Oklahoma Gas & Electric

Sooner Units 1 & 2, Muskogee Units 4 & 5
Dry FGD BART Analysis Follow-Up Report

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December 15, 2009

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1.0 INTRODUCTION

In spring 2008, S&L completed Best Available Retrofit Technology (BART) evaluations for Sooner Units 1 & 2, Muskogee Units 4 & 5, and Seminole Units 1, 2, & 3. The BART evaluations included an analysis of potentially feasible retrofit emission control technologies to control emissions of nitrogen oxide (NO_X), sulfur dioxide (SO_2), and particulate matter (PM_{10}) from each unit. BART evaluations included in the 2008 reports followed the five-step BART determination process described in Appendix Y to 40 CFR Part 51 "Guidelines for BART Determinations under the Regional Haze Rule." The five-step BART determination process includes:

Step 1: Identify all available retrofit control technologies;
Step 2: Eliminate technically infeasible options;
Step 3: Evaluate the control effectiveness of the remaining control options;
Step 4: Evaluate impacts and document the results; and
Step 5: Evaluate visibility impacts.

Step 4 of the process involves an evaluation of the potential environmental, energy, and economic impacts to the facility associated with the installation and operation of the technically feasible retrofit control options. To address economic impacts, S&L prepared a cost estimate for each technically feasible retrofit control option. To the extent possible, cost estimating methodologies described in the Office of Air Quality Planning and Standards Cost Control Manual ("OAQPS Cost Manual") were used to estimate annual costs. Cost estimates were used to evaluate the cost effectiveness of each technology in terms of annual dollars per ton of pollutant removed.

On November 13, 2009, the State of Oklahoma published its draft Regional Haze Implementation Plan Revision ("Regional Haze Implementation Plan"). The draft implementation plan required OG&E to control SO_2 emissions from Sooner Units 1 & 2 and Muskogee Units 3 & 4 with dry flue gas desulfurization (DFGD) control systems as BART. In the draft implementation plan, the Oklahoma Department of Environmental Quality (DEQ) questioned the cost estimates included in OG&E's 2008 BART evaluation, stating "OG&E's estimated costs were found to be substantially higher than those reported for similar projects." DEQ based its BART determination on revised cost estimates, both capital and operating and maintenance (O&M) costs, as well as a revised cost effectiveness evaluation.

Specifically, DEQ questioned the following items in the OG&E DFGD cost estimates:

a) The higher than expected DFGD capital costs when compared to other sources of information and the availability of back up information to support the cost estimates.
b) The high cost effectiveness ($9,625 to $10,843 $/ton) compared to other BART evaluations.
c) What the 2009 capital costs would be considering costs likely peaked in 2008 around the time of the original BART report and have likely fallen since then.
d) The accuracy of using factors from the EPA Air Pollution Control Cost Manual to develop annual operating costs given the large escalation in capital costs over the last few years.

The economic impact analysis included in the 2008 OG&E BART determinations calculated the cost effectiveness of DFGD control technology for Sooner Units 1 & 2 and Muskogee Units 4 & 5 on a dollar per ton of pollutant removed basis. Annual costs were calculated by adding annual operation and maintenance (O&M) costs to the annualized capital cost of a DFGD control system. To the extent possible, methodologies described in the OAQPS Cost Manual were used to estimate capital and O&M costs. Cost effectiveness ($/ton) of a DFGD was calculated by dividing the total annual cost ($/yr) by the reduction in annual emissions (ton/yr).

In addition to comments from DEQ, on December 4, 2009, the U.S. Department of the Interior, U.S. Fish and Wildlife Service (FWS), in consultation with the National Park Service (NPS) submitted comments to DEQ regarding the draft Regional Haze Implementation Plan. FWS/NPS agreed with DEQ that costs presented by OG&E for SO_2 control were excessive. To respond to DEQ and FWS/NPS questions and concerns, S&L prepared the following:

a) <u>Updated 2009 Conceptual Capital Cost Estimates</u>
The original 2008 BART report capital cost estimates were study type +/-30% estimates based primarily on conceptual cost estimates prepared for similar projects that were scaled to account for major differences. The 2009 conceptual capital cost estimate (included herein) for Sooner Units 1 & 2 is based on project-specific vendor quotations for certain major equipment items and inputs developed by performing preliminary project engineering. The 2009 conceptual capital cost estimate is in the +/-20% accuracy range. A comparison of the revised capital cost estimate against the sources cited by DEQ in the draft Regional Haze Implementation Plan is also included. The Muskogee Unit 4 & 5 capital cost estimate is still being developed, and will be submitted to DEQ within the next week. Due to similarities in the unit sizing, plant layouts, geographical location, and fuel sources, the base Muskogee estimate will be very similar to the Sooner estimate. The draft schedule included in Attachment A, assumes the Muskogee work will take place after the Sooner work; therefore, the Muskogee cost estimate will have additional escalation costs included.

b) Operating Cost Estimates

Operating costs included in the original 2008 BART report were primarily based on default factors taken from the OAQPS Cost Manual and U.S.EPA's Coal Utility Environmental Cost (CUECost) model. Updated operating costs included in this report were developed by S&L using OG&E supplied tax, wage, financial, and insurance information, as well as industry standards and vendor quotations.

c) Updated Cost Effectiveness Estimates

The updated conceptual capital cost and operating cost estimates were used to calculate revised cost effectiveness estimates.

d) Alternative Methods for Calculating Reductions in Annual Emissions and Visibility Impacts

FWS/NPS also questioned the methodology used by OG&E to calculate the amount of pollutant removed with DFGD controls. The amount of pollutant removed (tons/year) has a direct effect on the cost effectiveness of the pollution control system. To address the FWS/NPS comments, emission reductions from each of the OG&E units were calculated based on using two different baseline emission rates and three different post DFGD emission rates. This was done to show the effect on the cost effectiveness calculations, and to "envelope" the cost effectiveness calculations. Cost effectiveness in terms of modeled visibility improvements at affected Class I Areas ($/dV) were also revised to reflect the updated cost estimates.

e) Comparison against BART submittals from similar projects

Results of the OG&E BART cost effectiveness impacts ($/ton and $/dV) are compared against impacts reported in other BART evaluations.

