DOE/NETL's Mercury Control Technology Field Testing Program

Preliminary Economic Analysis of Wet FGD Co-Benefit Enhancement Technologies

Prepared for

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I. EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) projects that the total capacity of U.S. coal-fired power plants equipped with flue gas desulfurization (FGD) systems for sulfur dioxide (SO_2) control will more than double to approximately 231 gigawatts (GW) by 2020.[1] Based on previous EPA modeling, about 90% of these new scrubbers will be wet FGD systems. The anticipated expansion in FGD capacity is directly linked to EPA's Clean Air Interstate Rule (CAIR) that will permanently cap emissions of SO_2 and nitrogen oxides (NOx) in 28 Eastern U.S states and the District of Columbia.[2]

Mercury (Hg) emissions testing conducted by the U.S. Department of Energy's National Energy Technology Laboratory (NETL) and others has shown that elemental mercury (Hg^0) oxidation can occur across selective catalytic reduction (SCR) systems designed for NOx control and wet FGD systems offer "co-benefit" oxidized mercury (Hg^{2+}) removal.[3,4,5] Oxidized forms of Hg are water-soluble and therefore readily captured in wet FGD systems. Consequently, the Hg capture efficiency of wet FGD systems depends largely on the fraction of Hg^{2+} at the FGD inlet. Although the Federal regulatory structure for Hg emissions from coal-fired power generation facilities is once again uncertain following the U.S. DC Circuit Court of Appeals decision to vacate EPA's Clean Air Mercury Rule (CAMR) on February 8, 2008,[6] optimizing the "co-benefit" capture of Hg across wet FGD systems will likely continue to be a compliance strategy for many U.S. coal-fired power plants.

Working collaboratively with EPA, power plant operators, the Electric Power Research Institute (EPRI), and a host of research organizations and academic institutions, NETL has evaluated technologies designed to promote Hg^0 oxidation and enhance wet FGD Hg capture.[7] This report provides "study-level" cost estimates for two such technologies: fixed-bed Hg^0 oxidation catalysts, and coal treatment with a calcium bromide ($CaBr_2$) solution.[a] The Hg^0 oxidation catalyst economics are based on the pilot-scale performance of a palladium (Pd#1) catalyst at Great River Energy's North Dakota (ND) lignite-fired Coal Creek Station, and gold (Au) catalysts evaluated at Luminant Power's Monticello Station and SRP's Coronado Station. Monticello burns a blend of 50% Texas lignite (TxL) and 50% Powder River Basin (PRB) subbituminous coals, while Coronado burns PRB subbituminous coal. The cost estimates developed for $CaBr_2$ coal treatment are based on the results of full-scale field tests conducted at Luminant Power's Monticello Station and Southern Company's PRB-fired Plant Miller Unit 4.

The economics were developed for "representative" 500 megawatt (MW) units burning three types of low-rank coal: North Dakota (ND) lignite, Powder River Basin (PRB) subbituminous, and a blend of 50% Texas lignite (TxL) and 50% PRB subbituminous coals.[b] It is assumed each of these coal-fired units is equipped with a large cold-side electrostatic precipitator (CS-ESP) for particulate control and a wet FGD system for SO_2 and Hg^{2+} co-removal. In addition, cost estimates for $CaBr_2$ coal treatment at the "representative" PRB-fired unit are provided both with

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[a] For comparison, cost estimates for untreated and chemically-treated activated carbon injection (ACI) both with and without the inclusion of potential by-product impacts are also presented in this report.

[b] This report does not include cost estimates for a "representative" bituminous coal-fired unit for three reasons: (1) the results of NETL pilot-scale Hg^0 oxidation catalyst testing at Plant Yates were difficult to interpret due to frequent pilot unit outages and an abbreviated test schedule; (2) NETL has not evaluated $CaBr_2$ coal treatment at a bituminous unit; and (3) bituminous-fired units, in comparison to those burning lower-rank coals, tend to have higher concentrations of flue gas Hg^{2+} and therefore exhibit higher levels of co-benefit Hg capture across wet FGD systems, under baseline conditions.

and without SCR operation.[c] To develop cost estimates for these Hg control technologies, a number of assumptions were made regarding the "representative" coal-fired units, including:

- The flue gas at the CS-ESP outlet contains 15% Hg^{2+}, with the balance being Hg^0;
- The existing CS-ESP is adequately sized to capture activated carbon to maintain particulate emissions compliance;
- No baseline Hg capture across the existing CS-ESP;
- The existing wet FGD system will capture Hg^{2+} with a net efficiency of 90%;[d]
- The existing wet FGD system will treat 100% of the flue gas;
- ACI will not affect the Hg oxidation percentage at the CS-ESP outlet;
- The plant currently sells all of its fly ash (a sensitivity case where the plant landfills its fly ash is included); and
- Once an ACI system is installed for Hg control, the plant would lose all revenues from fly ash sales; instead, the plant must pay for fly ash disposal.

This analysis provides a comparison of cost estimates for 73% total Hg removal across the "representative" coal-fired units. Annual operating and maintenance (O&M) costs were calculated using an assumed capacity factor of 80%. The cost incurred to replace each Hg^0 oxidation catalyst biennially represents the bulk of the annual O&M cost for this technology. Catalyst costs are based on estimated purchases prices of $1,100 per cubic foot ($\$/ft^3$) for the Pd#1 catalyst and $\$1,500/ft^3$ for the Au-based Hg^0 oxidation catalysts, and required volumes of 4,640, 5,890, and 6,060 ft^3 for the "representative" ND lignite-fired, 50:50 TxL and PRB-fired, and PRB-fired units, respectively. Meanwhile, the primary operating cost for Hg control via $CaBr_2$ coal treatment is consumption of the 52 wt% $CaBr_2$ solution (delivered cost of $0.90/lb).

As shown in Table ES-1, the 20-year levelized (Current$) incremental increase in cost of electricity (COE) is less than 1.80 mills per kilowatt-hour (mills/kWh) for 73% total Hg removal with Pd#1 and Au-based Hg^0 oxidation catalysts at the three "representative" coal-fired units, while the incremental cost of control is less than $17,000 per pound of Hg removed ($/lb Hg removed), excluding the "representative" PRB-fired unit.[e] This technology is particularly advantageous for power plants that currently sell their fly ash for beneficial-use applications since catalyst operation has minimal impact on fly ash quality. The primary O&M cost associated with this technology is biennial catalyst replacement caused by gradual catalyst deactivation.

A sensitivity analysis was conducted to illustrate the impact of Pd#1 and Au-based Hg^0 oxidation catalyst regeneration on process economics. However, it is not feasible to develop a detailed estimate for catalyst regeneration economics since little is known about what minimum conditions (temperature and exposure time) are needed to regenerate the catalysts, how long the regenerated catalysts will remain active relative to the activity of fresh catalysts, and how many times a catalyst can be regenerated before it must be replaced. As a result, it is assumed that the Pd#1 and Au-based catalysts can be regenerated once, after two years in service, and then would

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[c] Plant Miller Unit 4 is equipped with an SCR for NOx control. Measurements taken at the SCR inlet were used to estimate the cost of $CaBr_2$ coal treatment without SCR operation, while readings taken at the CS-ESP outlet were used to estimate the $CaBr_2$ injection costs with an SCR in-service.

[d] The possibility of Hg^0 re-emissions, where Hg^{2+} is chemically-reduced within the absorber, could limit the overall Hg capture efficiency of wet FGD systems.

[e] The 20-year levelized costs are calculated in current (i.e., real) dollars using 2006 as the base year.

be replaced after a total of four years of service. In addition, the analysis assumes that the costs associated with regeneration could be represented as an annual cost, and expressed as a percentage of the original catalyst cost. For this analysis, regeneration cost factors of 5 and 10% are used.

These regeneration cost factors result in annual charges that range from $255,000 for 5% of the Pd#1 catalyst cost to about $909,000 for 10% of the Au-based Hg^0 oxidation catalyst installed at the "representative" PRB-fired unit. In comparison to the Hg^0 oxidation catalyst economics based on biennial replacement, a single-cycle thermal regeneration reduces the 20-year levelized incremental costs by about 20 to 30% and makes this technology more cost-competitive. However, chemically-treated ACI and/or $CaBr_2$ coal treatment remain lower cost Hg control options for the "representative" units in spite of these cost reductions.

The economics presented for 73% total Hg removal via $CaBr_2$ coal treatment are very promising. More specifically, the cost of $CaBr_2$ coal treatment at the "representative" PRB-fired unit equipped with an SCR is about one-third the estimate provided for chemically-treated ACI, when by-product impacts are excluded. Addition of a 52 wt% $CaBr_2$ solution at an injection rate of about 5.90 lb/hr is required to achieve 73% total Hg removal at the "representative" PRB-fired unit equipped with an SCR, resulting in 20-year levelized costs of 0.08 mills/kWh and $2,200/lb Hg removed. Without an SCR in-service, a $CaBr_2$ injection rate of 322 lb/hr is required to achieve the same level of control and the levelized costs rise to 0.80 mills/kWh and $21,200/lb Hg removed.

Using $CaBr_2$ injection to achieve 85% total Hg removal at the "representative" PRB-fired unit equipped with an SCR, results in 20-year levelized costs of 0.13 mills/kWh and $2,800/lb Hg removed. This analysis shows that Hg control via $CaBr_2$ coal treatment is not a capital-intensive process and high levels of FGD Hg capture can be achieved at relatively low injection rates, particularly at units equipped with an SCR for NOx control.

The preliminary results for these wet FGD enhancement technologies, particularly $CaBr_2$ coal treatment, are very encouraging both in terms of the level of Hg^0 oxidation achieved and the cost of control on a mills/kWh and $/lb Hg removed basis. However, it must be kept in mind that the results are based on pilot-scale tests for the Hg^0 oxidation catalysts and short-term field tests for $CaBr_2$ coal treatment. It should also be noted that the economic analyses represent "snapshots" in time based on the methodology used, and the assumptions made regarding the "representative" coal-fired units. Applicability of these "study-level" cost estimates to individual power plants will depend upon fuel characteristics, equipment configuration, flue gas temperature, and other generating unit-specific conditions.

Table ES-1 - Summary of 20-Year Levelized Costs for 73% Total Hg Removal via Hg^0 Oxidation Enhancement Technologies at the 500 MW "Representative" Units

Mercury Control	Pd#1 Catalyst	Au Catalyst	$CaBr_2$ Coal Treatment	Au Catalyst	$CaBr_2$ Coal Treatment	$CaBr_2$ Coal Treatment
"Representative" Unit	ND Lignite	50:50 TxL & PRB	50:50 TxL & PRB	PRB	PRB	PRB ***w/ SCR***
20-Year Levelized Costs (Current$)						
COE Increase, mills/kWh	1.02	1.74	0.73	1.79	0.80	0.08
$/lb Hg Removed	$15,500	$16,500	$6,980	$47,500	$21,200	$2,200

II. INTRODUCTION

Coal combustion flue gas contains varying percentages of three Hg species: particulate-bound (Hg_P), Hg^{2+}, and Hg^0. Mercury speciation, or the relative proportion of the three chemical forms of Hg, has a profound effect on the "co-benefit" Hg capture efficiency of existing air pollution control device (APCD) configurations.[8] However, "co-benefit" Hg capture, as measured by the Ontario Hydro method during EPA's 1999 Information Collection Request campaign, across units burning different coal ranks and equipped with various APCD configurations is quite variable, ranging from 0 to more than 90%.[9]

Coal-fired Hg emissions testing conducted by the U.S. Department of Energy's NETL and others has shown that Hg^0 oxidation can occur across SCR systems designed for NOx control and wet FGD systems offer "co-benefit" Hg^{2+} removal.[3,4,5] Oxidized forms of Hg are water-soluble and therefore readily captured in wet FGD systems. Consequently, the Hg capture efficiency of wet FGD systems depends largely on the fraction of Hg^{2+} at the FGD inlet. The following factors impact the Hg^{2+} concentration in coal combustion flue gas, which influences the level of Hg capture across wet FGD systems.[4]

- *Coal chlorine content* – The predominant form of Hg^{2+} in coal combustion flue gas is mercuric chloride. Coals with greater than 500 ppm by weight of chlorine have approximately 80% Hg^{2+} in the flue gas.
- *Unburned carbon in fly ash* – Unburned carbon can adsorb gas-phase Hg to form Hg_P. In the presence of sufficient chlorine compounds, it also can serve as a catalyst for Hg^0 oxidation.
- *Temperature* – Hg^0 oxidation occurs between 300°F and 850°F. As a result, the temperature gradient across the air heater of a coal-fired power plant can affect Hg^0 oxidation.
- *Upstream APCD* – Hg^0 oxidation can occur across SCR systems designed for NO_x control.[10]

Enhancing FGD Mercury Capture

Although the Federal regulatory structure for Hg emissions from coal-fired power generation facilities is once again uncertain following the U.S. DC Circuit Court of Appeals decision to vacate EPA's CAMR on February 8, 2008,[6] optimizing the "co-benefit" capture of Hg across wet FGD systems will likely continue to be a compliance strategy for many U.S. coal-fired power plants. In fact, the total capacity of U.S. coal-fired power plants equipped with FGD systems for SO_2 control is projected by EPA to more than double to approximately 231 GW by 2020.[1] Based on previous EPA modeling, about 90% of these new scrubbers will be wet FGD systems. The anticipated expansion in FGD capacity is directly linked to EPA's CAIR that will establish a market-based allowance cap-and-trade program to permanently cap emissions of SO_2 and NOx in 28 Eastern U.S states and the District of Columbia.[2] Based on 2003 emission levels, CAIR will reduce SO_2 emissions by more than 70%, while NOx emissions will decrease by approximately 60% when fully implemented.

Oxidation of flue gas Hg^0 followed by absorption of Hg^{2+} across a wet FGD system has the potential to be a reliable and cost-effective Hg control strategy for some coal-fired power plants. To enhance Hg capture across FGD systems, NETL has funded the development of technologies, such as fixed-bed Hg^0 oxidation catalysts and chemical additives that promote Hg^0 oxidation in coal combustion flue gas. These efforts were part of NETL's Hg control technology field testing program that focused on slip-stream and full-scale field testing of control technologies, as well as bench- and pilot-scale development of novel concepts.[11] Working collaboratively with EPA, power plant operators, EPRI, and a host of research organizations and academic institutions, NETL has successfully achieved both the near- and longer-term performance and cost goals of the program that mandate greater than 90% Hg capture at a cost of 25 to 75% less than baseline (1999) estimates of $60,000/lb Hg removed.

Mercury Oxidation Catalysts

URS, through funding provided by NETL and EPRI, has demonstrated at pilot-scale the ability of fixed-bed honeycomb catalysts to promote Hg^0 oxidation in coal combustion flue gas and enhance Hg capture across a downstream wet FGD. In a full-scale application, the catalysts would be installed at the outlet of the existing CS-ESP or FF to: (1) minimize fly ash deposition on the catalysts; (2) prevent or minimize catalyst erosion; and (3) ensure a low flue gas temperature and flow rate, which reduces the catalyst space velocity and minimizes the length of catalyst required.

