GREENIDGE MULTI-POLLUTANT CONTROL PROJECT

U.S. DOE Cooperative Agreement No. DE-FC26-06NT41426

CONSOL Energy Inc.
Research & Development
4000 Brownsville Road
South Park, PA 15129-9566

D. P. Connell
Principal Investigator
(412) 854-6559
danielconnell@consolenergy.com

QUARTERLY PROGRESS REPORT
FOR WORK PERFORMED DURING THE PERIOD
October 1, 2007 to December 31, 2007

February 12, 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 from coal-fired electrical 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 seventh to be submitted for the Greenidge Multi-Pollutant Control Project, summarizes work performed on the project between October 1 and December 31, 2007. During the period, commercial operation of the multi-pollutant control system at AES Greenidge continued. The accumulation of large particle ash (LPA) and fly ash in the in-duct SCR reactor persisted, despite the modifications that were made in September 2007 to improve the performance of the unit's LPA removal system. As a result, outages were required in mid-November and in late December to clean the SCR reactor; during the December outage, the existing catalyst layer was also replaced with a freshly cleaned layer. The project team's primary focus during the first quarter of 2008 will be to develop a solution for this SCR plugging problem. Also, in October and November 2007, we completed three weeks of process performance testing to evaluate the effects of high-sulfur coal, changes in scrubber operating conditions, reduced unit loads, and waste wood co-firing on the performance of the multi-pollutant control system. As with the guarantee tests that were conducted in March, all of the Hg tests completed during the quarter indicated greater than 90% Hg removal, irrespective of unit operating conditions or of the presence or absence of activated carbon injection. The Turbosorp® system continued to meet its performance target for SO_2 control, consistently achieving >95% removal efficiency, even when the unit was firing high-sulfur (i.e., 4.4 - 4.9 lb SO_2 / mmBtu) coal. However, 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 0.13-0.14 lb/mmBtu, and all high-load NH_3 slip tests performed during the quarter indicated greater than the targeted 2 ppmv of slip). Performance testing of the multi-pollutant control system will continue through the first half of 2008.

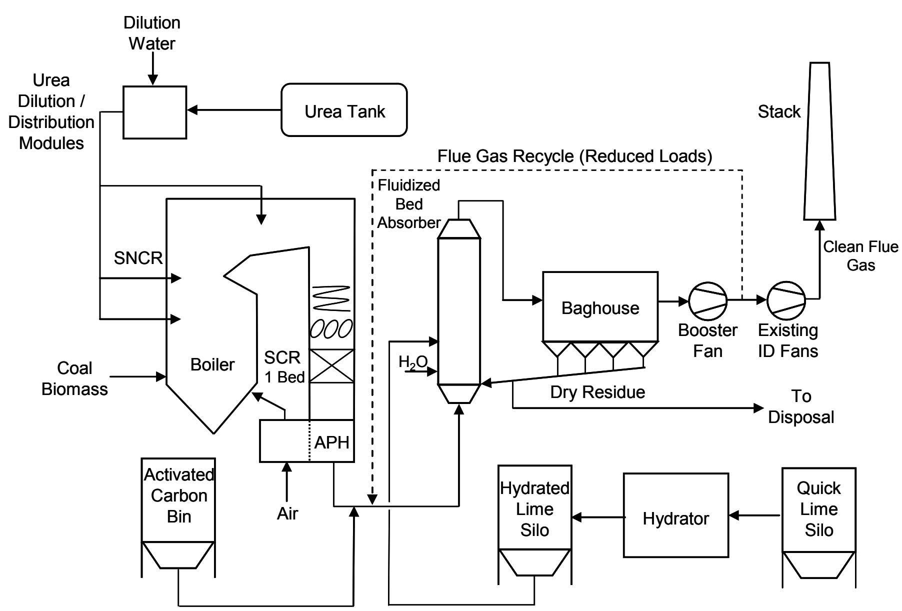


Figure 1. Schematic of the multi-pollutant control system being demonstrated at AES Greenidge Unit 4.

2.0 Work Performed and Results Obtained During the Reporting Period

Highlights of the Greenidge Multi-Pollutant Control Project during the period from October 2007 through December 2007 included the completion of three weeks of process performance testing of the multi-pollutant control system and the presentation of project results at two major conferences. The multi-pollutant control system continued to be affected by the accumulation of large particle ash and fly ash in the in-duct SCR catalyst; the project team remains focused on developing a solution for this problem. Work performed and results obtained between October 1, 2007, and December 31, 2007, 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 fourth quarter of calendar year 2007 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

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. As discussed in previous quarterly progress reports, the Title V permit was revised as part of its regularly scheduled renewal process so that it reflects the emission requirements set forth in the consent decree between AES and the State of New York. The newly renewed permit is valid through November 4, 2012.

Also during the quarter, the New York State DEC requested additional information regarding AESG's Request for Information (RFI) application for its State Pollutant Discharge Elimination System (SPDES) permit. The plant is operating with an "administratively renewed" SPDES permit while the renewal process for the permit is completed.

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), but contingent on certain activities under Tasks 3.2 and 3.3, had not yet been attained as of the end of the fourth quarter of 2007. We expect that these two remaining milestones will be completed in early 2008.

Task 3.1 – Phase 3 Project Management

Project management activities during the fourth quarter of calendar year 2007 focused on coordinating process performance testing of the multi-pollutant control system with the operational challenges posed by the system's SCR plugging problem. As discussed below under Task 3.3, we completed three weeks of process performance testing at AES Greenidge Unit 4 during the quarter, in spite of several unit outages and derates caused by plugging of the SCR catalyst. Three additional weeks of process performance testing and one week of follow-up testing are planned for 2008. The project's cost and schedule performance through the end of the fourth quarter of 2007 are presented in greater detail in Section 3.0 of this report.

We also continued to publicize project results during the quarter. On December 11-13, we presented a poster titled "Mercury Capture in a Circulating Fluidized Bed Dry Scrubber at AES Greenidge Unit 4" at the DOE-NETL Mercury Control Technology Conference in Pittsburgh, PA, and on December 12, we gave a presentation titled "Follow-on Turbosorp Testing Results from the Greenidge Multi-Pollutant Control Project" at the POWER-GEN conference in New Orleans, LA. Copies of the poster and POWER-GEN presentation are included as Attachments A and B, respectively, to this report. In addition, during the quarter, we submitted an abstract titled "The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation" to the organizers of the Power Plant Air Pollutant Control MEGA Symposium, which will be held in Baltimore, MD, in August 2008, and our abstract titled "Results from the First Year of Operation of a Circulating Fluidized Bed Dry Scrubber with High-Sulfur Coal at AES Greenidge Unit 4" was accepted for presentation at the 2008 Electric Power Conference, which will be held in Baltimore on May 6-8. A copy of the first abstract is included as Attachment C to this report; the second abstract was included as an attachment to our last quarterly progress report.

Task 3.2 – Plant Operations

AES Greenidge continued routine operation of the multi-pollutant control system throughout the fourth quarter of calendar year 2007. The Turbosorp® system operated regularly throughout the quarter, achieving an average SO_2 emission rate of ~0.18 lb/mmBtu when AES Greenidge Unit 4 was operating above 42 MW_g (based on preliminary hourly average data from the unit's stack CEM).

As discussed in the project's last quarterly progress report, most of the operational problems encountered to-date with the Turbosorp® system have involved the lime hydration system, which is the most mechanically complex part of the process. In early October, AES Greenidge Unit 4 was fired using a higher-than-normal sulfur coal (i.e., containing approximately 4.4 - 4.9 lb SO_2 / mmBtu), resulting in increased hydrated lime demand for the scrubber. Although this demand was well within the design margin for the lime hydration system, the hydrated lime classifier plugged numerous times on October 3 and 4, causing the lime hydration system to trip. AES Greenidge personnel were diligent in unplugging the hydrator and in taking deliveries of hydrated lime to allow the unit to continue to operate during this period, and the problems subsided when the unit returned to firing coal with more typical sulfur content (i.e., 4.0 - 4.3 lb SO_2 / mmBtu). In mid-November one of the hydrated lime classifier fan bearings failed, forcing the plant to take the hydrator offline for repair. AESG continued to operate Unit 4 using hydrated lime from their new onsite storage tanker, which they began renting during the quarterly reporting period; however, the unit eventually had to be derated when the onsite supply of hydrate was depleted and the truck en route to replenish it broke down. Deliveries of hydrated lime resumed later in the day, allowing the unit to return to high load, and the problem was repaired. The plant also encountered sporadic plugging in the hydrated lime classification system during November. Late that month, they slowed the speed of one of the rotary feeders in the classification system, because they believed that the feeder previously was operating too rapidly to allow its pockets to fill, causing fines to build up in the system. This modification appeared to improve the performance of the lime hydration system for the remainder of the quarter. AES Greenidge is planning to add an additional, permanent hydrated lime storage silo in 2008 in order to afford them greater flexibility for performing offline maintenance on the hydrator without adversely affecting the operation of Unit 4.