2.0 2009 COST ESTIMATES AND COST EFFECTIVNESS UPDATE

2.1 2009 CONCEPTUAL CAPITAL COST ESTIMATE

The 2009 conceptual capital cost estimate and supporting information for Sooner Units 1 and 2 are included in Attachment A. Muskogee capital conceptual capital cost estimates will be completed at a later date but are expected to be very close to the Sooner costs except for the escalation values. Table 1 provides a summary of the Sooner Station 2009 conceptual capital cost estimate with the costs divided evenly between Units 1 and 2.

Table 1
Sooner Unit 1 or Unit 2
2009 Capital Cost Estimate

Item	2009 Cost Estimate
Direct Costs	$162,651,000
Indirect Costs	$24,045,000
Escalation	$23,301,000
Sales Tax	$0
Contingency	$29,337,000
AFUDC & Bond Costs	$52,960,000
TOTAL CAPITAL COST	**$292,294,000**
Cost Per kw (gross)	$514

The conceptual cost estimate provided in Attachment A takes into account the retrofit difficulty that can be expected from the existing Sooner site configuration. In degree of difficulty, the retrofit at Sooner could be described as average. The new DFGD locations are relatively clear but Unit 1 is tightly bounded on the east side by two coal conveyors that supply both units and on the west by high voltage duct-bank, ash piping, and circulating water piping. This existing equipment creates a narrow construction corridor for installing the DFGD equipment. As a result, the DFGD has a long narrow configuration with relatively long ductwork runs. There is also some ash piping and supports near the existing chimney and ID fans that would have to be relocated to accommodate the new ductwork. The existing storm sewer system in the new DFGD area would have to be completely removed and reinstalled to accommodate the new equipment foundations. A main east-west underground piping run also goes through the new DFGD area and would have to be relocated. All of the site-specific retrofit challenges, including equipment relocations, have been taken into consideration in the conceptual cost estimate.

2.2 METHODOLOGY FOR DEVELOPING THE CONCEPTUAL COST ESTIMATE

S&L developed the 2009 Sooner capital cost estimates using the following methodology:

- Sooner plant design data was used to develop datasheets to specify the dry FGD, baghouse, and ID booster fan operating conditions. The datasheets were issued to various manufacturers to obtain budgetary quotations. Costs obtained from these quotations were used to derive the pricing used in the capital cost estimate. The cost development for the spray dryer absorbers and baghouse used in the estimate is described in Attachment A.
- A general arrangement (GA) drawing was developed using the information received in the budgetary quotations. The GA drawing was used to estimate the major installation quantities for the project including ductwork, structural steel, foundations, relocations, cable, and pipelines.
- A motor list was assembled and used to develop the auxiliary power system sizing and quantities.
- Mass balances were prepared and used to size the flue gas, material handling, material storage, and piping systems.
- A schedule was developed to estimate escalation and AFUDC costs. It was assumed the new DFGDs would come on line at six month intervals with the last unit being completed at Muskogee near the end of 2015.
- Range estimating techniques were used to identify the appropriate amount of contingency to obtain a 95% confidence level. The contingency level was approximately 14%.
- A design and cost basis document was prepared to document the major assumptions and inputs for developing the cost estimate.
- Labor cost estimates were developed using Oklahoma area wage rates, installation quantities, and installation rates taken from the S&L database.

This methodology provides a conceptual capital cost estimate with accuracy in the range of ±20%. This methodology provides a better estimate of the capital costs associated with installing DFGD control systems, and a more accurate estimate of the actual costs that OG&E would incur to install DFGD at the Sooner and Muskogee Stations.

2.3 COMPARISON BETWEEN 2008 AND 2009 COST ESTIMATES

A comparison of the 2008 and 2009 cost estimates for Sooner Units 1 & 2 is provided in Table 2.

Table 2
Sooner Unit 1 or Unit 2
2008 and 2009 Capital Cost Estimate Comparison(1)

Item	2008 Cost Estimate	2009 Cost Estimate
Total Costs ($)	$390,406,000	$292,294,000
Cost per kw ($/kw)	$686	$514
Cost Difference (%)	Base	-25%
Contingency ($)	$56,598,000	$29,337,000

(1) The Total Project Cost for DFGD on both units at the Sooner Station is estimated to be $584,589,800. Costs summarized in this table are divided equally between the two units.

Major factors contributing to the reduction of costs from 2008 to 2009 include:

a) Direct Costs
The 2008 estimate was prepared when the demand for DFGD systems was high and costs were near their peak. It is estimated that major equipment costs have dropped approximately 15% to 20% since this time.

b) Contingency Costs
The 2009 estimate was based on vendor quotations for major equipment and preliminary engineering to develop quantities. As a result of this additional cost certainty, the contingency factor in the 2009 estimate (14%) is approximately 6% lower than the 2008 estimate. The difference in contingency amounts between the two estimates is illustrated in Table 2-2.

c) Escalation Costs
The estimate of future escalation is lower in 2009 than it was in early 2008 when prices had been rapidly increasing over the previous three years. The difference in overall project escalation factors is about 10%.

The cumulative effect of changes in the above three cost items, with all other things being equal, would be about a 20% to 30% reduction in pricing from 2008 to 2009. The actual decrease was about 25% which falls into this range. We believe this validates the capital costs provided in the 2008 estimate.

