Preliminary Performance Testing Results from the Greenidge Multi-Pollutant Control Project

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INTRODUCTION

There are about 440 coal-fired electrical generating units (EGUs) in the United States with capacities of 50-300 MW_e that currently are not equipped with selective catalytic reduction (SCR), flue gas desulfurization (FGD), or mercury control systems. These smaller units are a valuable part of the nation's energy infrastructure, constituting about 60 GW of installed capacity. However, with the onset of the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), Clean Air Visibility Rule (CAVR), and various state environmental actions requiring deep reductions in emissions of SO_2, NO_x, and mercury, 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 (DOE's) Power Plant Improvement Initiative (PPII), seeks to demonstrate a solution for these units. As part of the project, an innovative combination of technologies including combustion modifications, a hybrid selective non-catalytic reduction/selective catalytic reduction (SNCR/SCR) system, and a Turbosorp® circulating fluidized bed dry scrubbing system with baghouse ash recycling and activated carbon injection, were installed on the 107 MW_e AES Greenidge Unit 4 in Dresden, NY. Figure 1 presents a photograph of the plant taken prior to the installation of the multi-pollutant control system. 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 co-fires biomass at up to 10% of its heat input. As such, it is representative of many of the 440 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_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. 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 has a capital cost of about \$340/kW and occupies a <0.5-acre footprint 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 ≥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.

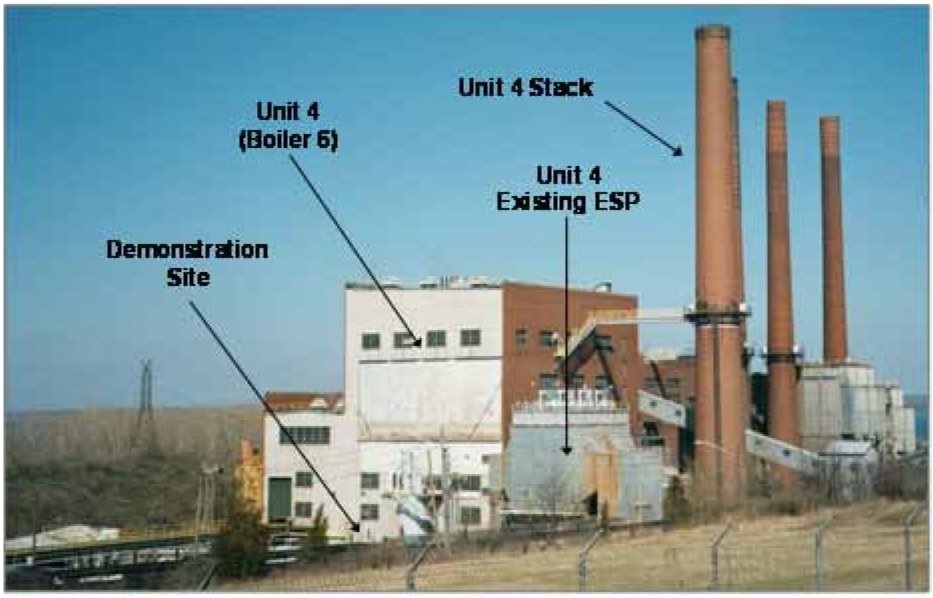

Figure 1. Photograph of the AES Greenidge plant prior to the installation of the multi-pollutant control system.

Start-up and commissioning of the multi-pollutant control system at AES Greenidge were completed in early 2007, and the project recently entered an approximately 1.5-year period of operation and testing of the new system. This paper presents emissions reduction results from the first round of performance tests, which were conducted at AES Greenidge in late March and early May 2007. The design of the multi-pollutant control system is also discussed, and key features of the system that make it well-suited for application to smaller coal-fired EGUs are highlighted. Data generated as part of the Greenidge Project are useful for evaluating the applicability of the multi-pollutant control system to the large fleet of existing, smaller coal-fired units.

MULTI-POLLUTANT CONTROL SYSTEM DESIGN

Figure 2 presents a schematic of the process that is being demonstrated as part of the Greenidge Multi-Pollutant Control Project. 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_x emission rate of ~0.30 lb/mmBtu prior to the installation of the new combustion modifications.

NO_x 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 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 reduction via SCR. The hybrid NO_x control system at AES Greenidge Unit 4 also includes combustion modifications to achieve further reductions in NO_x emissions and to improve the performance of the hybrid SNCR/SCR system. Hence, a full-load NO_x emission rate of $\leq$0.10 lb/mmBtu results from the combination of 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 ~42% to 0.144 lb/mmBtu, and the SCR, which is designed to further reduce NO_x by $\geq$31% to $\leq$0.10 lb/mmBtu.