Extended pilot-scale evaluations of Pd#1- and/or Au-based Hg^0 oxidation catalysts have been completed at Great River Energy's (GRE) Coal Creek Station (CCS) Unit 1, City Public Service of San Antonio's J.K. Spruce Plant, Luminant Power's Monticello Station Unit 3, Southern Company's Plant Yates Unit 1, and SRP's Coronado Generating Station (SRP- and EPRI-funded test). Under NETL's Phase III field testing program, a full-scale field test of a Au-based catalyst is scheduled to begin in 2008 at Lower Colorado River Authority's Fayette Unit 3. Refer to Appendix B of this report for additional information on these testing campaigns.

Chemical Additives

A promising Hg control strategy for power plants burning low-chlorine coal is halogen addition to promote Hg^0 oxidation, thereby enhancing Hg capture across a downstream wet FGD. NETL field testing has shown that coal treatment with $CaBr_2$ can promote flue gas Hg^0 oxidation and enhance FGD Hg capture. This approach maximizes the residence time available for interactions between the additive and Hg^0. In particular, an aqueous $CaBr_2$ solution has shown promise during a full-scale field test completed at Luminant Power's Monticello Unit 3, which burns a coal blend consisting of 50% Texas lignite (TxL) and 50% PRB subbituminous.[12] EPRI and Southern Company also funded a full-scale evaluation of $CaBr_2$ injection at Southern Company's PRB-fired Plant Miller Unit 4.[13] Refer to Appendix C of this report for additional information on these tests.

III. ECONOMIC FRAMEWORK

This report provides "study-level" cost estimates for two technologies designed to enhance Hg capture across a wet FGD system: fixed-bed Hg^0 oxidation catalysts, and coal treatment with an aqueous $CaBr_2$ solution.[a] The economics were developed for "representative" 500 MW units burning three types of low-rank coal: ND lignite, PRB subbituminous, and a 50:50 blend of TxL and PRB subbituminous coals.[b,f] It is assumed each of these coal-fired units is equipped with a large CS-ESP for particulate control and a wet FGD system for SO_2 and Hg^{2+} co-removal. In addition, cost estimates for $CaBr_2$ coal treatment at the "representative" PRB-fired unit are provided both with and without SCR operation.[c]

Table 1 provides a breakdown of the Hg control technologies analyzed for each of the "representative" coal-fired units. In addition, the test site where the underlying data was generated is identified. Cost estimates for $CaBr_2$ coal treatment at the "representative" ND lignite-fired unit are not included in this report, because NETL has not conducted field testing for this coal from which to estimate $CaBr_2$ injection rates. For comparison, cost estimates are also provided for treated and untreated ACI for the ND lignite and PRB "representative" units. ACI cost estimates are not provided for the TxL/PRB blend, because NETL has not conducted ACI field testing for this coal blend from which to estimate ACI rates. Data collected during two separate NETL full-scale field tests at Basin Electric's Leland Olds Station Unit 1 was used to develop cost estimates for Hg control at the ND lignite-fired unit via the injection of: NORIT's untreated DARCO® Hg sorbent,[14] and ALSTOM's chemically-treated Mer-Clean™ 8 sorbent.[15] The untreated DARCO® Hg sorbent is injected upstream of the CS-ESP, while the Mer-Clean™ 8 sorbent is injected upstream of the air preheater via ALSTOM's Mer-Cure™ process. For the "representative" PRB-fired unit, cost estimates for untreated DARCO® Hg and chemically-treated Mer-Clean™ 8 injection are based on the results of NETL field tests at GRE's Stanton Station Unit 1 and PacifiCorp's Dave Johnston Unit 3, respectively. For detailed information pertaining to the methodology used to develop ACI cost estimates presented in this report, please refer to the May 2007 NETL report.[16]

Table 1 - Breakdown of Hg Control Technologies Analyzed for Each of the "Representative" Units

"Representative" Unit	Oxidation Catalyst	$CaBr_2$ Coal Treatment	Untreated ACI (DARCO® Hg)	Chemically-treated ACI (Mer-Clean™ 8)
ND Lignite	Pd#1 (CCS)	--	Leland Olds	Leland Olds
50:50 TxL & PRB	Au (Monticello)	Monticello	--	--
PRB	Au (Coronado)	Plant Miller	Stanton #1	Dave Johnston

To develop cost estimates for these Hg control technologies, a number of assumptions were made regarding the "representative" coal-fired units, including:

- The flue gas at the CS-ESP outlet contains 15% Hg^{2+}, with the balance being Hg^0;
- The existing CS-ESP is adequately sized to capture activated carbon to maintain particulate emissions compliance;
- No baseline Hg capture across the existing CS-ESP;
- The wet FGD system will capture Hg^{2+} with a net efficiency of 90%;

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[f] Coal properties and power plant operating conditions for each of these "representative" units is presented in Appendix A of this report.

- The existing wet FGD system will treat 100% of the flue gas;
- ACI will not affect the Hg oxidation percentage at the CS-ESP outlet;
- The plant currently sells all of its fly ash (a sensitivity case where the plant landfills its fly ash is included); and
- Once an ACI system is installed for Hg control, the plant would lose all revenues from fly ash sales; instead, the plant must pay for fly ash disposal.

Oxidation Catalyst Performance Assumptions

For this analysis, the Pd#1 and Au-based Hg^0 oxidation catalysts must maintain at least 55% incremental Hg capture over the life of the catalyst. Based on the assumptions of 15% Hg^{2+} at the CS-ESP outlet and 90% Hg^{2+} capture across the wet FGD, this is equivalent to 61% total Hg removal. Upon reaching the 61% total Hg capture threshold, the catalyst must be either replaced or regenerated. In short, this analysis assumes that total Hg capture across the Hg^0 oxidation catalysts will gradually decrease from 85 to 61% over the two-year effective catalyst life. As a result, the "representative" units achieve an average total Hg capture of 73% over the two-year life of the catalysts. The following is a discussion of the methodology used to establish these performance assumptions for the Hg^0 oxidation catalysts.

Mercury control via oxidation catalysis is dependent on the level of Hg^0 oxidation across the catalyst. Therefore, the minimum level of Hg^0 oxidation required to achieve at least 55% incremental Hg removal must be calculated to determine the effective life of the catalysts.

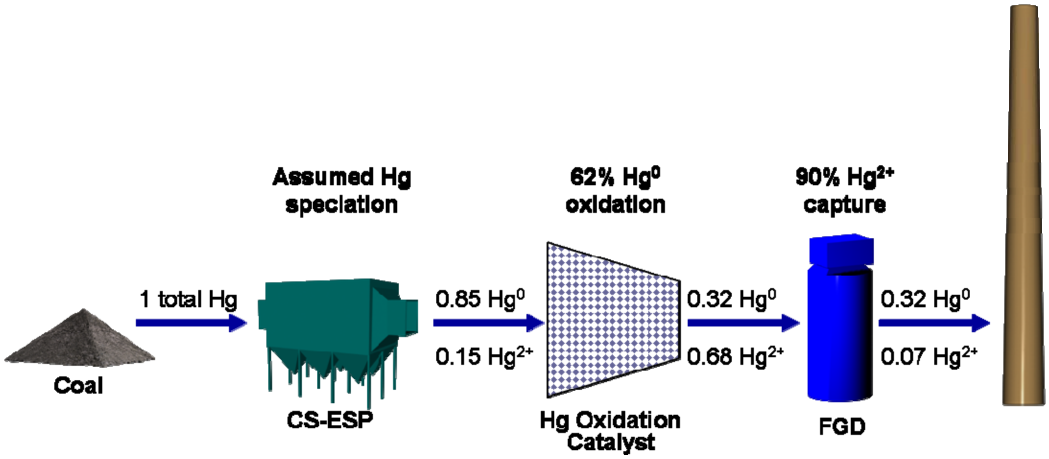
By assuming 15% Hg^{2+} at the CS-ESP outlet and 90% Hg^{2+} capture across the wet FGD, the level of baseline Hg capture across the "representative" units can be calculated using Equation 1. Using the percent baseline Hg capture across the existing wet FGD and the requirement of at least 55% incremental Hg capture due to the Hg^0 oxidation catalysts, the resulting total Hg capture across the units can be calculated using Equation 2.

$$\%\,Baseline\ Hg\ capture = (0.15 \times 0.90) \times 100\% = 13.5\% \qquad Eqn\ 1$$

$$\%\,Total\ Hg\ capture = [1 - ((1 - 0.135) \times (1 - 0.55))] \times 100\% = 61\% \qquad Eqn\ 2$$

A simplified process flow diagram for the Hg^0 oxidation catalysis technology is provided below. As shown in Figure 1, the Pd#1 and Au-based Hg^0 oxidation catalysts must oxidize at least 62% of the incoming Hg^0 to maintain 61% or greater total Hg capture across the "representative" units. However, due to the aforementioned catalyst deactivation observed during pilot-scale testing at CCS, the catalyst must initially achieve higher levels of Hg^0 oxidation to ensure that the 62% oxidation requirement is sustained over a sufficient timeframe prior to catalyst replacement or regeneration.

Figure 1 - Process Flow for Oxidation Catalysis



Based on laboratory screening results and a design flue gas flow rate of 2,000 actual cubic feet per minute (acfm), the quantity of catalyst installed at the pilot test sites was varied to achieve the desired level of Hg^0 oxidation. Table 2 provides the dimensions of the Pd#1 and Au-based catalysts loaded into the pilot catalyst skids at CCS, Monticello, and Coronado. In general, the Pd#1 and Au-based catalysts evaluated by URS were sized to achieve an initial 95% Hg^0 oxidation.

Table 2 - Pilot-Scale Catalyst Dimensions

Pilot Test Site	Coal Rank	Catalyst	Manufacturer	Cells/in^2 (cpsi)	Cross Section	Length	Area Velocity (ft^2/hr)
Coal Creek	ND Lignite	Pd#1	Prototech	64	30” x 30”	9”	49
Monticello	50:50 TxL & PRB	Au	Prototech	64	30” x 30”	9”	50
Coronado	PRB	Au	Johnson Matthey	64	18” x 18”	24”	52

Assuming the area/space velocity values are identical for pilot- and full-scale Hg^0 oxidation catalyst installation, the required catalyst volume and the effective catalyst life can be estimated for the 500 MW “representative” coal-fired units. Table 3 provides the estimated Hg^0 oxidation catalyst volumes required for the “representative” units analyzed in this report. These values are based on the pilot-scale (2,000 acfm) catalyst dimensions shown in Table 2, and the flue gas flow rates provided in Appendix A for the “representative” units.

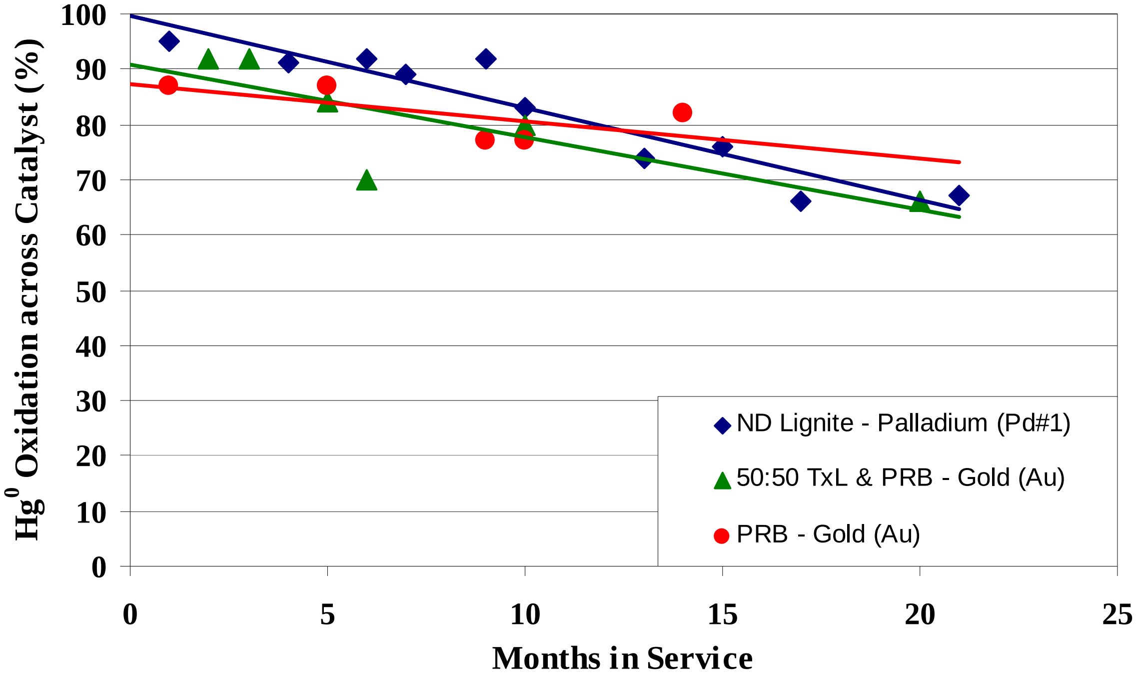
Table 3 - Estimated Catalyst Volume for the 500 MW “Representative” Units

“Representative” Unit	ND Lignite	50:50 TxL & PRB	PRB
Catalyst	Pd#1	Au	Au
Catalyst Volume (ft^3)	4,640	5,890	6,060

The pilot-scale catalyst activity data provided in Figure 2 can be used to determine the effective catalyst life (i.e., how long each catalyst can be expected to achieve at least 62% Hg^0 oxidation in the 500 MW “representative” units), assuming the area/space velocity values are identical for pilot- and full-scale catalyst installation. Note that URS anticipated that the Hg^0 oxidation catalysts would initially have a significant capacity for adsorbing Hg from the flue gas. With Hg being adsorbed from the flue gas, it is not possible to get an accurate measurement of Hg^0 oxidation. The percent oxidation across the catalyst is based on the drop in Hg^0 across the catalysts, and with Hg being adsorbed it is not possible to distinguish between the drop in concentration due to adsorption and that from oxidization. Therefore, catalyst activity measurements, such as those shown in Figure 2 for the Pd#1 and Au-based catalysts, were delayed until the catalyst had achieved Hg adsorption breakthrough (i.e., the catalyst inlet and outlet total Hg concentrations are approximately equal).

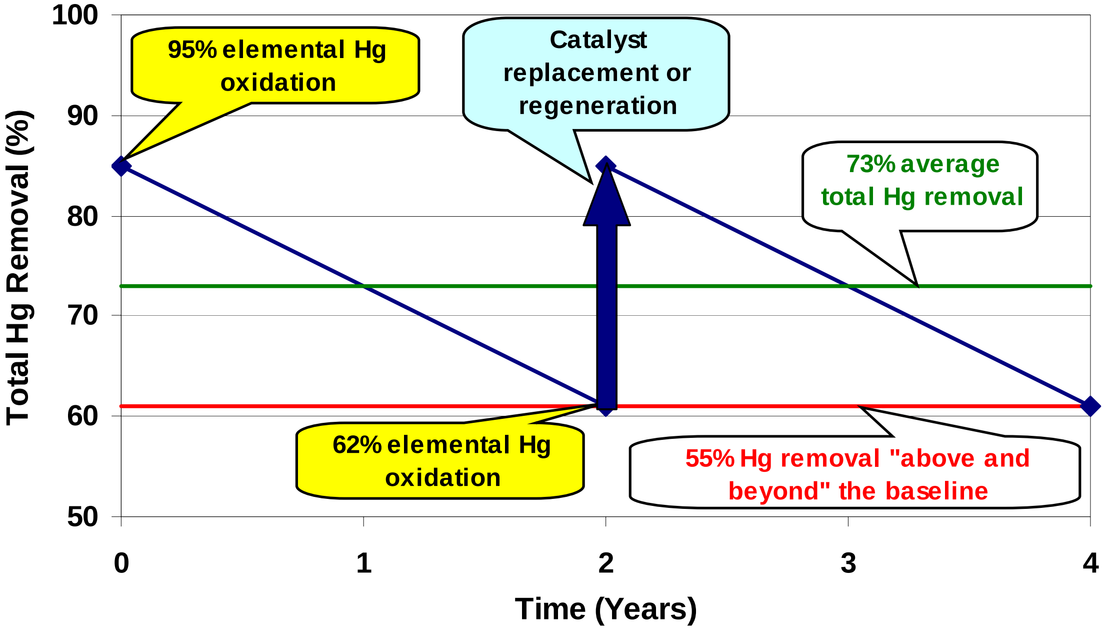
For both the Pd#1 and Au-based catalysts, the effective catalyst life is approximately two years. After two years of continuous operation, the Hg^0 oxidation catalysts must be either replaced or regenerated. Most plants operate no more than two years without taking at least a one- to two-week outage, which should be an adequate amount of time to replace or regenerate the catalyst. Therefore, this analysis assumes that catalyst replacement or regeneration would occur during scheduled plant outages.

