

The Greenidge Multi-Pollutant Control Project: Key Technical and Economic Features of a New Approach for Reducing Emissions from Smaller Coal-Fired Units

Extended Abstract # 386

Daniel P. Connell

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

Douglas J. Roll, P.E., and William B. Rady

AES Greenidge LLC, 590 Plant Road, Dresden, NY 14441

Richard F. Abrams

Babcock Power Environmental Inc., 5 Neponset Street, Worcester, MA 01615

Wolfe P. Huber, P.E.

U.S. Department of Energy, National Energy Technology Laboratory, 626 Cochran Mill Road, Pittsburgh, PA, 15236

INTRODUCTION

A new approach to multi-pollutant control is being demonstrated at the coal-fired, 107 MW_e AES Greenidge Unit 4 (Boiler 6) in Dresden, NY, as part of the Greenidge Multi-Pollutant Control (MPC) Project. The project, which is part of the U.S. Department of Energy's (DOE) Power Plant Improvement Initiative, is being conducted by a team including CONSOL Energy Inc. as prime contractor, AES Greenidge LLC as host site, and Babcock Power Environmental Inc. as engineering, procurement, and construction (EPC) contractor. All funding for the project is being provided by the U.S. DOE, through its National Energy Technology Laboratory, and by AES Greenidge. The MPC system, which was installed in 2006 and is being tested while the unit fires 2-4% sulfur eastern U.S. bituminous coal and co-fires up to 10% biomass, includes a hybrid selective non-catalytic reduction (SNCR) / in-duct selective catalytic reduction (SCR) system to reduce NO_x emissions by $\geq 60\%$, followed by a Turbosorp[®] circulating fluidized bed dry scrubber system to reduce emissions of SO₂, SO₃, HCl, and HF by $\geq 95\%$. Mercury removal of $\geq 90\%$ is also targeted via the co-benefits afforded by the in-duct SCR, dry scrubber, and baghouse and by injection of activated carbon upstream of the scrubber, as required. The objective of the project is to substantiate that this combination of technologies can cost-effectively provide deep emissions reductions when retrofitted on existing coal-fired electrical generating units (EGUs) with capacities less than 300 MW_e.

There are currently about 440 coal-fired EGUs in the United States with capacities of 50-300 MW_e that are not equipped with SCR, flue gas desulfurization (FGD), or mercury control systems, and plans for air pollution control retrofits have not been announced for a majority of these units. These 440 smaller coal-fired units represent more than 60 GW of installed electric generating capacity; hence, curtailment or loss of their generation would exacerbate electricity supply and distribution problems throughout the United States. However, these EGUs are subject to progressively more rigorous environmental regulations such as the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and various state actions. Conventional control technologies being installed on newer, larger EGUs are capable of achieving these rigorous regulations, but entail large capital investments and large space requirements that make them unattractive for this fleet of older, smaller EGUs. Hence, there is a strong need to demonstrate and commercialize technologies specifically designed to meet the environmental

compliance requirements of these smaller coal-fired units. The Greenidge Multi-Pollutant Control Project responds to this need.

This paper summarizes the design of the MPC system being demonstrated at AES Greenidge and highlights important technical and economic differences between this system and more conventional retrofit options (i.e., SCR, SNCR, wet FGD, spray dryer) as applied to smaller coal-fired units.

PROCESS DESIGN

Figure 1 presents a schematic of the MPC process that is being demonstrated. The design for AES Greenidge Unit 4 is based on the use of a 2.9%-sulfur bituminous coal and a baseline NO_x emission rate of ~ 0.30 lb/MMBtu. NO_x control is the first step in the process and is accomplished using urea-based, in-furnace SNCR followed by a single-bed SCR reactor that is installed in a modified section of the ductwork between the unit's economizer and air heaters. The SCR process is fed by ammonia slip from the SNCR process; static mixers located just upstream of the SCR are used to homogenize the velocity, temperature, and composition of the flue gas to promote optimal ammonia utilization and NO_x reduction across the relatively small SCR catalyst. The hybrid NO_x control system at AES Greenidge Unit 4 also includes combustion modifications to achieve further reductions in NO_x emissions and to improve the performance of the hybrid SNCR/SCR system. Hence, a full-load NO_x emission rate of ≤ 0.10 lb/MMBtu results from the combination of the combustion modifications, which are designed to produce NO_x emissions of 0.25 lb/MMBtu, the SNCR, which is designed to reduce NO_x by $\sim 42\%$ to 0.144 lb/mmBtu, and the SCR, which is designed to further reduce NO_x by $\geq 31\%$ to ≤ 0.10 lb/MMBtu.

