GREENIDGE MULTI-POLLUTANT CONTROL PROJECT

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QUARTERLY PROGRESS REPORT
FOR WORK PERFORMED DURING THE PERIOD
January 1, 2008 to March 31, 2008

May 14, 2008

1.0 Executive Summary

As part of the Greenidge Multi-Pollutant Control Project, CONSOL Energy Inc. (CONSOL), AES Greenidge LLC (AESG), and Babcock Power Environmental Inc. (BPEI) installed and are testing an integrated multi-pollutant control system on one of the nation's smaller existing coal-fired power plants - the 107-MWe AES Greenidge Unit 4 (Boiler 6). The overall goal of this approximately 2.5-year project, which is being conducted as part of the U.S. Department of Energy's (DOE's) Power Plant Improvement Initiative (PPII), is to demonstrate that the multi-pollutant control system being installed, which includes 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, can cost-effectively reduce emissions of NO_x, SO_2, Hg, acid gases (SO_3, HCl, HF), and particulate matter (PM) from coal-fired electric generating units (EGUs) with capacities of 50 MWe to 600 MWe. Smaller coal-fired units, which constitute a significant portion of the nation's existing generating capacity, are increasingly vulnerable to retirement or fuel switching as a result of progressively more stringent state and federal environmental regulations. The Greenidge Project will demonstrate the commercial readiness of an emissions control system that is particularly suited, because of its low capital and maintenance costs and small space demands, to meet the requirements of this large group of existing EGUs. All funding for the project is being provided by the U.S. DOE, through its National Energy Technology Laboratory (NETL), and by AES Greenidge.

The multi-pollutant control system is depicted in Figure 1. The NO_x control system consists of commercially available combustion modifications (installed outside of the scope of the DOE project), a urea storage, dilution, and injection system (SNCR), and a single-bed, in-duct SCR reactor that is fed by ammonia slip from the SNCR process. The Turbosorp® system for SO_2, SO_3 (visible emissions), mercury, HCl, HF, and particulate matter control consists of a lime hydrator and hydrated lime feed system, a process water system, the Turbosorp® vessel, a baghouse for particulate control, an air slide system to recycle solids collected in the baghouse to the Turbosorp® vessel, and an activated carbon injection system for mercury control. A booster fan is also installed to overcome the pressure drop resulting from the installation of the SCR catalyst, Turbosorp® scrubber, and baghouse.

Specific objectives of the project are as follows:

- Demonstrate that the hybrid SNCR/SCR system, in combination with combustion modifications, can reduce high-load NO_x emissions from the 107-MWe AES Greenidge Unit 4 to ≤0.10 lb/mmBtu (a reduction of ≥60% following the combustion modifications) while the unit is firing >2%-sulfur coal and co-firing up to 10% biomass.
- Demonstrate that the Turbosorp® circulating fluidized bed dry scrubber can remove ≥95% of the SO_2 emissions from AES Greenidge Unit 4 while the unit is firing >2%-sulfur coal and co-firing up to 10% biomass.
- Demonstrate ≥90% mercury removal via the co-benefits afforded by the SNCR/SCR and Turbosorp® circulating fluidized bed dry scrubber (with baghouse) systems and, as required, by carbon or other sorbent injection.
- Demonstrate ≥95% removal of acid gases (SO_3, HCl, and HF) by the Turbosorp® circulating fluidized bed dry scrubber.

- Evaluate process economics and performance to demonstrate the commercial readiness of an emission control system that is suitable for meeting the emission reduction requirements of boilers with capacities of 50 MWe to 600 MWe.

This quarterly report, the eighth to be submitted for the Greenidge Multi-Pollutant Control Project, summarizes work performed on the project between January 1 and March 31, 2008. During the period, commercial operation of the multi-pollutant control system at AES Greenidge continued. The system operated from January 3 through March 31 without requiring an outage to remove large particle ash (LPA) from the in-duct SCR reactor. This marks the longest period of continuous operation without a catalyst cleaning outage since start-up of the multi-pollutant control system in early 2007. Nevertheless, accumulation of LPA caused a gradual increase in the pressure drop across the reactor between January and March, eventually forcing a small derate at the end of the quarter, and the project team developed plans to install a smaller-pitch LPA screen in May 2008 to further mitigate the SCR plugging problem. The Turbosorp® system continued to operate commendably, achieving an average SO_2 emission rate of ~0.13 lb SO_2 / mmBtu, which is well below the unit's permitted rate (30-day rolling average) of 0.19 lb SO_2 / mmBtu. Results became available from the four reduced-load Hg tests performed in November 2007, and each showed ≥99% Hg removal as a co-benefit of the in-duct SCR, Turbosorp® scrubber, and baghouse, without any activated carbon injection. AESG generally had to operate the hybrid NO_x control system above its performance target of 0.10 lb/mmBtu for high-load NO_x emissions in order to achieve acceptable combustion characteristics, steam temperatures, and NH_3 slip. (Average high-load NO_x emissions during the quarter were 0.14 lb/mmBtu, and NH_3 slip tests performed in March indicated greater than the targeted 2 ppmv of slip). During the week of March 10, we completed a series of process performance tests to evaluate the multi-pollutant control system while AES Greenidge Unit 4 co-fired sawmill waste wood with coal. Results of those tests are still being analyzed. Two additional weeks of process performance testing and one week of follow-up testing are planned for May and June 2008, following the installation of the smaller-pitch LPA screen and a clean catalyst layer in early May.

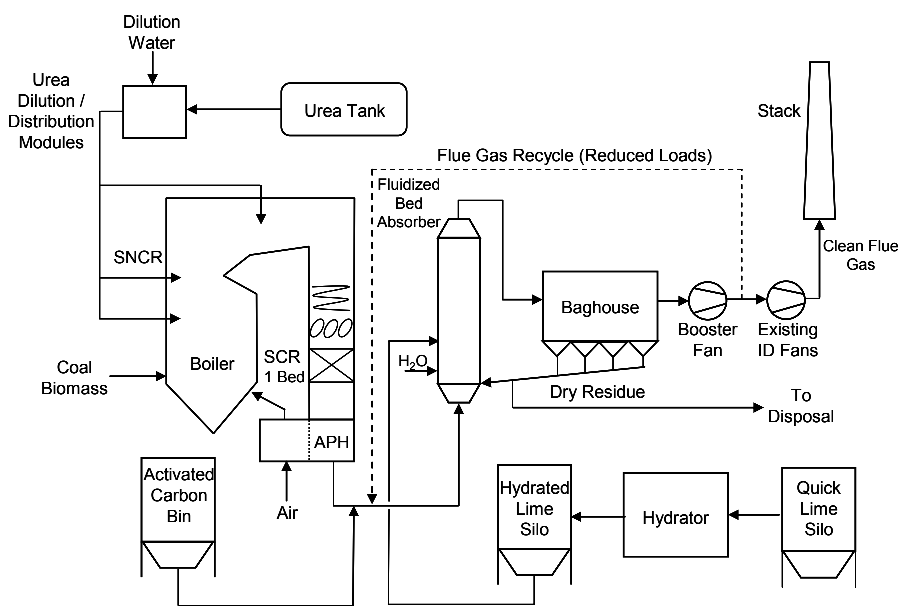


Figure 1. Schematic of the multi-pollutant control system being demonstrated at AES Greenidge Unit 4.

2.0 Work Performed and Results Obtained During the Reporting Period

Highlights of the Greenidge Multi-Pollutant Control Project during the period from January 2008 through March 2008 included the completion of another week of process performance testing of the multi-pollutant control system and the presentation of project results at a major power industry conference. For the first time since start-up of the multi-pollutant control system in early 2007, the system operated for an entire quarter without requiring an outage to clean large particle ash from the in-duct SCR catalyst. Nevertheless, accumulation of LPA caused a gradual increase in the pressure drop across the reactor between January and March, and the project team developed plans to install a smaller-pitch LPA screen in May 2008 to further mitigate the SCR plugging problem. Work performed and results obtained between January 1, 2008, and March 31, 2008, are described below by Statement of Project Objectives task number.

Tasks 1.1 and 2.1 – Project Management

These tasks are complete. Project management activities during the first quarter of calendar year 2008 are summarized below under Task 3.1 – Phase 3 Project Management.

Task 1.2 – Total Process Definition and Design

As discussed in the quarterly progress report for the third calendar quarter of 2006, this task is complete.

Task 1.3 – Procurement

As discussed in the quarterly progress report for the fourth calendar quarter of 2006, this task is complete.

Task 1.4 – Environmental/Regulatory/Permitting

As reported last quarter, the modified Title V air permit for AES Greenidge was issued in final form by the New York State Department of Environmental Conservation (DEC) on November 5, 2007. The newly renewed permit, which reflects the emission requirements set forth in the consent decree between AES and the State of New York, is valid through November 4, 2012. On February 28, 2008, the New York State DEC approved the curve that establishes the permitted NO_x emission rate for AES Greenidge Unit 4 as a function of unit load.

The State Pollutant Discharge Elimination System (SPDES) permits for AES Greenidge and for the Lockwood Landfill (where AES Greenidge disposes its ash) and the solid waste permit for the Lockwood Landfill are in various stages of renewal. These permits are being modified to reflect changes resulting from the installation of the multi-pollutant control system. The AES Greenidge plant continues to operate with an “administratively renewed" SPDES permit while the renewal process for that permit is completed. The Request for Information application for the Lockwood SPDES permit is due to the New York State DEC in July 2008. Finally, AES is awaiting renewal of the solid waste permit for the Lockwood Landfill; correspondence with the New York State DEC with respect to that permit is still ongoing.

At the end of February and beginning of March 2008, three samples collected from the wastewater treatment plant at AES Greenidge had total suspended solids (TSS) concentrations that exceeded permit conditions. The greater-than-normal TSS concentrations appeared to be caused by excess calcium, which could have resulted from Turbosorp® product ash or fugitive lime being washed into the wastewater. AES Greenidge promptly notified the New York State DEC of the problem, and they have implemented corrective measures in the wastewater treatment plant to resolve it.

Task 1.5 – Environmental Information Volume

As discussed in the quarterly progress report for the second calendar quarter of 2006, this task is complete.

Task 1.6 – Baseline Testing

As discussed in the quarterly progress report for the second calendar quarter of 2006, this task is complete.

