</sub> concentration at the inlet to the Turbosorp<sup>®</sup> system that day was 26.5 ppmvd @ 3% O<sub>2</sub>, and the average SO<sub>3</sub> removal efficiency was 97%. SO<sub>3</sub> removal efficiencies observed since the May test period have varied considerably, owing largely to variations in SO<sub>3</sub> concentrations at the Turbosorp<sup>®</sup> inlet, as illustrated in Table 2. These variations are likely due to fluctuations in fuel sulfur content, boiler operating conditions, scrubber operating conditions, and SO<sub>3</sub> removal across the air heater. (Six of the 21 SO<sub>3</sub> measurements summarized in Table 2 were conducted while Unit 4 was operating at reduced load, and four of the measurements were conducted while scrubber operating conditions were purposely being altered). The average SO<sub>3</sub> concentration measured at the stack since the installation of the multi-pollutant control system is 0.7 ppmvd @ 3% O<sub>2</sub>; eighteen of the 21 stack SO<sub>3</sub> concentrations measured to date were less than 1 ppmvd, which approaches the practical field detection limit of the controlled condensation method. Hence, installation of the Turbosorp<sup>®</sup> system has resulted in very low SO<sub>3</sub> emissions from AES Greenidge Unit 4.

The Turbosorp<sup>®</sup> system demonstrated attainment of its performance target for HCl removal efficiency (≥ 95%) throughout its first year of operation. The average HCl removal efficiency measured during 13 tests between March 29, 2007, and March 13, 2008, was 96.2%. HF concentrations at the stack have been below the method detection limit for all 13 tests performed to date. For five of these tests, the HF concentration measured at the inlet to the Turbosorp<sup>®</sup> system was also below the detection limit (i.e., < 0.35 ppmvd @ 3% O<sub>2</sub>). The average HF concentration at the Turbosorp<sup>®</sup> inlet during the remaining nine tests was 1.46 ppmvd @ 3% O<sub>2</sub>, which is less than half the amount predicted from the coal fluorine analysis, and the average HF removal efficiency during these tests was > 86.9%. The disparity between the inlet HF concentration and coal fluorine content has not been resolved.

## Particulate Matter

Installation of the Turbosorp<sup>®</sup> system, including a new baghouse, at AES Greenidge Unit 4 has resulted in a substantial reduction in primary (non-condensable) particulate matter emissions from the unit. The average PM emission rate measured during 22 full-load tests between March 28 and October 11, 2007, following the installation of the multi-pollutant control system, was < 0.001 lb/mmBtu. This represents a more-than 98% reduction over the baseline full-load PM emission rate of 0.063 lb/mmBtu measured in November 2004. The improvement in PM emissions has occurred in spite of the substantial increase in flue gas particulate loading brought about by the hydrated lime, reaction products, and high solid recycle rate in the Turbosorp<sup>®</sup> system. It results largely from the superior performance of the baghouse relative to the unit's old ESP. In addition, the fluidized bed absorber is thought to promote agglomeration of fine particles, making them easier to capture in the downstream PM collection device, although tests have not yet been conducted to confirm this hypothesis.

## OPERATING AND MAINTENANCE EXPERIENCE

The greatest problem encountered during the first year of operation of the multi-pollutant control system at AES Greenidge Unit 4 has been the accumulation of large particle ash in the in-duct SCR catalyst. The project team worked throughout the first year to resolve this problem. Otherwise, operating and maintenance (O&M) requirements have been relatively minor and have been handled by the plant's existing staff. O&M experience during the first year of operation is described in more detail in the subsections below.

### Large Particle Ash

Soon after start-up of the multi-pollutant control system in early 2007, AES Greenidge began experiencing problems with large particle ash accumulation in the in-duct SCR catalyst. The LPA, which consists of pieces of slag that in many cases are too large to pass through the honeycomb catalyst, becomes lodged in the catalyst channels and promotes subsequent accumulation and bridging of fly ash, eventually plugging a substantial portion of the catalyst. This causes an increase in the pressure drop across the SCR reactor. At AES Greenidge, the pressure drop becomes substantial enough over time that it poses an implosion risk for downstream ductwork. As a result, the unit must be derated and/or taken offline for catalyst cleaning. Numerous outages were required for this purpose during the first year of commercial operation of the multi-pollutant control system. LPA accumulation in the SCR catalyst can also contribute to decreased NO<sub>x</sub> removal efficiency, increased ammonia slip, and increased catalyst erosion.

