The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation

Paper # 15

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ABSTRACT

The Greenidge Multi-Pollutant Control Project is being conducted at the 107-MW AES Greenidge Unit 4 as part of the U.S. Department of Energy's (DOE) Power Plant Improvement Initiative (PPII) to demonstrate an innovative combination of technologies that is well-suited for reducing emissions from the nation's large fleet (~60 GW) of smaller coal-fired units. The technologies, which include a NOxOUT CASCADE® hybrid selective non-catalytic reduction / selective catalytic reduction (SNCR/SCR) system and a Turbosorp® circulating fluidized bed dry scrubber, were installed in 2006 with a capital cost of < \$350/kW and a footprint of < 0.5 acre, substantially less than the cost and space that would have been required for a conventional SCR and wet scrubber.

Testing in 2007 with 2.4-3.2% sulfur coal demonstrated the system's ability to reduce NO_x emissions to 0.10 lb/mmBtu and emissions of SO_2, SO_3, and HCl by 96-97%. Mercury emissions were reduced by more than 95% without any activated carbon injection (ACI). Additional tests have been conducted through mid-2008 to establish the effects of plant operating conditions on the performance of the multi-pollutant control system. These tests have consistently shown at least 95% SO_2 removal, $\geq$ 95% mercury removal (with no activated carbon injection), and very low emissions of SO_3, HCl, and particulate matter. NO_x emissions have averaged between 0.10 and 0.15 lb/mmBtu during longer-term operation. The performance of the multi-pollutant control system during its first year of commercial operation is discussed, and process economics are presented.

INTRODUCTION

The Greenidge Multi-Pollutant Control Project is being conducted as part of the U.S. Department of Energy's Power Plant Improvement Initiative to demonstrate an air emissions control retrofit option that is well-suited for the nation's vast existing fleet of smaller, uncontrolled coal-fired

electric generating units (EGUs). There are about 420 coal-fired EGUs in the United States with capacities of 50-300 MW$_e$ 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 various state and federal environmental regulations requiring deep reductions in emissions of SO_2, NO_x, 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 Project seeks to establish the commercial readiness of a multi-pollutant control system that is designed to meet the needs of smaller coal-fired EGUs by offering deep emission reductions, low capital costs, small space requirements, applicability to high-sulfur coals, low maintenance requirements, and good turndown capabilities. The system includes combustion modifications and a NOxOUT CASCADE® hybrid SNCR/SCR system for NO_x control, as well as a Turbosorp® circulating fluidized bed dry scrubber for SO_2, SO_3, HCl, and HF control. A baghouse, integral to the Turbosorp® system, provides particulate control. Baghouse ash is recycled to the scrubber to improve sorbent utilization. Mercury control is accomplished via the co-benefits afforded by the in-duct SCR, Turbosorp® scrubber, and baghouse, and, if required, by injection of activated carbon upstream of the scrubber.

The multi-pollutant control system is being demonstrated at the 107 MW$_e$ (Energy Information Administration 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 described above. Before the multi-pollutant control project, the unit was equipped with a separated overfire air (SOFA) system for NO_x control and an electrostatic precipitator (ESP) for particulate matter control; fuel sulfur content was restricted in order to meet its permitted SO_2 emission rate of 3.8 lb/mmBtu.

The Greenidge Project is being conducted by a team including CONSOL Energy Inc. Research & Development (CONSOL R&D) 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. (BPEI) as engineering, procurement, and construction (EPC) contractor. The NOxOUT CASCADE® technology was supplied by Fuel Tech under subcontract to BPEI; the SCR reactor was supplied by BPEI, and the Turbosorp® technology was supplied by BPEI under license from 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 less than 0.5 acre for the AES Greenidge Unit 4 application, can achieve full-load NO_x emissions of ≤ 0.10 lb/mmBtu, reduce SO_2 and acid gas (SO_3, HCl, and HF) emissions by $\geq 95\%$, and reduce Hg emissions by $\geq 90\%$, 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. During that time, the performance of the multi-pollutant control system has been monitored closely using plant operating data and data that were generated during a series of performance testing campaigns led by CONSOL R&D. This paper focuses on key performance results observed between March 2007 and May 2008. Process economics incorporating these performance results are also presented.

PROCESS DESIGN

Figure 1 presents a schematic of the multi-pollutant control process that is being demonstrated as part of the Greenidge Project. The design for AES Greenidge Unit 4 retrofit 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_x emission rate of ~ 0.30 lb/mmBtu prior to the installation of the new combustion modifications.