Apart from minor problems with the lime hydration system, most of the operational challenges encountered to-date with the multi-pollutant control system have been associated with the hybrid NO_x control system. As discussed in previous quarterly reports, although the system demonstrated attainment of its NO_x emission performance target of 0.10 lb/mmBtu during guarantee testing in late March, 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. The average high-load NO_x emission rate during the fourth calendar quarter of 2007 was 0.13-0.14 lb/mmBtu, based on preliminary hourly average data from the unit's stack CEM.

The accumulation of large particle ash and fly ash in the in-duct SCR catalyst continued to adversely affect the operation of AES Greenidge Unit 4 during the fourth calendar quarter of 2007. Plugging of the catalyst continued in spite of the installation of an LPA removal system (including a sloped screen, soot blowers, and vacuum ports) in May 2007 and the implementation of modifications (including rotary soot blowers, a rake soot blower, and a spring seal) in September 2007 to improve the system.

Early in October 2007, AES Greenidge again began to observe an increase in the pressure drop across the in-duct SCR catalyst. (Increasing pressure drop was not observed across the LPA screen, as it had been in the past, suggesting that the new rotary soot blowers installed during the September outage were effective in cleaning LPA from the screen). The plant took several actions to try to alleviate this problem, including increasing the discharge pressure and frequency of operation of the rake soot blower above the catalyst and resuming operation of the sonic horn system, but these were unsuccessful in reversing the trend. As of the end of October, the plant was derated to about 95 MW_n in order to maintain sufficient pressure downstream of the reactor to avoid risk of ductwork implosion. The unit was further derated in early November to allow it to continue to operate while AES completed an outage at another of its New York power plants.

Then, on November 9-12, AES Greenidge held an outage to inspect and clean the in-duct SCR catalyst. Upon entering the SCR reactor, plant personnel discovered a substantial amount of modestly sized large particle ash distributed relatively evenly over the surface of the catalyst. (They did not observe mounding of ash as they had during previous outages). Some of the LPA was small enough to have passed directly through the mesh of the LPA screen, and some LPA also likely reached the catalyst by passing through gaps where the screen meets the duct walls. In addition, the spring seal that was installed in September to close the gap between the upper and lower sections of LPA screen did not flex as it was designed to, creating another gap for LPA to penetrate. The inspection confirmed that the new rotary soot blowers that were installed in September to clean LPA from the LPA screen were working effectively. The plant vacuumed the LPA from the surface of the catalyst, collected samples for evaluation, and installed a temporary fix for the spring seal. When the unit returned to service, the pressure drop across the SCR was greater than its normal baseline, likely because some LPA was lodged deep within the catalyst and could not be removed as part of the cleaning.

The pressure drop across the SCR reactor increased relatively rapidly following the mid-November outage, and Unit 4 was derated for much of December in order to maintain sufficient pressure downstream of the reactor. At the end of the month, AES Greenidge held another outage to inspect and clean the SCR reactor. Also, during this outage, the existing, plugged SCR catalyst layer was replaced with the original catalyst layer, which had been removed from the reactor in May 2007 and sent for professional cleaning in early December. Figure 2 presents a photograph of a plugged catalyst module that was removed from the SCR reactor in December. The outage began on December 27, and the work in the SCR reactor was completed successfully by December 30, but a problem with the unit's distributed control system (unrelated to the multi-pollutant control system) prevented it from returning to service by year's end.

Figure 2. Photograph of a partially plugged catalyst module (viewed from the inlet end) that was removed from the in-duct SCR reactor during the late December outage.

The project team is focused on diagnosing the catalyst plugging problem so that a solution can be developed to overcome it. It appears that the catalyst plugging is due at least in part to LPA that is small enough to pass through the LPA screen but large enough to lodge in the catalyst or catalyst screen. (The catalyst screen is located below the LPA screen, just above and parallel to the surface of the catalyst). This physical mechanism of plugging is supported by observations of small LPA pieces lodged in the catalyst and catalyst screen during the November and December outages (see Figures 3 and 4), as well as by the results of BPEI's dissection of a catalyst element that was pulled from the SCR reactor during the November outage. AESG is considering modifications to the LPA screen and/or catalyst to alleviate this mechanical plugging mechanism. It has also been hypothesized that a chemical mechanism may be

Figure 3. Photograph of a portion of the SCR catalyst (inlet end) taken during the December 2007 outage. Small pieces of LPA can be seen protruding from some of the catalyst channels.

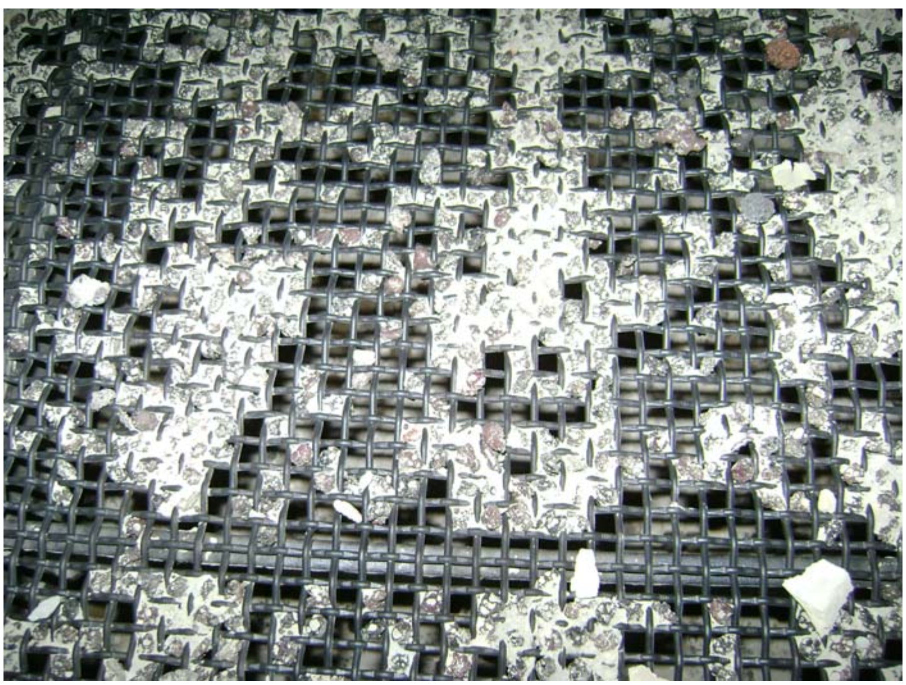


Figure 4. Photograph of a portion of the catalyst screen taken during the November 2007 outage. Small pieces of LPA (surrounded by light-colored fly ash) are visibly lodged in the screen.

contributing secondarily to the plugging. Upon inspecting the SCR reactor during the December outage, plant personnel observed weak agglomerates of fine ash adhering to structures above the catalyst and protruding from the bottom of the catalyst (see Figure 5). Some of the catalyst channels also appeared to be plugged by “sticky” fly ash. To investigate the possibility of a chemical mechanism, samples of the various types of ash and other deposits found in the SCR reactor were collected during the outage and sent to CONSOL for bulk chemical analysis and to Lehigh University for X-ray diffraction analysis. Work on diagnosing and developing a solution for the SCR plugging problem will continue in the first quarter of 2008.