Figure 2 - Pilot-Scale Catalyst Activity Data



The linear catalyst deactivation profile that is assumed for the Pd#1 and Au-based Hg^0 oxidation catalysts installed at the “representative” units is illustrated in Figure 3. Total Hg capture across the units would gradually decrease from 85% to 61% over the two-year catalyst life. Upon reaching the 55% incremental Hg capture threshold (61% total Hg removal), the catalyst must be either replaced or regenerated. As shown in the figure, the “representative” units achieve an average total Hg capture of 73% over the two-year life of the catalysts. Based on the level of baseline Hg capture (13.5%), this equates to 69% average incremental Hg capture due to the installation of the Hg^0 oxidation catalysts.

Figure 3 - Total Hg Removal Trend with Operation of Hg^0 Oxidation Catalyst Technology at the "Representative" Units



Note the two-year catalyst replacement cycle results in relatively "high" Hg capture in the first year, but "low" Hg capture in the second. This could present a compliance problem for a plant during the second year if the state decides to implement a Hg regulation more stringent than the CAMR cap-and-trade rule. The use of multiple Hg^0 oxidation catalyst layers, similar to an SCR arrangement, could potentially increase the average Hg capture. However, this Hg control strategy would lead to increased costs and more frequent outages for catalyst replacement and regeneration.

Calcium Bromide Performance Assumptions

To develop cost estimates for Hg control via coal treatment with an aqueous $CaBr_2$ solution, the $CaBr_2$ injection rate required to achieve a given level of Hg control must be determined. Although higher performance levels are possible, the target for this analysis is 73% total Hg removal for equitable comparison with the Hg^0 oxidation catalysts. Full-scale field testing data generated during $CaBr_2$ coal treatment is typically reported as percent Hg^{2+} at the CS-ESP outlet as a function of the $CaBr_2$ injection rate, which is expressed as parts per million (ppm) bromine (Br) in the dry coal.

To develop a relationship between total Hg removal and the $CaBr_2$ injection rate, this analysis assumes 15% Hg^{2+} at the CS-ESP outlet under baseline conditions, and 90% of the total Hg^{2+} present at the CS-ESP outlet will be removed across the downstream wet FGD. Applying these assumptions to the full-scale field testing data generated at Monticello and Plant Miller yields the data presented in Figure 4. The non-linear regression curves, also shown in Figure 4, were developed to determine the $CaBr_2$ injection rate required to achieve 73% total Hg removal across the "representative" units.[g] The two datasets presented for the "representative" PRB-fired unit (based on Plant Miller data) illustrate the positive impact that SCR operation can have on the Hg^0

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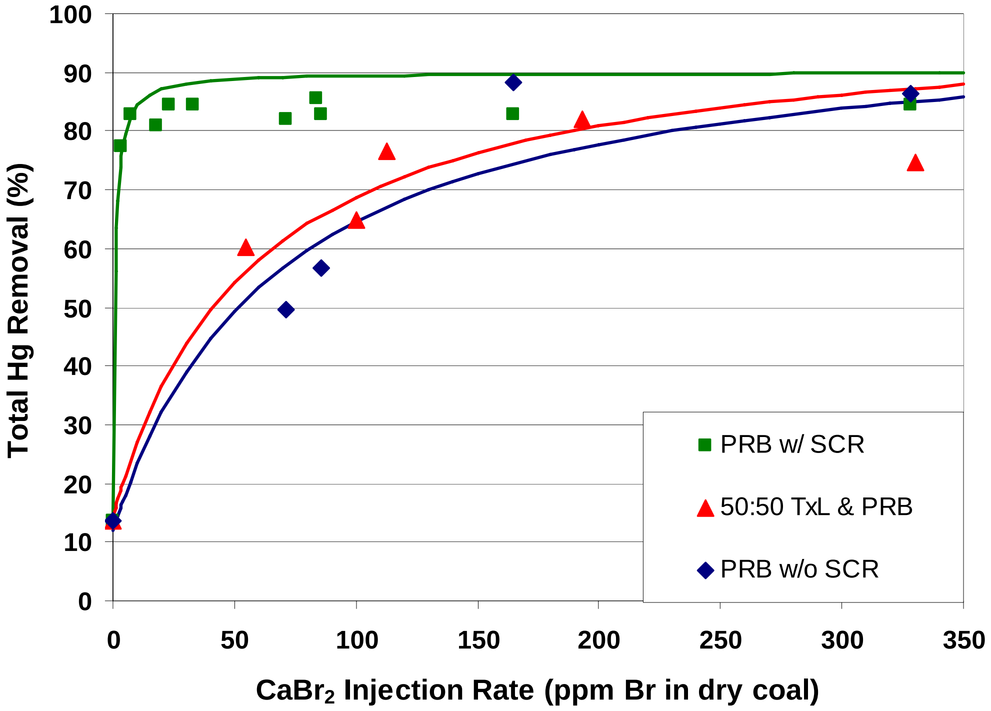
[g] Appendix C provides a detailed description of the full-scale $CaBr_2$ coal treatment field tests, while Appendix E includes results from the non-linear regression analyses.

oxidation potential of $CaBr_2$. However, it should be noted that the "w/o SCR" data is based on sampling in the high-temperature region upstream of the SCR. It is likely that additional Hg^0 oxidation would occur as the flue gas cools across the air preheater.

Figure 4 - Total Hg Removal Across "Representative" Units as a Function of the $CaBr_2$ Injection Rate



Capital Cost Estimates

The total capital requirement (TCR) to install each of the Hg control technologies analyzed in this report at the "representative" 500 MW coal-fired units would include both direct and indirect cost components. The total direct cost (TDC) for each Hg-specific control technology is calculated as the sum of the following cost components: (1) uninstalled equipment cost; (2) materials and labor associated with site integration; (3) applicable taxes; and (4) installation costs that can vary significantly depending on plant-specific retrofit issues. The indirect costs were estimated as percentages of the TDC using the EPRI Technical Assessment Guide (TAG™) methodology. For instance, 10% of the TDC was set aside for general facility fees as well as engineering fees. The project contingency was calculated as 15% of the TDC, while 5% was used for the process contingency. However, the capital cost required to install and calibrate a Hg monitoring system was excluded from this economic analysis since utilities will incur these costs regardless of their Hg control strategy.

Hg^0 Oxidation Catalysts

Based on pilot-scale testing at CCS, URS completed a preliminary economic analysis of Hg control via oxidation catalysis at a full-scale 500 MW coal-fired unit. This analysis included a detailed inventory of cost estimates for essential equipment and supplies for construction and site integration, in addition to, an itemized breakdown of installation cost estimates.[17] The URS analysis shows that the cost of foundations and structural steel to construct the catalyst support structure accounts for about 50% of the uninstalled equipment cost. The system is also equipped with 20 sonic horns to prevent fly ash from accumulating within the catalyst cells, and thereby minimize pressure drop across the Hg^0 oxidation catalysts. In addition, the TCR for the Hg^0 oxidation catalyst systems includes pre-production costs for process design and project management, detailed design and procurement, and construction management. However, the initial catalyst loading charge is not included in the capital cost estimates presented in this report. It is assumed that the plant's existing wet FGD system is designed for scrubbing 100% of the flue gas. Therefore, any cost required to upgrade an existing FGD system from partial scrubbing to 100% scrubbing are not included in this analysis.

As shown in Tables 4-6, the installed TCR for the Hg^0 oxidation catalyst systems ranges from about $1.35 million ($2.69/kW) for the 500 MW "representative" ND lignite-fired unit to about $1.76 million ($3.53/kW) for the "representative" PRB-fired unit. The variability in installed TCR for these units can be attributed to differences in the required catalyst volume for the "representative" units (Table 3).

$CaBr_2$ Coal Treatment

Capital cost estimates for the aqueous $CaBr_2$ storage and injection system are based on a URS analysis of results obtained during NETL field testing at Monticello.[12] The system consists of a storage tank, four transfer pumps, piping, flowmeters, and controllers to enable the $CaBr_2$ injection rate to be adjusted based on power plant operating conditions. Plant-required costs to install the injection skid include site preparation, foundation installation, and piping and electrical connection. As shown in Tables 5-7, the installed TCR for the aqueous $CaBr_2$ storage and injection system is approximately $780,000 ($1.56/kW) for the 500 MW "representative" units.

Annual Operating and Maintenance (O&M) Costs

Hg^0 Oxidation Catalysts

Annual O&M costs were calculated using an assumed capacity factor of 80%. The cost incurred to replace each Hg^0 oxidation catalyst biennially represents the bulk of the annual O&M cost for this technology. Catalyst costs are based on estimated purchases prices of $1,100/$ft^3$ for the Pd#1 catalyst and $1,500/$ft^3$ for the Au-based Hg^0 oxidation catalysts, and required volumes of 4,640, 5,890, and 6,060 ft^3 for the "representative" ND lignite-fired, 50:50 TxL and PRB-fired, and PRB-fired units, respectively (Table 3). Due to biennial catalyst replacement, these values yield a "two-year" catalyst cost that must be reduced by approximately 50% to calculate an "annual", or "first-year" catalyst cost. The "first-year" catalyst consumption costs presented in Tables 4-6 include purchasing, delivery, and installation. Catalyst delivery and installation were each calculated as 1% of the "first-year" catalyst cost. This analysis assumes that the catalysts would be disposed as a hazardous waste at a cost of 3% of the "first-year" catalyst cost. In addition, the annual O&M cost includes an electric power requirement for the sonic horns.

$CaBr_2$ Coal Treatment

The primary operating cost for the $CaBr_2$ injection system is consumption of the 52 wt% $CaBr_2$ solution (estimated delivered cost of $0.90/lb). To calculate the annual $CaBr_2$ consumption cost, the required $CaBr_2$ injection rate (based on the non-linear regression curves shown in Figure 4) was converted from units of "ppm Br in dry coal" to "pounds of 52 wt% $CaBr_2$ solution injected per hour (lb/hr)". To do so, the coal flow rate (on a dry basis) was calculated using the coal moisture content provided in Appendix A. In addition, the quantity of water (H_2O) present in the 52 wt% $CaBr_2$ solution was calculated using Equation 3. This shows that one pound of $CaBr_2$ is equivalent to 1.923 pounds of 52 wt% $CaBr_2$ solution.

$$\frac{1\,lb\,CaBr_2}{1\,lb\,CaBr_2 + x\,lb\,H_2O} = 0.52;\;\; x = 0.923\,lb\,H_2O \qquad \text{Eqn 3}$$

Equation 4 was then used to calculate the 52 wt% $CaBr_2$ solution injection rate on a lb/hr-basis.

$$\frac{lb\,dry\,coal}{hr} \times \frac{lb\,Br}{10^6\,lb\,coal} \times \frac{MW_{CaBr2}}{MW_{Br}} \times \frac{1.923\,lb\,CaBr_2\ solution}{1\,lb\,CaBr_2} = \frac{lb\,CaBr_2\ solution}{hr} \qquad \text{Eqn 4}$$

Where: lb Br = $CaBr_2$ injection rate in ppm Br in dry coal
Molecular weight $(MW)_{CaBr2}$ = 199.88 g/mol
MW_{Br} = 79.9 g/mol

Finally, to calculate the annual $CaBr_2$ consumption cost, the 80% capacity factor and estimated delivered cost of \$0.90/lb were applied to the calculated $CaBr_2$ injection rate required to achieve the desired level of total Hg removal across the "representative" units. The "other" annual O&M costs for the $CaBr_2$ injection system include O&M labor, replacement parts, and utilities. The utilities required to operate the injection system are electric power for the blower and process controls, natural gas (~50 cubic feet per hour) is needed to prevent salt formation in colder climates, and water (~5 gallons per minute) to further dilute the 52 wt% $CaBr_2$ solution.

IV. RESULTS

Tables 4-6 provide cost estimates for 73% total Hg removal via oxidation catalysis and $CaBr_2$ coal treatment at the "representative" ND lignite-fired, 50:50 TxL and PRB-fired, and PRB-fired units, respectively.[h] These cost estimates assume that the Pd#1 and Au-based Hg^0 oxidation catalysts would be replaced biennially (no regeneration). In addition to capital and "first-year" annual O&M costs, these tables provide 20-year levelized cost estimates for the incremental increase in cost of electricity (COE), expressed in units of mills per kilowatt-hour (mills/kWh), and the incremental cost of Hg control (\$/lb Hg removed).[i] The 20-year levelized costs are calculated in current (i.e., real) dollars using 2006 as the base year. For comparison, cost estimates are also provided for treated and untreated ACI for the ND lignite and PRB "representative" units.[j] For the ACI analyses, cost estimates are provided with and without the inclusion of potential by-product impacts.[k] A key advantage of Hg control via $CaBr_2$ coal treatment and Hg^0 oxidation catalysis is no adverse impact on fly ash utilization applications sensitive to an increase in carbon content.

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[h] $CaBr_2$ cost estimates are not provided for ND lignite because NETL has not conducted field testing for this coal from which to estimate additive injection rates.

[i] Economic assumptions are documented in Appendix A of this report.

[j] ACI cost estimates are not provided for the TxL/PRB blend because NETL has not conducted ACI field testing for this coal blend from which to estimate ACI rates.

[k] For this analysis, the total by-product impacts are based on an estimated value of \$35 per ton of fly ash generated, which includes \$18/ton for lost revenue from fly ash sales (assuming 100% utilization) and \$17/ton for non-hazardous fly ash disposal.