LPA poses a potential problem for many conventional SCR installations, but it is often easily mitigated by installing a screen and hopper at a 90° bend in the ductwork upstream of the reactor. Because of the in-duct SCR design at AES Greenidge, however, the flue gas flow between the economizer and SCR reactor is vertically downward, with no available 90° bends or hoppers. Hence, the development of an effective LPA removal system for this application was very challenging. The solution that has been implemented consists of a sloped screen installed in the ductwork between the economizer and the catalyst, intersecting the static mixers. The screen crosses an expansion joint, and hence, it is installed in two sections. Eight vacuum ports were installed at the base of the screen to remove the collected LPA; soot blowers are located beneath the screen to help transport the LPA to the vacuum ports. The screen, vacuum ports, and two soot blowers were originally installed in May 2007. In September 2007, the two soot blowers were replaced with four rotary soot blowers, and a spring seal was installed to close the gap between screen sections. A rake soot blower was also installed above the SCR catalyst to aid in resuspending accumulated fly ash. In late 2007, patches were installed to eliminate openings in several areas of the screen. These improvements have increased the time between derates and/or catalyst cleaning outages from less than one month to about three months. However, LPA particles that are large enough to plug the catalyst are still passing the screen. A smaller-pitch screen will be installed in May 2008; it is expected that this will significantly reduce the severity of the problem.

### Ammonia Slip

Ammonia slip from the hybrid SNCR/SCR system at AES Greenidge Unit 4 has been greater than expected during the first year of operation. This problem is much less troublesome than the LPA problem described above. However, since AES Greenidge Unit 4 fires high-sulfur coal, ammonia slip is a particular concern because it can cause ammonium bisulfate fouling in the air heaters, thereby decreasing their heat transfer capability and adding pressure drop. As discussed above, the accumulation of LPA in the SCR catalyst likely contributes to the ammonia slip, although ammonia concentrations greater than the target of 2 ppmvd @ 3% O<sub>2</sub> have been observed at the air heater inlet even when the unit was operating with a relatively clean catalyst. Figure 8 summarizes all of the ammonia slip measurements that have been performed to-date. Ammonia concentrations of 2 ppmvd were observed during two tests in late June 2007; otherwise, measured full-load ammonia concentrations at the air heater inlet have ranged from 2.5 to 6.6 ppmvd. The low-load tests on November 13-14, 2007, were conducted while urea was only being injected into the highest-temperature zone of the SNCR system. The average ammonia slip during these tests was 0.2 ppmvd. As shown in Figure 8, the ammonia slip increased rapidly upon introduction of urea into the mid-temperature zone at intermediate load. The high ammonia concentrations on November 16, 2007, and March 10 and 13, 2008, occurred during periods with significant LPA accumulation in the in-duct SCR reactor. Thus far, the higher-than-expected ammonia slip has not significantly affected unit operability or byproduct handling, as it has only led to a need for periodic washing of the air heater

baskets. However, the effect of ammonia slip will continue to be monitored as catalyst activity decreases with time.

