

FY04-L(50)-125

“Large-Scale Mercury Control Technology Testing for Lignite-Fired Utilities—Oxidation Systems for Wet FGD”

Contractor: Energy & Environmental Research Center
Principal Investigator: Steve Benson

PARTICIPANTS

<u>Sponsor</u>	<u>Cost Share</u>
Basin Electric Power Cooperative	\$ 1,993
Great River Energy	\$ 2,073
Minnkota Power Cooperative	\$ 66,312
Ottertail Power Cooperative	\$ 979
Montana Dakota Utilities	\$ 625
SaskPower	\$ 46,150
Falkirk Mine	\$ 1,092
Westmoreland	\$ 1,092
BNI	\$ 1,092
Coteau Mine	\$ 1,092
ADA-ES	\$104,500
EPRI	\$ 71,000
TXU	\$ 78,072
NDIC	\$172,500
DOE	<u>\$1,602,295</u>
Total Cost	\$2,150,767

Project Schedule - 36 Months

Contract Date – 2/25/04

Start Date – 2/25/04

Completion Date – ~~9/30/06~~

Extension to – 3/31/07

Project Deliverables

Contract Signed: 2/25/04(✓)

Quarterly Reports: 12/31/03 (✓)

3/31/04(✓); 6/30/04(✓); 9/31/04(✓);

12/31/04(✓);3/31/05(✓); 6/30/05(✓);

9/31/05(✓); 12/31/05(✓);

3/31/06(✓); 6/30/06(✓)

Final Report: 3/31/07(✓)

OBJECTIVE / STATEMENT OF WORK:

Demonstrate a mercury “chemical addition” oxidation process in flue gas upstream of pollution control equipment, specifically, electrostatic precipitators followed by wet scrubbers. Host sites are Minnkota Power Cooperative MRY Unit 2 (*cyclone-fired*, ESP, wet scrubber) and Texas Utilities Monticello Unit 3 (*wall-fired*, ESP, wet scrubber).

STATUS

Oct – Dec 2003

A kick-off meeting was held in Nov, 2003 in Pittsburgh to officially kick off the project. Field tests will begin in approximately one year. Near-term needs will focus on preliminary planning, design and fabrication

of equipment, drafting of site-specific test plans, and completed design of ash corrosion probes and furnace ports at the MRY Station identified for placement.

Jan – Mar 2004. Activities this quarter included drafting test plans for the MRY and Monticello Stations.

April – June 2004. The additive system and the corrosion probes that will be used in this program were successfully used in testing at the Leland Olds Station under a related program. The probes will be used to determine the potential impact that chlorine introduced into the boiler will have on corrosion.

July – September 2004. Testing for the MRY Station is scheduled for the 1st Quarter of 2005. Site-specific test plan preparation, and design and fabrication of additive equipment is on-going.

September – December, 2004. Detailed planning for the MRY plant is on-going with testing scheduled to begin in February, 2005. Corrosion probes to define baseline conditions were removed after 8 weeks of exposure.

January – March, 2005. The sorbent injection skid for the oxidizing agent and sorbent injection have been installed in the MRY plant. Baseline corrosion probes were undergoing analysis & new probes installed for the upcoming 4 week test. A draft test plan is under review by the project sponsors and participants.

April – June, 2005. Baseline and parametric tests at the MRY II (ESP, Wet FGD) plant were completed in April, 2005 using three injection rates of powered activated char (PAC). Testing continued with SEA1, SEA 2 and magnesium chloride, followed by a combination of both PAC and SEA 1 & 2. SEA 1 was not particularly effective at oxidizing mercury, indicating only 16% reduction. SEA 2 achieved a 44% reduction, although the target was 50%. It is thought that the ash high sodium content reduces the injected SEA oxidation chemicals. At high levels of SEA 1 and PAC, roughly 53% of the elemental mercury was captured. The target removal was 55 %.

July – September, 2005. An extended test, following parametric tests, were conducted using a PAC, SEA (proprietary oxidation chemicals) and a combination of PAC to demonstrated mercury removal rates up to 50% or more. Removal rates as high as 75% (spikes) was achieved with only SEA, but at very high rates; PAC injection was required to achieve a more consistent mercury capture rate of about 55%. A preliminary conclusion is that achieving a consistent 50% capture rate would require high SEA injection rates. As the overall test was in progress, the cost of SEA increased significantly. An important concern is boiler corrosion, as shown by coupon probes inserted in the boiler to characterize metal waste. It appears to be an issue; laboratory analyses are on-going.

October – December, 2005. Full-scale boiler halogen injection tests were performed at the TXU's Monticello Steam Electric (MoSES) Unit 3 to evaluate mercury oxidation and removal across a cold-side ESP/wet FGD system in a Texas lignite-derived flue gas stream. Short-term parametric tests were followed by 2-week continuous chemical injection tests. Results will be presented in the next quarterly report.

January – March, 2006. Samples and data collected during the chemical injection tests were analyzed from the tests conducted at MoSES Unit 3. The average mercury removal across the ESP/FGD system was 59% at an average injection rate of 113 ppm Bromine in the coal. At the MRY plant, SEA2 additive may be contributing to corrosion in the economizer and AHI long-term test coupons. Additional investigation into this will occur in the next quarter.