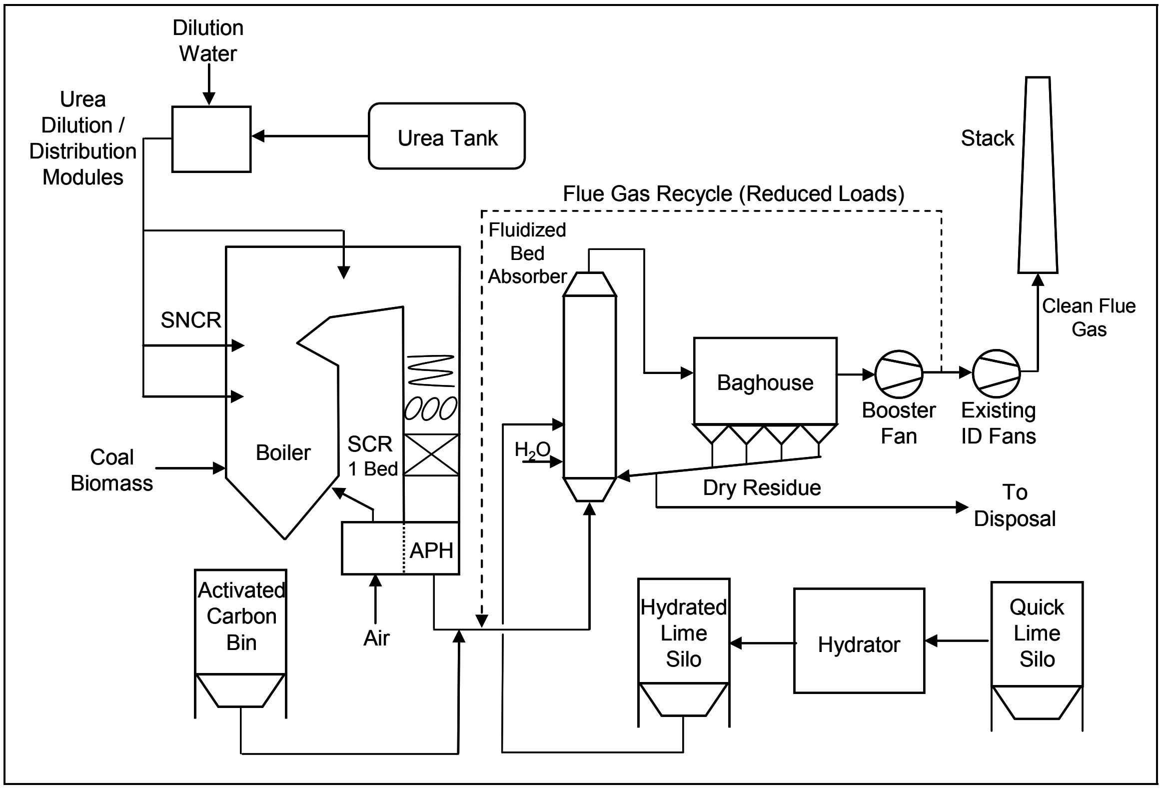

Figure 2. Schematic of the multi-pollutant control process being demonstrated on AES Greenidge Unit 4.

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 supplied from an on-site hydrator installed as part of the project at AES Greenidge, are injected separately into a fluidized bed absorber, where the flue gas is evaporatively cooled 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., $CaSO_3{\cdot}½H_2O$, $CaSO_4{\cdot}½H_2O$, $CaCl_2$, CaF_2), which are separated from the flue gas in a new eight-compartment pulse jet baghouse and recycled to the absorber via air slides at a high ratio to the inlet solids in order to maximize pollutant removal and lime utilization. As shown in Figure 2, 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.

Mercury control in the multi-pollutant control system is accomplished via the co-benefits afforded by the 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 very 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.[1-2] 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,[3] the removal of Hg^{2+} (a Lewis acid) via chemisorption by moistened, basic $Ca(OH)_2$ particles in the scrubber,[4-5] and the removal of Hg^{2+} and possibly some Hg^0 via adsorption onto carbon-containing fly ash and $Ca(OH)_2$ at low temperatures in the baghouse,[6] 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 is likely that its combination of an in-duct SCR, $Ca(OH)_2$-based scrubber, and baghouse will result in high mercury removals without any activated carbon injection when applied to bituminous coal-fired units. To ensure high mercury removal efficiencies, the multi-pollutant control system also includes an activated carbon injection system installed upstream of the 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 (~170°F) provided by the circulating fluidized bed dry scrubber and baghouse.

APPLICABILITY TO SMALLER COAL-FIRED UNITS

As discussed in the Introduction, the multi-pollutant control system being demonstrated at AES Greenidge was designed with the overall goal of providing an integrated process that is well suited for reducing emissions of a number of pollutants from smaller (i.e., 50-300 MW_e) coal-fired EGUs. Therefore, the design responded to a number of objectives that are consistent with the needs of these smaller units. These objectives, which are synonymous with the advantages of the multi-pollutant control system over technologies that have conventionally been applied to smaller coal-fired units, are discussed below.

Deep Emission Reductions

Conventional low-capital-cost air pollution control options for smaller coal-fired units, such as low-NO_x burners or stand-alone SNCR to reduce NO_x emissions and combustion of low-sulfur coal or use of sorbent injection in the furnace or ductwork to limit SO_2 emissions, in most cases do not produce emission rates consistent with the low levels established in environmental regulations that recently have been promulgated or proposed. Hence, units employing these options are increasingly vulnerable to highly volatile allowance costs or even retirement as new regulations are enacted. Thus, it was essential that the Greenidge multi-pollutant control process be designed to achieve deeper emissions reductions than these conventional low-capital-cost options and to meet or exceed applicable state and federal regulatory requirements for air emissions.