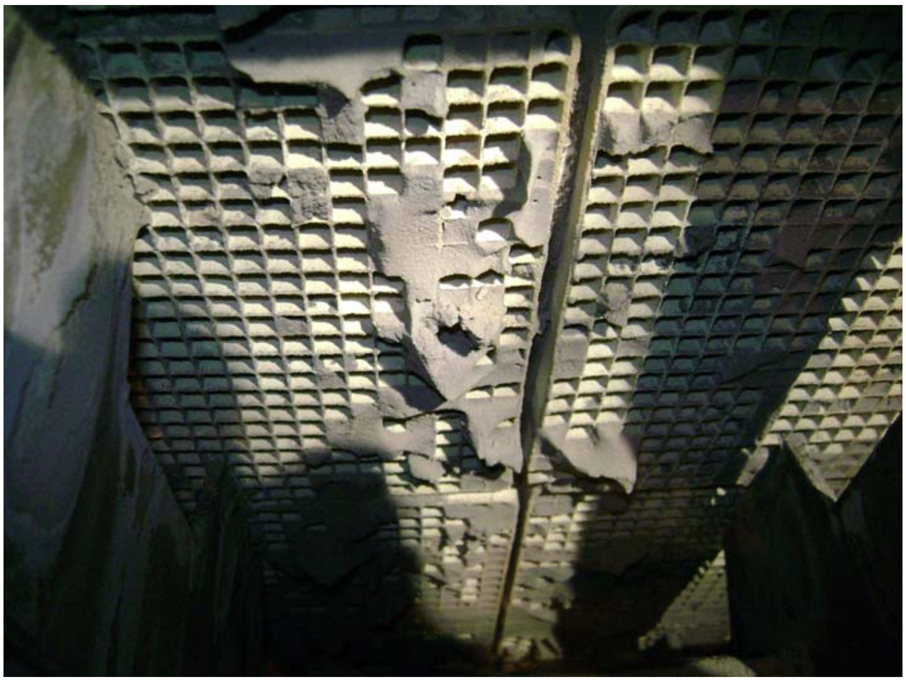


Figure 5. Photograph of a portion of the outlet end of the SCR catalyst taken during the December 2007 outage. Weak agglomerates of fly ash can be seen protruding from some of the catalyst channels.

Task 3.3 – Testing and Evaluation

During the fourth calendar quarter of 2007, we completed the first three weeks of field sampling for process performance testing of the multi-pollutant control system at AES Greenidge. The process performance tests are designed to build upon the results of the guarantee tests that were conducted in March-June 2007 by establishing the performance of the multi-pollutant control system as a function of changes in various plant operating conditions. Process performance tests were performed during the weeks of October 1, October 8, and November 12. These test periods are described in greater detail below.

Week of October 1 – High-Sulfur Coal Testing

The tests during the week of October 1 were conducted to evaluate the performance of the multi-pollutant control system while AES Greenidge Unit 4 was firing a higher-than-normal sulfur coal. The sulfur content of the coal was ~4.4 - 4.9 lb SO_2 / mmBtu during these tests. The Turbosorp® scrubber proved capable of consistently achieving >95% SO_2 removal efficiency during the test period (the average SO_2 removal efficiency during the five Hg tests performed that week was ~96%); however, the lime hydration system was often unable to keep up with the increased hydrated lime demand resulting from the higher-sulfur coal. As stated under Task 3.2, the hydrated lime classifier plugged numerous times on October 3 and October 4, causing the lime hydration system to trip. This hindered the tests that were planned for those days; however, AES Greenidge was diligent in unplugging the hydrator and in taking deliveries of hydrated lime to allow the tests to proceed. During the week, we completed three Hg tests including simultaneous sampling at the SCR inlet, SCR outlet, air heater outlet, and stack without any activated carbon injection; two Hg tests including simultaneous sampling at the air heater outlet and stack with activated carbon injection; four SO_3 tests including simultaneous sampling at the SCR inlet and SCR outlet; two SO_3 tests including simultaneous sampling at the air heater outlet and stack; and two HCl/HF tests including simultaneous sampling at the air heater outlet and stack. In addition, various plant operating data and solid and liquid process samples were collected during the test period for use in evaluating the performance of the multi-pollutant control system. Representatives from DOE-NETL visited AES Greenidge on October 3 to observe the testing.

Results from the tests became available in December 2007. The measured coal-to-stack mercury removal efficiencies for the five tests performed during the week of October 1 ranged from 92.7% to 98.7%. As was the case with the guarantee tests performed in March, these tests demonstrated that activated carbon was not required to achieve greater than 90% Hg removal efficiency. The Hg tests performed at the inlet and outlet of the SCR, which were intended to examine Hg oxidation across the catalyst, were inconclusive. The measured SO_3 removal efficiencies across the Turbosorp® system were 95.2% and 91.0%, and the average SO_2-to-SO_3 conversion across the SCR catalyst was 0.36%. (Concentrations of SO_3 at the stack were ≤ 1 ppmv, approaching the practical field detection limit for the controlled condensation method). The average HCl removal efficiency across the Turbosorp® system was 96.0%, and the average HF removal efficiency across the system was >87.1%. (HF concentrations at the stack were below the method detection limit).

Week of October 8 – Turbosorp® System Parametric Testing

The tests during the week of October 8 were conducted 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. During these tests, AES Greenidge Unit 4 fired coal with a sulfur content of ~4.0 - 4.3 lb SO_2 / mmBtu. The Turbosorp® system was operated with a different Ca/S set point on each of October 8, October 9, and October 10, while all other relevant set points were held constant. On each of these days, CONSOL completed an SO_3 test, HCl/HF test, and Hg test at each of the air heater outlet and stack. (Coal mill problems on October 9 forced us to terminate the Hg test early on that day). On October 11, we planned to replicate the October 8 settings and then increase the Turbosorp® outlet temperature set point by 5 °F (from 160 to 165 °F). However, we observed a lower SO_2 removal efficiency on October 11 than on October 8 under these settings, and we were unable to raise the temperature by 5 °F and remain within the plant's permit limit for SO_2 emissions. As a result, we ran the October 11 tests with a 165 °F Turbosorp® outlet temperature set point, but with the hydrated lime injection set to control automatically to a 0.2 lb/mmBtu SO_2 emission rate. We completed a mercury test and an SO_3 test at each of the air heater outlet and stack under these conditions. Also, during each day of testing on the week of October 8, an ammonia slip test was conducted at the air heater inlet. As with the tests on the week of October 1, various plant operating data and solid and liquid process samples were collected during the October 8-11 test period for use in evaluating the performance of the system.

The coal-to-stack mercury removal efficiencies measured during the four tests on October 8-11 ranged from 94.6% to 99.5%. No activated carbon was injected during these tests. (SO_2 removal efficiencies during these four tests ranged from 93% to 99%, depending on the scrubber operating conditions). Hence, all of the tests completed to-date have shown greater than 90% Hg removal, regardless of unit operating conditions or of whether or not activated carbon was being injected into the system. The SO_3 removal efficiencies measured across the Turbosorp® system on October 8-11 ranged from 78.8%-95.2% (three of the four tests had removal efficiencies greater than 93%); the HCl removal efficiencies ranged from 92.2% to 98.0%, and the HF removal efficiencies ranged from >76.7% to >89.0%. (Again, HF concentrations at the stack were below the method detection limit). We are still working to assess these results in the context of the scrubber data and other plant operating data that were collected during the tests. The average ammonia slip measured at the air heater inlet during the four days of testing was 3.7 ppmvd @ 3% O_2.

Week of November 12 – Reduced Load and Biomass Testing

The tests during the week of November 12 were designed to evaluate the performance of the multi-pollutant control system when Unit 4 operates at reduced loads and when it co-fires biomass (waste wood from a furniture manufacturing process) with coal. Two weeks of testing were originally planned to assess these variables; however, due to the SCR pressure drop problems described under Task 3.2, only one week of testing could be completed. Additional testing at reduced loads and with waste wood co-firing will be conducted as part of the three weeks of process performance tests planned for 2008.