Tasks 2.2 and 2.3 – General Civil/Structural and Process System Construction

As discussed in the quarterly progress report for the first calendar quarter of 2007, these tasks are complete.

Task 2.4 – Plant Start-Up and Commissioning

As discussed in the project's last quarterly progress report, all major activities associated with start-up and commissioning of the multi-pollutant control system were completed by the end of the first quarter of calendar year 2007. However, two engineering, procurement, and construction (EPC) contract milestones that are associated with Task 2.4 (i.e., achievement of final completion, submittal of final documents) had not yet been attained as of the end of the first quarter of 2008. We expect that these two remaining milestones, which are not on the project's critical path, will be completed during the upcoming quarter.

Task 3.1 – Phase 3 Project Management

Project management activities during the first quarter of calendar year 2008 focused on further developing a strategy for mitigation of the multi-pollutant control system's SCR plugging problem and on planning for additional testing of the multi-pollutant control system. Meetings were held at AES Greenidge on January 17 and February 19 for these purposes. As discussed under Task 3.2 below, AES Greenidge plans to install a smaller-pitch large particle ash screen during their planned spring outage in May 2008 to reduce the severity of the SCR plugging problem. During the first quarter of 2008, we completed one week of process performance testing of the multi-pollutant control system (see discussion under Task 3.3); two additional weeks of process performance testing and one week of follow-up testing are planned for May and June 2008, following the completion of the spring outage. This will satisfy the project's testing requirements. On March 17, we met with DOE to discuss various project administrative topics, including budget requirements through the end of the project period. The project is still on track for completion in October 2008. The project's cost and schedule performance through the end of the first quarter of 2008 are presented in greater detail in Section 3.0 of this report.

We also continued to publicize project results during the quarter. On January 30, we gave a presentation titled "Mercury Removal Performance of the Greenidge Multi-Pollutant Control System" at the EUEC Energy & Environment Conference in Tucson, AZ. In addition, on March 20, we gave a presentation titled "The Greenidge Multi-Pollutant Control Project: Demonstration of an Innovative Retrofit Option for Smaller Coal-Fired Power Plants" to the Energy Technology Group of the American Chemical Society (ACS), Pittsburgh Section. Copies of the EUEC and ACS presentations are included as Attachments A and B, respectively, to this report.

In January, we submitted an abstract titled "First-Year Operating Experience from the Greenidge Multi-Pollutant Control Project" to the organizers of the 2008 Clearwater Coal Conference (June 1-5, Clearwater, FL), and in February, we submitted an abstract titled "The Greenidge Multi-Pollutant Control Project: Demonstration Results and Deployment of Innovative Technology for Reducing Emissions from Smaller Coal-Fired Power Plants" to the organizers of the 2008 Pittsburgh Coal Conference (September 29-October 2, Pittsburgh, PA). Copies of these abstracts are included as Attachments C and D to this report. The Clearwater Coal Conference abstract was accepted for presentation, and we expect to receive notification regarding acceptance of the Pittsburgh Coal Conference abstract during the upcoming quarter. Also, in March, our abstract titled "The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation" was accepted for presentation at the 2008 Power Plant Air Pollutant Control "MEGA" Symposium, which will be held on August 25-28 in Baltimore, MD. We submitted a presentation titled "Results from the First Year of Operation of a Circulating Fluidized Bed Dry Scrubber with High-Sulfur Coal at AES Greenidge Unit 4" to the organizers of the 2008 Electric Power Conference; Doug Roll from AES Greenidge will give that presentation in Baltimore, MD, on May 8.

Finally, on March 26-27, we submitted final versions of two reports titled "Guarantee Testing Results from the Greenidge Multi-Pollutant Control Project" and "Addendum to Guarantee Testing Results from the Greenidge Multi-Pollutant Control Project" to DOE. The first report describes the results of NO_x, NH_3, SO_2, SO_3, Hg, HCl, and HF measurements that were performed by CONSOL and Clean Air Engineering (CAE) at AES Greenidge Unit 4 on March 28-30 and May 1-4, 2007, and the addendum describes the results of additional NH_3, NO_x, and CO measurements that were performed by CONSOL and CAE on May 31-June 1 and June 20-21, 2007.

Task 3.2 – Plant Operations

Routine commercial operation of the multi-pollutant control system at AES Greenidge Unit 4 continued throughout the first quarter of calendar year 2008. During the quarter, the system achieved an average SO_2 emission rate of ~0.13 lb/mmBtu when Unit 4 was operating above 42 MW_{gross}, and it achieved an average high-load NO_x emission rate of ~0.14 lb/mmBtu (based on preliminary hourly average data, weighted by heat input, from the unit's stack CEM).

For the first time since start-up of the multi-pollutant control system in early 2007, the hybrid NO_x control system operated for an entire quarter without requiring an outage to clean large particle ash from the in-duct SCR reactor. As discussed in the project's last quarterly progress report, AES Greenidge held an outage in late December 2007 to inspect and clean the SCR reactor and to replace the SCR catalyst layer with a freshly cleaned layer. (This fresh layer is the original catalyst that was installed when the SCR was constructed in 2006; it was removed from the reactor in May 2007 after becoming plugged with large particle ash and sent for professional cleaning in early December 2007). Although the work in the SCR was complete, a problem with the Unit 4 distributed control system (DCS) prevented the unit from returning to service by the end of the year. The DCS problem was resolved in early January 2008, and Unit 4 returned to service on the morning of January 3. The pressure drop across the SCR reactor returned to its full-load baseline of about 1.1 – 1.2 i.w.c. for a clean catalyst. However, the pressure drop across the reactor gradually increased throughout the quarter. We suspect that AES's efforts to thoroughly patch gaps in the LPA screen during the December 2007 outage, along with the installation of a freshly cleaned catalyst during that outage, helped to slow the rate of catalyst plugging relative to last year. Moreover, Unit 4 was derated because of coal quality issues for a time in February and early March, which may have helped to reduce the rate of LPA accumulation in the catalyst. At the end of March, the pressure drop across the SCR was nearly 4 i.w.c., and plant personnel had to derate Unit 4 to 95 MW_{net} to avoid the risk of implosion of the ductwork located between the air preheaters and the Turbosorp® scrubber. (Pressure drop arising from air heater fouling also contributes to the negative static pressure downstream of the air preheaters, and hence, to the derate. This fouling can result from ammonium bisulfate formation on the air preheater baskets, which may be promoted by an increase in ammonia slip from the SCR reactor as the catalyst becomes plugged). AES Greenidge plans to operate Unit 4 until its planned spring outage, which is scheduled to begin on the evening of May 2, without taking an outage for catalyst cleaning.

Thus, although the severity of the LPA problem appeared to decrease during the first quarter of 2008, plugging of the in-duct SCR catalyst continued to be a problem for AES Greenidge Unit 4. The project team worked throughout the quarter to diagnose the cause of the SCR plugging problem and to develop a solution for implementation during the May 2008 outage. During the outage in late December 2007, AES Greenidge collected ten samples of LPA, fly ash, and other deposits from the SCR reactor and surrounding ductwork. These samples were sent to CONSOL for bulk chemical analysis and to Lehigh University for X-ray diffraction (XRD) analysis to determine whether the physical mechanism of catalyst plugging by LPA was being exacerbated by a chemical mechanism of plugging. Results of the bulk chemical analyses were discussed during a project status review meeting including representatives from CONSOL, AES Greenidge, and DOE on January 17, and results of the bulk chemical analyses and XRD analyses were discussed during a meeting including representatives from Lehigh, AES Greenidge, DOE, CONSOL, Fuel Tech, and Cormetech on February 19. The bulk chemical analysis results did not indicate any chemical mechanisms of plugging, although several interesting observations were noted with respect to the sulfur, ammonia, iron, and carbon content of the samples. Apart from typical ash components (e.g., Fe_2O_3, Al_2O_3, SiO_2), XRD analysis identified calcium sulfate, sodium nitrate, and calcium urate hexahydrate (a possible product of urea decomposition) in some of the samples; however, the abundance of these components was small relative to the ash components, and no clear evidence of a chemical mechanism of catalyst plugging was discovered.

Hence, it appears that the catalyst plugging is caused largely by pieces of LPA that are small enough to pass through the LPA screen but large enough to lodge in the catalyst. The LPA in the catalyst channels can then promote subsequent accumulation and bridging of fly ash, especially in areas of reduced flue gas velocity. (Accumulation of LPA and/or fly ash also contributes to an altered velocity profile through the catalyst). This physical mechanism of plugging is supported by observations of LPA lodged in the catalyst and catalyst screen during the late December outage and by BPEI's dissection of a catalyst element that was pulled from the SCR reactor during the unit's November 2007 outage. Therefore, AES Greenidge plans to modify the LPA screen to address the catalyst plugging problem mechanically (i.e., by preventing LPA from penetrating the screen and lodging in the catalyst). During the unit's scheduled outage in early May 2008, the current LPA screen will be replaced with a new, smaller-pitch screen to improve the ability to filter small pieces of LPA from the flue gas. The catalyst layer currently being used will also be replaced at that time with the layer that was removed during the late December outage, which was sent in mid-March for professional cleaning. Several of the catalyst modules were damaged after being sent for cleaning. AES Greenidge plans to have these damaged modules refitted with larger-pitch catalyst so that the performance of this catalyst can be evaluated during the period of operation following the May outage. Plant personnel are also considering altering the rake soot blower during the May outage so that it blows at a 45° angle rather than perpendicularly relative to the catalyst surface. (In early January, AES decreased the intensity of the rake soot blower to reduce catalyst erosion, which was observed during the late December 2007 outage).

Apart from the catalyst plugging problem, the only operational issue with the hybrid NO_x control system during the quarter occurred during mid-February, when Unit 4 was firing a lower-sulfur, lower-Btu coal than normal. For a time, plant personnel had trouble maintaining a NO_x emission rate near the setpoint of 0.125 lb/mmBtu with this fuel. However, they were eventually able to improve NO_x emissions by adjusting the burner tilts. (As discussed in previous quarterly reports, although the hybrid NO_x control system demonstrated attainment of its NO_x emission performance target of 0.10 lb/mmBtu during guarantee testing in late March 2007, the plant has generally had trouble achieving this emission rate while also maintaining acceptable combustion characteristics, sufficiently high steam temperatures, and sufficiently low ammonia slip for routine operation. As a result, they have normally operated the NO_x control system so that it achieves a high-load NO_x emission rate between 0.10 lb/mmBtu and 0.15 lb/mmBtu).