The process being demonstrated at AES Greenidge is well suited for achieving NO_x emission reductions of about 50-75%, compared with the 20-35% reduction typically achievable by SNCR.[7] It also is designed to achieve greater than 95% removal of SO_2, comparable to the 95-98% removals characteristic of today's best available wet scrubbing technologies for larger coal-fired units.[8] Both NO_x and SO_2 are regulated under CAIR. Furthermore, the multi-pollutant control system is designed to achieve greater than 90% capture of mercury, which is regulated under CAMR and is a topic of many state environmental actions, and to reduce emissions of SO_3, HCl, and HF by at least 95%. SO_3, HCl, and HF contribute to the formation of acid aerosols, and emissions of these compounds must be reported to the U.S. Environmental Protection Agency (EPA) as part of the national Toxics Release Inventory (TRI) program. Elevated concentrations of SO_3 in flue gas can also result in the formation of visible emissions (i.e., "blue plumes"), which are often particularly problematic for coal-fired power plants with SCR systems because SO_3 can be generated by oxidation of SO_2 across the SCR catalyst. Although the Greenidge multi-pollutant control process includes an SCR reactor, the downstream circulating fluidized bed dry scrubber is designed for deep SO_3 removal, eliminating the potential for plume visibility problems due to SO_3. Finally, for plants currently using an ESP to control particulate matter emissions, installation of the circulating fluidized bed dry scrubber and baghouse is expected to afford a substantial improvement in particulate matter control.

Low Capital Costs

There are commercially-available conventional technologies, such as full-scale SCR systems and limestone forced oxidation wet scrubbers, that are capable of achieving or exceeding the deep emissions reductions targeted for the Greenidge multi-pollutant control process. However, operators of smaller coal-fired EGUs, which are penalized by economies of scale, often cannot afford the large capital costs associated with these technologies. Hence, the multi-pollutant control process being demonstrated at AES Greenidge was designed to achieve deep emission reductions while offering substantially reduced capital costs compared to these conventional state-of-the-art technologies.

By using a compact, single-bed SCR reactor that is installed in a modified section of ductwork between the unit's economizer and air heater, 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. Also, unlike wet FGD systems, the Turbosorp® system does not produce saturated flue gas, and therefore is constructed from carbon steel rather than from the expensive corrosion-resistant materials required for wet scrubbers. For the same reason, use of the Turbosorp® system also does not entail the installation of a new corrosion-resistant stack, which is commonly required for wet scrubber retrofits. Because of these factors, as well as the mechanical simplicity of the Turbosorp® system relative to wet scrubbers, the EPC capital cost of the multi-pollutant control system at AES Greenidge was only about $340/kW, which is almost 40% less than the estimated capital cost for a conventional system comprising a stand-alone SCR and wet limestone forced oxidation scrubber as applied to that unit.[9]

In exchange for its substantially reduced capital costs, the Greenidge multi-pollutant control system has higher variable operating costs (because of its lower reagent utilization and its use of more expensive urea and lime reagents rather than the ammonia and limestone reagents commonly used in stand-alone SCR and wet scrubber systems, respectively) and lower NO_x removal efficiency relative to a conventional stand-alone SCR / wet FGD system (SCRs are capable of achieving 80-90% or greater NO_x reduction). Variable operating & maintenance costs for the AES Greenidge system are projected to average $5.64/MWh, or $233/ton of SO_2 removed and $839/ton of NO_x removed.[10] Whereas this tradeoff between capital costs and variable operating costs may be unattractive for large coal-fired EGUs, it is consistent with the needs of owners of smaller units, who in many cases cannot justify or afford the large capital costs (per unit of electrical output) needed to retrofit with conventional technologies for deep emissions reductions.

Small Space Requirements

The relatively large amount of space required to install conventional SCR and wet FGD systems further prevents these technologies from being widely applied to smaller coal-fired EGUs. Many smaller coal-fired units do not have sufficient physical space to easily accommodate both an SCR and a wet scrubber; this increases the difficulty, and hence the capital cost, of retrofitting these technologies. Therefore, an objective in designing the Greenidge multi-pollutant control system was to minimize its required footprint.

The SNCR portion of the multi-pollutant control process requires only a small amount of space for a urea storage tank, a small shed containing a urea circulation module, and several small urea distribution skids located around the boiler. Unlike a conventional stand-alone SCR reactor, the single-bed SCR reactor requires essentially no new land area, as it is installed in a modified ductwork section between the economizer and air heater and needs only a few new support beams. The in-duct SCR reactor at AES Greenidge fits within the existing boiler building in a space with horizontal dimensions of 52 ft x 27 ft and a vertical height of 23 ft. (The cross-sectional area of the reactor itself is 45 ft x 14 ft). The arrangement of the circulating fluidized bed dry scrubber, baghouse, and associated equipment is also compact. The various pieces of equipment are vertically tiered to permit gravity-assisted transport of solids where possible, and as a result, required only ~0.4 acre of land for the installation at AES Greenidge. Figures 3 and 4 present photographs showing the installations of the in-duct SCR reactor and the Turbosorp® system, respectively, at AES Greenidge.

