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May 23, 2011



U.S. Environmental Protection Agency  
Region 6  
1445 Ross Avenue, Suite 1200  
Dallas, Texas 75202-2733

Attn: Mr. Joe Kordzi  
Air Planning Section (6PD-L)

Re: Docket No. EPA-R06-OAR-2010-0190

Dear Mr. Kordzi,

The comments of Oklahoma Gas and Electric Company (OG&E) on the proposed regional haze rule for Oklahoma are attached. OG&E serves approximately 785,000 customers in a service territory spanning 30,000 square miles in Oklahoma and western Arkansas.

EPA's proposed federal plan to reduce haze in Oklahoma and neighboring states should be rejected in favor of the plan submitted by Oklahoma. The federal plan would result in Oklahomans being saddled with billions of unnecessary utility costs. OG&E believes that the EPA proposal is contrary to the Clean Air Act and the agency's own rules. It is disconcerting to see the agency fail to follow its own rules and guidelines in establishing both the cost and visibility improvement estimates underlying the proposed rule. OG&E also believes that the EPA consultant made fundamental engineering and legal errors in developing opinions on the projected costs of installing and operating scrubbers.

Should the EPA rule be finalized in its current form, it would likely trigger the largest customer rate increase in OG&E's history while the resulting impact on regional haze would be practically imperceptible. The Oklahoma plan that EPA should approve calls for use of low sulfur coal instead of scrubbers and gives OG&E the flexibility of burning less coal and more natural gas on a timetable that both achieves the goals of the Regional Haze rule and minimizes the cost impact to OG&E customers.

OG&E looks forward to implementing a regional haze plan that recognizes the unique setting and interests of Oklahomans while achieving the goals established by the Clean Air Act. Please let me know if you have any questions about these comments or want more information about any aspect of them.

Sincerely,

A handwritten signature in blue ink that reads "Patricia D. Horn".

Patricia D. Horn

Before the  
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

COMMENTS

of

OKLAHOMA GAS AND ELECTRIC COMPANY

on

PROPOSED RULE REGARDING FEDERAL IMPLEMENTATION PLAN FOR  
INTERSTATE TRANSPORT OF POLLUTION AFFECTING VISIBILITY AND BEST  
AVAILABLE RETROFIT TECHNOLOGY DETERMINATIONS

Proposed by

The United States Environmental Protection Agency

On March 22, 2011

Docket No. EPA-R06-OAR-2010-0190

## **I. INTRODUCTION**

Oklahoma Gas and Electric Company (“OG&E”) believes that EPA’s proposal to reject Oklahoma’s Regional Haze Implementation Plan Revision (“SIP”) and issue a federal implementation plan (“FIP”) is illegal, arbitrary and capricious. *See* 76 Fed. Reg. 16,168 (March 22, 2011) (the “Proposed Rule”). The Proposed Rule is legally defective because it attempts to usurp the broad authority given to Oklahoma to make Best Available Retrofit Technology (“BART”) determinations under the Clean Air Act (“CAA”). Moreover, EPA’s evaluation of the cost and visibility impacts of various BART options is infected with legal and technical errors. Approval of the SIP is the only alternative that complies with Congress’s delegation of powers to Oklahoma, the relevant CAA requirements and EPA’s directions for determining BART.

More specifically, the Proposed Rule improperly attempts to determine BART for sulfur dioxide (“SO<sub>2</sub>”) emissions at the eligible coal-fired electrical generating units (“EGUs”) at the Muskogee (Units 4 and 5) and Sooner (Units 1 and 2) Generating Stations owned and operated by OG&E (the “OG&E Units”). The proposed BART determinations rest on a fatally flawed analysis that ignores both EPA’s own requirements for making BART determinations and basic engineering principles. EPA improperly adopts, without evidence of any critical review, the erroneous opinions of an unqualified third party expert who manipulates cost estimates to meet the predetermined objective of justifying the use of dry flue gas desulfurization technology (“Dry FGD” or “scrubbers”) at the OG&E Units. EPA compounds these errors by using the wrong yardstick to measure the resulting visibility improvement.

The result is a Proposed Rule that would require a capital investment of as much as \$1.5 billion to achieve visibility improvements that are essentially imperceptible to the human eye. As a consequence of such an enormous investment, OG&E would be locked into the use of coal for the foreseeable future. EPA’s approach is particularly short-sighted in the context of a proposal that “does not involve decisions intended to mitigate environmental health or safety risks.” (*Id.* at 16,195.) For the foregoing reasons, explained in OG&E’s detailed comments below, EPA should approve the SIP promulgated by Oklahoma, as to do otherwise would be illegal, arbitrary and capricious.

## **II. EPA CANNOT REJECT OKLAHOMA’S BART DETERMINATIONS FOR THE OG&E UNITS**

The Proposed Rule illegally usurps the authority of the State of Oklahoma to determine BART for its sources. EPA cannot reject the BART determinations made by the Oklahoma Department of Environmental Quality (“ODEQ”) with respect to SO<sub>2</sub> emissions at the OG&E Units and issue a Federal Implementation Plan (“FIP”) that substitutes EPA’s BART judgments for those made by the State.<sup>1</sup>

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<sup>1</sup> OG&E agrees with, and is not providing further comment on, EPA’s proposal to approve ODEQ’s BART determinations for particulate matter (“PM”) and nitrogen oxides (“NO<sub>x</sub>”) at OG&E’s Muskogee, Sooner and Seminole Generating Stations and for SO<sub>2</sub> at the Seminole Generating Station (Units 1, 2 and 3). OG&E also is not commenting on the Proposed Rule as it relates solely to electrical generating units owned or operated by the

The CAA expressly grants to the states the primary authority to determine BART by weighing the five statutory criteria set forth in Section 169A of the CAA. 42 U.S.C. § 7491(g)(2). Section 169A provides that “in determining [BART] *the [s]tate* (or the Administrator in determining emission limitations which reflect such technology) shall take into consideration [five BART factors].”<sup>2</sup> (*Id.*) (emphasis added). Section 169A also provides that sources subject to BART “shall procure, install, and operate, as expeditiously as practicable (and maintain thereafter) the [BART], *as determined by the State* (or the Administrator in the case of a plan promulgated under section 7410(c) of this title) . . . .” 42 U.S.C. § 7491(b)(2)(A) (emphasis added).

EPA may disapprove a SIP and issue a FIP under § 7410(c) only where a state’s SIP fails to meet minimum CAA requirements. 42 U.S.C. § 7410(k)(3); *see also Train v. Natural Res. Def. Council*, 421 U.S. 60, 79 (1975). In the case of the “Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations” issued by EPA, 70 Fed. Reg. 39,104 (July 6, 2005) (collectively the “Regional Haze Rule”), the CAA requires only that states engage in the process of weighing the five statutory factors in determining BART for eligible facilities. 42 U.S.C. § 7491(g)(2).

The U.S. Court of Appeals for the D.C. Circuit has affirmed that EPA’s role in determining Regional Haze plans is limited, stating that the CAA “calls for states to play the lead role in designing and implementing regional haze programs.” *Am. Corn Growers Ass’n v. E.P.A.*, 291 F.3d 1, 2 (D.C. Cir. 2002). The Circuit Court reversed a portion of EPA’s original Regional Haze Rule because it found that EPA’s method of analyzing visibility improvements distorted the statutory factors and was “inconsistent with the Act’s provisions giving the *states* broad authority over BART determinations.” *Id.* at 8; *see also Utility Air Regulatory Group v. EPA*, 471 F.3d 1333, 1336 (D.C. Cir. 2006) (The second step in a BART determination “requires *states* to determine the particular technology that an individual source ‘subject to BART’ must install”) (emphasis added).

The Proposed Rule ignores the plain language of the CAA and the Court of Appeals’ recognition of the states’ dominant role in determining BART in an effort to advance EPA’s preference for scrubbers on all EGUs. EPA does not have authority to disapprove a SIP simply because it disagrees with a state’s choice in emission control measures for specific sources. *Florida Power & Light Co. v. Costle*, 650 F.2d 579, 581 (5th Cir. 1981) (“If an [sic] SIP or a revised SIP meets the statutory criteria, however, the EPA must approve it”); *Train*, 421 U.S. at 79 (EPA has “no authority to question the wisdom of a State’s choices of emission limitations if they are part of a plan which satisfies the standards of [the Act] . . . the Agency may devise and

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(continued...)

American Electric Power/Public Service Company of Oklahoma, nor is OG&E providing comment on EPA’s proposal to refrain from taking action on whether Oklahoma has satisfied reasonable progress requirements.

<sup>2</sup> Section 169A of the CAA requires that States determine the appropriate level of BART control by considering five factors: (i) the costs of compliance; (ii) the energy and non-air quality environmental impacts of compliance; (iii) any existing pollution control technology in use at the source; (iv) the remaining useful life of the source; and (v) the degree of improvement in visibility that may reasonably be expected as a result of such technology. The implementing EPA rule is identical. *See* 40 C.F.R. § 51.308(e)(1)(ii).

promulgate a specific plan of its own only if a [s]tate fails to submit an implementation plan which satisfies those standards”).

For example, in *Commonwealth of Vir. v. EPA*, 108 F.3d 1397 (D.C. Cir. 1997), EPA attempted to condition approval of a SIP on the State’s adoption of the California Low Emission Vehicle program. The Court of Appeals rejected EPA’s attempt, stating:

[W]e are aware of no case (EPA has cited none) supporting [the proposition]. . . that under section 110 EPA may condition approval of a [SIP] on the [S]tate’s adopting a particular control measure . . . Despite the volumes of legislative history on the [CAA] and its amendments, EPA has offered no committee reports, no statements on the floor of either house, suggesting that anyone in Congress ever shared its view of section 110.

*Id.* at 1406.

In addition to plain statutory language and the case law interpreting this language, the legislative history behind the CAA amendments regarding regional haze is clear that Congress intended to vest individual states with broad authority to make BART determinations. For example, the following exchange occurred during debate in the U.S. Senate between Senators McClure (R-Idaho) and Muskie (D-Maine) preceding adoption of the Conference Agreement supporting Section 169A of the CAA:

Senator McClure: Under the conference agreement, does the [s]tate retain the sole authority for identification of sources for the purpose of visibility issues under this section?

Senator Muskie: Yes; the [s]tate, not the Administrator, identifies a source that may impair visibility and thereby falls within the requirement of section 128.

Senator McClure: And does this also hold true for determination of “Best Available Retrofit Technology”?

Senator Muskie: Yes; here again it is the [s]tate which determines what constitutes “Best Available Retrofit Technology,” as defined in section 128. . . .

123 Cong. Rec. 13696, 13709 (1977).

Consistent with this legislative intent, EPA itself has explained that “the [s]tate must determine the appropriate level of BART control for each source subject to BART.” 70 Fed. Reg. at 39,107. In the Proposed Rule, EPA acknowledges that, in making BART determinations, “[s]tates are free to determine the weight and significance to be assigned to each factor.” 76 Fed. Reg. at 16,174. EPA has even acquiesced that “[i]n some cases, the [s]tate may determine that a source has already installed sufficiently stringent emission controls for compliance with other programs . . . such that no additional controls would be needed for compliance with the BART requirement.” Regional Haze Regulations, 64 Fed. Reg. 35,714, 35,740 (July 1, 1999).

Thus, the plain language of the CAA, court decisions interpreting that language, and EPA's own Regional Haze Rule all require that states – and not EPA – have the authority to make BART determinations for affected sources within those states. To challenge Oklahoma's BART determination, EPA must show that the State's BART determination *process* was defective. EPA has not, and cannot, show this for the Oklahoma SIP.

As required by the CAA, Oklahoma made BART determinations based on the State's careful consideration of each of the CAA's statutory factors. As ODEQ stated in the SIP:

DEQ conducted a thorough case-by-case five-factor BART analysis for each of the BART-subject units. DEQ determined that Dry-Flue Gas Desulfurization with Spray Dryer Absorber ("Dry FGD with SDA" [or "DFGD"]) is not cost-effective for SO<sub>2</sub> control for any of the six coal-fired steam electric units reviewed. . . . This determination is based on the capital cost of add-on controls, and the long term viability of coal with respect to other environmental programs, and national commitments.

. . .

Revised cost estimates were provided by the affected facilities that are based on vendor quotes and go well beyond the default methodology recommended by EPA guidance. The cost estimates are credible, detailed, and specific for the individual facilities. The final estimate for Dry FGD with SDA for the six coal-fired units was on average 153% greater than the high end costs assumed by DEQ in the Draft SIP. These costs put the projects well above costs reported for other BART determinations, and above the levels DEQ considered reasonable for cost effectiveness both in terms of dollars per ton of pollutant removed and dollars per deciview (e.g., \$10,000,000/dv) of improved visibility.

(Oklahoma SIP at 81.)

EPA has not shown that Oklahoma's BART determinations were the result of a failure to consider the required factors. Instead, the Proposed Rule reflects nothing more than a disagreement with the State's conclusions as to the appropriate level of BART for the OG&E Units. Contrary to the division of authority established by the CAA, EPA proposes to replace the BART determinations made by the State with the different (and materially flawed) opinions of EPA's consultant. EPA's proposal to override the authority of the State on this basis is illegal, arbitrary, and capricious.

### **III. EPA CANNOT SUBSTITUTE AN UNQUALIFIED CONSULTANT'S JUDGMENT FOR THE STATE'S CONSIDERED DETERMINATION**

Instead of affording Oklahoma the discretion given to it under the CAA, EPA wholly disregards the State's reasoned BART determinations in favor of an opinion offered by a paid consultant and professional litigation witness who has no experience designing scrubbers or estimating their costs. EPA hired Phyllis Fox, Ph.D. ("Dr. Fox") to assess "the suitability and costs" of installing scrubbers to control SO<sub>2</sub> emissions at the OG&E Units. 76 Fed. Reg. at

16,182. EPA commissioned Dr. Fox's report entitled, "Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2[,], Muskogee Units 4 & 5[,], Northeastern Units 3 & 4" (the "Fox Report") and incorporates it wholesale into the Proposed Rule as a Technical Support Document ("TSD"). Dr. Fox, however, lacks adequate foundation to evaluate, and is unqualified to opine about, the costs of installing and operating scrubbers at the OG&E Units.

Dr. Fox's conclusions are unreliable because she lacks the knowledge, skill, experience, training, and education to proffer opinions on the projected costs and visibility impact of installing and operating scrubbers at the OG&E Units. She has never designed, installed, or operated a scrubber and has never visited the OG&E Units. While Dr. Fox's *curriculum vitae* reflects her experience as a consultant and witness on various environmental litigation topics, including permitting and condemnation cases, she has little or no experience evaluating the costs of installing and operating pollution control equipment, let alone as retrofit technology at EGUs. Dr. Fox is not qualified, and certainly not more qualified than OG&E or Oklahoma, to properly evaluate the cost effectiveness of scrubbers at the OG&E Units.

The opinions contained in the Fox Report also lack adequate foundation. Dr. Fox concedes throughout her report that she lacks information relied on by ODEQ to reach its conclusions, but nonetheless she offers opinions contrary to those conclusions. For example, she acknowledges that because she did not see the parties' "spreadsheets disclosing their cost calculations," she was unable to perform a complete analysis. (Fox Report at 2.) She also allows that she lacked the information necessary to reproduce the bag and cage replacement costs estimated by Sargent & Lundy LLC ("Sargent & Lundy") on behalf of OG&E.<sup>3</sup> (Fox Report at 30.)

Dr. Fox also appears to lack relevant knowledge about the OG&E Units and the facilities at which these units are located. Dr. Fox did not attempt to meet, or even communicate, with OG&E or Sargent & Lundy about the particular design parameters, engineering specifications or other intricacies associated with the OG&E Units. Indeed, Dr. Fox did not visit either the Muskogee or Sooner Generating Stations. Actually seeing the units that are the subject of her analysis and understanding their place in the overall design of the facilities would certainly be a critical step in designing *retrofit* technology for them. Yet being uninformed does not prevent Dr. Fox from expressing opinions, including opinions based on EPA's Office of Air Quality Planning and Standards Control Cost Manual (the "Control Cost Manual"), which specifically provides for flexibility in developing Dry FGD cost estimates because such control systems are "either so large or so site-specific in design that suppliers design, fabricate and construct each

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<sup>3</sup> Sargent & Lundy, unlike Dr. Fox, is well qualified to perform the cost analysis for the Muskogee and Sooner units. Sargent & Lundy has decades of experience providing comprehensive consulting, engineering, design, and analysis for electric power generation, specifically in the area of retrofit and environmental compliance projects. To develop both the general and site-specific cost estimates that are hereinafter discussed, Sargent & Lundy worked closely with OG&E's engineers in a collaborative effort. As part of this effort, Sargent & Lundy engineers visited the Muskogee and Sooner Generating Stations numerous times so as to understand the specific design and engineering aspects of the affected units and the overall facilities.

control according to the specific needs of the facility.”<sup>4</sup> Nor does Dr. Fox’s lack of information give EPA any pause in adopting her opinions without critical review. Because Dr. Fox is admittedly missing information that is vital to a complete and accurate analysis, her opinions are without sufficient foundation and are therefore unreliable.

For these reasons, EPA’s reliance on the Fox Report is arbitrary, capricious and contrary to applicable law. As shown below, Dr. Fox’s lack of qualifications and foundation are apparent in her analysis of the cost effectiveness of installing and operating scrubbers at the OG&E Units.

#### **IV. SCRUBBERS ARE NOT COST EFFECTIVE**

EPA has to approve the SIP because, as has been repeatedly demonstrated, scrubbers are not cost effective. In May 2008, OG&E submitted BART evaluations, including cost estimates for installing and operating scrubbers at the OG&E Units, which were prepared according to the Control Cost Manual. In November 2008, EPA sent a letter to ODEQ, attached hereto as Exhibit A, in which EPA acknowledged that “OG&E did utilize the ‘EPA Air Pollution Control Cost Manual’ when constructing its [May 2008] cost estimates.”<sup>5</sup> These BART evaluations were updated in September 2009 to reflect the use of annual actual baseline emissions for the 2004-2006 periods, as required by EPA. (The May 2008 estimates together with the September 2009 emissions revisions are referred to herein as the “May 2008 BART Evaluations.”) The updated evaluations did not alter the total annual costs of control contained in the original May 2008 evaluations.

Using the proper emissions baseline, the May 2008 BART Evaluations showed average cost effectiveness for Dry FGD to be \$9,923 per ton of SO<sub>2</sub> removed at Muskogee and \$10,234 per ton of SO<sub>2</sub> removed at Sooner.<sup>6</sup> Nonetheless, after the September 2009 update, EPA and ODEQ asked for vendor quotations and other site-specific information to supplement and address questions regarding the outcome of the prior Control Cost Manual analysis.<sup>7</sup> OG&E obliged and submitted site-specific cost estimates in December 2009 (the “December 2009

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<sup>4</sup> U.S. EPA, EPA Air Pollution Control Cost Manual, Report EPA/452/B-02-001, 6th Ed., January 2002 at 2-27.

<sup>5</sup> ODEQ also has acknowledged that OG&E’s cost estimates comported with the Control Cost Manual. According to ODEQ, “OG&E evaluated the economic, environmental, and energy impacts associated with the two proposed control options. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Control Cost Manual.” (Oklahoma SIP, Appendix 6-4, OG&E Muskogee at 7; OG&E Sooner at 7.)

<sup>6</sup> Thus, the May 2008 BART Evaluations showed the costs of Dry FGD for Muskogee and Sooner would be more than ten times the average cost expected by EPA for this technology and nearly five times as much as the upper limit of EPA’s expected cost range. *See* 70 Fed. Reg. at 39,132 (estimating an average cost of \$919 per ton and a cost range of \$400 to \$2,000 per ton of SO<sub>2</sub> removed). The annual cost of Dry FGD at Muskogee was estimated to be \$136,922,500 for both units and the annual cost at Sooner was estimated to be \$142,063,600 for both units. (May 2008 Bart Evaluations.)

<sup>7</sup> ODEQ also acknowledged this point in its proposed SIP, stating: “[i]n response to the ODEQ draft evaluation and EPA and FLM comments, OG&E submitted revised cost estimates during the public meeting held for the Oklahoma draft SIP.” (Oklahoma SIP, Appendix 6-4, OG&E Muskogee at 14.)

Budget Cost Estimates”).<sup>8</sup> Although OG&E used the cost categories prescribed by the Control Cost Manual to develop the December 2009 Budget Cost Estimates, their site-specific nature meant that they could not achieve the Control Cost Manual’s primary objective of national comparability for costs of control equipment at one facility to costs of similar equipment at another facility. As OG&E stated in its comments to the proposed Oklahoma SIP:

To address comments from ODEQ and EPA, OG&E obtained the site-specific Budget Cost Estimates in December 2009. . . . Those estimates depart significantly from the methods in EPA's Control Cost Manual for determining costs associated with projected operations at the four coal-fired units at Sooner and Muskogee Generating Stations. While OG&E believes that ODEQ and EPA lacked any basis to require OG&E to depart from the published methodology for calculating costs, the site-specific Budget Cost Estimates nonetheless confirm that Dry FGD is not a cost effective option for OG&E's units.

(OG&E Comments at 25.)

Thus, the record shows that ODEQ had before it both the cost estimates that even EPA acknowledged followed the Control Cost Manual guidelines (i.e., the May 2008 BART Evaluations) and the more site-specific cost estimates that reflect actual vendor quotes and greater detail than required by the Control Cost Manual (i.e., the December 2009 Budget Cost Estimates). The record fully supports the fact that ODEQ faithfully executed the responsibility assigned to it by the CAA to balance the statutory factors, including the cost of controls. As a result, EPA’s proposed rejection of ODEQ’s analysis in favor of the Fox Report is arbitrary and capricious.

#### **A. EPA Adopted Legally Improper Approaches In Its Consideration of the SIP**

Rather than acknowledging that ODEQ complied with the requirements of the CAA and deferring to the State’s BART determination as the CAA requires, EPA commissioned the Fox Report to justify EPA’s desire to have scrubbers installed on the OG&E Units.<sup>9</sup> And to mask the fact that it lacks any meritorious grounds to disapprove ODEQ’s BART determination, EPA improperly combines the proposed disapproval of the SIP with its own BART determination in

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<sup>8</sup> On or about January 28, 2010, OG&E provided EPA with copies of vendor proposals and pricing quotes that were obtained in connection with the December 2009 Budget Cost Estimates as Confidential Business Information pursuant to 40 C.F.R. Part 2.203 *et. seq.* Subject to OG&E’s continuing claim of confidentiality, these documents should be included in the Administrative Record for the Proposed Rule.

<sup>9</sup> The Fox Report was not available to ODEQ when it issued the SIP. During the state rulemaking process, EPA had the same opportunity to comment on the proposed SIP as did other interested parties. Yet, EPA made the Fox Report available to ODEQ and the public for the first time when EPA issued the Proposed Rule. While ODEQ was developing the SIP, EPA made only general assertions regarding its beliefs that the May 2008 BART Evaluations may have overstated certain costs (despite having acknowledged that they were prepared in accordance with the Control Cost Manual) and, consequently, requested more site-specific estimates. ODEQ subsequently concluded that OG&E's December 2009 Budget Cost Estimates addressed EPA's concerns and finalized the SIP on that basis. *See* ODEQ Summary of Comments and Staff Responses for Proposed Revision to the Oklahoma Regional Haze SIP (Response No. 14).

the proposed FIP as if the fact that EPA would reach a different BART determination is itself sufficient grounds to disapprove the SIP.<sup>10</sup> As discussed above, EPA's approach turns the CAA on its head and ignores its plain language.

The Proposed Rule compounds EPA's legally improper approach by relying on the Fox Report's erroneous determination that scrubbers are cost effective. Indeed, that premise is central to EPA's purported basis for proposing to reject the SIP and issue the FIP. In the Fox Report, which was adopted with no apparent critical review by EPA, Dr. Fox sets forth two options for installing scrubbers at OG&E's affected units, which she calls "Option 1" and "Option 2," and estimates cost effectiveness for both. For Option 1, Dr. Fox estimates costs for a large-sized scrubber that is consistent with the size assumed by Sargent & Lundy in its cost estimates. (Fox Report at 5.) Dr. Fox, however, arbitrarily assumes use of a different coal than currently used at the OG&E Units to support her opinion that this size scrubber can remove a much higher level of SO<sub>2</sub> than has historically been emitted by the OG&E Units and, therefore, in her view, would be cost effective.

For Option 2, Dr. Fox estimates costs for a small-sized scrubber that was not considered appropriate by Sargent & Lundy in any of its cost estimates. (*Id.* at 6.) She then uses the lower SO<sub>2</sub> removal rates reflected in Sargent & Lundy's evaluation and based on the actual historical emissions at the OG&E Units. The smaller scrubber is not technically feasible and should not be used to calculate cost effectiveness. In addition, Dr. Fox erroneously adjusts OG&E's cost estimates downward on the basis that those estimates "did not follow the Air Pollution Control Cost Manual when possible, as specified in the BART guidelines." 76 Fed. Reg. 16,183. The OG&E cost estimates that EPA uses as the basis for these adjustments, however, are the site-specific December 2009 Budget Cost Estimates prepared by Sargent & Lundy at the request of EPA and not the May 2008 BART Evaluations that both EPA and ODEQ recognized had followed the Control Cost Manual.

Dr. Fox's analyses for both Option 1 and Option 2, and her "adjustments" to OG&E's cost estimates (each as reflected in EPA's Tables 4, 5 and 6), are materially flawed. With respect to the "large" scrubber (Option 1), Dr. Fox grossly overestimates the amount of SO<sub>2</sub> that could be removed from such a system by using a calculation methodology that is not only factually incorrect, but not allowed by EPA. With respect to the "small" scrubber (Option 2), Dr. Fox's cost estimates are invalid because the scrubber design she uses is too small to work on OG&E's units without effectively derating them (i.e., making them incapable of generating the power they were built to produce). Likewise, Dr. Fox has no basis for arbitrarily adjusting the site-specific December 2009 Budget Cost Estimates on the grounds that they fail to comport with the Control Cost Manual.

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<sup>10</sup> EPA's promulgation of the proposed FIP before its disapproval of the SIP becomes final is contrary to the plain language of 42 U.S.C. § 7410(c), which provides that the Administrator shall promulgate a FIP "after the Administrator ... finds that the plan or plan submitted by the State does not satisfy the minimum criteria established [by the CAA]..." (emphasis added). EPA's approach here demonstrates the significance of keeping the promulgation of EPA's desired FIP separate from its attempt to justify its action with regard to a SIP.

The Regional Haze Rule is clear about the method that must be used to calculate the cost effectiveness of a particular control technology. First, the total annual cost of control for a technically feasible control device must be developed according to the Control Cost Manual to “maintain and improve consistency” in the review process.<sup>11</sup> Second, the amount of a pollutant that the device will control on an annual basis must be determined using past actual emissions from the source and projections of emissions following installation of the device. The purpose of using past actual emissions as the baseline is to give a realistic depiction of the amount of a pollutant that a device will actually control. 70 Fed. Reg. at 39,167. In fact, EPA has revised cost effectiveness calculations in other BART determinations to ensure that emission reductions are calculated this way. *See, e.g.*, 74 Fed. Reg. 44,313, 44,321 (Aug. 28, 2009). The use of a consistent calculation methodology helps achieve the national uniformity that EPA requires in the regional haze context.

As shown in Table IV.1 below, only one of the cost estimates available to EPA for the OG&E Units– the May 2008 BART Evaluations – follows the Control Cost Manual and otherwise meets the standards established by the Regional Haze Rule:<sup>12</sup>

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<sup>11</sup> 40 C.F.R. Pt. 51, App. Y(IV)(D)(4)(a)(5); *see also* 70 Fed. Reg. at 39,166 (“In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual.”).

<sup>12</sup> While OG&E maintains that the December 2009 Budget Cost Estimates also comply with the Control Cost Manual, those estimates provide a much higher level of detail than is required by the Control Cost Manual. Where necessary, the December 2009 Budget Cost Estimates depart from the straightforward application of the Control Cost Manual’s factors to achieve the level of detail and specificity requested by EPA during development of the SIP.

**Table IV.1: Cost Estimates Performed for the OG&E Units:<sup>13</sup>**

	<b>May 2008 BART Evaluations</b>	<b>December 2009 Budget Cost Estimates</b>	<b>EPA Table 4/ Fox App. 1</b>	<b>EPA Table 5/ Fox Option 2</b>	<b>EPA Table 6</b>	<b>Fox Report Option 1</b>
<b>Technically Feasible Control</b>	Yes	Yes	Yes	No	No	Yes
<b>Control Cost Manual</b>	Yes	Site-specific	Modified Site- specific	No	No	Site- specific
<b>Actual Emission Baseline</b>	Yes	Yes	No	Yes	Yes	No
<b>Muskogee Cost Effectiveness<sup>14</sup> (\$/ton)</b>	\$9,923	\$7,435	\$1,317	\$5,102	\$2,366	\$2,208
<b>Sooner Cost Effectiveness<sup>14</sup> (\$/ton)</b>	\$10,234	\$6,748	\$1,291	\$4,594	\$2,048	\$2,157

Using the proper estimates contained in the May 2008 BART Evaluations, scrubbers at the OG&E Units are expected to cost approximately \$10,000 per ton of SO<sub>2</sub> removed. The Regional Haze Rule, in contrast, estimates an average cost of \$919 per ton and a cost range of \$400 to \$2,000 per ton of SO<sub>2</sub> removed. 70 Fed. Reg. at 39,132-39,133. Thus, the cost of scrubbers at the OG&E Units, at more than ten times the cost estimated by EPA in the Regional Haze Rule for this technology, demonstrates that scrubbers are not cost effective for controlling SO<sub>2</sub> at the OG&E Units.

**B. Cost Estimates Cannot Be Based On Technically Infeasible Controls**

The cost estimates developed for “Option 2” in the Fox Report and incorporated into Tables 5 and 6 of the Proposed Rule are invalid because they are based on a technically infeasible control option. EPA’s guidelines, which were issued to help states “identify those sources that must comply with the BART requirement and . . . determine the level of control

<sup>13</sup> The column headings in Table IV.1 identify the source of a particular cost effectiveness estimate. The May 2008 BART Evaluations and the December 2009 Budget Cost Estimates were reviewed by ODEQ in the development of the SIP. References to EPA Tables are to the tables presented in the Proposed Rule and the corresponding option presented in the Fox Report, where applicable. EPA Table 4 and Fox Report Option 1 estimated cost effectiveness for a scrubber sized to handle maximum actual SO<sub>2</sub> loadings using a projected emissions baseline. EPA Table 5 and EPA Table 6 estimated cost effectiveness for a scrubber sized to handle average SO<sub>2</sub> loadings using an actual emissions baseline.

<sup>14</sup> The May 2008 BART Evaluations and the December 2009 Budget Cost Estimates developed cost effectiveness estimates for each unit. The number presented here is the average of the cost effectiveness estimate for each unit at the appropriate station.

technology that represents BART for each source,” sets out five basic steps to complete a BART analysis: (1) identify all available retrofit control technologies; (2) eliminate technically infeasible options; (3) evaluate control effectiveness of remaining control technologies; (4) evaluate impacts and document the results; and (5) evaluate visibility impacts. 40 C.F.R. Pt. 51, App. Y(II)(A); 69 Fed. Reg. 25,184, 25,186 (May 5, 2004).