Apart from a few short-lived problems, the Turbosorp® scrubber and ancillary equipment operated normally throughout the first quarter of 2008. The lime hydration system required maintenance on January 15-16 and was offline for a time (among other things, a bolt fell out of the ball mill, allowing balls to spill out); AES continued to operate the Turbosorp® system during this period using hydrated lime from its onsite inventory and purchased hydrated lime. The plant later encountered some problems with the air slides during the weekend of January 19-20. The problems appeared to result from the control strategy for disposing ash from the system, which biased the entire ash disposal to one of the air slides, causing the ash removal system on that side to plug. The unit had to be derated to about 50 MW for several hours while the blockage was cleared. AES is considering modifying the control scheme for the ash disposal system to prevent this problem from recurring.

In February, plant personnel encountered some problems with freezing lines and valves in the lime hydration system and with freezing and clogging of the dosing valves in the Turbosorp® system during periods of cold weather. They succeeded in overcoming these problems by cleaning, heating, and/or insulating the problem areas, and they were able to operate the Turbosorp® scrubber with a very low set point for SO_2 emissions to make up for the higher-than-normal emissions encountered during the problem period. AES found it to be relatively easy to achieve very low SO_2 emissions with the lower-sulfur coal (e.g., 2.8 lb SO_2 / mmBtu) that they fired at times in February.

Early in March, AES Greenidge encountered some problems with frozen pressure transmitters in the Turbosorp® system, which caused them to lose the fluidized bed several times. Plant personnel succeeded in thawing the transmitters, and the scrubber returned to normal operation. In addition, the plant experienced problems with balls escaping from the lime hydration system's ball mill and ultimately jamming the rotary feeder that removes heavies from the hydrated lime classifier. In mid-March, an escaped ball caused a screw conveyer failure, forcing the lime hydration system offline for repair. Plant personnel were able to continue to operate the Turbosorp® scrubber using hydrated lime from their onsite storage tanker while the repairs were completed. They are in the process of adding magnets at the inlet and outlet of the bucket elevator to capture escaped balls before they can cause problems elsewhere in the system.

Task 3.3 – Testing and Evaluation

During the first calendar quarter of 2008, we continued to analyze the results of the process performance tests that were conducted at AES Greenidge in late 2007. Moreover, on March 10-13, 2008, we completed a fourth round of process performance testing of the multi-pollutant control system. These activities are described in more detail below.

As discussed in the project's last quarterly progress report, three weeks of process performance testing were conducted at AES Greenidge Unit 4 during October and November 2007. The two weeks of tests in October were conducted to evaluate the performance of the multi-pollutant control system while Unit 4 was firing a higher-than-normal sulfur coal (i.e., 4.4 – 4.9 lb SO_2 / mmBtu) and to examine the effects of changes in the Ca/S molar ratio and approach temperature on the multi-pollutant removal performance of the Turbosorp® system. Flue gas sampling results from the October test period were summarized in the last quarterly report.

The week of tests in November was designed to evaluate the performance of the multi-pollutant control system when Unit 4 was operating at reduced loads and when it was co-firing biomass (waste wood from a furniture manufacturing process) with coal. The tests were conducted on November 13-16. Ammonia slip results from the November test period were reported last quarter; SO_3 and Hg testing results from that period became available in January 2008. During the first night of testing, we performed two Hg tests and three SO_3 tests at low load (56 MW_{gross}), and during the second night, we performed two Hg tests and three SO_3 tests at intermediate load (79-85 MW_{gross}). The coal-to-stack mercury removal efficiencies measured during the four reduced-load Hg tests, which did not include any activated carbon injection, were all 99% or greater. The SO_3 removal efficiencies measured across the Turbosorp® scrubber (and baghouse) on each night ranged from 84% to 96 or 97%. (The SO_3 concentration at the Turbosorp® inlet trended upward with time each night). The average SO_3 removal efficiency during the low-load tests was 92.6%, and the average SO_3 removal efficiency during the intermediate-load tests was 89.1%. During the last day of testing, we performed two SO_3 tests at 102-103 MW_{gross} with waste wood co-firing. The measured SO_3 removal efficiencies during these tests were 96.4% and 95.9%.

Because only one day of testing with biomass co-firing could be completed in November 2007, additional biomass co-firing tests were performed on the week of March 10. During the March 2008 test series, the waste wood originated from a sawmill rather than from a furniture manufacturing plant, and therefore it did not contain any synthetic glues. Figure 2 presents a photograph of the waste wood that was used during the test period. On March 10, we completed one test run during which we simultaneously measured SO_3 at four locations (economizer outlet, air heater inlet, air heater outlet, and stack), HCl, HF, and PM at two locations (air heater outlet and stack), and ammonia slip at the air heater inlet. On March 11, we completed two test runs, each of which included simultaneous measurement of mercury at the economizer outlet, air heater inlet, air heater outlet, and stack. (The mercury and SO_3 measurements at the economizer outlet and air heater inlet were conducted to examine Hg and SO_2 oxidation across the in-duct SCR catalyst). Unit 4 began co-firing a drier wood product on March 12, which enabled the wood to provide a greater percentage of the unit's heat input. That day, we completed two Hg test runs, each including simultaneous sampling at the economizer outlet, air heater inlet, air heater outlet, and stack, with this drier wood. Finally, on March 13, we completed three test runs during which we simultaneously measured SO_3 (economizer outlet, air heater inlet, air heater outlet, and stack), HCl/HF/PM (air heater outlet and stack), and ammonia slip (air heater inlet) while the unit co-fired the drier wood product. Figure 3 presents a photograph showing SO_3, HCl, HF, and PM sampling at the air heater outlet on March 13. Solid and liquid process samples and plant operating data were collected throughout the test period for use in evaluating the overall performance of the multi-pollutant control system. In addition, on March 10 and 13, we ran several tests without urea injection in order to establish the baseline NO_x emission rate from the unit's low-NO_x burners and separated overfire air system.

Figure 2. Photograph of sawmill waste wood that was co-fired with coal during process performance testing of the multi-pollutant control system at AES Greenidge Unit 4 on March 10-13, 2008.

As of the end of the quarter, the flue gas and process samples collected during the tests on March 10-13 were being analyzed by CONSOL's analytical laboratory. The average ammonia slip measured during the four tests at the air heater inlet on March 10 and 13 was 5.9 ppmvd @ 3% O_2 (range = 5.4 - 6.4 ppmvd @ 3% O_2). This is among the highest ammonia concentrations that we have observed at the air heater inlet during the project, likely because the catalyst was relatively dirty during the March 2008 test period (i.e., the testing was not conducted immediately after a catalyst cleaning outage, as was the case with several previous testing campaigns). Results for SO_3, Hg, HCl, HF, and PM will become available in the early part of the second quarter of 2008.

Three additional test series are planned as part of the project. The first of these series, scheduled for the week of May 18, 2008, is designed to generate additional information about the performance of the multi-pollutant control system at reduced unit loads, and in particular, to thoroughly characterize the performance of the NO_x control system (i.e., ammonia slip, NO_x and CO grid profiles, SCR velocity profile) as a function of load following the installation of the smaller-pitch LPA screen and clean catalyst layer in early May. The remaining two test series include follow-up testing of the multi-pollutant control system (i.e., a repeat of the guarantee testing after the system has operated commercially for more than one year) and additional parametric testing of the Turbosorp® system. These tests are planned for June 2008.

Figure 3. Photograph showing SO_3, HCl, HF, and PM sampling activities at the AES Greenidge Unit 4 air heater outlet on March 13, 2008.

3.0 Status Reporting

3.1 Cost Status

Table 1 summarizes the cost status of the Greenidge Multi-Pollutant Control Project through the end of the first quarter of calendar year 2008. As shown in the table, actual incurred costs for the first quarter of 2008 were \$508,554 greater than baseline planned costs for that quarter, and cumulative actual incurred costs were \$916,551 greater than cumulative planned costs as of the end of the quarter.

The positive cost variance (i.e., indicating that actual incurred costs exceeded baseline planned costs) for the first quarter of 2008 arose largely because costs for consumables (i.e., urea, pebble lime, and hydrated lime) were \$418,982 greater than originally budgeted for the quarter. As discussed in previous quarterly progress reports, the higher-than-expected costs for consumables resulted primarily from significant price escalation that has occurred since the baseline cost plan was developed. In addition, costs for testing and project administration were \$89,572 greater than originally planned for the quarter. This variance does not indicate that testing and administration were significantly over budget for the quarter. Rather, it reflects an improvement in schedule performance. The costs associated with the process performance tests that were conducted during March 2008 were originally planned for the second quarter of 2007, but project delays prevented them from being incurred until the current quarter.

Because costs for consumables have been greater than expected, the project as a whole was slightly over budget as of the end of the first quarter of 2008. The cumulative cost variance of $916,551 includes $1,465,839 in cost overruns for consumables. These overruns are partially offset by a negative variance of $266,084 for two EPC contract payment milestones that were originally planned for completion during the first calendar quarter of 2007 but had not yet been achieved as of the end of March 2008, as well as a negative variance of $283,204 associated with testing and project administration. This latter variance consists largely of costs associated with two remaining weeks of process performance testing, which were originally scheduled for May-July 2007 but have yet to be completed.

During the first quarter of 2008, cumulative actual costs for consumables and EPC contract milestones surpassed the project's total budgeted cost for these items. As a result, beginning in mid-March, AES Greenidge began covering 100% of the cost of these items so that remaining DOE funds can be used to complete remaining testing and reporting requirements, in accordance with the overall project budget. Therefore, the federal share of the actual incurred costs and variance shown in Table 1 for the first quarter of 2008 is less than 43.8%, which had been the federal cost sharing percentage in all previous quarters. The AES Greenidge cost share has increased correspondingly.

We anticipate that the project's total cumulative cost variance will continue to be positive during the upcoming quarter, as spending for consumables continues to outpace our original budget and we continue to incur costs associated with the delayed testing activities and EPC contract milestones. (The variance for the federal share is expected to decrease, however, per the discussion in the previous paragraph).

3.2 Milestone Status

The critical path project milestone plan (from the Statement of Project Objectives) and status for the Greenidge Multi-Pollutant Control Project are presented in Table 2. None of the project's six critical path project milestones were scheduled for the current reporting period, and all previous critical path milestones have been achieved on or ahead of schedule.