During the overnight period on November 13-14, we performed three ammonia slip tests at the air heater inlet, three SO_3 tests at the air heater outlet and stack, and two Hg tests at the stack while Unit 4 was operating at low load (~57 MW_g) and firing 100% coal. Then, during the overnight period on November 14-15, we completed four ammonia slip tests at the air heater inlet, three SO_3 tests at the air heater outlet and stack, and two Hg tests at the stack while Unit 4 was operating at intermediate load (~75-80 MW_g) and firing 100% coal. AES Greenidge Unit 4 began co-firing waste wood on November 15; however, as discussed under Task 3.2, one of the hydrated lime classifier fan bearings failed that day, forcing the plant to take the hydrator offline. AES continued to operate Unit 4 using hydrated lime from their new onsite storage tanker, but waste wood co-firing was discontinued and the unit eventually had to be derated when the onsite supply of hydrate was depleted and the truck en route to replenish it broke down. This delayed the start of testing on November 16. In spite of the problems encountered early in the day, we succeeded in completing three ammonia slip tests at the air heater inlet, two SO_3 tests at the air heater outlet and stack, and one mercury test at the air heater outlet and stack on the afternoon of November 16 while the unit was operating near full load and co-firing biomass. During all of the testing periods, NO_x and SO_2 were monitored using the plant's CEMS, and solid and liquid process samples were collected for analysis.

Results of the ammonia slip tests conducted in November showed that ammonia slip increased substantially with increasing unit load. Ammonia concentrations at the air heater inlet ranged from 0.2 ppmv at 56 MW_g, when urea was being injected only into high-temperature regions of the furnace, to 6.2 ppmv at 102 MW_g, when urea was being injected into lower-temperature regions of the furnace. The urea injection rate into zone 2 (the intermediate-temperature zone) appeared to be the strongest predictor of ammonia slip. Results of the mercury and SO_3 tests from November will be available in early 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 fourth quarter of calendar year 2007. As shown in the table, actual incurred costs for the fourth quarter of 2007 were $647,449 greater than baseline planned costs for that quarter, and cumulative actual incurred costs were $407,997 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 fourth quarter of 2007 arose largely because costs for consumables (i.e., urea, pebble lime, and hydrated lime) were $513,263 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 $134,187 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 October and November were originally planned for the first and second quarters 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 fourth quarter of 2007. This quarter marked the first occasion that the project's cumulative actual incurred costs were greater than its baseline planned costs since quarterly reporting began in the second quarter of 2006. The cumulative cost variance includes $1,046,858 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 December, as well as a negative variance of $372,777 associated with testing and project administration. This latter variance consists largely of costs associated with three remaining weeks of process performance testing, which were originally scheduled for April through July 2007 but have yet to be completed.

We anticipate that the project's 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.

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. As discussed above, in addition to the follow-up tests, three weeks of process performance testing are planned for the first half of 2008. We currently expect that the remaining process performance tests will be completed in April through June and that the follow-up tests will begin on the week of June 23, in time to meet this next critical path milestone. (Most of the remaining tests will be performed after the unit's scheduled May 3-11 outage, because the SCR catalyst will be cleaned during the outage, and tests involving the SCR will provide more valuable results if conducted with a clean catalyst layer). However, any unexpected delays in the process performance testing, such as those resulting from unanticipated plant problems or from derates due to SCR plugging, could jeopardize our ability to meet this milestone.

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				
Non-Federal Share		$8,481,387	$2,409,918	$2,109,425	$1,418,114	$698,779	$1,948,053	$656,465				
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				
Cumulative Incurred Costs		$15,091,436	$19,379,547	$23,132,973	$25,656,308	$26,899,687	$30,365,974	$31,534,062				
Variance[c]												
Federal Share		($666,156)	$71,352	($491,467)	($476,607)	$178,974	$1,279,026	$283,583				
Non-Federal Share		($854,749)	$91,552	($630,605)	($611,537)	$229,642	$1,641,123	$363,866				
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				
Cumulative Variance		($1,520,905)	($1,358,001)	($2,480,074)	($3,568,217)	($3,159,601)	($239,452)	$407,997				

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.

4.0 Significant Accomplishments during the Reporting Period

Significant accomplishments during the fourth quarter of calendar year 2007, which are described more fully in Section 2.0 above, were as follows:

- Commencement of process performance testing of the multi-pollutant control system, including the completion of three weeks of field tests examining the performance of the system as a function of fuel, load, and scrubber operating conditions
- Completion of seven tests demonstrating that the multi-pollutant control system achieves greater than 90% Hg removal without the need for any activated carbon injection (all Hg tests conducted to-date have shown greater than 90% Hg removal)
- Demonstration of >95% SO_2 removal in the Turbosorp® scrubber while AES Greenidge Unit 4 was firing high-sulfur (i.e., 4.4 – 4.9 lb SO_2 / mmBtu) coal
- Continued commercial operation of the multi-pollutant control system
- Presentation of project results at the DOE-NETL Mercury Control Technology Conference and at the POWER-GEN conference

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

As described under Section 2.0 above, during the fourth quarter of 2007, AES Greenidge Unit 4 continued to experience problems with large particle ash and fly ash accumulating in the in-duct SCR catalyst. These problems persisted in spite of the installation of an LPA removal system in May 2007 and the subsequent modification of this system in September 2007. AES Greenidge coped with the problem during the quarter by taking outages in mid-November and late-December to remove the accumulated ash from the SCR reactor. During the December outage, the plant also replaced the catalyst layer then being used with the unit's original catalyst layer, which had been removed from the reactor in May 2007 and professionally cleaned in early December. Having now determined that the September modifications to the LPA removal system were not fully effective in resolving the SCR plugging problem, the project team is intently focused on diagnosing and developing a solution for the problem. Samples of LPA, ash, and other deposits were collected in the SCR reactor and surrounding ductwork during the late December outage for chemical characterization, and the project team is exploring whether modifications to the design of the LPA screen and/or catalyst may help to mitigate the problem. This work will continue into the first quarter of 2008.

Although three weeks of process performance testing were successfully completed during the quarter, a fourth week of planned testing was delayed because of the SCR plugging problem. We plan to complete the postponed testing during the first half of 2008. (Much of the remaining testing is scheduled to occur after the plant's scheduled outage in early May 2008, during which the SCR reactor will be cleaned and any required modifications will likely be implemented). We do not anticipate that the delayed process performance tests will impact the overall project end date of October

2008, because the project schedule affords flexibility for completing them during the year-long period between the guarantee tests and follow-up tests.

Finally, as described earlier, the plant continued to encounter minor operational problems with the classification portion of the lime hydration system during the quarter. Some of these problems occurred during periods of process performance testing, threatening the successful completion of the tests. However, AES Greenidge generally succeeded in maintaining operation of the unit by taking deliveries of hydrated lime and repairing the problems as they arose, thereby allowing the tests to proceed. During the quarter, the plant adjusted one of the rotary feeders in the hydrated lime classification system to prevent fines from accumulating in the system, helping to alleviate the classifier problems. The plant also added a temporary hydrated lime storage tanker during the quarter, and they are considering adding an auxiliary hydrated lime storage silo in 2008, to increase their onsite stockpile of hydrated lime for use when the hydrated lime system must be taken offline for maintenance.

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

As discussed in Section 2.0 above, we presented a poster titled “Mercury Capture in a Circulating Fluidized Bed Dry Scrubber at AES Greenidge Unit 4” at the DOE-NETL Mercury Control Technology Conference in Pittsburgh, PA, on December 11-13. We also gave a presentation titled “Follow-on Turbosorp Testing Results from the Greenidge Multi-Pollutant Control Project” at the POWER-GEN conference in New Orleans, LA, on December 12. Finally, we submitted an abstract titled “The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation” to the organizers of the Power Plant Air Pollutant Control MEGA Symposium, which will be held in Baltimore, MD, in August 2008. Copies of the Mercury Control Technology Conference poster, POWER-GEN presentation, and MEGA Symposium abstract are included as Attachments A, B, and C, respectively, to this report.