Figure 3. Photograph of the in-duct SCR reactor installed on AES Greenidge Unit 4.

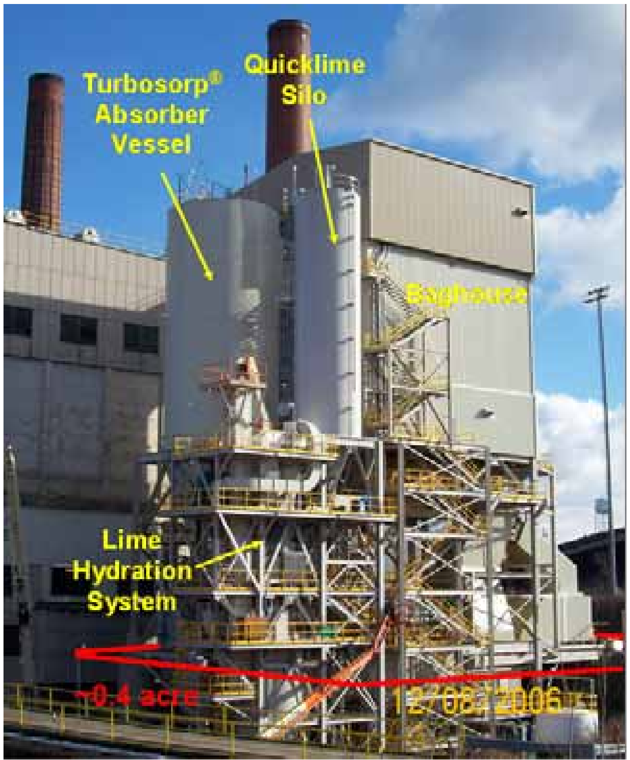

Figure 4. Photograph of the Turbosorp® system installed on AES Greenidge Unit 4.

Applicability to High-Sulfur Coals

Greater than 80% of the 440 smaller existing coal-fired units that are candidates for the multi-pollutant control process being demonstrated at AES Greenidge are located east of the Mississippi River, where high-sulfur eastern U.S. bituminous coal is a candidate fuel source. The dispatch economics of these units improve significantly with the installation of low-cost SO_2 removal systems that allow the use of higher-Btu, higher-sulfur, less-expensive coals with a net reduction in SO_2 emissions and a corresponding reduction in the need for high-cost allowances. Hence, an important design objective for the Greenidge multi-pollutant control system was that it be able to achieve deep SO_2 emission reductions when applied to units firing high-sulfur (i.e., >2%-sulfur) coals.

Lime spray dryers provide a relatively low-capital-cost means for achieving deep reductions in SO_2 emissions, as does the Turbosorp® circulating fluidized bed dry scrubber being installed as part of the multi-pollutant control process at AES Greenidge. However, spray dryers are only capable of achieving these deep reductions (i.e., >90%) when applied to units that fire coals with sulfur contents of about 2% or less. In spray dryer systems, lime and water are injected into the absorber vessel together as a slurry, rather than separately as in the Turbosorp® system. As a result, flue gases with high SO_2 concentrations require slurry injection rates so great that the water in the slurry cannot be completely evaporated. This causes plugging and binding of the bags used in the downstream fabric filter, as well as plugging of discharge feeders and conveyers. As discussed above, in the Turbosorp® system, water injection and hydrated lime injection are carried out separately, such that the $Ca(OH)_2$ injection rate is controlled solely by the pollutant loading and desired emission reduction, without being limited by the temperature or moisture content of the flue gas. As a result, the Turbosorp® can be operated to achieve deep emission reductions for a wide range of fuels, including high-sulfur coals.

Low Maintenance Requirements

Insofar as the PPII seeks to improve the reliability of the nation's energy supply, minimization of maintenance requirements was an objective in the design of the Greenidge multi-pollutant control system, such that system maintenance will not adversely affect unit availability. A drawback of both wet scrubbers and lime spray dryers is their use of slurries to introduce the limestone or lime into the system, resulting in high maintenance requirements and potential for operational problems. Problems arising from the use of slurries can include pipe plugging, nozzle plugging, solids build-up, and erosion and abrasion of pumps, pipes, and vessels. Wet scrubbers in particular are relatively complex, as they produce a slurry product and require pumps for slurry recirculation as well as maintenance-intensive dewatering equipment.

The Turbosorp® circulating fluidized bed dry scrubber being installed as part of the Greenidge multi-pollutant control system is expected to afford substantially reduced maintenance requirements compared to these more conventional FGD technologies. In the Turbosorp® process, lime is injected into the absorber as a dry hydrate rather than as a slurry. A blower is used to pneumatically convey the dry hydrated lime to the absorber for injection. The solids collected in the baghouse are also completely dry and are recycled to the absorber using air slides. Gravity provides the motive force for injection via the differential height between the bottom of the baghouse and the injection point on the absorber tower. Apart from the lime hydration system, the system's only pump is used to inject liquid water into the absorber vessel. Hence, the process avoids the problems with plugging, erosion, abrasion, and scaling that can result from pumping and handling slurries in other types of scrubbing systems. The Turbosorp® system also includes comparatively few moving parts, and as implied in the preceding subsection, is less likely to cause plugging and binding of fabric filter bags than a spray dryer is.