2.4 UPDATED TOTAL ANNUAL COSTS AND COST EFFECTIVENESS

In general, total annual costs are the sum of the capital recovery costs and annual O&M costs. Cost effectiveness of a pollution control system is calculated by dividing the total annual cost of the control system ($/year) by the total annual quantity of pollutant removed by the system (tons/year); where:

- Annual Cost (Reference Year $/year) = Annualized Capital Costs + Annual Operating Costs;

- Annualized Capital Costs (Reference Year $/year) = Total Capital Requirement x Capital Recovery Factor;

- Total Capital Requirement (Reference Year $) = All capitalized expenses as of the commercial operating date, including direct costs, indirect costs, and allowance for funds used during construction (AFUDC);

- Capital Recovery Factor = The factor that converts the Total Capital Requirement into equal annual costs over the depreciable life of the asset, accounting for OG&E returns on debt and equity and income taxes, expressed in real terms (i.e., inflation removed); and

- Annual Operating Costs (Reference Year $/year) = Variable O&M Costs + Fixed O&M Costs + Indirect Operating Costs.

The following sections describe the derivation of these components of the cost estimate.

2.4.1 Capital Costs

Conceptual capital costs for the DFGD control projects at each OG&E station were calculated using the methodology described in Section 2.2. The total capital requirement (TCR) is the sum of direct costs, indirect costs, contingency, escalation, and allowance for funds used during construction. Direct costs include equipment, material, labor, spare parts, special tools, consumables, and freight. Indirect costs include engineering, procurement, construction management, start-up, commissioning, operator training, and owner's costs.

Escalation and AFUDC were calculated from the estimated distribution of cash flows during the construction period and OG&E's before-tax weighted average cost of capital of 8.66%/year. The 37-day tie-in outage for each unit is assumed to be coordinated with the normal 5-week scheduled outage such that incremental replacement cost is negligible.

The TCR for each unit is summarized in Tables B-1 through B-4 in Attachment B.

Capital Recovery Factor

The capital recovery factor converts the TCR into equal annual costs over the depreciable life of the asset, accounting for OG&E returns on debt and equity and income taxes, expressed in real terms (i.e., inflation removed). These are also referred to as levelized capital charges. Property taxes and insurance are sometimes included with the capital charges, but are classified in this analysis as part of the Indirect Operating Costs to be consistent with the BART reports. The economic parameters used to derive the levelized capital charges are summarized in Table 3.

Table 3
Economic Parameters to Derive Levelized Capital Charges

Commercial Operation Date (Reference Year)	
Sooner	2014
Muskogee	2015
Depreciable Life	20 years
Inflation Rate	2.50%/year
Effective Income Tax Rate – Federal and State	38.12%
Common Equity Fraction	0.557
Debt Fraction	0.443
Return on Common Equity	
Nominal	10.75%/year
Real	8.05%/year
Return on Debt	
Nominal	6.03%/year
Real	3.44%/year
Discount Rate (after-tax cost of capital)	
Nominal	7.64%/year
Real	5.43%/year
Tax Depreciation	20-year straight line
Levelized Capital Charges (real)	10.36%/year

Based upon the above parameters, the real levelized capital charge rate (capital recovery factor) is 10.36%/year. The derivation of this value is shown in Table B-5 in Attachment B. The TCR multiplied by 10.36% thus determines the Annualized Capital Costs.

2.4.2 Operating Costs

Annual operating costs for the DFGD system consist of variable O&M costs, fixed O&M costs, and indirect operating costs. The derivation of each cost component is described below.

Variable O&M

Variable O&M costs are items that generally vary in proportion to the plant capacity factor. These consist of lime reagent costs, water costs, FGD waste disposal costs, bag and cage replacement costs, ash disposal costs, and auxiliary power costs, which were derived as follows:

- Lime Reagent. Based on material balances for the average fuel composition and 90% capacity factor. The first-year delivered cost of lime is \$118.80/ton for Sooner and \$105.53/ton for Muskogee based on budgetary lime quotations received for truck delivery.

- Water. Based on 205,256 lb/hr at full load at Sooner, 219,839 lb/hr at full load at Muskogee, and 90% capacity factor. The first-year cost of water is \$0.49/1000 gallons at Sooner and \$2.57/1000 gallons at Muskogee. Water unit costs are based on information received from OG&E. The Muskogee water cost includes the cost of purchasing water. Sooner does not have any water purchase costs.

- FGD Waste Disposal. Based on material balances for the average fuel composition and 90% capacity factor. The first year cost of on-site disposal is \$39.60/ton at Sooner and \$40.59/ton at Muskogee. Disposal cost only includes FGD by-products and does not include fly ash.

- Bag and Cage Replacement. Based on the exhaust gas flow through the baghouse, air-to-cloth ratio of 3.5 for pulse jet baghouse, 4% contingency for bag cleaning, and 3-year bag life. The first year bag cost (including fabric and hangers) is \$3.22/ft^2 at Sooner and \$3.31/ft^2 at Muskogee.

- Ash Disposal. Assumed no increase in ash disposal with the fabric filter due to the existing ESP remaining in service.

- Auxiliary Power Cost. Based on auxiliary power calculations and 90% capacity factor. The first year auxiliary power cost is \$83.83/MWh at Sooner and \$85.92/MWh at Muskogee.

Fixed O&M

Fixed O&M costs are recurring annual costs that are generally independent of the plant capacity factor. These consist of operating labor, supervisor labor, maintenance materials, and maintenance labor, which were derived as follows:

- Operating Labor. Based on three shifts/day 365 days/year. The first year labor rate (salary plus benefits) is $57.33/hour at Sooner and $58.76/hour at Muskogee.