April – June, 2006. The ESP and wet FGD at MRY Unit 2 were very inefficient at removing Hg from eh lignite coal combustion flue gas, primarily because elemental mercury was dominant. Additions of SEA2 combined with 0.15 lb/Macf PAC yielded removal efficiencies in the range of 50% to 65%.

Final Report. The Energy & Environmental Research Center (EERC) evaluated Hg control technologies at Minnkota Power Cooperative's Milton R. Young (MRY) Station Unit 2, a 450-MW

lignite-fired cyclone unit near Center, North Dakota, and URS evaluated the same at TXU Energy's Monticello Steam Electric Station (MoSES) Unit 3, a 793-MW lignite-Powder River Basin (PRB) subbituminous coal-fired unit near Mt. Pleasant, Texas. A cold-side ESP and wet FGD scrubber were used at MRY and MoSES for controlling particulate and sulfur dioxide (SO₂) emissions, respectively. Several approaches for significantly and cost-effectively oxidizing Hg⁰ in lignite combustion flue gases, followed by capture in an ESP and/or FGD scrubber, were evaluated. Calcium chloride (CaCl₂), magnesium chloride (MgCl₂), and a proprietary sorbent enhancement additive (SEA), hereafter referred to as SEA2, were added to the lignite feeds to enhance Hg capture in the ESP and/or wet FGD at MRY Unit 2. In addition, powdered activated carbon (PAC) was injected upstream of the ESP at MRY Unit 2. Calcium chloride and calcium bromide (CaBr₂) were evaluated at MoSES by URS. The work involved establishing Hg concentrations and removal rates across existing ESP and FGD units, determining costs associated with a given Hg removal efficiency, quantifying the balance-of-plant impacts of the control technologies, and facilitating technology commercialization. The primary project goal was to achieve ESP-FGD Hg removal efficiencies of ≥55% at MRY and MoSES for about a month.

Hg in the flue gas at MRY Unit 2 was dominated by the elemental form. MgCl₂ and CaCl₂ injections were ineffective in promoting Hg⁰ oxidation and capture in an ESP-FGD. Relatively low additions of SEA2, however, significantly improved the Hg removal efficiency of the ESP-FGD, although the goal of 55% Hg removal was not achieved using as much as 75 ppm SEA2 (dry coal basis). Most of the Hg removal occurred in the ESP, suggesting that SEA2 addition promoted the conversion of Hg⁰ to particulate-bound Hg. SEA2 addition (50–100 ppm, dry coal basis) combined with 0.15-lb/Macf PAC injection was performed for a month during which Hg removal efficiencies generally ranged from 50% to 65%. The month-long testing was not sufficient to evaluate the balance-of-plant impacts such as corrosion and ESP and FGD performance.

Economic evaluations of Hg control for MRY Unit 2 were performed assuming various CaCl₂, SEA2, CaCl₂ with PAC, and SEA2 with PAC injection rates. The estimated cost for maintaining a 55% Hg removal efficiency at MRY Unit 2 by using SEA2 in combination with a small amount of PAC was estimated as follows: 1) Levelized annual cost: \$2,121,169; 2) annual cost, \$/MWh (mills/kWh): 0.63; and 3) cost of Hg removal, \$/lb: 16,639.

MoSES Unit 3 fires a 50:50 blend of Texas lignite and subbituminous PRB coals. Baseline flue gas Hg measurements indicated that the ESP outlet flue gas contained about 25% Hg²⁺ and 75% Hg⁰. CaCl₂ injection was incapable of sustaining the Hg⁰ oxidation necessary for the Hg removal target of 55%. In contrast, parametric tests with CaBr₂ demonstrated up to 78% Hg⁰ oxidation at an injection rate of 200 ppm Br in the coal. Based on these parametric test results, CaBr₂ was selected for evaluation involving two 2-week continuous-injection tests. The furnace injection of CaBr₂ did not significantly improve ESP Hg removal. The oxidized Hg was removed by the FGD scrubber. During baseline and the first week of each long-term injection test, Hg partitioned to the FGD solids; however, during the second week of each test, Hg transitioned to the liquor phase. At an injection rate of 113 ppm Br in the coal, >85% of the Hg in the FGD by-product was contained in the liquor.

Economic evaluations of Hg control for MoSES Unit 3 were performed assuming various CaBr₂ injection rates. The estimated cost for maintaining a ≥55% Hg removal efficiency at MoSES Unit 3 using CaBr₂ was estimated as follows: 1) Levelized annual cost: \$2,933,996; 2) annual cost, \$/MWh (mills/kWh): 0.50; and 3) cost of Hg removal, \$/lb: 7336.

The project provided information on the mechanisms of Hg transformations and interactions with fly ash, flue gas components, and oxidation additives; results on Hg emissions and reduction potential for the oxidation additive-based technology; and performance and cost data that will assist in developing an overall compliance strategy. Data generated from demonstration provided insight into technology applicability. Overall effectiveness of the technology was quantified as were limitations and/or problems of implementation.