ATTACHMENT A

Mercury Capture in a Circulating Fluidized Bed Dry Scrubber at AES Greenidge Unit 4

Presented at the DOE-NETL Mercury Control Technology Conference, December 11-13, 2007, Pittsburgh, PA

Mercury Capture in a Circulating Fluidized Bed Dry Scrubber at AES Greenidge Unit 4

Daniel P. Connell and James E. Locke, *CONSOL Energy Inc. Research & Development, South Park, PA*
Douglas J. Roll, *AES Greenidge LLC, Dresden, NY*

Project Background

- Part of U.S. Department of Energy'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 (43.8%)
  - AES Greenidge LLC (56.2%)
- 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

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[a]
SO_2 removal	≥ 95%	96%
SO_3 removal	≥ 95%	97%
HCl removal	≥ 95%	97%
HF removal	≥ 95%	Indeterminate[b]

[a]Although the target of 0.10 lb/mmBtu was demonstrated in short-term testing, the plant routinely has had to operate at ~0.13 lb/mmBtu to maintain acceptable combustion characteristics, steam temperatures, and ammonia slip; [b]Concentrations at both the inlet and outlet of the Turbosorp® scrubber were less than the detection limit

Mercury Testing Methodology

- All sampling and analysis performed by CONSOL Energy Research & Development
- All flue gas Hg measurements conducted using the Ontario Hydro Method (ASTM D 6784-02)
  - Liquid samples analyzed by cold vapor atomic absorption spectroscopy (March 2007) or cold vapor atomic fluorescence spectroscopy (October 2007)
  - Particulate samples analyzed in accordance with ASTM D 6414 or ASTM D 6722
- Coal samples (composite of all feeders) collected at the beginning and middle of each test and analyzed for Hg by ASTM D 6722
- Solid and liquid process samples (e.g., ash, lime, urea, water) and plant operating data also collected during each test to assess process performance
- QA/QC
  - Pre- and post-test leak checks performed for each test
  - O_2 concentration monitored continuously at meter exhaust
  - Blank sampling trains analyzed to check for contamination
  - Laboratory procedures included use of independent calibration verification standards, duplicate or triplicate analyses, matrix spikes, digestion duplicates, and digestion spikes, with a 10% relative percent difference criterion for duplicates/triplicates and a 100±10% recovery criterion for standards and spikes
  - Material balances performed for each of the March tests to ensure that the total mercury output from the process agreed reasonably well with the total mercury input to the process (material balances for the October tests have not yet been completed)

CONSOL ENERGY

Motivation

- There are ~ 440 existing coal-fired units in the United States that are not equipped with FGD, SCR, or Hg control systems
  - Represent ~ 60 GW of installed capacity
  - Greater than 80% are located east of the Mississippi River
  - Most have not announced plans to retrofit
- It is difficult to retrofit these smaller units for deep emission reductions
  - Large capital costs
  - Space limitations
- These units are increasingly vulnerable to retirement or fuel switching because of progressively more stringent environmental regulations
  - CAIR, CAMR, CAVR, state regulations
- Hence, there is a need to commercialize technologies designed to meet the environmental compliance requirements of these units
- The Greenidge Project seeks to demonstrate an innovative combination of technologies that are designed to satisfy this need by affording deep emission reduction capabilities, low capital costs (~$340/kW*), small space requirements (~0.5 acre*), applicability to high-sulfur coals (2-4%*), low maintenance requirements, and operational flexibility

*For AES Greenidge Unit 4 installation

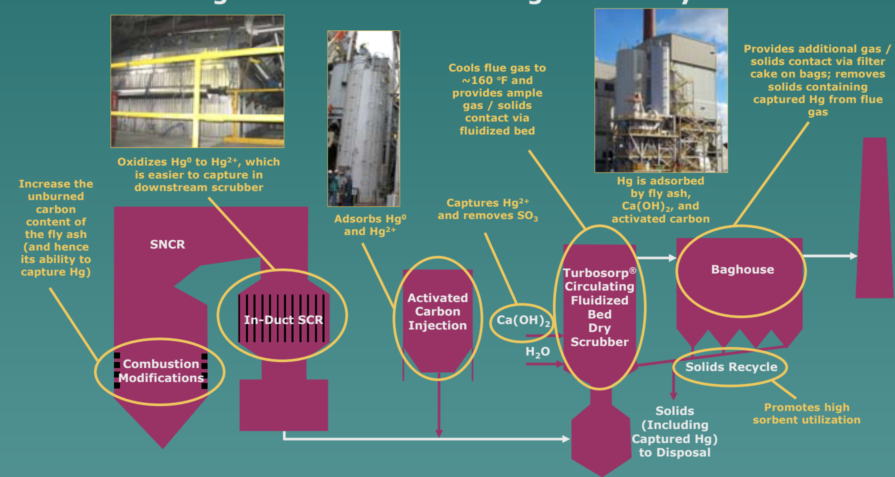
Host Site
AES Greenidge Unit 4 (Boiler 6)

- 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 ºF
- Fuel:
  - Eastern U.S. bituminous coal
  - Biomass (waste wood) – up to 10% of total heat input
- Existing emission controls:
  - Overfire air (natural gas reburn not in use)
  - ESP
  - No FGD - mid-sulfur coal to meet permit limit of 3.8 lb SO_2/mmBtu

Technology

- Combustion Modifications (low-NO_x burners, overfire air)
- Hybrid Selective Non-Catalytic Reduction / Selective Catalytic Reduction (SNCR/SCR) System
  - SNCR includes 3 zones of urea injection; it is designed to reduce NO_x by ~42% and provide NH_3 for the downstream SCR reactor
  - SCR is an in-duct design with a single layer of catalyst (1.3 m deep); it is fed entirely by NH_3 slip from the SNCR and designed for ~30% NO_x removal efficiency
- Powdered Activated Carbon Injection System
  - Projected injection rate for 90% Hg capture: 0 – 3.5 lb/mmacf
- Turbosorp® Circulating Fluidized Bed Dry Scrubber
  - Water and dry hydrated lime injected separately; operating temperature ~ 160 °F, nominal Ca/S ~ 1.6 mol/mol for 2.5% sulfur coal; designed to accommodate coals containing up to 4.0% sulfur
  - Lime hydration system installed as part of project for onsite production of $Ca(OH)_2$ from pebble lime
- Baghouse
  - 8-compartment pulse jet fabric filter; nominal air-to-cloth ratio = 3 (ft³/min)/ft²
  - ~95% of baghouse solids are recycled to Turbosorp® scrubber using air slides
  - Booster fan installed downstream of baghouse to overcome pressure drop

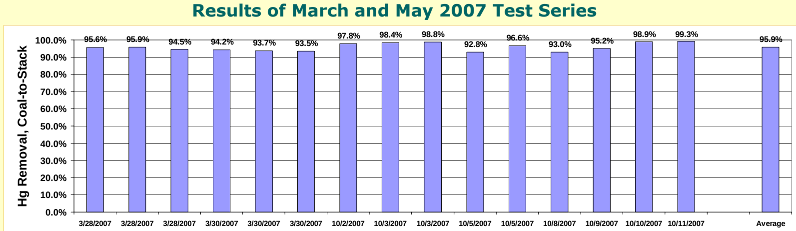
Design Features Contributing to Mercury Control



Hg Reduction Target: ≥90% (coal-to-stack)

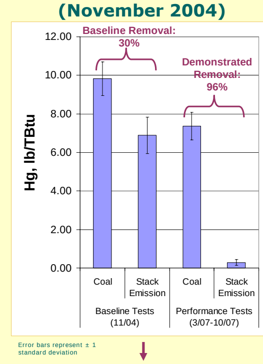
Mercury Testing Results To-Date

Results of March and May 2007 Test Series



	3/28/2007	3/28/2007	3/28/2007	3/30/2007	3/30/2007	3/30/2007	10/2/2007	10/3/2007	10/3/2007	10/5/2007	10/5/2007	10/8/2007	10/9/2007	10/10/2007	10/11/2007	Average
Gross Generation (MW)	105.1	105.7	105.1	105.4	105.4	105.4	108.7	107.3	106.6	107.7	108.3	108.0	106.1	108.2	107.5	Range: 105.1 – 108.7
Hg from Coal (lb/TBtu)	7.34	8.19	6.86	6.92	6.45	6.38	7.64	7.42	7.43	7.33	6.87	7.47	7.11	7.94	9.21	Range: 6.38 – 9.21
Hg Emission Rate (lb/TBtu)	<0.32	<0.34	<0.38	<0.40	<0.41	<0.42	0.17	0.12	0.09	0.53	0.23	0.53	0.34	0.08	0.06	Range: 0.06 – 0.53
Coal Sulfur (lb SO_2/mmBtu)	3.89	3.90	3.77	3.72	3.80	3.80	4.70	4.87	4.75	4.51	4.42	4.12	4.03	4.24	4.30	Range: 3.72 – 4.87
SO_2 Removal (%)	95.5	95.4	94.0	92.9	95.3	95.5	96.6	96.8	96.2	96.0	96.0	99.0	99.0	93.5	94.6	Range: 92.9 – 99.0
Scrubber Outlet Temperature (°F)	163.2	163.3	162.8	162.1	161.9	161.7	158.6	158.7	159.1	160.4	160.0	159.9	160.2	160.5	165.2	Range: 158.6 – 165.2
Unburned Carbon in Fly Ash (%)	20.9	16.9	17.9	17.9	17.5	15.6	20.5	14.4	25.3	21.9	17.5	15.4	17.1	18.7	16.4	Range: 14.4 – 25.3
PAC Injection Rate (lb/mmacf)	0	0	0	3	3	3	0	0	0	3	3	0	0	0	0	Range: 0 – 3
Hg Mass Balance Closure (%)	100.3	93.0	108.8	118.7	119.2	120.6	NA	NA	NA	NA	NA	NA	NA	NA	NA	Range: 93.0 – 120.6