- Supervisory Labor. This was based on 15% of operating labor, according to the EPA Control Cost Manual, page 2-31. S&L determined that the EPA approach provides a reasonable estimate for this cost item.

- Maintenance Materials. This was based on 0.6% of the total plant investment, based on Sargent & Lundy's experience on other FGD projects.

- Maintenance Labor. This was based on 110% of operating labor, according to the EPA Control Cost Manual, page 2-31. S&L determined that the EPA approach provides a reasonable estimate for this cost item.

Indirect Operating Costs

Indirect operating costs are recurring annual costs for the FGD system that are not part of the direct O&M. These consist of property taxes, insurance, and administration, which were derived as follows:

- Property Taxes. Calculated as 0.60 % of total capital investment at Sooner and 0.85% of total capital investment at Muskogee, according to OG&E property tax rates. These rates are significantly lower than those used in the EPA Air Pollution Control Cost Manual 6th Ed., page 2-34.

- Insurance. Calculated as 0.0105 % of total capital investment at both Sooner and Muskogee, according to OG&E insurance rates. These rates are significantly lower than those used in the EPA Air Pollution Control Cost Manual 6th Ed., page 2-34.

- Administration. These are calculated as 20% of the fixed O&M based on Sargent & Lundy's experience on other projects. This results in significantly lower costs compared to those obtained using the methodology described in the EPA Air Pollution Control Cost Manual 6th Ed., page 2-34.

Total Annual Operating Costs

The total annual operating costs for each unit are calculated in Tables B-1 through B-4 in Attachment B and are approximately $29 to $32/kw per year. These costs compare favorably with industry O&M data for existing coal plants, and are within the normal range of expected O&M costs for dry FGD systems. The annual operating cost of approximately $29 to $32/kw is significantly lower than the $68/kw calculated in the 2008 BART report which was derived using OAQPS Cost Manual and CUECost default factors, and is lower than the $43 to $47/kw estimated by the DEQ in the draft Regional Haze Implementation Plan.

2.4.3 2009 Cost Effectiveness

Total annual DFGD costs for each unit are summarized in Table 4. Detailed cost calculations are shown in Tables B-1 through B-4 in Attachment B. Total annual costs are divided by the annual tons of SO_2 removed to calculate average control technology cost effectiveness. Annual emission reductions associated with DFGD control systems are summarized in Table 5 using the same basis as the September 2009 OG&E BART update. The SO_2 control efficiency for each unit is summarized in Table 6

Table 4
DFGD Total Annual Cost Summary

Unit	Capital Recovery ($/year)	Annual O&M ($/year)	Total Annual Cost ($/year)
Muskogee 4	$31,854,600	$18,285,500	$50,140,100
Muskogee 5	$31,854,600	$18,285,500	$50,140,100
Sooner 1	$30,281,800	$16,550,500	$46,832,300
Sooner 2	$30,281,800	$16,550,500	$46,832,300

Table 5
BART Annual SO2 Emission Reductions with Dry FGD

Unit	Baseline Annual SO2 Emissions (1) (tpy)	Projected Post-Control Annual Emissions (2) (tpy)	Annual Emission Reductions (tpy)
Muskogee 4	9,113	2,160	6,953
Muskogee 5	9,006	2,160	6,846
Sooner 1	9,394	2,017	7,377
Sooner 2	8,570	2,017	6,553

(1) In this table baseline SO_2 emissions are calculated as the average actual SO_2 emission rate during the baseline years of 2004 – 2006.

(2) In this table projected post-control SO_2 emissions are calculated based on a controlled SO_2 emission rate of 0.10 lb/mmBtu and a 90% capacity factor.

Table 6
Average Cost Effectiveness

Unit	Annual Cost ($/year)	SO_2 Removed (tons/year)	Average Cost Effectiveness ($/ton)
Muskogee 4	$50,140,100	6,953	$7,211
Muskogee 5	$50,140,100	6,846	$7,324
Sooner 1	$46,832,300	7,377	$6,348
Sooner 2	$46,832,300	6,553	$7,147

Cost effectiveness is a function of both the cost of a control system and the annual tons of pollutant removed. With respect to tons removed, various bases can be used to calculate both the baseline emission rate and the post-project controlled emission rate. Varying either the baseline calculation or the projected emissions calculation will result in a different cost effectiveness value.

To account for this variability, the cost effectiveness of DFGD controls at Sooner and Muskogee were calculated using various baseline and projected SO_2 emission rates. Emission rates were chosen to "envelope" the cost effectiveness of the DFGD control systems. For example, baseline SO_2 emissions were based on the actual average SO_2 emission rate during the 2004-2006 baseline period, as well as the highest annual SO_2 emissions during the baseline period. Projected SO_2 emissions were calculated using the presumptive SO_2 emission rate of 0.15 lb/mmBtu, as well controlled SO_2 emission rates of 0.10 and 0.08 lb/mmBtu. Finally, capacity factors of either 90% (which is more representative of actual operations) or 100% (which represents potential emissions but would not represent actual operations) were also used.

Although annual O&M costs will vary depending on the controlled SO_2 emission rate (i.e., lower post-project SO_2 emission rates will have a higher annual variable O&M cost), for this analysis total annual costs were held constant. Cost effectiveness calculations for two alternative scenarios are summarized in Tables 5a & 6a and 5b & 6b.

Table 5a
BART Annual SO2 Emission Reductions with Dry FGD
(Scenario 2)

Unit	Baseline Annual SO2 Emissions (1) (tpy)	Projected Post-Control Annual Emissions (2) (tpy)	Annual Emission Reductions (tpy)
Muskogee 4	9,775	3,600	6,175
Muskogee 5	10,224	3,600	6,624
Sooner 1	10,189	3,361	6,828
Sooner 2	8,746	3,361	5,385

(1) In this table baseline SO_2 emissions reflect the highest annual SO_2 emission rate during the baseline years of 2004 – 2006.
(2) In this table projected post-control SO_2 emissions are calculated based on a controlled SO_2 emission rate of 0.15 lb/mmBtu (the presumptive BART emission rate) and a 100% capacity factor.