Option 2 of the Fox Report (as incorporated into Tables 5 and 6 of the Proposed Rule) runs afoul of the second step of these guidelines. The cost estimates in Option 2 are based on the observation contained in the Fox Report that the December 2009 Budget Cost Estimates “assumed that the Sooner and Muskogee plants burned coal with a higher sulfur content [1.172 lb/MMBtu uncontrolled SO<sub>2</sub> emissions] than they are currently burning [0.51 lb/MMBtu uncontrolled SO<sub>2</sub> emissions].” (Fox Report at 6.) To address this perceived “mismatch,” Dr. Fox establishes Option 2 whereby she reduces the size of the scrubber, and its capital costs, by approximately 50%. Unlike the December 2009 Budget Cost Estimates, however, the scrubber that Dr. Fox sizes does not account for the SO<sub>2</sub> content of the coal that OG&E actually uses at the OG&E Units. Moreover, this small-sized scrubber would result in a grossly undersized and ineffective control system that would not be able to handle the OG&E Units’ flue gas flow rates if the units were fired at full load.

First, the Option 2 scrubber could not handle half of the coal that OG&E actually uses at its four affected units. As explained in Section 4.1.1 of the BART Costing Analysis Report prepared by Sargent & Lundy in May 2011 and attached hereto as Exhibit B (the “BART Costing Analysis”), the size and design of Dry FGD is generally divided into two major systems: (1) the reactant handling system (including lime receiving, lime slurry preparation and ash handling components); and (2) the flue gas path (including the scrubbing vessel, filter, fans and duct work). The Fox Report bases its scrubber costs for Option 2 on a scrubber design for which the reactant system would be able to handle only the average fuel sulfur content of the coal that OG&E burns at the OG&E Units. Sargent & Lundy, on the other hand, estimated *capital* costs for a scrubber that was designed to be capable of controlling the highest sulfur coal that could be delivered to OG&E but estimated *operating* costs using the coal’s average sulfur content.

The appropriateness of the Sargent & Lundy design is demonstrated by Tables IV.2 and IV.3 below, which show that the sulfur content of coal actually delivered to the OG&E Units during the previous five years varied such that designing a scrubber for only the average sulfur content would result in the lime supply being inadequate when coal with higher than average sulfur content is delivered and burned:

**Table IV.2: Sulfur Content of Coal Delivered to Muskogee Units (% Sulfur)**

	<b>Min.</b>	<b>Max.</b>	<b>Avg.</b>
<b>2006</b>	0.18	0.41	0.26
<b>2007</b>	0.17	0.48	0.26
<b>2008</b>	0.16	0.42	0.24
<b>2009</b>	0.17	0.43	0.27
<b>2010</b>	0.17	0.47	0.26

**Table IV.3: Sulfur Content of Coal Delivered to Sooner Units (% Sulfur)**

	<b>Min.</b>	<b>Max.</b>	<b>Avg.</b>
<b>2006</b>	0.16	0.39	0.25
<b>2007</b>	0.15	0.49	0.25
<b>2008</b>	0.16	0.43	0.25
<b>2009</b>	0.17	0.59	0.26
<b>2010</b>	0.17	0.39	0.26

Thus, for example, in 2009 at Muskogee, the scrubber costed by Dr. Fox in Option 2 would be designed to handle coal with a 0.27% sulfur content, but half the time, Muskogee would be burning coal with sulfur content ranging from 0.27% to 0.43%. A functional system must be designed to handle the maximum sulfur content.

Second, Option 2 is flawed because a scrubber that is half the size of the one designed by Sargent & Lundy could not handle the air flow from the OG&E Units if they were fired at full load. Sargent & Lundy estimated costs for a scrubber that was designed to handle the quantity of flue gas that would be generated at full load heat input to each of the OG&E Units. The Fox Report, on the other hand, presumed to reduce (*by one half*) the size of the entire scrubbing vessel based solely on the assumed sulfur content of coal. (Fox Report at 6.) This approach is wrong as a matter of basic process engineering. This is because flue gas flow, although a function of the fuel being burned (such as heating value, carbon content and moisture), is not affected by the sulfur content of the fuel. EPA recognizes this relationship in its monitoring rules, 40 C.F.R. Part 75, App. F, ¶3.3.5, but in its blind adoption of the Fox Report, fails to acknowledge this fundamental flaw in Dr. Fox's approach.

As further detailed in Section 4.1.1 of the BART Costing Analysis, a half-size scrubber can handle only half of the flue gas flow of a full size scrubber. To achieve the appropriate flue gas flow rate on the half-sized scrubber in Option 2, OG&E would be limited to burning half the amount of coal that the OG&E Units are capable of burning and, consequently, generating half the amount of electricity. The enormous costs that would be associated with this effective derating of the OG&E Units are not reflected in the Proposed Rule and are not required by the CAA.

Consequently, Option 2 and the cost estimates presented in Tables 5 and 6 of the Proposed Rule must be discarded because they are based on a technically infeasible control option. The fact that Option 2 suggests the use of a half-sized scrubber that would effectively

derate OG&E Units shows the fundamental scientific weakness of the entire Fox/EPA analysis and renders that analysis, and the Proposed Rule, arbitrary, capricious and contrary to applicable law.

**C. Cost Effectiveness Determinations Must Use Total Annual Costs Of Control Constructed According To The Control Cost Manual**

A critical element in any regional haze cost effectiveness evaluation is determining the total annual costs of a control using a capital recovery factor and annual operating costs. EPA has maintained that the Control Cost Manual must be used to determine these costs for all BART evaluations to ensure nationwide consistency. 40 C.F.R. Pt. 51, App. Y(IV)(D); 70 Fed. Reg. at 39,166. EPA, however, failed to consider the only cost estimates that complied with the Control Cost Manual (i.e., the May 2008 BART Evaluations) and ignored its own rules in adjusting other cost estimates.

*1. EPA Ignored the Only Cost Estimate Constructed in Accordance with the Control Cost Manual*

As described above, when OG&E prepared and submitted the May 2008 BART Evaluations, it did so in conformity with the Control Cost Manual. EPA said so. ODEQ said so. Yet, in her analysis, EPA's consultant considers only the December 2009 Budget Cost Estimates. She repeatedly criticizes Sargent & Lundy (and OG&E) for not strictly applying the "generic" cost factors set forth in the Control Cost Manual and then adjusts selected portions of the December 2009 Budget Cost Estimates downward on that basis.<sup>15</sup> (Fox Report at 9.) For example, Dr. Fox discounts the December 2009 Budget Cost Estimates by adjusting the 8.23% interest rate used by Sargent & Lundy to a 7% default interest rate used in the Control Cost Manual. Although Sargent & Lundy had used the 7% default rate in the May 2008 BART Evaluations it was, as explained in Section 4.2.6.1 of the BART Costing Analysis, adjusted for site-specific accuracy in the December 2009 Budget Cost Estimates. (Fox Report at 15.) Dr. Fox also unreasonably complains that the December 2009 Budget Cost Estimates prohibit the national comparability amongst BART determinations that is demanded by EPA, stating:

To compare costs among units, a level playing field must be established by following the same cost rules in each determination. The [December 2009] cost estimating method deviates from the standard procedure used to establish the range of acceptable cost effectiveness values. In other words, the [December 2009] cost effectiveness analyses compare apples and oranges.

(Fox Report at 10.)

EPA relies on Dr. Fox's adjustments to develop the cost effectiveness estimate used in Table 4 of the Proposed Rule without offering any explanation for why it completely ignored the

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<sup>15</sup> As described above, the December 2009 Budget Cost Estimates were prepared at EPA's and ODEQ's request to supplement the May 2008 BART Evaluations and to provide more detail than required by the Control Cost Manual.

May 2008 BART Evaluations, which EPA admits were done according to the Control Cost Manual. 76 Fed. Reg. at 16,183; (Ex. B.) EPA’s actions in this regard are disingenuous. EPA cannot acknowledge receipt of cost estimates that are in compliance with the Control Cost Manual, ask for a site-specific cost estimate that deviates from the Control Cost Manual, and then reject that site-specific estimate for not conforming to the Control Cost Manual.

Dr. Fox’s entire analysis with respect to the December 2009 Budget Cost Estimates is without merit on this basis alone. And EPA’s reliance on the Fox Report’s conclusions in Table 4 of the Proposed Rule is, for these reasons, arbitrary, capricious and contrary to applicable law.

2. The Line-Item “Adjustments” to the December 2009 Budget Cost Estimates Are Erroneous

The Proposed Rule falls short in yet another respect. Even if EPA could properly use the December 2009 Budget Cost Estimates as the basis for its consultant’s cost analysis (which OG&E denies), the arbitrary line-item “adjustments” that Dr. Fox makes to those Budget Cost Estimates fail in at least two significant ways. First, Dr. Fox is inconsistent in her cost adjustments and unjustifiably manipulates them to her advantage. Second, the adjustments themselves are erroneous. The cumulative effect of Dr. Fox’s adjustments, when compared to the December 2009 Budget Cost Estimates, is illustrated in the following table:

**Table IV.4: December 2009 Budget Cost Estimates v. EPA Revisions for SO<sub>2</sub> Control**

	Sooner		Muskogee	
	Dec. 2009 Budget Cost Estimates	Cost Estimates for Proposed Rule Table 4	Dec. 2009 Budget Cost Estimates	Cost Estimates for Proposed Rule Table 4
Capital Costs	\$584,589,800	\$298,530,748	\$634,387,200	\$307,153,696
Capital Recovery	\$60,563,600	\$24,057,519	\$65,722,600	\$24,752,412
Annual O&M	\$33,101,000	\$31,992,212	\$36,877,800	\$36,449,343
Total Annual Costs	\$93,664,600	\$56,049,731	\$102,600,400	\$61,201,755
SO <sub>2</sub> Emission Reductions	13,930	43,428	13,799	46,458
Cost Effectiveness \$/ton	\$6,724	\$1,291	\$7,435	\$1,317
(\$/dV)*	\$38,387,131	Not Provided	\$24,330,187	Not Provided

\* \$/dV = cumulative reduction of all Class I Areas (December 28, 2009, page 15)

The extent of EPA’s error in relying on these adjustments is fully described in the attached BART Costing Analysis. (Ex. B.) However, the examples highlighted in this Section are illustrative of the problems with the analyses set forth in the Fox Report.

First, rather than strictly apply the Control Cost Manual, Dr. Fox “adjusts” the December 2009 Budget Cost Estimates down to reflect either “actual” costs or Control Cost Manual assumed costs, whichever best supports her position. For example, Dr. Fox uses Sargent & Lundy’s low site-specific factors for property taxes, insurance, and administrative charges when the Control Cost Manual calls for higher factors. (Fox Report at 32.) And yet, when it works to her advantage, Dr. Fox adjusts other actual costs downward to be consistent with her view of the Control Cost Manual’s default factors. (*Id.* at 30.) Dr. Fox’s selective manipulation of the data

in this manner is not allowed by the Control Cost Manual, represents a significant departure from generally accepted principles of cost engineering, and is arbitrary and capricious.

Second, Dr. Fox's adjustments to OG&E's line-item costs are themselves erroneous. For example, Dr. Fox arbitrarily includes a 5% "discount" in her cost calculation based on an unsupported (and undocumented) assumption that vendors would reduce costs because scrubbers would be installed on multiple units. (Fox Report at 23.) Dr. Fox also incorporates an additional 5% reduction in "equipment, material, and labor costs" into her cost-effectiveness analysis, which she rationalizes could be achieved by combining process units. (*Id.*) These "reductions," however, are not provided for in the Control Cost Manual and are not supported by the level of engineering conducted for the OG&E Units to date. Dr. Fox even admits that she cannot "precisely estimate the reduction in cost from taking into account" these factors. (*Id.*)

Dr. Fox's "adjustments" on this point delete up to ten percent of the total costs estimated in the December 2009 Budget Cost Estimates based purely on Dr. Fox's subjective and unsupported belief that such discounts can be obtained. As pointed out previously, the December 2009 Budget Cost Estimates were based on vendor quotations. To obtain those quotations, Sargent & Lundy conducted preliminary engineering and provided vendors with plant design sheets and other specific information. The vendors who submitted quotations knew that they were being asked to provide quotations for multiple scrubbers and it is reasonable to conclude that they worked any potential discounts into the site-specific estimates. Furthermore, Dr. Fox has not provided any information to suggest that she conducted the detailed engineering analysis that would be necessary to accurately determine whether process units could be combined, let alone whether they could be combined at a lower cost. It is apparent that her 10% reduction is based on nothing more than her guess work and desire to lower the total overall cost.

The conclusions in the Fox Report with respect to interest rates and the useful life of scrubbers similarly exemplify the depth of error in EPA's cost analysis. Dr. Fox argues that the Control Cost Manual requires that annualized capital recovery cost be calculated by multiplying the total capital investment by a capital recovery factor calculated from a formula based on a 7% social interest rate and over a 30-year lifetime. (Fox Report at 14.) The Control Cost Manual states that this social interest rate may be used when "State, local, Tribal, and other governmental authorities assess pollution control costs;" however, "the social rate of interest is probably not appropriate for industry." Control Cost Manual, § 2.4.2. Because OG&E is a taxed investor-owned utility that recovers its capital investment costs through electric rates and not a governmental agency, the 7% interest rate is entirely inappropriate for a site-specific estimate.<sup>16</sup>

Dr. Fox also does not (and cannot) justify the 30-year useful life metric that she uses in her cost effectiveness calculations when the Control Cost Manual uses a 20-year useful life for other pollution control equipment and does not specify otherwise for Dry FGD. As discussed in

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<sup>16</sup> The use of the 7% social rate of interest may be appropriate for a generic Control Cost Manual estimate as demonstrated by Sargent & Lundy's use of it in the May 2008 BART Evaluations. When preparing a site-specific estimate, it is appropriate to use the cost of capital that is specific to the site owner, which in this case is not a governmental agency.

Section 4.2.6.1 of the BART Costing Analysis, nearly all other BART determinations for scrubbers have assumed a 20 year useful life in cost effectiveness calculations.

The Fox Report's unjustified conclusions about the possible availability of more cost effective options for designing and integrating the scrubbers into the Muskogee and Sooner facilities provide yet another example of the analytical flaws contained in the Fox Report. In her report, Dr. Fox suggests that cost savings could be achieved by including the use of existing electrostatic precipitators ("ESPs") (rather than new baghouses) for PM control and using a single pass scrubber design (rather than a recycle system). As detailed in Section 4.1.3 of the BART Costing Analysis, however, the additional PM from a Dry FGD would increase particulate loading to the existing ESPs by more than 300% and would lead to less effective SO<sub>2</sub> control and significant (and costly) balance-of-plant impacts.

Any capital cost savings that could be associated with a single-pass system would be more than offset by increased reactant and by-product disposal costs. Perhaps this is why 74 of the 75 dry scrubbers installed through 2010 (as reported by EPA) have been designed as recycling systems with a fabric filter baghouse. Dr. Fox admittedly lacks adequate foundation for making her assumption regarding this design parameter, yet she makes it anyway. (Fox Report at 24-25.)

Similar inaccuracies are apparent throughout the Fox Report as detailed in the attached BART Costing Analysis, including with respect to indirect capital costs, total annual costs, and operating and maintenance costs. For these and the additional reasons described in the BART Costing Analysis, Dr. Fox's unjustified discounts and line-item adjustments (and EPA's reliance on them in the Proposed Rule) are arbitrary, capricious and contrary to applicable law.

#### **D. Past Actual Emissions Must Be Used To Calculate Cost Effectiveness**

The cost effectiveness calculations used to derive the figures in Table 4 of the Proposed Rule impermissibly use projected, rather than actual, baseline emissions. As further detailed in Section 4.1.4 of the BART Costing Analysis, this faulty methodology, which EPA has expressly stated is not allowed, artificially increases the calculated quantity of SO<sub>2</sub> removed by scrubbers by nearly 300%.<sup>17</sup> The significance of using proper baseline emissions is illustrated by the following Table IV.5, which, for purposes of illustration only, uses the inaccurate and understated costs set forth in Appendix 1 of the Fox Report and reflected in Table 4 of the Proposed Rule:

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<sup>17</sup> Dr. Fox's suggestion that her calculation method is needed to address a mismatch between scrubber size and SO<sub>2</sub> emission reductions is technically erroneous and legally irrelevant. It is technically erroneous as discussed above and in Section 4.1.4 of the BART Costing Analysis because the December 2009 Budget Cost Estimates were based on a scrubber sized (and costed) to handle the full load flue gas flow rates while operating costs and annual SO<sub>2</sub> emission reductions were calculated using the baseline actual SO<sub>2</sub> loading to the scrubber. All of these values are consistent and appropriate for evaluating the cost effectiveness of the retrofit Dry FGD control system. Even if there were some sort of technical mismatch between the size of the scrubber and the unit being controlled, it is legally irrelevant to the determination of projected emission reductions because the Regional Haze Rule unequivocally requires the use of past actual emissions to establish projected emission reductions.

**Table IV.5: Impact of Baseline Emissions Calculation Method on Cost Effectiveness**

	Sooner		Muskogee	
	Using Actual Baseline Emissions	Using Projected Baseline Emissions	Using Actual Baseline Emissions	Using Projected Baseline Emissions
Total Annual Costs as reflected in EPA Table 4	\$56,049,731	\$56,049,731	\$61,201,755	\$61,201,755
SO <sub>2</sub> Emission Reductions	13,930	43,428	13,799	46,458
Cost Effectiveness \$/ton	\$4,024	\$1,291	\$4,435	\$1,317

EPA has been clear that baseline emissions for purposes of cost effectiveness calculations are to be based on actual—not potential or projected—emissions. The Regional Haze Rule states that baseline emissions should “represent a realistic depiction of anticipated annual emissions for the source.” 70 Fed. Reg. at 39,167. In reviewing the cost effectiveness analyses for the Salt River Project (“SRP”) Navajo Generating Station in Arizona, EPA found that SRP’s use of “the same 24-hour average actual emission rate from the highest emitting day used for its modeling inputs” was incorrect. 74 Fed. Reg. at 44,321. EPA revised SRP’s calculations “by starting with baseline emission rates for NO<sub>x</sub> averaged over 2004–2006 . . . .” *Id.*

Instead of using past actual emissions for the baseline to determine the amount of SO<sub>2</sub> that scrubbers would control at the OG&E Units, EPA and Dr. Fox use projected emissions in direct contravention of the Regional Haze Rule. Dr. Fox estimates the "potential SO<sub>2</sub> emissions reductions" from the larger Option 1 scrubber using assumptions about projected capacity factors and SO<sub>2</sub> concentrations at the scrubber inlet. (Fox Report at 6, n. 14.) With these assumptions, Dr. Fox arrives at an estimate of the "design basis reduction" for dry scrubbing of 43,428 tons per year at Sooner and 46,458 tons per year at Muskogee.<sup>18</sup>

The error in Dr. Fox's approach, as adopted by EPA, is obvious when these projected rates are compared to actual emissions. The average actual SO<sub>2</sub> emissions during the 2004-2006 period used by EPA in other BART determinations were 17,964 tons per year at Sooner and

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<sup>18</sup> The calculation of “design basis reduction” is derived from an uncontrolled SO<sub>2</sub> emissions rate of 6,440 lb/hr at the inlet of each hypothetical Muskogee scrubber. For Sooner, Dr. Fox assumes 6,020 lb/hr SO<sub>2</sub> at the scrubber inlet. These numbers are supposedly taken from OG&E’s December 2009 Budget Cost Estimates, which included mass balance diagrams as Attachment 1 to the Dry FGD Design and Cost Estimate Basis Document. The specific pages referenced by Dr. Fox in her report, however, show process flow diagrams, process parameters, and stream characteristics for Sooner and Muskogee. (Fox Report at 6, n. 14.) The diagrams show maximum inlet sulfur levels of 1.176 lb/mmBtu. Even if Dr. Fox were correct in ignoring baseline actual emissions, the particular average sulfur content that is used in these calculations also is contrary to the BART Guidelines which specify that “you calculate baseline emissions based upon continuation of past practice” for parameters like fuel type unless there is a clear reason for diverging from past practice. 70 Fed. Reg. at 39,167. In this case, past practice indicates that OG&E actually burns fuel with an average sulfur content of 0.509lb/mmBtu SO<sub>2</sub> at Muskogee and 0.507 lb/mmBtu SO<sub>2</sub> at Sooner. *See* (Sargent & Lundy Dry FGD Design and Cost Estimate Basis Document at 79). Dr. Fox based her calculations on the use of coal with significantly higher average sulfur content without justification.

18,119 tons per year at Muskogee. *See* (December 2009 Budget Cost Estimates at 13-14, Tables 5 and 6.) These past actual emission rates show that the EPA analysis is untethered to reality and to EPA's own requirements for determining cost effectiveness. Over half of the amount of SO<sub>2</sub> that EPA estimates would be controlled by scrubbers is not actually emitted from the OG&E Units as they are currently operated. The use of a projected "design basis reduction" artificially inflates the amount of SO<sub>2</sub> supposedly available for removal by scrubbers.

As demonstrated by Table IV.5 above, the cost effectiveness values calculated at the proper emissions baseline, even assuming EPA's deflated costs, are \$4,020 per ton of SO<sub>2</sub> removed at Sooner and \$4,435 per ton of SO<sub>2</sub> removed at Muskogee. These amounts far exceed the average cost expected by EPA for this technology and underscore the fact that if the proper actual emission baseline is used, scrubbers are not cost effective. *See* 70 Fed. Reg. at 39,133 (estimating an average cost of \$919 per ton and a cost range of \$400 to \$2,000 per ton of SO<sub>2</sub> removed).

The cost effectiveness determination becomes even clearer when cost estimates constructed according to the Control Cost Manual are used instead of the costs developed for EPA by Dr. Fox. EPA's use of the wrong methodology to calculate the cost effectiveness values set forth in Table 4 of the Proposed Rule is arbitrary, capricious and contrary to applicable law.

## **V. EPA'S ANALYSIS OF BART VISIBILITY IMPACTS FOR THE OG&E UNITS IS FLAWED**

In the Proposed Rule, EPA proposes to disapprove Oklahoma's SO<sub>2</sub> BART determinations and require dry scrubbers based both on: (1) EPA's own calculation that scrubbers are cost effective in \$/ton and (2) EPA's view that a significant visibility improvement would result from the use of dry scrubbers at OG&E's Sooner and Muskogee units and AEP's Northeastern unit. *See* 76 Fed. Reg. at 16,186. Like EPA's cost calculations, EPA's visibility assessment is arbitrary, capricious and inconsistent with the CAA and the Regional Haze Rule.

EPA offers the following discussion of the visibility improvement associated with scrubbers in Section V.E.3 of the Proposed Rule ("Our Conclusion on Oklahoma's SO<sub>2</sub> BART Evaluations for the Six OG&E and AEP/PSO Units"):

[O]ur modeling indicates that dry scrubbing will result in a 2.89 deciview improvement in visibility at the Wichita Mountains. Furthermore, the addition of scrubbers (wet or dry) on each of the three facilities (2 units at each facility) will reduce visibility impairment at Class I areas (Wichita Mountains and/or other surrounding Class I areas) from values that are above the 1 deciview impact that is a direct causation of visibility impairment to levels that are below the 0.5 deciview threshold that ODEQ used for determining if a source contributed to visibility impairment. We consider the reduction in visibility impairment at Wichita Mountains, Caney Creek, Upper Buffalo, and Hercules-Glades to be significant both for the RH SIP and also for reduction of visibility impairment on other states in meeting the requirements of the 110(a)(2)(D) SIP . . . .

76 Fed. Reg. at 16,186.

EPA's conclusions regarding visibility improvement in the Proposed Rule are materially flawed in several respects. First, the CAA does not allow EPA to overturn a state's BART determination based on a projection of the combined visibility improvement resulting from the use of a control technology at three separate facilities (i.e., 2.89  $\Delta$ -dv improvement from scrubbers at Sooner, Muskogee and Northeastern combined). Rather, visibility improvement must be assessed on a facility-by-facility basis. Second, Oklahoma has discretion to decide what weight to assign the visibility improvement projected for a control technology at an individual facility in the overall BART analysis. Third, EPA cannot ignore Oklahoma's reasonable analysis of visibility improvement cost effectiveness in terms of dollars per deciview of improvement (" $\$/\Delta$ -dv").

ODEQ considered the proper measures of visibility improvement in its BART analysis, and EPA is not permitted to substitute its judgment for that of the State, especially when its judgment is based on an approach that is not permitted by law. Moreover, it is apparent that, when considered on a facility-specific basis as required by the CAA and EPA's own guidelines, the imperceptible projected visibility improvements from dry scrubbers at the OG&E Units do not justify rejection of the SIP and adoption of the FIP. EPA must acknowledge that Oklahoma acted reasonably in deciding that the projected visibility improvement (in " $\Delta$ -dv") from scrubbers is too small, and the costs of scrubbers per  $\Delta$ -dv of visibility improvement is much too high, to support a determination that scrubbers are BART for SO<sub>2</sub>. At the OG&E Units, for the reasons set forth in this Section V, EPA's failure to do so is arbitrary, capricious and contrary to applicable law.

**A. EPA May Not Disapprove Of The State's BART Determination Based On An Estimate Of The Combined Visibility Improvement From Scrubbers At Multiple Facilities**

In the Proposed Rule, EPA justifies its disapproval of the State's SO<sub>2</sub> BART determination for the OG&E Units and its proposed FIP based in part on an estimate of 2.89  $\Delta$ -dv of visibility improvement at Wichita Mountains over Low NO<sub>x</sub> Burners ("LNB") due to the combined effects of dry scrubbing at three separate facilities. *See* 76 Fed. Reg. at 16,185-16,186 (discussing the sum of 1.05  $\Delta$ -dv + 0.75  $\Delta$ -dv + 1.09 $\Delta$ -dv). This approach of setting BART for an individual source based on the aggregate visibility improvement that would result from the use of a control technology at multiple sources is clearly inconsistent with the CAA and EPA's own guidelines. Whether reviewing a SIP or proposing its own FIP, EPA, like individual states, is required to consider the visibility improvement associated with scrubbers on a facility-by-facility basis.

Indeed, EPA has already considered and rejected an aggregate, multi-facility approach to visibility assessment. In the 1999 Regional Haze Rule, EPA required that states look at the visibility impacts of multiple BART sources when determining both the applicability of the Regional Haze Rule to individual sources and the appropriate level of BART control for individual sources. *See* 64 Fed. Reg. at 35,767 (directing states to evaluate BART for a single source in light of the visibility improvement expected "from all sources subject to BART . . ."). This type of aggregate approach, however, was rejected by the D.C. Circuit Court in *American Corn Growers*, 291 F.3d 1, and subsequently by EPA in the Regional Haze Rule. After noting

that *American Corn Growers* prohibited a multi-facility approach to visibility analysis when identifying sources subject to BART, EPA stated:

The court in *American Corn Growers* also found that our interpretation of the CAA requiring the States to consider the degree of improvement in visibility that would result from the cumulative impact of applying controls in determining BART was inconsistent with the language of the Act . . . Based on its review of the statute, the court concluded that the five statutory factors in section 169A(g)(2) “were meant to be considered together by the states.”

. . .

Pursuant to the remand in *American Corn Growers*, we are amending the regional haze rule to require the States to consider the degree of visibility improvement resulting from a source’s installation and operation of retrofit technology, along with the other statutory factors set out in CAA section 169A(g)(2), when making a BART determination. This has been accomplished by listing the visibility improvement factor with the other statutory BART determination factors in 40 CFR 51.308(e)(1)(A), so that *States will be required to consider all five factors, including visibility impacts, on an individual source basis when making each individual source BART determination.*

70 Fed. Reg. at 39,106 (emphasis added) (internal citations omitted).

Nonetheless, in the Proposed Rule EPA rejects Oklahoma’s SO<sub>2</sub> BART analysis based in part on EPA’s evaluation of visibility impacts using a cumulative, multi-facility approach. Specifically, EPA states that “our modeling demonstrates that substantial visibility improvement is achievable based on the installation of these controls. In particular, our modeling indicates that dry scrubbing will result in a 2.89 deciview improvement in visibility at the Wichita Mountains.” 76 Fed. Reg. at 16,186. The 2.89  $\Delta$ -dv improvement that EPA references is based on impermissibly combining impacts from scrubbers at OG&E’s Sooner and Muskogee units and AEP’s Northeastern unit. EPA’s actions in this regard are arbitrary, capricious and inconsistent with the Regional Haze Rule, its own guidelines, and the language of the CAA (for the reasons outlined in *American Corn Growers*). EPA must instead apply the same individual facility approach that was used by Oklahoma when making the State’s BART determinations.

**B. The State’s BART Determinations Are Reasonable Even In Light Of EPA’s Projected Visibility Improvements For Each Facility**

In addition to erroneously applying a multi-facility assessment of visibility impacts, EPA proposes to overturn the State’s SO<sub>2</sub> BART determination on the grounds that scrubbers would reduce visibility impairment at Class I areas from values that are above 1.0 dv to levels that are below 0.5 dv. 76 Fed. Reg. at 16,186. This reasoning is legally flawed and once again ignores the State’s discretion to weigh projected visibility improvement in the overall BART analysis.

As an initial matter, states are directed under the Regional Haze Rule to use thresholds of 1.0  $\Delta$ -dv and 0.5  $\Delta$ -dv when conducting modeling to identify which sources are *subject to* the

BART requirement in the first place. 70 Fed. Reg. at 39,161. The Regional Haze Rule, however, does not require the use of those thresholds when judging the significance of visibility improvements that would result from possible controls at a BART-subject facility. Instead, when determining BART, the Regional Haze Rule is clear that the State has discretion to evaluate visibility improvement in a number of ways:

When making this determination [BART Step 5 on visibility impacts], you have flexibility in setting absolute thresholds, target levels of improvement, or de minimis levels since the deciview improvement must be weighed among the five factors, and you are free to determine the weight and significance to be assigned to each factor.

...

70 Fed. Reg. at 39,170. In exercising its discretion, the State may consider other factors, such as the incremental degree of visibility improvement (in  $\Delta$ -dv) that would result from adding scrubbers to each individual facility and the costs per  $\Delta$ -dv of visibility improvement.

Although EPA estimates the incremental visibility improvements over LNB that would be achieved by dry scrubbing at each individual facility along with the multi-facility cumulative estimates (Tables 8 and 9 of the Proposed Rule), EPA does not provide a meaningful analysis of the facility-specific estimates. There is only a general statement that “[t]he visibility improvements documented in Table 9 are significant and will result in marked steps toward reaching natural background conditions.” 76 Fed. Reg. at 16,186. This is insufficient to justify EPA’s disagreement with ODEQ’s conclusion that “it is too expensive to control the SO<sub>2</sub> emissions from the OG&E . . . units in question and that the potential visibility benefits are not substantial enough to justify additional control.” *Id.*

It is apparent in the SIP that ODEQ determined that the projected visibility improvements from the installation of Dry FGD at the OG&E Units would be nearly imperceptible and insignificant relative to contributions from Texas sources. A 1.0  $\Delta$ -dv change is the level of visibility improvement that can be perceived by most people. 76 Fed. Reg. at 16,172 (“[E]ach deciview change is an equal incremental change in visibility perceived by the human eye. Most people can detect a change in visibility at one deciview.”). With one exception, the incremental visibility improvements projected by EPA to result from the addition of dry scrubbers to each of the OG&E Units are less than 1.0  $\Delta$ -dv at each Class I area.