Figure 1. Schematic of the multi-pollutant control process being demonstrated at AES Greenidge Unit 4.
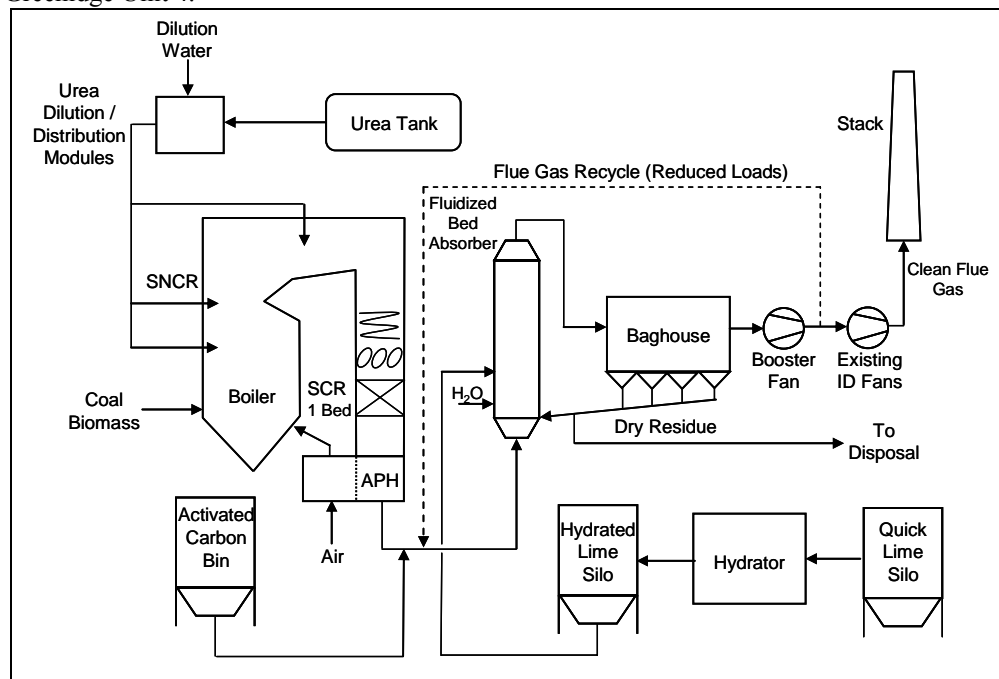
NO_x control is the first step in the process and is accomplished using urea-based, in-furnace SNCR followed by a single-layer SCR reactor that is installed in a modified section of the ductwork between the unit's economizer and its two air heaters. The SCR process is fed exclusively by ammonia slip 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_x 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_x removal by the SNCR system, as well as sufficient NH_3 slip to permit additional NO_x

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reduction via SCR. The hybrid NO_x control system at AES Greenidge Unit 4 also includes combustion modifications (low-NO_x burners and SOFA) to achieve further reductions in NO_x emissions and to improve the performance of the hybrid SNCR/SCR system. Hence, the system is designed to achieve a full-load NO_x emission rate of ≤ 0.10 lb/mmBtu by combining the combustion modifications, which are designed to produce NO_x emissions of 0.25 lb/mmBtu, the SNCR, which is designed to reduce NO_x by $\sim 42\%$ to 0.144 lb/mmBtu, and the SCR, which is designed to further reduce NO_x by $\geq 30\%$ to ≤ 0.10 lb/mmBtu. The SNCR system at AES Greenidge includes three zones of urea injection. At high generator loads, urea is injected into the mid- and low-temperature zones to maximize NO_x 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_x removal of 20-25% via SNCR. Below the minimum SNCR operating temperature, NO_x emissions continue to be controlled by the unit's low-NO_x combustion system.

Emissions of SO_2 and other acid gases are reduced by $\geq 95\%$ 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 ($Ca(OH)_2$), 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_2, SO_3, HCl, and HF) to form dry solid products (i.e., hydrates of $CaSO_3$ and $CaSO_4$, $CaCl_2$, CaF_2), 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 1.8% of the net electric output of AES Greenidge Unit 4.

Because water and dry hydrated lime are injected separately into the Turbosorp® absorber vessel, the hydrated lime injection rate is controlled solely by the SO_2 loading in the flue gas and by the desired SO_2 emission reduction, without being limited by the flue gas temperature or moisture content. As a result, the Turbosorp® system affords greater flexibility than a spray dryer for achieving deep emission reductions from a wide range of fuels, including high-sulfur coals. This is an important feature, as more than 80% of the 420 candidate units identified earlier are located east of the Mississippi River, where high-sulfur coal is a potential fuel source. The high solids recycle rate from the baghouse to the absorber vessel promotes efficient sorbent utilization in the Turbosorp® system. The projected calcium-to-sulfur (Ca/S) molar ratio for the design fuel (4.0 lb SO_2 / mmBtu) is 1.6-1.7, based on moles of inlet SO_2. Finally, unlike wet FGD systems and spray dryers, the Turbosorp® system does not require slurry handling. This is expected to result in reduced maintenance requirements relative to the alternative technologies.

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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, and, if required, by injection of activated carbon just upstream of the scrubber. 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 coal, achieves a high level of mercury removal (i.e., 89-99%) without the need for any mercury-specific control technology.[1] This high level of removal likely results from a combination of factors, including the conversion of elemental mercury (Hg^0) to oxidized mercury (Hg^{2+}) across the SCR catalyst, the removal of Hg^{2+} (a Lewis acid) and SO_3 (which can interfere with Hg adsorption on carbon particles) by moistened, basic $Ca(OH)_2$ particles in the scrubber, and the removal of Hg^{2+} and Hg^0 via adsorption onto carbon-containing fly ash and $Ca(OH)_2$ 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, $Ca(OH)_2$-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 (including those that were in place prior to installation of the multi-pollutant control system) 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® 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® system, respectively, at AES Greenidge Unit 4. The SCR reactor 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-layer 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® 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® system relative to a wet FGD system, contribute to its comparatively lower capital costs.

PERFORMANCE AND COST RESULTS

Circulating Fluidized Bed Dry Scrubber

Guarantee testing of the multi-pollutant control system at AES Greenidge Unit 4 was completed during March – May 2007. The Turbosorp® system demonstrated attainment of its performance

target for SO_2 removal efficiency on March 29, achieving 96% removal while the unit fired coal with a sulfur content of 3.8 lb SO_2 / mmBtu. (SO_2 was measured at the scrubber inlet using EPA Method 6C and at the stack using the unit's continuous emissions monitor).