Table 4 - Cost Estimates for 500 MW ND Lignite-fired Unit (2006$)

Hg Control Technology	**Pd#1 Catalyst**	**DARCO® Hg** (untreated ACI)	**Mer-Clean™ 8** (chemically-treated ACI)
Average Total Hg Removal, %	73%	73%	73%
Catalyst/PAC Cost	$1,100/ft^3	$0.60/lb	$1.35/lb
Catalyst Volume, ft^3	4,640 ft^3	--	--
ACI Rate, lb/MMacf	--	10.00	0.41
Coal Hg Content, lb/TBtu	10.50	10.50	10.50
Unit APCD	CS-ESP & wet FGD	CS-ESP & wet FGD	CS-ESP & wet FGD
TCR, $	$1,350,000	$1,830,000	$4,000,000
TCR, $/kW	$2.69	$3.67	$8.00
First-Year Annual O&M with 80% Capacity Factor			
Catalyst/PAC Consumption Cost, $/yr[1]	$2,600,000	$5,140,000	$469,000
Catalyst/PAC Disposal, $/yr	$76,600	$72,900	$2,960
Other, $/yr	$1,750	$125,000	$186,000
Total, $/yr	$2,680,000	$5,340,000	$658,000
By-product Impacts, $/yr	$0	$4,050,000	$4,050,000
20-Year Levelized Cost *without* By-product Impacts (Current$)			
COE Increase, mills/kWh	1.02	1.98	0.38
$/lb Hg Removed	$15,500	$30,100	$5,830
20-Year Levelized Cost *with* By-product Impacts (Current$)			
COE Increase, mills/kWh	1.02	3.43	1.83
$/lb Hg Removed	$15,500	$52,100	$27,800

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[1] The cost includes delivery and installation for the Pd#1 catalyst.

Table 5 - Cost Estimates for 500 MW 50:50 TxL and PRB-fired Unit (2006$)

Hg Control Technology	Au Catalyst	$CaBr_2$ (52 wt% solution)
Average Total Hg Removal, %	73%	73%
Catalyst/$CaBr_2$ Cost	$1,500/ft^3	$0.90/lb
Catalyst Volume, ft^3	5,890 ft^3	--
$CaBr_2$ Injection Rate, lb/hr	--	294
Coal Hg Content, lb/TBtu	16.98	16.98
Unit APCD	CS-ESP & wet FGD	CS-ESP & wet FGD
TCR, $	$1,710,000	$780,000
TCR, $/kW	$3.42	$1.56
First-Year Annual O&M with 80% Capacity Factor		
Catalyst/$CaBr_2$ Consumption Cost, $/yr[m]	$4,510,000	$1,850,000
Catalyst Disposal, $/yr	$132,525	$0
Other, $/yr	$1,750	$114,000
Total, $/yr	$4,640,000	$1,970,000
20-Year Levelized Cost *without* By-product Impacts (Current$)		
COE Increase, mills/kWh	1.74	0.73
$/lb Hg Removed	$16,500	$6,980

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[m] The cost includes delivery and installation for the Au-based catalyst.

Table 6 - Cost Estimates for 500 MW PRB-fired Unit (2006$)

Hg Control Technology	**Au Catalyst**	**CaBr$_2$** w/o SCR (52 wt% solution)	**CaBr$_2$** w/SCR (52 wt% solution)	**DARCO® Hg** (untreated ACI)	**Mer-Clean™ 8** (treated ACI)
Average Total Hg Removal, %	73%	73%	73%	73%	73%
Catalyst/PAC/CaBr$_2$ Cost	$1,500/ft^3	$0.90/lb	$0.90/lb	$0.60/lb	$1.35/lb
Catalyst Volume, ft^3	6,060 ft^3	--	--	--	--
ACI Rate, lb/MMacf	--	--	--	4.13	0.14
CaBr$_2$ Injection Rate, lb/hr	--	322	5.90	--	--
Coal Hg Content, lb/TBtu	6.00	6.00	6.00	6.00	6.00
Unit APCD	CS-ESP & wet FGD		***SCR***, CS-ESP & wet FGD	CS-ESP & wet FGD	
TCR, $	$1,760,000	$780,000	$780,000	$1,830,000	$4,000,000
TCR, $/kW	$3.53	$1.56	$1.56	$3.67	$8.00
First-Year Annual O&M with 80% Capacity Factor					
Catalyst/PAC/CaBr$_2$ Consumption Cost, $/yr[m]	$4,640,000	$2,030,000	$37,200	$2,090,000	$155,000
Catalyst/PAC Disposal, $/yr	$136,000	$0	$0	$29,600	$978
Other, $/yr	$1,750	$114,000	$114,000	$125,000	$186,000
Total, $/yr	$4,770,000	$2,140,000	$151,000	$2,240,000	$342,000
By-product Impacts, $/yr	$0	$0	$0	$3,250,000	$3,250,000
20-Year Levelized Cost *without* By-product Impacts (Current$)					
COE Increase, mills/kWh	1.79	0.80	0.08	0.87	0.27
$/lb Hg Removed	$47,500	$21,200	$2,200	$23,100	$7,200
20-Year Levelized Cost *with* By-product Impacts (Current$)					
COE Increase, mills/kWh	1.79	0.80	0.08	2.03	1.43
$/lb Hg Removed	$47,500	$21,200	$2,200	$54,000	$38,100

Cost estimates for 85% total Hg removal via CaBr$_2$ coal treatment are presented in Table 7 for the TxL/PRB blend and PRB coals.[n] Again for comparison, Table 7 also includes a cost estimate for 85% total Hg removal via treated ACI for the PRB coal. For CaBr$_2$ coal treatment, the 20-

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[n] A cost estimate for 85% total Hg removal via Hg^0 oxidation catalysis is not provided because pilot-scale testing indicates this level of control would not be practical to maintain due to the decrease in catalyst activity over time as shown in Figure 2.

year levelized incremental cost of 85% total Hg control ranges from about $12,000 to less than $3,000/lb Hg removed. These costs are more than 75% below NETL's baseline estimate of $60,000/lb Hg removed.

Table 7 - Cost Estimates for 85% Total Hg Removal (2006$)

Hg Control Technology	**$CaBr_2$** (52 wt% solution)	**$CaBr_2$** w/ SCR (52 wt% solution)	**Mer-Clean™ 8** (treated ACI)
Total Hg Removal, %	85%	85%	85%
Coal Rank	50:50 TxL & PRB	PRB	PRB
PAC/$CaBr_2$ Cost	$0.90/lb	$0.90/lb	$1.35/lb
ACI Rate, lb/MMacf	--	--	0.30
$CaBr_2$ Injection Rate, lb/hr	647	25	--
Coal Hg Content, lb/TBtu	16.98	6.00	6.00
Unit APCD	CS-ESP & wet FGD	***SCR***, CS-ESP & wet FGD	CS-ESP & wet FGD
TCR, $	$780,000	$780,000	$4,000,000
TCR, $/kW	$1.56	$1.56	$8.00
First-Year Annual O&M with 80% Capacity Factor			
PAC/$CaBr_2$ Consumption Cost, $/yr	$4,080,000	$160,000	$341,000
PAC Disposal, $/yr	$0	$0	$2,150
Other, $/yr	$114,000	$114,000	$186,000
Total, $/yr	$4,190,000	$274,000	$529,000
By-product Impacts, $/yr	$0	$0	$3,250,000
20-Year Levelized Cost *without* By-product Impacts (Current$)			
COE Increase, mills/kWh	1.53	0.13	0.34
$/lb Hg Removed	$12,100	$2,800	$7,460
20-Year Levelized Cost *with* By-product Impacts (Current$)			
COE Increase, mills/kWh	1.53	0.13	1.50
$/lb Hg Removed	$12,100	$2,800	$33,200

V. DISCUSSION

The intent of this analysis was to develop and compare preliminary cost estimates for two technologies designed to promote Hg^0 oxidation and enhance Hg capture across a downstream wet FGD: Hg^0 oxidation catalysts and $CaBr_2$ coal treatment. For 73% total Hg removal with Pd#1 and Au-based Hg^0 oxidation catalysts, the incremental increase in COE is less than 1.80 mills/kWh for the three 500 MW "representative" coal-fired units, while the incremental cost of control is less than $17,000/lb Hg removed, excluding the "representative" PRB-fired unit. As shown in Tables 4-6, this technology is particularly advantageous for power plants that currently sell their fly ash for beneficial-use applications.[o] The primary O&M cost associated with this technology is biennial catalyst replacement caused by gradual catalyst deactivation.

The economics presented for 73% total Hg removal via coal treatment with an aqueous $CaBr_2$ solution are very promising. More specifically, the cost of $CaBr_2$ coal treatment at the "representative" PRB-fired unit equipped with an SCR is about one-third the estimate provided for chemically-treated ACI, when by-product impacts are excluded. Addition of a 52 wt% $CaBr_2$ solution at an injection rate of about 5.90 lb/hr is required to achieve 73% total Hg removal at the "representative" PRB-fired unit equipped with an SCR, resulting in 20-year levelized costs of 0.08 mills/kWh and $2,200/lb Hg removed. Without an SCR in-service, a $CaBr_2$ injection rate of 322 lb/hr is required to achieve the same level of control and the levelized costs rise to 0.80 mills/kWh and $21,200/lb Hg removed.

A $CaBr_2$ injection rate of 25 lb/hr is required to achieve 85% total Hg removal at the "representative" PRB-fired unit equipped with an SCR, resulting in 20-year levelized costs of 0.13 mills/kWh and $2,800/lb Hg removed. In general, this analysis shows that Hg control via $CaBr_2$ coal treatment is not a capital-intensive process and high levels of FGD Hg capture can be achieved at relatively low injection rates, particularly at low-rank coal-fired units equipped with an SCR for NOx control.

"Representative" ND Lignite-fired Unit

Table 4 presents cost estimates for 73% total Hg removal via the installation of a Pd#1 Hg^0 oxidation catalyst, untreated DARCO® Hg injection, and chemically-treated Mer-Clean™ 8 injection. Installed capital cost estimates range from about $1.35 million ($2.69/kW) for the oxidation catalyst system, excluding the initial Pd#1 catalyst loading, to $4 million ($8.00/kW) for ALSTOM's Mer-Cure™ Process that is used to inject the chemically-treated Mer-Clean™ 8 sorbent. The relative cost-effectiveness of these technologies is highly dependent on the potential by-product impacts associated with Hg control via ACI. When by-product impacts are excluded, the 20-year levelized costs for the Pd#1 catalyst, 1.02 mills/kWh increase in COE and $15,500 on a dollar per pound of Hg removed basis, are about 50% of the untreated ACI costs, but approximately three times higher than the figures presented for chemically-treated ACI. Conversely, with the inclusion of potential by-product impacts, the Pd#1 catalyst levelized costs are nearly one-half of the costs calculated for chemically-treated ACI. Note that data was not available for $CaBr_2$ coal treatment at a ND lignite-fired unit.

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[o] See By-product Impacts section later in report for detailed discussion of potential ACI impact on fly ash sales.

“Representative” 50:50 TxL and PRB-fired Unit

As shown in Table 5, installed capital cost estimates are $780,000 ($1.56/kW) for the $CaBr_2$ storage and injection system and $1.71 million ($3.42/kW) for the oxidation catalyst system, excluding the initial Au catalyst loading. Most notably, the 20-year levelized cost of 73% total Hg removal via $CaBr_2$ coal treatment is more than 50% less than the cost calculated for the Au-based Hg^0 oxidation catalyst. For 73% total Hg control, addition of a 52 wt% $CaBr_2$ solution to the coal at an injection rate of about 294 lb/hr results in a levelized incremental increase in COE of 0.73 mills/kWh and an incremental cost of $6,980/lb Hg removed. While significantly higher than the cost calculated for $CaBr_2$ coal treatment, the incremental cost of 73% total Hg removal via the installation of a Au-based catalyst (~$16,500/lb Hg removed) is nearly 75% less than NETL’s baseline cost estimate of $60,000/lb Hg removed.

A $CaBr_2$ injection rate of about 647 lb/hr is required to achieve 85% total Hg removal (Table 7), resulting in a 20-year levelized incremental increase in COE of 1.53 mills/kWh and an incremental cost of about $12,100/lb Hg removed. This figure is about one-fifth of NETL’s baseline cost estimate. Note that data was not available for untreated and chemically-treated ACI at a 50:50 TxL and PRB-fired unit. As a result, potential by-product impacts were not considered for this “representative” unit.

“Representative” PRB-fired Unit

Table 6 presents cost estimates for 73% total Hg removal via the installation of a Au-based Hg^0 oxidation catalyst, untreated DARCO® Hg injection, chemically-treated Mer-Clean™ 8 injection, and $CaBr_2$ coal treatment with and without SCR operation. Installed capital cost estimates range from about $780,000 ($1.56/kW) for the $CaBr_2$ storage and injection system to $4 million ($8.00/kW) for ALSTOM’s Mer-Cure™ Process that is used to inject the chemically-treated Mer-Clean™ 8 sorbent. The low cost technology for this unit is $CaBr_2$ coal treatment with an SCR in-service, while installation of a Au-based Hg^0 oxidation catalyst and untreated ACI result in the highest costs (~2.00 mills/kWh increase in COE & ~$50,000/lb Hg removed). A $CaBr_2$ injection rate of about 5.90 lb/hr is required to achieve 73% total Hg removal with an operating SCR, resulting in incremental increase in COE of 0.08 mills/kWh and an incremental cost of about $2,200/lb Hg removed. For comparison, the levelized cost is an order of magnitude less than $CaBr_2$ coal treatment without an SCR and about one-third the cost calculated for chemically-treated ACI, when by-product impacts are excluded.

The data presented in Table 6 indicate that the selection of a specific Hg control could depend on both the presence of an SCR system for NOx control and potential by-product impacts. For the scenarios where the “representative” unit is not equipped with an SCR, Hg control via chemically-treated ACI (excluding by-product impacts) is about one-third the cost of $CaBr_2$ coal treatment due to a significantly higher injection rate requirement of about 322 lb/hr. When by-product impacts are considered, $CaBr_2$ coal treatment is more cost-effective than chemically-treated ACI. Similarly, 73% total Hg removal via the installation of a Au-based Hg^0 oxidation catalyst becomes more cost-effective than untreated ACI with the inclusion of potential by-product impacts.

As shown in Table 7, cost estimates for 85% total Hg removal were calculated for $CaBr_2$ coal treatment with an SCR in-service and chemically-treated ACI. Addition of a 52 wt% $CaBr_2$ solution to the coal at an injection rate of about 25 lb/hr results in the lowest 20-year levelized costs. For comparison, the levelized costs calculated for chemically-treated ACI are about three times higher, when by-product impacts are excluded.

Hg^0 Oxidation Catalyst Regeneration

To maintain the necessary level of Hg^0 oxidation, the Pd#1 and Au-based catalysts must be replaced biennially. Consequently, the primary O&M cost associated with this technology is catalyst replacement due to deactivation. Realizing that cost reductions could be achieved by extending the effective life of the catalysts, URS conducted *in-situ* thermal catalyst regeneration tests during pilot-scale testing at CCS. Following thermal regeneration in July 2004, Hg^0 oxidation across the Pd#1 catalyst increased from 67 to 88% (near the 95% activity of the fresh catalyst).[p] However, it is important to note that these "proof of concept" tests were conducted simply to determine if the catalysts could be thermally regenerated, and conditions were not optimized to ensure the effectiveness of the thermal regeneration.

A sensitivity analysis was conducted to illustrate the impact of Pd#1 and Au-based Hg^0 oxidation catalyst regeneration on process economics. However, it is not feasible to develop a detailed estimate for catalyst regeneration economics since little is known about what minimum conditions (temperature and exposure time) are needed to regenerate the catalysts, how long the regenerated catalysts will remain active relative to the activity of fresh catalysts, and how many times a catalyst can be regenerated before it must be replaced. As a result, it is assumed that the Pd#1 and Au-based catalysts can be regenerated once, after two years in service, and then would be replaced after a total of four years of service. In addition, the analysis assumes that the costs associated with regeneration could be represented as an annual cost, and expressed as a percentage of the original catalyst cost. For this analysis, regeneration cost factors of 5 and 10% are used.