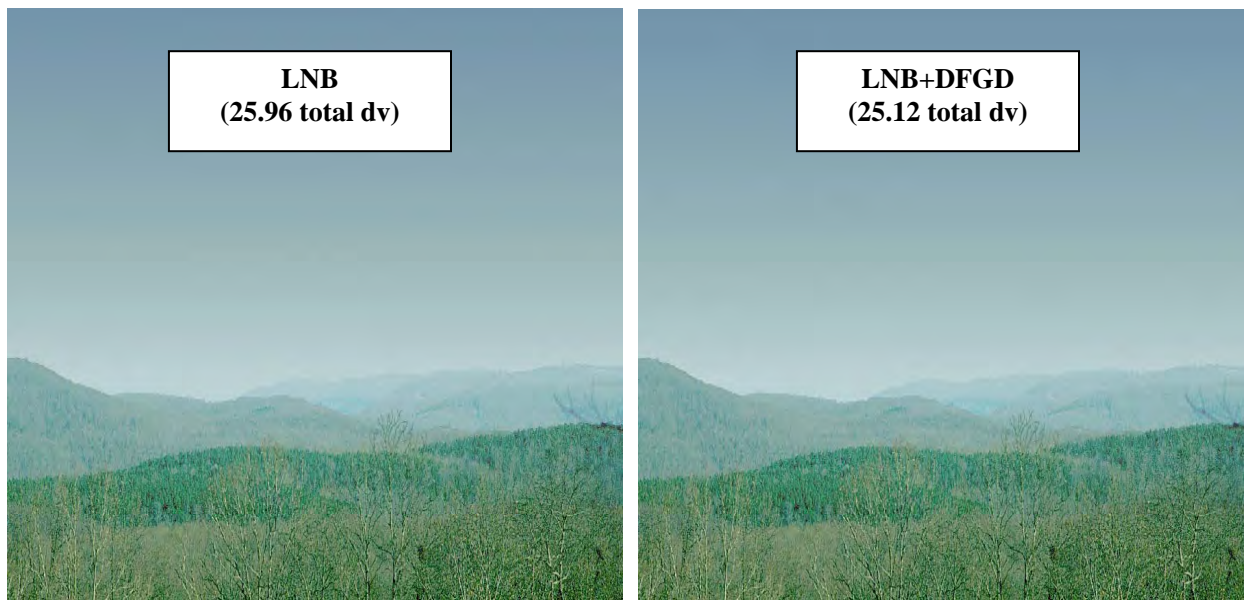
Figures V.1 and V.2 are Winhaze Software Images showing the maximum visibility improvement that is projected to occur at a Class I area as a result of adding Dry FGD at Muskogee and Sooner.<sup>19</sup> The left side of each Figure shows visibility conditions with the use of

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<sup>19</sup> Winhaze is a computer imaging software program that simulates visual air quality differences in various national park, wilderness and urban scenes. Users can select a scene and then model it using different optical parameters to simulate effects on the scene. Winhaze is available for download as freeware at <ftp://ftp.air-resource.com/WINHAZE>.

LNB only, while the right side shows conditions with both LNB and Dry FGD. Figure V.1 reflects an incremental Dry FGD improvement of 0.84  $\Delta$ -dv at Upper Buffalo (25.96 dv minus 25.12 dv), which is not within the perceptible range. The maximum Dry FGD improvement reflected in Figure V.2 for Sooner (1.05  $\Delta$ -dv at Wichita Mountains) is only barely within the range thought to be perceptible to most people. Figure V.2, however, actually shows little-to-no perceptible change associated with Dry FGD over LNB.<sup>20</sup>

**Figure V.1: Winhaze Images Showing Incremental Visibility Improvement at Upper Buffalo Class I Area from Dry FGD at Muskogee (0.84  $\Delta$ -dv)\***

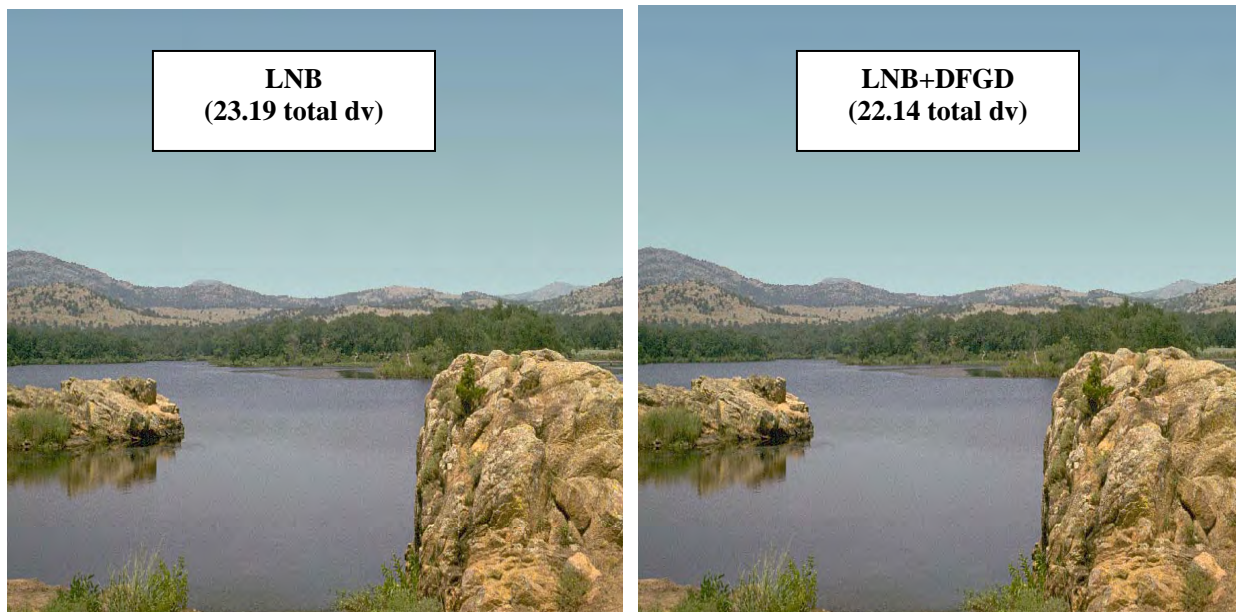


\*Images developed from the existing baseline impairment for the average of the 20% worst days based on monitor data and the projected visibility improvement ( $\Delta$ -dv) for Dry FGD from Table 8 of EPA's Proposed Rule.

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<sup>20</sup> These Figures and Table 8 of EPA's Proposed Rule may even overstate the visibility improvement from Dry FGD. The Proposed Rule relies on peak 24-hour emission rates to determine the baseline impairment attributable to each facility, but 30-day average emission rates are used to determine the visibility impairment attributable to each facility for the control scenarios.

**Figure V.2: Winhaze Image Showing Incremental Visibility Improvement at Wichita Mountains Class I Area from Dry FGD at Sooner (1.05  $\Delta$ -dv)\***



\* Images developed from the existing baseline impairment for the average of the 20% worst days based on monitor data and the projected visibility improvement ( $\Delta$ -dv) for Dry FGD from Table 8 of EPA's Proposed Rule.

EPA states in the preamble to the Regional Haze Rule that, “[e]ven though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I areas.” 70 Fed. Reg. at 39,129. In other words, less-than-perceptible visibility improvements may be considered significant where visibility modeling shows that a source is one of the larger stationary source contributors to visibility impairment at a Class I area. This is not the case with OG&E’s facilities. Rather, Oklahoma’s modeling shows that the majority of visibility-impairing pollutants originate outside Oklahoma because prevailing winds transport a considerable proportion of visibility impairing aerosols from Texas, and more than one-tenth of visibility impairment at the Wichita Mountains results from international transport. (Oklahoma SIP at 48.)

Texas alone contributes more to visibility impairment at the Wichita Mountains than do sources in Oklahoma. (*Id.*) Oklahoma is a relatively minor contributor to visibility impairment for any Class I area outside of the State. (*Id.*) To put it in perspective, ODEQ’s modeling shows that even if all of the point sources within Oklahoma were turned off, the Wichita Mountains would still not meet the glide path under the Regional Haze Rule due to visibility impairment from Texas and international sources.

Given the minor role played by OG&E’s facilities relative to other source contributions, the visibility improvements projected to result from Dry FGD do not justify EPA’s proposed decision to overturn the State-determined BART for the OG&E Units. EPA’s failure to address these important factors in support of the Oklahoma SIP is arbitrary, capricious and contrary to applicable law.

**C. EPA May Not Ignore The State's Reasonable Analysis Of Visibility Improvement Cost Effectiveness**

The Proposed Rule is similarly flawed in that EPA, without explanation, ignores the widely-used metric of visibility cost effectiveness, which reflects two of the five BART factors (cost and visibility impact) that Oklahoma was required to (and did) consider. Indeed, Oklahoma reasonably concluded that the cost effectiveness of scrubbers in  $\$/\Delta$ -dv for the OG&E Units fell outside the normal range for BART.

The Regional Haze Rule specifically authorizes states to select BART based on a consideration of “total annualized costs (\$), cost effectiveness ( $\$/\text{ton}$ ), and incremental cost effectiveness ( $\$/\text{ton}$ ), and/or any other cost-effectiveness measures (such as  $\$/\text{deciview}$ .” 70 Fed. Reg. at 39,170. The Regional Haze Rule also recognizes that the metric of  $\$/\Delta$ -dv reflects the visibility improvement of a control option as well as its cost. *See* 70 Fed. Reg. at 39,130 (“Other ways that visibility improvement may be assessed to inform the control decisions would be . . . consideration of the cost-effectiveness of visibility improvements (i.e. the cost per change in deciview) . . .”).

In its SIP, Oklahoma selected low sulfur coal as SO<sub>2</sub> BART for the OG&E Units based on the weight of all relevant factors, including the capital cost of add-on controls, the cost effectiveness of add-on controls both in  $\$/\text{ton}$  and  $\$/\Delta$ -dv, the degree of visibility benefit ( $\Delta$ -dv) from add-on controls, the long term viability of coal with respect to other environmental programs, and national commitments. The State did not rely exclusively on  $\$/\Delta$ -dv as its decision-making metric, but it did consider  $\$/\Delta$ -dv as it was authorized to do under the Regional Haze Rule.

EPA may not ignore the  $\$/\Delta$ -dv metric now in disapproving of the State's determinations. Furthermore, EPA has not—and cannot—show that scrubbers are cost-effective in terms of  $\$/\Delta$ -dv, even using EPA's own grossly understated estimates of the total annual costs of scrubbers. EPA's failure to recognize Oklahoma's assessment of the  $\$/\Delta$ -dv metric for SO<sub>2</sub> control at the OG&E Units is arbitrary, capricious and contrary to applicable law.

**D. Even Accepting EPA's Cost Estimates In The Proposed FIP, Scrubbers Are Not Cost Effective In Dollars Per  $\Delta$ -DV Of Visibility Improvement**

As noted above, the Proposed Rule ignores visibility improvement cost effectiveness ( $\$/\Delta$ -dv) and, therefore, fails to provide a fair analysis of the State's conclusions regarding the costs and benefits of scrubbers at the OG&E Units. Even accepting EPA's grossly understated costs, scrubbers are not cost effective for the OG&E Units in terms of  $\$/\Delta$ -dv.

The Federal Land Managers (“FLM”) have asserted that \$10 - \$19 million/ $\Delta$ -dv should be considered reasonable for SO<sub>2</sub> control. *See* U.S. Fish and Wildlife Service and National Park Service Comments Regarding Oklahoma Draft Regional Haze State Implementation Plan

(December 4, 2009).<sup>21</sup> In developing the SIP, ODEQ took the FLM's comments under advisement but questioned the rationale behind a threshold as high as \$19 million/ $\Delta$ -dv. See Summary of FLM Comments and Staff Responses for Proposed Revision to the Oklahoma RH SIP (prior to the Dec. 19, 2009 public hearing).<sup>22</sup>

In any event, EPA's own understated cost estimates indicate that scrubbers would cost \$30.9 million/ $\Delta$ -dv at Sooner and \$22.9 million/ $\Delta$ -dv at Muskogee. These costs are far above even the FLM's view of the reasonable range of  $\$/\Delta$ -dv for SO<sub>2</sub> control. OG&E's May 2008 BART Evaluations, which were developed consistent with the Control Cost Manual, indicate even higher  $\$/\Delta$ -dv for scrubbers (\$68.6 million/ $\Delta$ -dv for Sooner and \$44.6 million/ $\Delta$ -dv for Muskogee).<sup>23</sup>

The poor cost effectiveness of scrubbers in  $\$/\Delta$ -dv for the OG&E Units is a function of the already low emissions and low baseline visibility impacts of those units. Compared to other facilities for which such costly controls have been considered for BART, the OG&E Units already have relatively low baseline visibility impacts on few Class I areas. The high cost of installing and operating Dry FGD on these units would produce a relatively small improvement in visibility at Class I areas.

To demonstrate these points, the following discussion compares factors related to visibility improvement cost effectiveness for the OG&E Units with those of three other facilities with large baseline impacts: Boardman Power Plant, San Juan Generating Station, and Four Corners Power Plant. This discussion accepts EPA's revisions to the scrubber cost estimates for the OG&E Units solely for the purpose of illustrating that the visibility improvement projected by EPA to result from scrubbers at the OG&E Units does not justify even EPA's own grossly understated costs.

#### *1. Boardman Power Plant Unit 1*

The State of Oregon has finalized—and EPA has proposed to approve—a Regional Haze SIP that establishes SO<sub>2</sub> BART for the Boardman Power Plant. 76 Fed. Reg. 12,651 (March 8, 2011). Provided that Boardman closes by no later than 2020, the SIP calls for the installation

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<sup>21</sup> Available at [http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional\\_Haze/SIP/Comments/FLM\\_Final\\_Comments.pdf](http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze/SIP/Comments/FLM_Final_Comments.pdf) (last checked May 19, 2011).

<sup>22</sup> Available at [http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional\\_Haze/SIP/Appendices/Comments%20and%20Responses%20from%20FLMs%20in%20regards%20to%20Oklahoma%20RH%20SIP.pdf](http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze/SIP/Appendices/Comments%20and%20Responses%20from%20FLMs%20in%20regards%20to%20Oklahoma%20RH%20SIP.pdf) (last checked May 19, 2011).

<sup>23</sup>The visibility cost effectiveness estimates in the May 2008 BART Evaluations were calculated using the highest projected visibility improvement at a single Class I area. The estimates presented here are calculated using the total annual cost of control estimated in the May 2008 BART Evaluations and the cumulative visibility improvement projected by EPA for scrubbers at the OG&E Units (2.07  $\Delta$ -dv for Sooner and 3.07  $\Delta$ -dv for Muskogee at all four Class I areas). OG&E believes that these visibility cost effectiveness figures are more accurate than the figures developed using the erroneous EPA estimates of total annual cost of control. Even using EPA's erroneously low total annual costs of control, however, scrubbers fail the test for visibility cost effectiveness.

and use of dry sorbent injection ("DSI") at Boardman's coal-fired unit. Oregon Regional Haze SIP (revised Dec. 19, 2010) at 155. Without early closure, Oregon's 2009 Regional Haze SIP would have required dry scrubbers to satisfy BART. *See* Oregon 2009 Regional Haze Plan.<sup>24</sup> Boardman, however, is in a very different situation than Sooner and Muskogee with respect to the costs and visibility impacts of scrubbers.

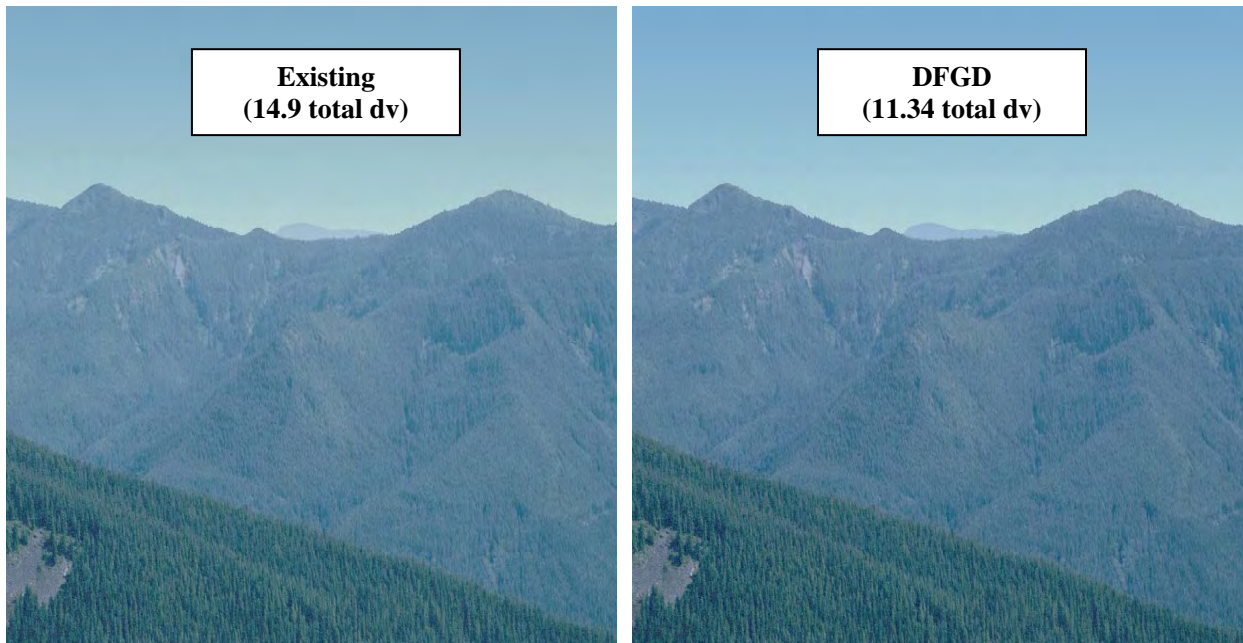
As shown in Table V.1 below, Boardman causes or contributes to visibility impairment at 14 Class I areas while Sooner and Muskogee each impact just 4 areas. 76 Fed. Reg. at 12,656. Sooner and Muskogee's total baseline impacts for the four Class I areas (4.28  $\Delta$ -dv and 5.37  $\Delta$ -dv, respectively) pale in comparison to Boardman's total baseline visibility impact of 31.5  $\Delta$ -dv. Not surprisingly, Dry FGD at the OG&E Units would produce a much smaller improvement in visibility than is projected for Dry FGD at Boardman. For the OG&E Units, EPA's own projected improvement from scrubbers at all four areas is 2.07  $\Delta$ -dv for Sooner and 3.07  $\Delta$ -dv for Muskogee. Scrubbers at Boardman, on the other hand, would improve visibility by a total of 10.62  $\Delta$ -dv for all 14 areas combined (assuming early closure). Without early closure, the projected visibility improvement from scrubbing at Boardman is even greater—20.49  $\Delta$ -dv combined at all 14 areas.

Boardman also differs from OG&E's facilities with respect to the maximum amount of visibility improvement projected for a single Class I area. Without early closure, scrubbers at Boardman would improve visibility by 3.56  $\Delta$ -dv at the Mt. Hood Class I area. The maximum visibility improvements projected for a single Class I area due to adding Dry FGD (rather than just LNBS) at Sooner and Muskogee are much lower—1.05  $\Delta$ -dv at Wichita Mountains and 0.84  $\Delta$ -dv at Upper Buffalo, respectively, according to Table 8 of the proposed FIP. Figure V.3 is a Winhaze Software Image showing the incremental visibility improvement from adding Dry FGD at Boardman without early closure. While Figures V.1 and V.2 above show little-to-no perceptible change from adding Dry FGD at Sooner and Muskogee, the improvement shown in Figure V.3 for Boardman is perceptible.

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<sup>24</sup> Available at <http://www.deq.state.or.us/aq/haze/docs/May09/2008ORRHplan.pdf> (last checked May 19,2011).

**Figure V.3: Winhaze Image Showing Incremental Visibility Improvement at Mt. Hood Class I Area from Adding Dry FGD at Boardman (3.56  $\Delta$ -dv) Without Early Closure**



\* Images developed from the existing baseline impairment for the average of the 20% worst days based on monitor data and the visibility improvement ( $\Delta$ -dv) projected for Semi-Dry FGD in Appendix D.1 of the Oregon Regional Haze SIP.

Oregon acknowledged the significant differences in visibility impacts from Boardman compared to Sooner and Muskogee when responding to comments on BART for Boardman. In response to a comment asserting that dry scrubbers are not cost effective if closure occurs in 2020, the Oregon Department of Environmental Quality claimed that \$5,535 per ton of SO<sub>2</sub> reduced was cost effective for Boardman, but only in light of the significant visibility improvements achieved. Oregon Regional Haze SIP, Appx D.6 at D-124 and D-125. The Oregon SIP noted that a survey of other BART determinations suggested an upper threshold of \$3,000 per ton for SO<sub>2</sub> BART. *Id.*

Oregon distinguished those other BART determinations on the grounds that they “involved plants that are located in the Midwest that impact only a few Class I areas at levels much lower than the Boardman Plant.” *Id.* The Oregon SIP continued: “For example, the cost of dry scrubbers for 4 units at 2 plants in Oklahoma (OG&E Muskogee and Sooner) ranged from \$6,348 to \$7,324/ton. Each of these plants only impact four Class I areas at less than 1.5 dV, approximately 1/3 of the Boardman Plant impacts.” *Id.* The Oregon SIP concluded that “a higher cost effectiveness threshold is appropriate for the Boardman Plant due to the frequency and magnitude of its visibility impacts on Class I areas.” *Id.*<sup>25</sup>

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<sup>25</sup> Although the Department thought the average cost effectiveness of dry scrubbing was reasonable for Boardman at \$5,535 per ton in light of significant visibility impacts, scrubbers were ultimately rejected based on incremental cost effectiveness values of \$7,169 per ton.

Considerations of cost relative to visibility impact are readily apparent when expressed in terms of visibility improvement cost effectiveness (in  $\$/\Delta$ -dv), which EPA fails to consider in its analysis of the Oklahoma SIP. At Boardman, Dry FGD is estimated to cost either \$6.25 million or \$8.24 million per  $\Delta$ -dv of visibility improvement, if closure occurs in either 2020 or 2018. Without early closure, the estimated cost per  $\Delta$ -dv improvement of Dry FGD for Boardman is \$3.46 million/ $\Delta$ -dv considering all fourteen Class I areas impacted by the facility.

In contrast, EPA’s own understated costs of Dry FGD are much higher for Sooner and Muskogee when considered on a  $\$/\Delta$ -dv basis (\$30.9 million/ $\Delta$ -dv and \$22.9 million/ $\Delta$ -dv, respectively). OG&E’s May 2008 BART Evaluations, which were developed consistent with the Control Cost Manual, indicate significantly higher  $\$/\Delta$ -dv for scrubbers (\$68.6 million/ $\Delta$ -dv for Sooner and \$44.6 million/ $\Delta$ -dv for Muskogee).

**Table V.1: Visibility Cost Effectiveness of Dry FGD for Sooner, Muskogee and Boardman**

	Sooner	Muskogee	Boardman (2020 Closure) <sup>26</sup>	Boardman (No Closure) <sup>27</sup>
# Class I Areas Impacted	3 <sup>28</sup>	4	14	14
# Class I Areas Within 300 km	1	4	14	14
Baseline (Dv) at Max-Impacted Area	2.08	1.52	4.98	4.98
Baseline (Dv) at All Class I Areas	4.28	5.37	31.5	31.5
Max Improvement (Dv) at One Class I Area	1.05	0.84	1.24	3.56
Improvement (Dv) at All Class I Areas	2.07	3.07	10.62	20.49
Costs Per Dv for All Areas (\$1,000)	\$30.9	\$22.9	\$6.25 (2020 Closure) \$8.25 (2018 Closure)	\$3.46

## 2. San Juan Generating Station

The NO<sub>x</sub> BART evaluation in EPA’s proposed FIP for the San Juan Generating Station provides another striking contrast to EPA’s proposed SO<sub>2</sub> BART for the OG&E Units. 76 Fed. Reg. 491 (Jan. 5, 2011). As indicated in the proposed FIP, San Juan causes or contributes to visibility impairment at 16 Class I Areas, with total baseline impact at all these areas of 33.18  $\Delta$ -dv. *Id.* at 503. EPA’s projected visibility improvement from the installation and operation of Selective Catalytic Reduction technology (“SCR”) to control NO<sub>x</sub> emissions at San Juan is 21.69  $\Delta$ -dv. *Id.* These impacts are much higher than the cumulative visibility improvement projected by EPA for scrubbers at the OG&E Units (2.07  $\Delta$ -dv for Sooner and 3.07  $\Delta$ -dv for Muskogee at all four Class I areas)

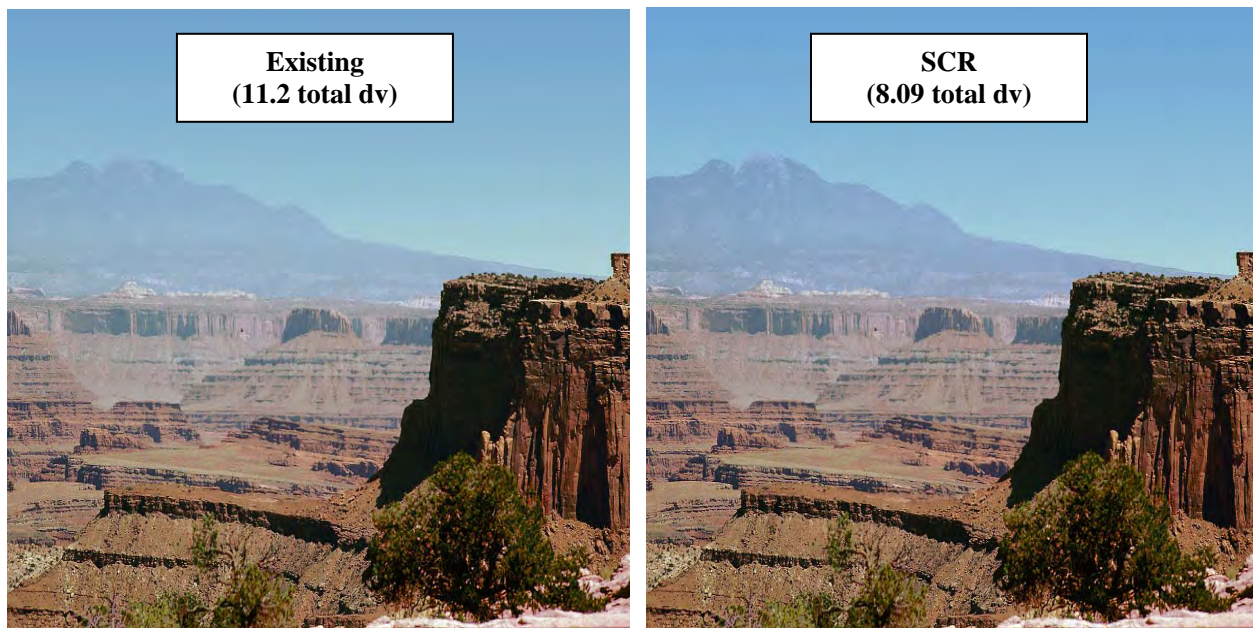
<sup>26</sup> See Oregon SIP Appendix D.6 and D.7 (Oregon Dep’t of Environmental Quality 2010 BART Report and Addendum.

<sup>27</sup> See Oregon SIP Appendix D.1 Oregon Dep’t of Environmental Quality 2008 BART Report.

<sup>28</sup> Sooner’s impact at a fourth Class I area—Hercules Glades—is less than 0.5  $\Delta$ -dv, which is EPA’s threshold for determining whether sources “contribute” to visibility impairment.

San Juan also differs from OG&E's facilities with respect to the maximum amount of visibility improvement projected for BART at a single Class I area. At Canyonlands, SCR for San Juan is projected to improve visibility by 3.11  $\Delta$ -dv, compared to maximum visibility improvements (as calculated by EPA) of just 1.05  $\Delta$ -dv and 0.84  $\Delta$ -dv for Dry FGD at Sooner and Muskogee, respectively. Figure V.4 is a Winhaze Image showing visibility improvement projected for the EPA-proposed NO<sub>x</sub> BART at San Juan. While Figures V.1 and V.2 above show little-to-no perceptible change from adding Dry FGD at Sooner and Muskogee, the improvement shown in Figure V.4 for San Juan is clear.

**Figure V.4: Winhaze Image Showing Incremental Visibility Improvement at Canyonlands Class I Area from Adding SCR at San Juan (3.11  $\Delta$ -dv)\***



\* Images developed from the existing baseline impairment for the average of the 20% worst days based on monitor data and the visibility improvement ( $\Delta$ -dv) projected for SCR in Table 8 of EPA's Proposed FIP for BART at San Juan. 76 Fed. Reg. at 503.

Like the proposed FIP for Oklahoma, EPA's proposal for San Juan fails to consider the costs of SCR in terms of dollars per  $\Delta$ -dv of improvement. Based on the costs and visibility improvement projected separately by EPA in the proposed FIP for San Juan, SCR at San Juan will cost \$8.4 million per  $\Delta$ -dv of visibility improvement at all impacted Class I areas. EPA's own understated projections for Dry FGD at the OG&E Units are well beyond this range (\$30.9 million/ $\Delta$ -dv for Sooner and \$22.9 million/ $\Delta$ -dv for Muskogee). OG&E's May 2008 BART Evaluations, which were developed consistent with the Cost Control Manual, indicate significantly higher \$/ $\Delta$ -dv for scrubbers (\$68.6 million/ $\Delta$ -dv for Sooner and \$44.6 million/ $\Delta$ -dv for Muskogee).

**Table V.2: Visibility Cost Effectiveness for Sooner, Muskogee and San Juan**

	Sooner – Dry FGD	Muskogee – Dry FGD	San Juan Station – SCR*
# Class I Areas Impacted	3	4	16
# Class I Areas in 300 km	1	4	16
Baseline (Dv) at Max-Impacted Area	2.08	1.52	5.15
Baseline (Dv) at All Class I Areas	4.28	5.37	33.18
Max Improvement (Dv) at One Class I Area	1.05	0.84	3.11
Improvement (Dv) at All Class I Areas	2.07	3.07	21.69
Costs Per Dv at All Areas (\$1,000)	\$30.9	\$22.9	\$8.4

\*See 76 Fed. Reg. at 491.