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

Figure 3. Photograph of the Turbosorp® system at AES Greenidge Unit 4.
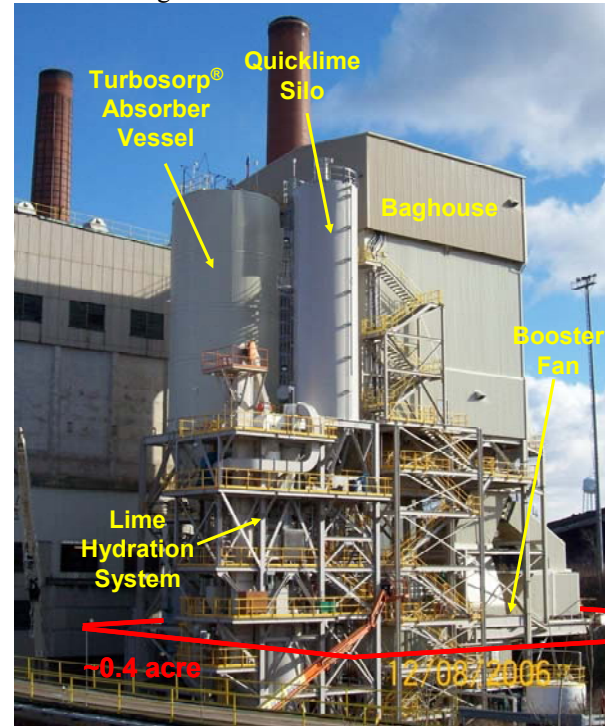
This level of performance continued throughout the first year of operation of the Turbosorp® system while Unit 4 fired mid-to-high sulfur eastern U.S. bituminous coals. To exemplify the longer-term SO_2 reduction efficiency of the circulating fluidized bed dry scrubber, Figure 4 shows the hourly SO_2 rate measured at the Turbosorp® inlet and stack during the first three months of 2008, as well as the hourly SO_2 removal percentages calculated from these data. Hourly average inlet SO_2 rates ranged from 2.62 to 4.52 lb/mmBtu during the quarter. Overall, the Turbosorp® system reduced SO_2 emissions from 3.41 lb/mmBtu to 0.13 lb/mmBtu during January-March, resulting in a removal efficiency of 96.3%.

AES Greenidge routinely operates the scrubber with an SO_2 emission rate set point of 0.10 lb/mmBtu, which is below its permitted emission rate of 0.19 lb/mmBtu (30-day rolling average), in order to provide a margin for transient upsets in system performance. These upsets, which are evidenced by the spikes in stack SO_2 emission rate in Figure 4, can be caused either by routine operating and maintenance activities (e.g., change-out of the water injection lance) or by unexpected equipment problems (e.g., frozen valves and pressure transmitters during cold weather periods). However, such upsets occur infrequently, and the Turbosorp® system has easily maintained SO_2 emissions within the unit's permit limit. The system is also capable of attaining very deep SO_2 removal efficiencies, even when the unit fires high-sulfur coals. During the three months depicted in Figure 4, removal efficiencies ≥ 99% were observed during 23% of the one-hour periods for which SO_2 data were available. Moreover, during performance testing in October

2007, the scrubber achieved 96-97% SO_2 removal while Unit 4 fired coal containing 4.5-4.9 lb SO_2 / mmBtu.

Figure 4. SO_2 removal performance of the Turbosorp® system at AES Greenidge Unit 4 during January-March 2008. Data were obtained from the unit's air heater outlet SO_2 monitor and stack continuous emissions monitor.
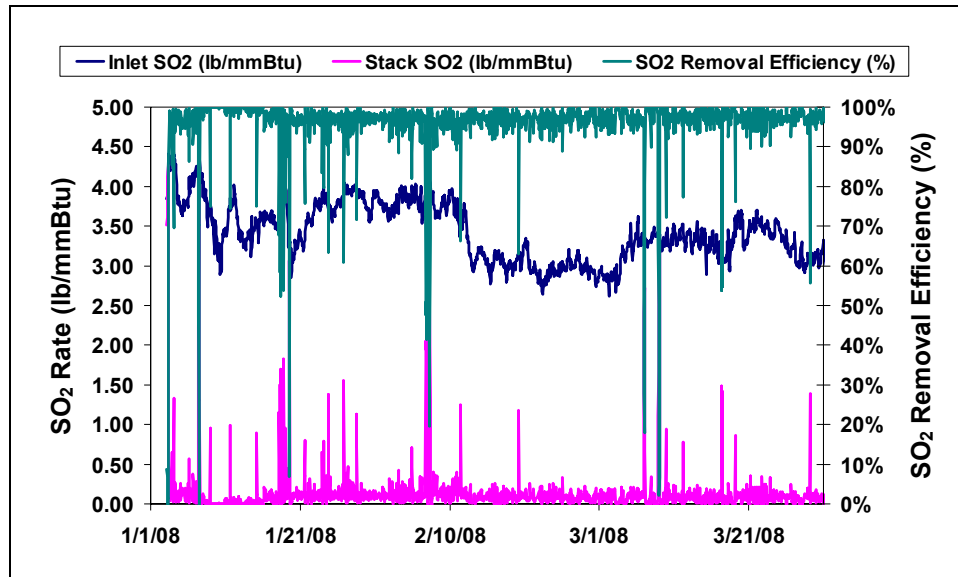
The variable operating costs of the Turbosorp® process depend strongly on the amount of hydrated lime required to achieve a given level of SO_2 removal. Ca/S molar ratios (based on inlet SO_2) were estimated during six days of process performance testing in October 2007. Scrubber operating conditions were varied over the course of these six days. The ratios were derived from the pebble lime feed rate, change in hydrated lime silo level, and coal feed rate and sulfur content measured on each day. For each daily ratio, the number of moles of calcium is based on the available $Ca(OH)_2$ content of hydrated lime samples collected on that day, and the number of moles of inlet sulfur is computed as 95% of the sulfur fed with the coal. (Available $Ca(OH)_2$, determined in accordance with ASTM C25, averaged 96% of the total elemental calcium in the samples). It is important to recognize that these Ca/S ratios depend on a number of measurements and, hence, are susceptible to several sources of error. Nevertheless, the ratios generally varied according to expectation. Process conditions on October 9 and 10 (coal sulfur content = 4.1 lb SO_2 / mmBtu, SO_2 removal efficiency = 95%, Turbosorp® outlet temperature = 160 ºF) 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 1.68, consistent with the projected range of 1.6-1.7 cited earlier in this paper. Higher Ca/S molar ratios (average = 2.0) were required on the first two days of testing, when the coal sulfur content (average = 4.6 lb SO_2 / mmBtu) and SO_2 removal efficiency (average = 97%) were greater than design conditions, and on the last day, when the scrubber outlet temperature was raised by 5 ºF from its typical set point of 160 ºF. (The coal sulfur content on this last day of testing was 4.2 lb SO_2 / mmBtu, and the SO_2 removal efficiency was 93%). Additional parametric testing of the Turbosorp® system was conducted on June 16-19, 2008, to elucidate the relationships between SO_2 removal efficiency, approach to adiabatic saturation, and Ca/S; however, results of this testing are not yet available.