Operational Flexibility

Unlike larger baseload units, many smaller coal-fired EGUs routinely cycle their loads in response to electricity demand. Hence, a multi-pollutant control system designed for these smaller units should feature turndown capabilities to permit continued emissions reductions at reduced operating loads. The design of the multi-pollutant control system being demonstrated at AES Greenidge includes these capabilities.

For conventional SCR systems, low-load operation is constrained by reduced flue gas temperatures, which can cause incomplete ammonia consumption across the SCR catalyst, resulting in high ammonia slip and ammonium bisulfate fouling in the air heater. At sufficiently low temperatures, catalyst plugging and deactivation can also occur via the formation of salts in the SCR reactor. These constraints are particularly stringent for units that fire high-sulfur coals. Stand-alone SCR installations typically employ an economizer gas bypass and/or water flow circuit modifications to raise the flue gas temperature at the SCR inlet during low-load operation.

However, because of the hybrid NO_x control strategy included as part of the Greenidge multi-pollutant control process, NO_x removal capabilities are available to some extent at lower operating loads without the need for any such modifications.

The operating strategy for the hybrid system is shown conceptually in Figure 5. As illustrated in the figure, operation of the system varies with generator load, resulting in three distinct operating ranges: a high-load range in which NO_x reduction is accomplished via SCR, SNCR, and low-NO_x burners; an intermediate-load range in which NO_x reduction is accomplished via SNCR and low-NO_x burners (but not SCR), and a low-load range in which NO_x reduction is accomplished via low-NO_x burners (but not SCR or SNCR). At generator loads that produce economizer outlet temperatures below the minimum operating temperature for the SCR reactor (~600°F for AES Greenidge Unit 4), urea injection into the upper region of the furnace, which is used to generate ammonia slip for the SCR, is discontinued. However, urea continues to be injected into higher-temperature areas of the furnace 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 (~528°F for AES Greenidge Unit 4), which is the minimum economizer outlet temperature at which it is safe to introduce very small amounts of ammonia into the SCR catalyst, urea injection into the furnace is discontinued. However, NO_x emissions continue to be controlled via the unit's low-NO_x combustion system. Hence, for smaller units that regularly cycle loads based upon peak and off-peak demands, the load-following capabilities of the hybrid SNCR/SCR process can help to contribute to lower NO_x emission averages.

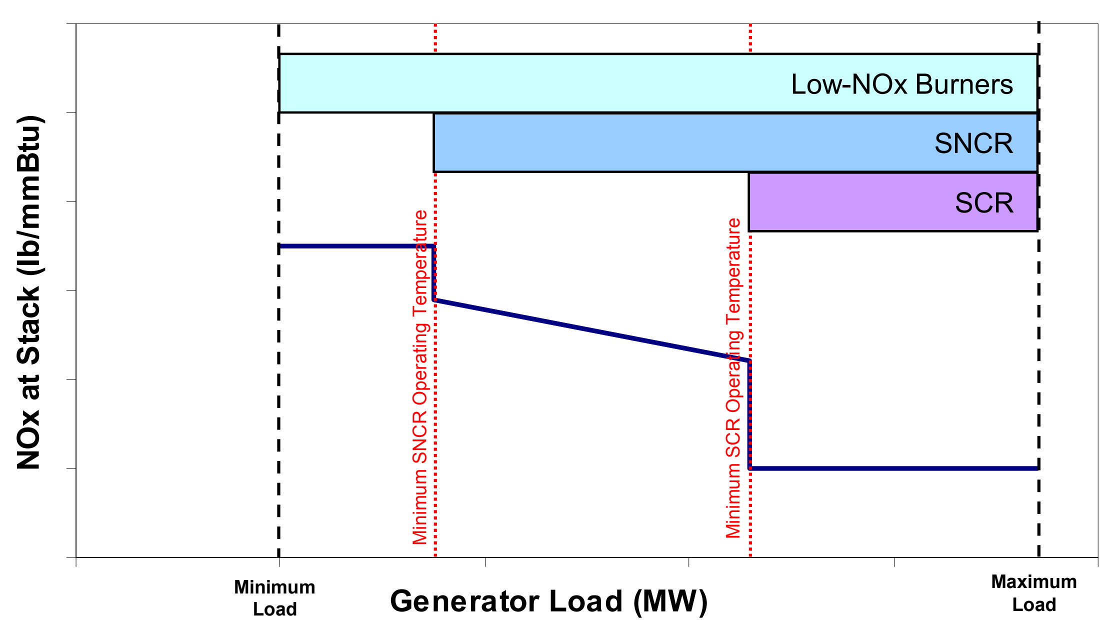

Figure 5. Operating strategy for the hybrid NO_x control system being demonstrated at AES Greenidge.