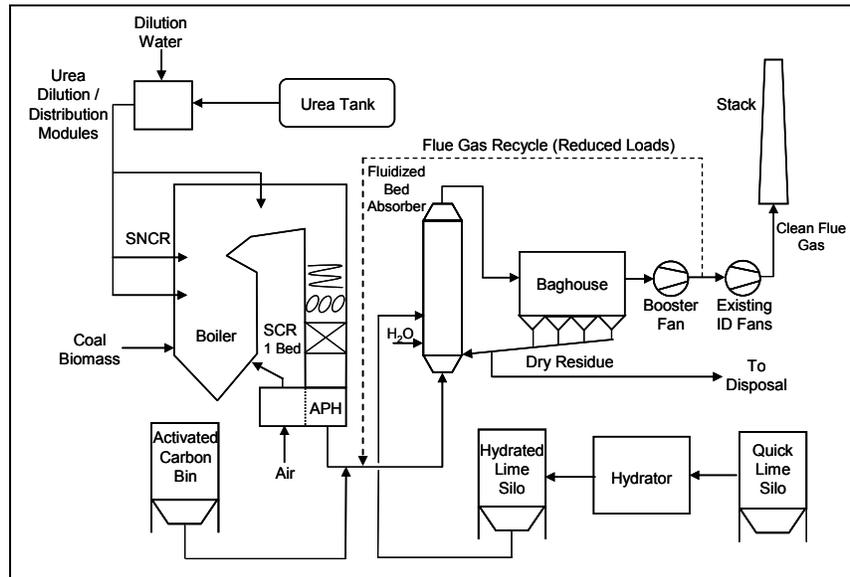


Figure 1. Schematic of the multi-pollutant control process being demonstrated at AES Greenidge Unit 4.

Emissions of SO_2 and other acid gases are reduced by $\geq 95\%$ in the Turbosorp[®] circulating fluidized bed dry scrubber system, which is installed downstream of the air heaters. In the Turbosorp[®] system, water and dry hydrated lime, which is supplied from an on-site hydrator being installed at AES Greenidge, are injected separately into a fluidized bed absorber, where the flue gas is evaporatively cooled and brought into intimate contact with the hydrated lime reagent in a fast fluidized bed. The hydrated lime reacts with the acidic constituents of the flue gas (i.e., SO_2 , SO_3 , HCl , and HF) to form dry solid products, which are separated from the flue gas in a new baghouse and recycled to the absorber via air slides at a

high ratio to the inlet solids in order to maximize pollutant removal and lime utilization. An activated carbon injection system is also installed upstream of the Turbosorp[®] scrubber for Hg control.

COMPARISON WITH OTHER RETROFIT OPTIONS

To illustrate key technical and economic aspects of the MPC system being demonstrated at AES Greenidge, this system was compared with more conventional post-combustion retrofit options. All comparisons were performed using the AES Greenidge Unit 4 design basis. Capital costs for the hybrid SNCR/SCR system and Turbosorp[®] system are the approximate EPC costs for the AES Greenidge installation; EPC costs for the other technologies were estimated using the Integrated Environmental Control Model (IECM).¹ Highlights of the comparisons are summarized below.

NO_x Control

As shown in Table 1, the hybrid SNCR/SCR system that is part of the Greenidge MPC process provides a compromise between the deep NO_x removal capability of full-scale SCR and the low capital cost of stand-alone SNCR. By using a single-bed, in-duct SCR reactor, the hybrid SNCR/SCR system avoids much of the capital cost associated with the multi-bed reactor, structural support steel, foundations, and new ductwork runs required for a conventional stand-alone SCR system. As a result, the capital costs for the hybrid SNCR/SCR at AES Greenidge are estimated to be at least 40% less than the capital costs for a full-scale, stand-alone SCR. (The EPC cost of about \$140/kW shown in Table 1 for SCR may be low; capital costs of \$150-\$175/kW have been reported for SCR retrofits on 100-399 MW units).² In exchange for its substantially reduced capital costs, the hybrid SNCR/SCR system has substantially greater reagent costs (because of its lower reagent utilization and its use of urea rather than ammonia) and lower NO_x removal efficiency than a conventional full-scale SCR system. Whereas this tradeoff may be unattractive for large coal-fired EGUs, it is consistent with the needs of operators of smaller units, who in many cases cannot afford the large capital costs (per unit of electrical output) needed to retrofit with conventional technologies for deep emissions reductions.