Sorbent utilization in the Turbosorp® system was also analyzed over the six-month period from August 1, 2007, through January 31, 2008, using lime delivery data (i.e., truck weights) and SO_2 data from the plant's online analyzers. During this period, the average SO_2 rate measured at the inlet to the Turbosorp® scrubber was 3.83 lb/mmBtu, and the average SO_2 removal efficiency was 95.9%. Lime consumption (measured as available CaO) totaled 10,792 tons, and the amount of SO_2 fed to the scrubber totaled 6,848 tons, resulting in an average Ca/S molar ratio of 1.80. This is slightly greater than the targeted ratio of 1.6-1.7, although the SO_2 removal efficiency was slightly higher than the design efficiency of 95%, and the calculation is susceptible to a number of sources of measurement error, including errors in the truck weights, stack flow rate measurements, available CaO measurements, and SO_2 measurements. (The SO_2 content measured at the scrubber inlet tends to be biased low relative to the coal sulfur content).

The Turbosorp® system also achieved its performance targets for SO_3 and HCl removal efficiency (both ≥ 95%) during guarantee testing in May 2007. The average SO_3 removal efficiency measured during the May test period (using the controlled condensation method) was 97.1%, and the average HCl removal efficiency measured during that period (using U.S. EPA Method 26A) was 97.2%. (HF concentrations were also measured using Method 26A; however, concentrations at the inlet and outlet of the scrubber were near or below the method detection limit, precluding the determination of a removal efficiency). Table 1 summarizes all of the SO_3 and HCl measurements that have been performed at AES Greenidge Unit 4 through May 2008. The average HCl removal efficiency observed during 18 tests between March 2007 and May 2008 was 96.1%. SO_3 removal efficiencies measured since the guarantee test period have varied considerably, owing largely to variations in SO_3 concentrations at the Turbosorp® inlet. These variations in removal efficiency are likely due to fluctuations in fuel sulfur content, boiler operating conditions, scrubber operating conditions, and SO_3 removal across the air heater. (During the SO_3 tests, unit loads varied from 55 MW_g to 109 MW_g; coal sulfur content varied from 3 lb/mmBtu to 5 lb/mmBtu, and SO_2 removal efficiency varied from < 85% to > 99%). The average SO_3 concentration measured at the stack since the installation of the multi-pollutant control system is 0.7 ppmvd @ 3% O_2; twenty-three of the 26 stack SO_3 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® system has resulted in very low SO_3 emissions from AES Greenidge Unit 4.

Table 1. Summary of results from SO_3 and HCl testing performed at AES Greenidge Unit 4 between March 29, 2007, and May 22, 2008. SO_3 was measured using the controlled condensation method, and HCl was measured using U.S. EPA Method 26A.

Analyte	Number of Tests	Concentration at Turbosorp® Inlet, ppmvd @ 3% O_2 Mean (Range)	Concentration at Stack, ppmvd @ 3% O_2 Mean (Range)	Removal Efficiency, % Mean (Range)
SO_3	26	12.1 (4.7 - 28.7)	0.7 (0.2 - 1.7)	93.0 (78.8 - 98.4)
HCl	18	36.9 (26.1 - 48.6)	1.4 (0.2 - 2.9)	96.1 (89.5 - 99.4)

Installation of the Turbosorp® system, including a new baghouse, at AES Greenidge Unit 4 has resulted in a substantial reduction in primary (non-condensable) particulate matter (PM) emissions from the unit. Figure 5 compares PM emission rates measured before and after installation of the system (using U.S. EPA Method 5 or 17). The average PM emission rate measured during 30 full-load tests between March 2007 and March 2008, 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 average PM emission rate observed during 11 reduced-load tests in November 2007 and May 2008 was similarly < 0.001 lb/mmBtu). 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 solids recycle rate in the Turbosorp® system. It results largely from the superior performance of the baghouse relative to the unit's old ESP. Particle agglomeration in the fluidized bed absorber may also contribute to improved PM capture efficiency.