Table 6a
Average Cost Effectiveness
(Scenario 2)

Unit	Annual Cost ($/year)	SO_2 Removed (tons/year)	Average Cost Effectiveness ($/ton)
Muskogee 4	$50,140,100	6,175	$8,120
Muskogee 5	$50,140,100	6,624	$7,569
Sooner 1	$46,832,300	6,828	$6,859
Sooner 2	$46,832,300	5,385	$8,697

Table 5b
BART Annual SO2 Emission Reductions with Dry FGD
(Scenario 3)

Unit	Baseline Annual SO2 Emissions (1) (tpy)	Projected Post-Control Annual Emissions (2) (tpy)	Annual Emission Reductions (tpy)
Muskogee 4	9,775	1,920	7,855
Muskogee 5	10,224	1,920	8,304
Sooner 1	10,189	1,793	8,396
Sooner 2	8,746	1,793	6,953

(1) In this table baseline SO_2 emissions reflect the highest annual SO_2 emission rate during the baseline years of 2004 – 2006.
(2) In this table projected post-control SO_2 emissions are calculated based on a controlled SO_2 emission rate of 0.08 lb/mmBtu and a 100% capacity factor. A controlled SO_2 emission rate of 0.08 lb/mmBtu represents the lowest SO_2 emission rate that could reasonably be expected to be achieved on a large subbituminous coal-fired unit with a retrofit DFGD control system.

Table 6b
Average Cost Effectiveness
(Scenario 3)

Unit	Annual Cost ($/year)	SO_2 Removed (tons/year)	Average Cost Effectiveness ($/ton)
Muskogee 4	$50,140,100	7,855	$6,383
Muskogee 5	$50,140,100	8,304	$6,038
Sooner 1	$46,832,300	8,396	$5,578
Sooner 2	$46,832,300	6,953	$6,736

Cost effectiveness varies depending on the baseline and controlled SO_2 emission rates used in the evaluation. Under all scenarios, DFGD cost effectiveness on the OG&E units is greater than $5,550/ton. Based on the BART presumptive level of 0.15 lb/mmBtu, and assuming a 100% capacity factor, cost effectiveness of DFGD on the Muskogee and Sooner units would be in the range of $6,859 to $8,697/ton (see, Table 6a). Cost effective values calculated using the BART presumptive level should be used to compare cost effective at other BART applicable sources.

In addition to calculating cost effectiveness on a $/ton basis, with respect to regional haze impacts, cost effectiveness can be calculated as a function of annual costs and modeled visibility improvements at the affected Class I Areas. Modeled visibility improvements will be a function of the proximity of the unit to the Class I Area, baseline and controlled emissions, and the pollutant being controlled. Table 7 provides a summary of the modeled reduction in visibility impairment (measured in deciview- dv) resulting from DFGD controls on the Muskogee and Sooner generating units. The cost effectiveness of DFGD controls as a function of modeled reductions in visibility impairment (using two different impact criteria) is provided in Tables 8 and 8a.

Table 7
Modeled Visibility Improvement at the Class I Areas (dv)

Class I Area	Muskogee Units 4 & 5	Sooner Units 1 & 2
Wichita Mountains National Wildlife Refuge	1.275	0.51
Caney Creek Wilderness Area	0.804	0.32
Upper Buffalo Wilderness Area	1.11	0.44
Hercules-Glades Wilderness Area	1.028	1.17
Total	**4.217**	**2.44**

Table 8
Average Cost Effectiveness ($/dv)

Unit	Annual Cost ($/year)	Modeled Visibility Improvement(1) (dv)	Average Cost Effectiveness ($/dv)
Muskogee 4 & 5	$100,280,200	1.275	$78,651,137
Sooner 1 & 2	$93,664,600	1.17	$80,055,214

(1) The modeled reduction in visibility impairment used in this table represents the highest single modeled reduction at a single Class I Area.

Table 8a
Average Cost Effectiveness ($/dv)

Unit	Annual Cost ($/year)	Modeled Visibility Improvement(1) (dv)	Average Cost Effectiveness ($/dv)
Muskogee 4 & 5	$100,280,200	4.217	$23,779,986
Sooner 1 & 2	$93,664,600	2.44	$38,387,131

(1) The modeled reduction in visibility impairment used in this table represents the cumulative reduction of all Class I Areas.

Based on the cost effectiveness calculations summarized above, taking into considered modeled visibility improvements at all of the affected Class I areas, the cost effectiveness of DFGD on Sooner Units 1 & 2 will be in the range of $38,387,000/dv, and the cost effectiveness of DFGD on Muskogee Units 4 & 5 will be in the range of $23,780,000/dv.

2.5 COMPARISON OF 2009 CAPITAL COSTS AGAINST OTHER PUBLISHED CAPITAL COST INFORMATION

Appendix 6-4 of the November 13, 2009 Oklahoma draft Regional Haze Implementation Plan Revision includes DEQ's BART analysis for each OG&E BART applicable unit. In each of the OG&E BART determinations, DEQ revised the cost estimates for retrofit DFGD control systems, including revisions to the capital costs and annual O&M costs. Although DEQ stated that, in general, the cost estimating methodology used by OG&E "followed guidance provided in the EPA Air Pollution Cost Control Manual," DEQ concluded, based on a review of other BART submittals, that OG&E's costs were substantially higher than those reported for similar projects. (Draft Regional Haze Implementation Plan, Appendix 6-4, page cliii). DEQ proceeded to revise the capital costs and O&M costs based on cost information provided in the following publications: (1) a Colorado Department of Public Health and Environment report titled "Summary of Research and Potential Control Options, Emission Reductions and Costs for Reducing SO2 and NOx from Existing Major Colorado Point Sources"; (2) a March 1, 2009 article in Power, on online industry magazine, titled "Update: What's That Scrubber Going to Cost" written by George W. Sharp of American Electric Power; and (3) a report prepared by Sargent & Lundy for the National Lime Association titled "Flue Gas Desulfurization Technology Evaluation, Dry Lime vs. Wet Limestone FGD" dated March 2007.