The next critical path project milestone calls for follow-up testing of the multi-pollutant control system to begin during the second quarter of calendar year 2008. The follow-up tests are designed to reevaluate the performance of the multi-pollutant control system under guarantee testing conditions after more than a year of commercial operation. These tests are currently scheduled to begin during the week of June 9, in time to meet the critical path milestone. (As discussed above, in addition to the follow-up tests, two

Table 1. Cost plan/status for the Greenidge Multi-Pollutant Control Project.

Baseline Reporting Quarter	YEAR 1 Start: 1/1/2006 End: 12/31/2006				YEAR 2 Start: 1/1/2007 End: 12/31/2007				YEAR 3 Start: 1/1/2008 End: 12/31/2008			
	Q1	Q2[a]	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Baseline Cost Plan By Calendar Quarter												
Federal Share		$7,276,205	$1,806,841	$2,135,468	$1,581,828	$365,626	$239,208	$228,040	$235,068	$292,521	$176,448	$4,170
Non-Federal Share		$9,336,136	$2,318,366	$2,740,030	$2,029,651	$469,137	$306,930	$292,599	$301,617	$375,335	$226,402	$5,351
Total Planned (Federal and Non-Federal)		$16,612,341	$4,125,207	$4,875,498	$3,611,479	$834,763	$546,138	$520,639	$536,685	$667,856	$402,850	$9,521
Cumulative Baseline Cost		$16,612,341	$20,737,548	$25,613,047	$29,224,525	$30,059,288	$30,605,426	$31,126,065	$31,662,750	$32,330,606	$32,733,456	$32,742,976
Actual Incurred Costs[b]												
Federal Share		$6,610,049	$1,878,193	$1,644,001	$1,105,221	$544,600	$1,518,234	$511,623	$382,148			
Non-Federal Share		$8,481,387	$2,409,918	$2,109,425	$1,418,114	$698,779	$1,948,053	$656,465	$663,091			
Total Incurred Costs-Quarterly (Federal and Non-Federal)		$15,091,436	$4,288,111	$3,753,426	$2,523,335	$1,243,379	$3,466,287	$1,168,088	$1,045,239			
Cumulative Incurred Costs		$15,091,436	$19,379,547	$23,132,973	$25,656,308	$26,899,687	$30,365,974	$31,534,062	$32,579,301			
Variance[c]												
Federal Share		($666,156)	$71,352	($491,467)	($476,607)	$178,974	$1,279,026	$283,583	$147,080			
Non-Federal Share		($854,749)	$91,552	($630,605)	($611,537)	$229,642	$1,641,123	$363,866	$361,474			
Total Variance-Quarterly (Federal and Non-Federal)		($1,520,905)	$162,904	($1,122,072)	($1,088,144)	$408,616	$2,920,149	$647,449	$508,554			
Cumulative Variance		($1,520,905)	($1,358,001)	($2,480,074)	($3,568,217)	($3,159,601)	($239,452)	$407,997	$916,551			

Notes: Some numbers may not add perfectly because of rounding. [a]Costs for Q2 2006 include costs for that quarter as well as pre-award costs incurred beginning in January 2002. Unallowable direct costs totaling $359,077 and indirect costs totaling $25,135 that were applied to these direct costs have been removed from the baseline costs for Q2 2006, consistent with Amendment No. A002 to Cooperative Agreement DE-FC26-06NT41426. [b]Actual incurred costs are all costs incurred by the project during the quarter, regardless of whether these costs were invoiced to DOE as of the end of the quarter. [c]Negative variance, ( ), means that actual incurred costs are less than baseline planned costs.

Table 2. Milestone plan / status report.

Critical Path Project Milestone Description	Project Duration - Start: 5/19/06 End: 10/18/08												Planned Start Date	Planned End Date	Actual Start Date	Actual End Date	Comments (notes, explanation of deviation from baseline plan)
	2006				2007				2008								
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4					
Initiate scrubber system installation		A	P										9/30/06	9/30/06	5/30/06	5/30/06	
Commence tie-in outage			A	P									12/31/06	12/31/06	9/29/06	9/29/06	
Begin guarantee/performance testing					P A								3/31/07	3/31/07	3/28/07	3/28/07	
Begin routine plant operation and data collection for long-term testing						P A							6/30/07	6/30/07	6/21/07	6/21/07	
Begin follow-up testing										P			6/30/08	6/30/08			
Complete analyses of process performance and economics											P		9/30/08	9/30/08			

NOTE: “A” indicates actual completion; “P” indicates planned completion.

additional weeks of process performance testing are planned for the second quarter of 2008. All of these remaining tests will be performed after the unit's scheduled outage in early May 2008, because a clean SCR catalyst and more efficient LPA screen will be installed during the outage, and tests involving the SCR will provide more valuable results if conducted with a clean catalyst). However, any unexpected delays, such as those resulting from unanticipated problems during the outage or from problems with operation of the unit or multi-pollutant control system, could jeopardize our ability to meet this milestone.

4.0 Significant Accomplishments during the Reporting Period

Significant accomplishments during the first quarter of calendar year 2008, which are described more fully in Section 2.0 above, were as follows:

- Operation of the multi-pollutant control system from January 3 through March 31, 2008, without taking an outage to remove LPA from the in-duct SCR reactor
- Development of a plan to install a smaller-pitch LPA screen in May 2008 to further mitigate the SCR plugging problem
- Completion of a week of process performance testing of the multi-pollutant control system while AES Greenidge Unit 4 co-fired biomass with coal
- Confirmation that greater than 99% Hg removal (coal-to-stack) was attained without any activated carbon injection during each of the four reduced-load Hg tests performed in November 2007 (all Hg tests performed to-date have shown greater than 90% removal)
- Continued commercial operation of the multi-pollutant control system
- Presentation of project results at the EUEC Energy and Environment Conference and at the March luncheon of the Energy Technology Group of the American Chemical Society, Pittsburgh Section
- Submittal of the guarantee testing report (including an addendum describing additional testing results) to DOE

5.0 Problems/Delays and Actions Taken/Planned to Resolve Them

During the first quarter of 2008, AES Greenidge Unit 4 continued to experience problems with large particle ash and fly ash accumulating in the in-duct SCR catalyst, although these problems were less severe than they had been during 2007. As discussed earlier in Section 2.0, although the pressure drop across the SCR reactor increased gradually throughout the quarter, AES Greenidge did not have to take any outages between January 3 and March 31, 2008, to remove LPA from the catalyst. This marks the longest period of continuous operation without a catalyst cleaning outage since the multi-pollutant control system started up in early 2007. Nevertheless, at the end of March, plant personnel had to derate Unit 4 slightly because of elevated pressure drop across the SCR reactor (and across the air preheaters, which become more susceptible to fouling when ammonia slip increases as a result of catalyst plugging). Hence, the SCR plugging problem is not fully resolved. The project team worked throughout the quarter to develop a plan to further mitigate this problem. CONSOL and Lehigh University chemically analyzed samples of LPA, fly ash, and other deposits that were collected in and around the SCR reactor in late December 2007. Personnel from CONSOL, Lehigh, AES, DOE, Fuel Tech, and Cormetech reviewed the results of these analyses in February 2008 and did not find any strong evidence of a chemical mechanism of catalyst plugging. As a result, AES Greenidge has decided to try to mitigate the problem mechanically by installing a smaller-pitch LPA screen that will more efficiently capture pieces of LPA that are small enough to penetrate the current screen but large enough to lodge in the catalyst. The smaller-pitch screen will be installed during the unit's planned spring outage in early May 2008, and it is expected to significantly reduce the severity of the SCR plugging problem. Also during the outage, AES Greenidge will install a clean catalyst layer (i.e., the layer that was removed from the reactor in December 2007 and sent for professional cleaning). Several of the catalyst modules will likely be refitted with larger-pitch catalyst so that the performance of this catalyst can be evaluated during the period of operation following the outage. In the event that the new LPA screen does not sufficiently resolve the catalyst plugging problem, plant personnel would consider altering the catalyst pitch as a next corrective measure.

Process performance testing of the multi-pollutant control system continued to be behind schedule as of the end of the first quarter of 2008. The process performance tests were originally planned for March – July 2007, but they were delayed largely because of the large particle ash problems that have affected Unit 4 and because start-up and commissioning of the system and demonstration of the ammonia slip guarantee took longer than expected during the first half of 2007. Three of the six planned weeks of process performance testing were completed during the fourth quarter of 2007, and as discussed above, a fourth week of process performance testing was completed in March 2008. As of the end of the quarter, however, the pressure drop across the in-duct SCR reactor was too high to allow further testing. AES Greenidge plans to operate Unit 4 until its scheduled May outage without taking an outage for catalyst cleaning. (They will derate the unit as necessary to enable continued operation). Hence, the two remaining weeks of process performance testing are planned for May and June 2008, following the outage. Moreover, as discussed in Section 3.2, follow-up testing of the multi-pollutant control system is scheduled for the week of June 9, keeping the project's critical path on schedule. Therefore, we do not anticipate that the delayed process performance testing will impact the overall project end date of October 2008.

Finally, as described in Section 2.0, the plant encountered several minor operational problems with the Turbosorp® system and ancillary equipment during the quarter. In general, these problems were transient and were able to be resolved without a significant impact on unit operations. As discussed in the project's last quarterly project report, AES mobilized a temporary hydrated lime storage tanker to provide them with flexibility for taking the lime hydration system offline to repair the minor problems that occasionally affect that system. They plan to install a permanent, auxiliary hydrated lime storage silo in 2008. Plant personnel also routinely operate the Turbosorp® system with a setpoint well below its 0.19 lb SO_2 / mmBtu permit limit for SO_2 emissions (30-day rolling average) to provide flexibility for tolerating occasional upsets to the operation of that system. (For example, during the quarterly reporting period, freezing of lines, valves, and pressure transmitters disrupted operation of the Turbosorp® system on several occasions, causing short-lived increases in SO_2 emissions). Corrective measures are being implemented to minimize recurrence of the minor problems encountered during the quarter. Plant personnel improved insulation and heating to address cold weather problems; they are adding magnets to capture any balls that escape from the ball mill so that they will not damage the lime hydration system, and they are reevaluating the control logic for the ash disposal system to minimize the possibility for plugging of that system.