Comparison with Baseline Tests (November 2004)



94% Hg Reduction Over Baseline

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 NO_x 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

- The multi-pollutant control system being demonstrated at AES Greenidge Unit 4 is uniquely designed to meet the needs of smaller coal-fired units
  - Has demonstrated deep reductions in SO_2 emissions (> 95%) and NO_x emissions (> 60%) while requiring a capital investment of only $340/kW and a footprint of < 0.5 acre for a 107 MW unit
  - Deep SO_3 and HCl removal and reduced PM emissions are zero cost co-benefits
- Testing results thus far have shown the system to be very effective in achieving deep Hg removal efficiency
  - Greater than 90% Hg removal efficiency (coal-to-stack) observed in all 15 tests conducted to-date
  - Average demonstrated removal efficiency (96%) represents 94% reduction over baseline
- Based on results to-date, projected incremental cost to achieve 90% Hg capture is $0
  - Ten tests have shown >90% Hg capture in the circulating fluidized bed dry scrubber and baghouse without any 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 at reduced boiler loads
  - Hg removal with biomass co-firing
  - Role of the in-duct SCR in oxidizing Hg
  - Hg removal as a function of fly ash unburned carbon content, fuel, and scrubber operating conditions
  - Stability of the captured Hg in the scrubber solids / ash

ATTACHMENT B

Follow-on Turbosorp Testing Results from the Greenidge Multi-Pollutant Control Project

Presented at POWER-GEN, December 11-13, 2007, New Orleans, LA

Follow-on Turbosorp® Testing Results from the Greenidge Multi-Pollutant Control Project

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

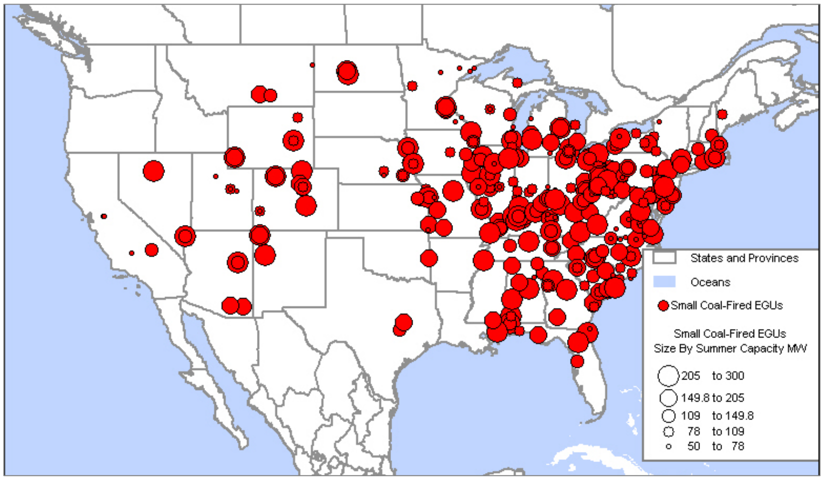
Richard F. Abrams
Babcock Power Environmental

Daniel P. Connell
CONSOL Energy Inc. Research & Development

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

- ~ 440 units not equipped with FGD, SCR, or Hg control
  - Represent ~ 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 reheat unit
- Boiler:
  - Combustion Engineering tangentially-fired, balanced draft
  - 780,000 lb/h steam flow at 1465 psig and 1005 ^oF
- Fuel:
  - Eastern U.S. bituminous coal
  - Biomass (waste wood) – up to 10% heat input
- Original emission controls:
  - Overfire air (natural gas reburn not in use)
  - ESP
  - No FGD - mid-sulfur coal to meet permit limit of 3.8 lb SO_2/MMBtu

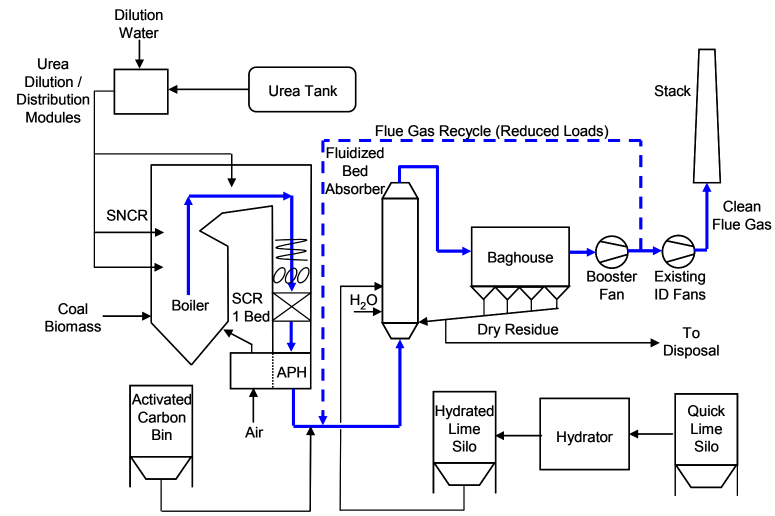
www.babcockpower.com

Design Objectives

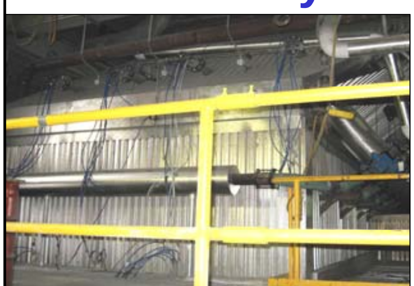
- Deep emission reductions
- Low capital costs
- Small space requirements
- Applicability to high-sulfur coals
- Low maintenance requirements
- Operational flexibility