As shown in Table 8, these regeneration cost factors result in annual charges that range from \$255,000 for 5% of the Pd#1 catalyst cost to about \$909,000 for 10% of the Au-based Hg^0 oxidation catalyst installed at the "representative" PRB-fired unit. The "first-year" catalyst consumption costs shown are approximately 25% of the original catalyst cost. The annual cost of catalyst regeneration could be further reduced if the oxidation catalysts are able to endure multiple regeneration cycles. Conversely, assuming that regeneration will restore the original catalyst activity and allow the catalysts to maintain the necessary level of Hg^0 oxidation over two additional years of service may be optimistic since the impacts of regeneration and extended flue gas exposure on the rate of catalyst deactivation are unknown at this time.

In comparison to the Hg^0 oxidation catalyst economics presented in Tables 4-6, a single-cycle thermal regeneration reduces the 20-year levelized incremental costs by about 20 to 30% and makes this technology more cost-competitive. However, chemically-treated ACI and/or $CaBr_2$ coal treatment remain lower cost Hg control options for the "representative" units in spite of these cost reductions.

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[p] A more complete discussion of the thermal regeneration tests is provided in Appendix D.

Table 8 - Hg^0 Oxidation Catalyst Economics with Thermal Regeneration

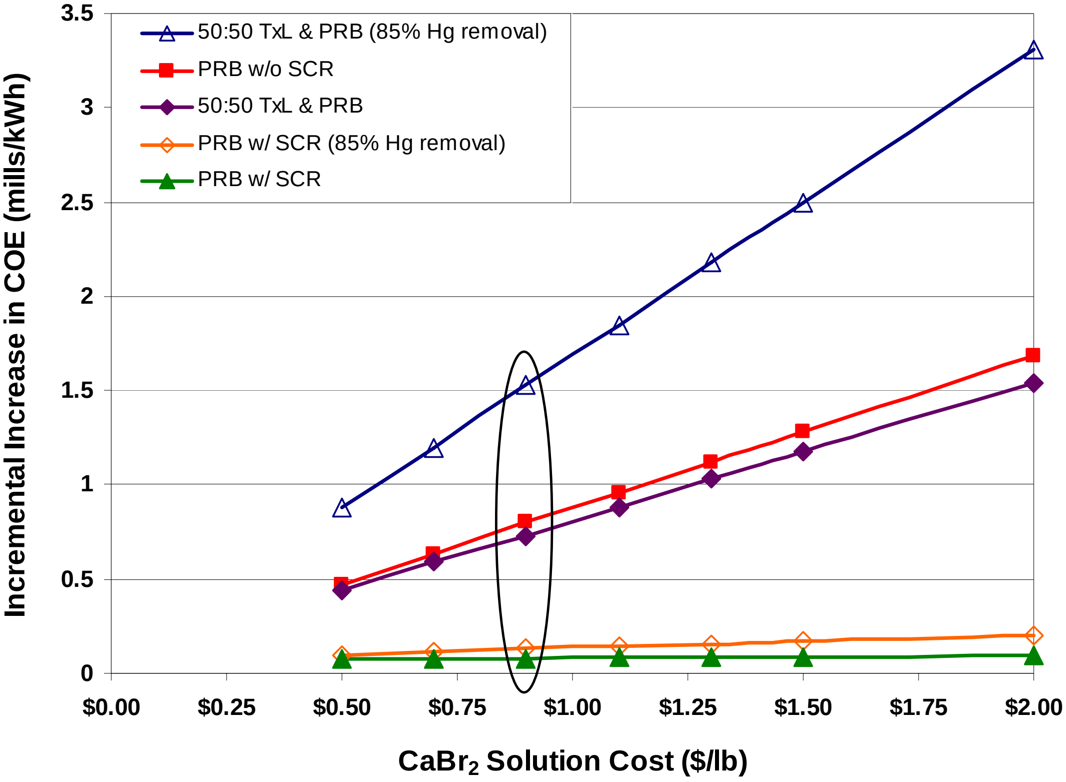
"Representative" Unit	**ND Lignite**		**50:50 TxL & PRB**		**PRB**	
Average Total Hg Removal, %	73%		73%		73%	
Catalyst (Regeneration Cost Factor)	Pd#1 (5%)	Pd#1 (10%)	Au (5%)	Au (10%)	Au (5%)	Au (10%)
Catalyst Cost	\$1,500/ft^3	\$1,500/ft^3	\$1,500/ft^3	\$1,500/ft^3	\$1,500/ft^3	\$1,500/ft^3
Catalyst Volume, ft^3	4,640 ft^3	4,640 ft^3	5,890 ft^3	5,890 ft^3	6,060 ft^3	6,060 ft^3
Coal Hg Content, lb/TBtu	10.50	10.50	16.98	16.98	6.00	6.00
Unit APCD	CS-ESP and wet FGD					
TCR, \$	\$1,350,000	\$1,350,000	\$1,710,000	\$1,710,000	\$1,760,000	\$1,760,000
TCR, \$/kW	\$2.69	\$2.69	\$3.42	\$3.42	\$3.53	\$3.53
First-Year Annual O&M with 80% Capacity Factor						
Catalyst Consumption Cost, \$/yr[m]	\$1,310,000	\$1,310,000	\$2,280,000	\$2,280,000	\$2,340,000	\$2,340,000
Catalyst Disposal, \$/yr	\$38,300	\$38,300	\$66,300	\$66,300	\$68,200	\$68,200
Catalyst Regeneration, \$/yr	\$255,000	\$510,000	\$442,000	\$884,000	\$454,000	\$909,000
Other, \$/yr	\$1,750	\$1,750	\$1,750	\$1,750	\$1,750	\$1,750
Total, \$/yr	\$1,610,000	\$1,860,000	\$2,780,000	\$3,230,000	\$2,870,000	\$3,320,000
20-Year Levelized Cost *without* By-product Impacts (Current\$)						
COE Increase, mills/kWh	0.64	0.73	1.23	1.55	1.27	1.59
\$/lb Hg Removed	\$9,660	\$11,000	\$11,700	\$14,700	\$33,700	\$42,300

These results underscore the importance of Hg^0 oxidation catalyst regeneration to the economics of this technology. As a result, future testing of Hg^0 oxidation catalysts should focus on determining: (1) the minimum requirements for catalyst regeneration; and (2) the effective life of regenerated catalysts. URS initiated this process by regenerating the Pd#1 catalyst evaluated at CCS and installing the regenerated Pd#1 catalyst in the pilot catalyst skid used at Monticello. Following *in-situ* catalyst cleaning in August 2006, Hg^0 oxidation was approximately 72% across the regenerated Pd#1 catalyst after 17 months of pilot-scale operation at Monticello. These efforts will allow for a more-refined economic assessment of regenerated Hg^0 oxidation catalysts in the future.

Calcium Bromide Cost Sensitivity

Figure 5 illustrates the linear relationship that exists between the delivered cost of the 52 wt% CaBr$_2$ solution and the 20-year levelized incremental increase in COE. For this sensitivity analysis, the CaBr$_2$ solution cost varies from \$0.50/lb to \$2.00/lb, and the oval symbol indicates the delivered $CaBr_2$ solution cost of \$0.90/lb that was used to complete this economic analysis. Unless otherwise noted, the data presented in Figure 5 is for 73% total Hg removal across the “representative” coal-fired units.

Figure 5 - Sensitivity of the 20-Year Levelized Incremental Increase in COE to Changes in the Delivered Cost of the 52 wt% $CaBr_2$ Solution



In general, the degree of sensitivity exhibited by the increase in COE to changes in $CaBr_2$ solution cost is related to the $CaBr_2$ injection rate required to achieve the desired level of Hg control. For the “representative” PRB-fired unit equipped with an SCR, $CaBr_2$ injection rates of about 5.90 and 25 lb/hr are required to achieve 73 and 85% total Hg removal, respectively. The low $CaBr_2$ injection rates lead to only subtle changes in the incremental increase in COE as the $CaBr_2$ solution cost increases from \$0.50/lb to \$2.00/lb. Conversely, a $CaBr_2$ injection rate of about 647 lb/hr is needed to reach 85% total Hg removal at the “representative” 50:50 TxL and PRB-fired unit, resulting in an incremental increase in COE that ranges from about 0.90 to 3.30 mills/kWh over the $CaBr_2$ solution cost range. Meanwhile, the degree of sensitivity displayed by the data presented for 73% total Hg removal at the “representative” 50:50 TxL and PRB-fired and PRB-fired (no SCR) units is similar to due to required $CaBr_2$ injection rates of 294 and 322 lb/hr, respectively.

By-product Impacts

The ACI systems are typically designed to inject Hg adsorbents upstream of a CS-ESP to enable the simultaneous capture of spent PAC and fly ash. This Hg control strategy will result in commingling of the PAC and fly ash that could potentially have an adverse effect on the marketability of the fly ash. As shown in Table 9, nearly 45% of all fly ash generated in 2006 avoided disposal through a variety of beneficial-use applications based on data collected by the

American Coal Ash Association (ACAA).[18] For instance, one of the highest-value reuse applications for fly ash is use as a substitute for Portland cement. The utilization of fly ash in concrete production is particularly sensitive to carbon content as well as the surface area of the carbon present in the fly ash. With this in mind, the 20-year levelized costs for Hg control via ACI provided in Tables 4-7 are presented with and without the inclusion of potential by-product impacts.

Table 9 - 2006 ACAA Coal Combustion Product Production and Use Survey

	Fly Ash	FGD Gypsum	Other Wet FGD
Total Generation, tons/yr	72,400,000	12,100,000	16,300,000
Total Utilization, tons/yr	32,423,569	9,561,489	904,348
% of Generation that is Utilized	44.78%	79.02%	5.55%

A key advantage of Hg control via $CaBr_2$ coal treatment and Hg^0 oxidation catalysts is that fly ash quality is preserved. However, these technologies may also have an impact on future by-product utilization and disposal. While wet FGD systems have always been effective in capturing Hg^{2+}, it is anticipated that Hg concentrations in FGD by-products will increase, albeit slightly, following the installation of technologies designed to enhance FGD Hg capture.[7] The majority of non-gypsum wet FGD by-products produced in 2006 were disposed; however, nearly 80% of the FGD gypsum generated by wet FGD systems was reused. Primarily, FGD gypsum serves as a substitute feedstock for rock gypsum in the production of wallboard. With increased public awareness of and concern about Hg, the notion that FGD gypsum contains “increased” levels of Hg could significantly dampen or destroy the market for FGD materials.

Although wet FGD by-product impacts are not considered in this economic analysis, it is feasible that the mere association of FGD materials with Hg could increase overall control costs. In an effort to minimize the potential by-product impacts associated with enhanced FGD Hg control, NETL, in collaboration with industry and other key stakeholders, has led a focused R&D effort that includes both in-house and extramural activities to better understand the mechanisms of Hg capture and retention in FGD systems, while also investigating the fate of mercury in FGD gypsum during disposal of the raw material as well as during wallboard production.[19,20]

Other Issues Affecting the Economics of Mercury Control

The deactivation of Hg^0 oxidation catalysts may be accelerated by fly ash accumulating within the catalyst cells. Catalyst activity measurements conducted by URS in January 2003 at CCS revealed that the catalyst surfaces were becoming plugged due to build-up of fly ash in the horizontal-gas-flow catalyst cells, despite installation downstream of a high-efficiency CS-ESP.[q] This was confirmed by pressure drop increases across the catalysts and by opening and physically inspecting the catalyst chambers to observe and clean out the fly ash buildup. Consequently, in March 2003, URS installed a small, 17-inch sonic horn on the pilot-scale Pd #1 catalyst box to provide occasional pulses of acoustic energy to the catalyst to dislodge accumulated particulate matter. Subsequent pilot-scale testing at Monticello and Coronado also utilized sonic horns to prevent severe fly ash buildup on the catalysts.

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[q] Pilot-scale testing at J.K Spruce Plant has shown that sonic horns may not be required for installations downstream of a FF.

Additional factors can influence the cost of Hg control, including, but not limited to, economic factors (labor rate, taxes and contingencies, economic life of capital equipment, etc.), process disruptions (unexpected or excessive outages, etc.), price and reliability of consumables (e.g., PAC, catalyst, additive, etc.) supply, and modifications to existing equipment. The estimates developed here assume an uncomplicated retrofit and minimal economic impact due to the installation, regeneration, and replacement of Hg^0 oxidation catalysts and $CaBr_2$ injection system installation, assuming that these activities occur during regularly scheduled plant outages. The estimates are also based on the assumption that Hg control will not cause any balance-of-plant impacts (e.g., the existing ESP and wet FGD performance will not be negatively affected).

VI. SUMMARY

The intent of this analysis was to develop and compare preliminary cost estimates for two technologies designed to promote Hg^0 oxidation and enhance Hg capture across a downstream wet FGD: Hg^0 oxidation catalysts and $CaBr_2$ coal treatment. The economics were developed for "representative" 500 MW units burning ND lignite, PRB subbituminous, and a 50:50 blend of TX lignite and PRB subbituminous coals. It is assumed that each of these coal-fired units is equipped with a large CS-ESP for particulate control and a wet FGD system for SO_2 and Hg^{2+} co-removal. For the PRB-fired unit, economics for Hg control via $CaBr_2$ coal treatment are provided both with and without SCR operation.

For 73% total Hg removal with Pd#1 and Au-based Hg^0 oxidation catalysts, the 20-year levelized incremental increase in COE is less than 1.80 mills/kWh for the three 500 MW "representative" coal-fired units, while the incremental cost of control is less than $17,000/lb Hg removed, excluding the "representative" PRB-fired unit. The primary O&M cost associated with this technology is biennial catalyst replacement caused by gradual catalyst deactivation. This technology is particularly advantageous for power plants that currently sell their fly ash for beneficial-use applications.

A sensitivity analysis was conducted to illustrate the impact of Pd#1 and Au-based Hg^0 oxidation catalyst regeneration on process economics. It is assumed that the Pd#1 and Au-based catalysts can be regenerated once, after two years in service, and then would be replaced after a total of four years of service. The cost associated with regeneration is estimated to be 5% to 10% of the original catalyst cost. In comparison to the Hg^0 oxidation catalyst economics that assume biennial replacement, a single-cycle thermal regeneration reduces the 20-year levelized incremental costs by about 20 to 30% and makes this technology more cost-competitive.

The economics presented for 73% total Hg removal via $CaBr_2$ coal treatment are very promising. More specifically, the cost of $CaBr_2$ coal treatment at the "representative" PRB-fired unit equipped with an SCR is about one-third the estimate provided for chemically-treated ACI, when by-product impacts are excluded. Addition of a 52 wt% $CaBr_2$ solution at an injection rate of about 5.90 lb/hr is required to achieve 73% total Hg removal at the "representative" PRB-fired unit equipped with an SCR, resulting in 20-year levelized costs of 0.08 mills/kWh and $2,200/lb Hg removed. Without an SCR in-service, a $CaBr_2$ injection rate of 322 lb/hr is required to achieve the same level of control and the levelized costs rise to 0.80 mills/kWh and $21,200/lb Hg removed.