In its comments to DEQ regarding the draft Regional Haze Implementation Plan FWS/NPS agreed with DEQ that costs presented by OG&E for SO2 control were excessive. In addition, FWS/NPS provided an alternative lower cost analysis using capital costs "taken from the 2007 Flue Gas Desulfurization Technology Evaluation, Dry Lime vs. Wet Limestone FGD, prepared for National Lime Association."

We address each of the referenced documents below.

2.5.1 Colorado Department of Public Health and Environment Report

The Colorado Department of Public Health and Environment report included unit capital costs for retrofit dry scrubbers on 500 MW units burning PRB coal. The report was prepared by BBC Research and Consulting, and relied on cost data in a 2003 report prepared by Sargentt & Lundy titled "Economics of Lime and Limestone for Control of Sulfur Dioxide" (the 2003 National Lime Report). As discussed in more detail below, capital costs included in the 2003 National Lime Report were intended to provide a comparison between lime-based and limestone-based scrubbing technologies, and were not intended to be used as the basis for a project-specific capital cost estimate.

2.5.2 2007 National Lime Association Report

Both DEQ and FWS reference the 2007 National Lime Report prepared by Sargent & Lundy as a basis for their capital cost revisions. In fact, the FWS's alternative capital costs were based on numbers provided in the 2007 National Lime Report. However, the National Lime report was only intended to provide a comparative cost effectiveness evaluation of wet limestone-based FGD control systems and dry lime-based control systems. The report was not intended to provide an evaluation of total capital requirements for either type of control technology and was not intended to serve as the basis for a capital cost estimate. The 2007 report clearly states:[1]

> FGD prices have seen a minimum of 25% inflation in the past year. Some recent contracts have been signed at prices over 300% higher than the market of 5 years ago. The costs [in this report] have been prepared on a consistent, uniform basis and show a level that some buyers achieved in mid-2006. Sargent & Lundy cautions the reader that the costs provided herein are not indicative of any cost you may actually achieve. However, we believe the costs are valid for comparative purposes. These costs should *not* be used for any of these purposes;
>
> - Planning the cost of a FGD project
> - Budget requests or allocations
> - Solicitation of pollution control bonds
>
> In today's market place, it is impossible to determine capital cost of an FGD system until the contract is signed with the supplier.

Capital costs in both the 2003 and 2007 National Lime Reports were developed for comparative purposes only. Furthermore, costs in the 2007 report were based on 2006 dollars and did not include escalation, which can add approximately 10% to 20% to the project cost. Nor do the reports take into consideration any site-specific retrofit challenges. Capital costs in the National Lime Reports were presented on a consistent basis for comparative purposes only. Cost estimates using the methodology described in Section 2.1 of this report provide a more accurate accounting of actual costs that will be incurred by OG&E to install and operate dry FGD control systems at Sooner and Muskogee

[1] See, Sargent & Lundy, "Flue Gas Desulfurization Technology Evaluation, Dry Lime vs. Wet Limestone FGD," prepared for the National Lime Association, March 2007, page 2 (emphasis in the original).

2.5.3 "Update: What's That Scrubber Going to Cost" article

DEQ also used capital cost estimates summarized in a March 1, 2009 article in "Power" an online industry magazine to adjust the capital costs for DFGD retrofit projects at the OG&E stations. The Power article provided a survey of FGD projects at large electric utility generating stations during the period of December 2007 through June 2008. The article summarized the average total installed costs of FGD control systems as reported by the survey respondents, noting that the reported costs "were expected to have wide variation, principally because of the peculiarities that exist at each project site, the retrofit project complexity, and the timing differences between projects." Therefore, assigning a project-specific cost based on information summarized in the article would not be correct without taking into consideration project specific details.

Furthermore, the 2009 OG&E conceptual capital cost of $514/kw is reasonably close to the $359 to $471/kw taken from this article. The article reported that the 2008 cost surveys were 28% higher than those reported in the 2007 survey with an average of $359/kw for 600 to 900 MW plant range and $471/kw for 300 to 599 MW range. Note that these values are averages and include units with wide ranges of in service dates. In fact, 55% of the units in the survey were expected to be in operation by 2009 whereas the OG&E units are not expected to be in operation until 2014 and 2015. The 55% of the units in operation by 2009 would have had their major equipment purchased prior to the 28% run up in pricing in 2008 from late 2006 and prior to the 22% run up in pricing from 2006 to 2007 referenced in the same article. The OG&E units would be subject to these escalated costs and future escalation.

In addition, the OG&E units would also require a higher level of contingency since the projects are still in the early study phase. As a result, units going into service in the near future would be expected to be below the average cost while units going into service at later dates would be expected to be above the average cost. The article only provides an average cost and does not provide any information on the cost distribution about the average. A wide distribution is expected as indicated at the bottom of page 65 where it states that "average total installed costs reported by the survey respondents were expected to have wide variation" based partially on the "timing differences between projects." Because of the expected wide variation in project costs, this report can be used to illustrate recent industry cost trends but should not be used to estimate the cost of specific units that will not go into service for another 5 to 7 years. Again, it is believed that the methodology described in Section 2.1 will provide more accurate results for a specific project than the cited article.