www.babcockpower.com

Multi-Pollutant Control Process

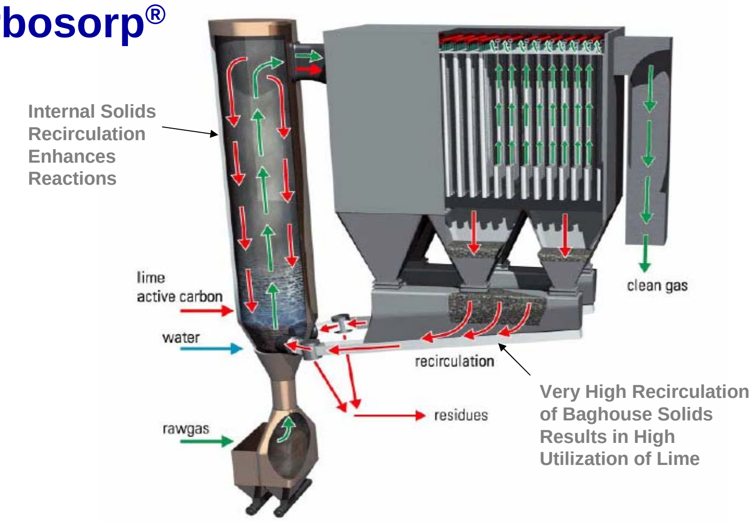


Hybrid NO_x Control

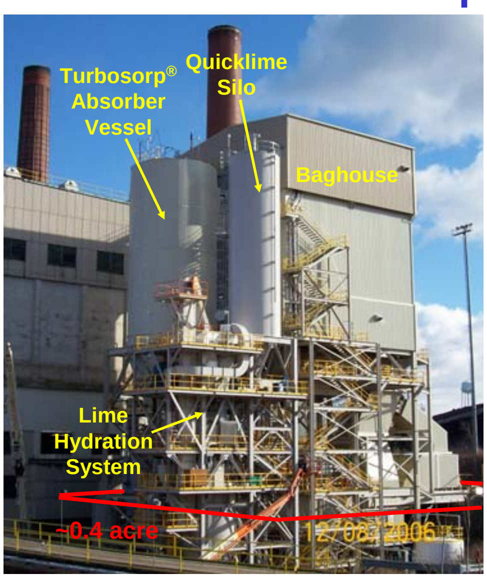


- Combustion Modifications
  - Replace coal, combustion air, and overfire air nozzles
  - Reduce NO_x to 0.25 lb/MMBtu
- SNCR
  - Three zones of urea injection
  - Provide NH_3 slip for SCR
  - Reduce NO_x by ~ 42.5% (to 0.144 lb/MMBtu)
- SCR
  - Single catalyst bed (1.3 m)
  - Cross section = 45’ x 14’
  - Fed by NH_3 slip from SNCR
  - Reduce NO_x by > 30% (to ≤ 0.10 lb/MMBtu)

Turbosorp®



Turbosorp® System



- Completely dry
- Separate control of reagent, water, and recycled solid injection
- Applicable to high-S coal
- High solids recirculation
- 15-25% lower reagent consumption than SDA
- Carbon steel construction
- No wet stack
- Low maintenance requirements
  - Few moving parts
  - No slurries
  - No dewatering

Mercury Control

- System design favors high Hg removal without activated carbon injection
  - Hg oxidation across in-duct SCR catalyst
  - Low temperature (~170 ^{o}F) in scrubber / baghouse
  - Ample gas / solids contact in scrubber / baghouse
  - Similar to SCR / SDA / FF with bituminous coal
    - Field sampling shows 90% Hg removal often achieved with no ACI
- To ensure ≥ 90% Hg removal, demonstration at AES Greenidge includes an activated carbon injection system
  - Turbosorp® system provides high carbon residence time
  - Projected activated carbon requirement: 0.0 – 3.5 lb/mmacf

www.babcockpower.com

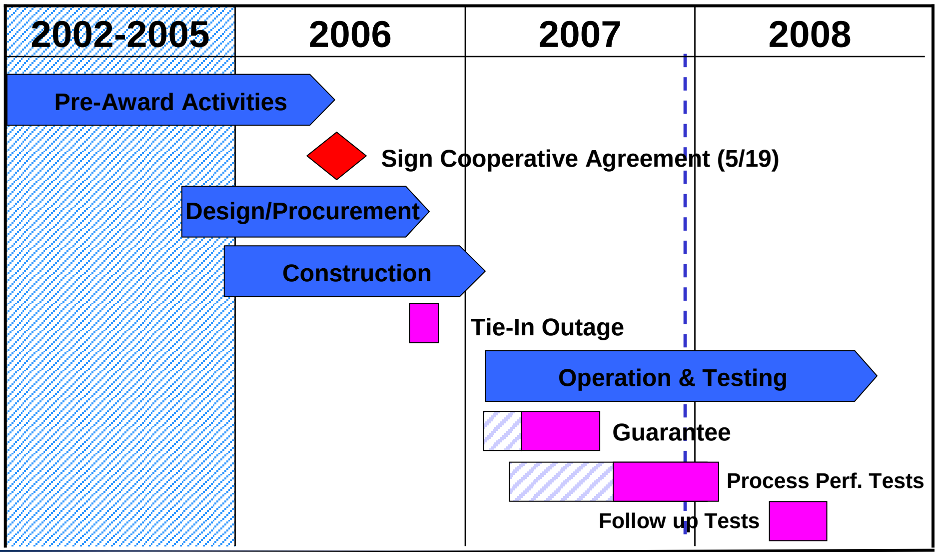
Performance Targets

Fuel: 2-4% sulfur bituminous coal, up to 10% biomass

Parameter	Goal
NO_x	≤ 0.10 lb/mmBtu (full load)
SO_2	≥ 95% removal
Hg	≥ 90% removal
SO_3, HCl, HF	≥ 95% removal