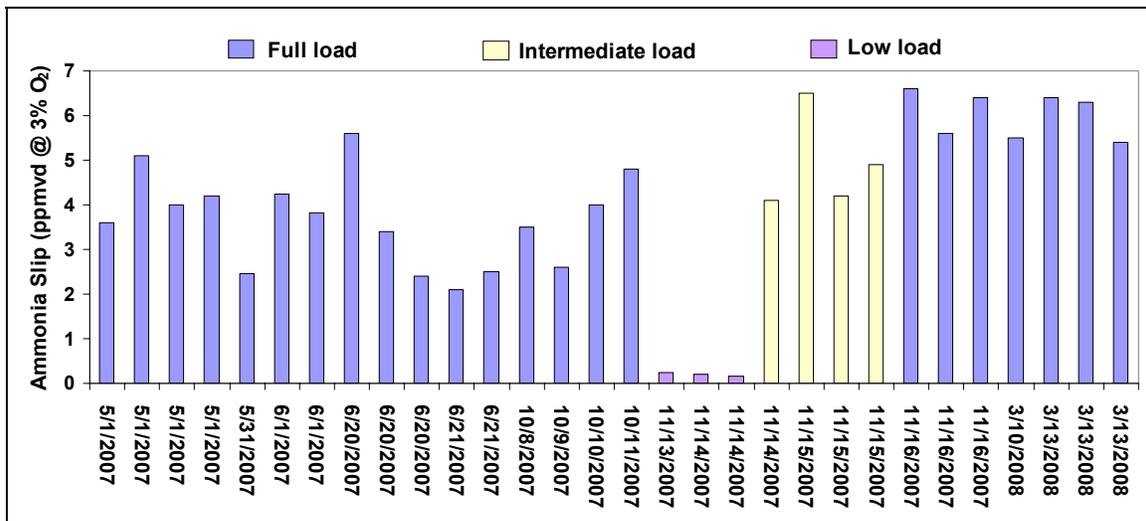


Figure 8. Summary of ammonia slip measurements at the air heater inlet, May 2007–March 2008.

## Turbosorp® System Maintenance Requirements

The majority of the O&M requirements associated with the Turbosorp® system have involved the lime hydration system, which is the most mechanically complex part of the process. The most common problem is plugging in the hydrated lime classification system. Adjustments have been made to reduce the accumulation of fines in the classifier, helping to lessen the severity of the problem. The plant has also encountered some problems with balls escaping from the ball mill and causing damage elsewhere in the system, as well as with freezing of lines and valves during periods of cold weather. On one occasion, the bucket elevator shaft failed, and on another, water was overfed to the hydrator. These problems have usually been resolved without impacting the operation of the Turbosorp® scrubber. Plant personnel can continue to operate the scrubber while the hydrator is offline by using hydrated lime from their onsite inventory or by taking deliveries of hydrated lime. However, in a few instances, lack of hydrated lime availability has forced the unit to derate. Hence, AES is increasing the plant's onsite storage capacity for hydrated lime. A temporary storage tanker was added during the fourth quarter of 2007, and a supplemental, permanent hydrated lime storage silo is planned for construction in 2008.

Routine maintenance requirements in the Turbosorp® system include changing out and cleaning the Turbosorp® water injection lance (about once per week) and unplugging the vents from the ash disposal silos (several times per day). The plant had to install additional compressor capacity to compensate for greater-than-expected compressed air demand from the baghouse. In addition, there have been occasional problems with plugging of lines and dosing valves in the ash recirculation and disposal system. However, no condensation problems have been observed in the absorber vessel or baghouse.

## Byproducts

The major byproduct from the multi-pollutant control system is the product ash from the Turbosorp® system. (The only other byproduct is 19 gpm of once-through cooling water). This product ash is similar to spray dryer ash in that it is a mixture of CaSO<sub>3</sub> and CaSO<sub>4</sub> (including hydrates), fly ash, CaCO<sub>3</sub>, Ca(OH)<sub>2</sub>, CaO, CaCl<sub>2</sub>, CaF<sub>2</sub>, and inerts. It is a dry, free-flowing powder that contains about 1% moisture. Apart from significantly increasing the quantity of material to be handled, the addition of the Turbosorp® system has not caused any major changes in the plant's ash handling practices. Approximately 3.2 tons of scrubber byproduct (excluding fly ash) are produced for each ton of SO<sub>2</sub> removed, assuming design conditions. AES Greenidge currently disposes of the product ash at a landfill adjacent to the plant site. However, the project team is exploring potential beneficial reuses for the ash, which could include use in mine reclamation, use as a structural or flowable fill, or use in manufactured aggregate production. The product ash contains the Hg captured by the multi-pollutant control process. Mercury leaching tests have been performed on seven product ash samples using the Synthetic Precipitation Leaching

Procedure (U.S. EPA Method 1312). For each of these samples, the amount of Hg in the leachate was < 0.35 µg/L (the detection limit for the CVAAS method), which equates to < 1.5% of the total Hg in the ash.