3.0 BART Report Comparisons

The cost effectiveness of a pollution control system is a function of the total annual cost of the system (taking into consideration capital recovery and annual O&M) and the amount of pollutant removed by the control system (tons per year). With respect to regional haze impacts, cost effectiveness can also be measured as a function of total annual costs divided by the modeled improvement in visibility at the nearby Class I Areas. This measure of cost effectiveness is reported in total annual dollars per deciview change in visibility impairment ($/dv). Thus, in addition to costs, two site-specific factors that impact cost effectiveness are the quantity of pollutant removed and the reduction in modeled visibility impairment.

3.1 COMPARISON OF BASELINE SO_2 EMISSIONS

Table 9 provides a summary of the baseline SO_2 emission rates included in several BART evaluations. A more detailed comparison of some of the costs and cost effectiveness calculations included in various BART determinations is included in Attachment C.

Table 9
Comparison of Baseline SO_2 Emissions at Several BART Units

Station	Baseline SO_2 Emission Rate (lb/mmBtu)	Baseline SO_2 Emissions (tpy)
Muskogee Unit 4	0.507	9,113
Muskogee Unit 5	0.514	9,006
Sooner Unit 1	0.509	9,394
Sooner Unit 2	0.516	8,570
NPPD Gerald Gentleman Unit 1	0.749	24,254
NPPD Gerald Gentleman Unit 2	0.749	25,531
White Bluff Unit 1	0.915	31,806
White Bluff Unit 2	0.854	32,510
Boardman Unit 1	0.614	14,902
Northeastern Unit 3	0.900	16,000
Northeastern Unit 4	0.900	16,000
Naughton Unit 1	1.180	8,624
Naughton Unit 2	1.180	11,187
OPPD Nebraska City Unit 1	0.815	24,191

Of the units listed in Table 9, the OG&E units have the lowest baseline SO_2 emission rates, and among the lowest baseline annual SO_2 emissions (tpy). Baseline emissions have a direct effect on the cost effectiveness of a pollution control system, as shown below:

Cost Effectiveness = Total Annual Costs / (Baseline Emissions – Projected Emissions)

Assuming total annual costs and projected emissions are similar, cost effectiveness will be a function of the baseline emissions. This holds true for units firing subbituminous coals with baseline SO_2 emission rates in the range of 0.5 lb/mmBtu to approximately 2.0 lb/mmBtu because removal efficiencies achievable with DFGD control will vary based on inlet SO_2 loading. In general, DFGD control systems are capable of achieving higher removal efficiencies on units with higher inlet SO_2 loading.[2] DFGD control systems will be more cost effective on units with higher baseline SO_2 emissions because the control system will be capable of achieving higher removal efficiencies and remove more tons of SO_2 per year for similar costs. Conversely, DFGD will be less cost effective, on a $/ton basis, on units with lower SO_2 baseline emissions. The difference in baseline SO_2 emissions summarized above accounts for some of the variability seen in the BART cost effectiveness calculations. On the basis of the baseline emission rates alone, with all other factors being equal, the cost effectiveness of the OG&E units would be about 55% to 185% higher than the other units listed in Table 9.

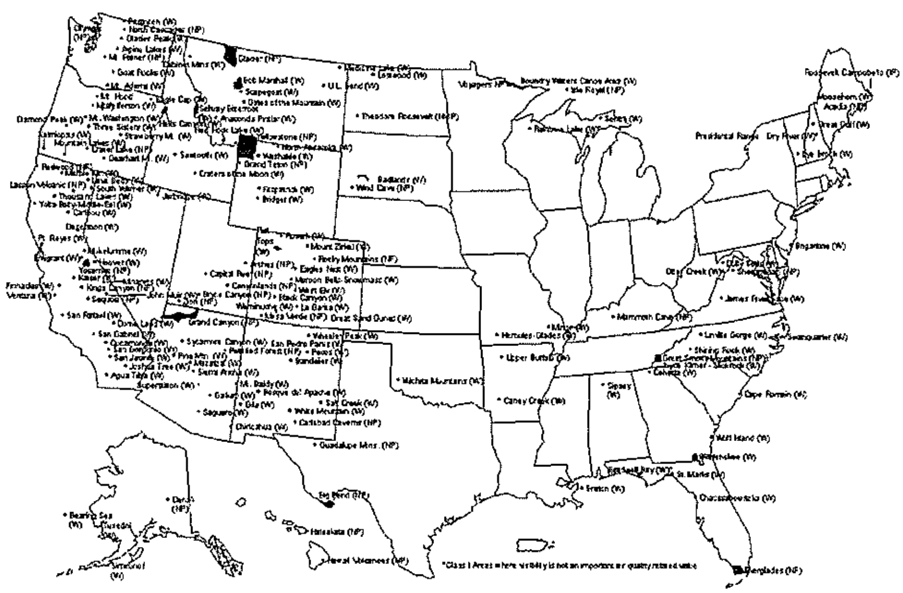
3.2 COMPARISON OF MODELED VISIBILITY IMPROVEMENT

Finally, with respect to regional haze impacts, cost effectiveness can also be calculated as a function of modeled improvements in visibility at the Class I areas. This cost effectiveness measurement can be presented by dividing the total annual costs by the degree of visibility improvement at an individual Class I area, or by dividing total annual costs by the sum of visibility improvement across all affected Class I areas. Using either approach, control technologies installed on units with higher baseline emissions and located nearer a Class I area will be more cost effective.