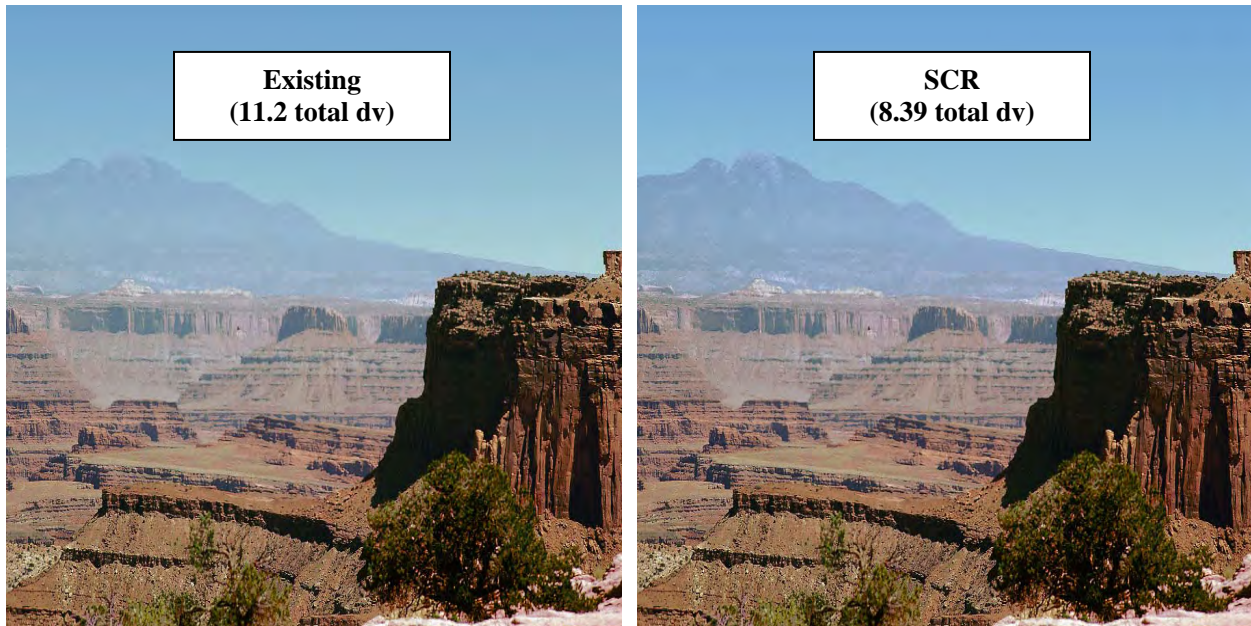
3. Four Corners Power Plant Units 1 - 5

On October 19, 2010, EPA proposed a source-specific FIP to satisfy BART for NO<sub>x</sub> emissions from the Four Corners Power Plant located on the Navajo Nation. 75 Fed. Reg. 64,221 (October 19, 2010). The proposed FIP, which requires SCR for NO<sub>x</sub> control, provides another telling contrast to the visibility improvement and cost effectiveness values projected for Dry FGD at the OG&E Units.

As shown in Table V.3 below, Four Corners causes or contributes to visibility impairment at 16 Class I Areas. *Id.* at 64,224. The total baseline impact at all 16 of these areas is 42.94 Δ-dv. *Id.* at 64,231. EPA also projects that the installation and use of SCR at Four Corners will cause a visibility improvement of 23.34 Δ-dv at all impacted Class I areas. *Id.* at 64,230. These impacts are well beyond the improvement projected over LNB due to Dry FGD at the OG&E Units (2.07 Δ-dv for Sooner and 3.07 Δ-dv for Muskogee at all four Class I areas).

Four Corners also differs from OG&E’s facilities with respect to the maximum amount of visibility improvement projected for a single Class I area. SCR at Four Corners would improve visibility by 2.81 Δ-dv at the Canyonlands Class I area. *Id.* The maximum visibility improvements projected for a single Class I area due to adding Dry FGD (rather than just LNBS) at Sooner and Muskogee are much lower—1.05 Δ-dv at Wichita Mountains and 0.84 Δ-dv at Upper Buffalo, respectively, according to Table 8 of the proposed FIP. Figure V.5 is a Winhaze Software Image showing the incremental visibility improvement from adding SCR at Four Corners. While Figures V.1 and V.2 above show little-to-no perceptible change from adding Dry FGD at Sooner and Muskogee, the improvement shown in Figure V.5 for Four Corners is perceptible.

**Figure V.5: Winhaze Image Showing Incremental Visibility Improvement at Canyonlands Class I Area from Adding SCR at Four Corners (2.81  $\Delta$ -dv)\***



\* Images developed from the existing baseline impairment for the average of the 20% worst days based on monitor data and the visibility improvement ( $\Delta$ -dv) projected for SCR in Table 3 of EPA’s Proposed FIP for BART at Four Corners. 75 Fed. Reg. at 64,229.

In the proposed FIP for Four Corners, EPA fails to consider the costs of SCR in terms of dollars per  $\Delta$ -dv of improvement. Based on the costs and visibility improvement projected separately by EPA in the proposed FIP, SCR is expected to cost \$4.0 million per  $\Delta$ -dv of visibility improvement at all impacted Class I areas. EPA’s own understated projections for Dry FGD at the OG&E Units are well beyond this range (\$30.9 million/ $\Delta$ -dv for Sooner and \$22.9 million/ $\Delta$ -dv for Muskogee). OG&E’s May 2008 BART Evaluations, which were developed consistent with the Control Cost Manual, indicate significantly higher \$/ $\Delta$ -dv for scrubbers (\$68.6 million/ $\Delta$ -dv for Sooner and \$44.6 million/ $\Delta$ -dv for Muskogee).

**Table V.3: Visibility Cost Effectiveness for Sooner, Muskogee and Four Corners**

	Sooner – Dry FGD	Muskogee – Dry FGD	Four Corners – SCR*
# Class I Areas Impacted	3	4	16
# Class I Areas in 300 km	1	4	16
Baseline (Dv) at Max-Impacted Area	2.08	1.52	5.24
Total Baseline (Dv) at All Class I Areas	4.28	5.37	42.94
Max Improvement (Dv) at One Class I Area	1.05	0.84	2.81
Total Improvement (Dv) at All Class I Areas	2.07	3.07	23.34
Costs Per Dv at All Areas (\$1,000)	\$30.9	\$22.9	\$4.0

\*See 75 Fed. Reg. at 64,221.

In the Proposed Rule, EPA conveniently fails to consider (or even mention) visibility improvement cost effectiveness, even though Oklahoma, consistent with the Regional Haze Rule, relied partially on the  $\$/\Delta$ -dv metric in reaching its BART determinations. This selective approach to evaluating the State's determinations is arbitrary, capricious, and contrary to applicable law, especially since a  $\$/\Delta$ -dv assessment highlights another fundamental flaw in EPA's proposal to overturn the State-determined SO<sub>2</sub> BART. As detailed above, the visibility improvement projected for Dry FGD does not justify the high costs required to install and operate the technology. Dry FGD falls outside the reasonable range of  $\$/\Delta$ -dv of visibility improvement even using EPA's own grossly understated scrubber cost estimates.

## **VI. OKLAHOMA'S SIP IS NOT FLAWED BY VIRTUE OF REGIONAL MODELING**

In the Proposed Rule, EPA claims that Oklahoma's 2018 emission projections were based on Central Regional Air Planning Association ("CENRAP") modeling that assumed the presumptive SO<sub>2</sub> BART limit (0.15 lb/mmBtu) for OG&E's Sooner and Muskogee facilities. 76 Fed. Reg. at 16,189. If the presumptive limit had not been assumed, EPA asserts the projected impacts on visibility at Class I areas outside Oklahoma would be greater than what Oklahoma estimated in the SIP. 76 Fed. Reg. at 16,175. EPA finds this to be a defect in Oklahoma's long-term strategy for Regional Haze and in its BART determinations for Sooner and Muskogee. 76 Fed. Reg. at 16,169. EPA reasons that the proposed FIP is necessary to cure these defects.

There are two fundamental problems with EPA's reasoning. First, with respect to BART, EPA may not pre-determine the SO<sub>2</sub> emissions limit based on assumptions made during regional modeling. BART for a specific source cannot automatically require the use of scrubbers because of assumptions made during CENRAP modeling. Rather, the CAA and EPA's own regulations are clear that BART should be determined based on the five statutory factors as applied to an individual facility. 42 U.S.C. § 7491(g)(2) (defining BART as source-specific evaluation of five factors); 40 C.F.R. § 51.301 (defining BART as an emission limitation established for sources on a "case-by-case basis").

Second, EPA's reasoning with respect to the Oklahoma long term strategy lacks sufficient basis and is inconsistent with the regional haze regulations. When setting reasonable progress goals for their own Class I areas, the states are authorized to consider the same five statutory factors that are used in determining BART, including the costs of additional controls. 40 C.F.R. § 51.308(d)(1)(i)(A). As spelled out in the State's BART analyses, additional SO<sub>2</sub> controls beyond the ODEQ-determined BART of low-sulfur coal would not be appropriate for Sooner and Muskogee as part of Oklahoma's long-term strategy for Wichita Mountains.

For Class I areas in other states, a state must ensure that it has included in its long-term strategy all measures needed to achieve its apportionment of emission reduction obligations agreed upon through the regional planning process. 40 C.F.R. § 51.308(d)(2)(ii). In the SIP, ODEQ found that its long-term strategy for achievement of reasonable progress goals in other Class I areas required no further rules or action for Oklahoma sources because emissions from Oklahoma were found (through the regional planning process) to impair visibility at all relevant Class I areas other than Wichita Mountains only insignificantly. (Oklahoma SIP at 86.) Thus, contrary to EPA's implication in the Proposed Rule, the Oklahoma long-term strategy is

consistent with the agreements reached during regional planning. EPA fails to justify, or even explain, its basis for assuming that the regional planning process would have come to a different conclusion concerning Oklahoma's impact on other states' Class I areas if a different SO<sub>2</sub> emission rate had been assumed for just two sources within the entire State of Oklahoma.<sup>29</sup>

## **VII. THE CONTINGENT BART DETERMINATION IN THE REGIONAL HAZE AGREEMENT CAN BE APPROVED**

The SIP includes a Regional Haze Agreement between ODEQ and OG&E and an associated contingent BART determination that applies if EPA rejects ODEQ's determination that low sulfur coal is BART and all appeals are exhausted. In that event, the Regional Haze Agreement requires OG&E to either (1) meet emission limits consistent with installation of dry scrubbers by January 1, 2018 or (2) achieve a combined annual SO<sub>2</sub> emission limit that is equivalent to installing dry scrubbers on two units and converting the other two units to natural gas by December 31, 2026.

EPA proposed to reject the Regional Haze Agreement with its contingent BART determination in the belief that the contingent BART determination does not provide for compliance within the time frames provided by the CAA and the 2026 compliance option should be evaluated as an alternative to BART. Neither belief is correct. Consequently, EPA's rejection of the Regional Haze Agreement with its contingent BART determination is arbitrary, capricious and contrary to applicable law.

### **A. ODEQ's Contingent BART Determination Is Not A BART Alternative And Implements BART In A Timely Fashion**

EPA's analysis of the contingent BART determination misapprehends the nature of the contingent BART and incorrectly finds that the SIP fails to meet the time frame mandated by the CAA. In the Proposed Rule, EPA analyzes the SIP's contingent BART determination as a BART alternative under the terms of 40 CFR § 51.308, and faults the determination for allowing "OG&E and AEP/PSO additional time in which to meet the less stringent emissions limitations." 76 Fed. Reg. at 16,187. These conclusions are incorrect.

First, ODEQ's contingent BART determination is not a BART alternative as described in 40 C.F.R. §51.308(e)(2). The SIP states that in the event ODEQ's determination that scrubbers are not cost effective is rejected by EPA and after all appeals are exhausted, ODEQ will determine scrubbers are BART and impose a 0.10 lb/mmBtu emissions limit by 2018. (Oklahoma SIP at 82.) Because this contingent determination is not a BART alternative, EPA is wrong to suggest that it is subject to the requirement that the emissions controls associated with ODEQ's contingent plan must achieve greater reasonable progress than BART. 76 Fed. Reg. at

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<sup>29</sup> EPA applies the same faulty reasoning to its analysis of the SIP's compliance with the interstate transport requirements of CAA § 110 ("Interstate Transport Rule"). See 76 Fed. Reg. at 16,193. This, too, is in error. Because the SIP concluded that Oklahoma sources only insignificantly impair visibility in all relevant Class I areas, and because EPA offers no evidence to the contrary, EPA's conclusion that the FIP is necessary to comply with the Interstate Transport Rule is entirely unsupported, arbitrary, capricious and contrary to governing law.

16,187. Rather, where this contingency is triggered, ODEQ determines that scrubbers *are* BART.

Second, the contingent BART finding will require the installation of BART within the statutory timeframe. The CAA requires that “BART must be installed and operational . . . in no event later than five years after approval of an implementation plan.” 42 U.S.C. § 7491(g)(4). The contingent finding is not triggered until the appellate process has concluded. If there is a final appellate ruling that scrubbers are BART, the contingent BART finding requires scrubbers to be installed by the beginning of 2018. This deadline could actually provide a shorter time for compliance than the five years mandated by the CAA if a final appellate ruling is not made before 2013, a circumstance that is entirely possible if a final EPA rule is not issued until the latter part of this year.

It is therefore arbitrary, capricious and premature for EPA to reject ODEQ’s contingent BART determination as failing to achieve greater reasonable progress and meet the statutory BART timeframe.

#### **B. ODEQ Has The Authority To Include The 2026 Compliance Option In The Regional Haze Agreement As Part Of Its Long-Term Strategy**

EPA’s consideration of the 2026 compliance option in the Regional Haze Agreement is incomplete and misleading. ODEQ included this compliance option in the Regional Haze Agreement under its authority to implement a long-term strategy. Regional Haze Agreement ¶ 25. EPA, however, mistakenly rejects the agreement as failing to meet the standards of a BART alternative. 76 Fed. Reg. at 16,187. Because the 2026 compliance option is not a BART alternative, ODEQ did not have to demonstrate that it would achieve greater reasonable progress than BART. The Regional Haze Rule provides ODEQ with full authority to adopt this compliance option as part of the long-term strategy in the name of reasonable progress without making a formal BART-alternative showing. 40 C.F.R. § 51.308(d)(3).

Further, EPA loses sight of the long-term national goal in its evaluation of the 2026 compliance option. The national goal is to achieve background visibility conditions by 2064. *See* 42 U.S.C. § 7491(a)(1); 40 C.F.R. § 51.308(d)(1)(i)(B). If OG&E elected to implement the 2026 compliance option, cumulative SO<sub>2</sub> emissions from the affected OG&E Units ultimately would be approximately 57% less than would be achieved through the installation and operation of dry scrubbers on all four units. (Oklahoma SIP at 84.). The Regional Haze Agreement could achieve even greater SO<sub>2</sub> emission reductions than are achievable with scrubbers alone and, unlike scrubbers, would avoid extending the life expectancy of coal as the primary fuel for the OG&E Units.

### **VIII. THE EMISSION RATES AND IMPLEMENTATION SCHEDULE IN THE PROPOSED RULE MUST BE REVISED**

For all of the foregoing reasons, EPA lacks authority to disapprove of the State-determined BART for SO<sub>2</sub> emissions from the OG&E Units. The Proposed Rule and the underlying Fox Report conflict with the CAA and EPA’s own rules and guidelines. The State acted within its statutory authority in concluding that low sulfur coal is BART for the affected

units. Accordingly, EPA must approve the BART determinations for the OG&E Units contained in the SIP. However, even assuming that EPA could require Dry FGD for the OG&E Units (which OG&E denies), EPA lacks a reasonable basis for proposing an SO<sub>2</sub> emission rate of 0.06 lb/mmBtu and a three-year implementation schedule for the installation and use of Dry FGD.

#### **A. EPA's Proposed SO<sub>2</sub> Emissions Limit Is Unjustified**

EPA's BART determination does not support the proposed emission rate for scrubbers. EPA's proposed SO<sub>2</sub> emissions limit of 0.06 lb/mmBtu is well below the presumptive BART limit of 0.15 lb/mmBtu established in the regulations. Appendix Y to 40 C.F.R. Part 51 establishes a control level "of either 95 percent control or 0.15 lbs/mmBtu, for each EGU greater than 200 MW that is currently uncontrolled *unless you determine that an alternative control level is justified based on a careful consideration of the statutory factors.*" (emphasis added). EPA seeks to deviate from the presumptive limit simply because "there are already facilities operating below this emission rate, using dry scrubbing technologies, and that burn similar coals." 76 Fed. Reg. at 16,187. However, the facilities that EPA references are: (i) a new boiler that achieved the lowest average SO<sub>2</sub> emission rate of any boiler in the United States; and (ii) a permitted EGU that has not even commenced commercial operation. As detailed in Section 5.1 of the BART Costing Analysis, EPA's departure from the presumptive limits in the Proposed Rule on this basis is unjustified and the SO<sub>2</sub> limit that EPA seeks to impose cannot technically be achieved by a retrofit control system, including at the OG&E Units.

OG&E also notes that available information suggests that EPA's proposed emission limit might effectively require wet flue gas desulfurization technology ("Wet FGD") to guarantee continuous compliance. OG&E's comments have focused primarily on Dry FGD because Wet FGD is less cost effective than Dry FGD. EPA readily admits that the average calculated cost effectiveness of a wet scrubber is higher than for a dry scrubber. 76 Fed. Reg. at 16,184. Although a Wet FGD control system may provide an incremental reduction in overall SO<sub>2</sub> emissions from the subject units, the incremental costs associated with the additional SO<sub>2</sub> reductions are significantly higher than the average cost effectiveness of either control system.

Wet FGD systems have a higher initial capital requirement (compared to dry systems), require more energy to operate, and have somewhat higher annual operating costs. The total annual costs for Wet FGD control systems on these units are estimated to be over \$11,000,000/year higher than the total annual costs for Dry FGD systems. The incremental cost effectiveness of the Wet FGD systems is estimated to be approximately \$13,000/ton, which is substantially higher than the average cost effectiveness of the Dry FGD control systems. EPA's analysis with respect to Wet FGD suffers from the same material flaws, discussed above, as its Dry FGD analysis. OG&E maintains that, like Dry FGD, Wet FGD is not cost effective and is therefore not BART for the OG&E Units. For these and the additional reasons set forth in Section 5.3 of the BART Costing Analysis, EPA cannot adopt an emission rate that would require the installation of Wet FGD.

**B. A Three Year Deadline Is Not Feasible For Installing Dry FGD On All Four Of The Affected Sooner And Muskogee Units**

EPA's proposal to require compliance within three years of the effective date of the final rule is unreasonable. It would take much longer than three years to install FGD systems on all four of OG&E's affected units and, even if it could be done, a three year timeframe would dramatically escalate the cost of the scrubbers. The Regional Haze Rule provides up to five years for the installation and operation of BART equipment. 40 C.F.R. §51.308(e)(1)(iv) ("each source subject to BART [shall] be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.")

The SIP proposed by Oklahoma correctly allowed up to five years for compliance. Any truncation of this five year compliance period must be compelling and justified by EPA based on a specific analysis of cost effectiveness, benefit and feasibility at a particular facility. EPA, however, offers no justification in support of its proposed timeframe.

It would be nearly impossible for OG&E to install FGD as retrofit control technology on all four of its units within three years. In addition to actual on-site construction time (and as detailed in Section 5.2 of the BART Costing Analysis), the time line for installing scrubbers has to include time for engineering, permitting, bidding and negotiation with contractors and suppliers and equipment fabrication and delivery. The timing of on-site construction at the OG&E Units also must be staggered to ensure that labor is available and staged to occur during planned outages in spring and fall to maintain system reliability. Even if five years were allowed to complete the process, OG&E estimates that it may be difficult to complete four scrubber installations in that timeframe.<sup>30</sup>

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<sup>30</sup> Other companies have commented that a three year timeline for the installation of control equipment on one unit—let alone four—is not sufficient. *See, e.g.*, Docket EPA-R06-OAR-2010-0846, Request for Extension of Public Comment Period on Proposed Federal Implementation Plan to Establish Best Available Retrofit Technology for the San Juan Generating Station, PNM Resources, submitted Jan. 14, 2011, p. 2 ("Given that PNM has been concerned that even a five-year implementation period would be extremely difficult, PNM will need time to review EPA's justification for setting a three-year deadline for compliance."); Cichanowicz, J.E., Implementation Schedules for Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Process Equipment, (Oct. 1, 2010), p. 3-1 (illustrating examples of FGD installation that all took longer than three years to complete); Comments of Edison Mission Energy on EPA's Notice of Data Availability for Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, submitted Feb. 8, 2011, pp. 5-6 ("EME submits that it actually takes between 40 and 60 months to install an FGD system and make it fully operational . . ."); Docket No. EPA-HQ-OAR-2002-0058 Comments on Proposed Rule, Domtar Corporation, submitted Aug. 26, 2010, p. 43 ("The design, procurement, installation, and shakedown of a retrofit project (e.g., installing a scrubber on a large boiler) can easily take more than three years.") *See* Docket EPA-HQ-OAR-2003-0053, Oglethorpe Power Corporation's Comments on the Proposed Supplement to the Interstate Air Quality Rule ("IAQR"), submitted July 26, 2004, p. 4 (stating that in deciding whether a reduction is highly cost-effective, one must consider "the feasibility of the deadline for control). Regardless of the cost of controls (in \$/ton of pollutant removed), if controls cannot feasibly [sic] be installed and made operational by a given compliance deadline . . . the emissions reductions . . . are by definition not cost effective."); and Docket EPA-HQ-OAR-2009-0491 Comment on Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, Council of Industrial Boiler Owners, submitted Oct. 5, 2010, p. 12 ("The compliance period EPA has proposed is unreasonable and will cause costs to dramatically escalate for both EGUs and non-EGUs subject to pollution reduction requirements. Large engineering projects to retrofit

Another complicating factor in determining the time line for scrubber installation is the possibility that OG&E may be required to obtain a construction permit for any scrubbers under the Prevention of Significant Deterioration (“PSD”) permit tailoring rule for greenhouse gas (“GHG”) emissions. 75 Fed. Reg. 31,514 (June 3, 2010). Operating any scrubbers installed at the OG&E Units will take a significant amount of additional power. This power would be generated by burning additional fuel, which would increase GHG emissions from the unit being scrubbed. *See* 40 C.F.R. 52.21(b)(49)(i). OG&E will have to assess whether the increase in GHG emissions would require a PSD permit. If a PSD permit is needed, it must be obtained before construction commences, and it can take 18-24 months to obtain a PSD permit. It would be impossible to accommodate this permit application process in a three-year compliance period.

Even if it were possible to accomplish, installing scrubbers on the OG&E Units within the three year timeframe proposed by EPA would increase the already exorbitant costs of installing scrubbers. EPA fails to account for this fact anywhere in its Proposed Rule. The cost estimates contained in both the May 2009 BART Evaluations and the December 2009 Cost Estimates were based on a five-year implementation schedule, and EPA’s unjustified departure from this timeline is arbitrary and capricious.

## **IX. EPA FAILED TO CONSIDER ALL PERTINENT FACTORS IN PROPOSING BART IN THE FIP**

Federal law requires that “in proposing a FIP to address BART, [EPA] must consider the same factors as [s]tates.” 76 Fed. Reg. 16,187; *see also* 42 U.S.C. § 7491 (g)(2) (providing that “in determining [BART] the Administrator . . . shall take into consideration [the five BART factors]”). EPA, however, may only propose a FIP in circumstances where, unlike here, a state has failed to meet the minimum requirements set forth by the CAA with respect to its SIP. 42 U.S.C. § 7410(k)(3). In the Proposed Rule, EPA did not conduct its own five-factor BART analysis. Instead, it relied mainly on ODEQ’s analyses with certain adjustments recommended by EPA’s consultant. As a result, EPA did not consider all pertinent factors in proposing BART in the FIP.

### **A. Costs Associated With The Recent PSD Tailoring Rule Were Not Evaluated**

The PSD Tailoring Rule was adopted by EPA after Oklahoma made its BART determinations and submitted its SIP. EPA failed to consider the impact that these revisions to the PSD permit program could have on scrubber installation costs. The PSD program now requires new and modified sources with significant net GHG emission increases to satisfy Best Available Control Technology (“BACT”). As previously discussed, installation of scrubbers could result in a significant net GHG emissions increase from the OG&E Units.

Without consideration of the potential added cost triggered by the tailoring rule, EPA’s analysis of the cost efficiency of dry scrubbers is incomplete and almost certainly understated.

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(continued...)

engineered equipment, such as SCRs or SO<sub>2</sub> scrubbers to large boilers, take a considerable amount of time to execute”).

Satisfying BACT could potentially involve changes to the method of operation of the OG&E Units or installation of additional control technologies.<sup>31</sup> At a minimum, BACT would impose *some* additional cost that must be included in any determination that dry scrubbers are BART for the OG&E Units. EPA's failure to account for these costs is arbitrary and capricious.

Conversely, the BART determination in the SIP (low-sulfur coal) does not present a GHG BACT issue. The contingent and alternative BART determinations provided for in the Regional Haze Agreements (fuel switching or emissions reductions comparable to fuel switching by 2026) provide OG&E the flexibility to employ innovative technologies developed over the life of OG&E's compliance obligations to control emissions from the OG&E Units and to meet evolving air standards (including GHG BACT). The SIP would give the company the option to reduce SO<sub>2</sub> emissions in a variety of ways, including through the increased use of natural gas and wind generation, the installation of emission controls, or reducing coal combustion.

### **B. Requiring Scrubbers Prevents OG&E From Switching To Cleaner Burning And Renewable Fuels**

If OG&E is required to elect whether to install scrubbers or retire and replace electric generating units with natural gas on roughly the same time frame, the economic analysis suggests that rate increases to customers will be lower with scrubbers. Installation of scrubbers is projected to cost more than \$1.5 billion. With this type of capital investment, OG&E would be locked economically into maximizing the use of its coal-fired units for the foreseeable future. Acknowledging this significant concern, ODEQ found in the SIP that installation of scrubbers "would further extend the life expectancy of coal as the primary fuel in the Sooner facility for at least 20 years and beyond." (Oklahoma SIP at 82.)

EPA fails to address these concerns, or to acknowledge the potential long-term impacts of forcing OG&E to commit to coal for years to come. Oklahoma has excellent resources for generating electricity with natural gas and wind. Moreover, the Regional Haze Agreement outlined by ODEQ in the SIP (and rejected by EPA) contemplates tapping the State's resources for a switch to cleaner fuels. As the SIP described, the fuel change prescribed by the Regional Haze Agreement is expected to reduce "the cumulative SO<sub>2</sub> emissions from Sooner Units 1 and 2 and Muskogee Units 4 and 5 [to] approximately fifty-seven percent (57%) less than would be achieved through the installation and operation of Dry FGD with SDA at all four (4) units." (Oklahoma SIP at 84.) OG&E should have the flexibility to take advantage of evolving technologies and to utilize these local clean energy sources at its plants in the future, while achieving the same (or better) reduction in impact on visibility. EPA's failure to consider these issues in its Proposed Rule is not only short-sighted, but it is arbitrary, capricious and contrary to applicable law.

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<sup>31</sup> In November 2010, EPA issued a set of guidance documents to help state permitting authorities understand the process of issuing PSD permits and determining BACT for greenhouse gas emissions. See EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases," available online at <http://www.epa.gov/nsr/ghgpermitting.html>. The guidance does not prescribe a specific type of technology as BACT for any particular industrial sector, but instead identifies a host of "available" control technologies that permitting authorities should consider for several sectors, including electric generation. Energy efficiency requirements and carbon capture and storage equipment are two possibilities identified by EPA.

### **C. Forthcoming Regulatory Changes Should Be Considered In EPA's Analysis**

Other regulatory developments in the period since Oklahoma submitted its SIP should be considered in EPA's BART analysis. It is prudent to anticipate that new federal requirements regulating air emissions from coal fired EGUs, including the OG&E Units, will become effective in the next five to ten years. In fact, several such rules have already been proposed by EPA. For example:

- On May 3, 2011, EPA proposed a rule containing the first national standards to reduce emissions of hazardous air pollutants from new and existing coal and oil-fired electric utility steam generating units ("EGU MACT Proposal"). 76 Fed. Reg. 24,975 (May 3, 2011). The EGU MACT Proposal requires the application of maximum achievable control technology ("MACT"), pursuant to Section 112(d) of the CAA. Once finalized later this year, these regulations could require OG&E to implement additional controls that may or may not be consistent with the proposed FIP.
- On April 20, 2011, EPA also proposed rules to implement cooling water intake structure requirements for existing intake structures under section 316(b) of the Clean Water Act. 76 Fed. Reg. 22,173 (April 20, 2011). OG&E has several stations that will be subject to these requirements when they are finalized.
- On June 21, 2010, EPA issued a proposed rule that seeks to change the regulation of ash and other residuals from the combustion of coal either under Subtitle C as a hazardous waste or Subtitle D as a solid waste of Resource Conservation and Recovery Act ("RCRA"). 75 Fed. Reg. 35,128 (June 21, 2010). This measure could increase the cost of coal combustion if it ultimately requires all ash to be disposed of off-site as hazardous waste.

OG&E may face additional compliance requirements through EPA's National Ambient Air Quality Standards revisions ("NAAQS") and proposed Clean Air Transport Rule. These measures could similarly lead to a requirement that OG&E implement additional control measures at its generation units.

The control requirements and costs of these other rules should be considered in establishing the remaining useful life of the OG&E Units for the BART analysis. Depending on the outcome of these rulemaking processes, it is possible that the operation of some or all of the OG&E Units may not continue to be economically viable. However, if EPA's Proposed Rule is finalized, OG&E could be placed in a vice between the pressure to keep its coal units operating for more than twenty years to recoup the one-and-a-half billion dollars spent on scrubbers and the pressure to shut down and replace its coal units due to the looming cost of compliance with other EPA regulatory efforts. The danger for enormous waste is present where, only shortly after implementing scrubbers to comply with EPA's FIP, the OG&E Units become economically unviable with the added cost of new control measures based on the rule making efforts outlined above or future regulatory efforts.

The flexibility afforded by the SIP not only meets the requirements of the Regional Haze Rule for SO<sub>2</sub> emissions, but will give OG&E the ability to employ innovative technology (including the use of alternative fuels) to meet future air requirements in the evolving regulatory landscape. The current situation—where EPA is seeking to require the installation of scrubbers at enormous cost to achieve visibility improvements at one federal wilderness area that are essentially not even perceptible to the human eye—underscores the need for EPA, like Oklahoma, to take a common sense approach to regional haze that considers all of the relevant factors. EPA’s failure to do so in the Proposed Rule is arbitrary, capricious and contrary to applicable law.

## **X. CONCLUSION**

For the reasons set forth above, EPA must not finalize the Proposed Rule or promulgate a FIP for Oklahoma pursuant to the Regional Haze Rule. EPA must instead approve the Oklahoma SIP in its entirety, including the State’s BART determinations for SO<sub>2</sub> control for the four-coal fired units at OG&E’s Muskogee and Sooner Generating Stations.

# **EXHIBIT A**



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
REGION 6  
1445 ROSS AVENUE, SUITE 1200  
DALLAS, TX 75202-2733

RECEIVED

NOV 10 2008

November 4, 2008

AIR QUALITY

Mr. Eddie Terrill, Director  
Air Quality Division  
Oklahoma Department of Environmental Quality  
P.O. Box 1677  
Oklahoma City, OK 73101-1677

Dear Mr. Terrill:

On August 29, 2008, we were informed by Lee Warden, of your staff, that the final three BART applications from AEP-Public Service of Oklahoma were available for review from the Oklahoma Department of Environmental Quality (ODEQ) website. We have completed our review of these documents and our comments are enclosed.

If you have any questions, please feel free to contact me at (214) 665-3102, or Joe Kordzi of my staff, who can be reached at (214) 665-7186.

Sincerely,

A handwritten signature in black ink, appearing to read "Guy R. Donaldson".

Guy R. Donaldson  
Chief  
Air Planning Section

Attachment

EPA Region 6 Comments on ODEQ's BART Engineering Analyses  
11/4/08

1. OG&E should explain the statement (and the accompanying figures on Table 4-9) on page 53 of the BART engineering analyses for the Sooner plant: "Although the wet FGD control systems result in lower SO<sub>2</sub> mass emission rates, modeled visibility impairments are generally less with dry FGD controls."
2. OG&E reports the SO<sub>2</sub> emission rates for Units 4 and 5 of the Muskogee plant are 0.80 and 0.85 lbs/MMBtu, respectively. OG&E is proposing that it not meet the BART presumptive emission rate for SO<sub>2</sub> of 0.15 lbs/MMBtu for these units and that BART be deemed to be no additional SO<sub>2</sub> controls, due to the costs of installing a wet or dry Flue Gas Desulfurization (FGD) system. OG&E estimates the costs of a wet FGD system to be \$4,789/ton and a dry FGD system to be \$4,554/ton. However, OG&E estimates that either dry or wet FGD would result in an average decrease of approximately 1.0 dv at the nearest four Class I areas, ranging from a 0.739 dv improvement at Hercules-Glades (with wet FGD) to a 1.275 dv improvement at Caney Creek (with dry FGD).