## PROCESS ECONOMICS

Table 3 summarizes the estimated economic performance of the multi-pollutant control system at AES Greenidge Unit 4. The process economics are expressed in constant 2005 dollars, consistent with the start of construction at AES Greenidge, and are based on the design and actual costs (where available) for the Unit 4 installation. Key assumptions are listed below the table. The total EPC capital cost for the multi-pollutant control system (excluding the ACI system, but including all other ancillary equipment) was \$343/kW. This is about 40% less than the estimated cost would have been to retrofit AES Greenidge Unit 4 with conventional SCR and wet FGD systems. Costs for the activated carbon injection system are not shown in Table 3, because testing has shown that the ACI system is not needed to achieve the project's Hg removal target. If included, the ACI system would add about \$6/kW to the EPC capital cost. Total levelized costs, including levelized capital and fixed and variable O&M costs, are about \$3,504 / ton of NO<sub>x</sub> removed and \$567 / ton of SO<sub>2</sub> removed. These prices also cover mercury control, acid gas control, and improved primary particulate matter control, which are co-benefits of the SO<sub>2</sub> and NO<sub>x</sub> control systems and add no incremental cost. The costs for urea in the NO<sub>x</sub> control system and for lime and waste disposal in the Turbosorp<sup>®</sup> system, which are the costs that figure into the unit's dispatch calculations, are \$626 / ton of NO<sub>x</sub> and \$241 / ton of SO<sub>2</sub>, respectively. Hence, installation of the multi-pollutant control system has improved the unit's dispatch economics relative to purchasing allowances.

**Table 3.** Process economics (constant 2005 dollars) for the AES Greenidge Unit 4 design case.

	<b>EPC Capital Cost (\$/kW)</b>	<b>Fixed O&amp;M Costs (\$/MWh)</b>	<b>Variable O&amp;M Costs (\$/MWh)</b>	<b>Total Levelized Cost</b>
NO <sub>x</sub> Control	114 <sup>a</sup>	0.39	0.85	\$3,504 / ton NO <sub>x</sub>
SO <sub>2</sub> Control	229 <sup>b</sup>	0.88	5.26	\$567 / ton SO <sub>2</sub>

<sup>a</sup>Includes combustion modifications, SNCR, in-duct SCR, static mixers, and LPA removal system. <sup>b</sup>Includes scrubber, process water system, lime storage and hydration system, baghouse, ash recirculation system, and booster fan. Assumptions: Plant size = 107 MW net, Capacity factor = 80%, Coal sulfur = 4.0 lb SO<sub>2</sub> / mmBtu, NSR = 1.35, Ca/S = 1.65, NO<sub>x</sub> emissions = 0.10 lb/mmBtu, SO<sub>2</sub> removal efficiency = 95%, 50% urea solution = \$1.35/gal, Pebble lime = \$115/ton, Waste disposal = \$17/ton, Internal COE = \$40/MWh, Plant life = 20 years, Fixed charge factor = 13.05%, AFUDC = 2.35%, Other assumptions based on Greenidge design basis, common cost estimating practices, and market prices.

## CONCLUSIONS

In summary, the multi-pollutant control process being demonstrated at AES Greenidge Unit 4 is uniquely designed to meet the needs of smaller coal-fired units by offering deep emission reductions, low capital costs, small space requirements, applicability to high-sulfur coals, low maintenance requirements, operational flexibility, and improved dispatch economics. The system has routinely achieved ≥ 95% SO<sub>2</sub> and ≥ 90% Hg removal efficiency during its first year of operation, but problems with combustion performance, large particle ash, and ammonia slip have forced it to operate slightly above its NO<sub>x</sub> emission target of 0.10 lb/mmBtu. Co-benefits of the system include substantially reduced SO<sub>3</sub>, HCl, HF, and particulate matter emissions. The LPA problem significantly impacted unit operability during the past year; however, a solution to this problem is being implemented. Additional performance testing will be conducted at AES Greenidge through summer 2008.

## ACKNOWLEDGMENT AND DISCLAIMER

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