Using $CaBr_2$ injection to achieve 85% total Hg removal at the "representative" PRB-fired unit equipped with an SCR, results in 20-year levelized costs of 0.13 mills/kWh and $2,800/lb Hg removed. In general, this analysis shows that Hg control via $CaBr_2$ coal treatment is not a capital-intensive process and high levels of FGD Hg capture can be achieved at relatively low injection rates, particularly at low-rank coal-fired units equipped with an SCR for NOx control.

The preliminary results for these wet FGD enhancement technologies, particularly $CaBr_2$ coal treatment, are very encouraging both in terms of the level of Hg^0 oxidation achieved and the cost of control on a mills/kWh and $/lb Hg removed basis. However, it must be kept in mind that the results are based on pilot-scale tests for the Hg^0 oxidation catalysts and short-term field tests for $CaBr_2$ coal treatment. It should also be noted that the economic analyses represent “snapshots” in time based on the methodology used, and the assumptions made regarding the “representative” coal-fired units. Applicability of these “study-level” cost estimates to individual power plants will depend upon fuel characteristics, equipment configuration, flue gas temperature, and other generating unit-specific conditions.

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APPENDIX A

Power Plant and Coal Data

Economic Assumptions

Power Plant Data	**ND Lignite**	**50:50 TxL & PRB**	**PRB**
Unit Capacity, MW	500	500	500
Net Plant Heat Rate, Btu/kWh	10,500	10,357	10,500
Capacity Factor, %	80	80	80
Flue Gas Temperature, °F	300	345	300
Flue Gas Flow Rate, ACFM	2,039,197	2,589,594	2,004,122
Coal Flow Rate, lb/hr	700,000	698,476	622,850
Ash exiting the boiler, %	80	80	80
Coal Mercury Content, lb/Trillion Btu	10.50	16.98	6.00
Mercury in Flue Gas, lb/hr	0.0551	0.0879	0.0315
Coal Properties			
Coal Ultimate Analysis (ASTM, as rec'd), wt%			
Moisture	32.00	30.62	30.24
Carbon	45.06	42.61	48.18
Hydrogen	2.80	3.16	3.31
Nitrogen	1.50	0.61	0.70
Sulfur	0.94	0.4	0.37
Ash	5.90	10.26	5.32
Oxygen	11.70	11.69	11.87
HHV, Btu/lb	7,500	7,414	8,429

Variable O&M and Costs	
Catalyst Delivery	1% of "first-year" catalyst cost
Catalyst Installation	1% of "first-year" catalyst cost
Catalyst Disposal	3% of "first-year" catalyst cost
PAC Disposal Cost	$17/ton
Fly ash Disposal Cost	$17/ton
Revenue From Fly Ash Sales	$18/ton
Power Cost	$0.05/kW
Operating Labor	$45/hr
PAC Injection Maintenance Costs	5% of equipment cost
PAC Injection Periodic Replacement Items	$10,000 Flat Rate

Economic Factors	
Cost Basis - Year Dollars	Current 2006
Annual Inflation	3.0%
Discount Rate (MAR)	11.2%
AFUDC Rate	10.8%
First Year Fixed Charge Rate, Current$	20.7%
First Year Fixed Charge Rate, Const$	17.0%
Lev Fixed Charge Rate, Current$ (FCR)	15.7%
Lev Fixed Charge Rate, Const$ (FCR)	13.0%
Service Life, years	20
Escalation Rates :	
Consumables (O & M)	3.0%
Fuel	5.0%
Power	3.0%

APPENDIX B

NETL (and EPRI) Testing of Elemental Mercury Oxidation Catalysts

MERCURY OXIDATION CATALYST TEST RESULTS

URS has demonstrated at pilot-scale the use of solid honeycomb catalysts to promote Hg^0 oxidation in flue gas from coal-fired power plants that have wet FGD systems. To provide longer-term catalyst life data, continuous pilot-scale testing took place for an extended time period at Great River Energy's (GRE) Coal Creek Station (CCS) Unit 1, City Public Service of San Antonio's J.K. Spruce Plant, Luminant Power's Monticello Station Unit 3, Southern Company's Eastern bituminous coal-fired Plant Yates Unit 1, and SRP's PRB-fired Coronado Station (SRP- and EPRI-funded test). NETL plans to begin a full-scale evaluation of a Au-based Hg^0 oxidation catalyst in 2008 at Lower Colorado River Authority's PRB-fired Fayette Unit 3.

In a full-scale application, the Hg^0 oxidation catalysts would be installed downstream of an existing CS-ESP or FF to: (1) minimize fly ash deposition on the catalysts; (2) prevent or minimize catalyst erosion; and (3) ensure a low flue gas temperature and flow rate, which reduces the catalyst space velocity and minimizes the length of catalyst required.

Great River Energy's Coal Creek Station

At CCS, the pilot catalyst skid was installed in late August 2002 by GRE near the induced draft (ID) fans located at the outlet of the CS-ESP, with the flue gas entering the pilot unit being withdrawn from one ID fan outlet duct and returning to the inlet duct of an adjacent fan. Based on laboratory screening results, the quantity of catalyst installed was varied to achieve the desired level of Hg^0 oxidation. In general, the catalysts were sized to achieve a predicted 95% Hg^0 oxidation.

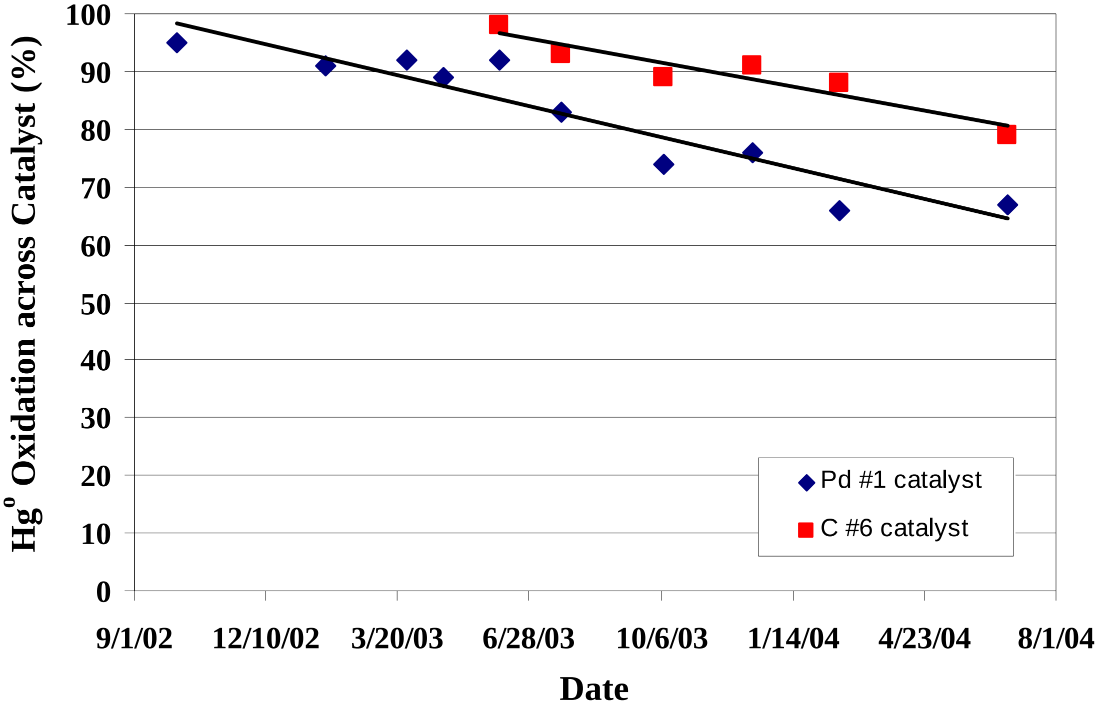
The pilot-scale catalyst skid at CCS was comprised of four catalyst chambers, each representing a cube that is one meter in all three directions. The design flue gas flow rate through each chamber was 2,000 actual cubic feet per minute (acfm), for a total of 8,000 acfm to the catalyst skid. The Hg semi-continuous emission monitor (SCEM) developed through funding provided by EPRI was used to measure Hg concentrations and speciation at the pilot unit inlet and at the outlets of each catalyst chamber. To determine the Hg^0 oxidation across each catalyst, the SCEM was cycled between the five measurement locations and between measuring Hg^0 and total Hg. Periodically, the analyzer results were verified by conducting manual flue gas sampling efforts in parallel across each catalyst chamber by the Ontario Hydro method.

Four Hg^0 oxidation catalysts were evaluated simultaneously during pilot-scale testing at CCS; however catalyst loading was staggered due to production delays. The SCR catalyst, prepared by Ceramics Gmbh and Company (formerly Siemens), and the Pd#1 catalyst, prepared by Prototech, were installed in the pilot catalyst skid and start-up occurred during the first week of October 2002. Meanwhile, production of the experimental C#6 and SBA#5 catalysts by Applied Ceramics, Inc. was delayed due to research directed toward determining mixing, extruding, drying, and firing parameters. The SBA#5 catalyst was installed in the pilot unit in early December 2002, while the C#6 catalyst was installed on June 5, 2003.

URS anticipated that the Hg^0 oxidation catalysts would initially have a significant capacity for adsorbing Hg from the flue gas. With Hg being adsorbed from the flue gas, it is not possible to get an accurate measurement of Hg^0 oxidation. The percent oxidation across the catalyst is based on the drop in Hg^0 across the catalysts, and with Hg being adsorbed it is not possible to distinguish between the drop in concentration due to adsorption and that from oxidization.

Therefore, catalyst activity measurements, such as those shown in Figure B-1 for the Pd#1 and C#6 catalysts at CCS, were delayed until the catalyst had achieved Hg adsorption breakthrough (i.e., the catalyst inlet and outlet total Hg concentrations are approximately equal).

Figure 2 – Pilot-Scale Catalyst Activity Data



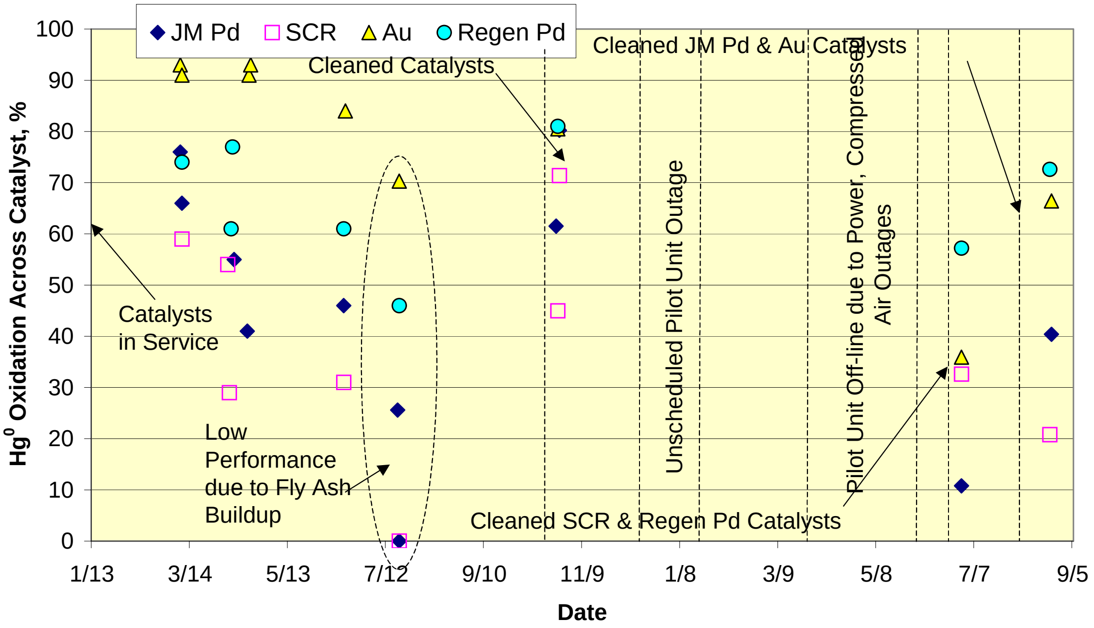
In June 2004, URS conducted the final catalyst activity measurements at CCS. These Hg SCEM readings showed 79% Hg^0 oxidation for the C#6 catalyst, with nearly 13 months of operation in flue gas, and about 67% oxidation for the Pd#1 catalyst after more than 20 months of operation. Significantly lower activity was measured for the SCR catalyst, with 26% oxidation measured after 20 months of operation and for the SBA#5 catalyst, with only 12% oxidation measured after 18 months of operation. As shown in the figure, the Pd#1 and C#6 Hg^0 oxidation catalysts experienced a gradual deactivation over time during pilot-scale testing at CCS.

During pilot-scale wet FGD testing, URS observed a phenomenon known as Hg^0 re-emissions where previously captured Hg^{2+} is chemically-reduced within the FGD liquor and emitted as Hg^0. Specifically, URS observed 79% total Hg capture across the wet FGD, although 84% of the Hg at the FGD inlet was oxidized.

Luminant Power's Monticello Station Unit 3

Luminant's Monticello Unit 3 fires a blend of 50% Texas lignite and 50% PRB subbituminous coals. In January 2005, the following Hg^0 oxidation catalysts were installed downstream of the existing CS-ESP at Monticello: (1) Au-based; (2) SCR; (3) regenerated Pd#1 from CCS; and (4) fresh Pd#1. As shown in Figure B-2, all four catalysts have lost a significant amount of activity for Hg^0 oxidation, in a total of 13 to 14 months of flue gas exposure. In early July 2006, Hg^0 oxidation ranged from about 10% across the fresh Pd#1 catalyst to nearly 60% across the regenerated Pd#1 catalyst. While recording these activity measurements, URS observed severe fly ash buildup on the catalyst surfaces likely caused by frequent pilot unit outages.

Figure B-2 – Catalyst Activity Results for Monticello



URS decided to manually scrub the catalyst surfaces to remove the fly ash buildup prior to the final catalyst activity measurements scheduled for August 2006. Following *in-situ* catalyst cleaning, Hg^0 oxidation was approximately 72% across the regenerated Pd#1 catalyst and 66% across the Au catalyst. These final catalyst activity measurements were conducted after 17 months of pilot-scale operation at Monticello.

Tests completed in April 2005 indicated total Hg capture across a pilot-scale wet FGD ranged from 76 to 87%, compared to only 36% removal under baseline conditions. This equates to about 70% incremental Hg capture due to the catalysts.