Similarly, OG&E reports the SO<sub>2</sub> emission rate for Units 1 and 2 of the Sooner plant are 0.86 lbs/MMBtu. OG&E is proposing that BART for these units be no additional SO<sub>2</sub> controls, with the cost of a wet FGD system to be \$5,143/ton and a dry FGD system to be \$4,797/ton. However, OG&E estimates that either dry or wet FGD would result in an average decrease of approximately 0.5 dv, ranging from 0.32 dv improvement at Hercules-Glades (with dry FGD) to 1.17 dv at Wichita Mountains (with dry FGD).

Regarding its cost estimates, OG&E's estimates seem high compared to what EPA has seen in other BART analyses. OG&E cites increased equipment costs, in part due to the "sellers market" that resulted from the CAIR program. Since the CAIR has been vacated, OG&E should solicit revised bids from pollution control equipment vendors. Region 6 is aware of similarly sized and configured facilities that estimate much lower costs for the installation of wet or dry FGD systems. Region 6 notes that OG&E did utilize the "EPA Air Pollution Control Cost Manual" when constructing its cost estimates. However, OG&E should also note any areas in which where it has deviated from that guidance. In any case, considering the significant projected gains in visibility that are projected from the installation of FGD systems at the OG&E facilities, Region 6 does not view the cost estimates that OG&E has presented as a compelling reason not to require their installation.

3. OG&E states that because the gas-fired Seminole Units 1, 2 and 3 have historically operated as peaking units, cost impact evaluations, including total annual costs and total annual emission reductions, were calculated using a more representative annual capacity factor of 50%. This assumption significantly affects the visibility projections of these units, which are balanced against the cost

of the potential NOx controls when O&E proposes a BART level of control of combustion controls and flue gas recirculation (LNB/OFA+FGR). ODEQ should ensure this capacity factor assumption is a permit limit.

4. AEP PSO discounts the installation of Flue Gas Recirculation (FGR) on Unit 3 of its Southwestern facility and Unit 2 of its Northeastern facility by stating on page 6-2 of its August, 2008 BART engineering analysis for Unit 3, "This control option would also place load limits on the boiler and also call for plant component upgrades. As with the Burners Out Of Service, IFGR [induced FGR] is considered technically infeasible as a stand alone NOx control for Southwestern Power Station Unit 3." Region 6 is aware of other gas-fired EGUs, similar to this facility, that either have or are planning to install FGR as a NOx control technology. Therefore, AEP PSO should re-evaluate this option. Region 6 estimates that the addition of FGR could reduce NOx emissions by as much as an additional 15% over AEP's proposal of using just Low NOx Burners (LNB) with Overfire Air (OFA).
5. AEP should explain why the Comanche facility limits its NOx control options to dry LNB and why FGR and OFA are not considered.
6. AEP should correct the BART Summary Table 1-1 in its May 30, 2008 BART assessment for Units 3 and 4 of the Northeastern facility to include OFA, along with LNB.
7. Despite its earlier pronouncement<sup>1</sup> on its Northeastern facility Units 3 and 4 that, "AEP plans to meet the SO2 presumptive BART limits through the use of flue gas desulfurization (FGD) system," it has apparently changed that position in its May 30, 2008 submittal. Apparently, AEP now proposes that BART for SO2 control on Units 3 and 4 is "low sulfur fuel." Since it does not appear from a reading of its BART analyses for the Northeastern facility that AEP plans to do anything to its existing coal supply other than adding that label, Region 6 concludes it is proposing "no-control" for BART SO2. Because the visibility effects from Units 3 and 4 are very significant to a number of Class I areas, Region 6 is unable to recommend that ODEQ approve this BART determination. The following comments add additional clarity:
  - a. AEP should greatly expand its costs estimates for FGD, providing a cost basis for each line item. AEP should follow EPA's Control Cost Manual, and justify and indicate where it deviates from that document.
  - b. It does not appear that AEP actually used its five factor analysis in its BART recommendation, since Region 6 cannot find where in its BART analysis it uses this information to justify a no-control option for SO2.

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<sup>1</sup> Best Available Retrofit Technology (BART) Determination American Electric Power Northeastern Power Plant, March 2007.

- c. AEP estimates the visibility impact due to SO<sub>2</sub> alone on the Caney Creek, Hercules Glades, Upper Buffalo, and Wichita Mountains Class I areas are 4.54, 3.12, 4.72, and 5.17 dv, respectively. It estimates the installation of dry FGD would reduce these impacts to 0.72, 0.57, 0.38, and 1.01, dv, respectively. AEP estimates the average cost effectiveness for dry FGD would be \$3,266/ton. The above comment concerning AEP's cost estimate notwithstanding, Region 6 does not view the cost estimates that AEP has presented for dry FGD as a compelling reason not to require its installation.

# **EXHIBIT B**

# Oklahoma Gas & Electric



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## Sooner Units 1 & 2, Muskogee Units 4 & 5 BART Costing Analysis Report

*Prepared by: Sargent & Lundy LLC  
Chicago, Illinois*



May 20, 2011

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## 1.0 INTRODUCTION

On March 22, 2011, the U.S. Environmental Protection Agency (“EPA” or the “Agency”) issued a draft Regional Haze Federal Implementation Plan for the State of Oklahoma (the “Proposed FIP”).<sup>1</sup> EPA claims that the Proposed FIP was developed to implement the federal regional haze rules found in 40 CFR 51, Subpart P, and address visibility impacts in national parks and wilderness areas (“Class I Areas”). In the draft rule, EPA proposes to partially approve and partially disapprove portions of the Oklahoma Regional State Implementation Plan submitted to EPA on February 19, 2010 (the “Oklahoma SIP”).

Specifically, EPA proposes to disapprove the sulfur dioxide (“SO<sub>2</sub>”) best available retrofit technology (“BART”) determinations made by Oklahoma for six coal-fired sources in Oklahoma, including OG&E’s Sooner Units 1 & 2 and Muskogee Units 4 & 5. EPA proposes replacing the Oklahoma SIP SO<sub>2</sub> provisions applicable to these units with a FIP specifically imposing more stringent SO<sub>2</sub> BART emission limits and control technology requirements on those sources.<sup>2</sup> EPA proposes to approve Oklahoma’s particulate matter (“PM”) and nitrogen oxide (“NO<sub>x</sub>”) BART determinations for OG&E Sooner Units 1 & 2 and Muskogee Units 4 & 5.<sup>3</sup> A comparison of the BART determinations and emission limits contained in the Oklahoma SIP and the Proposed FIP for the OG&E Sooner and Muskogee units is provided in Table 1-1.

**Table 1-1  
OG&E Sooner and Muskogee Stations: SIP and Proposed FIP Emission Limit Comparison\***

BART Emission Limits	Sooner Units 1 & 2		Muskogee Units 4 & 5	
	Oklahoma SIP	Proposed FIP	Oklahoma SIP	Proposed FIP
<b>NO<sub>x</sub> Control - Technology</b>	LNB/OFA	No Changes	LNB/OFA	No Changes
Emission Rate (lb/MMBtu)	0.15 (30-day avg.)		0.15 (30-day avg.)	
Emission Rate (lb/hr)	767 (30-day avg.)		822 (30-day avg.)	
Emission Rate (TPY)	3,361 (12-mo. avg.)		3,600 (12-mo. avg.)	
<b>SO<sub>2</sub> Control – Technology</b>	low sulfur coal	<b>FGD</b>	low sulfur coal	<b>FGD</b>
Hourly Rate (lb/MMBtu)	0.65 (30-day avg.)	<b>0.06 (30-day avg.)</b>	0.65 (30-day avg.)	<b>0.06 (30-day avg.)</b>
Emission Rate (lb/hr)	3,325 (30-day avg.)		3,562 (30-day avg.)	
Annual Rate (lb/MMBtu)	0.55 (12-mo. avg.)		0.55 (12-mo. avg.)	
<b>PM<sub>10</sub> Control – Technology</b>	ESP	No Changes	ESP	No Changes
Emission Rate (lb/MMBtu)	0.10 (30-day avg.)		0.10 (30-day avg.)	
Emission Rate (lb/hr)	512 (3-hour avg.)		548 (3-hour avg.)	
Emission Rate (TPY)	2,241 (12-mo. avg.)		2,400 (12-mo. avg.)	

\*Oklahoma SIP, Tables VI-6 and VI-7, and proposed §52.1923(d).

<sup>1</sup> See, 76 Fed. Reg. 16168, March 22, 2011.

<sup>2</sup> *Id.* at 16170.

<sup>3</sup> *Id.* at 16181.

With respect to Oklahoma’s SO<sub>2</sub> BART determinations, EPA proposes to find that the Oklahoma Department of Environmental Quality (“ODEQ”) did not properly follow the requirements of section 51.308(e)(1)(ii)(A) in determining BART.<sup>4</sup> Specifically, EPA proposes that ODEQ did not properly determine the costs of compliance in its BART evaluation of post-combustion SO<sub>2</sub> control technologies “when it relied on cost estimates that greatly overestimated the costs of dry and wet scrubbing to conclude that these controls were not cost effective.”<sup>5</sup> To make this determination, EPA retained a consultant to independently assess the suitability and costs of installing post-combustion FGD controls on the subject coal-fired units in Oklahoma. EPA reviewed the consultant’s report and agreed with her findings that both wet and dry scrubbing alternatives would be cost-effective in terms of dollars per ton (\$/ton) of SO<sub>2</sub> removed.<sup>6</sup> A comparison of the ODEQ’s and the consultant’s revised cost effectiveness estimates for dry scrubbers installed on the OG&E units is provided in Table 1-2.

**Table 1-2**  
**OG&E Sooner and Muskogee Stations: SIP and Proposed FIP Cost-Effectiveness Comparison\***

Plant	ODEQ Projected Cost Effectiveness (\$/ton SO <sub>2</sub> removed)	EPA’s Projected Cost Effectiveness (\$/ton SO <sub>2</sub> removed)
Sooner Unit 1	\$6,348	\$1,291
Sooner Unit 2	\$7,147	\$1,291
Muskogee Unit 4	\$7,378	\$1,317
Muskogee Unit 5	\$7,493	\$1,317

\*76 FR 16183, Table 4.

This report reviews the basis for ODEQ’s cost effectiveness evaluation and EPA’s revised cost effectiveness evaluation, focusing on the cost estimates prepared for the OG&E Sooner and Muskogee Generating Stations. Revisions to the ODEQ cost estimates proposed by EPA’s consultant are reviewed on a line-by-line basis, and the technical bases and assumptions upon which the consultant relies to revise the cost estimates are reviewed. Responses to those revisions are provided herein.

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<sup>4</sup> *Id.* at 16182.

<sup>5</sup> *Id.*

<sup>6</sup> *Id.* at 16184.

## 2.0 BACKGROUND

The Regional Haze Rule requires certain existing stationary facilities found to cause or contribute to visibility impairment in Class I areas to install and maintain BART. The Oklahoma SIP identified the BART-eligible sources in Oklahoma.<sup>7</sup> OG&E's Sooner Generating Station Units 1 & 2 and Muskogee Generating Stations Units 4 & 5 were identified in the Regional Haze SIP as being BART-eligible sources.

In May 2008, Sargent & Lundy LLC ("S&L") completed BART evaluations for OG&E's Sooner Units 1 & 2, Muskogee Units 4 & 5, and Seminole Units 1, 2, & 3, which were updated in September 2009 to reflect proper baseline emissions in accordance with EPA guidance (together, the "May 2008 BART Evaluations"). The May 2008 BART Evaluations included an analysis of potentially feasible retrofit emission control technologies to control emissions of SO<sub>2</sub>, NO<sub>x</sub>, and PM from each unit and was prepared in accordance with the five-step BART determination process described in Appendix Y to 40 CFR Part 51.

On November 13, 2009, the State of Oklahoma published its draft Regional Haze Implementation Plan Revision (the "Draft Oklahoma SIP"). The Draft Oklahoma SIP proposed SO<sub>2</sub> emission controls for Sooner Units 1 & 2 and Muskogee Units 3 & 4, but also stated that the Department was continuing to evaluate the cost effectiveness calculations, and "[i]n the event that the evaluation demonstrates that the costs associated with the current SO<sub>2</sub> BART determinations (i.e., Dry FGD-SDA) are unreasonable, the SO<sub>2</sub> BART determinations for these sources could potentially be changed to only include the continued use of low-sulfur coal."<sup>8</sup>

In response to ODEQ and EPA's requests for additional cost details beyond what was provided in the May 2008 BART Evaluations, OG&E authorized S&L to prepare a more detailed BART cost estimate for the Sooner and Muskogee units, which S&L completed and OG&E submitted to ODEQ and EPA in December 2009 (the "December 2009 Budget Cost Estimates"). The December 2009 Budget Cost Estimates included a conceptual cost estimate of the total capital requirements to install dry flue gas desulfurization ("DFGD") and fabric filter ("FF") baghouse control systems at all four of the OG&E units (i.e., Muskogee Units 3 and 4 and Sooner Units 1 and 2). Capital costs in the December 2009 Budget Cost Estimates were based on site-specific general arrangements prepared for each facility and budgetary equipment cost estimates provided by equipment vendors. Annual operating and maintenance ("O&M") costs were calculated based on an estimate of both variable and fixed O&M costs. Annual operating costs were calculated for the air pollution control systems based on control system material balance calculations and preliminary control system operating design parameters.

In the final Oklahoma SIP, ODEQ determined that flue gas desulfurization was not a cost-effective SO<sub>2</sub> control option for any of the six coal-fired steam electric units in Oklahoma.<sup>9</sup> For the Sooner and Muskogee Stations, ODEQ based its determination, in part, on the capital costs, annual O&M costs, and cost effectiveness evaluations included in the May 2008 BART Evaluations and the December 2009 Budget Cost Estimates, which ODEQ characterized as "credible, detailed, and specific for the individual facilities."<sup>10</sup> The Department concluded that costs for installing and operating DFGD were

<sup>7</sup> Oklahoma Regional Haze Implementation Plan Revision, February 2, 2010, page 71.

<sup>8</sup> Draft Oklahoma Regional Haze SIP, November 13, 2009, page 77.

<sup>9</sup> Oklahoma Regional Haze Implementation Plan Revision, February 2, 2010, page 82.

<sup>10</sup> *Id.* at 81.

properly calculated and that these costs put the FGD projects “above the levels DEQ considered reasonable for cost effectiveness, both in terms of dollars per ton of pollutant removed and dollars per deciview (e.g., \$10,000,000/dv) of improved visibility.”<sup>11</sup>

In its proposed rule, EPA proposes to reject the Department’s SO<sub>2</sub> BART determinations and issue a FIP with its own SO<sub>2</sub> control requirements and emission rates for the Sooner and Muskogee coal-fired units. Specifically, EPA rejects the cost estimates included in the Oklahoma SIP and concludes that a FGD control system is in fact cost-effective BART control technology in terms of dollars per ton of SO<sub>2</sub> removed for all four OG&E units.<sup>12</sup> To make this determination, EPA retained a consultant to “independently” assess the suitability and costs of installing post-combustion FGD controls on the subject coal-fired units in Oklahoma. The consultant’s evaluation focused on, and made significant revisions to, S&L’s December 2009 Budget Cost Estimates. A comparison of the December 2009 Budget Cost Estimates and the consultant’s revised costs is provided in Table 2-1. The consultant’s evaluation did not address the May 2008 BART Evaluations.

**Table 2-1**  
**SO<sub>2</sub> Source Control Cost Effectiveness Comparison**

	Sooner Units 1 & 2		Muskogee Units 4 & 5	
	S&L 2009 Cost Estimates	EPA Revised Cost Estimates	S&L 2009 Cost Estimates	EPA Revised Cost Estimates
Capital Costs	\$584,589,800	\$298,530,748	\$634,387,200	\$307,153,696
Capital Recovery	\$60,563,600	\$24,057,519	\$65,722,600	\$24,752,412
Annual O&M	\$33,101,000	\$31,992,212	\$36,877,800	\$36,449,343
Total Annual Costs	\$93,664,600	\$56,049,731	\$102,600,400	\$61,201,755
SO <sub>2</sub> Emission Reductions	13,930	43,428	13,799	46,458
Cost Effectiveness \$/ton	\$6,724	\$1,291	\$7,435	\$1,317
(\$/dv)*	\$38,387,131	Not Provided	\$24,330,187	Not Provided

\* \$/dV = cumulative reduction of all Class I Areas (December 28, 2009, page 15)

The consultant’s detailed report (hereinafter referred to as the “Fox Report”) was incorporated into the Technical Support Document (“TSD”) for the Proposed FIP.<sup>13</sup> Although EPA should have based its evaluation on the May 2008 BART Evaluations, the Revised BART Cost-Effectiveness Analysis solely focuses on the consultant’s revisions to the December 2009 Budget Cost Estimates.

<sup>11</sup> Oklahoma Regional Haze Implementation Plan Revision, February 2, 2010, page 81.

<sup>12</sup> See, 76 FR 16184.

<sup>13</sup> Dr. Phyllis Fox, *Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2 Muskogee Units 4 & 5 Northeastern Units 3 & 4*. Report Prepared for U.S.EPA, RTI Project Number 0109897.004.085.

### 3.0 SUMMARY AND CONCLUSIONS

This report has been prepared in response to EPA's proposal to disapprove the SO<sub>2</sub> BART determinations made by Oklahoma, and impose more stringent SO<sub>2</sub> BART emission limits for OGE's Muskogee Units 4 and 5 and Sooner Units 1 and 2. S&L reviewed the basis for ODEQ's cost effectiveness evaluation and revisions to the ODEQ cost estimates proposed by EPA's consultant. This review identifies several deficiencies in the methodology used for developing EPA's revised cost estimates.

EPA incorrectly concludes that the cost to install dry scrubbers at OG&E's Sooner and Muskogee Stations was significantly overestimated in the Oklahoma SIP. EPA and its consultant contend that the costs for the DFGD were overestimated for the following reasons: (1) a much bigger scrubber was costed than was assumed in the BART analysis; (2) OG&E's engineering consultant (S&L) did not follow standard BART cost estimating guidelines; (3) some costs included in the December 2009 Budget Cost Estimates were significantly outside the range of the actual costs estimated by EPA; (4) the December 2009 Budget Cost Estimates contained double counting; and (5) the December 2009 Budget Cost Estimates failed to evaluate the most cost effective options.<sup>14</sup> The revised costs set forth by EPA's consultant, and adopted by EPA in its proposed rule, are seriously flawed. The December 2009 Budget Cost Estimates are based on properly sized DFGD/FF systems and scoping-level cost estimates that are consistent with the cost estimating methodology described in the *OAQPS Control Cost Manual*.<sup>15</sup> Scoping-level cost estimates provide more detailed and robust estimates of the capital costs associated with installing the DFGD and baghouse control systems.

In the Proposed FIP, EPA concludes, based on performance information provided in the TSD that dry scrubbers on the OG&E units could meet an SO<sub>2</sub> emission limit of 0.06 lb/MMBtu (30-day rolling average) using the combination of DFGD/FF. EPA's proposed limit of 0.06 lb/MMBtu does not represent a permit limit or an emission rate that can be achieved using DFGD/FF under normal operating conditions. Some reasonable margin must be provided between the design target and the enforceable permit limit to allow for normal fluctuations in the controlled emission rate. Based on review of SO<sub>2</sub> emissions from existing units equipped with a retrofit DFGD control technology, the lowest emission rate achieved in practice is approximately 0.088 lb/MMBtu (annual average). A permit limit below approximately 0.10 lb/MMBtu (30-day average) would eliminate almost all the margin between the design target of a retrofit DFGD/FF control system and the permit limit.

EPA proposes that the OG&E Muskogee and Sooner units achieve compliance with the BART SO<sub>2</sub> emission limits within three (3) years of the effective date of the final rule. EPA's proposed 3-year compliance schedule is not practical nor even reasonable for installation of four DFGD/FF systems. Although a 5-year compliance schedule could present challenges, this schedule would be expected to provide an adequate timeframe for installing four DFGD systems.

EPA concludes that wet flue gas desulfurization ("WFGD") is a cost effective option for the OG&E units. The May 2008 BART Evaluations identified incremental WFGD cost effectiveness values of \$13,281/ton for the Muskogee units, and \$18,255/ton for the Sooner units. The incremental WFGD cost effectiveness levels are significantly higher than the cost effectiveness values for DFGD systems. Therefore, WFGD is not a cost effective control option for the OG&E units.

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<sup>14</sup> See, Revised BART Cost-Effectiveness Analysis, page 2. See also, 76 FR 16183, col. 1.

<sup>15</sup> EPA's *OAQPS Control Cost Manual*, Fifth Edition, February, 1996, EPA 453/B-96-001.

#### **4.0 EPA's REVISED BART COST-EFFECTIVENESS ANALYSIS FOR FLUE GAS DESULFURIZATION AT SOONER UNITS 1 & 2 AND MUSKOGEE UNITS 4 & 5**

EPA incorrectly concludes that the cost to install dry scrubbers at OG&E's Sooner and Muskogee Stations was significantly overestimated in the Oklahoma SIP. With respect to the December 2009 Budget Cost Estimates prepared by S&L, EPA and its consultant contend that the costs for the DFGD were overestimated for the following reasons: (1) a much bigger scrubber was costed than was assumed in the BART analysis, resulting in a "mismatch" between annual costs and annual emission reductions; (2) OG&E's engineering consultant (S&L) did not follow standard BART cost estimating guidelines; (3) some costs included in the December 2009 Budget Cost Estimates were significantly outside the range of the actual costs estimated by EPA; (4) the December 2009 Budget Cost Estimates contained double counting; and (5) the December 2009 Budget Cost Estimates failed to evaluate the most cost effective options.<sup>16</sup> The revised costs set forth by EPA's consultant, and adopted by EPA in its proposed rule, are seriously flawed as the following sections of this report demonstrate.

#### **4.1 Design Basis Parameters**

Guidelines for preparing BART determinations are provided in Appendix Y to 40 CFR Part 51 *Guidelines for BART Determinations Under the Regional Haze Rule* (the "BART Guidelines"). The BART Guidelines provide a process for making BART determinations. Part IV of the BART Guidelines describes a five-step process for the analysis of control options for sources subject to BART.<sup>17</sup> Step four of the process evaluates potential impacts associated with the installation and operation of a particular control option, including an evaluation of the costs of compliance. In the final rule implementing the regional haze regulations and BART Guidelines, EPA describes the following three-step process to estimate the control costs: (1) define the emissions units being controlled; (2) identify design parameters for the emissions control system; and (3) develop cost estimates based on the control system design parameters.<sup>18</sup>

Design parameters for a dry FGD control system include, but are not necessarily limited to, fuel characteristics and consumption rates, flue gas flow rates and temperatures, SO<sub>2</sub> inlet loading to the scrubber, type of sorbent to be used (e.g., lime), calcium-to-sulfur (Ca:S) stoichiometric ratio, and the pressure drop across the control system.<sup>19</sup> Design parameters that served as the basis for S&L's December 2009 Budget Cost Estimates were included in Attachment 1 (Mass Balance Diagrams) of the December 2009 submittal.

##### **4.1.1 Scrubber Size**

EPA's consultant incorrectly argues that the BART cost-effectiveness "calculation requires that costs for the control technology are consistent with the calculated emission reductions," and that "[i]n performing its BART analysis, Sargent & Lundy assumed that the Sooner and Muskogee plants burned coal with a higher sulfur content [1.172 lb/MMBtu uncontrolled SO<sub>2</sub> emissions] than they are currently burning [0.51 lb/MMBtu uncontrolled SO<sub>2</sub> emissions]." The consultant

<sup>16</sup> See, Revised BART Cost-Effectiveness Analysis, page 2. See also, 76 FR 16183, col. 1.

<sup>17</sup> See, 70 FR 39164.

<sup>18</sup> See, 70 FR 39166, col. 2.

<sup>19</sup> Babcock & Wilcox, *Steam: Its Generation and Use*, 41<sup>st</sup> Edition, page 35-13.

argues that this assumption led to S&L costing a much bigger scrubber than is necessary for the coal currently being burned, and resulted in a “mismatch” between annual costs and emission reductions.<sup>20</sup>

To address this perceived mismatch, EPA’s consultant revises S&L’s December 2009 capital cost estimate based on “the capacity of the scrubber system to remove SO<sub>2</sub> in pounds per hour” using the following equation:

$$C_b = C_a(S_b/S_a)^n$$

Where:

C<sub>a</sub> = S&L’s capital cost estimate for a full-size scrubber

S<sub>b</sub> = SO<sub>2</sub> removed at an inlet of 0.51 lb/MMBtu (2,092 lb/hr removed)

S<sub>a</sub> = SO<sub>2</sub> removed at an inlet of 1.172 lb/MMBtu (5,504 lb/hr removed)

n = 0.69 (exponent used to approximate the cost of a different sized, but similar, industrial process based on the “six-tenth rule”)

Using the equation: C<sub>b</sub> = (2,092 – 5,504)<sup>0.69</sup> = 0.51 x C<sub>a</sub>.

In other words, EPA’s consultant reduces the size of the scrubber, and the capital costs of the scrubber, by approximately 50% based on the capacity of the scrubber to remove SO<sub>2</sub> in pounds per hour. This approach is referred to as “Option 2” in the consultant’s report.<sup>21</sup>

**Response:** The argument made by EPA’s consultant that the December 2009 Budget Cost Estimates resulted in a “mismatch between annual costs and emission reductions” is incorrect. As discussed in more detail below, S&L prepared a cost estimate for a DFGD control system based on OG&E-specific design parameters, and calculated annual SO<sub>2</sub> emission reductions in accordance with the BART Guidelines. There was no mismatch between the cost calculation and the emission reduction calculation in the December 2009 Budget Cost Estimates. Furthermore, the approach proposed by EPA’s consultant to adjust the capital costs for the “Option 2” scrubber is incorrect and would result in a grossly undersized and ineffective control system.

The design and sizing of a flue gas desulfurization control system is generally divided into two major systems: (1) the flue gas path; and (2) the reactant handling (or wet) system. The flue gas path includes the scrubbing vessel (e.g., spray dryer absorber), duct work, fabric filter (if needed), foundations, support structures and fans. On a DFGD, the reactant handling system includes the lime receiving, lime slurry preparation, reactant recycle, and ash handling systems. The sizing of the reactant handling system is based on the amount of sulfur that will be removed from the flue gas; however, the required size of the flue gas path is a function of flue gas volume and is independent of the fuel sulfur content.

The primary design parameter for sizing a dry scrubber is flue gas flow rate.<sup>22</sup> Flue gas flow rate is a function of the fuel being burned (i.e., heating value, carbon content, moisture, etc.), but is

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<sup>20</sup> See, Revised BART Cost-Effectiveness Analysis, page 3.

<sup>21</sup> *Id.*, at page 7 and footnote 20.

<sup>22</sup> Babcock & Wilcox, *Steam: It’s Generation and Use*, 41<sup>st</sup> Edition, page 35-13.

not a function of the fuel sulfur content. The dry scrubbers used as the basis for the December 2009 Budget Cost Estimates were sized to handle the quantity of flue gas that would be generated at full load heat input to each OG&E unit firing subbituminous coal.<sup>23</sup> The volume of flue gas produced by combustion of subbituminous coal is essentially constant regardless of the subbituminous coal's fuel sulfur content.<sup>24</sup>

The sulfur content of the fuel, and SO<sub>2</sub> loading to the scrubber, will not affect the size (or cost) of the gas path portions of the FGD system, including the scrubber vessel, duct work, baghouse, support systems, and fans. Reducing the size of these systems based on fuel sulfur content would result in an undersized reactor vessel, unacceptably high flue gas velocities at the scrubber inlet, insufficient residence time in the spray dryer for the SO<sub>2</sub> removal reaction to take place, and high flue gas velocities in the fabric filter, which will shorten the filter bag life. Reducing the size of the vessels, as EPA's consultant suggests, would result in a higher than recommended pressure requirement. The increased pressure requirement would increase power requirements for the induced draft fan, thus greatly reducing the units' net power generation. In addition, the higher pressure drop would greatly increase the material cost requirements associated with reinforcing the boiler and ductwork to withstand the higher negative pressures.<sup>25</sup>

While SO<sub>2</sub> loading to the scrubber does affect the size of the lime slurry, recycle slurry, and ash handling systems, the capital costs associated with these systems are minimal compared to the capital costs associated with the flue gas path and scrubbing system. In general, the gas path components of the dry FGD control system account for more than 80% of the total capital cost of the system. Furthermore, the size of the reactant and ash handling systems cannot be designed for an average fuel sulfur content (as suggested by EPA's consultant), but must be sized based on a reasonable estimate of the maximum fuel sulfur content expected at the facility.<sup>26</sup> Sizing the reactant handling system for an "average" coal would result in the lime supply being inadequate for coals with sulfur contents higher than the average, which, by definition, would be approximately one-half of all the coal fired.

The consultant's "Option 2" cost estimate, based on the improperly-sized scrubber, is patently wrong and inconsistent with the unit-specific control system design parameters for the OG&E boilers necessary to handle the fuel burning load at these facilities. Arbitrarily adjusting the size of the scrubber based on "the capacity of the scrubber system to remove SO<sub>2</sub> in pounds per hour" would result in a grossly undersized and ineffective control system. Cost estimates included in the December 2009 Budget Cost Estimates were properly based on sizing the scrubber to handle full load flue gas flows from the OG&E boilers. In contrast to the approach taken by EPA and its consultant, S&L used the appropriate design parameter for sizing, and costing a FGD control system.<sup>27</sup> As was explained earlier, an under-sized DFGD system will prevent the units from achieving the current net power output due to excessive pressure drop in the scrubber system and

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<sup>23</sup> See, Sargent & Lundy December 2009 Cost Estimate, Attachment 1.

<sup>24</sup> See, e.g., 40 CFR 75 Appendix F, Section 3.3.

<sup>25</sup> National Fire Protection Association, *NFPA 85: Boiler and Combustion Systems Hazards Code*, 2007 Edition, Section 6.5.

<sup>26</sup> Babcock & Wilcox, *Steam: Its Generation and Use*, 41<sup>st</sup> Edition, page 35-13.

<sup>27</sup> *Id*

the entire boiler draft system. Additionally, sizing the lime storage, preparation, and slurry injection systems for the average SO<sub>2</sub> loading rather than the design SO<sub>2</sub> loading could greatly limit the fuel supply options. In particular, since there is a natural variation in the sulfur content of a coal shipment, it is quite possible that there would be insufficient capacity in the lime preparation system to produce sufficient lime slurry to achieve necessary SO<sub>2</sub> emissions reductions.