The circulating fluidized bed dry scrubber and activated carbon injection systems are designed to achieve ≥95% SO_2 and acid gas removal and ≥90% Hg removal when the unit is operating at any point between its minimum load (42 MW_g) and full load. Flue gas recycle is required at low loads to provide sufficient flow to the absorber so that a fluidized bed can be maintained.

PRELIMINARY PERFORMANCE RESULTS

Construction of the multi-pollutant control system at AES Greenidge was completed largely in 2006, and commissioning of the system was completed in March 2007. The first series of tests evaluating the emissions reduction performance of the system were conducted during March 28-30 and May 1-4, 2007. The objective of these tests was to determine whether the system was capable of achieving its performance targets (i.e., NO_x emissions ≤0.10 lb/mmBtu, SO_2 and acid gas removal efficiency ≥95%, Hg removal efficiency ≥90%) when AES Greenidge Unit 4 was operating at design conditions. Additionally, Hg removal across the Turbosorp® system was determined both with and without activated carbon injection (ACI) in order to provide a preliminary indication of whether ACI is needed to achieve 90% Hg removal.

NO_x, SO_2, and Hg measurements were performed on March 28-30, 2007. During that period, AES Greenidge Unit 4 was operated at design load (~105 MW_g) using Pittsburgh seam coal with an average sulfur content of 2.5% (as-fired), or 3.8 lb SO_2 / mmBtu. NO_x and SO_2 measurements were performed by Clean Air Engineering (CAE) using EPA Method 7E (modified to incorporate the use of CAE's Multi-Point Automated Sampling System) and EPA Method 6C, respectively. Hg measurements were performed by CONSOL R&D using the Ontario Hydro method (ASTM D6784-02).

NO_x testing was completed on March 28. Flue gas samples were extracted from 24-point sampling grids located at both the inlet and the outlet of the SCR catalyst to enable the NO_x reduction contributed by the SCR to be differentiated from that contributed by the combustion modifications and SNCR. Three approximately one-hour-long tests including simultaneous sampling at the SCR inlet and SCR outlet were completed. Results are summarized in Table 1. The NO_x concentration of 51.8 ppmvd (corrected to 3% O_2) at the SCR outlet equates to a NO_x emission rate of 0.07 lb/mmBtu, which is below the performance target for NO_x emissions of ≤0.10 lb/mmBtu. (The NO_x emission rate measured by the plant's stack CEM during the same period was 0.096 lb/mmBtu, substantially greater than the value measured at the SCR outlet, but still below the performance target of 0.10 lb/mmBtu. We are still investigating the cause of this measurement discrepancy). The NO_x removal performance of the system (as measured by CAE at the SCR inlet and outlet) was better than the targeted performance, owing to the combination of a NO_x emission rate at the inlet to the SCR (0.12 lb/mmBtu) that was less than the design value of 0.144 lb/mmBtu (implying that the combustion modifications and/or SNCR system reduced NO_x emissions to a greater extent than they were projected to) and a NO_x removal efficiency across the single-bed SCR (41%) that was greater than the design value of 31%.

Table 1. Summary of results of NO_x testing at AES Greenidge Unit 4 on March 28, 2007.

	Duration (min)	**NO_x at SCR Inlet (ppmvd @ 3% O_2)**	**NO_x at SCR Outlet (ppmvd @ 3% O_2)**	**NO_x Removal Across SCR (%)**
Test # 1	63	92.6	52.7	43.1
Test # 2	71	86.3	52.7	38.9
Test # 3	71	84.6	50.1	40.8
AVERAGE		87.8	51.8	41.0

Although preliminary performance testing results demonstrated the ability of the hybrid NO_x control system to exceed its performance target for NO_x emissions, operation of the system was hampered for several months after start-up by the accumulation of large particle ash (LPA) on the surface of the in-duct SCR catalyst. Accumulation of LPA repeatedly caused gradual increases in the pressure drop across the SCR reactor, forcing several outages for catalyst cleaning. Also during this period, ammonia slip concentrations greater than the target of 2 ppmvd were observed. A solution to the LPA problem was implemented in mid-May 2007, consisting of a sloped screen installed between the economizer and SCR reactor to filter out the LPA before it reaches the catalyst. The screen, which was designed by BPEI, had to be engineered to effectively remove LPA in spite of the challenges posed by the vertical downflow configuration and limited space above the SCR reactor. Sootblowers were installed to prevent LPA from accumulating in the screen; the collected LPA is removed from the base of the screen by a series of vacuum ports. The performance of the hybrid SNCR/SCR system, including both its NO_x removal performance and its ammonia slip performance, were reevaluated following the installation of the screen. Results were not yet available when this paper was submitted.