Southern Company's Plant Yates Unit 1

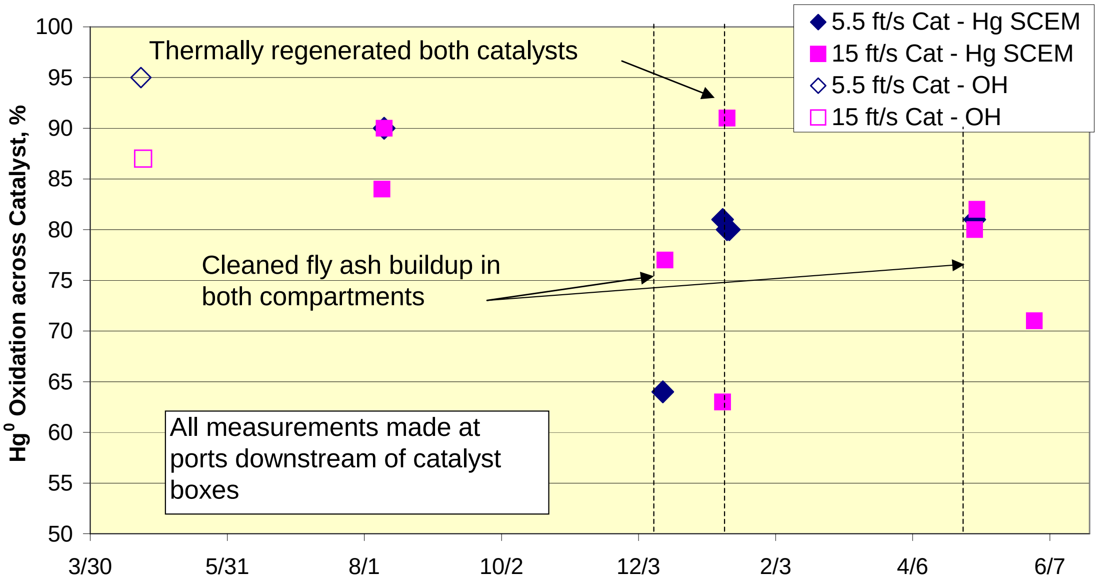
URS completed additional pilot-scale testing of Hg^0 oxidation catalysts at Southern Company's Plant Yates Unit 1, which fires a low-sulfur Eastern bituminous coal. The pilot catalyst skid installed downstream of the existing CS-ESP at this unit was loaded with fresh Pd#1 and Au catalysts, along with regenerated SCR and Au catalysts from J.K. Spruce Plant in December 2005. After nearly 11 months of operation, Hg^0 oxidation measured 58% across the fresh Au-based catalyst, 38% across the fresh Pd#1 catalyst, 32% across the regenerated SCR catalyst, and 26% across the regenerated Au catalyst. The pilot catalyst skid was taken off-line in January 2007 to accommodate a sulfur trioxide (SO_3) injection test plan.

SRP's Coronado Station

Through funding provided by SRP and EPRI, URS conducted a pilot-scale evaluation of two Au-based Hg^0 oxidation catalysts (5 and 15 ft/sec variations) developed by Johnson Matthey at SRP's Coronado Station. Coronado is a PRB-fired unit equipped with a hot-side ESP (HS-ESP) and wet FGD. Pilot-scale testing took place between March 2006 and June 2007 at this facility.

As shown in Figure B-3, URS characterized Au-based Hg^0 oxidation catalyst activity through both Hg SCEM and Ontario Hydro measurements. Following about 15 months of pilot-scale operation at Coronado, approximately 80% Hg0 oxidation has been maintained across the Au-based Hg^0 oxidation catalysts.

Figure B-3 – Catalyst Activity Results for Coronado



URS also conducted two pilot-scale wet FGD tests downstream of the 15 ft/sec Au-based Hg^0 oxidation catalyst. In April 2006, 83% total Hg removal was observed across the wet FGD. However, during a second test conducted in May 2007, total FGD Hg capture was limited to about 28%. URS believes that Hg capture was limited by Hg^0 re-emissions in the 2007 test, which may be the result of a change in the chemistry of the full-scale wet FGD at Coronado. The full-scale FGD provided make-up slurry to the pilot system for this test.

LCRA's Fayette Unit 3

URS will conduct a full-scale (~200 MW) evaluation of a Au-based Hg^0 oxidation catalyst (15 ft/sec) at Lower Colorado River Authority's (LCRA's) PRB-fired Fayette Power Project Unit 3, under NETL's Phase III Hg control technology field testing program. Testing is scheduled to begin in 2008. The objectives of the project are to test at full-scale (~200 MW) the use of solid, heterogeneous catalyst downstream of a CS-ESP to promote the Hg^0 oxidation in coal flue gas, and to demonstrate that catalytically oxidized Hg is removed by a downstream wet FGD absorber and ends up in the FGD by-products. The test is intended to confirm the required catalyst quantities and catalyst life for achieving an average of 70% or greater Hg^0 oxidation in PRB flue gases over a 24-month period.

Unit 3 has a nameplate generating capacity of 460 MW, and is equipped with low NOx burners for NOx control, a CS-ESP for particulate control, and a wet FGD system for SO_2 control. The FGD system has three modules, two of which are normally operated. Approximately 15% of the flue gas from Unit 3 bypasses the FGD system. Thus, each FGD module treats approximately 200 MW of flue gas. The Au-based Hg^0 oxidation catalyst was installed immediately upstream of one of the three FGD modules on Unit 3. For that module, an existing duct section was removed and replaced with a catalytic reactor containing the Au-based catalyst. Sufficient catalyst volume was installed to achieve a predicted Hg oxidation percentage increase of 90% or greater across the catalyst. Sonic horns were installed to keep the horizontal gas flow catalysts clear of fly ash buildup.

The project represents the next logical advancement of the catalytic oxidation technology from its current pilot-scale. It will answer technical questions such as the catalyst quantity required to achieve high Hg^0 oxidation percentages, catalyst life, the efficiency of capture of catalytically oxidized Hg in full-scale wet FGD systems, and the ability to keep the catalysts clean of fly ash buildup at full-scale with sonic horns.

APPENDIX C

NETL (and EPRI) Testing of Calcium Bromide Coal Treatment

CALCIUM BROMIDE COAL TREATMENT TEST RESULTS

NETL field testing has also shown that coal treatment with chemical additives can promote flue gas Hg^0 oxidation and enhance FGD Hg capture. This approach maximizes the residence time available for interactions between the additive and Hg^0. In particular, an aqueous $CaBr_2$ solution has shown promise during a full-scale field test completed at Luminant Power's Monticello Unit 3, which burns a coal blend consisting of 50% TxL and 50% PRB subbituminous. EPRI and Southern Company also funded a full-scale evaluation of $CaBr_2$ injection at Southern Company's PRB-fired Plant Miller Unit 4.

Luminant Power's Monticello Station Unit 3

During full-scale parametric testing at Monticello, URS evaluated the performance of calcium chloride ($CaCl_2$) and $CaBr_2$ coal treatment. These trials clearly displayed the superior performance of $CaBr_2$ as 72% Hg^{2+} was observed at the CS-ESP outlet with an injection rate of 100 ppm Br in the coal (on a dry basis). As a result, long-term testing was conducted with $CaBr_2$. The two-week test, at a $CaBr_2$ injection rate of 55 ppm Br in the coal, oxidized 67% of the Hg entering the FGD, resulting in an average total Hg capture of 65%. At a $CaBr_2$ injection rate of 113 ppm Br in the coal, Hg^0 oxidation reached 85%, resulting in an average total Hg capture of 86% over the subsequent two-week test. In addition, a short-term test conducted with a $CaBr_2$ injection rate of 330 ppm Br in the coal resulted in 92% total Hg capture across the ESP/FGD configuration at Monticello.

"Representative" 50:50 TxL & PRB-Fired Unit

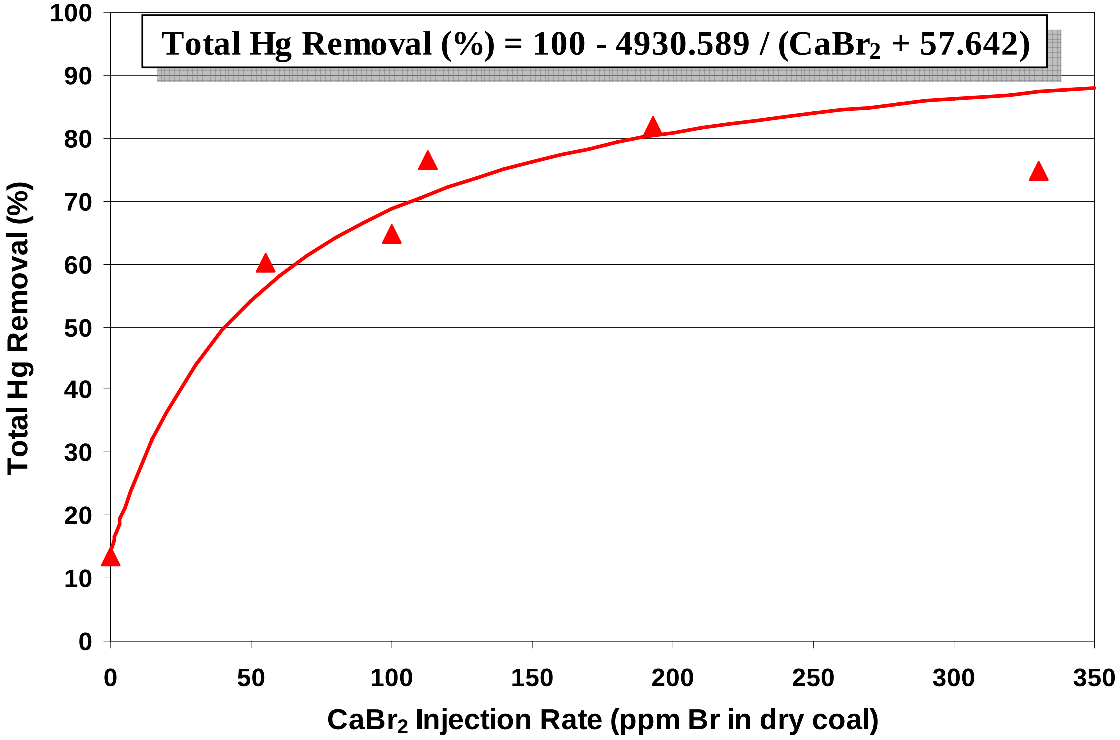
Cost estimates provided in this report for the "representative" 50:50 TxL and PRB-fired unit are based on the performance of $CaBr_2$ coal treatment at Monticello. As shown in Table C-1, total Hg removal across the "representative" unit was estimated using Monticello data and applying the following assumptions: (1) 15% Hg^{2+} at the CS-ESP under baseline conditions; and (2) 90% Hg^{2+} capture across the wet FGD.

Table C-1 – $CaBr_2$ Coal Treatment Data for the "Representative" 50:50 TxL & PRB-Fired Unit

$CaBr_2$ Rate (ppm Br in dry coal)	Hg^{2+} at CS-ESP Outlet (%)	Hg^{2+} Capture across Wet FGD (%)	Total Hg Removal across "Representative" Unit (%)
0	15	90	13.5
55	67	90	60.3
100	72	90	64.8
113	85	90	76.5
193	91	90	81.9
330	83	90	74.7

To determine the $CaBr_2$ injection rate required to achieve a given level of total Hg removal, a non-linear regression equation was developed to empirically fit the data. Figure C-1 displays the total Hg removal data for the "representative" unit and the non-linear regression curve.

Figure C-1 - CaBr$_2$ Coal Treatment Data and Regression Curve for the "Representative" 50:50 TxL & PRB-Fired Unit



The following non-linear regression equation was used to empirically fit the data. Note that CaBr$_2$ represents the CaBr$_2$ injection rate in "ppm Br in dry coal." Details of the regression results are provided in Appendix E of this report.

Total Hg Removal (%) = 100 – a / (CaBr$_2$ + b)

Where a = 4930.589
b = 57.642

Southern Company's Plant Miller Unit 4

EPRI and Southern Company funded a full-scale field test of CaBr$_2$ coal treatment at Southern Company's PRB-fired Plant Miller Unit 4. This unit is equipped with an SCR for NOx control and a CS-ESP. A 52 wt% CaBr$_2$ solution was added to the furnace at injection rates ranging from three to 328 ppm Br in the coal (dry basis), and the resulting changes in Hg speciation were measured at the SCR inlet and outlet, the air preheater outlet, and the CS-ESP outlet. Measurements taken at the SCR inlet were used to approximate the performance of CaBr$_2$ coal treatment at a "representative" PRB-fired not equipped with an SCR. Plant Miller is not equipped with a wet FGD, therefore FGD Hg capture could not be calculated.

Under baseline conditions, about 60% Hg^{2+} was measured at the CS-ESP outlet. At a $CaBr_2$ injection rate of 7 ppm Br in the dry coal, 92% Hg^{2+} was observed at the CS-ESP. Little to no improvement in performance was observed at higher $CaBr_2$ injection rates. Meanwhile, a $CaBr_2$ injection rate of 165 ppm Br in the dry coal was required to achieve 98% Hg^{2+} at the SCR inlet. These results indicate that operation of an SCR has a positive impact on the Hg^0 oxidation potential of $CaBr_2$ coal treatment.

During these short-term tests, $CaBr_2$ injection had no effect on coal feeder or boiler operation. The effects of Br on concrete admixtures were evaluated after fly ash samples showed an appreciable increase in Br concentration. The set time, air content, and slump were not affected, but a 15% decrease in compressive strength was observed for the concrete specimens produced with Br-containing fly ash. Note that these results are not conclusive. Further investigation will take place during a $CaBr_2$ injection tests scheduled for Winter 2008 at Plant Miller.

"Representative" PRB-Fired Unit with an SCR

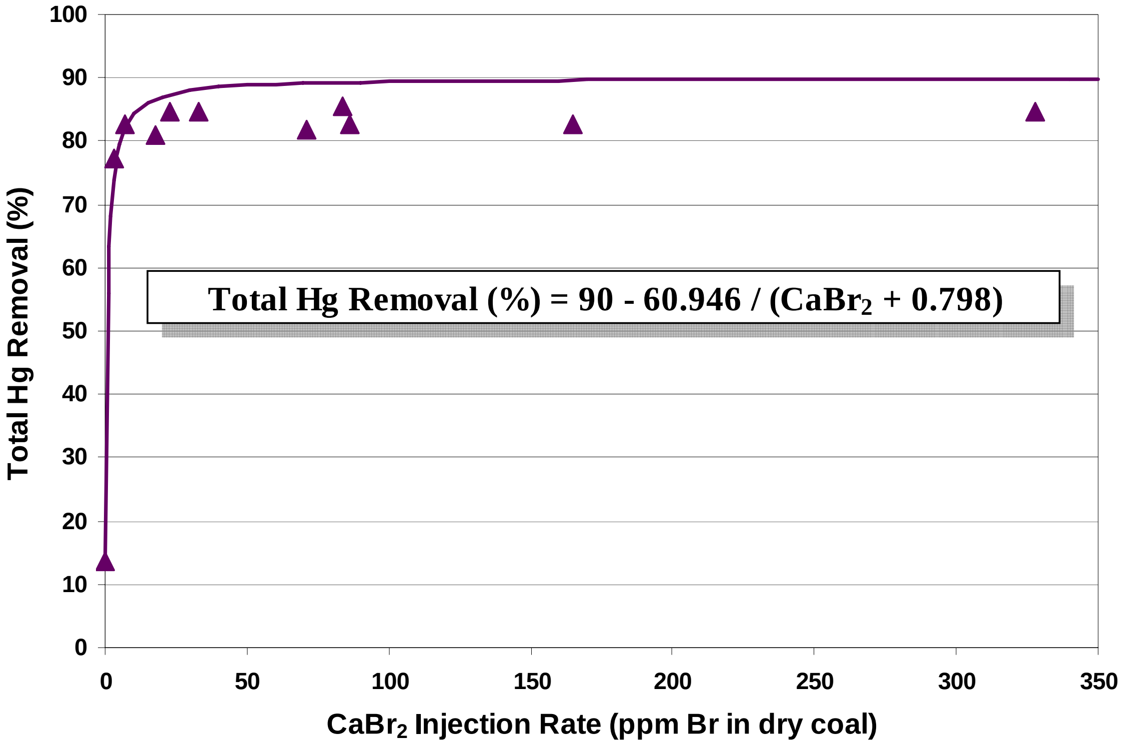
Cost estimates provided in this report for the "representative" PRB-fired unit equipped with an SCR are based on the performance of $CaBr_2$ coal treatment at Plant Miller (as measured at the CS-ESP outlet). As shown in Table C-2, total Hg removal across the "representative" unit was estimated using Plant Miller data and applying the following assumptions: (1) 15% Hg^{2+} at the CS-ESP under baseline conditions; and (2) 90% Hg^{2+} capture across the wet FGD.