6.0 Products Produced and Technology Transfer Activities Accomplished During the Reporting Period

As discussed in Section 2.0 above, we gave a presentation titled “Mercury Removal Performance of the Greenidge Multi-Pollutant Control System” at the EUEC Energy & Environment Conference in Tucson, AZ, on January 30. We also gave a presentation titled “The Greenidge Multi-Pollutant Control Project: Demonstration of an Innovative Retrofit Option for Smaller Coal-Fired Power Plants” at the March 20 luncheon of the Energy Technology Group of the American Chemical Society, Pittsburgh Section. We submitted abstracts on the project to the organizers of the 2008 Clearwater Coal Conference, which will be held in Clearwater, FL, on June 1-5, and to the organizers of the 2008 Pittsburgh Coal Conference, which will be held in Pittsburgh, PA, on September 29-October 2. Copies of the EUEC presentation, ACS presentation, Clearwater Coal Conference abstract, and Pittsburgh Coal Conference abstract are included as Attachments A, B, C, and D, respectively, to this report. Finally, we completed two reports titled “Guarantee Testing Results from the Greenidge Multi-Pollutant Control Project” and “Addendum to Guarantee Testing Results from the Greenidge Multi-Pollutant Control Project.” (The first report describes the results of guarantee tests that were performed at AES Greenidge Unit 4 between March 28 and May 4, 2007, and the addendum describes the results of additional NH_3, NO_x, and CO measurements that were performed between May 31 and June 21, 2007). The guarantee testing report and addendum were submitted to DOE on March 26 and 27, respectively.

ATTACHMENT A

Mercury Removal Performance of the Greenidge Multi-Pollutant Control System

Presented at the EUEC Energy & Environment Conference, January 28-30, 2008, Tucson, AZ

Mercury Removal Performance of the Greenidge Multi-Pollutant Control System

Daniel P. Connell and James E. Locke
CONSOL Energy Inc., Research & Development

Douglas J. Roll, P.E.
AES Greenidge LLC

Wolfe P. Huber, P.E.
U.S. Department of Energy, National Energy Technology Laboratory

Richard F. Abrams
Babcock Power Environmental Inc.

EUEC Energy & Environment Conference, January 30, 2008, Tucson, AZ

Greenidge Multi-Pollutant Control Project

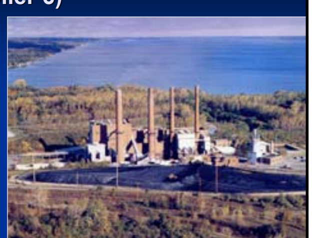
- Part of U.S. DOE's Power Plant Improvement Initiative
- Participants
  - CONSOL Energy Inc. (administration, testing, reporting)
  - AES Greenidge LLC (host site, operations)
  - Babcock Power Environmental Inc. (EPC contractor)
- Funding
  - U.S. Department of Energy, National Energy Technology Laboratory
  - AES Greenidge LLC
- Goal: Demonstrate a multi-pollutant control system that can cost-effectively reduce emissions of NO_x, SO_2, mercury, acid gases (SO_3, HCl, HF), and particulate matter from smaller coal-fired EGUs

Existing U.S. Coal-Fired EGUs
50-300 MW_e

Existing U.S. Coal-Fired EGUs
50-300 MW_e

- ~ 420 units not equipped with FGD, SCR, or Hg control
  - Represent almost 60 GW of installed capacity
  - Greater than 80% are located east of the Mississippi River
  - Most have not announced plans to retrofit
- Difficult to retrofit for deep emission reductions
  - Large capital costs
  - Space limitations
- Increasingly vulnerable to retirement or fuel switching because of progressively more stringent environmental regulations
  - CAIR, CAMR, CAVR, state regulations
- Need to commercialize technologies designed to meet the environmental compliance requirements of these units

AES Greenidge Unit 4
(Boiler 6)



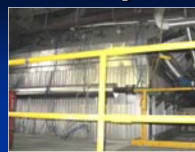
- Dresden, NY
- Commissioned in 1953
- 107 MW_e (net) reheat unit
- Boiler:
  - Combustion Engineering tangentially-fired, balanced draft
  - 780,000 lb/h steam flow at 1465 psig and 1005 °F
- Fuel:
  - Eastern U.S. bituminous coal
  - Biomass (waste wood) – up to 10% heat input
- Existing emission controls:
  - Overfire air (natural gas reburn not in use)
  - ESP
  - No FGD – mid/high-sulfur coal to meet permit limit of 3.8 lb SO_2/MMBtu

Design Objectives

- Deep emission reductions
- Low capital costs
- Small space requirements
- Applicability to high-sulfur coals
- Low maintenance requirements
- Operational flexibility

Multi-Pollutant Control System

- Combustion modifications
  - Low-NO_x burners and overfire air
- Hybrid SNCR / SCR
  - Single-bed, in-duct SCR fed by NH_3 slip from urea-based SNCR



- Activated carbon injection
- Turbosorp® circulating fluidized bed dry scrubber
  - Separate injection of water and dry hydrated lime
  - Includes onsite lime hydrator
- Pulsejet baghouse
  - ~95% of solids recycled to scrubber via air slides
  - Booster fan installed downstream

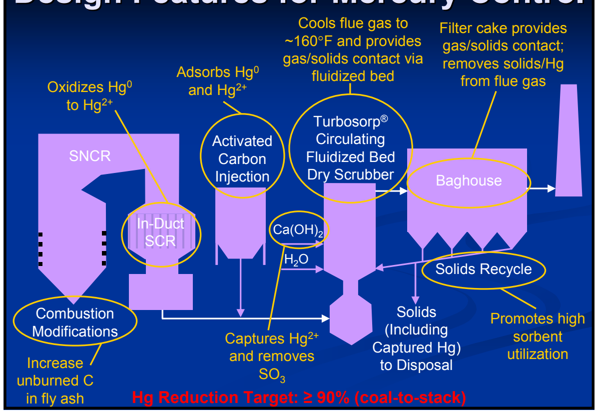
Guarantee Testing Results

March – May 2007, 2.4-3.2% Sulfur Eastern U.S. Bituminous Coal

Parameter	Performance Target	Measured Performance
NO_x emission rate	≤ 0.10 lb/mmBtu	0.10 lb/mmBtu*
SO_2 removal	≥ 95%	96%
SO_3 removal	≥ 95%	97%
HCl removal	≥ 95%	97%
HF removal	≥ 95%	Indeterminate

* Performance of hybrid NO_x control system has been affected by large particle ash and ammonia slip. Plant typically operates at 0.10-0.15 lb/mmBtu to maintain acceptable combustion characteristics.

Design Features for Mercury Control

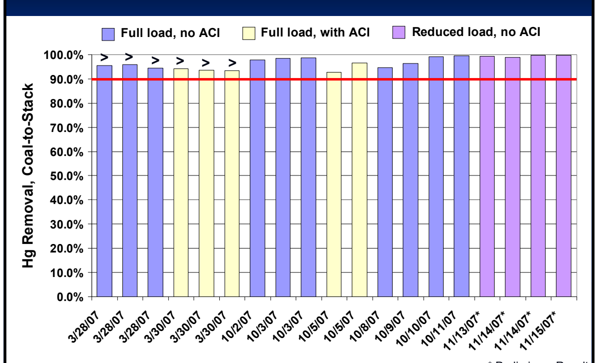


Mercury Testing Methodology

- Flue gas measurements
  - Ontario Hydro Method (ASTM D 6784-02)
  - Liquid samples analyzed by CVAAS (3/07) or CVAFS (10/07-11/07)
  - Particulate samples analyzed per ASTM D 6414 or ASTM D 6722
- Coal samples
  - Collected at beginning / middle of each test (composite of all feeders)
  - Analyzed for Hg by ASTM D 6722

- QA/QC
  - Pre- and post-test leak checks
  - O_2 monitored at meter exhaust
  - ICV standards, duplicate/triplicate analyses, matrix spikes, digestion duplicates, digestion spikes; 100±10% RPD or recovery required
  - Material balance performed for each test

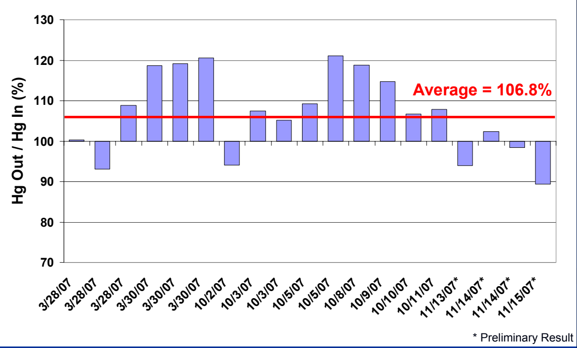
Mercury Removal Efficiency



Plant Conditions During Hg Tests

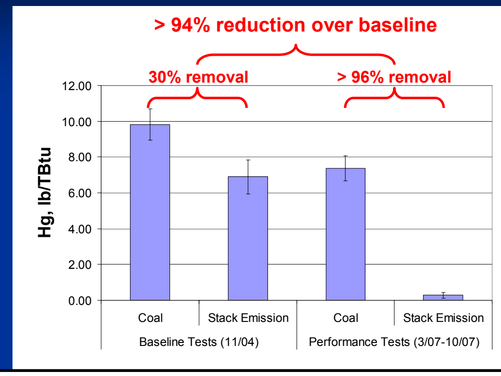
Parameter	Range
Coal Hg content (lb / TBtu)	6.4 – 13.7
Coal S content (lb SO_2 / mmBtu)	3.7 – 4.9
Coal Cl content (wt. %, dry)	0.07 – 0.11
Gross generation (MW)	56.4 – 108.7
Fly ash unburned carbon (%)	9.2 – 25.3
Activated carbon injection rate (lb / mmacf)	0 - 3
SO_2 removal efficiency (%)	92.9 – 99.0
Scrubber outlet temperature (°F)	158.6 – 165.2

Mercury Material Balances



Mercury Reduction Over Baseline

Full-Load Data



Leachability of Captured Hg from Turbosorp® Product Ash

Synthetic Precipitation Leaching Procedure (EPA Method 1312)

	11/14/07	11/15/07	11/16/07
Hg in product ash sample, mg/kg	0.464	0.602	0.667
Hg leached from sample, mg/kg	<0.007	<0.007	<0.007
Hg leached from sample, %	<1.51	<1.16	<1.05