In its comments to DEQ, FWS/NPS argued that cost effectiveness should "consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of

[2] Removal efficiencies achievable with DFGD will be a function of several unit-specific process parameters. Process parameters affecting removal efficiency include: inlet and outlet flue gas temperatures; reactant stoichiometric ratio; how close the DFGD is operated to saturation conditions; the amount of solids product recycled to the atomizer, and the inlet SO_2 concentration. Chemical and physical limitations including flue gas temperature, Ca/S stoichiometry, approach to saturation, mixing and reaction time limit the control efficiency of the DFGD control systems.

improving visibility across all of the Class I areas affected."[3] FWS/NPS reasoned that "[i]t is not appropriate to use the same metric to evaluate the effects of reducing emission from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas."[4] Taking the cumulative impact approach, cost effectiveness will also be a function of the number of Class I areas affected by an individual BART applicable unit. Controls would be more cost-effective on units in near proximity to a Class I area, as well as units located within 300 km of a number of Class I areas. Figure 1 shows the location of the Class I areas in the U.S.



Map of 156 National Park and Wilderness Areas
Protected by EPA's Regional Haze Rule

Figure 1
Class I Areas

A majority of the Class I areas are located in the western part of the U.S. Simply due to the number of Class I areas in the west, it is likely that a BART applicable unit located in the western U.S. will be closer to a Class I area, and that emissions from the unit will affect visibility at more Class I areas. For example, the Boardman Generating Station located in north central Oregon approximately 150 miles east of Portland, is located within 300 km of 14 Class I areas. By comparison, the Sooner and Muskogee stations are located within 300 km of one and four Class I areas, respectively.

[3] FWS/NPS Comments, page 3.
[4] *Id.*

Taking the cumulative impact approach, control technologies will be more cost effectiveness on units affecting a number of Class I areas. For example, modeled visibility improvement at each Class I areas affected by the Sooner, Muskogee, and Boardman stations are summarized in Table 10. Assuming the cost of retrofit controls are similar at all three stations, and assuming that each station achieves similar emission reductions, DFGD controls would be more cost effective at the Boardman Station (on a $/dv basis) simply due to the cumulative improvement in visibility improvement.

Table 10
Comparison of Baseline SO_2 Emissions at Several BART Units

	Muskogee Units 4 & 5	Sooner Units 1 & 2	Boardman Unit 1
1	1.275	0.51	0.777
2	0.804	0.32	0.439
3	1.11	0.44	0.802
4	1.028	1.17	0.544
5	na	na	0.774
6	na	na	0.655
7	na	na	0.659
8	na	na	0.969
9	na	na	0.924
10	na	na	0.614
11	na	na	0.776
12	na	na	0.354
13	na	na	0.681
14	na	na	0.874
Total	**4.217**	**2.44**	**9.842**

In its BART analysis submitted to the Oregon Department of Environmental Quality, total capital requirements and total annual costs for DFGD were estimated at $247,293,000 and $36,322,000, respectively. Using the sum of modeled visibility improvements at all 14 Class I areas, cost effectiveness of the DFGD control system would be $3,690,510/dv (e.g., $36,322,000 divided by 9.842 dv). By comparison, because the OG&E stations are located relatively far from a limited number of Class I areas, cost effectiveness at the Sooner and Muskogee stations would be $38,387,000/dV and $23,780,000/dv, respectively.[5]

[5] Sooner = $93,664,600 ÷ 2.44 dv = $38,387,000/dv
Muskogee = $100,280,200 ÷ 4.217 dv = $23,780,000/dv

4.0 Conclusions

Sargent & Lundy updated the retrofit DFGD control system cost estimates for the Sooner and Muskogee Generating Stations. The 2009 conceptual cost estimate (included in this report) was based on project-specific vendor quotations for certain major equipment items and inputs developed by performing preliminary project engineering. The 2009 conceptual capital cost estimate is in the ±20% accuracy range. Total annual costs associated with the installation of DFGD, including capital recovery costs and annual O&M costs were also updated. Annual O&M costs were derived from preliminary engineering mass balance calculations and project-specific unit costs. The cost estimating methodology used herein to develop both capital and O&M costs provides a more accurate estimate of actual costs that OG&E would incur with the installation and operation of DFGD on the Sooner and Muskogee units.

The 2009 conceptual capital cost estimate and supporting information for Sooner Units 1 & 2 are included in Attachment A. Detailed total annual cost summaries, including capital recovery, variable O&M, and fixed O&M calculations are included in Attachment B. Based on the cost estimates, the total capital requirements for DFGD controls on all four OG&E units will be in the range of $1.17 billion dollars. Total annual operating costs will be in the range of $93.6 million/year at Sooner and $100.3 million/year at Muskogee.

Cost effectiveness of a pollution control system is a function of the total annual cost of the system and the quantity of pollutant removed (tons/year). Because of the relatively low baseline SO_2 emission rates at both Muskogee and Sooner (see, Table 9), DFGD will be less cost effective on these units than on similarly sized units with higher baseline SO_2 emissions. Based on expected reductions in actual annual SO_2 emissions, the cost effectiveness of DFGD on the OG&E units will be in the range of $6,348 to $7,324/ton (see, Table 6).

In addition to calculating cost effectiveness on a $/ton basis, with respect to regional haze impacts, cost effectiveness can be calculated as a function of annual costs and modeled visibility improvements at the affected Class I Areas. Modeled visibility improvements will be a function of the proximity of the unit to the Class I Area, baseline and controlled emissions, and the pollutant being controlled. Because the OG&E stations are located relatively far from a limited number of Class I areas, DFGD will be less cost effective (on a $/dv basis) on the OG&E units than on similarly sized units located closer to a Class I area or within 300 km of several Class I areas. Based on modeled visibility improvements, the cost effectiveness at the Sooner and Muskogee stations would be $38,387,000/dV and $23,780,000/dv, respectively.