Table 1. Comparison of NO_x control retrofit options for AES Greenidge Unit 4.

	Hybrid SNCR/SCR	SCR	SNCR
Approx. EPC Capital Cost (\$)	\$9,000,000	\$15,000,000 ^a	\$2,000,000 ^a
NO _x Removal Efficiency	≥60%	80-90%	20-35%
Reagent	Urea	Ammonia	Urea
Reagent Cost (\$/ton NO ₂ removed) ^b	\$827	\$93	\$891

^aEstimated in IECM using design specifications for AES Greenidge Unit 4 and assuming a retrofit factor of 1.4 and 2005 dollars. ^dAssumes costs of \$410/ton for urea and \$250/ton for ammonia.

Other strengths of the hybrid SNCR/SCR system are its small space requirement and its turndown capability. The SNCR portion of the MPC process requires only a small amount of space for a urea storage tank, urea circulation module, and several small urea distribution skids. Moreover, unlike a conventional stand-alone SCR reactor, the single-bed SCR reactor requires essentially no new land area, as it is installed in a modified ductwork section between the economizer and air heater and needs only a few new support beams. The in-duct SCR being installed at AES Greenidge is designed to fit within the existing boiler building in a space with horizontal dimensions of 52 ft x 27 ft and a vertical height of 23 ft. Another strongpoint of the hybrid NO_x control strategy is its load following capability. Although operation of the single-bed SCR must be discontinued (by restricting NH₃ slip from SNCR to <2 ppmv) at operating loads that produce economizer outlet temperatures below ~600°F, NO_x removal capabilities of 20-25% are still achievable at these reduced loads via continued operation of the SNCR. For smaller

units that regularly cycle loads based upon electricity demand, the load following capabilities of the hybrid SNCR/SCR process can help to contribute to lower NO_x emission averages.

SO₂ and Acid Gas Control

Table 2 compares key technical and economic features of the Turbosorp[®] system that is part of the Greenidge MPC process with those of two conventional FGD technologies: a wet limestone forced oxidation (WLFO) scrubber and a spray dryer. When applied to low-sulfur coals, the Turbosorp[®] scrubber offers slightly lower capital costs, better SO₂ removal efficiency, and better reagent utilization than a spray dryer. Moreover, in spray dryer systems, lime and water are injected into the absorber vessel together as a slurry, rather than separately as in the Turbosorp[®] system. As a result, spray dryers are only capable of achieving deep (e.g., 90%) removal efficiencies when applied to units that fire coals containing less than ~2% sulfur, because greater concentrations require slurry injection rates so high that the water cannot be completely evaporated. In the Turbosorp[®] system the lime injection rate is controlled solely by the pollutant loading and desired emission reduction, without being limited by the temperature or moisture content of the flue gas; hence, the system can be operated to achieve deep emission reductions for a wide range of fuels, including high-sulfur coals. This is an important distinction, because greater than 80% of the coal-fired units that are candidates for the multi-pollutant control process being demonstrated at AES Greenidge are located east of the Mississippi River, where high-sulfur bituminous coal is an economically attractive fuel source.

Table 2. Comparison of SO₂ control retrofit options for AES Greenidge Unit 4.

	Turbosorp[®] System with New Baghouse	Wet Limestone Forced Oxidation Scrubber	Spray Dryer Absorber with New Baghouse
Approx. EPC Capital Cost (\$)	\$25,000,000	\$43,000,000 ^a	\$31,000,000 ^a
SO ₂ Removal Efficiency	95%	98%	90%
SO ₃ Removal Efficiency	95%	50%	95%
Reagent	Lime	Limestone	Lime
Ca/S for 2.9%-S Coal	1.6 ^b	1.03 ^c	Not Feasible
Reagent Cost for 2.9%-S Coal (\$/ton SO ₂ removed) ^d	\$155	\$42	Not Feasible

^aEstimated in IECM using design specifications for AES Greenidge Unit 4 and assuming a retrofit factor of 1.2 and 2005 dollars. ^bBased on moles of inlet SO₂. ^cBased on moles of SO₂ removed. ^dAssumes delivered costs of \$100/ton for lime and \$25/ton for limestone, with 95% reagent purity.