#### **4.1.2 Capital Cost: Overestimating and Lower Cost Options**

In addition to arguing that the scrubber was oversized, EPA's consultant incorrectly suggests that the OG&E BART analysis "made no apparent effort to minimize costs and overlooked many obvious opportunities to lower costs, including factoring in capital cost reductions due to multiple identical units, use of common facilities, use of existing equipment, and consideration of other scrubbing options."<sup>28</sup> To attempt to account for these supposed opportunities to lower costs, EPA's consultant arbitrarily assumes that: (1) vendors would offer a 5% discount on equipment costs for multiple identical units and large unit operations; and (2) designing the control system to use common facilities (e.g., single lime preparation and ash handling systems, and/or a single fabric filter) would reduce equipment, material, and labor costs by an additional 5%. EPA's consultant offers no independent authority to support her assumption that these cost savings could be achieved.

**Response:** The methodology used by S&L to prepare the December 2009 Budget Cost Estimates is described in detail in Section 4.2.2 of this report. S&L did not simply rely on stock vendor prices for generic equipment. Rather, the 2009 Cost Estimate was based on budgetary quotes supplied by equipment vendors for the major pieces of equipment - the scrubber vessel, fabric filter baghouse, reactant handling and preparation system, and ash handling systems. To obtain those budgetary quotes, equipment vendors were provided with plant design data sheets for all of the generating units, which included a general description of each unit, boiler size, fuel specifications, mass balances, flue gas volumes, and temperatures. Thus, vendors providing estimates were already aware of opportunities for quantity and size "discounts" and of the general design that, to the extent supported by the engineering data, could allow the potential use of common facilities. Common facilities include lime storage and preparation systems, lime slurry storage tanks, and waste disposal silos. EPA's consultant, on the other hand, had no basis to assume the budgetary quotes in the December 2009 Budget Cost Estimates did not already reflect the multiple units or to arbitrarily reduce capital costs by 5% for an unsupported "multiple unit discount."

Using information provided by the equipment vendors, site-specific general arrangements were prepared for each station. These general arrangements could be used to speculate regarding opportunities to use common facilities; however, significantly more engineering would be needed to optimize the control system layout and determine if, and to what extent, OG&E could take advantage of potential opportunities to use common facilities. That level of engineering is beyond the scope of a study-level or even a scoping-level cost estimate.<sup>29</sup> Because the scope of

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<sup>28</sup> Revised BART Cost-Effectiveness Analysis, page 22.

<sup>29</sup> See, e.g., EPA *OAQPS Control Cost Manual*, Fifth Edition, February, 1996, EPA 453/B-96-001, pg. 2-4

opportunities, if any, to optimize the design of the control system and utilize common facilities cannot be known without significantly more detailed engineering – neither done nor required for BART purposes – EPA’s consultant’s reduction of equipment, material, and labor costs by an additional 5% for common facilities was entirely arbitrary. Based on the level of engineering underlying the cost estimates, it is impossible to say whether any savings could be realized or whether, in fact, the generating stations would incur additional costs to retrofit the control systems into the existing facilities. The degree of engineering needed to determine any cost savings or additional expenditures would involve development of system specifications, formal bid by system suppliers, development with the system suppliers of agreed upon general arrangements, a study of the auxiliary power systems to determine the extent of upgrades required, and the complexity of retrofitting common facilities based on the operations of common units.

#### **4.1.3 Capital Cost: Lower Cost Options**

EPA’s consultant also incorrectly argues in her report that capital costs were overestimated because more economical options for designing and integrating the scrubbers into the plant were not explored, including the option of reusing the existing electrostatic precipitators (ESPs) instead of installing new baghouses, and using a one-pass scrubber design rather than the more expensive recycle system.<sup>30</sup> These arguments, however, are unsupported.

**Response:** As an initial response, it is important to reiterate that the December 2009 Budget Cost Estimates were prepared in response to ODEQ’s request for a more refined cost estimate of the DFGD control option at the Sooner and Muskogee Stations. The December 2009 Budget Cost Estimates supplemented, but did not replace, OG&E’s May 2008 BART Evaluations. In her report, however, EPA’s consultant focused exclusively on the December 2009 Budget Cost Estimates, but apparently did not review OG&E’s May 2008 BART Evaluations, or the BART determinations published by ODEQ to support the Oklahoma SIP.<sup>31</sup> Both included a comprehensive review of potential SO<sub>2</sub> control technologies, including:

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<sup>30</sup> *Id* at page 24.

<sup>31</sup> See, Final Oklahoma Regional Haze SIP, Appendix 6-4.

<b><i>Control Strategy / Technology</i></b>
<i>Pre-Combustion Controls</i>
<i>Fuel Switching</i>
<i>Coal Washing</i>
<i>Coal Processing</i>
<i>Post-Combustion Controls</i>
<i>Wet Flue Gas Desulfurization</i>
<i>Wet Lime FGD</i>
<i>Wet Limestone FGD</i>
<i>Wet Magnesium Enhanced Lime FGD</i>
<i>Jet Bubbling Reactor FGD</i>
<i>Dual Alkali Scrubber</i>
<i>Wet FGD with Wet Electrostatic Precipitator</i>
<i>Dry Flue Gas Desulfurization</i>
<i>Spray Dryer Absorber</i>
<i>Dry Sorbent Injection</i>
<i>Circulating Dry Scrubber</i>

As mentioned in those documents, reusing the existing ESPs downstream of a DFGD control system would be impractical and ineffective for numerous reasons. First, DFGD control would increase particulate loading to the ESP by more than 300%.<sup>32</sup> The performance of electrostatic precipitators is a function of the electrical characteristics (i.e., resistivity) of the particles entering the precipitator. The resistivity of lime and reaction products from a spray dryer system are higher than that of fly ash and consequently will reduce the collection efficiency of the precipitator. Additionally, increasing the inlet dust loading by more than 300% will result in the outlet dust loading also increasing 300%. Unlike a fabric filter where the buildup of a filter cake on the filter bags will increase efficiency, a precipitator's efficiency is a function of the electrical characteristics of the particles entering the precipitator and the specific collection area (which is the ratio of the collection surface available and the volume of the flue gas entering the precipitator). Second, the dry powder produced in the DFGD contains a mixture of unreacted lime, fly ash, and reaction by-products. On units equipped with a baghouse, this powder will form a filter cake on the fabric filter bags. Additional SO<sub>2</sub> removal occurs as the flue gas passes through this filter cake. SO<sub>2</sub> removal in the fabric filter can account for up to 20% of the overall SO<sub>2</sub> removal achieved by the system. This would not be the case with an ESP, where only minor SO<sub>2</sub> removal might occur while the dry powder is "in-flight" in the duct work before it is collected on the ESP collection plates.<sup>33</sup> Finally, using an ESP for particulate collection downstream of a DFGD can result in significant balance-of-plant impacts. For example, if the ESP were used, flue gas temperatures at the DFGD outlet would be approximately 30 to 40°F above the adiabatic saturation temperature. Operating the ESP at these temperatures would likely result in severe corrosion issues due to acid condensation on the casing walls and charging and

<sup>32</sup> See, *Dry FGD Design and Cost Estimate Basis Document*, prepared by Sargent & Lundy LLC, Attachment 1, December 11, 2009.

<sup>33</sup> Babcock & Wilcox, *Steam: Its Generation and Use*, 41<sup>st</sup> Edition, page 35-13.

collection electrodes. This, in turn, could necessitate replacing the ESP internals with stainless steel components, at a considerable cost.

Industry experience demonstrates that the combination of DFGD/FF provides more effective SO<sub>2</sub> control than the combination of DFGD/ESP, and that using an ESP downstream of a DFGD control system can result in significant balance-of-plant impacts as described above. Because of the technical limitations of the DFGD/ESP design, there is no reason, from either a technical feasibility or control effectiveness standpoint, to include a cost estimate of the DFGD/ESP option in the OG&E BART determinations. It should also be noted that the very low emission rate proposed by EPA's consultant (0.06 lb/mmBtu) is not consistent with a DFGD retrofit that employs existing ESPs. If that emission rate can be achieved at all with a DFGD retrofit system, it would have to be a DFGD/FF installation.

We also disagree with the consultant's suggestion that the costs of the dry scrubbing system could have been minimized using a single-pass scrubber design rather than the recycle design used in S&L's December 2009 Budget Cost Estimates.<sup>34</sup> Single-pass systems differ from recycle systems in that they do not recycle unreacted lime collected in the particulate control system, and thus they do not include the recycle slurry preparation and delivery systems. While it is true that the recycle system will add approximately 6% to the overall capital cost of the FGD control system, single-pass systems have significantly higher reactant consumption rates, generate more solid waste by-products for disposal, and have higher annual O&M costs.<sup>35</sup> Recycling the FGD by-products improves the lime utilization rate, and can reduce overall lime consumption by 25 to 50%, which will significantly reduce annual O&M costs for the system.<sup>36</sup> Dry FGD control systems designed as single-pass systems have also experienced significant operating issues including: (1) wetting of the spray dryer reactor vessel walls; (2) filling the bottom cone of the spray dryer with wet material resulting in lengthy forced outages of the plant; and (3) frequent (daily) maintenance of the atomizers compared to monthly maintenance on units with recycle systems.

Industry experience demonstrates that DFGD control systems designed with reactant recycle are more cost-effective than the single-pass designs. Any savings in capital costs associated with a single-pass design would be more than off-set by increased reactant costs and by-product disposal costs. Because the single-pass designs offer no advantages, from either a control effectiveness or cost standpoint, there was no reason to include a cost estimate of the single-pass design option in the May 2008 BART Evaluations or the December 2009 Budget Cost Estimates.

Nearly all recently designed and installed dry scrubbing systems on coal-fired electric generating units in the U.S. have been designed as recycle systems with a fabric filter baghouse. In fact, of the 75 dry lime systems reported by the U.S. EPA in 2010, only Great River Dam Authority (GRDA) Unit 2 is equipped with an ESP as its primary particulate control device.<sup>37</sup> This is

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<sup>34</sup> Revised BART Cost-Effectiveness Analysis, page 24.

<sup>35</sup> Babcock & Wilcox, *Steam: It's Generation and Use*, 41<sup>st</sup> Edition, page 35-15.

<sup>36</sup> *Id* at page 35-15.

<sup>37</sup> See, <http://camddataandmaps.epa.gov/gdm>. Several units listed on EPA's website are equipped with an ESP upstream of the DFGD, but those systems are not designed as the primary particulate matter collection device

because designing a retrofit DFGD control system to reuse existing ESPs will not provide as effective SO<sub>2</sub> control and will likely result in significant balance-of-plant impacts. Similarly, the single-pass design offers no advantage from either an effectiveness standpoint or cost standpoint. Therefore, contrary to the claims of EPA's consultant, there is no technical basis for including either control option in the May 2008 BART Evaluations or the December 2009 Budget Cost Estimates.

#### **4.1.4 Tons Removed (Annual Emission Reductions Relative to Costed Case)**

EPA's consultant incorrectly argues that the scrubber design utilized by S&L in connection with the December 2009 Budget Cost Estimates was "mismatched" with the calculation of annual emission reductions. Specifically, she argues that the S&L scrubber was designed for an SO<sub>2</sub> inlet rate of 1.176 lb/MMBtu SO<sub>2</sub>, while annual emission reductions were calculated based on an average inlet SO<sub>2</sub> loading of 0.51 lb/MMBtu. To address this perceived "mismatch," EPA's consultant uses the Option 1 cost estimates (based on the higher sulfur coal) and calculates annual emission reductions based on each unit's potential-to-emit ("PTE") emissions (i.e., 1.176 lb/MMBtu uncontrolled and 91.5% removal).<sup>38</sup> This approach increases the quantity of SO<sub>2</sub> removed by the control technologies by approximately 300%. Of all the revisions EPA's consultant made to the December 2009 Cost Effectiveness evaluation, her use of this approach to calculate annual emission reductions has the biggest impact on the cost-effectiveness of the control system. This approach, however, was not only based on a misunderstanding of how emission reductions are properly calculated, but directly contradicts EPA's own requirements for calculating baseline emissions.

**Response:** There was no "mismatch" between the scrubber design and the annual reduction in SO<sub>2</sub> emissions in S&L's December 2009 Budget Cost Estimates. As discussed in Section 4.1.1, FGD design parameters used as the basis for S&L's December 2009 Budget Cost Estimates were appropriate for subbituminous coal-fired boilers. The consultant's argument that the size of the scrubber could have been minimized to match the sulfur content of the coal being fired is simply incorrect, and redesigning the scrubber, as she suggests, would result in an undersized and ineffective control system. More importantly, the approach used by EPA's consultant to calculate emission reductions is not consistent with the BART Guidelines or EPA's approach in other BART determinations. It also reflects a fundamental misunderstanding of how emission reductions are properly calculated. As a result, her approach significantly overestimates baseline SO<sub>2</sub> emissions from the subject units.

The BART Guidelines in Appendix Y to 40 CFR Part 51 state that "[t]he baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period."<sup>39</sup> EPA reiterated this approach to calculating baseline emissions in its Advanced Notice of Proposed Rulemaking for the Four

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and do not provide collection of the DFGD by-products. A large majority of the coal-fired electricity utility boilers in the U.S. equipped with a DFGD control system are designed with a fabric filter baghouse for particulate control.

<sup>38</sup> See, Revised BART Cost-Effectiveness Analysis, page 5.

<sup>39</sup> See, 70 FR 39167, col. 1.

Corners and Navajo Generating Station BART determinations. In its evaluation of the Navajo Generating Station's ("NGS's") BART cost-effectiveness evaluation, EPA revised the station's baseline NO<sub>x</sub> emissions to reflect an actual annual average rate, noting that "Appendix Y of the BART Guidelines states that average cost effectiveness should be based on the annualized cost and the difference between baseline annual emissions and annual emissions with the control technology."<sup>40</sup> EPA revised NGS's annual emission reduction calculation by starting with baseline actual annual emissions averaged over the baseline period of 2004 – 2006.<sup>41</sup>

This is precisely the method used by S&L in its December 2009 Budget Cost Estimates, and the approach used by ODEQ to develop the Oklahoma SIP.<sup>42</sup> In both, baseline emissions from each boiler were calculated as the average actual SO<sub>2</sub> emissions during the baseline years of 2004 – 2006.<sup>43</sup> EPA's consultant, on the other hand, ignores the BART Guidelines and arbitrarily calculates baseline emissions using the maximum design sulfur content of the coal. This flawed approach is inconsistent with the BART Guidelines and results in baseline emissions that are nearly three times each unit's actual baseline emissions.

Furthermore, EPA's revision does not match scrubber costs with SO<sub>2</sub> emission reductions. As discussed above, the December 2009 Budget Cost Estimates were based on a scrubber sized (and costed) to handle the full load flue gas flow rates. Annual O&M costs (discussed in more detail below) and annual SO<sub>2</sub> emission reductions were both calculated using the baseline actual SO<sub>2</sub> loading the scrubber. Thus, the scrubber size "matched" the proper parameter, flue gas flow rate, and the SO<sub>2</sub> emissions reductions calculated per EPA guidelines "matched" O&M costs. All of these values are consistent and appropriate for evaluating the cost effectiveness of the retrofit DFGD control system.

Calculating emission reductions using baseline actual emissions (i.e., the methodology used by S&L to calculate emission reductions in the December 2009 Budget Cost Estimates) is correct, consistent with the calculation of annual costs, and consistent with the approach described in the BART Guidelines. The approach used by EPA's consultant (i.e., arbitrarily setting baseline emissions equal to each units' PTE emissions) is inconsistent with the BART Guidelines, contradicts EPA's approach in several previously issued BART determinations, and does not reflect achievable annual SO<sub>2</sub> emission reductions from the use of retrofit DFGD control systems on the subject units.

#### **4.2 Costing Method (Failure to Follow Cost Manual)**

The BART Guidelines describe the methodology that should be used to determine control system costs and to calculate control system cost effectiveness. The guidelines state that "[i]n order to maintain and improve consistency, cost estimates should be based on the *OAQPS Control Cost Manual*, where possible."<sup>44</sup> EPA's consultant incorrectly argues that S&L did not follow the cost

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<sup>40</sup> See, 74 FR 44321.

<sup>41</sup> *Id.*

<sup>42</sup> See, Oklahoma Regional Haze SIP, Table VI-15, page 82, and Appendix 6-4.

<sup>43</sup> S&L December 2009 Cost Estimate, pg. 12.

<sup>44</sup> See, 70 FR 39166, col. 3, referring to EPA's *OAQPS Control Cost Manual*, Fifth Edition, February, 1996, EPA 453/B-96-001.

estimating methodology described in the *Control Cost Manual* when it prepared the December 2009 Budget Cost Estimates for properly-sized scrubbers (Option 1), and that the cost estimates for dry scrubbers at the Sooner and Muskogee Stations were excessive.<sup>45</sup> As examples, EPA's consultant argues that S&L "escalated costs to future build dates while BART is based on present dollars; included contingencies that are excessive for BART determinations; failed to optimize costs; double counted costs; and used inflated factors."<sup>46</sup> The consultant concludes that "[t]hese deviations resulted in excessively high scrubber costs compared to estimates in other BART analyses and in published cost surveys."<sup>47</sup>

**Response:** The December 2009 Budget Cost Estimates were prepared in accordance with the BART Guidelines and are consistent with the cost estimating methodology described in the *Control Cost Manual*. Once again (and as mentioned above), EPA's consultant completely ignores the fact that the December 2009 Budget Cost Estimates were meant to supplement, not replace, the prior May 2008 BART Evaluations. At ODEQ's and EPA's request, the December 2009 Budget Cost Estimates provided significantly more detail than required by the *Control Cost Manual*. In connection with those budgetary estimates, S&L established reasonable design parameters for the control system, obtained budgetary equipment costs from vendors for the major equipment, and provided a reasonable basis for all line items included in the cost estimate. A brief description of the cost estimating methodology described in the *Control Cost Manual* is provided below, followed by a brief description of the methodology S&L used to develop the December 2009 Budget Cost Estimates and a line-by-line review of EPA's revisions to the December 2009 Budget Cost Estimates.

#### 4.2.1 The *Control Cost Manual* Methodology

In general, the cost estimating procedure described in the *Control Cost Manual* consists of five steps: (1) obtaining the facility parameters and regulatory options for a given facility; (2) roughing out the control system design; (3) sizing the control system components; (4) estimating the cost of these individual components; and (5) estimating the costs (capital and annual) of the entire system.<sup>48</sup> The *Control Cost Manual* describes the equipment and other direct costs that are typically included in a cost estimate and provides cost factors that can be used to calculate certain indirect costs. Specific chapters are provided for a number of add-on air pollution control systems;<sup>49</sup> however, the *Control Cost Manual* does not include a chapter for wet and dry scrubbers for SO<sub>2</sub>.<sup>50</sup> In fact, the *Control Cost Manual* specifically states that for certain control systems, including FGD units, it deviates from its standard approach of providing study level costs and, instead, provides a description of the factors that influence Total Capital Investment ("TCI") for the analyst to consider when dealing with a vendor quotation.<sup>51</sup> The *Control Cost Manual* takes this approach because "the control in question is either so large or so site-specific in

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<sup>45</sup> Revised BART Cost-Effectiveness Analysis, page 9.

<sup>46</sup> *Id.*

<sup>47</sup> *Id.*, footnote 30.

<sup>48</sup> *Control Cost Manual*, page 2-23.

<sup>49</sup> See e.g., Baghouses and Filters (Section 6, Chapter 1) and SCR for NO<sub>x</sub> control (Section 4.2, Chapter 2)

<sup>50</sup> *Control Cost Manual*, Section 5.2, Chapter 2 "Planned Chapter."

<sup>51</sup> *Control Cost Manual*, page 2-27.

design that suppliers design, fabricate, and construct each control according to the specific needs of the facility.”<sup>52</sup>

With respect to cost-effectiveness evaluations, the *Control Cost Manual* provides a methodology to calculate the Total Annual Cost (“TAC”) associated with the air pollution control system. TAC includes three elements and is calculated using the following equation:

$$\text{TAC} = \text{DC} + \text{IC} - \text{RC} \text{ (Control Cost Manual, equation 2-1, page 2-7)}$$

Where:

- DC = direct costs;
- IC = indirect costs; and
- RC = recovery credits

Direct costs are those that tend to be directly proportional (variable costs) or partially proportional (semi-variable costs) to some measure of productivity (e.g., exhaust gas processed by the control system per unit time).<sup>53</sup> Direct costs include raw materials (reagents), utilities, waste treatment and disposal, maintenance materials, replacement parts, and operating, supervisory, and maintenance labor. Indirect, or “fixed,” annual costs are independent of the level of production, and would be incurred even if the control system were shut down. Indirect costs include the capital recovery costs, administrative charges, property taxes, and insurance.<sup>54</sup> Recovery credits account for materials or energy recovered by the control system, which may be sold, recycled, or reused to offset the direct and indirect annual costs.

Capital recovery can represent a significant portion of the annual indirect costs, especially on large capital intensive air pollution control projects. Capital recovery is an annualized cost of capital calculated as an annual payment sufficient to finance total capital costs over the life of the investment. The annualized capital recovery cost is a function of the TCI, operational life of the control technology, and an appropriate discount interest rate that reflects the financial structure of the applicant’s business.<sup>55</sup>

TCI includes all costs required to purchase equipment needed for the control system (purchased equipment cost), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs).<sup>56</sup> Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance

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<sup>52</sup> *Id.*

<sup>53</sup> *Id.*, at page 2-7.

<sup>54</sup> *Id.*, at page 2-9.

<sup>55</sup> *Id.*, at page 2-21. See also, *Control Cost Manual*, Section 2.4.2, page 2-13.

<sup>56</sup> *Id.* at page 2-5.

test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies. TCI also includes costs for working capital and off-site facilities.<sup>57</sup>

The *Control Cost Manual* provides a road map for estimating capital costs, annual operating costs, and total annual costs associated with an air pollution control system. However, the *Control Cost Manual* also provides flexibility, and is not so prescriptive as to explicitly exclude from a cost estimate actual tangible costs that an applicant will incur as part of an air pollution control project. For example, the *Control Cost Manual* states that “the user has to be able to exercise ‘engineering judgment’ on those occasions when the procedures may need to be modified or disregarded;”<sup>58</sup> and that “the application of an appropriate [indirect capital cost] factor requires the subjective application of the analyst’s best judgment.”<sup>59</sup>

#### 4.2.2 Sargent & Lundy’s Control Cost Estimates

The BART Guidelines include the following three-step approach to developing an equipment cost estimate: (1) identify the emissions units being controlled; (2) identify design parameters for emission controls; and (3) develop cost estimates based on these design parameters.<sup>60</sup> With respect to developing cost estimates, the BART Guidelines instruct that the basis for equipment cost estimates should be documented, either with data supplied by an equipment vendor or by a referenced source such as the *Control Cost Manual*; however, guidelines do not limit the analyst to using study-level costs and default factors found in the *Control Cost Manual*. In fact, the BART Guidelines clearly state that the cost analysis should take into account any site-specific design or other conditions that affect the cost of a particular control technology, provided that the cost estimate includes documentation of any additional information that was used for the cost calculations, including any information supplied by vendors that affects assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that differs from the *Control Cost Manual*.<sup>61</sup>

The May 2008 BART Evaluations and the December 2009 Budget Cost Estimates prepared by S&L were both prepared in accordance with the BART Guidelines and the *Control Cost Manual* methodology. The May 2008 BART Evaluations were study-level cost estimates, which incorporated many *Control Cost Manual* default factors for certain indirect costs. This is the standard level of review that EPA requires for BART determinations.<sup>62</sup> However, here, EPA sought additional, more site-specific information, which was the purpose behind developing the December 2009 Budget Cost Estimates. These estimates were developed using refined capital cost estimates, budgetary costs from equipment vendors, site-specific balance-of-plant costs, and specific indirect cost factors. This level of detail goes above and beyond what is required by the *Control Cost Manual* and departs from its default factors to achieve its site specific purpose, but the December 2009 Budget Cost Estimates still follow the *Control Cost Manual’s* methodology. Specifically, the December 2009 Budget Cost Estimates were prepared as follows:

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<sup>57</sup> *Id.*

<sup>58</sup> *Id.*, at page 1-7.

<sup>59</sup> *Id.*, at page 2-28.

<sup>60</sup> See, 70 FR 39166, col. 2.

<sup>61</sup> See, 70 FR 39166, col. 3, and footnote 15.

<sup>62</sup> See, 70 FR 39127, col. 2.

- Plant design data were 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.
- 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 for the installation of each control system. It was assumed the new FGD control systems would come on line at six month intervals with the last unit being completed at Muskogee near the end of 2015 (five years after the presumed BART effective date).
- A design and cost basis document was prepared to document the major assumptions and inputs for developing the cost estimate.

The methodology used in the December 2009 Budget Cost Estimates is consistent with the approach described in the *Control Cost Manual* and provides a conceptual capital cost estimate, or scoping-level estimate, with accuracy in the range of  $\pm 20\%$ . Cost estimates using default factors in the *Control Cost Manual*, like those contained in the May 2008 BART Evaluations, are directed toward a study-level estimate with a nominal accuracy of  $\pm 30\%$ .<sup>63</sup> The *Control Cost Manual* states that “[s]tudy-level estimates are acceptable for regulatory development because they represent a compromise between the less accurate order-of-magnitude and the more accurate, but more costly, estimate types.”<sup>64</sup> The methodology used by S&L to prepare the December 2009 Budget Cost Estimates provides more detailed and robust estimates of the capital costs associated with installing the DFGD and baghouse control systems on a large subbituminous coal-fired boiler and more specific estimates of the actual costs that OG&E would incur to install these control systems at the Sooner and Muskogee Stations.

#### **4.2.3 Indirect Capital Cost Line Items**

Other than arguing that S&L “oversized” the dry scrubber (discussed in section 4.1.1), EPA’s consultant does not specifically challenge the direct capital cost estimates provided in the December 2009 Budget Cost Estimates. However, EPA’s consultant does incorrectly argue that the December 2009 Budget Cost Estimates failed to follow the *Control Cost Manual* guidelines by including escalation, bond costs, Allowance for Funds Used During Construction (“AFUDC”), and excessive contingency, and by annualizing the capital costs using an allegedly inflated capital

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<sup>63</sup> *Control Cost Manual*, page 2-3.

<sup>64</sup> *Id.*, at page 2-4.

recovery factor.<sup>65</sup> Each of the indirect capital cost line-items that were adjusted by EPA's consultant is addressed below:

Escalation: EPA's consultant argues that the *Control Cost Manual* approach "explicitly excludes future escalation as cost comparisons are made on a current real dollar basis" and that escalation is a contingency and is double counted, as discussed elsewhere.<sup>66</sup>

**Response:** The constant dollar approach described in the *Control Cost Manual* annualizes (in constant dollars) the costs of installation, maintenance, and operation of a pollution control device over the life of the control system. The *Control Cost Manual* recommends translating the costs in each future year to year zero using an equivalent uniform annual cash flow ("EUAC") method.<sup>67</sup> The EUAC method equalizes all future costs of maintenance and operation into equal annual payments over the life of the control system, and works best when annual cash flows are normalized to one year, typically year zero. The constant dollar approach described in the *Control Cost Manual* only requires the analyst to establish a baseline year from which total annual costs can be equalized (in constant dollars) over the life of the control system.<sup>68</sup> The *Control Cost Manual* does not dictate any specific baseline year and allows the analyst to establish the commercial operating date ("COD") of the control system as the baseline year.

The approach used by S&L to develop the Sooner and Muskogee cost estimates is consistent with the methodology described in the *Control Cost Manual*. S&L defined the baseline year for both the Muskogee and Sooner Generating Stations as the projected COD of the FGD control systems (i.e., 2014 for Sooner and 2015 for Muskogee). Construction of an FGD control system can take from approximately 32 to 40 months from start of construction to COD; thus, it is reasonable to establish the COD as the baseline year from which future maintenance and O&M costs are calculated.

Budgetary equipment cost estimates, which formed the basis of the December 2009 Budget Cost Estimates, were obtained from equipment vendors in 2009 dollars. To put those estimated costs into constant dollars for the baseline year, as the *Control Cost Manual* requires, they were then escalated to the respective baseline years of 2014 and 2015. For consistency, annual O&M and auxiliary power costs in 2009 dollars were also escalated to the respective baseline years. From those baseline years, the O&M and auxiliary power costs were calculated using the constant dollar approach over the operating life of the control equipment. Inflation was removed from the discount rate and from the O&M and auxiliary power costs with respect to the baseline year and the 20-year operating life of the control equipment. This approach is consistent with the constant dollar approach described in the *Control Cost Manual*, and EPA's consultant has not shown otherwise.<sup>69</sup>

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<sup>65</sup> Revised BART Cost-Effectiveness Analysis, page 11.

<sup>66</sup> *Id.*, footnote 35 reference page 2-36 of the *Control Cost Manual*.

<sup>67</sup> *Control Cost Manual*, page 2-20.

<sup>68</sup> *Id.*

<sup>69</sup> EPA's consultant references an example on Page 2-36 of the *Control Cost Manual* to support her conclusion that the *Control Cost Manual* explicitly excludes future escalation. However, the example cited is intended to

Allowance for Funds Used During Construction: EPA’s consultant incorrectly argues that an AFUDC is not part of the “constant dollar approach found in the EPA *Control Cost Manual* and should not be included in the BART cost-effectiveness analyses.”<sup>70</sup> The consultant argues that AFUDC capitalizes interest and allowed return on equity costs that are not realized during the construction period and adds them to the base rate paid by customers so that they can be recovered from future customers when the assets are used. The consultant argues that these costs are not part of the constant dollar approach found in the *Control Cost Manual* and that the most recently issued sections of the *Control Cost Manual* explicitly set AFUDC equal to zero.<sup>71</sup>

**Response:** AFUDC is more than an accounting method, as EPA’s consultant suggests, and provides a way of measuring the real cost of interest over the construction period. AFUDC accounts for the time value of money associated with the distribution of construction cash flows over the construction period, which for an FGD system could be spread over a construction period of 32-40 months. TCI, as defined in the *Control Cost Manual*, includes all costs required to purchase equipment needed for the control system (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and building, working capital, and off-site facilities.<sup>72</sup>

A cost breakdown of TCI is presented in several examples in the *Control Cost Manual*. For example, Table 1.4 and Table 2.5 therein explicitly identify AFUDC as component “E” of the TCI, where  $TCI = D + E + F + G + H + I$ , where:

- D = Total Plant Cost
- E = AFUDC
- F = Royalty Allowance
- G = Preproduction Cost
- H = Inventory Capital
- I = Initial Catalyst and Chemicals

References 9 and 10 on page 2-38 of the *Control Cost Manual* explicitly include AFUDC as a cost component and reference two reports, by Shattuck and Kaplan, in support of its use.<sup>73,74</sup>

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show how the methodology can be used to compare two competing air pollution control systems. The example provides a cash flow analysis for two competing control systems and uses the cash flow analysis to calculate the net present value of each system, assuming O&M costs and projected revenues are constant over time. The example uses net present value factors for an assumed interest rate to translate future costs to year zero values so the net present value of each technology can be compared. This is clearly meant to be a very simplified example of how the cost estimating methodology in the *Control Cost Manual* can be used to compare two competing technologies and provides no basis for concluding that the *Control Cost Manual* explicitly excludes escalation to a future baseline year.

<sup>70</sup> Revised BART Cost-Effectiveness Analysis, page 12.

<sup>71</sup> *Id.*, reference examples in Section 4, Chapter 1, Table 1-4; and Chapter 2, Table 2.5 of the *Control Cost Manual*.

<sup>72</sup> *Control Cost Manual*, page 2-5.