Table C-2 – $CaBr_2$ Coal Treatment Data for the "Representative" PRB-Fired Unit with an SCR

$CaBr_2$ Rate (ppm Br in dry coal)	Hg^{2+} at CS-ESP Outlet (%)	Hg^{2+} Capture across Wet FGD (%)	Total Hg Removal across "Representative" Unit (%)
0	15	90	13.5
3	86	90	77.4
7	92	90	82.8
18	90	90	81
23	94	90	84.6
33	94	90	84.6
71	91	90	81.9
84	95	90	85.5
86	92	90	82.8
165	92	90	82.8
328	94	90	84.6

To determine the $CaBr_2$ injection rate required to achieve a given level of total Hg removal, a non-linear regression equation was developed to empirically fit the data. Figure C-2 displays the total Hg removal data for the "representative" unit and the non-linear regression curve.

Figure C-2 - $CaBr_2$ Coal Treatment Data and Regression Curve for the "Representative" PRB-Fired Unit with an SCR



The following non-linear regression equation was used to empirically fit the data. Note that $CaBr_2$ represents the $CaBr_2$ injection rate in "ppm Br in dry coal." Note the leading coefficient was changed from 100 to 90 for this dataset to better approximate the data trend. Details of the regression results are provided in Appendix E of this report.

Total Hg Removal (%) = 90 – a / ($CaBr_2$ + b)

Where a = 60.946
b = 0.798

"Representative" PRB-Fired Unit without an SCR

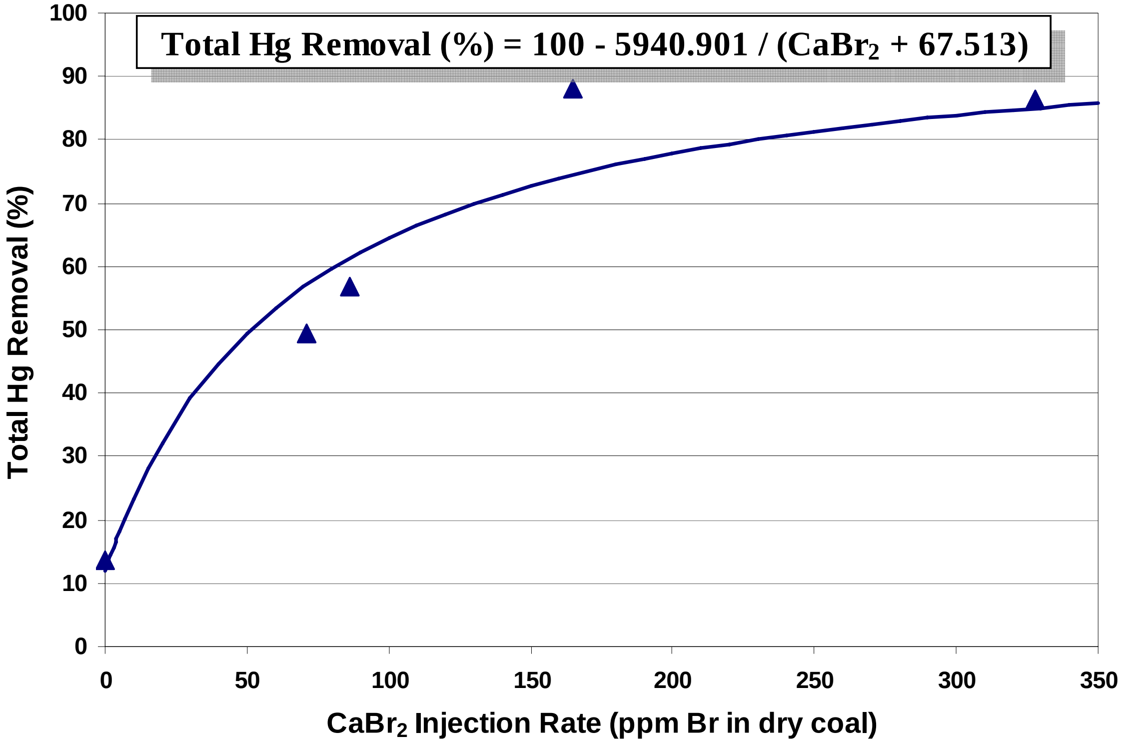
Cost estimates provided in this report for the "representative" 50:50 PRB-fired unit not equipped with an SCR are based on the performance of $CaBr_2$ coal treatment at Plant Miller (as measured at the SCR inlet). As shown in Table C-3, total Hg removal across the "representative" unit was estimated using Plant Miller data and applying the following assumptions: (1) 15% Hg^{2+} at the CS-ESP under baseline conditions; and (2) 90% Hg^{2+} capture across the wet FGD.

Table C-3 – $CaBr_2$ Coal Treatment Data for the "Representative" PRB-Fired Unit without an SCR

$CaBr_2$ Rate (ppm Br in dry coal)	Hg^{2+} at SCR Inlet (%)	Hg^{2+} Capture across Wet FGD (%)	Total Hg Removal across "Representative" Unit (%)
0	15	90	13.5
71	55	90	49.5
86	63	90	56.7
165	98	90	88.2
328	96	90	86.4

To determine the $CaBr_2$ injection rate required to achieve a given level of total Hg removal, a non-linear regression equation was developed to empirically fit the data. Figure C-3 displays the total Hg removal data for the "representative" unit and the non-linear regression curve.

Figure C-3 - $CaBr_2$ Coal Treatment Data and Regression Curve for the "Representative" PRB-Fired Unit without an SCR



The following non-linear regression equation was used to empirically fit the data. Note that $CaBr_2$ represents the $CaBr_2$ injection rate in "ppm Br in dry coal." Details of the regression results are provided in Appendix E of this report.

Total Hg Removal (%) = 100 – a / ($CaBr_2$ + b)

Where a = 5940.901
b = 67.513

APPENDIX D

Oxidation Catalyst Regeneration

MERCURY OXIDATION CATALYST REGENERATION

During pilot-scale testing at CCS, URS conducted *in-situ* thermal regeneration tests by exposing the oxidation catalysts to heated air. Catalyst regeneration was initiated by replacing the sonic horn on the inlet of the catalyst chamber with a 36-kW duct heater. The inlet flue gas flow to the compartment being regenerated was closed off, and an air supply was connected to the duct heater. The duct heater outlet air temperature was set at 600^{o}F. This was set as the upper limit for the regeneration air temperature based on the temperature rating for the gasket material used to seal the compartment access covers. The regeneration air flow was limited by the heater capacity (~280 acfm) as measured downstream of the catalyst, at a maximum temperature of 410-420^{o}F. This downstream temperature was also a constraint on the thermal regeneration, as the Teflon seats in the downstream catalyst chamber flow control valves could not exceed 450^{o}F. The difference between the inlet air temperature of 600^{o}F and the maximum outlet temperature achieved, of 420^{o}F, was due to heat losses through catalyst chamber walls.

After heating each catalyst with 600^{o}F air overnight, it was placed back in flue gas service and catalyst activity was measured by SCEM to determine if the Hg^0 oxidation activity increased. The results from these catalyst regeneration tests are presented in Table C-1. The Pd#1 activity improved to near the activity of the fresh catalyst (88% vs. 95%), while the SCR catalyst improved to about two-thirds of its original activity (46% vs. 67%). However, within the limitations of the test conducted, the C#6 catalyst did not regenerate. After the catalysts were recovered from the pilot unit, samples of the C #6 catalyst were thermally regenerated in the lab to see if greater improvements could be realized with higher regeneration temperatures.

Table C-1 – *In-Situ* Thermal Catalyst Regeneration Results from CCS

	Hg^0 Oxidation across Catalyst (%)			
	Fresh Catalyst	**End of Test (6/04)**	**Before Regeneration**	**After Regeneration**
Pd#1	**95%** (10/02)	**67%**	**79%** (7/04)	**88%** (7/04)
SCR	**67%** (10/02)	**26%**	**25%** (7/04)	**46%** (7/04)
C#6	**98%** (6/03)	**79%**	**53%** (9/04)	**48%** (9/04)

For the Pd#1 catalyst, URS observed that the activity was higher prior to regeneration in late July 2004 than it had been at the end of the long-term catalyst pilot evaluation in June 2004. During the time that elapsed between when the long-term test ended and the regeneration tests were conducted, the pilot unit was shut down several times, and ambient air was allowed to enter the catalyst chambers while new ports were welded onto the catalyst outlet duct to accommodate pilot wet FGD tests. It is likely that the species that adversely affect the activity of the Pd #1 desorbed to some extent just by ceasing flue gas flow through the catalyst several times and exposing the catalyst to ambient air.

URS was forced to estimate the oxidation across the C #6 catalyst prior to regeneration; because there was not a catalyst inlet Hg^0 concentration measurement near the time the outlet was measured. Consequently, the catalyst inlet Hg^0 concentration was estimated from the inlet total measured near that time multiplied by an interpolated inlet oxidation percentage (34%). This value was interpolated between the oxidation measured previously (36%) and after the regeneration was completed (32%).

Assuming this estimate for the C#6 catalyst is reasonably accurate, the activity prior to regeneration (53%) was lower than the end of test value from June (79%). During the three months that elapsed between the end of the long-term test and when this regeneration test was conducted, the pilot unit was shut down and restarted a number of times, and operated for several periods with flue gas flow through the catalysts but without the sonic horns in service. It is possible that the C #6 catalyst became partially plugged with fly ash prior to the thermal regeneration test.

The most important note about these regeneration test results is that they were intended to be "proof of concept" tests to determine if the catalysts could be thermally regenerated. The conditions were not optimized to ensure the effectiveness of the thermal regeneration, though. For example, it is known that the air entering the catalyst chamber was at 600^{o}F, and that the air in the 6-in. discharge piping from the catalyst chamber reached a maximum of 410 to 420^{o}F, but it is not known what was the actual maximum temperature achieved at the catalyst surfaces. Also, the regeneration air flow of approximately 280 acfm was much lower than the normal flue gas flow through these catalysts (1500 to 2000 acfm), and the regeneration air flow was introduced from the top surface of the catalyst chamber inlet transition duct rather than through the centered inlet duct run. Because of this, it is possible that only portions of the catalysts saw appreciable regeneration air flow. In future regeneration tests, URS believes that a larger heater should be used, to allow a greater air flow that will better distribute across the catalyst cross section, and that thermocouples be retrofitted to the catalyst chamber to allow temperatures to be monitored across the cross section of the catalyst outlet plane.

APPENDIX E

Non-Linear Regression Analysis for $CaBr_2$ Coal Treatment

$CaBr_2$ Coal Treatment at "Representative" 50:50 TxL & PRB-fired unit

Iteration History [b]

Iteration Number [a]	Residual Sum of Squares	Parameter A	Parameter B
1.0	4402.624	40.000	.400
1.1	784.923	2698.261	27.037
2.0	784.923	2698.261	27.037
2.1	275.597	4286.581	46.659
3.0	275.597	4286.581	46.659
3.1	224.452	4818.478	55.545
4.0	224.452	4818.478	55.545
4.1	222.749	4918.420	57.442
5.0	222.749	4918.420	57.442
5.1	222.737	4929.611	57.628
6.0	222.737	4929.611	57.628
6.1	222.737	4930.523	57.641
7.0	222.737	4930.523	57.641
7.1	222.737	4930.589	57.642

Derivatives are calculated numerically.

a. Major iteration number is displayed to the left of the decimal, and minor iteration number is to the right of the decimal.

b. Run stopped after 14 model evaluations and 7 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval Lower Bound	95% Confidence Interval Upper Bound
A	4930.589	968.266	2242.251	7618.927
B	57.642	13.570	19.967	95.317

Correlations of Parameter Estimates

	A	B
A	1.000	.936
B	.936	1.000

ANOVA [a]

Source	Sum of Squares	df	Mean Squares
Regression	25934.593	2	12967.296
Residual	222.737	4	55.684
Uncorrected Total	26157.330	6	
Corrected Total	3130.515	5	

Dependent variable: VAR00002

a. R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .929.

$CaBr_2$ Coal Treatment at "Representative" PRB-fired unit w/ SCR

Iteration History [b]

Iteration Number [a]	Residual Sum of Squares	Parameter	
		A	B
1.0	828.765	40.000	.400
1.1	336.664	56.404	.658
2.0	336.664	56.404	.658
2.1	251.366	59.889	.770
3.0	251.366	59.889	.770
3.1	249.403	60.780	.795
4.0	249.403	60.780	.795
4.1	249.399	60.931	.798
5.0	249.399	60.931	.798
5.1	249.399	60.945	.798
6.0	249.399	60.945	.798
6.1	249.399	60.946	.798

Derivatives are calculated numerically.

[a] Major iteration number is displayed to the left of the decimal, and minor iteration number is to the right of the decimal.

[b] Run stopped after 12 model evaluations and 6 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval	
			Lower Bound	Upper Bound
A	60.946	21.147	13.109	108.784
B	.798	.285	.154	1.442

Correlations of Parameter Estimates

	A	B
A	1.000	.981
B	.981	1.000

ANOVA [a]

Source	Sum of Squares	df	Mean Squares
Regression	68541.471	2	34270.736
Residual	249.399	9	27.711
Uncorrected Total	68790.870	11	
Corrected Total	4416.120	10	

Dependent variable: VAR00002

[a] R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .944.

$CaBr_2$ Coal Treatment at "Representative" PRB-fired unit w/o SCR

Iteration History [b]

Iteration Number [a]	Residual Sum of Squares	Parameter	
		A	B
1.0	4826.496	40.000	.400
1.1	728.328	3530.963	35.364
2.0	728.328	3530.963	35.364
2.1	294.623	5544.916	60.071
3.0	294.623	5544.916	60.071
3.1	272.545	5963.612	67.552
4.0	272.545	5963.612	67.552
4.1	272.410	5940.609	67.509
5.0	272.410	5940.609	67.509
5.1	272.410	5940.934	67.513
6.0	272.410	5940.934	67.513
6.1	272.410	5940.901	67.513

Derivatives are calculated numerically.

[a] Major iteration number is displayed to the left of the decimal, and minor iteration number is to the right of the decimal.

[b] Run stopped after 12 model evaluations and 6 derivative evaluations because the relative reduction between successive residual sums of squares is at most SSCON = 1.00E-008.

Parameter Estimates

Parameter	Estimate	Std. Error	95% Confidence Interval	
			Lower Bound	Upper Bound
A	5940.901	1557.439	984.434	10897.368
B	67.513	20.954	.826	134.199

Correlations of Parameter Estimates

	A	B
A	1.000	.943
B	.943	1.000

ANOVA[a]

Source	Sum of Squares	df	Mean Squares
Regression	20819.180	2	10409.590
Residual	272.410	3	90.803
Uncorrected Total	21091.590	5	
Corrected Total	3769.092	4	

Dependent variable: VAR00002

[a] R squared = 1 - (Residual Sum of Squares) / (Corrected Sum of Squares) = .928.

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