Process Economics

Constant 2005 Dollars

	Capital Cost ($/kW)	Fixed & Variable O&M Cost ($/MWh)	Total Levelized Cost ($/ton removed)
NO_x Control	106	1.19	\$3,290 / ton NO_2
SO_2 Control	229	5.23	\$513 / ton SO_2
Hg Control (incremental)[a]	0	0	0

Assumptions: Plant size = 107 MW, Capacity factor = 80%, Coal sulfur = 4.0 lb SO_2/mmBtu, Baseline NOx emission rate = 0.30 lb/mmBtu, SNCR normalized stoichiometric ratio = 1.5, Ca/S = 1.55, Quicklime = \$110/ton, Urea (50% w/w) = \$1.25/gal, Waste disposal = \$12/ton, Plant life = 20 years, Fixed charge factor = 13.05%, Other assumptions based on common estimating practices and current market prices

[a]Based on performance testing results to-date

Conclusions

- Greenidge MPC process uniquely designed to meet needs of smaller coal-fired units
  - Demonstrated > 95% SO_2 removal and > 60% NO_x removal with capital cost of ~ \$340/kW and footprint of ~ 0.5 acre for 107 MW unit
  - Deep SO_3 and HCl removal and reduced PM emissions are zero cost co-benefits
- Testing results have shown deep Hg removal efficiency
  - Greater than 90% removal efficiency observed in all 19 tests completed thus far, regardless of operating conditions
  - Average demonstrated full-load removal efficiency (> 96%) represents > 94% reduction over baseline
- Projected incremental cost for 90% Hg capture is \$0
  - Ten full-load tests and four reduced-load tests have shown > 90% Hg capture with no activated carbon injection

Future Plans

- Testing and evaluation will continue at AES Greenidge Unit 4 through October 2008
- Additional Hg tests will focus on:
  - Hg removal with biomass co-firing
  - Hg speciation and role of the in-duct SCR in oxidizing Hg
  - Hg removal as a function of fly ash unburned carbon content, fuel, load, and scrubber operating conditions
  - Stability of the captured Hg in the scrubber solids / ash

Disclaimer

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ATTACHMENT B

The Greenidge Multi-Pollutant Control Project: Demonstration of an Innovative Retrofit Option for Smaller Coal-Fired Power Plants

Presented to the Energy Technology Group of the American Chemical Society, Pittsburgh Section, March 20, 2008, Pittsburgh, PA

The Greenidge Multi-Pollutant Control Project: Demonstration of an Innovative Retrofit Option for Smaller Coal-Fired Power Plants

Dan Connell

CONSOL Energy Inc. Research & Development

Energy Technology Group Luncheon, Pittsburgh Section, American Chemical Society
March 20, 2008

Greenidge Multi-Pollutant Control Project

- Part of U.S. DOE's Power Plant Improvement Initiative
- Participants
  - CONSOL Energy Inc. (administration, testing, reporting)
  - AES Greenidge LLC (host site, operations)
  - Babcock Power Environmental Inc. (EPC contractor)
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- Goal: Demonstrate a multi-pollutant control system that can cost-effectively reduce emissions of NO_x, SO_2, mercury, acid gases (SO_3, HCl, HF), and particulate matter from smaller coal-fired EGUs

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  - Represent almost 60 GW of installed capacity
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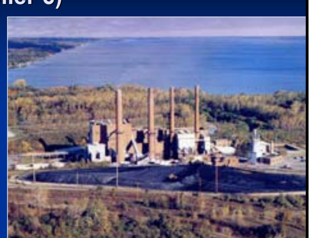
  - Space limitations
- Increasingly vulnerable to retirement or fuel switching because of progressively more stringent environmental regulations
  - CAIR, Hg MACT, CAVR, state regulations
- Need to commercialize technologies designed to meet the environmental compliance requirements of these units

AES Greenidge Unit 4
(Boiler 6)



- Dresden, NY
- Commissioned in 1953
- 107 MW_e (EIA net winter capacity)
- Reheat unit
- Boiler:
  - Combustion Engineering tangentially-fired, balanced draft
  - 780,000 lb/h steam flow at 1465 psig and 1005 °F
- Fuel:
  - Eastern U.S. bituminous coal
  - Biomass (waste wood) – up to 10% heat input
- Existing emission controls:
  - Overfire air (natural gas reburn not in use)
  - ESP
  - No FGD – mid/high-sulfur coal to meet permit limit of 3.8 lb SO_2/MMBtu

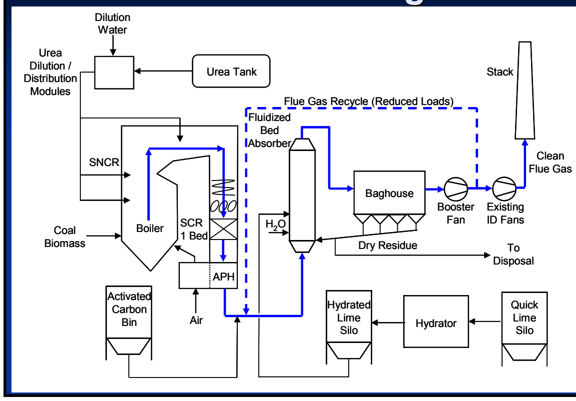
Design Objectives

- Deep emission reductions
- Low capital costs
- Small space requirements
- Applicability to high-sulfur coals
- Low maintenance requirements
- Operational flexibility

Multi-Pollutant Control Process

- Combustion modifications
  - Low-NO_x burners and overfire air
  - Installed outside of DOE scope
- NO_xOUT CASCADE® hybrid SNCR/SCR (Fuel Tech)
  - Urea-based, in-furnace selective non-catalytic reduction
  - Single-bed, in-duct selective catalytic reduction
- Activated carbon injection
- Turbosorp® circulating fluidized bed dry scrubber (Austrian Energy / Babcock Power Environmental)
- Pulsejet baghouse

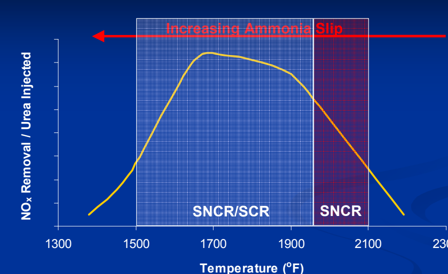
Process Flow Diagram



Hybrid NO_x Control

- Combustion Modifications
  - Replace coal, combustion air, and overfire air nozzles
  - Improve fuel/air mixing, burner exit velocity, secondary airflow control, and upper furnace mixing; reduce CO
  - Reduce NO_x to 0.25 lb/MMBtu
- SNCR
  - $CO(NH_2)_2 + 2\ NO + ½\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$
  - Reduce NO_x by ~ 42.5% (to 0.144 lb/MMBtu)
- SCR
  - $4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$
  - $NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O$
  - Reduce NO_x by > 30% (to ≤ 0.10 lb/MMBtu)

SNCR for Hybrid System

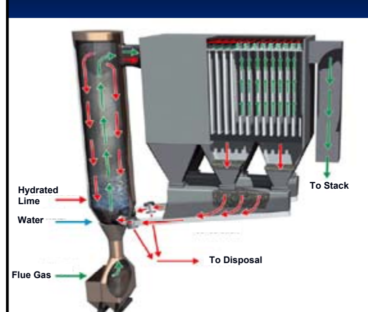


- Hybrid SNCR operates at lower temperature than stand-alone SNCR
  - Enables greater NO_x reduction and better urea utilization by SNCR
  - Provides ammonia slip for additional NO_x reduction by SCR

Single-Bed, In-Duct SCR

- Compact design
  - Bed depth ~ 1.3 m
  - Cross section ~ 45' x 14'
- No ammonia injection grid
- Designed for lower NO_x removal efficiency than conventional SCR
- Includes Delta Wing™ static mixers to improve reagent, flow, temperature, and ash distribution

Turbosorp® System



- Completely dry
- Separate control of hydrate, water, and recycled solid injection
- High solids recirculation
- Applicable to high-sulfur coals
- 15-25% lower reagent consumption than spray dryers
- Low capital and maintenance costs relative to other FGD technologies

Circulating Fluidized Bed Dry Scrubber Chemistry

$$Ca(OH)_2 + SO_2 \leftrightarrow CaSO_3 \cdot \frac{1}{2} H_2O + \frac{1}{2} H_2O$$

$$Ca(OH)_2 + SO_3 \leftrightarrow CaSO_4 \cdot \frac{1}{2} H_2O + \frac{1}{2} H_2O$$

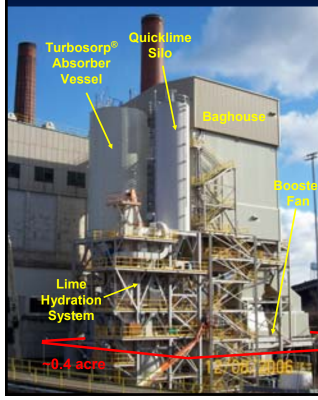
$$CaSO_3 \cdot \frac{1}{2} H_2O + \frac{1}{2} O_2 \leftrightarrow CaSO_4 \cdot \frac{1}{2} H_2O$$

$$Ca(OH)_2 + 2\ HCl \leftrightarrow CaCl_2 + 2\ H_2O$$

$$Ca(OH)_2 + 2\ HF \leftrightarrow CaF_2 + 2\ H_2O$$

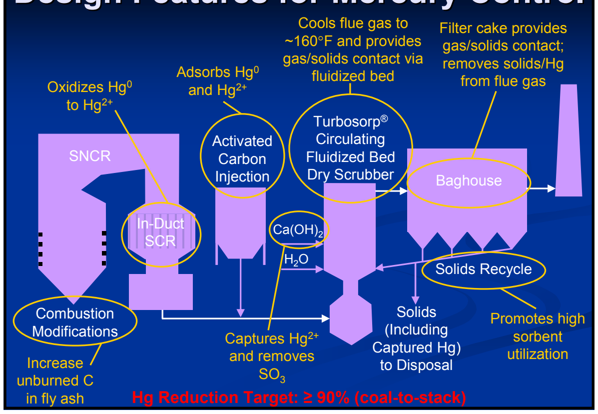
$$Ca(OH)_2 + CO_2 \leftrightarrow CaCO_3 + H_2O$$