Figure 5. Summary of particulate matter emission rates measured at AES Greenidge Unit 4 before and after installation of the multi-pollutant control system. Error bars represent ± 1 standard deviation.
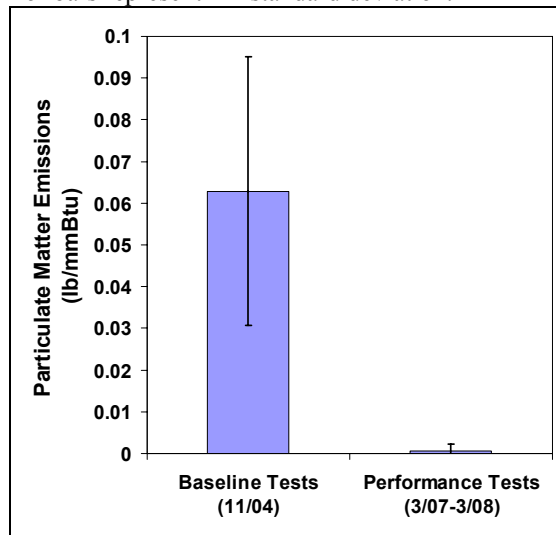
As discussed above, the Turbosorp® system is mechanically simple relative to many alternative FGD technologies, and therefore, it is expected to afford low maintenance requirements. This has generally been true at AES Greenidge during the first year of operation of the system. AES has been able to operate and maintain the Turbosorp® system (and the rest of the multi-pollutant control system) without adding any new operating and maintenance (O&M) personnel. 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 has been plugging in the hydrated lime classification system. Problems with the lime hydration system 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. Other 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). In addition, there have been occasional problems with malfunctioning instruments and with plugging of lines and valves in the ash recirculation and disposal system. However, no condensation problems have been observed in the absorber vessel or baghouse.

The only major byproduct from the multi-pollutant control system is the product ash from the Turbosorp® system, which is very similar to spray dryer ash. Approximately 3.2 tons of scrubber byproduct (excluding fly ash) are produced for each ton of SO_2 removed, assuming design conditions. AES Greenidge generally disposes of the product ash at a landfill adjacent to the plant site. However, plant personnel succeeded in supplying 3,500 tons of product ash for use as flowable fill, and the project team continues to seek potential beneficial reuses for the ash, which could also include use in mine reclamation or use in manufactured aggregate production.

Hybrid NO_x Control System

The hybrid NO_x control system has significantly reduced NO_x emissions from AES Greenidge Unit 4, although it has performed less optimally than the Turbosorp® system. During guarantee testing on March 28, 2007, the combustion modifications and hybrid SNCR/SCR system demonstrated an average full-load NO_x emission rate of 0.10 lb/mmBtu, thereby satisfying the project's performance target for NO_x emissions. However, AES Greenidge 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_x firing. This change in turn caused boiler conditions to deviate from the design basis for the SNCR system, promoting less-than-optimal performance of that system. The NO_x control problems have been exacerbated by the accumulation of large particle ash (LPA) in the in-duct SCR reactor, which contributes to decreased NO_x removal efficiency and increased ammonia slip from the reactor. As a result, the unit has generally operated with high-load NO_x emissions of 0.10-0.15 lb/mmBtu since the guarantee testing period.

Figure 6 shows average NO_x emissions from AES Greenidge Unit 4 as a function of gross generator load during the first three months of 2008. As illustrated in the figure, the unit's permit limit varies according to the turndown strategy for the hybrid NO_x control system. The permitted NO_x emission rate is 0.15 lb/mmBtu for gross generator loads above 68 MW, but it 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. The overall average NO_x emission rate during January-March 2008 was 0.15 lb/mmBtu. The average NO_x emission rate for gross generator loads above 68 MW was 0.14 lb/mmBtu, and the average rate for gross generator loads between 53 and 68 MW was 0.23 lb/mmBtu. This NO_x 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 7 illustrates the relationship between unit load, urea injection scheme, and ammonia slip for the hybrid SNCR/SCR system at AES Greenidge Unit 4. Data were obtained during parametric testing of the system in November 2007 and May 2008. As discussed earlier, at low load, urea is only injected into Zone 1 (high-temperature zone), and at high load, urea is only injected into Zone 2 (mid-temperature zone) and Zone 3 (low-temperature zone). Injection of urea into lower-temperature regions of the boiler generates ammonia; however, the SCR reactor is designed to consume almost all of this ammonia via reaction with NO_x, leaving very little ammonia slip at the air heater inlet. Ammonia slip can cause ammonium bisulfate fouling in the air heaters; hence, it is a particular concern for plants like AES Greenidge that fire high-sulfur coal. The project's targeted ammonia slip for all unit loads is ≤ 2 ppmvd (corrected to 3% O_2) at the air heater inlet.