<sup>73</sup> Shattuck, D. M., et al., Retrofit FGD Cost-Estimating Guidelines, Electric Power Research Institute, Palo Alto, CA (CS-3696, Research Project 1610-1), October 1984.

<sup>74</sup> Kaplan, N., et al., “Retrofit Costs of SO<sub>2</sub> and NO<sub>x</sub> Control at 200 U.S. Coal-Fired Power Plants,” Pittsburgh Coal Conference, 1990.

The report by Shattuck was published in connection with an EPRI funded research project and cost estimating software for FGD retrofits. The report by Kaplan was published by the EPA, Air and Energy Engineering Research Laboratory, in collaboration with EPRI, the U.S. Department of Energy, and an industry technical advisory committee represented by seven major utility companies. These FGD cost studies were developed from the most comprehensive industry experience of the late 1980's and early 1990's. The EPA built upon this knowledge base and costing methodology in its publication of the *Control Cost Manual* in 2002. Thus, the *Control Cost Manual* allows the time value of money, measured by the real discount rate, to be incorporated into the cost estimate.

The examples referenced by EPA's consultant to argue that the *Control Cost Manual* "explicitly set AFUDC equal to zero" (i.e., Section 4, Chapter 1, Tables 1.4; and Chapter 2, Table 2.5) are simplified examples of cost estimates for a selective non-catalytic reduction ("SNCR") and selective catalytic reduction ("SCR") control system, respectively. Both of the tables include a line item for AFUDC, but zero out AFUDC for the example. The construction period for an SNCR is relatively short, approximately seven months, and the construction period for an SCR may be approximately 18 months. On the basis of a 7% real interest rate applied, on average, over one-half of the construction period, the AFUDC would be approximately 2% of the SNCR cost and 5% of the SCR cost. Nevertheless, the calculations of TCI in both examples include AFUDC, as well as other indirect costs, although some of these other costs were also assumed to be zero to simplify the example. The simplifying assumption that AFUDC should be zero for those examples does not mean that such costs are prohibited by the *Control Cost Manual* and, at any rate, the zero adjustment would not be appropriate for a FGD because of its long construction period. On the basis of a construction period of approximately 42 months, for example, the AFUDC would be approximately 12% of the FGD cost in real terms.

Section 2.3.1 of the *Control Cost Manual* (Elements of Total Capital Investment) describes the need for TCI to include all expenditures incurred during the construction phase of the project, including direct costs, indirect costs, fuel and consumables expended during start-up and testing, and other capitalized expenses. The only items explicitly mentioned to be excluded are common facilities that already exist at the site. AFUDC is part of the expense that will be incurred with the installation of a large air pollution control system, and the accepted practice in the utility industry and by financial institutions is to treat AFUDC as a capitalized expenditure. This approach is recognized in publications by the U.S. Department of Energy – Energy Information Administration (DOE/EIA), such as the *Annual Energy Outlook*,<sup>75</sup> and in publications by the Electric Power Research Institute (EPRI), such as the *Technical Assessment Guide*.<sup>76</sup> As previously mentioned, the EPA clearly followed this approach in its studies of retrofit costs of SO<sub>2</sub> and NO<sub>x</sub> in the years leading up to its publication of the *Control Cost Manual*. Furthermore, AFUDC has been included in several other coal-fired boiler BART determinations, and AFUDC is included as a line item in EPA's

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<sup>75</sup> See, DOE/EIA-0383 (2011), March 2011

<sup>76</sup> See, *TAG Technical Assessment Guide*, EPRI, page 2-15.

CUECost worksheets for FGD control systems.<sup>77</sup> In cases where the time value of money during the construction period would be significant (e.g., projects with longer construction periods such as the installation of DFGD), the *Control Cost Manual* clearly allows inclusion of AFUDC. Thus, EPA's consultant is incorrect to adjust the capital cost estimate by arbitrarily setting AFUDC to zero. It is not required by the *Control Cost Manual* and does not reflect the true cost of the DFGD.

**Bond Costs:** EPA's consultant suggests that Bond Costs represent a portion of the cost of financing the project, and are therefore similar to AFUDC. The consultant also argues that the Bond Costs represent "transfer payments and thus are not valid under the constant dollar approach in the *Cost Manual* and should not be included in the BART cost effectiveness analysis."<sup>78</sup>

**Response:** Bond costs represent tangible expenses paid to a bond underwriter for actual services associated with financing a large capital project. Bond costs are distinct from AFUDC, which represents the real cost of interest for the distributed cash flows during construction (as discussed above).

Section 2.3.1 of the *Control Cost Manual* (Elements of Total Capital Investment) describes the need for TCI to include all expenditures incurred during the construction phase of the project, including direct costs, indirect costs, fuel and consumables expended during start-up and testing, and other capitalized expenses. Bond costs are an indirect tangible cost paid to a bond underwriter for actual services.

Bond costs are clearly not "transfer payments." Transfer payments generally refer to reallocations of income between sectors of the economy that are not for current products or services.<sup>79</sup> Examples of transfer payments are government subsidies, welfare payments, and benefits paid under various social insurance programs. Transfer payments are not matched to productive activity and are not received in exchange for goods or services.<sup>80</sup> As mentioned previously, bond costs are paid to a bond underwriter in exchange for actual services and, therefore, are not transfer payments. Because bond costs are not "transfer payments," are distinct from AFUDC, and should be included in the calculation of indirect capital costs, as allowed by the *Control Cost Manual*, it is incorrect and inaccurate to arbitrarily set Bond Costs to zero in the capital cost estimate.

**Contingency:** EPA's consultant incorrectly states that the "S&L capital cost estimates include a contingency of about 14% of the total project capital cost plus escalation," and argues that the method used by S&L to determine an appropriate contingency was "not appropriate for determining BART cost effectiveness, which must follow the *Cost Manual*."<sup>81</sup> The consultant also incorrectly argues that it is "unprecedented to use range estimating, a

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<sup>77</sup> Coal Utility Environmental Cost (CUECost) Worksheets, prepared by Raytheon Engineers & Contractors, Inc. and Easter Research Group, Inc., EPA Contract No. 68-D7-001.

<sup>78</sup> Revised BART Cost-Effectiveness Analysis, page 12.

<sup>79</sup> G. Sirkin, *Introduction to Macroeconomic Theory*, Richard D. Irwin, Inc., 1965.

<sup>80</sup> E. Shapiro, *Macroeconomic Analysis*, Harcourt, Brace & World, Inc., 1966.

<sup>81</sup> Revised BART Cost-Effectiveness Analysis, page 13.

financial risk management and decision making technique” to estimate contingency in a cost effectiveness analysis.<sup>82</sup> Although EPA’s consultant agrees that contingency is allowed in the capital cost estimate, she incorrectly adjusts S&L’s cost estimate by using a “standard contingency factor” of 3% of the purchased equipment cost based on the *Control Cost Manual* examples for a fabric filter and wet scrubber for acid gas control.<sup>83</sup>

**Response:** The *Control Cost Manual* defines indirect installation costs to include “costs such as; construction and contractor fees, startup and testing, inventory capital, and any process and project contingency costs.”<sup>84</sup> Contingency is intended to represent “unforeseeable elements of cost, particularly in fixed investment estimates, which previous experience has shown to be statistically likely to occur.”<sup>85</sup> Contingency is based on the level of project definition (typically expressed as the percent of complete design), and the level of confidence required. Thus, a larger contingency is generally needed if the project is not well defined and/or if a high level of confidence is needed.

Based on the level of engineering completed for the December 2009 Budget Cost Estimates, S&L determined, using a range estimating technique, that a 14% contingency was needed to provide a 95% confidence level in the cost estimate. This level of contingency is typical for a scoping-level cost estimate. Range estimating is a commonly used technique to determine the level of contingency needed in a cost estimate (based on the level of engineering completed) to achieve the desired level of confidence. As EPA’s consultant admits, the contingencies provided for in the December 2009 Budget Cost Estimates “may be chosen by a project proponent to forecast final costs at an early planning stage...” (p.13). The December 2009 Budget Cost Estimates were done, at the request of EPA, to provide this type of detailed and site-specific estimate.

Indeed, the *Control Cost Manual* allows the analyst to include both process and project contingencies in an estimate of the indirect capital costs, and does not specify any particular methodology for estimating an appropriate level of contingency. Nowhere does the *Control Cost Manual* mandate using a generic 3% contingency as suggested by EPA’s consultant. In fact, the SNCR and SCR examples in the *Control Cost Manual* include a Process Contingency of 5% of the Direct Capital Costs, and a Project Contingency of 15% of the Total Direct Capital Costs + Indirect Installation Costs.<sup>86</sup> Using these examples, contingencies would result in a significantly higher contingency than that included in S&L’s December 2009 Budget Cost Estimates.

The range estimating process used by S&L in its December 2009 Budget Cost Estimates to establish contingency uses cost probabilities and Monte Carlo analysis to determine and apply an appropriate contingency. This methodology provides a more detailed estimate of contingency, based on the level of engineering completed, than arbitrarily applying a generic

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<sup>82</sup> *Id.*, at page 12, footnote 41.

<sup>83</sup> *Id.*, at page 13, footnote 44.

<sup>84</sup> *Control Cost Manual*, page 1-32.

<sup>85</sup> Perry’s *Chemical Engineers’ Handbook*, 4<sup>th</sup> Edition, page 26-3.

<sup>86</sup> See, e.g., *Control Cost Manual* Section 4, Chapter 2, Table 2-5.

3% contingency factor derived from the *Control Cost Manual* example for a fabric filter baghouse. EPA's consultant's use of 3% is clearly arbitrary, is not supported by the *Control Cost Manual*, and disregards the site specific level of engineering done to develop the December 2009 Budget Cost Estimates.

BOP Profits: EPA's consultant incorrectly asserts that "[p]rofits are commonly embedded in labor rates, supplies and materials," and that "[n]o support or justification for these estimates was provided" in S&L's December 2009 Budget Cost Estimates.<sup>87</sup>

**Response**: BOP refers to the balance-of-plant contractor who designs and integrates the control system into the existing facility. Crew wage rates included in S&L's December 2009 Budget Cost Estimates did not include contractor's general and administrative ("G&A") expenses and profit. Wage rates included in the cost estimate include base pay for skilled crafts, fringe benefits, worker's compensation, federal and state unemployment insurance, and applicable taxes. Therefore, contractor profit was included as a separate line item in the cost estimate as BOP Profits. It would be incorrect to arbitrarily remove BOP Profits from the capital cost estimate.

#### 4.2.4 Construction Cost Line Items

EPA's consultant acknowledges that the calculation of TCI includes indirect installation costs, but incorrectly argues that certain "other costs," such as labor rates, per diem expenses, and labor productivity and overtime efficiency adjustments, that were included in the December 2009 Budget Cost Estimates were overestimated. Construction cost line items rejected or revised by EPA's consultant are addressed below:<sup>88</sup>

Labor Rates: EPA's consultant argues that the labor rates used by S&L were excessive for an open shop project in Oklahoma and the general region.

**Response**: EPA's consultant bases her review on wage survey data provided on state and national websites. In the December 2009 Budget Cost Estimates, S&L included a man-hour estimate and a crew wage rate for the installation of each major piece of equipment. Non-union craft labor rates were developed from the publication "Merit Shop Wage and Benefit Survey," published by Personnel Administration, Inc. (PAS), for Region 6, which includes average Journeyman rates for Arkansas, Louisiana, New Mexico, Oklahoma, and Texas. Costs were added to the labor rates to cover FICA, workmen's compensation, federal and state unemployment insurance, and all applicable taxes. The resulting burdened craft rates were used to develop crew rates applicable to the tasks being performed. In developing the crew rates, additional allowances were included to cover construction equipment, site overheads, small tools, and jobsite consumables and incidentals. Burdened labor rates more accurately reflect the labor costs associated with a large construction project. It would be incorrect and inaccurate to arbitrarily remove these additional costs from the Labor Rate calculation.

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<sup>87</sup> Revised BART Cost-Effectiveness Analysis, page 13.

<sup>88</sup> See, Revised BART Cost-Effectiveness Analysis, pages 15 - 18.

Per Diem Expense: EPA’s consultant incorrectly argues that the per diem expense used by S&L in the December 2009 Budget Cost Estimates was excessive for the Oklahoma market and that per diem is not being paid for “open shop jobs in today’s soft labor market.”

**Response:** The reasons for including a per diem in the cost estimate are two-fold. First, per diem costs will be incurred to attract and retain a skilled labor force for major construction projects. Second, per diem costs will be incurred to cover a “traveling” labor force. Because of the size of these projects, the local labor force will be insufficient to perform all of the work associated with the construction of the DFGD/FF control systems. Therefore, it is reasonable to assume that it will become necessary to draw labor from outside the local area and that these non-local craftsmen would be paid per diem.

Per diem rates are not included in the wage rates; thus, there is no double counting. Per diem costs are shown as a separate line item under Other Costs as an indirect construction cost. Although unemployment has been a problem in the U.S. over the past few years, unemployment has been more pronounced within the manufacturing and service sectors. Oklahoma has consistently showed lower unemployment rates than the national average. The latest available data (March 2011) from the Bureau of Labor Statistics show that the unemployment rate in Oklahoma is 6.1% compared to 8.8% for the entire U.S.<sup>89</sup> Based on our experience with large construction projects, and given the current job market in Oklahoma, a per diem allowance will likely be needed to attract skilled trade labor to the job sites.

Labor Productivity: EPA’s consultant incorrectly argues that the construction man-hour adjustment used by S&L to account for labor productivity was “another form of contingency, specifically disallowed by the *Cost Manual*,” and strikes this cost as double counting on the basis that a general contingency was included elsewhere in the cost analysis. As a result, EPA’s consultant deducts the 15% productivity contingency from the estimated capital costs in Appendix 1, Line 23.

**Response:** To calculate labor costs, S&L determined the construction man-hours required for each DFGD/FF construction and applied a factor to account for labor productivity. It is common practice on large construction projects to apply a productivity factor to account for local worker productivity and construction site conditions. The methodology used in the *Control Cost Manual* recognizes the need to adjust labor costs to local conditions. The example given in Table 4-11 therein indicates a range of default personnel hourly rates and cost factors, incorporating differences in wage rates, overhead, and fees for various employee types. The *Control Cost Manual* indicates on the same page (p. 4-27) that “the default values can be modified if location specific or vendor specific information is available.”

S&L applied U.S. Productivity Factors published in the 2008 Front-End/Conceptual Estimating Year Book published by Compass International. As described in that publication, the normal approach for comparing process, refinery, and manufacturing construction productivity is to compare various locations around the U.S. to a benchmark of 1.00 for Texas Gulf Coast Cost Productivity (a well known and understood benchmark). Based on

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<sup>89</sup> Bureau of Labor Statistics, Data Tables & Calculators by Subject, <http://data.bls.gov/timeseries/LASST40000003>.

available historical data from the past 20 to 30 years, the productivity factor for Open Shop/Non-Union labor for Oklahoma was listed as 1.05 in the Compass International publication. S&L included an additional 10% factor to account for the fact that the OG&E DFGD/FF construction projects are back-fit projects that would require a significant amount of work in tight site conditions. Industry experience shows that back-fit projects and tight site conditions adversely affect labor productivity.<sup>90</sup>

The previously cited report by the EPA, Air and Energy Engineering Research Laboratory, which was developed in collaboration with EPRI, the U.S. Department of Energy, and an industry technical advisory committee, includes cost multipliers as cost model inputs for estimating FGD retrofit costs.<sup>91</sup> The list of cost multipliers includes regional cost factors and access/congestion factors. These factors are derived from empirical data for specific conditions and are necessary to adjust reference prices to local conditions, as allowed by the *Control Cost Manual*. These factors are distinct from the contingency, which is a cost that is statistically likely to occur based on the level of project definition (typically expressed as the percent of complete design) and the level of confidence required.

Overtime Inefficiency: EPA's consultant incorrectly argues that the overtime inefficiency adjustment used by S&L was "another form of contingency, specifically disallowed by the *Cost Manual*," and that it should also be considered double counting as a general contingency was included elsewhere in the cost analysis. She argues that the new scrubbers would be installed during normal maintenance outages by working five 10 hour days and that the efficient scheduling of the labor pool should not result in an overtime inefficiency. On these bases, EPA's consultant sets overtime inefficiency equal to zero in Appendix 1, Line 28.

**Response:** S&L's December 2009 Budget Cost Estimates assumed a fifty-hour work week would be needed to attract and retain the construction labor force necessary to complete the DFGD/FF construction projects. These projects would require a large labor force, and it is reasonable to assume that a fifty-hour work week (which includes incentive pay for overtime hours) will be required to attract the necessary labor force. However, longer work weeks, as well as other factors, can also affect labor productivity.<sup>92</sup> There are numerous publications such as AACE, RS Means, Mechanical Contractors Association of America, and engineering magazines (e.g., ENR) that support these overtime and labor productivity assumptions.<sup>93,94,95,96</sup>

The Overtime Inefficiency line item included in S&L's December 2009 Budget Cost Estimates was not intended to account for spot overtime; rather, it accounted for scheduled

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<sup>90</sup> Compass International Consultants Inc., *The 2010 Global Construction Cost and Reference Yearbook*, pages 527 - 529.

<sup>91</sup> Kaplan, N., et al., "Retrofit Costs of SO<sub>2</sub> and NO<sub>x</sub> Control at 200 U.S. Coal-Fired Power Plants," Pittsburgh Coal Conference, 1990.

<sup>92</sup> See, e.g., RSMMeans Labor Rates for the Construction Industry 2010, RSMMeans Engineering, December 2009, page 316.

<sup>93</sup> Engineering News-Record, June 18, 2009, page 60.

<sup>94</sup> Mechanical Contractors Association of America, Inc., *Bulletin No. OT 2: How Much Does Overtime Really Cost?*, 1994.

<sup>95</sup> Mechanical Contractors Association of America, Inc., *Bulletin No. PD 1: Labor Productivity*, 1994.

<sup>96</sup> Mechanical Contractors Association of America, Inc., *Bulletin No. PD 2: Factors Affecting Labor Productivity*, 1994.

overtime that would be incurred when a construction project extends over a 3 to 4 year period. Overtime Inefficiency costs were calculated as a loss of labor productivity based on hours worked per week and assuming an overtime cost equal to 1.5 times the base pay rate. Overtime pay takes into account only the wage rates, fringes, and applicable taxes, but excludes contractor's construction equipment and site overhead costs.

#### 4.2.5 Cost: Double Counting

EPA's consultant also incorrectly argues that S&L's December 2009 Budget Cost Estimates double count certain indirect capital costs associated with financing and constructing the air pollution control systems. Based on her review of S&L's cost estimates, she concludes that the following indirect capital costs have been double counted in the cost estimates for the Sooner and Muskogee units:<sup>97</sup>

Owner's Costs: While acknowledging that "owner's [sic] do incur some costs" when installing large air pollution control systems, EPA's consultant argues that facility owners generally retain engineering firms to manage and implement capital projects and that the Owner's Costs included in the December 2009 Budget Cost Estimates (estimated at 5% of the total capital expended) were excessive.

**Response:** Owner's Costs include a variety of non-financial costs incurred by the owner to support the air pollution control project. Owner's Costs are project-specific, but generally include costs incurred by the owner to manage the project, hire and retain staff to support the project, and costs associated with third party assistance associated with project development and financing. Owner's Costs include, but may not necessarily be limited to:

- site investigations (geotechnical, hydrology, etc.) for project design;
- environmental permitting/approvals;
- insurance during construction;
- site security during construction;
- transmission interconnection (if applicable);
- fuel interconnection (if applicable);
- owner's mobilization costs;
- owner's project management and support staff;
- insurance advisor;
- labor relations consultant;
- tax consultant;
- financial advisor;
- legal advisor;
- market consultant; and
- community relations/community outreach program.

Owner's Costs are real costs that the owner will incur during the project and are typically included in cost estimates prepared for large air pollution control retrofit projects. In fact, U.S. EPA's Coal Quality Environmental Cost (CUECost) model includes Owner's Costs (or "Home Office" costs) in its air pollution control system cost estimating workbook and

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<sup>97</sup> See, Revised BART Cost-Effectiveness Analysis, pages 19 - 22.

interrelated set of spreadsheets. CUECost uses a factor of 10% of the total installed cost to estimate Owner's Costs and Engineering Costs for limestone forced oxidation and lime spray dryer control systems.<sup>98</sup> Based on our experience on large air pollution control system projects and given the site specific nature of the December 2009 Budget Cost Estimates, it is reasonable to estimate Owner's Costs using a factor of 5% of the total direct costs for large air pollution control system retrofit projects, and it would be incorrect and inaccurate to arbitrarily exclude Owner's Costs from the cost estimate.

Engineering/Procurement: EPA's consultant incorrectly argues that "[a] portion of the S&L engineering/procurement costs is double counted." This statement is based on her assumption that "vendor proposals that Sargent & Lundy relied on include the cost to both design and supply the dry scrubber and baghouse."<sup>99</sup> Thus, because S&L also separately calculated engineering/procurement, EPA's consultant assumes that the engineering and procurement costs for the vendor-supplied portion of the capital costs are double counted.

**Response:** Engineering/Procurement costs are included in the calculation of indirect installation costs.<sup>100</sup> Major equipment engineering and procurement costs are included as part of the vendor equipment costs; however, there are significant engineering and procurement costs associated with balance-of-plant (BOP) equipment and integrating the control system into the existing facility. Major equipment suppliers, including those who supplied estimates in connection with the December 2009 Budget Cost Estimates, furnish their equipment with no foundations or other support structures and do not integrate the control systems into the existing facility for functional operation. The Engineering/Procurement line item includes the costs for engineering and procuring all BOP equipment, including ID fans, dampers, expansion joints, pumps, air compressors, and electrical equipment (high voltage power transformers, switchgear, motor control centers). Engineering/Procurement also includes the engineering design and detailed drawings for buildings, support steel, foundations, ductwork, BOP piping, BOP compressed and instrument air systems, electrical design (including auxiliary power requirements, raceway, conduits, cabling, controls, and instrumentation), resolving interferences, and preparing a general work installation specification. Based on project experience an Engineering/Procurement cost estimated at 6.5% of the total direct costs is reasonable for the installation and integration of DFGD and FF control systems and does not double count vendor engineering costs or Owner's Costs.

Construction Management: EPA's consultant incorrectly argues that BOP construction management costs occur in two places in S&L's Cost Estimate: first, under "total indirect costs" where S&L estimated construction management as 2% of the total direct costs; and second under "other costs" where S&L estimated the BOP contractor's general and administrative costs as 5% of BOP materials and labor costs.

**Response:** The BOP contractor's G&A costs and the construction management cost shown as an indirect capital cost in S&L's December 2009 Budget Cost Estimates are two distinct

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<sup>98</sup> See, Coal Utility Environmental Cost (CUECost) Workbook User's Manual Version 1.0, prepared by Raytheon Engineers & Contractors, Inc. and Eastern Research Group, Inc., EPA Contract No. 68-D7-0001, Appendix B, pages B-3 and B-6.

<sup>99</sup> See, Fox Report, page 20

<sup>100</sup> *Control Cost Manual*, page 2-6.

line items and do not double count the construction management costs. As discussed above, crew wage rates in the cost estimate included base pay for skilled crafts, fringe benefits, worker's compensation, federal and state unemployment insurance, and applicable taxes, but do not include contractor G&A expenses or profit. Therefore, contractor G&A was included as a separate line item in the cost estimate.

The construction management line item included as an indirect capital cost accounts for the costs associated with the services of a third-party construction management or engineering firm. This is a different contractor than the BOP contractor. Based on our experience on similar construction projects and considering the site specific nature of the December 2009 Budget Cost Estimates, a construction management cost equal to 2% of the total direct costs is consistent with Owner's Costs at 5% of the total direct costs. If the construction management costs were excluded, Owner's Costs would need to be increased.

Startup & Commissioning Craft Support: EPA's consultant incorrectly argues that the vendor proposals that S&L relied on to prepare the December 2009 Budget Cost Estimates included the cost to commission the units; thus, including a line item for startup and commissioning resulted in double counting.

**Response:** Equipment suppliers, including those who provided estimates in connection with the December 2009 Budget Cost Estimates, provide very limited field support during control system startup and commissioning. The Start-up & Commissioning line item accounts for the craft support required by the general work contractor (as opposed to the equipment suppliers) during the duration of start-up and commissioning (which can take several months). Project schedules developed for the Sooner and Muskogee DFGD projects included a five-month startup/commissioning duration for the first unit and an additional five-months for the second unit, but not at the same time. The same durations were true for the Muskogee units due to the similarities between the Sooner and Muskogee Units (e.g., comparable boiler size and fuels fired). The 10 months of craft support will require extended mobilization, supervision, and labor costs to help the owner during the startup/commissioning period. Cost estimates provided by the equipment suppliers include limited field support during startup, but do not include all of the craft support needed during startup and commissioning; thus, there is no double counting, and it is incorrect and inaccurate to arbitrarily exclude these costs from the cost estimate.

Operator Training & Manuals: EPA's consultant incorrectly argues that the vendor proposals that S&L relied on to prepare the December 2009 Budget Cost Estimates include these costs; thus, she argues that including a line item for operating training and manuals resulted in double counting.

**Response:** Operator training costs are not generally included in budgetary proposals received from equipment vendors and were not included in the proposals received in connection with the December 2009 Budget Cost Estimates. Because of the staggered start-up schedule for each station discussed above, separate operator training will be required. Operator training for a major air pollution control system can be extensive and is very important for the efficient, safe and reliable operation of the control system. Similarly, budgetary proposals from the equipment vendors do not include operating manuals. These manuals are needed for operating training and for safe operation of the control systems. Operator Training &

Manuals costs included in the December 2009 Budget Cost Estimates were based on our previous experience for similar type and size applications and include manuals for major FGD equipment as well as all BOP equipment. Because these costs are not included in the vendor quotes, there is no double counting, and it is incorrect and inaccurate to arbitrarily exclude these costs from the cost estimate.

#### 4.2.6 Total Annual Costs

Total annual costs (“TAC”) include the annualized cost of capital and the annual O&M costs associated with the control system. Under the *Control Cost Manual* methodology, total capital costs are annualized by calculating an annual payment sufficient to finance the investment over its entire life.<sup>101</sup> EPA’s consultant incorrectly argues that S&L did not follow the *Control Cost Manual* when it calculated the annual capital recovery cost, and that S&L’s O&M cost estimates also required adjustments.<sup>102</sup> Each element of the TAC cost evaluation is reviewed below:

##### 4.2.6.1 Capital Recovery

EPA’s consultant argues that the *Control Cost Manual* requires the analyst to calculate the annualized capital recovery cost (“CRC”) by multiplying the TCI by a capital recovery factor (“CRF”) calculated from a formula based on a 7% social interest rate and 30-year equipment lifetime. EPA’s consultant argues that S&L did not use the standard capital recovery method “as required by the *Manual*” in the December 2009 Budget Cost Estimates. The 7% social interest rate and 30-year equipment lifetime do not apply here.

**Response:** The *Control Cost Manual* calculates CRC by applying a CRF to TCI. The CRF is calculated using the following equation:

$$\text{CRF} = [i \times (1 + i)^n] / [(1 + i)^n - 1]$$

Where:

n = annualization period or equipment life, and  
i = interest rate

Example calculations provided in the *Control Cost Manual* use a social discount interest rate of 7.0% and an equipment life of 5 to 25 years (depending on the control system).

Although the *Control Cost Manual* uses the methodology described above to calculate an annualized capital recovery cost, the *Control Cost Manual* does not limit the analyst to using that method, nor does the *Control Cost Manual* dictate using a 7% social discount interest rate in the calculation. In fact, Section 2.4.2 of the *Control Cost Manual* (Interest Rates) states that the social discount rate of 7.0% may be used when “State, local, Tribal, and other governmental authorities assess pollution control costs;” however, “the social rate of interest is probably not appropriate for industry.”<sup>103</sup> The *Control Cost Manual* goes on to state that the industrial planner “must also understand how the cost of each device fits into the financial structure of their business.”<sup>104</sup> Because OG&E is an investor-owned utility company and not

<sup>101</sup> See, *Control Cost Manual*, page 2-21.

<sup>102</sup> See, Revised BART Cost-Effectiveness Analysis, pages 13 – 15 (capital recovery) and 27 – 32 (O&M costs).

<sup>103</sup> *Control Cost Manual*, page 2-13.

<sup>104</sup> *Id.*

a governmental agency, the *Control Cost Manual* suggests that it use an appropriate discount rate that more accurately reflects OG&E's capital structure.

Capital investment costs for an investor-owned utility such as OG&E are recovered by annual revenue requirements after the facility becomes operational and placed into the rate base. These revenue requirements consist of capital recovery, debt return, equity return, and income taxes. EPA's consultant fails to consider that the CRF (calculated using the equation above) includes not only recovery of the principle but also a return on the principal. The rate of return is equal to the discount rate. For an investor owned utility such as OG&E, which is financed by a mix of debt and equity, the discount rate is equal to the weighed average of the equity return and debt return (see our comment on the "Discount Interest Rate" below). EPA's consultant inaccurately makes it appear as if debt returns and equity returns are not legitimate components or somehow overstate the capital recovery cost, which is not correct.

The CRF equation in the *Control Cost Manual* provides a simplified derivation of the annual capital charge rate for entities that do not pay income taxes, such as a municipality or governmental agency. Using this equation in a scoping-level cost estimate is incomplete and inaccurate if applied to investor-owned utility companies such as OG&E. A more complete derivation of the annual capital costs based on OG&E's company-specific capital structure is included in Attachment B, Table B-5, of the December 2009 Budget Cost Estimates. The approach described therein is the accepted approach used in the utility industry and by financial institutions and conforms with the intended use of the *Control Cost Manual*.

Control System Useful Life: EPA's consultant calculates the CRF using a scrubber life of 30 years, arguing that standard cost estimating handbooks and published reports identify 30 years as a typical life for a scrubber. The consultant then uses a 30-year lifetime to decrease the annual capital costs calculated by S&L in the December 2009 Budget Cost Estimates by approximately 30% (0.1036/0.0806).

**Response:** The useful life of a control technology is not specifically defined in the *Control Cost Manual* and EPA's consultant's use of a 30-year lifetime is arbitrary, especially considered in light of the site specific nature of the December 2009 Budget Cost Estimates. In general, useful life varies according to the type of control system and with the severity of the environment in which the control system is installed.<sup>105</sup> Indeed, the *Control Cost Manual* also references "Economic Life" of the control system and provides examples where it is appropriate to use that metric in cost calculations.<sup>106</sup> Here, as is typical in the industry, the useful life of a control system is considered to end when the cost of the equipment has fully depreciated and O&M costs begin to rise.<sup>107</sup> Thus, the term "useful life," as used in the *Control Cost Manual* and other economic impact analyses, is not necessarily the same as actual service life of the control system, and the consultant's reference to the actual age of certain existing scrubbers is not the appropriate measure.

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<sup>105</sup> *Control Cost Manual*, page 2-26.

<sup>106</sup> *Id.*, Section 1, Chapter 2, Table 2.3, page 2-26.