AES Greenidge Installation

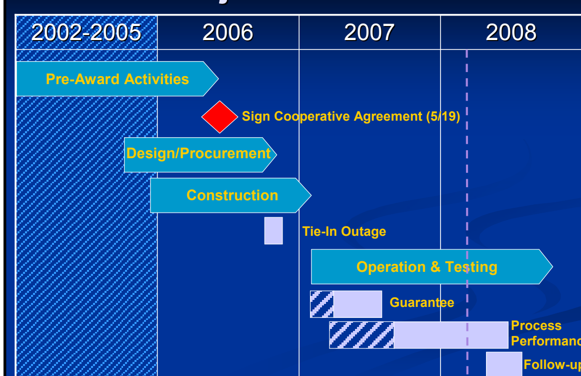


- Small footprint
- Carbon steel construction
- Includes:
  - Activated carbon injection system
  - Onsite lime hydration system
  - Eight-compartment pulsejet fabric filter
  - Booster fan
- Uses existing stack (liner not required)
- Projected Ca/S is 1.6-1.7 mol/mol for design fuel

Design Features for Mercury Control



Project Schedule



Guarantee Tests

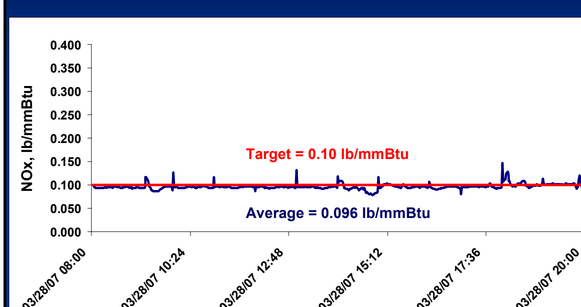
March-May 2007, 2.4-3.2% Sulfur Eastern U.S. Bituminous Coal

Parameter	Performance Target	Measured Performance
NO_x emission rate	≤ 0.10 lb/mmBtu	0.10 lb/mmBtu*
SO_2 removal	≥ 95%	96%
Hg removal	≥ 90%	
Activated C Injection		≥94%
No Activated C Injection		≥95%
SO_3 removal	≥ 95%	97%
HCl removal	≥ 95%	97%
HF removal	≥ 95%	Indeterminate

* Performance of hybrid NO_x control system has been affected by large particle ash and ammonia slip. Plant typically operates at 0.10-0.15 lb/mmBtu to maintain acceptable combustion characteristics.

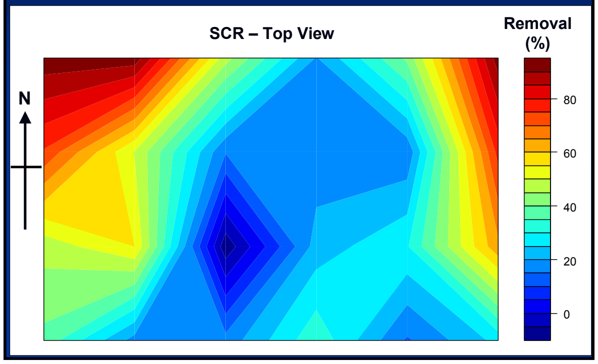
NO_x Emission Rate

March 28, 2007



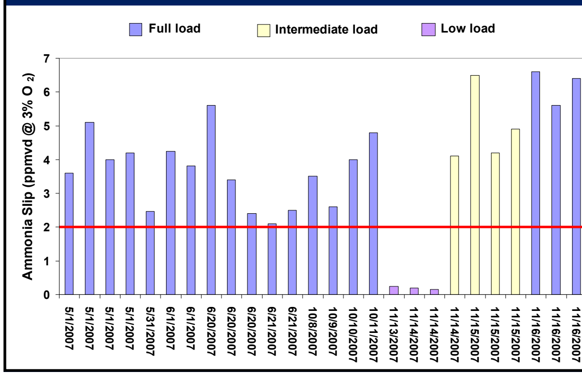
NO_x Removal Across SCR

March 28, 2007 – Three-Test Average



Ammonia Slip Testing Results

EPA CTM 027, Air Heater Inlet

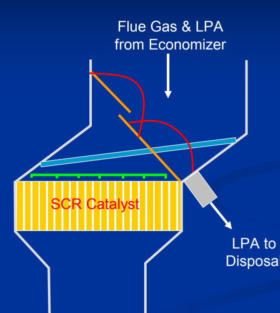


O&M Experience – Large Particle Ash

- Decreased NO_x removal efficiency
- Increased urea consumption, ammonia slip
- Increased pressure drop
- Forced outages for catalyst cleaning

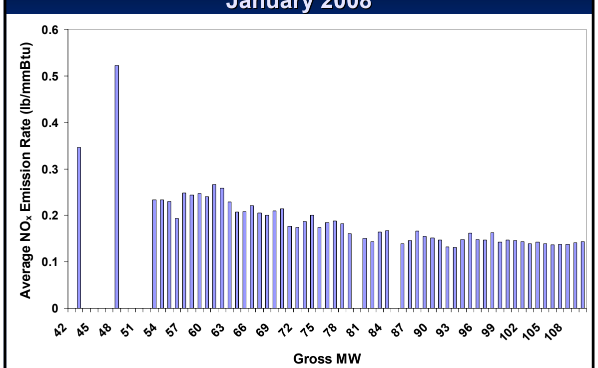
O&M Experience – Large Particle Ash

(continued)



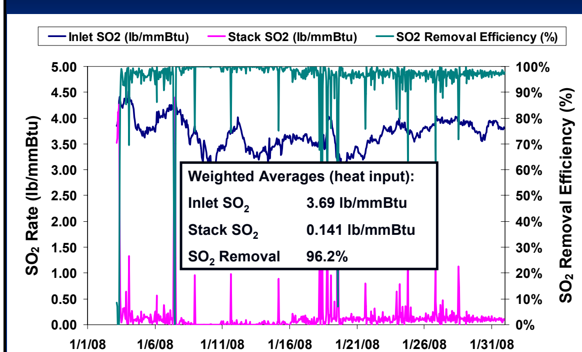
NO_x Emissions vs. Load

January 2008

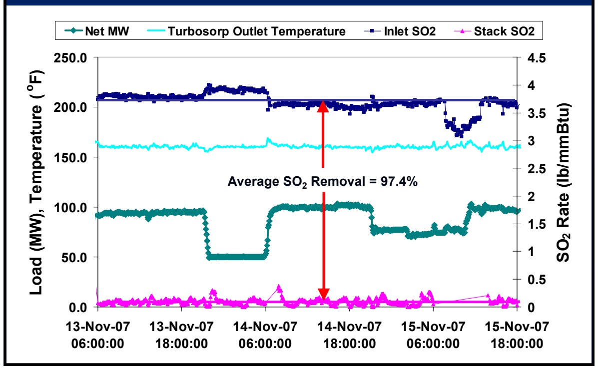


SO_2 Removal Performance

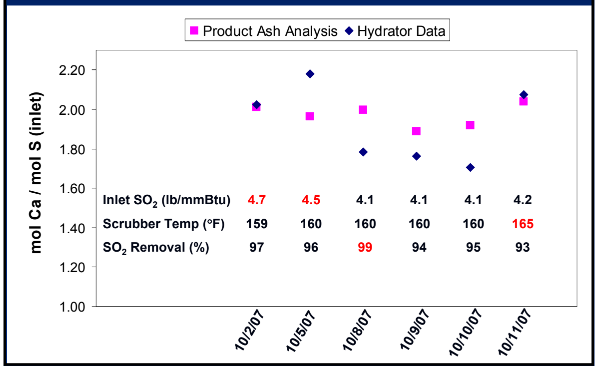
January 2008



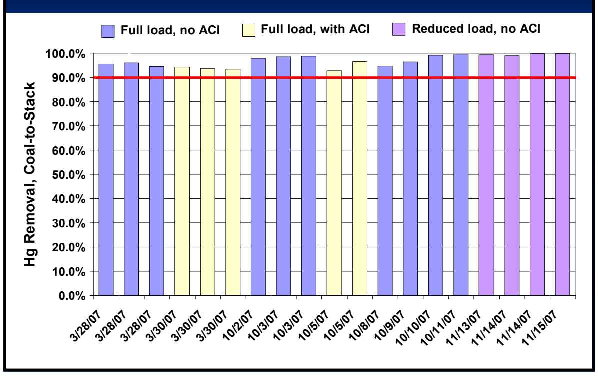
Turbosorp® System
Turndown



Hydrated Lime Utilization
October 2007 Testing



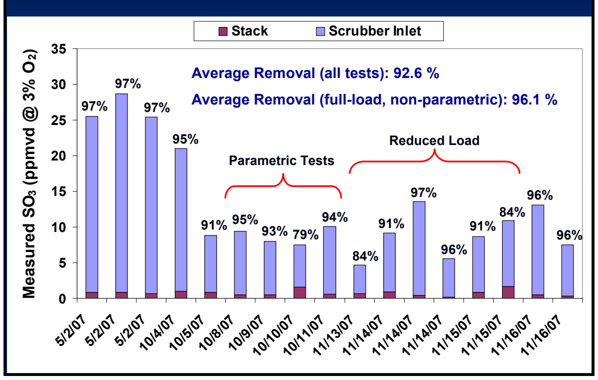
Hg Testing Results
Ontario Hydro Method



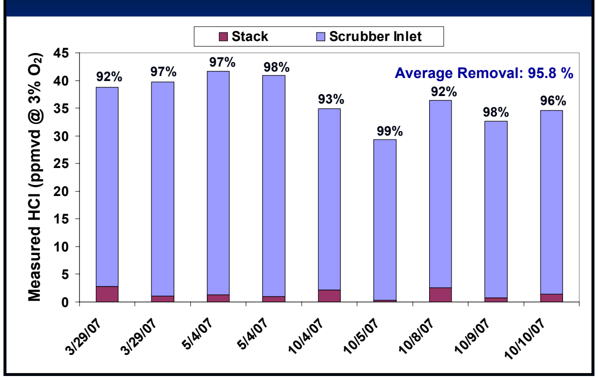
Plant Conditions During Hg Tests

Parameter	Range
Coal Hg content (lb / TBtu)	6.4 – 13.7
Coal S content (lb SO_2 / mmBtu)	3.7 – 4.9
Coal Cl content (wt. %, dry)	0.07 – 0.11
Gross generation (MW)	56.4 – 108.7
Fly ash unburned carbon (%)	9.2 – 25.3
Activated carbon injection rate (lb / mmacf)	0 - 3
SO_2 removal efficiency (%)	92.9 – 99.0
Scrubber outlet temperature (°F)	158.6 – 165.2