Table 2 presents the results of SO_2 measurements that were performed at AES Greenidge Unit 4 on March 29. Three one-hour test runs were conducted, each including simultaneous measurements of SO_2 concentrations at the air heater outlet (upstream of the Turbosorp® system) and at the baghouse outlet (downstream of the Turbosorp® system). The average measured SO_2 removal efficiency across the Turbosorp® system (including the baghouse) during these three test runs (94.1%) was slightly less than the targeted removal efficiency of 95%, although the plant's continuous emission monitors at the air heater outlet and stack have frequently indicated removal efficiencies >95% during the first several months of operation of the multi-pollutant control system. Hence, preliminary results suggest that the Turbosorp® system is capable of attaining 95% SO_2 removal efficiency when the unit is firing >2%-sulfur coal. Additional tests are planned to evaluate the performance of the system as a function of fuel sulfur content, hydrated lime consumption rate, and approach to adiabatic saturation temperature in the absorber vessel.

Table 2. Summary of results of SO_2 testing at AES Greenidge Unit 4 on March 29, 2007.

	Duration (min)	**SO_2 at Air Heater Outlet (ppmvd @ 3% O_2)**	**SO_2 at Baghouse Outlet (ppmvd @ 3% O_2)**	**SO_2 Removal Across Turbosorp® System (%)**
Test # 1	61	1842	105	94.3
Test # 2	61	1822	92	95.0
Test # 3	60	1847	131	92.9
AVERAGE		1837	109	94.1

Figure 6 summarizes the results of Hg measurements that were performed at AES Greenidge on March 28 and 30. Three approximately two-hour-long test runs were performed on March 28, when the activated carbon injection system was not in service. Each test run included simultaneous sampling at the air heater outlet (upstream of the Turbosorp® system) and at the stack (downstream of the Turbosorp® system). Complete traverses of the duct cross section were performed during each test at each location. This testing protocol was repeated on March 30, except that the ACI system was operating on that day. The results shown in Figure 6 represent the averages of the three test runs performed at each location on each day. As shown in the figure, the average Hg concentrations measured at the air heater outlet were 10.06 µg/dscf on March 28 and 9.38 µg/dscf on March 30 (both concentrations corrected to 3% O_2). On both days, Hg concentrations at the stack were less than the analytical limit of detection. Thus, Hg removal efficiencies across the Turbosorp® system (including the baghouse) were >94% on March 28, when no activated carbon was being injected into the system, and >93% on March 30, when activated carbon was being injected. Hence, these initial results suggest that the multi-pollutant control system at AES Greenidge may be capable of achieving >90% Hg removal without the need for any activated carbon injection, although additional testing is required to confirm that this result is reproducible across a variety of plant operating conditions.

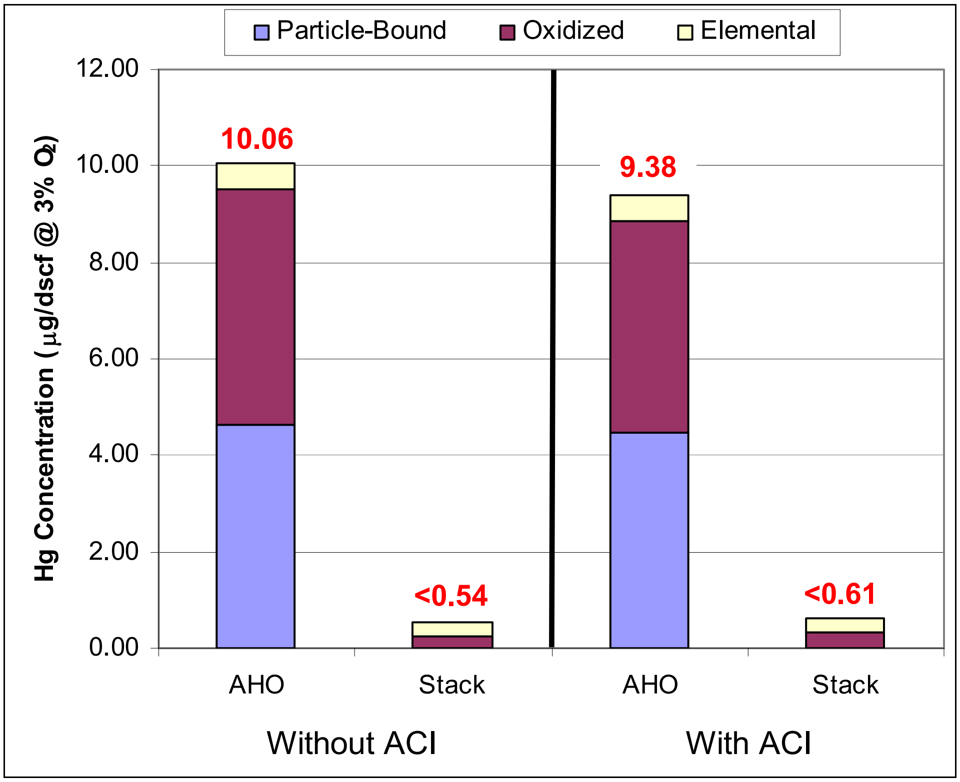

Figure 6. Summary of results of Hg testing at AES Greenidge Unit 4 on March 28 and 30, 2007. Each bar represents the average of three measurements conducted using the Ontario Hydro method at the air heater outlet (AHO) or stack. Triplicate measurements were performed on March 28 with no activated carbon injection (ACI) and again on March 30 with ACI.