<sup>107</sup> *Id.* at page 2-16

Although (as mentioned above) the *Control Cost Manual* does not include a specific chapter for wet or dry FGD control systems, the *Control Cost Manual* assumes a 20 year useful life for other large air pollution control systems. For example, the cost estimating example provided in the *Control Cost Manual* for fabric filter baghouse control systems assumes a 20 year useful life. (Section 6, Chapter 1, page 1-46 and page 1-48). Similarly, EPA assumes an equipment life of 20 years for SCR control systems (Section 4.2, page 2-48). Finally, a 20-year useful life has been used in several BART evaluations for retrofit FGD control systems.<sup>108</sup> EPA's consultant's use of a 30-year lifetime simply based on examples of scrubbers at other facilities (some of which have not even been in use for 30 years) is arbitrary and cannot be supported by the *Control Cost Manual*. To be consistent with other BART evaluations, a useful life of 20-years is appropriate for a retrofit DFGD/FF control system.

Discount Interest Rate: EPA's consultant argues that S&L's cost estimate assumed an interest rate of 8.23% (when the effect of debt, equity and taxes are included) in the calculation of the capital recovery cost and that it has long been standard practice to use an interest rate of 7% in regulatory cost effectiveness analyses.

**Response:** As discussed above, the 7% interest rate used in *Control Cost Manual* example calculations represents a "social discount rate" that may be used for "State, local, Tribal, and other governmental authorities." However, the *Control Cost Manual* clearly states that "the social rate of interest is probably not appropriate for industry," and that the analyst "must also understand how the cost of each device fits into the financial structure of their business."<sup>109</sup> Since OG&E is an investor-owned utility company and not a governmental agency, the *Control Cost Manual* allows it to use a discount rate that more accurately reflects its capital structure.

It is important to again note here that EPA chose to base its analysis on the December 2009 Budget Cost Estimates, which EPA and ODEQ requested be done to provide site specific estimates that went above and beyond what was required by the *Control Cost Manual*. Although the study-level cost estimates prepared for the May 2008 BART Evaluations used the default 7% social discount rate, S&L's December 2009 Budget Cost Estimates replaced the social discount rate with OG&E's after-tax weighted average cost of capital calculated based on OG&E's capital structure. The nominal rates were each deflated by an inflation rate of 2.5% to determine the real rate, as indicated in Table 3 of the December 2009 Budget Cost Estimates.

For example, the nominal return on equity of 10.75% was converted to a real rate as follows:

$$\{[(1.1075)/(1.025)] - 1\} \times 100 = 8.05\%.$$

The real discount rate is determined as:

$$(0.557 \times 8.05\%) + [(0.443 \times 3.44\%) \times (1 - 0.3812)] = 5.43\%.$$

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<sup>108</sup> See, e.g., *Best Available Retrofit Technology (BART) Determination, American Electric Power, Northeastern Power Plant*, May 30, 2008. *BART Five Factor Analysis, Kansas City Power & Light, LaCygne Generating Station*, August 2007.

<sup>109</sup> *Control Cost Manual*, page 2-13.

We also note that this discount rate is actually lower than the 7.0% social discount rate used in the *Control Cost Manual* examples. This discount rate is calculated based on the financial structure, using an approach that is accepted in the utility industry and by financial institutions, and conforms with the intended use of the *Control Cost Manual*. It would be inaccurate and incorrect in a scoping-level cost estimate like the December 2009 Budget Cost Estimates for an investor-owned utility company to arbitrarily calculate the annual cost of capital using a 7% social discount rate.

#### 4.2.6.2 Variable Operating and Maintenance (O&M) Costs

EPA's consultant argues that variable costs (as well as emission reductions) in S&L's December 2009 Budget Cost Estimates were based on "Option 2" (i.e., reducing SO<sub>2</sub> emissions from an uncontrolled rate of 0.509 lb/MMBtu to a controlled rate of 0.10 lb/MMBtu), while the scrubber sizing and capital costs were based on "Option 1" (i.e., reducing SO<sub>2</sub> emissions from an uncontrolled rate of 1.176 lb/MMBtu to a controlled rate of 0.10 lb/MMBtu). She concludes that this mismatch results in underestimating emission reductions and fixed O&M costs, while overestimating capital costs.

**Response:** As discussed above, there was no "mismatch" between the capital cost estimate and the annual O&M cost estimate included in S&L's December 2009 Budget Cost Estimates. Capital costs were based on sizing the DFGD/FF control systems to handle the full load flue gas flow rate associated with firing subbituminous coal. Annual O&M costs, and annual SO<sub>2</sub> emission reductions, were calculated based on the average actual baseline SO<sub>2</sub> loading to the scrubber. This approach is consistent and provides a more specific estimate of the annual O&M costs.

Annual O&M costs include both fixed and variable costs and indirect operating costs.<sup>110</sup> Variable O&M costs are items that generally vary in proportion to the plant capacity factor. Variable costs associated with DFGD control include lime reagent costs, water costs, FGD waste disposal costs, bag and cage replacement costs, ash disposal costs, and auxiliary power costs.<sup>111</sup> Line item variable O&M costs revised by EPA's consultant are reviewed below:

Lime Costs: EPA's consultant argues that S&L overestimated the amount of lime necessary for the 80% SO<sub>2</sub> removal case because the cost estimate was based on a stoichiometric ratio of 1.5 moles of calcium/mole of SO<sub>2</sub> entering the system rather than using the "rule of thumb" value of 1.2

**Response:** The stoichiometry required for a specific application is a function of several design parameters including, but not limited to, the spray-down temperature (i.e., the difference between the spray dryer inlet and outlet temperatures), the approach to the adiabatic saturation temperature in the scrubbing vessel, and the degree of recycle possible within the physical limits of the control system. For the OG&E dry scrubbers it was determined, based on the unit-specific design parameters and unit-specific SO<sub>2</sub> removal efficiencies developed in connection with the December 2009 Budget Cost Estimates, that a stoichiometric value of 1.5 was most appropriate for the process conditions. It is incorrect for EPA's consultant to arbitrarily recalculate the lime

<sup>110</sup> See, *Control Cost Manual*, Figure 2.3, page 2-8.

<sup>111</sup> See, Revised BART Cost-Effectiveness Analysis, pages 27-32.

consumption rate based on a rule of thumb value of 1.2 without taking into account the specific design parameters for the OG&E scrubbers (and again ignoring the site-specific nature of the December 2009 Budget Cost Estimates).

Water Cost: EPA's consultant argues that the water consumption rate used in the December 2009 Budget Cost Estimates of 5.3 gallons/MMBtu heat input was beyond the upper end of the range of 3.6 to 4.4 gal./MMBtu for other similar dry scrubbers.

**Response:** The water consumption in a DFGD control system is calculated based on the amount of water needed to cool the flue gas from the spray dryer inlet temperature to the spray dryer outlet temperature (the spray-down temperature); thus, water consumption is fixed by thermodynamics. Units that have a higher air heater outlet temperature and units with more air in-leakage will require more water than similar units with different design and operating parameters. For example, a 10°F change in the air heater outlet temperature will result in a 7% - 8% change in the amount of water needed to achieve the design approach-to-saturation temperature. The water consumption rate used in S&L's December 2009 Budget Cost Estimates was based on unit specific design and operating parameters, consistent with the purpose of those estimates. As mentioned previously, EPA chose to base its analysis on the site-specific December 2009 Budget Cost Estimates. It is incorrect and inaccurate for EPA's consultant to now arbitrarily adjust the water consumption rate based on "rule of thumb" water consumption rates.

FGD Waste Disposal Cost: EPA's consultant revises the FGD waste disposal cost by increasing the quantity of waste generated in the FGD (based on the higher inlet SO<sub>2</sub> loading rate). EPA's consultant also argues that the unit cost to dispose of the FGD solids is high compared to other similar BART cost analyses.

**Response:** Calculating the quantity of FGD waste generated based on an inlet loading rate of 1.176 lb/MMBtu is inconsistent with the rest of the variable O&M cost estimate. As discussed throughout this report, there was no inconsistency between the capital cost estimate and the annual O&M cost estimate. Capital costs were based on the flue gas flow rate, while variable O&M costs and the quantity of SO<sub>2</sub> removed from the flue gas were calculated based on the average SO<sub>2</sub> loading to the scrubber. This approach provides a consistent basis for estimating capital costs, O&M costs, and SO<sub>2</sub> removal. Revising the variable O&M costs based on the maximum inlet SO<sub>2</sub> loading rather than average SO<sub>2</sub> loading to the scrubber would overestimate the quantity of FGD waste generated and would be inconsistent with the rest of the variable O&M cost estimates.

Auxiliary Power Costs: EPA's consultant argues that the auxiliary power costs for the DFGD/FF control systems in S&L's December 2009 Budget Cost Estimates were overestimated primarily because the unit cost of electricity used in the cost estimate was "much higher than the cost to OG&E to produce electricity." The consultant argues that the "posted rates [for OG&E] energy charges for various types of off-peak uses are under \$50/MWh, as low as \$32/MWh for power and light uses in the winter and \$36/MWh for public school summer off-peak and all winter demand. Thus, she argues that the busbar cost to produce electricity is under \$50/MWh."

**Response:** EPA's consultant is mixing terminology by equating busbar costs to energy charges. Further, her price quotations completely ignore the summer on-peak period, which has significantly higher rates. By definition, busbar costs are the all-in cost to produce electricity, including capital charges, fixed O&M, variable O&M, and fuel. EPA's consultant selectively chooses only off-peak energy charges, which generally cover only variable O&M and fuel costs. In the long run, auxiliary power has a cost for both energy and capacity. Besides the variable production costs (i.e., variable O&M and fuel), auxiliary power requirements also reduce the installed net plant capacity. Capacity has a real value to OG&E, as may be measured by the \$/kW cost of base load replacement capacity, or the \$/kW cost of required capacity reserve margins. S&L used average year-round market retail rates of \$85.93/MWh (2015\$) for Sooner and \$83.83/MWh (2014\$) for Muskogee as the best long-run measure of auxiliary power capacity and energy costs.

The previously cited report by the EPA, Air and Energy Engineering Research Laboratory, which was developed in collaboration with EPRI, the U.S. Department of Energy, and an industry technical advisory committee, uses a value of \$50/MWh in constant 1988 dollars.<sup>112</sup> On the basis of an estimated inflation rate of 2.5%/year, this would be equivalent to a value of \$95/MWh (2014 \$) and \$97/MWh (2015 \$). It is clear from the magnitude of the auxiliary power rate that the EPA study accounted for both energy and capacity, as did S&L in the December 2009 Budget Cost Estimates.

#### 4.2.6.3 Fixed and Indirect Operating Costs

Despite her repeated admonition that OG&E should have remained wedded to default factors in the *Control Cost Manual*, EPA's consultant notably did not adjust the lower site-specific factors used for property taxes, insurance, and administrative charges in the December 2009 Budget Cost Estimates. 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. Indirect operating costs are recurring annual costs for the DFGD/FF control systems that are not part of the direct O&M. These consist of property taxes, insurance, and administration.

**Response:** With respect to indirect operating costs (including overhead, property taxes, insurance, and administration), EPA's consultant did not revise the factors that S&L used in the December 2009 Budget Cost Estimates (i.e., property taxes as 0.6% (Sooner) and 0.85% (Muskogee) of Total Capital Investment, and insurance as 0.0105% of TCI). Rather, she applied S&L's factors to her revised TCI calculation. However, the *Control Cost Manual* provides the following default factors for indirect operating costs: Overhead = 60% of sum of operating, supervisor, and maintenance labor plus maintenance materials; Administrative Charges = 2% of TCI; Property Tax = 1% of TCI; Insurance = 1% of TCI.<sup>113</sup> These default factors are significantly higher than the factors used by S&L in the December 2009 Budget Cost Estimates. If EPA's consultant argues that the *Control Cost Manual*

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<sup>112</sup> Kaplan, N., et al., "Retrofit Costs of SO<sub>2</sub> and NO<sub>x</sub> Control at 200 U.S. Coal-Fired Power Plants," Pittsburgh Coal Conference, 1990.

<sup>113</sup> See, e.g., *Control Cost Manual*, Section 1, Chapter 2, page 2-34. See also, Section 6, Chapter 1, Table 1.11.

mandates the use of other factors, for consistency, she should have revised these factors upwards, as well. Her selective use of updated, site-specific numbers where they lower overall costs and “rule of thumb” numbers from the *Control Cost Manual* where that approach lowers cost is inconsistent and arbitrary and shows that her approach was result-driven.**5.0 ADDITIONAL COMMENTS**

Based on its consultant’s erroneously revised and significantly understated cost estimates, EPA proposes to find that it could not accept the cost estimates for dry scrubbers in the Oklahoma SIP and concludes, “based on a controlled emission limit of 0.06 lb/MMBtu,” that dry scrubbers are “cost effective at Units 4 and 5 of the OG&E Muskogee plant, [and] Units 1 and 2 of the OG&E Sooner plant.”<sup>114</sup> EPA proposes that SO<sub>2</sub> BART for Muskogee Units 1 & 2 and Sooner Units 4 & 5 is an emission limit of 0.06 lb/MMBtu that applies singly to each of these units on a 30-day rolling average.<sup>115</sup> EPA also proposes compliance with the emission limits be within three (3) years of the effective date of the final rule; however, EPA specifically solicited comment on alternative compliance timeframes.<sup>116</sup> Comments on both the proposed BART SO<sub>2</sub> emission limits and the compliance timeframe, independent of the accuracy of the EPA’s cost analyses, are provided below.

### 5.1 BART SO<sub>2</sub> Emission Limit

In the Proposed FIP, EPA concludes, based on performance information provided in the TSD that dry scrubbers on the OG&E units could remove approximately 90% of the SO<sub>2</sub> when burning coal with an uncontrolled emission rate of approximately 0.51 lb/MMBtu, 91.5% when burning coal corresponding to ODEQ’s BART limit of 0.65 lb/MMBtu, and 95% when burning the coal used to size the scrubber, 1.18 lb/MMBtu.<sup>117</sup> Based on this information, EPA concludes that the OG&E units could meet an SO<sub>2</sub> emission limit of 0.06 lb/MMBtu (30-day rolling average) using dry scrubbing technologies. EPA notes, based on information provided in the TSD, that “there are already facilities operating below this emission rate, using dry scrubbing technologies, and that burn similar coals.”<sup>118</sup>

**Response:** The analysis upon which EPA appears to rely to establish the proposed BART SO<sub>2</sub> emission limit for the OG&E units is found in Section VI of the Fox Report.<sup>119</sup> That analysis includes: (1) a chart from an S&L report prepared in 2007 for the National Lime Association<sup>120</sup> showing the relationship between inlet SO<sub>2</sub> and SO<sub>2</sub> removal efficiency in a dry scrubber; (2) hourly SO<sub>2</sub> emissions data from 5/1/2008 to 7/1/2010 from the Newmont TS Power generating station in Nevada; and (3) proposed SO<sub>2</sub> emission limits included in the final Prevention of Significant Deterioration (“PSD”) permit issued for the Longleaf Generating Station in Georgia in 2007. Based on its analysis of this information, EPA concludes that the OG&E scrubbers could meet an enforceable permit limit of 0.06 lb/MMBtu.

EPA’s analysis of the technical capabilities of retrofit dry scrubbing systems, and its reliance on information summarized in the TSD, is inadequate for establishing an enforceable BART emission limit for the reasons discussed below:

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<sup>114</sup> See, 76 FR 16183, col. 3.

<sup>115</sup> *Id.* at 16194.

<sup>116</sup> *Id.*

<sup>117</sup> *Id.* at 16187.

<sup>118</sup> *Id.*

<sup>119</sup> See, Revised BART Cost-Effectiveness Analysis, pages 42-45.

<sup>120</sup> *Flue Gas Desulfurization Technology Evaluation Dry Lime vs. Wet Limestone FGD*, prepared by Sargent & Lundy LLC, March 2007 (the “National Lime Report”).

First, information provided in the National Lime Report was intended to provide a high-level comparison of the effectiveness and cost-effectiveness of wet and dry FGD control systems on coal-fired boilers firing various types of coal. The report was never intended to be a design document, nor was it based on OG&E-specific design parameters. Relying on removal efficiencies included in Figure 2.1-1 of the National Lime Report (EPA's TSD Figure 3) to establish an enforceable permit limit would be incorrect, as removal efficiencies in the report "represents a general guideline" for application of dry scrubbing technology and does not take into consideration any site-specific operating parameters.<sup>121</sup> Furthermore, EPA's consultant misrepresents information in the chart when she concludes that the "figure shows that a dry scrubber on the Sooner and Muskogee units can remove about 90% of the SO<sub>2</sub> when burning current coal (0.51 lb/MMBtu), 91.5% when burning the proposed BART coal (0.65 lb/MMBtu), and 95% when burning the coal used to size the scrubber (1.18 lb/MMBtu)."<sup>122</sup>

Second, hourly emissions data provided by EPA's consultant for the Newmont TS Power Generating facility ("Newmont") may provide insight into the technical capabilities of a dry scrubbing system on a new unit, but the Newmont emission data are not representative of emissions that would be achieved on a retrofit project and should not be used to establish an enforceable BART permit limit. The Newmont facility commenced commercial operation in May 2008 and is a new coal-fired boiler specifically designed with an integrated DFGD/FF control system. Controlled emissions achievable at a new facility would not be representative of emissions expected from a retrofit project.

Table 5-1 (below) lists the average annual SO<sub>2</sub> emissions from all existing coal-fired boilers equipped with dry lime scrubbing.<sup>123</sup> EPA relied on emissions data from the Newmont unit to establish the proposed BART emission limits for the OG&E units; however, the Newmont unit is a new boiler, and, based on 2009 emissions data summarized in Table 5-1, achieved the lowest average SO<sub>2</sub> emission rate of any boiler operating in the U.S. with dry scrubbing technology. This emission rate would be more representative of the lowest emission rate achieved in practice by the best controlled similar source, and might be representative of Lowest Achievable Emission Rate ("LAER") or Best Available Control Technology ("BACT") for a new source, but would not be representative of BART. In fact, the top four units listed in Table 5-1 are new units which commenced commercial operation since 2007 and were specifically designed with an integrated DFGD/FF control system. The first unit in the list equipped with a retrofit control system is Rawhide Station Unit 101. That unit achieved average annual SO<sub>2</sub> emissions of 0.088 lb/MMBtu (annual average). The average controlled SO<sub>2</sub> emission rate achieved by all existing units equipped with dry scrubbing technology in 2009 was 0.227 lb/MMBtu.

Third, EPA also relies on SO<sub>2</sub> emission rates included in the final PSD permit for the Longleaf Generating Station in Georgia to establish the BART emission limits for the OG&E units. The Longleaf PSD permit was issued in May 2007 and included an SO<sub>2</sub> emission limit of 0.065 lb/MMBtu (30-day average) when the uncontrolled SO<sub>2</sub> emission rate is less than or equal to 1.0 lb/MMBtu. Although the Longleaf unit has been permitted, it has not commenced commercial

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<sup>121</sup> National Lime Report, 2007, page 6.

<sup>122</sup> See, Fox Report, page 43.

<sup>123</sup> Emissions information was obtained from <http://camddataandmaps.epa.gov/gdm>. Only emissions from existing coal-fired units equipped with "dry lime scrubbing" and with an average hourly heat input to the boiler of 1,000 MMBtu/hr have been included in the summary. Smaller boilers (i.e., <1,000 MMBtu/hr) would be less than 1/5<sup>th</sup> the size of the OG&E units, and would not necessarily be considered a similar source.

operation and has not demonstrated the ability to achieve the proposed emission limits. It is not appropriate to establish BART emission limits based on PSD limits for a new facility that has not yet commenced commercial operation.

**Table 5-1**

		<b>Operating Time</b>	<b>SO2 Mass</b>	<b>SO2 Rate</b>	<b>Heat Input</b>	<b>Average Heat Input</b>	
<b>Facility Name</b>	<b>Unit ID</b>	<b>(hours)</b>	<b>(tons)</b>	<b>(lb/MMBtu)</b>	<b>(MMBtu)</b>	<b>(MMBtu/hr)</b>	<b>SO2 Control Info</b>
TS Power Plant (Newmont)	1	7,665	251.1	0.040	12,575,087	1,641	Dry Lime FGD
Wygen II	1	8,540	240.0	0.051	9,402,401	1,101	Dry Lime FGD
Weston	4	7,232	971.8	0.066	29,332,479	4,056	Dry Lime FGD
Walter Scott Jr. Energy Center	4	8,273	1,912.7	0.072	53,469,751	6,463	Dry Lime FGD
Springerville Generating Station	TS3	8,475	1,255.9	0.082	30,511,441	3,600	Dry Lime FGD
Springerville Generating Station	4	353	62.4	0.087	1,441,825	4,084	Dry Lime FGD
Rawhide Energy Station	101	8,742	1,060.8	0.088	24,246,173	2,773	Dry Lime FGD
Comanche (470)	2	7,829	1,243.9	0.091	27,423,612	3,503	Dry Lime FGD
Allen S King	1	7,659	1,636.4	0.093	35,025,363	4,573	Dry Lime FGD
Hardin Generating Station	U1	7,894	493.6	0.094	10,533,315	1,334	Dry Lime FGD
Hawthorn	5A	7,891	2,016.0	0.095	42,522,257	5,389	Dry Lime FGD
Louisa	101	8,234	2,250.1	0.097	46,174,909	5,608	Dry Lime FGD
Westmoreland Partners Roanoke Valley I	1	7,121	512.0	0.106	9,699,478	1,362	Dry Lime FGD
Craig	C3	7,374	1,686.3	0.116	29,057,229	3,940	Dry Lime FGD
Comanche (470)	1	8,170	1,556.7	0.128	24,247,113	2,968	Dry Lime FGD
Hayden	H2	8,540	1,476.3	0.13	22,693,898	2,657	Dry Lime FGD
Wygen I	1	8,504	568.3	0.131	8,701,644	1,023	Dry Lime FGD
Cope Station	COP1	7,918	1,595.2	0.133	24,011,603	3,033	Dry Lime FGD
Hayden	H1	6,871	953.4	0.134	14,196,961	2,066	Dry Lime FGD
Holcomb	SGU1	8,179	1,948.3	0.141	27,579,164	3,372	Dry Lime FGD
Logan Generating Plant	1001	8,250	768.8	0.144	10,673,611	1,294	Dry Lime FGD
North Valmy	2	8,152	1,441.1	0.151	19,143,530	2,348	Dry Lime FGD
Northside	2A	6,437	1,387.9	0.151	18,438,274	2,865	Dry Lime FGD
Northside	1A	6,265	1,397.1	0.153	18,222,684	2,909	Dry Lime FGD
Laramie River	3	6,905	3,520.9	0.169	41,586,809	6,023	Dry Lime FGD
Nebraska City Station	2	6,612	3,377.0	0.172	39,341,118	5,950	Dry Lime FGD
Cherokee	3	7,521	883.9	0.178	9,952,560	1,323	Dry Lime FGD
Cherokee	4	6,007	1,580.8	0.19	16,632,359	2,769	Dry Lime FGD
Grand River Dam Authority	2	8,151	4,569.4	0.198	46,197,277	5,668	Dry Lime FGD
Springerville Generating Station	2	7,820	2,807.6	0.216	26,050,908	3,331	Dry Lime FGD

**Table 5-1 continued:**

Indiantown Cogeneration, LP	1	7,523	1,968.9	0.252	15,651,993	2,080	Dry Lime FGD
Springerville Generating Station	1	7,706	3,148.6	0.255	24,686,814	3,204	Dry Lime FGD
Valmont	5	6,945	1,776.3	0.265	13,393,824	1,929	Dry Lime FGD
Bay Shore	1	8,128	2,130.2	0.3	14,179,523	1,745	Dry Lime FGD
Sherburne County	3	8,536	11,046.2	0.332	66,608,114	7,804	Dry Lime FGD
Brayton Point	1	7,135	2,507.4	0.346	14,494,875	2,032	Dry Lime FGD
Walter Scott Jr. Energy Center	3	7,533	7,982.9	0.346	46,124,800	6,123	Dry Lime FGD (Began May 15, 2009)
Antelope Valley	B1	8,432	7,038.7	0.366	38,437,954	4,559	Dry Lime FGD
Brayton Point	2	7,686	2,879.1	0.38	15,166,254	1,973	Dry Lime FGD
Antelope Valley	B2	8,530	7,359.2	0.389	37,867,178	4,439	Dry Lime FGD
Birchwood Power Facility	1	3,815	1,211.7	0.459	5,280,333	1,384	Dry Lime FGD
Wyodak	BW91	8,437	7,436.9	0.469	31,688,329	3,756	Dry Lime FGD
Genoa	1	7,515	6,457.7	0.731	17,668,769	2,351	Dry Lime FGD (Began Nov 16, 2009)
Deerhaven	B2	7,505	5,781.9	0.793	14,576,952	1,942	Dry Lime FGD (Began May 01, 2009)
Coyote	B1	6,722	12,017.3	0.834	28,835,063	4,290	Dry Lime FGD

Based on an uncontrolled SO<sub>2</sub> emission rate of 0.51 lb/MMBtu, the most aggressive design target for a DFGD/FF retrofit project on an existing boiler could be in the range of 0.06 lb/MMBtu. However, an emission rate as low as 0.06 lb/MMBtu does not represent a permit limit or an emission rate that can be achieved under normal operating conditions. Some reasonable margin must be provided between the design target and the enforceable permit limit to allow for normal fluctuations in the controlled emission rate.

A permit limit below approximately 0.10 lb/MMBtu (30-day average) would eliminate almost all the margin between the design target of a retrofit DFGD/FF control system and the permit limit. The BART emission limit established during the rulemaking process will be enforceable over the life of the unit. As a result, the BART analysis must take into account the full range of possible fuels, operating conditions, operating system fluctuations, and normal wear-and-tear on the units and control systems. Even with respect to the more stringent Best Available Control Technology (“BACT”) requirements under the New Source Review PSD regulations, EPA’s Environmental Appeals Board has recognized that “permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather will allow permittees to achieve compliance on a consistent basis.”<sup>124</sup> Indeed, various process parameters affect the efficiency of the DFGD process including: the type and quality of the reactant, reactant stoichiometric ratio, the inlet flue gas temperature, how close the SDA is operated to saturation conditions, and the amount of solids product recycled to the atomizer.<sup>125</sup>

<sup>124</sup> See, Three Mountain Power, PSD Appeal No. 01-05 at 21 (May 30, 2001), citing: In re Masonite Corp., 5 E.A.D. 560-61 (EAB 1994) (“There is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor.”); and In re Knauf Fiber Glass, GmbH, PSD Appeal Nos. 99-8 to -72, slip op. at 21 (EAB, Mar. 14, 2000) (“The inclusion of a reasonable safety factor in the emission limitation is a legitimate method of deriving a specific emission limitation that may not be exceeded.”).

<sup>125</sup> Babcock & Wilcox, *Steam: It’s Generation and Use*, 41<sup>st</sup> Edition, page 35-13

Even assuming DFGD/FF could somehow be a cost-effective retrofit technology for the OG&E units, imposing an enforceable BART emission limit of 0.06 lb/MMBtu is beyond the technical capabilities of the control technology. EPA's analysis of capabilities of a retrofit DFGD control system focused on emission rates achieved in practice by new units specifically designed with an integrated DFGD/FF control system. This emission rate is not representative of an enforceable BART limit on a retrofit project. Of the existing units equipped with a retrofit DFGD control technology, the lowest emission rate achieved in practice is approximately 0.088 lb/MMBtu (annual average) at Rawhide Station Unit 101.

Based on technical feasibility, physical limitations of the control system, emissions achieved in practice at existing sources, an emission rate of 0.10 lb/MMBtu (30-day average) as BART for SO<sub>2</sub> control would require the OG&E units to achieve actual SO<sub>2</sub> emissions at or below those currently achieved in practice by Rawhide Station Unit 101, while providing a reasonable margin for operating fluctuations and compliance. Imposing a BART emission limit of 0.06 lb/MMBtu is below the demonstrated capabilities of the control technology for retrofits, and would eliminate all margin between the possible design target of the control system and the enforceable permit limit.

## 5.2 3-Year Compliance Timeframe

EPA also proposes that the OG&E Muskogee and Sooner units achieve compliance with the BART SO<sub>2</sub> emission limits within three (3) years of the effective date of the final rule. EPA is also soliciting comments on alternative compliance schedules ranging from two (2) to five (5) years of the effective data.<sup>126</sup>

**Response:** To complete a DFGD project, extensive planning is required. The bid phase engineering, review, and contract negotiation can take up to one year to complete. After a bid is approved and a contract signed, the construction of a DFGD system will generally require about 32 to 40 months to complete. Following construction, final unit connections will require a plant outage. A typical schedule for installing a single DFGD system includes the following milestones:

- Baseline – Project Authorization
- 2 months – Issue RFQ to EPC Bidders
- 9 months – Contract Awarded
- 18 months – Complete Detailed Engineering and Design
- 19 months – Begin Absorber Fabrication
- 45 months – Pre-Operational Checkout
- 52 months – Complete Unit Tie-ins and Start-up

The schedule provided above does not account for installation of two units that would be required at each of the Sooner and Muskogee Stations. The construction activities for the four total DFGD units would have to be coordinated to account for staggered delivery of materials and to ensure that construction labor is available. In addition, the DFGD tie-in schedules must coincide with planned unit outages. Based on the general retrofit schedule provided above, and challenges associated with the simultaneous installation of four DFGD systems, a 3-year compliance schedule is not practical nor

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<sup>126</sup> See, 76 FR 16194, col. 1.

even reasonable. Although a 5-year compliance schedule could present challenges, this schedule would be expected to provide an adequate timeframe for installing four DFGD systems.

The costs included in the May 2008 BART Evaluations, the December 2009 Budget Cost Estimates, and Oklahoma's BART determinations were based on a 5-year implementation schedule. If it were possible to achieve a 3-year implementation for the four OG&E units, the DFGD system cost estimates would increase because of premiums for expediting the installation schedule.

### 5.3 Wet FGD Cost-Effectiveness

EPA also concludes that wet flue gas desulfurization ("WFGD") is a cost effective option for the OG&E units. This conclusion is based on EPA's estimation that, while their evaluation of costs indicate that the cost effectiveness for WFGD is 9% greater than for DFGD, the costs of WFGD "fall within the range of values found to be cost effective in similar wet scrubber cost determinations."<sup>127</sup>

**Response:** A majority of the WFGD systems designed to remove SO<sub>2</sub> from existing utility boilers have been designed as wet limestone scrubbers with spray towers.<sup>128</sup> WFGD systems using limestone as the reactant have demonstrated the ability to achieve greater than 95% SO<sub>2</sub> reduction on coal-fired boilers firing high-sulfur bituminous coals. On boilers firing low sulfur coals (such as OG&E's), however, the high removal efficiencies would not be expected because of the reduced SO<sub>2</sub> concentration in the flue gas. Even though WFGD systems are not typically used on utility boilers firing low sulfur subbituminous coals, there are no technical limitations that would preclude its use on the Sooner and Muskogee units.

While the May 2008 BART Evaluations identified WFGD technology as a technically feasible SO<sub>2</sub> control option capable of achieving a higher SO<sub>2</sub> reduction, WFGD was determined to result in higher costs compared to DFGD. As ODEQ recognized in its SIP, WFGD systems have higher capital costs, require more energy to operate, and higher annual operating costs, resulting in significantly higher annual costs. The May 2008 BART Evaluations identified incremental WFGD cost effectiveness values of \$13,281/ton for the Muskogee units, and \$18,255/ton for the Sooner units. The incremental WFGD cost effectiveness levels are significantly higher than the cost effectiveness values for DFGD systems. Therefore, WFGD is not a cost effective control option for the OG&E units.

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<sup>127</sup> See, 76 FR 16184, col 2.

<sup>128</sup> See, <http://camddataandmaps.epa.gov/gdm>