SO_3 Testing Results
Controlled Condensation Method

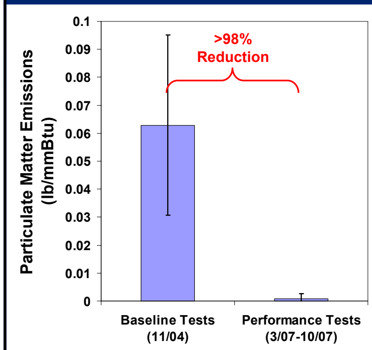


HCl Testing Results
EPA Method 26A



Particulate Testing Results

EPA Method 5/17, Full Load



New baghouse significantly reduces particulate matter emissions relative to old ESP, in spite of increased particle loading from Turbosorp® scrubber

Error bars represent ± 1 standard deviation

Turbosorp® Product Ash

- Similar to spray dryer ash
- Dry powder (~1% moisture)
- Contains $CaSO_3$, $CaSO_4$, fly ash, $CaCO_3$, $Ca(OH)_2$, CaO, $CaCl_2$, CaF_2, inerts
- AES Greenidge sends to landfill (adjacent to plant site)
- Potential uses
  - Mine reclamation
  - Structural / flowable fill
  - Manufactured aggregate
- Leachable Hg (EPA Method 1312) is below detection limit
  - <1.2 % of total Hg in ash (3 samples)

O&M Experience - Turbosorp®

- Lime hydration system
  - Most maintenance-intensive part of Turbosorp® system
  - Can use delivered / stored hydrate to allow offline maintenance
  - Issues encountered to-date
    - Plugging in hydrated lime classifier
    - Water overfed to hydrator
    - Freezing of lines and valves
    - Balls escaped from ball mill
    - Failed bucket elevator shaft
  - Improvements
    - Adjusted classifier rotary feeder to reduce accumulation of fines
    - Modified logic for hydrator water feed
    - Increased onsite hydrate storage capacity

O&M Experience - Turbosorp® (continued)

- Turbosorp® water injection lance
  - Changed about once per week
  - Retrofitted with high pressure quick disconnects
- Ash recycle and disposal system
  - Ash silo vents tend to plug
  - Some problems with freezing / clogging dosing valves
- Baghouse
  - Compressed air demand greater than expected
  - Temporary / permanent compressor capacity added
- No condensation issues encountered in absorber or baghouse

Economics

AES Greenidge Design Case

Constant 2005 Dollars

	EPC Capital Cost ($/kW)	Fixed & Variable O&M Cost ($/MWh)	Total Levelized Cost
NO_x Control	114[a]	1.25	\$3,504 / ton NO_2
SO_2 Control	229[b]	6.14	\$567 / ton SO_2
Hg Control (incremental)	6	0[c]	\$1,567 / lb Hg

[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
[c]Based on performance testing results to-date

Assumptions: Plant size = 107 MW net, Capacity factor = 80%, Coal sulfur = 4.0 lb SO_2/mmBtu, SNCR NSR = 1.35, Ca/S = 1.65, 50% Urea = \$1.35/gal, Quicklime = \$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

Economics

NO_x Control

	$/MWh	$/ton NO_2 removed
Levelized Capital (TCR)	\$2.24	\$2,252
Fixed O&M	\$0.39	\$395
Variable O&M	\$0.85	\$858
Urea	\$0.62	\$626
Replacement Catalyst	\$0.17	\$168
Power/Water	\$0.06	\$64
Total Levelized Cost	**\$3.49**	**\$3,504**

- Improved dispatch economics relative to purchasing allowances

Economics
SO_2 Control

	\$/MWh	\$/ton SO_2 removed
Levelized Capital (TCR)	\$4.54	\$241
Fixed O&M	\$0.88	\$47
Variable O&M	\$5.26	\$279
Lime + Waste Disposal	\$4.53	\$241
Power/Water	\$0.61	\$32
Baghouse Bags/Cages	\$0.12	\$6
Total Levelized Cost	**\$10.68**	**\$567**

- Improved dispatch economics relative to purchasing allowances
- Hg, acid gas, and improved primary particulate control for "free"

Summary

- Greenidge MPC process uniquely designed to meet needs of smaller coal-fired units
  - Deep emission reductions
  - Low capital costs
  - Small space requirements
  - Applicability to high-sulfur coals
  - Low maintenance requirements
  - Operational flexibility
  - Improved dispatch economics
- Performance testing results to-date are generally encouraging
  - Demonstrated attainment of performance guarantees for NO_x, SO_2, Hg, and acid gases
  - SO_2 removal efficiencies >95% routinely achieved
  - All tests have shown >90% Hg capture without ACI
  - Particulate matter emissions significantly reduced

Summary

- O&M challenges thus far
  - Large particle ash plugging in-duct SCR catalyst
  - Difficult to attain 0.10 lb/mmBtu NO_x emissions while maintaining good combustion, low ammonia slip
  - Lime hydration system is rather maintenance intensive
- Additional testing planned through summer 2008
  - Reduced load testing
  - Parametric scrubber testing
  - Follow-up testing

Disclaimer

ATTACHMENT C

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

Submitted to the Clearwater Coal Conference, June 1-5, 2008, Clearwater, FL

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

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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 innovative combination of air pollution control technologies that is well suited for reducing emissions of SO_2, NO_x, Hg, acid gases (SO_3, HCl, and HF), and particulate matter from smaller coal-fired electrical generating units (EGUs). There are more than 420 coal-fired 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, or mercury control systems. Many of these units, which collectively represent almost 60 GW of installed capacity, are difficult to retrofit for deep emission reductions because of space constraints and unfavorable economies of scale, making them increasingly vulnerable to retirement in the face of progressively more stringent environmental regulations. A multi-pollutant control system, which includes combustion modifications, a hybrid selective non-catalytic reduction (SNCR) / in-duct SCR system, and a Turbosorp® 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., with a capital cost of ~\$340/kW and a footprint of <0.5 acre. Start-up and commissioning were completed in early 2007. This presentation focuses on the experience gained from the first year of operation of the system. Apart from several minor issues with its on-site lime hydration system, the Turbosorp® scrubber has operated reliably since start-up and has consistently achieved the project's targeted SO_2 removal efficiency of ≥95%. Tests conducted in October 2007 demonstrated the system's ability to achieve 96% SO_2 capture when the unit was firing coal with a sulfur content of 4.7 lb SO_2/mmBtu, which is substantially greater than typical coal sulfur specifications for dry scrubbers. SO_3 and HCl removal efficiencies of >95% have frequently been observed during performance testing. Moreover, all tests performed to-date have demonstrated 93-99% mercury removal as a co-benefit of the hybrid NO_x control and Turbosorp® systems, without the need for any activated carbon injection. Most of the operational challenges encountered thus far have involved the hybrid SNCR/SCR system. That system attained its NO_x 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 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, which has forced several outages for catalyst cleaning. The effects of the multi-pollutant control system on the unit's emissions profile, operability, and variable operating costs will be discussed in detail, providing valuable information for generators seeking air emissions control retrofit options for their smaller coal-fired EGUs.

ATTACHMENT D

The Greenidge Multi-Pollutant Control Project: Demonstration Results and Deployment of Innovative Technology for Reducing Emissions from Smaller Coal-Fired Power Plants

Submitted to the Pittsburgh Coal Conference, September 29-October 2, 2008, Pittsburgh, PA

The Greenidge Multi-Pollutant Control Project: Demonstration Results and Deployment of Innovative Technology for Reducing Emissions from Smaller Coal-Fired Power Plants

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There are more than 420 coal-fired electric generating units (EGUs) in the United States with capacities of 50-300 MW that currently are not equipped with selective catalytic reduction (SCR), flue gas desulfurization, or mercury control systems. Many of these units, which collectively represent almost 60 GW of installed capacity, are difficult to retrofit for deep emission reductions because of space constraints and unfavorable economies of scale, making them increasingly vulnerable to retirement in the face of progressively more stringent environmental regulations.

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 a solution for these units. The 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, mechanical simplicity, and operational flexibility. The system comprises an innovative combination of technologies including combustion modifications, a NOxOUT Cascade® hybrid selective non-catalytic reduction (SNCR) / in-duct SCR system, and a Turbosorp® circulating fluidized bed dry scrubbing system with baghouse ash recycling and activated carbon injection. These technologies were retrofitted to the 107-MW AES Greenidge Unit 4 by Babcock Power Environmental Inc. in 2006, with a total plant cost of ~$340/kW and a footprint of <0.5 acre. Extensive testing is being carried out through mid-2008 to evaluate the performance of the multi-pollutant control system during its first year-and-a-half of commercial operation.

This paper summarizes performance and cost results from AES Greenidge Unit 4 and discusses commercial deployment of the demonstration technology. Guarantee tests conducted at AES Greenidge in 2007 proved that the multi-pollutant control system was capable of reducing NO_x emissions to 0.10 lb/mmBtu, SO_2 emissions by 96%, SO_3 and HCl emissions by 97%, and mercury emissions by >95% while the unit fired 2.4-3.2% sulfur eastern U.S. bituminous coal. Additional tests are now underway to characterize the performance of the system as a function of unit operating conditions; the results of these tests will be presented. The predominant operating challenges encountered to-date have arisen from the combustion system and from accumulation of large particle ash in the in-duct SCR catalyst; as a result, the unit has required several outages for catalyst cleaning and has routinely operated with NO_x emissions slightly greater than 0.10 lb/mmBtu. The Turbosorp® scrubber has operated commendably, demonstrating 96% SO_2 capture efficiency even when the unit was firing high-sulfur coal containing 4.7 lb SO_2/mmBtu. Moreover, all tests performed to-date have demonstrated 93-99% mercury removal as a co-benefit of the hybrid NO_x control and Turbosorp® systems, without the need for any activated carbon injection.

As a result of the success at AES Greenidge, three additional retrofit applications of the Turbosorp® system have been announced for smaller coal-fired EGUs (i.e., 50-300 MW) in the United States. Additional announcements are anticipated. Key characteristics of these announced deployments, including unit and fuel characteristics and performance targets, will be discussed.