The results presented in Figure 6 include a breakdown of Hg concentrations by Hg species (i.e., particle-bound, oxidized, and elemental), as determined according to the Ontario Hydro method. However, these speciation results should be interpreted cautiously. Whereas total Hg concentrations determined using the Ontario Hydro method are expected to be reliable, even in high-dust locations, Hg speciation results determined using that method can be biased in high-dust locations by adsorption of Hg onto the fly ash collected on the sample filter or by reaction of Hg with the fly ash.[11] This can lead to artificially high particle-bound and/or oxidized mercury concentrations, and artificially low elemental and/or oxidized mercury concentrations. (The direction of the bias in the oxidized mercury results depends upon the extent to which mercury is adsorbed as opposed to oxidized by the fly ash). Hence, it is likely that the mercury speciation observed at the air heater outlet, which included 46-48% particle-bound Hg, was biased relative to actual flue gas speciation as a result of this artifact. The air heater outlet is a high-dust location, containing 2.2-2.5 gr/dscf of particulate matter, and the high unburned carbon content of the fly ash sampled there (15-21%) would tend to promote adsorption of gas-phase Hg onto the ash. This high unburned carbon content may also have contributed to the high Hg removal efficiency observed when no activated carbon was being injected into the system; the relationship between the carbon content of the fly ash and the Hg removal performance of the system will be evaluated as part of future testing.

Acid gas testing was performed by CONSOL R&D at AES Greenidge Unit 4 on May 2-4, 2007. SO_3 was measured on May 2 using the controlled condensation method as described by DeVito and Smith,[12] but modified to allow for determination of SO_4^{2-} by ion chromatography rather than by $BaCl_2$ titration. HCl and HF were measured on May 4 using EPA Method 26A. Results are summarized in Table 3. (Each result represents the average of multiple measurements performed on the indicated test date; for each parameter, sampling was performed simultaneously at the air heater outlet and stack locations). As shown in the table, the Turbosorp® system (including the baghouse) removed about 97% of the SO_3 and HCl contained in the flue gas, thereby exceeding its performance target of ≥95% removal efficiency for these parameters. No HF was detectable at either the air heater outlet or the stack, making it impossible to calculate a removal efficiency for this species.

Table 3. Summary of AES Greenidge Unit 4 acid gas testing results from May 2-4, 2007.

Parameter	**Test Date (mm/dd/yy)**	**Average Concentration at Air Heater Outlet (ppmvd @ 3% O_2)**	**Average Concentration at Stack (ppmvd @ 3% O_2)**	**Removal Efficiency (%)**
SO_3	05/02/07	25.0[a]	0.7	97.1
HCl	05/04/07	40.1	1.1	97.2
HF	05/04/07	<0.23	<0.16	N/A

[a] O_2 concentration at air heater outlet estimated from measured stack O_2 concentration for purposes of correction.

Hence, preliminary performance testing results suggest that the multi-pollutant control system being demonstrated on AES Greenidge Unit 4 is capable of meeting or exceeding its performance targets for air emissions of NO_x, SO_2, Hg, and acid gases. Additional testing is underway to determine the repeatability of these results and the effect of variations in plant operating conditions on the performance of the system.

CONCLUSIONS

In conclusion, the multi-pollutant control system being demonstrated at AES Greenidge Unit 4, which includes the combination of combustion modifications, a hybrid SNCR/SCR system, and a Turbosorp® circulating fluidized bed dry scrubber with activated carbon injection (as required) and baghouse ash recycling, provides a relatively low-capital-cost means for smaller coal-fired EGUs to achieve deep reductions in emissions of SO_2, NO_x, Hg, and acid gases. In addition to its low capital cost ($340/kw for the 107-$MW_e$ AES Greenidge Unit 4 installation) and deep emission reduction capabilities (≤0.10 lb/mmBtu NO_x emissions, ≥95% removal of SO_2 and acid gases, ≥90% removal of Hg), key features of the system are its small space requirements (<0.5-

acre for AES Greenidge Unit 4), applicability to high-sulfur coals, low maintenance requirements, and operational flexibility. Commissioning of the demonstration unit at AES Greenidge Unit 4 was completed in March 2007, and preliminary results from performance testing of that unit during the spring of 2007 indicate that it succeeded in achieving emission removal efficiencies near or above the targets for NO_x, SO_2, Hg, and acid gases. Hg measurement results were particularly encouraging, as they suggest that the multi-pollutant control system is capable of achieving 90% Hg removal without the need for any activated carbon injection when the unit is operated according to design conditions. Operation of the multi-pollutant control system was hampered for several months after start-up by the accumulation of large particle ash on the surface of the in-duct SCR catalyst; however, a screen has since been installed above the catalyst to overcome that problem. The performance of the system will continue to be evaluated through October 2008 as part of the demonstration project being funded by DOE and AES Greenidge; results will provide valuable information for evaluating the applicability of the multi-pollutant control system to the large fleet of existing, smaller coal-fired units.

ACKNOWLEDGMENT AND DISCLAIMER

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