As shown in Figure 7, the ammonia slip is well within this target at low unit load, but it increases rapidly upon introduction of urea into Zone 2 at intermediate load. Ammonia slip concentrations measured at mid and high unit loads during the project's performance evaluation period have ranged from 2 to 7 ppmvd @ 3% O_2. 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 6. NO_x emissions (stack continuous emissions monitor) as a function of gross load at AES Greenidge Unit 4 during January-March 2008. The red line indicates the unit's permit limit (30-day rolling average).
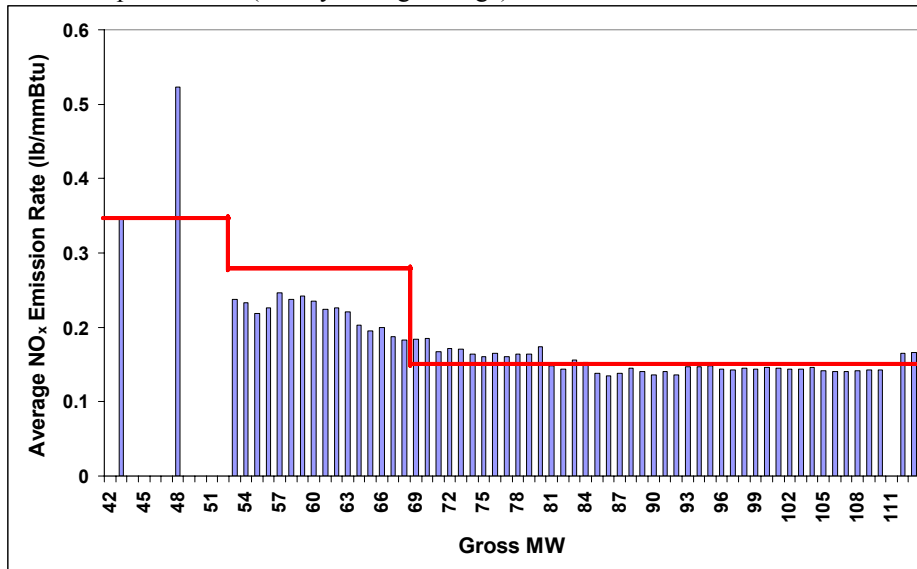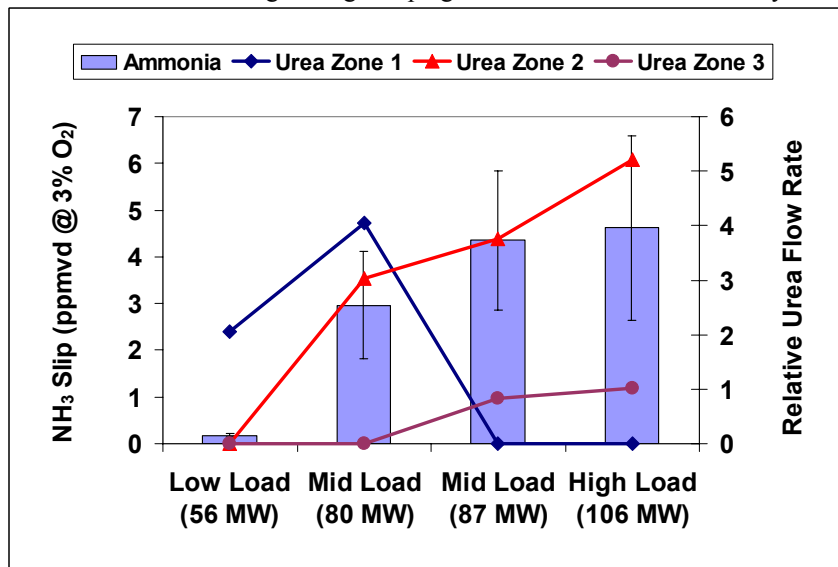

Figure 7. Ammonia slip as a function of gross unit load and urea injection regime at AES Greenidge Unit 4. Ammonia was measured at the air heater inlet using U.S. EPA CTM 027 during testing campaigns in November 2007 and May 2008.

Ammonium bisulfate fouling is also promoted by high concentrations of SO_3 in the flue gas. The catalyst in the hybrid SNCR/SCR system fosters the oxidation of a small portion of SO_2 to SO_3. During performance testing of the multi-pollutant control system in March 2008, SO_3 concentrations were measured at the inlet and outlet of the SCR reactor, as well as at the air heater outlet and stack, in order to evaluate the SO_2-to-SO_3 conversion across the catalyst. The average SO_3 concentrations measured during four test runs were 10.1 ppmvd at the SCR inlet, 18.4 ppmvd at the SCR outlet, 7.7 ppmvd at the air heater outlet, and 0.7 ppmvd at the stack (all concentrations corrected to 3% O_2). The increase in SO_3 concentration across the SCR reactor corresponded to an SO_2-to-SO_3 conversion rate of 0.5%, which is within the project's target of < 1% conversion. The significant decrease in the measured SO_3 concentration between the SCR outlet and air heater outlet may reflect the formation of ammonium bisulfate in the air heaters, especially given the relatively high ammonia slip (5.9 ppmvd @ 3% O_2) observed during the test period. It may also result simply from the condensation of SO_3 as sulfuric acid on the air heater baskets and its subsequent loss to the incoming combustion air.

The most troublesome problem encountered during operation of the multi-pollutant control system at AES Greenidge has been the accumulation of large particle ash in the in-duct SCR reactor. 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 could cause downstream ductwork to collapse. As a result, the unit must be derated and/or taken offline for catalyst cleaning. LPA accumulation in the SCR catalyst can also contribute to decreased NO_x removal efficiency, increased ammonia slip, and increased catalyst erosion.

The development of an effective LPA removal system for the in-duct SCR at AES Greenidge Unit 4 has been very challenging. The flue gas flows vertically downward between the economizer and SCR reactor, with no available 90° bends or hoppers that can be used for inertial capture of the LPA (as is often done in conventional SCR installations). The solution that has been implemented consists of a sloped screen installed in the ductwork between the economizer and the catalyst to remove the LPA from the flue gas. 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 spite of these improvements, however, LPA particles that were large enough to plug the catalyst still passed the screen. This is evident in Figure 8, which shows the pressure drop across the SCR catalyst and LPA screen as a function of time from July-December 2007. Accumulated LPA and fly ash were cleaned from the reactor during six outages in this six-month period. (Four of these outages were a direct result of the LPA problem, and two were caused by other plant problems). In late 2007, patches were installed to eliminate openings in several areas of the screen, and the catalyst was replaced with a clean layer. Unit 4 operated from January 3-May 2, 2008, without an outage, although it was derated for the last month of this period because of elevated pressure drop across the in-duct SCR reactor and air heaters. In May 2008, the existing LPA screen was removed and

replaced with a new, smaller-pitch screen to more efficiently remove small pieces of LPA from the flue gas. It is expected that this will significantly reduce the severity of the SCR plugging problem.