WLFO scrubbers are capable of achieving high SO₂ removal efficiencies when applied to units that fire high-sulfur coal. However, these scrubbers, which are mechanically complex and must be constructed from corrosion-resistant materials, have large capital costs when applied to smaller coal-fired units. As shown in Table 2, the EPC cost for the Turbosorp[®] system at AES Greenidge is estimated to be more than 40% less than the EPC cost for a WLFO retrofit. The difference in cost is likely even larger than that portrayed in the table, because WLFO scrubber retrofits generally entail the installation of a new corrosion-resistant stack, which can add several million dollars to the capital cost. Other advantages of the Turbosorp[®] system over a WLFO scrubber are its greater SO₃ removal capability and comparatively small space requirements and low maintenance requirements. The arrangement of the circulating fluidized bed dry scrubber, baghouse, and associated equipment is compact. The various pieces of equipment are vertically tiered to permit gravity-assisted transport of solids where possible and, as a result, require only about 0.4 acres of land for a 110 MW installation. Also, compared to WLFO scrubbers, which require pumps for slurry introduction and recirculation as well as dewatering equipment, the Turbosorp[®] system is expected to afford substantially reduced maintenance costs. Because the process introduces the hydrated lime reagent as a dry powder and produces a dry solid product, it avoids the problems with plugging, erosion, abrasion, and scaling that can result from

pumping and handling slurries in other types of scrubbing systems. In exchange for these advantages, the Turbosorp[®] system has substantially greater reagent costs (the largest component of variable O&M costs) than a WLFO scrubber. Again, however, this trade-off is consistent with the needs of many smaller coal-fired EGUs, as it allows owners to tailor SO₂ removal according to market conditions, while substantially reducing their need for capital.

Mercury Control

From a mercury control perspective, the Greenidge MPC process is very similar to a conventional air pollution control configuration comprising an SCR, spray dryer, and baghouse. Ontario-Hydro measurements have demonstrated that this configuration, when applied to plants firing bituminous coals, achieves a high level of mercury removal (i.e., 89-99%) without the need for any mercury-specific control technology.³ (For comparison, Hg removal in bituminous coal-fired units equipped with wet FGD typically ranges from 70-97% with SCR and from 41-91% with no SCR).³ Thus, it is likely that the Greenidge MPC process, with its combination of an in-duct SCR, Ca(OH)₂-based scrubber, and baghouse, will result in high mercury removals without any activated carbon injection when applied to bituminous coal-fired units. To ensure ≥90% Hg removal efficiency, the MPC demonstration also includes an activated carbon injection system. Relative to simple duct injection, very effective utilization of the activated carbon and high mercury capture are expected to result from the high solids/gas ratio, long residence time, and low temperature (~170°F) provided by the circulating fluidized bed scrubber and baghouse.

SUMMARY

In conclusion, the Greenidge MPC process, with its combination of relatively deep emission reduction capabilities, low capital costs, small space requirements, operational flexibility, and mechanical simplicity, is designed to meet the needs of coal-fired EGUs with capacities less than 300 MW_e. The Greenidge Project seeks to demonstrate that this process (including combustion modifications) can reduce emissions of NO_x by ≥67%, SO₂ and acid gases by ≥95%, and Hg by ≥90% when applied to a ~110 MW unit firing 2.9%-sulfur coal, while having a capital cost of only \$330/kW and a footprint of <0.5 acre. Testing is now underway to confirm the technical and economic performance of the system.

ACKNOWLEDGMENT AND DISCLAIMER

This material is based upon work supported by the Department of Energy under Award Number DE-FC26-06NT41426. 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.

REFERENCES

1. IECM-cs, version 5.2.0; Carnegie Mellon University: Pittsburgh, PA, 2006.
2. Cichanowicz, J.E. *Power* **2004**, *148(3)*, 32-40.
3. Miller, C.E.; Feeley, T.J.; Aljoe, W.W.; Lani, B.W.; Schroeder, K.T.; Kairies, C.; McNemar, A.T.; Jones, A.P.; Murphy, J.T. Mercury Capture and Fate Using Wet FGD at Coal-Fired Power Plants; DOE/NETL Mercury and Wet FGD R&D: Pittsburgh, PA, 2006.