www.babcockpower.com

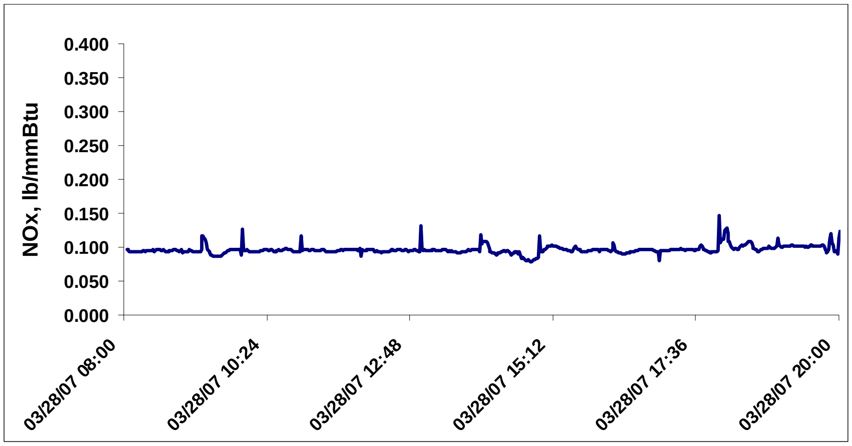
Project Schedule



Initial 2007 Data

NO_x Emission Rate

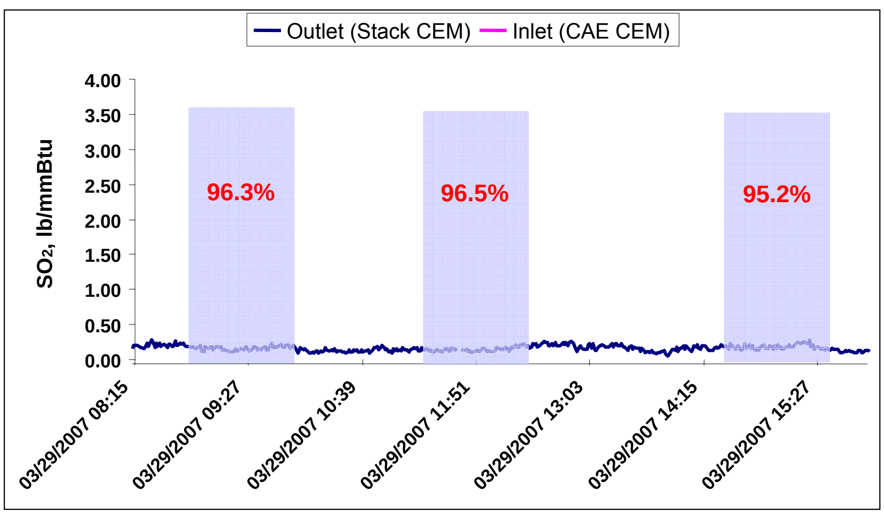
March 28, 2007



www.babcockpower.com

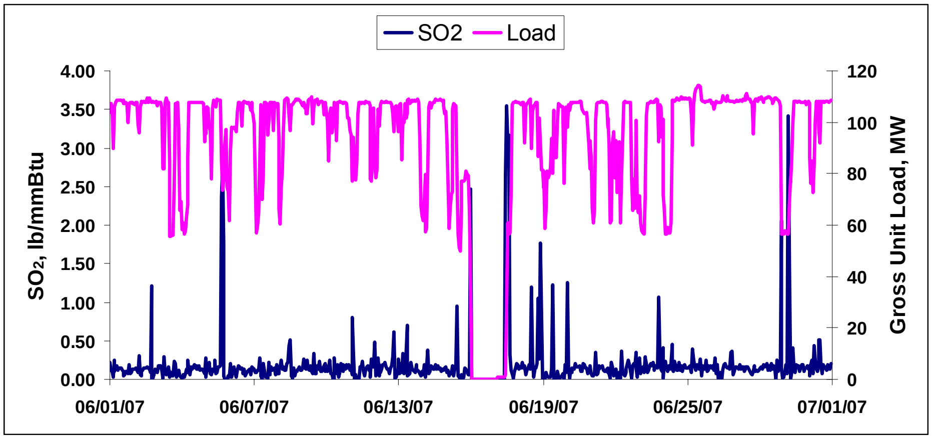
SO_2 Removal Efficiency

March 29, 2007

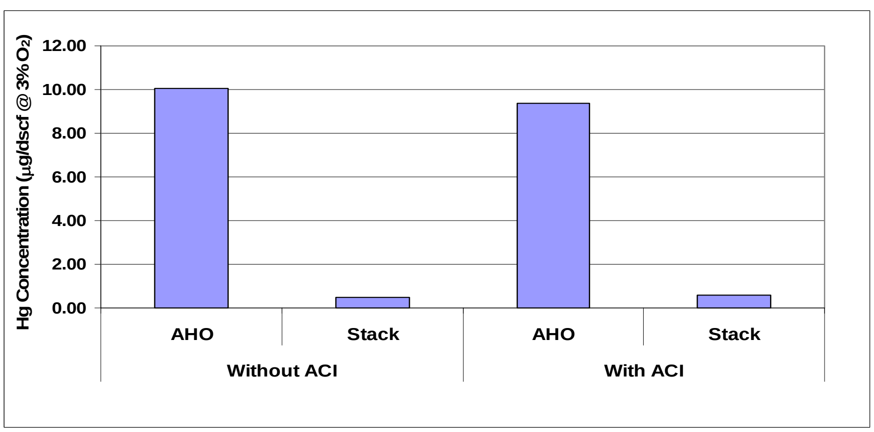


www.babcockpower.com

SO_2 Emissions
June 2007



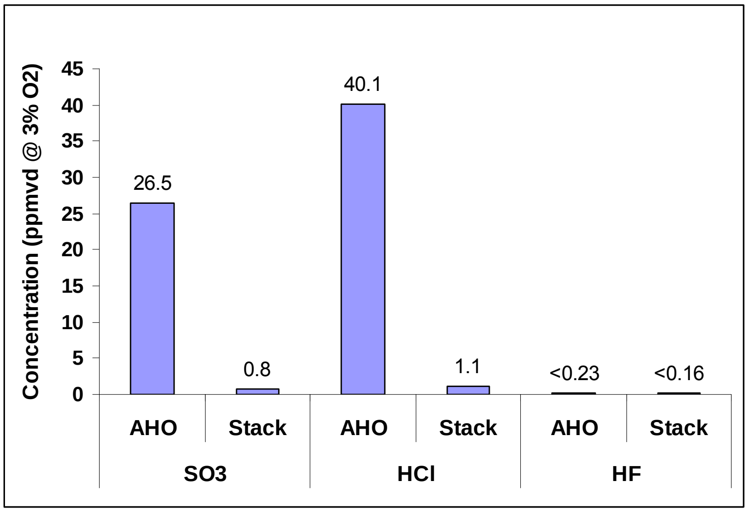
Mercury
March 28-30, 2007



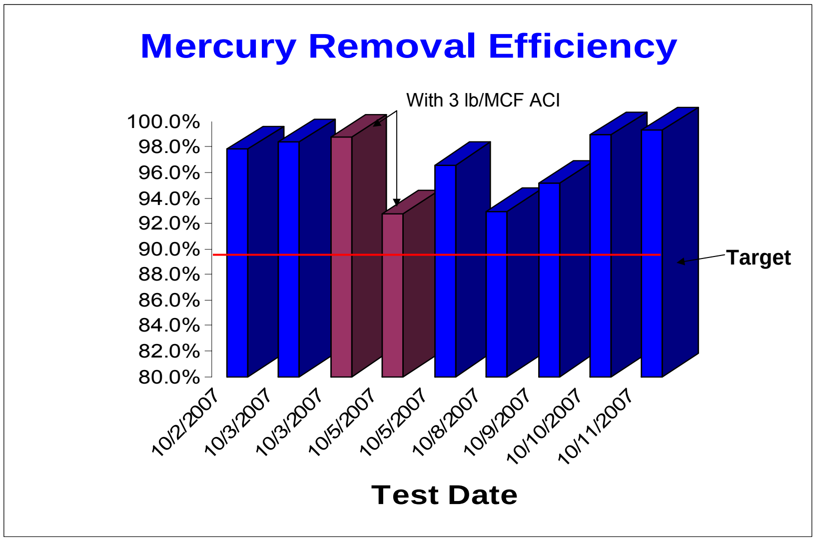
Average Removal Efficiency = >94.6% (LOD)

Acid Gases

May 2-4, 2007

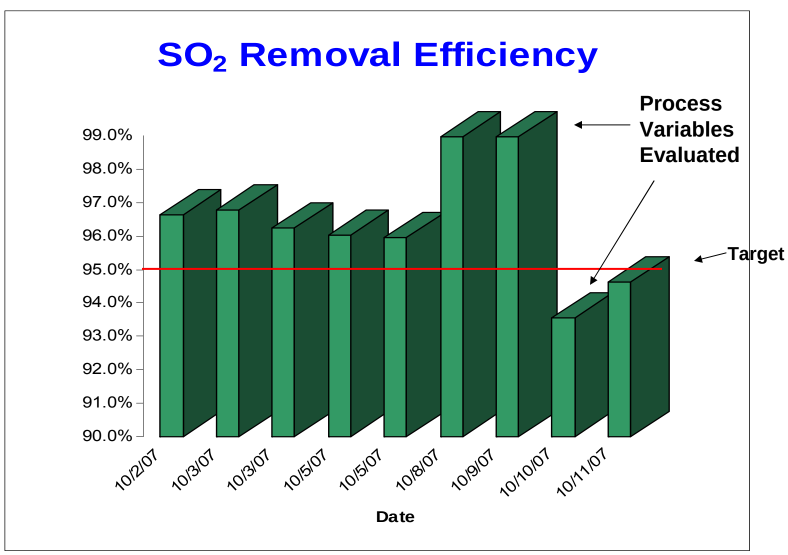


October 2007 Data



Average Removal Efficiency = 96.8%

www.babcockpower.com



Average SO_2 Removal Efficiency = 96.4%

www.babcockpower.com

Performance Comparison

- Mercury
  - Initial data averaged >94.6% removal (limits of detection)
  - Recent data showed average of **96.8%**
  - No noticeable change from ACI
  - Ash is high in unburned carbon (average ~18%)
  - Target removal efficiency is being met

Hg Removal Efficiency Remains High without ACI

Performance Comparison

- SO_2
  - Initial data averaged >96.0% removal
  - Recent data showed average removal of **96.4%**
  - Fuel sulfur loading increased 10% to 4.2 lb/MBtu
  - Performance guarantee continues to be met

SO_2 Removal Efficiency Remains High

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
- Ongoing performance testing results are encouraging
  – Demonstrated ability of system to achieve emission targets for NO_x, SO_2, Hg, and acid gases
- Additional testing planned

Thank You!

Questions?

Disclaimer

This presentation was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

ATTACHMENT C

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

Submitted to the Power Plant Air Pollutant Control MEGA Symposium, August 25-28, 2008, Baltimore, MD

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

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

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

Richard F. Abrams
Babcock Power Environmental Inc.

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

The Greenidge Project is being conducted at the 107-MW AES Greenidge Unit 4 as part of DOE's Power Plant Improvement Initiative to demonstrate a combination of technologies that is well-suited for reducing emissions from the nation's large fleet (~60 GW) of smaller coal-fired units. The technologies, which include a hybrid SNCR/SCR system and a Turbosorp® circulating fluidized bed dry scrubber, were installed in 2006 at a cost of ~$340/kW, substantially less than the cost for a conventional SCR and wet scrubber.

Testing in 2007 with 2.4-3.2% sulfur coal demonstrated the system's ability to reduce NO_x emissions to 0.10 lb/mmBtu and emissions of SO_2, SO_3, and HCl by 96-97%. All tests performed to-date have demonstrated 93-99% mercury removal without activated carbon injection. Additional parametric testing is being conducted through mid-2008. The effects of operating conditions on system performance will be discussed, and process economics incorporating first-year operating data will be presented.