Figure 8. Pressure drop measured across the SCR catalyst and LPA screen at AES Greenidge Unit 4, July - December 2007. Red arrows indicate outages during which the SCR reactor was cleaned.
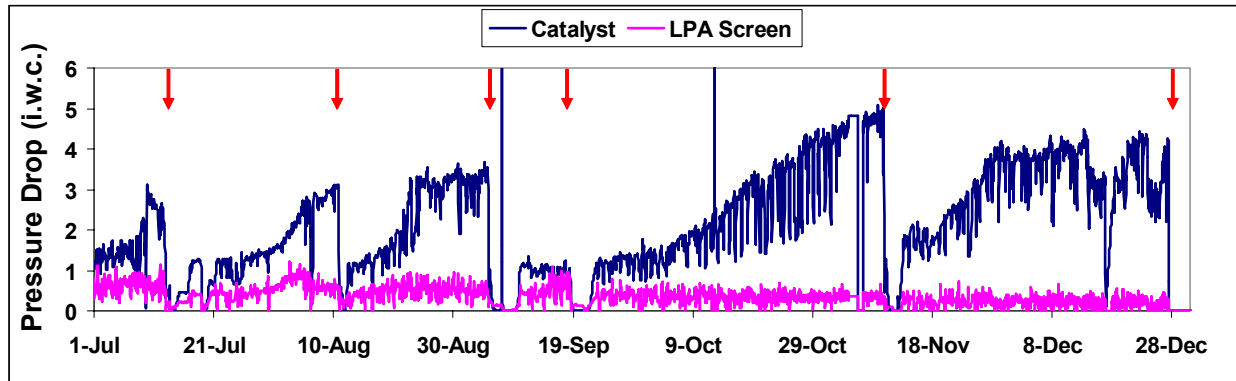

Mercury Control

The multi-pollutant control system at AES Greenidge Unit 4 has consistently exceeded its performance target of $\geq$ 90% Hg removal efficiency. As shown in Figure 9, twenty-five mercury tests were completed at AES Greenidge between March 2007 and May 2008. 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 first six tests, Hg was determined in the Ontario Hydro samples using cold vapor atomic absorption spectroscopy, and all Hg concentrations at the stack were below the method detection limit. Cold vapor atomic fluorescence spectroscopy was employed for subsequent tests so that stack Hg concentrations could be detected). All of the tests surpassed the project's target for Hg removal; measured coal-to-stack Hg removal efficiencies ranged from 92.8% to 99.8%. Moreover, 20 of the 25 tests were conducted without any activated carbon injection; the average Hg removal efficiency observed during these tests was 98.1%. (The activated carbon injection rate during the five tests that included ACI was approximately 3 lb/mmacf). High mercury removal efficiency was observed irrespective of plant operating conditions. 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, 3.3 – 4.9 lb SO_2 / mmBtu, and 0.07 – 0.11 % (dry) Cl. For the four tests on March 11-12, 2008, it also co-fired sawmill waste wood at less than 5% of the total heat input. The gross generator load during the reduced-load tests on November 13-15, 2007, and May 19-20, 2008, ranged from 56 to 84 MW; during the other 19 tests, the unit operated between 105 and 109 MW$_{gross}$. 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 25 Hg tests, likely contributing to the high Hg removal efficiencies that were observed.

As discussed above, the in-duct SCR reactor is also expected to contribute to the high Hg removal efficiency by converting some elemental mercury to oxidized mercury, which is more easily captured in the circulating fluidized bed dry scrubber. Hg oxidation is often observed across conventional SCR reactors, but the extent to which Hg would be oxidized across the

comparatively small in-duct SCR at AES Greenidge Unit 4 was uncertain when the process was being designed. To investigate Hg oxidation across the in-duct SCR catalyst, concentrations of Hg^0 and Hg^{2+} were measured at the inlet and outlet of the SCR reactor during the four tests on March 11-12, 2008. These measurements were conducted using a modified version of the Ontario Hydro method, in which sampling was performed at a constant, reduced flow rate, with the nozzle oriented away from the direction of flow to reduce uptake of particulate matter. (Hg speciation results determined using the Ontario Hydro method can be biased in high-dust locations by adsorption of Hg onto the fly ash that is collected on the sample filter. The fly ash can also promote Hg oxidation. However, these artifacts are expected to be minimal at the high temperatures around the SCR. The likelihood of bias is further reduced if the fly ash uptake is minimized. It is also important to note that the Ontario Hydro method has not been validated for high-temperature testing; however, flue gas conditions were similar at the SCR inlet and outlet, reducing the probability of relative measurement bias between those locations, and total Hg concentrations determined at both locations showed reasonable agreement with the coal Hg content and feed rate.) On average, Hg^{2+} accounted for 70% of the total gas-phase Hg (i.e., Hg^0 + Hg^{2+}) at the SCR inlet, and it accounted for 96% of the total gas-phase Hg at the SCR outlet. This result supports the role of the in-duct SCR in oxidizing Hg. Additional Hg measurements were performed around the SCR reactor in May and June 2008 to confirm the data from March; however, results of those additional measurements are not yet available.

Figure 9. Summary of coal-to-stack Hg removal efficiencies, March 2007 – May 2008.
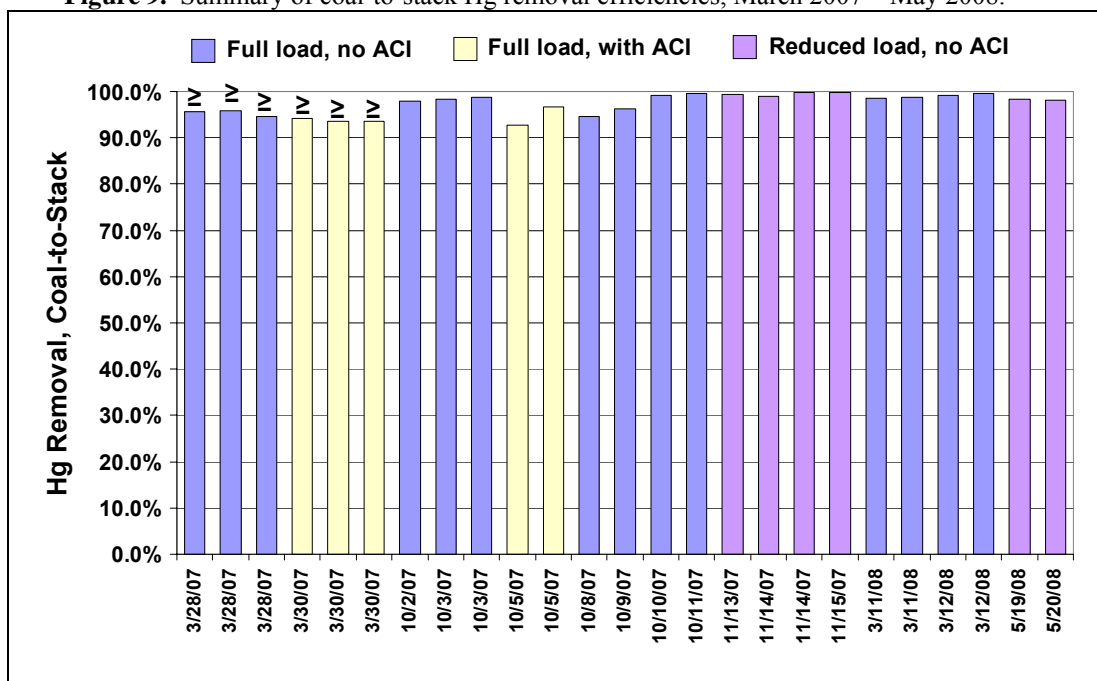
Process Economics

Table 2 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 design information and actual

cost and operating data (where available) for the Unit 4 installation. Key assumptions are listed below the table.

Table 2. Process economics (constant 2005 dollars) for the multi-pollutant control system at AES Greenidge Unit 4.

	EPC Capital Cost ($/kW)	Fixed O&M Costs ($/MWh)	Variable O&M Costs ($/MWh)	Total Levelized Cost
NO_x Control	114[a]	0.39	0.84	$3,487 / ton NO_x
SO_2 Control	229[b]	0.88	5.62	$586 / ton SO_2

[a]Includes combustion modifications, SNCR, in-duct SCR, static mixers, and LPA removal system. [b]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_2 / mmBtu, NSR = 1.35, Ca/S = 1.68 mol/mol, Pebble lime available CaO = 90%, NO_x emissions = 0.10 lb/mmBtu, SO_2 removal efficiency = 95%, Parasitic power = 1.84% of net load, 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.

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 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 2, 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.

As discussed above, no new employees were required to operate the multi-pollutant control system at AES Greenidge. However, the fixed O&M costs presented in Table 2 preliminarily assume 16 hours per day of operating labor to account for increased overtime and training arising from the system. Maintenance labor and materials costs are estimated as 1.5% of the total plant cost (40% labor, 60% materials), and administrative and support labor costs are estimated as 30% of total O&M labor costs. Actual fixed O&M costs will be tabulated at the end of the project's performance evaluation period.

Variable O&M costs include costs for pebble lime, urea, waste disposal, electricity, water, replacement catalyst, and replacement baghouse bags and cages. These costs were calculated using actual pricing and operating data from AES Greenidge, where available. Urea and pebble lime account for more than half of the variable O&M costs for the NO_x and SO_2 control systems, respectively. Costs for urea were computed assuming a normalized stoichiometric ratio (NSR = 2 x moles of urea ÷ moles of inlet NO_x) of 1.35, consistent with that observed during guarantee testing of the multi-pollutant control system in March 2008. (The process economics in Table 2 assume a NO_x emission rate of 0.10 lb/mmBtu, even though NO_x emissions have averaged higher than this during routine operation of the multi-pollutant control system). Costs for lime assume a Ca/S molar ratio of 1.68, per the October 2007 performance testing results that were presented earlier.

Total levelized costs for the multi-pollutant control system, including levelized capital and fixed and variable O&M costs, are about $3,487 / ton of NO_x removed and $586 / ton of SO_2 removed. These prices also cover mercury control, acid gas control, and improved primary particulate matter control, which are co-benefits of the SO_2 and NO_x control systems and add no incremental cost. Installation of the multi-pollutant control system has enabled AES Greenidge Unit 4 to satisfy its

air emissions requirements while remaining profitable, thereby contributing to a 20-30 year life extension for the unit.

SUMMARY

In conclusion, the Greenidge Project has demonstrated the commercial viability of a multi-pollutant control system that is designed to meet the needs of small coal-fired power plants that have traditionally been difficult to retrofit. The system, which includes combustion modifications, a hybrid SNCR/SCR system, and a circulating fluidized bed dry scrubber (with new baghouse), required an EPC capital cost of $343/kW ($2005) and a footprint of < 0.5 acre at the 107-MW AES Greenidge Unit 4. This is substantially less than the capital cost and space that would have been required to retrofit the unit with conventional SCR and wet FGD systems. The multi-pollutant control system has operated commercially for more than a year, and it has generally met or exceeded the project's performance targets. Tests completed since start-up of the system in early 2007 have consistently shown $\geq$ 95% SO_2 removal, $\geq$ 95% mercury removal (with no activated carbon injection), and very low emissions of SO_3, HCl, HF, and particulate matter. SO_2 removal efficiencies greater than 95% have been observed even when the unit fires high-sulfur coals containing up to 4.9 lb SO_2 / mmBtu. The performance of the hybrid SNCR/SCR system has been affected by problems with large particle ash, ammonia slip, and less-than-optimal combustion characteristics, and NO_x emissions have typically averaged closer to 0.15 lb/mmBtu than to the targeted emission rate of 0.10 lb/mmBtu. Nevertheless, the system has substantially improved the unit's NO_x emission profile. Further testing of the multi-pollutant control system at AES Greenidge Unit 4 was completed in June 2008; results from those tests will add to the data presented here. Information generated as part of the Greenidge Project is useful for informing the decisionmaking of generators seeking affordable retrofit options for their smaller coal-fired units.

ACKNOWLEDGMENT AND DISCLAIMER

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